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December 6, 1995

Re: Indian Point Unit No. 2
Docket No. 50-247

Document Control Desk
US Nuclear Regulatory Commission
Mail Station P1-137
Washington, DC 20555

SUBJECT: Final Response to Generic Letter 88-20, Supplement 4: Submittal of Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities

REFERENCES:
1) "Review of Response to Generic Letter 88-20, Supplement No. 4 - Individual Plant Examination for External Events - Indian Point Nuclear Generating Unit No. 2 (TAC No. M83631)", June 30 1992.
2) "Response to Generic Letter 87-02 Supplement 1 and Supplemental Response to Generic Letter 88-20 Supplement 4", *September* 21, 1992.

In response to Reference 1 above and Generic Letter 88-20 Supplement 4, enclosed is the Indian Point Unit No. 2 Individual Plant Examination for External Events (IPEEE) on a schedule consistent with that submitted in Reference 2.

This evaluation again builds on the earlier external events review provided in our Indian Point Probabilistic Safety Study (IPPSS) as well as the more recent August 12, 1988 Individual Plant Examination (IPE) for Severe Accident Vulnerabilities. Consistent with these previous evaluations, this IPEEE utilizes the probabilistic risk assessment methodology and continues to provide an accurate risk profile of the Indian Point Unit 2 facility.

Should you have any questions regarding this matter, please contact Mr. Charles W. Jackson, Manager, Nuclear Safety and Licensing.

Very truly yours,

Stephen E. Quinn

Subscribed and sworn to
before me this 6th day
of December, 1995.

Karen L. Lancaster
Notary Public

KAREN L. LANCASTER
Notary Public, State of New York
No. 60-4643659
Qualified In Westchester County
Term Expires 9/30/97

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Individual Plant Examination of External Events

for

Indian Point Unit No. 2

Nuclear Generating Station

Consolidated Edison Company of New York, Inc.

NUS Corporation

EQE International

December 1995

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LIST OF ACRONYMS AND ABBREVIATIONS

ACS	Accumulator System
AFW or AFWS	Auxiliary Feedwater System
AOI	Abnormal Operating Instruction
AOV	Air Operated Valve
ARP	Alarm Response Procedure
ASME	American Society of Mechanical Engineers
ASSS	Alternate Safe Shutdown System
ATWS	Anticipated Transient Without Scram
BOP	Balance of Plant
BTP	Branch Technical Position
COL	Check Off List
COMPBRN	EPRI Fire Risk Analysis Code (COMPBRN IIIE is current version)
Con Edison	Consolidated Edison Company of New York, Incorporated.
CCS or CCW	Component Cooling Water System
CSS	Containment Spray System
CST	Condensate Storage Tank
CVCS	Chemical Volume Control System
DBD	Design Basis Document
DBE	Design Basis Earthquake

LIST OF ACRONYMS AND ABBREVIATIONS

DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System(s)
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPS	Electric Power System
EPRI	Electric Power Research Institute
EQE	EQE International
ESFAS or SAS	Emergency Safety Features Actuation System
ESW	Designated Essential Service Water Header
EVENT V	Interfacing Systems LOCA (Also see VSEQ)
FCIA	Fire Compartment Interaction Analysis
FCU	Containment Air Recirculation and Filtration System (Fan Cooler Units)
FEDB	Fire Events Database
FIVE	Fire Induced Vulnerability Evaluation Methodology (EPRI)
FLDS	Internal Flood Plant Damage State
FPPP	IP2 Fire Protection Program Plan
FPS	Fire Protection System
FRSS	Fire Risk Scoping Study (Sandia)
FSAR	Final Safety Analysis Report (See UFSAR)

LIST OF ACRONYMS AND ABBREVIATIONS

GI	Generic Issue
GIP	Generic Implementation Procedure
GSI	Generic Safety Issue
GT	Gas Turbine
HCLPF	High Confidence of Low Probability of Failure
HEP	Human Error Probability
HPIS	High Pressure Injection System
HRA	Human Reliability Analysis
HRR	Heat Release Rate
HVAC	Heating, Ventilation and Air Conditioning System
IACCW	Instrument Air Closed Cooling Water 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
IPEEE	Individual Plant Examination of External Events
IPPSS	Indian Point Probabilistic Safety Study, including Amendments 1 and 2
LER	Licensee Event Report

LIST OF ACRONYMS AND ABBREVIATIONS

LLNL	Lawrence Livermore National Laboratory
LLOCA	Large Break Loss of Coolant Accident
LPIS	Low Pressure Injection System
LOCA	Loss of Coolant Accident
LOSP	Loss of Offsite Power
MAAP	Modular Accident Analysis Program
MCC	Motor Control Center
MG	Motor Generator
MOV	Motor Operated Valve
MSIVC	Closure of Main Steam Isolation Valve(s)
MSF	Main Steam Function
NESW	Designated Non-essential Service Water Header
NRC	Nuclear Regulatory Commission (See USNRC)
NSSS	Nuclear Steam Supply System
NUS	NUS Corporation
PDS	Plant Damage State
PGA	Peak Ground Acceleration
P&ID	Piping and Instrumentation Diagram
PLG	RISKMAN Developers (Formerly Pickard, Lowe and Garrick Inc.)

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LIST OF ACRONYMS AND ABBREVIATIONS

PMP	Probable Maximum Precipitation
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
PWST	Primary Water Storage Tank
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RISKMAN	PC based risk management software, developed by PLG
RPS	Reactor Protection System
RHR	Residual Heat Removal
RSS	Recirculation System
RXTRIP	Reactor Trip
RWST	Refueling Water Storage Tank
SAMG	Severe Accident Management Guidelines
SAO	Station Administrative Order
SDS	Seismic Damage State
SEL	Seismic Equipment List
SEWS	Seismic Evaluation Worksheets
SG	Steam Generator

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LIST OF ACRONYMS AND ABBREVIATIONS

SGTR	Steam Generator Tube Rupture
SIS	Safety Injection System
SLOCA	Small Break Loss of Coolant Accident
SOP	System Operating Procedure
SOR	Significant Occurrence Report
SQUG	Seismic Qualification Utility Group
SRP	Standard Review Plan
SSE	Safe Shutdown Earthquake
SSEL	Safe Shutdown Equipment List
SWS	Service Water System
TTRIP	Turbine Trip
UE&C	United Engineers and Constructors Corporation
UFSAR	Updated Final Safety Analysis Report for IP2
UHS	Uniform Hazard Spectrum
USI	Unresolved Safety Issue
USNRC	United States Nuclear Regulatory Commission
VCT	Volume Control Tank
VENT	EDG Building Ventilation System
VSEQ	Interfacing Systems LOCA (Event V)

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LIST OF ACRONYMS AND ABBREVIATIONS

WASH 1400	**Reactor Safety Study, USNRC 1978**
WDS	**Wind Initiated Plant Damage State**
WOG	**Westinghouse Owners Group**

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EXECUTIVE SUMMARY

1.1 BACKGROUND AND OBJECTIVES

This document reports the results of the Individual Plant Examination of External Events (IPEEE) of the Indian Point Nuclear Generating Station Unit No 2. This examination has been performed by the Consolidated Edison Company of New York (Con Edison) in response to Generic Letter 88-20, Supplement 4 (Reference 1-1) and the associated submittal guidance (NUREG-1407, Reference 1-2).

Indian Point Unit No.2 was the subject of a detailed, comprehensive risk assessment, the Indian Point Probabilistic Safety Study (IPPSS, Reference 1-3), which was initially 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 and adjucatory hearing 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.

In August, 1992, Con Edison submitted the results of an Individual Plant Examination (IPE, Reference 1-4) performed using probabilistic risk assessment which addressed the impact of internal initiating events. That effort incorporated model improvements, provided a more extensive evaluation of potential initiators, updated the Human Reliability Analysis and common cause treatments, and accounted for additional plant changes and equipment performance information since the 1989 update up through and including the 1991 refueling outage. This IPEEE effort builds upon all of the efforts described above.

The objectives of an Individual Plant Examination for External Events (IPEEE) as described in Generic Letter 88-20, Supplement 4 are similar to those of the IPE. As stated in Supplement 4, the general purpose of the IPEEE is 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 under full power operating conditions,

(3) to gain a qualitative understanding of the overall likelihood of core damage and radioactive material release, and

(4) if necessary, to reduce the overall likelihood of core damage and radioactive material releases by modifying hardware and procedures that would help prevent or mitigate severe accidents.

The secondary, but no less important objectives of both the the IPE and this 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 IPEEE in accordance with the requirements of the reporting guidelines in NUREG-1407.

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 overall 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 Indian Point Unit No.2 IPEEE project team included two permanent Con Edison members, located at the Indian Point Unit No.2 (IP2) site and having direct, continuing access to plant facilities, equipment, procedures and staff. Those two members alone have a combined total of more than 30 years of IP2 plant specific experience. Other utility staff, with extensive nuclear and IP2 specific experience, also participated substantially in this effort. The remainder of the IPEEE team was made up of engineers from the NUS Corporation and EQE International. The majority of those project members had participated in IP2 specific PRA and Engineering efforts prior to performance of the IPEEE, including personnel who had been major contributors to both the original IPPSS external event analyses and to the IP2 IPE. The onsite NUS project manager had extensive prior experience working at the IP2 site. The IPEEE team of Con Edison, NUS and EQE personnel, 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.

Many plant visits and walkdowns were performed in the course of the study to assess the expected plant response to all the specific events described in the Generic Letter and to search for any potentially risk significant external initiating events which might be unique to the IP2 site. The walkdowns performed are described in further detail in the sections dealing with each event. The seismic walkdown was closely coordinated with the walkdown performed in response to USI A-46 (Generic Letter 87-02, Reference 1-5).

In addition, numerous equipment inspections and discussions with plant operations personnel, systems engineers, operations support and training personnel were held throughout the effort. Extensive use was also made of the detailed walkdown which had been performed by the cable separartion project team in order to validate the as-built plant design.

1.3 OVERALL METHODOLOGY

The Indian Point Unit No.2 IPEEE utilized a probabilistic risk assessment approach to address those external events whose impact could not be screened out using the guidance provided in NUREG-1407. Those events included seismic events, high winds and internal fires. For internal fires, an initial analysis was performed using the Fire-Induced Vulnerability Evaluation (FIVE) process (Reference 1-6) to identify potentially risk significant fire events and focus the detailed analysis in those areas. The formal screening approach provided in NUREG-1407 was used for other external events. Although the licensing of Indian Point Unit No.2 predates the 1975 Standard Review Plan, a number of events were able to be evaluated through application of the progressive screening criteria. Based on this approach, only high winds required propagation of a full probabilistic risk assessment through the plant model. A full probabilistic risk assessment was also performed to address internal flooding events. Treatment of internal flooding events as part of this effort rather than in the IPE was requested and approved at the time of the initial IPE response.

The Indian Point Unit No. 2 IPEEE builds upon the applicable portions of the IPPSS using a PRA approach to address those externally initiated events which require detailed analysis. Although the overall methodology of the IPPSS is largely retained, the IPEEE reflects updates in hazard treatment and provides a thorough treatment of the combination of hazard induced and random failures.

Since quantification of those external events requiring a more detailed analysis involved incorporating the damage associated with each hazard to the previously developed internal plant model, the analysis of results was performed by examining the the results of that linking and searching for unique or previously unaccounted for impacts on mitigating system functions. The evaluation of the internal plant model utilized the process provided in NUMARC 91-04 (Reference 1-7) to categorize the systemic results obtained into functional sequences, quantify their relative significance and establish an appropriate focus and hierarchy for their consideration. By examining the results of this study relative to the results review performed for the IPE we are able to derive the benefit of that structured approach despite the need to address a spectrum of somewhat disparate events. In addition, the potential for such events to impact the ability to prevent early failure of the containment function was examined and various importance analyses and sensitivity studies were performed.

Finally, the IPEEE includes a specific evaluation of the decay heat removal (DHR) function within the framework of the plant model, thus allowing resolution of Unresolved Safety Issue A-45 for external events as part of this response.

1.4 SUMMARY OF MAJOR FINDINGS

Although a single overall approach is embodied in NUREG-1407 and used in this IPEEE, the degree to which that approach involved quantification varied by initiating event. The results for each event (or class of events) is therefore best given in the context of the detailed discussion of that event provided in subsequent sections of this report.

Since the original IPPSS also addressed the risk of external initiating events at Indian Point Unit 2, a brief comparison of the current results to the IPPSS results provides perspective. In general, for those events which were quantified in the IPPSS, the current results are consistent, with some differences in the specific scenarios which contribute to the result. The total calculated core damage frequency reported in Amendment 2 of the IPPSS, for seismic initiating events was 7.7 E-6 per year. The seismic core damage frequency found in this study was 1.46 E-5 per year, which was reduced to 1.1 E-5 per year following a modification (which has been completed) to the Component Cooling Surge Tank anchorage. The loss of the control building facilities (i.e. Central Control Room, Emergency Switchgear, etc.) through direct or indirect loss of the structure was the most significant contributor in both studies. Although some differences exist in the modelling, the major reason for the increase in frequency appears to relate to the use of the seismic hazard curves specified for this examination (Lawrence Livermore National Laboratory / EPRI) which are higher than those used in the original IPPSS analysis. In addition, changes in fragility estimates resulted from the different spectra required to be used for this study.

With respect to internal fires, the total core damage frequency reported in Amendment 2 of the IPPSS was 1.4 E-5 per year. The core damage frequency associated with internal fires in this study was 1.8 E-5 per year. This is a consistent result considering not only the changes in methodology and fire modelling which have occurred since the performance of the IPPSS, but more importantly the substantially more detailed effort undertaken in the IPEEE to identify cable routing and locations. The areas requiring detailed modelling and analysis were essentially the same for the two studies, although the IPEEE identified and evaluated additional fire scenarios associated with a central control room fire.

The core damage frequency associated with wind related initiating events in the IPPSS was 3.6 E-5 per year. The core damage frequency associated with wind related initiating events in the IPEEE was 3.0 E-5 per year. In both studies, the dominant scenarios involved loss of both normal and emergency power due to degradation or destruction of the structures housing the electrical supply equipment.

As mentioned above, internal flooding was also addressed in this study and was determined to have an overall core damage frequency of 6.7 E-6 per year. The scenarios quantified in this study included those addressed in the IPPSS as well as several additional scenarios developed through the more rigorous approach adopted for this study. Since the IPPSS internal flooding study was only semi-quantitative, a direct comparison is not feasible.

The evaluation of other external events incorporated updated information in a number of areas. The results and conclusions, however, are consistent with those found in the IPPSS.

As a general finding, although no vulnerabilities were discovered during this examination, several opportunities for improvement were identified which are being incorporated or evaluated. Those improvements are discussed in Section 8. It should be noted that due to the difficulty in assessing the degree of damage associated with structural failures, it was often necessary to make conservative assumptions regarding the effect of structural failures on the equipment housed in those structures and the adjacent structures that they may impact.

1.5 REFERENCES FOR SECTION 1

1-1 Generic Letter 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - 10CFR50.54(f)", United States Nuclear Regulatory Commission, June 28, 1991.

1-2 NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities", United States Nuclear Regulatory Commission, June, 1991.

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

1-4 "Individual Plant Examination for Indian Point Unit No. 2 Nuclear Generating Station", Consolidated Edison Company of New York, Inc., August, 1992.

1-5 Generic Letter 87-02, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46", United States Nuclear Regulatory Commission, February, 19, 1987.

1-6 EPRI TR-100370, "Fire-Induced Vulnerability Evaluation (FIVE)", Electric Power Research Institute, April 1992.

1-7 NUMARC 91-04, "Severe Accident Issue Closure Guidelines", Nuclear Energy Institute, January, 1992.

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.

In August, 1992, Con Edison submitted the results of an Individual Plant Examination (IPE, Reference 2-1) performed using probabilistic risk assessment which addressed the impact of internal initiating events. That effort incorporated model improvements, provided a more extensive evaluation of potential initiators, updated the Human Reliability Analysis and common cause treatments, and accounted for additional plant changes and equipment performance information since the 1989 update up through and including the 1991 refueling outage.

The current Individual Plant Examination of External Events (IPEEE) builds upon all of the above efforts. The IPPSS and IPE contain 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 IPEEE is an outgrowth of the IPPSS and uses the plant model developed in the IPE, the IPEEE report will not attempt to duplicate information already available in the IPPSS and IPE 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 4.

2.2 CONFORMANCE WITH GENERIC LETTER AND SUPPORTING MATERIAL

The objectives of an Individual Plant Examination of External Events (IPEEE) as described in Generic Letter 88-20, Supplement 4 are similar to those of the IPE. As stated in Supplement 4, the general purpose of the IPEEE is 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 under full power operating conditions,

(3) to gain a qualitative understanding of the overall likelihood of core damage and radioactive material release, and

(4) if necessary, to reduce the overall likelihood of core damage and radioactive material releases by modifying hardware and procedures that would help prevent or mitigate severe accidents.

The secondary, but no less important objectives of both the the IPE and this study were:

(1) to expand the inhouse PSA 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 IPEEE in accordance with the requirements of the reporting guidelines in NUREG-1407.

The current IPEEE effort incorporates changes to the IPPSS treatment of hazards based upon more current understanding, addresses a wider scope of potential initiators, and generally provides a more detailed analysis of the major classes of events. In doing so, however, it was recogninized that in many areas the work performed for the IPSSS is still applicable and technically robust. In those areas, the IPPSS results were retained and utilized. The IPEEE effort also included far more detailed walkdowns than the original IPPSS.

Con Edison believes that the effort described in this report represents an IPEEE which satisfies the request for additional information contained in Generic Letter 88-20, Supplement 4, consistent with our initial response, dated 12/24/91 (Reference 2-2). Con Edison further 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 IPE and the current IPEEE efforts, has provided us with the desired appreciation and understanding of the Indian Point Unit No. 2 risk profile such that the objective of Generic Letter 88-20 is also met.

To derive maximum benefit from the overall IPEEE/PRA process, the project was designed as a joint Con Edison/NUS/EQE effort and utility personnel were involved, to varying extents, in all aspects of the effort. The utility IPE team included members of both the onsite organization and engineering disciplines appropriate to each hazard addressed. The principal utility participants brought to the effort in depth systems knowledge and engineering expertise as well as extensive direct experience in plant operations, safety analyses and licensing requirements. The onsite 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. Much of the work on the project was performed at, or near the plant site.

Several provisions were incorporated into the effort to ensure the technical adequacy and validity of the work performed under the IPEEE. 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 a second level of review by personnel other than those performing the task.

In addition, two independent reviews were included in the project scope. An independent review was performed by an in-house review team. This effort drew upon experienced personnel, separate from the project team, possessing extensive plant specific experience in operations, engineering, safety and risk analysis. This review team was provided with project and task plans, analysis files and other work products. Review meetings were held with this in-house review team during which methodology, analysis and results were discussed for all of the events within the scope of this examination. An additional review of work products was performed by a team of industry recognized outside experts. A description of both of these independent reviews and the results are provided in Section 7. Plant walkdowns constituted an additional means for assuring the validity of the analyses. Walkdowns were an integral part of the effort and were also performed as part of the outside expert review.

All comments received as a result of the above reviews have been addressed and retained within the appropriate analysis files. Sensitivity studies were performed where it was believed that such studies could provide additional insights.

2.3 GENERAL METHODOLOGY

The Indian Point Unit No.2 IPEEE utilized a probabilistic risk assessment approach to address those external events whose impact could not be screened out using the guidance provided in NUREG-1407. A full probabilistic risk assessment was also performed to address internal flooding events. Treatment of internal flooding events as part of this effort rather than in the IPE was requested and approved at the time of the initial IPE response. The following discussion provides an overview description of the methodology employed in the IPEEE for each event:

2.3.1 Seismic Events

The seismic portion of the IPEEE utilized the probabilistic risk assessment approach by propagating the impact of seismic events through a modified plant model. The updated Lawrence Livermore National Laboratory mean seismic hazard curve for Indian Point was used as input for the magnitude and frequency of the seismic events. The seismic fragilities of structures and equipment were developed by a combination of specific calculations and use of generic fragilities for equipment which met a screening criteria for seismic ruggedness. The convolution of the hazard curves and the seismic fragilities provided a spectrum of seismic plant damage states which were then treated as "initiating events". These "initiating events" were then propagated through the plant model which was modified to reflect the seismic induced equipment failures associated with each damage state. This allowed seismic induced failures to be combined with random failures. Consistent with our proposed approach for relay chatter, the relays associated with IPEEE equipment were addressed by combining a search for "low seismic ruggedness relays" and selected chatter impact analyses with the full relay effort being conducted to satisfy Generic Letter 87-02.

2.3.2 Internal Fires

The internal fire portion of the IPEEE utilized a detailed probabilistic risk assessment approach to examine all fire scenarios which were determined to be potentially risk significant based on a progressive screening approach. The screening was performed consistent with the process provided by the EPRI Fire-Induced Vulnerability Evaluation (FIVE) methodology. The impact on plant equipment was calculated for each non-screened fire scenario. Each such scenario was then treated a separate "initiating event" and propagated through the plant model which was modified to reflect the fire induced equipment failures associated with each scenario. This allowed fire induced failures to be combined with random failures.

2.3.3 Other External Events

An initial review was made of the spectrum of external events delineated in PRA Procedures Guide to confirm that none of the events screened out on an industrywide basis represented unique hazards at the Indian Point 2 site. The methodology provided in Section 5 of NUREG-1407 was then used to address high winds, floods and transportation and nearby facility accidents. Of these events, only high winds required performance of a detailed probabilistic risk assessment.

The analysis of wind risk was similar to the seismic process. The wind analysis utilized the probabilistic risk assessment approach by propagating the impact of hurricanes, tornadoes and extratropical storms through a modified plant model. Amendment 2 of the Indian Point Probabilistic Safety Study (IPPSS) provided a detailed analysis of wind hazards for the Indian Point site. Following confirmation of its continued validity by review of the analysis, a site walkdown and examination of recent meteorological data, this hazard analysis was used as input for the magnitude and frequency of the wind events. The capabilities of plant structures and equipment to resist wind forces, which were developed during performance of the IPPSS, were reviewed and, where appropriate, updated based on plant changes and/or new information. The convolution of the hazard curves and the wind fragilities provided a spectrum of wind plant damage states which were then treated as "initiating events". These "initiating events" were then propagated through the plant model which was modified to reflect the wind induced structural and equipment failures associated with each damage state. This allowed wind induced failures to be combined with random failures.

2.3.4 Internal Flooding

As discussed in our IPE response and report, the impact of internal flooding events is being addressed in our IPEEE analysis. The internal flooding examination utilized a detailed probabilistic risk assessment approach to examine all flooding scenarios which were determined to be potentially risk significant based on a progressive screening process. The initial screening used very conservative assumptions regarding the impact of potential floods to identify flooding sources which were potentially risk significant. Those sources were then examined in greater detail to determine flood source frequencies and magnitudes (i.e. specific location and configuration, maximum flow rates, egress paths, etc.).

The impact on plant equipment was also calculated for each non-screened flooding scenario by examining critical flood heights, compartment volumes and ingress/egress paths. The analysis of flood sources and effects were then combined to provide flood damage states. Each such damage state was then treated a separate "initiating event" and propagated through the plant model which was modified to reflect the flood induced equipment failures associated with each flooding scenario. This allowed flood induced failures to be combined with random failures.

2.4 INFORMATION ASSEMBLY

2.4.1 Plant Layout and Containment Building Information

Indian Point Station Unit No. 2 (IP2) 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 IP2 UFSAR and system descriptions. The information in the IPSSS is supplemented, and where applicable, updated in Section 3 of the IP2 IPE report.
A summary of the major design features at Indian Point Unit No. 2 is provided in Table 2.4-1.

2.4.2 Plant Documentation Used and Confirmation of Currency

The identification and assembly of required information was a primary task in performing this assessment. Since a substantial effort was undertaken to assemble the necessary information in performing the original Indian Point Probabilistic Safety Study (IPPSS), the additional effort required for this examination was, therefore, to assemble the information needed to:

1) determine the need, and provide the data to update, and where appropriate, expand the original hazard analyses,

2) provide additional traceability, where required,

3) confirm or revise the previously determined capability of the plant structures and equipment to withstand the impact of the hazards involved,

4) identify any modifications to the original plant modelling required to address these events, or due to changes to plant equipment or procedures that have occurred since performance of the IPE.

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

The major sources of information used to develop the plant model, through which the impact of each hazard requiring a detailed analysis was propagated, are described in the Indian Point Unit 2 IPE submittal and include the plant licensing basis documents such as the UFSAR, Technical Specifications, 10CFR50.59 reports, and supporting documents such as System Descriptions, Emergency Operating Procedures, equipment manuals, etc. Many of these documents provided additional information useful to the IPEEE effort. Central to the IPEEE information gathering process, however, was the information and knowledge gained from the walkdowns performed for each portion of the IPEEE. Additional sources of information used in the IPEEE are described in the individual sections and include:

General: General Arrangement Drawings
Station Administrative Orders
Licensing Correspondence
IPPSS Analyses

Seismic:	NUREG-1488 (Revised LLNL Site Specific Seismic Hazard Estimates) EPRI NP-6395 (Site Specific Probabilistic Seismic Hazard Estimates) Detailed Structural Drawings Equipment Anchorage Drawings Indian Point Unit 2 Operating Equipment Database USI-A46 Equipment Anchorage Calculations Plant Specific Cable Tray Fragility Tests
Fire:	IP2 Fire Protection Program Plan Appendix R Submittals Electrical One Line and Detailed Wiring Diagrams Cable Routing Information Available Fire Brigade Response Information
Winds:	Detailed Structural Drawings Site Topography Maps Onsite and Local Climatological Data
Internal Flooding:	Structural and Piping Drawings Detailed Building Drainage Drawings
Other Events:	Site Topography Maps Site Drainage Drawings Indian Point Unit 2 Toxic Chemical Impact Study Army Corps of Engineers Waterborne Commerce Report Airline Routing Information

For those systems modelled in the IPE, a review of hardware and procedural changes was performed as part of that effort. Only plant changes since the cutoff date for that analysis (i.e. the 1991 refueling outage) needed to be further accounted for. The same process used for the IPE was performed for the IPEEE. This effort entailed a review of system drawings and current procedures as well as the 10CFR 50.59(b) reports for that period which describe the plant changes implemented during that period. Technical specifications and other licensing submittals were also reviewed. For the other detailed analyses (i.e. seismic, fire, wind and flooding) current structural and arrangement drawings were used to determine fragilities or confirm the continued applicability of previously determined fragilities. For the fire analysis, use was made of an extensive ongoing verification effort related to cable separation together with a specific review of current cable routing information.

2.4.3 Coordination of Activities

The IP2 IPEEE was performed as an integrated team effort with significant interface and discussion between the individuals performing the tasks associated with the various external events. The task plans for each portion of the examination were specifically reviewed to assure that they addressed issues of interaction. A listing of potential fire and flood sources was generated so that the engineers performing the seismic walkdown could search for interaction issues with the potential for jeopardizing the integrity of those sources.

2.5 REFERENCES FOR SECTION 2

2-1 "Individual Plant Examination for Indian Point Unit No. 2 Nuclear Generating Station", Consolidated Edison Company of New York, Inc., August, 1992.

2-2 Letter dated December 24, 1991, from S Bram (Con Edison) to Document Control Desk (USNRC), Response to NRC Generic Letter 88-20, Supplement 4 (180-day Response)

Table 2.4-1

Major Design Features

FUNCTION	DESIGN FEATURES	LOCATION	
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***	**Primary Auxiliary Building**	**(PAB)**
Emergency Core Cooling - Intermediate Pressure	**Four Accumulators**	**Containment Building**	**(VC)**
Emergency Core Cooling - Low Pressure	**Two RHR Pumps for Low Pressure Injection. Two Recirculation Pumps Low Pressure Recirculation with backup capability from the RHR Pumps.**	**RHR Pumps: Recirculation Pumps:**	**PAB VC**
Containment Pressure Protection	**Two Containment Spray Pumps (with spray additive) and Five Fan Cooler Units**	**Containment Spray Pumps: Fan Coolers:**	**PAB VC**
Primary Side Decay Heat Removal	**Two RHR Pumps Through two Heat Exchangers**	**RHR Pumps: RHR Heat Exchangers:**	**PAB VC**

Table 2.4-1
(continued)
Major Design Features

FUNCTION	DESIGN FEATURES	LOCATION	
Secondary Side Decay Heat Removal	Four Steam Generators supplied from two motor driven Auxiliary Feedwater Pumps (each feeding two SteamGenerators) and one Turbine Driven Pump (feeding all four Steam Generators)	Steam Generators: Auxiliary FW Pumps:	VC Auxiliary Bldg
Emergency AC Power	Three Emergency Diesel Generators feeding the four 480V Buses which feed safeguards equipment. Three Gas Turbine Generators (with blackstart capability) available for AC Power Recovery on loss of normal and emergency AC power	Emergency Diesels: 480V Buses: Gas Turbine 1: Gas Turbines 2 & 3:	EDG Building Control Building GT1 Bldg (15' Elev) Offsite
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	DC Buses: Batteries Battery Chargers	Control Bldg " "

SEISMIC ANALYSIS

This section provides a description of the methodology used to perform the seismic analysis for Indian Point 2, and a synopsis of the significant results for each portion of the analysis. The seismic analysis fulfills the objectives of the IPEEE, and provides a systematic examination to identify any plant-specific vulnerabilities to severe accidents initiated by seismic events. The organization of this section is:

The following table provides a cross-reference between the NUREG-1407 (Reference 3-1) Standard Table of Contents and this submittal:

NUREG-1407	Indian Point 2 Submittal
3.0 Methodology Selection	3.0
3.1 Seismic PRA	3.1
3.1.1 Hazard Analysis	3.1.1
3.1.2 Review of Plant Information and Walkdown	3.1.2 (Plant Information)
	3.1.3 (Walkdowns)
3.1.3 Analysis of Plant System and Structure Response	3.1.4
3.1.4 Evaluation of Component Fragilities and Failure Modes	3.1.5
3.1.5 Analysis of Plant Systems, Sequences	3.1.6
3.1.6 Analysis of Containment Performance	3.1.7
3.2 USI A-45, GI-131, and Other Seismic Safety Issues	3.2

The next section describes the overall methodology used for the seismic analysis.

3.0 METHODOLOGY SELECTION

In conformance with NRC Generic Letter 88-20, Supplement 4, and NUREG-1407, the seismic analysis for Indian Point 2 used the NRC-approved seismic PRA approach. The overall process is depicted in Figure 3.0-1, and the major steps are briefly described below.

Hazard Analysis

Site-specific seismic hazard analyses pertaining to the Indian Point facility have been performed by both EPRI and LLNL (References 3-2 and 3-3). For each study, the overall result is a description of the annual frequency of exceedence of various ground motion levels (accelerations) at Indian Point, and the associated uncertainty. The study considered multiple interpretations about the causes and physical characteristics of potentially active seismic sources in order to characterize seismic hazard uncertainty. Similarly, uncertainties in the ground motion attenuation equations were propagated through the hazard analysis. The result was a suite of hazard curves, and their associated weights, which represent the seismic hazard at the site, and the associated uncertainty. These hazard curves were then combined to determine the mean hazard curve, which was used for the baseline analysis, as permitted by NUREG-1407. While the LLNL mean hazard curve was used for the baseline, the EPRI hazard curve has essentially the same values. Section 3.1.1 provides more detail on the hazard curves.

Plant Information and Selection of Systems and Equipment

A comprehensive approach was used to identify systems and equipment that can provide safe shutdown of the reactor, and maintain a safe stable state after a beyond design basis earthquake. A seismic equipment list (SEL) was developed which includes the plant systems and components providing "level 1" safety functions to prevent core damage, as well as the structures, equipment, and actuation components necessary for the "level 2" functions of containment integrity, containment pressure suppression, containment heat removal, containment radioactivity removal, and containment isolation.

A plant-specific approach was followed which used the internal events IPE as the initial basis for the identification of the appropriate safety functions and systems, and the required equipment. However, several additional steps were used to identify equipment which was not in the IPE, but which would be important during and after an earthquake. For example, some components such as heat exchangers and filters were added to the SEL in order to maintain piping system boundary integrity and prevent flow diversion. Other components not explicitly in the IPE but added to the SEL are items such as electrical panels and cabinets which house SEL items. The relevant emergency operating procedures were reviewed and discussed with the training staff to verify that equipment and instrumentation used in the procedures, and considered critical to safe shutdown, was included in the SEL. Particular attention was placed on equipment important to containment performance, including the potential for interfacing systems LOCA, containment bypass, and containment isolation and actuation. A special effort was made to include equipment which could cause seismic-induced fires or floods, or releases of toxic or flammable gases.

This SEL was also compared with the A-46 program SSEL (safe shutdown equipment list), and the two lists were merged for walkdowns.

The overall result of this task was the seismic equipment list (SEL), which was used to guide the seismic capacity walkdowns, and for development of the IPEEE relay list.

Walkdowns

One of the most important tasks in the seismic PRA was the systematic walkdown of components on the SEL. The purpose was to identify equipment vulnerabilities in either the component load path or anchorage, potential seismic failure/falling and proximity interactions, and potential flooding or fluid spray interactions. The walkdowns were performed by teams of experienced seismic capability engineers, using the A-46 GIP and EPRI NP-6041 (References 3-4 and 3-5) procedures and worksheets. Extensive documentation was taken and incorporated into a seismic walkdown database. Based on these walkdowns, and associated seismic qualification and anchorage calculations, many of the SEL items could be screened at this stage as having high seismic capacity. Items which could not be screened required calculations of seismic fragility.

Analysis of Plant System and Structural Response

To calculate the seismic demand which could be placed on structures and components from a beyond-design-basis earthquake, estimates of structural response to seismic events were scaled from the new DBE spectra developed for the A-46 program. Since a PRA approach is utilized for the IPEEE, a structural response factor of safety was developed by comparison of the spectral accelerations for the DBE A-46 spectra and damping to the uniform hazard spectrum (UHS) and median centered damping used for the IPEEE. This factor and its variability were then used to scale design loads and spectra, and to define the uncertainty in these loads and spectra.

The two main results were the estimated median structure forces and the variability about the median for all structures of interest, and the probabilistic floor response spectra in these structures. These were then used for the structure fragility analysis and the equipment fragility analysis.

Evaluation of Fragilities and Failure Modes

For those structures and components that were not screened out based on the seismic capacity walkdowns, progressively more detailed calculations were performed to estimate the seismic capacity of each component. In essence, the factors of safety, conservatisms, and overdesign that are common in the seismic design, analysis, construction, and installation of structures and components are estimated, and a realistic estimate of the ability of a structure or component to withstand an earthquake is calculated. This capacity is expressed in the form of a family of fragility curves, with parameters for the median capacity, and the random and modeling uncertainties. This provides a realistic estimate of the probability of failure of the component (or structure) at each level of ground acceleration.

For structures, existing calculations performed for the IPPSS were updated to reflect the use of the uniform hazard spectral shape for defining the ground motion, and to incorporate refinements in methodology since the IPPSS. For equipment, a combination of updated IPPSS calculations, generic calculations, and extrapolations of A-46 calculations was used to determine equipment fragilities.

Analysis of Plant Systems and Sequences

The analysis of plant systems and potential accident sequences was similar to the internal events IPE, and used many of the same models and data. The primary model difference is that a seismic event tree was developed to delineate the potential combinations of seismic-induced failures, and resulting seismic scenarios, which were termed "seismic damage states." Traditional event tree techniques were used to identify each of the top seismic-induced events, and to formulate the nodal branching logic. The frequencies of these seismic damage states were quantified by convolving the Indian Point site-specific mean earthquake hazard curve with the structure and equipment seismic fragility curves. This quantification included dependent and correlated failures, and appropriate success states. For those scenarios that required additional non-seismic failures or human errors to occur to result in core damage, the IPE internal events model (event trees and system logic equations) was used to develop conditional core damage probabilities, with appropriate changes given the seismic damage state. These calculations incorporate random failures of equipment and operator actions. The overall frequency of seismic-induced core damage is then quantified from these intermediate results by adding up the individual scenarios.

The results are expressed in terms of dominant seismic sequences and dominant contributors. Sensitivity studies were performed for certain key issues, and a qualitative uncertainty analysis was performed including the uncertainties from the hazard curve and the fragilities.

Containment Performance

A number of containment performance related structures, systems, and components were evaluated to determine any unique containment performance issues, particularly with respect to the potential for containment bypass or early, large releases to the environment. The methodology included walkdowns of equipment such as penetrations and associated valves and piping, and the containment isolation actuation system. Potential impacts of the seismic damage states and dominant sequences on containment integrity, containment isolation, containment bypass, and containment heat removal/pressure suppression were addressed.

Relay Chatter Evaluation

As proposed for the Indian Point 2 IPEEE, Con Ed has performed a low ruggedness relay review for those relays that are associated with IPEEE-only equipment (that is, not on the A-46 SSEL). For a limited number of secondary circuit relays we have performed a relay chatter impact evaluation. The rest of the IPEEE equipment is included on the A-46 list, and was therefore included in the A-46 relay evaluation. A comprehensive list of relays associated with the control, actuation, and instrumentation of the A-46 equipment was generated as part of that program, and used for the relay chatter and seismic capacity evaluation performed to address the A-46 issue. Identification of the relays associated with the IPEEE equipment was done separately using as the basis those components and functions included in the plant model developed for the IPE. Relay mounting and model verification spot-checks, in accordance with EPRI NP-7148 (Reference 3-6), were performed during the equipment and cabinet walkdowns.

USI A-45, GI-131, and Other Seismic Safety Issues

In accordance with the IPEEE request, USI A-45 Decay Heat Removal, GI-131 In-Core Flux Mapping Seismic Interaction, seismic-induced fire and flood interactions, and other seismic safety issues were specifically identified and discussed.

A summary section is provided to list any potential plant-specific vulnerabilities, and document the status of planned plant modifications. The following subsections provide more detail on the methods used, and the results and insights.

3.1 SEISMIC PRA

3.1.1 Seismic Hazard Analysis

The seismic hazard defines the probability that specified levels of ground motion will be exceeded at the plant site in a given period of time, generally one year. Site-specific seismic hazard analyses pertaining to the Indian Point facility have been performed by both EPRI and LLNL (References 3-2 and 3-3). For each study, the overall result is a description of the annual frequency of exceedence of various ground motion levels (accelerations) at Indian Point, and the associated uncertainty. The studies considered multiple interpretations about the causes and physical characteristics of potentially active seismic sources in order to characterize seismic hazard uncertainty. Similarly, uncertainties in the ground motion attenuation equations were propagated through the hazard analysis. The results for each study were a suite of hazard curves, and their associated weights, which represent the seismic hazard at the site, and the associated uncertainty. These hazard curves were then combined to determine the mean hazard curve, which was used for the baseline analysis, as permitted by NUREG-1407.

The seismic hazard information used for the baseline analysis was developed from the LLNL revised hazard estimates, documented in NUREG-1488. The hazard acceleration and frequency information is:

Acceleration (g)	Cumulative Frequency of Exceedance (per year) Mean	15%	Median	85%
0.05	1.15E-3	2.32E-04	7.65E-04	2.17E-03
0.075	6.55E-4	1.20E-04	4.17E-04	1.21E-03
0.15	2.12E-4	2.93E-05	1.20E-04	4.00E-04
0.25	7.74E-5	8.20E-06	3.63E-05	1.47E-04
0.3	5.15E-5	4.85E-06	2.26E-05	9.72E-05
0.4	2.56E-5	1.81E-06	9.67E-06	4.91E-05
0.5	1.42E-5	7.34E-07	4.77E-06	2.64E-05
0.65	6.74E-6	2.22E-07	1.97E-06	1.21E-05
0.8	3.58E-6	7.78E-08	8.75E-07	6.09E-06
1.0	1.75E-6	2.23E-08	3.33E-07	2.97E-06

For comparison, the EPRI seismic hazard information is presented in the following table, which presents the basic parameters (the acceleration values in Gs and the mean frequency of exceedance per year) of both the LLNL and EPRI curves. The spaces with a "--" result from the different points used by LLNL and EPRI to describe the respective hazard curves. As can be seen, there is very little difference between the curves over the complete range of accelerations presented.

Acceleration (g)	LLNL	EPRI
0.005	--	1.10E-02
0.05	1.15E-3	1.40E-03
0.075	6.55E-4	--
0.1	--	5.00E-04
0.15	2.12E-4	--
0.25	7.74E-5	8.30E-05
0.3	5.15E-5	--
0.4	2.56E-5	--
0.5	1.42E-5	1.40E-05
0.65	6.74E-6	--
0.7	--	5.00E-06
0.8	3.58E-6	--
1.0	1.75E-6	1.50E-06

A sensitivity study was performed to determine the impact of using the EPRI hazard rather than the baseline LLNL hazard. The results showed that there was about a 10% reduction in overall core damage frequency using the EPRI hazard curve. There was no qualitative change in the dominant sequences or seismic failure modes.

NUREG-1407 also requests a rationale if the hazard curve is truncated before 1.5g. This study used the explicit data from the LLNL hazard curves, which only extends to 1.0g as shown above. Quantitatively, the maximum increase in core damage frequency from extrapolating the hazard curve beyond 1.0g would be only 1.75E-6 per year (which is the exceedance frequency of the 1.0g acceleration). This is relatively insignificant (about 10%) compared to the overall seismic core damage frequency, and certainly within the bounds of uncertainty. A qualitative examination of the impact of truncating the hazard curve at 1.0g shows that the ranking of the dominant sequences, and their dominant contributors, remains about the same. Finally, any extension of non-linear, composite hazard curves into low frequency, high acceleration regions of the earthquake hazard would be rough estimates at best. Since there could easily be upper bounds on the magnitudes of the earthquake sources, the hazard curve may decrease very quickly. A simple extrapolation with no geotechnical basis may misrepresent the actual hazard. Based on these observations, it was determined that hazard curve extrapolation would provide no additional insights into seismic risk or potential vulnerabilities for Indian Point 2.

In addition to the LLNL mean hazard curve used for the seismic PRA baseline, the LLNL and EPRI studies also provided ground response spectra with a mean return period of 10,000 years. These uniform hazard spectra (UHS) shapes are used in the evaluation of the probabilistic seismic response of structures and equipment, as described in Section 3.1.3.

3.1.2 Plant Information and Selection of Systems and Equipment

This section discusses the development and verification of the seismic equipment list (SEL) for Indian Point 2. A general description of the plant was presented in Section 1.2. The overall approach followed NRC and EPRI guidance, with the following steps:

- Utilize the IPE list of equipment as the initial basis
- Determine the potential initiating events that could occur with a seismic event, either due to the earthquake, or as random or consequential events
- Determine which safety functions would be required to respond to these events,

and which systems provide these safety functions to mitigate the events

- Remove systems and equipment from the IPE list which are either not required or not available
- Remove generically rugged, passive components (e.g., check valves or manual valves)
- Add components for pressure boundary integrity
- Add components for containment performance
- Add electrical panels and cabinets, and instrument racks
- Review loss of offsite power emergency procedures, and add equipment and instrumentation which would be needed after an earthquake
- Add unique Indian Point 2 equipment or features
- Cross-check and verify with the A-46 equipment list
- Add structures containing the above equipment

Using the above steps, approximately 800 components were placed on the SEL for seismic walkdown. These steps are discussed in more detail below.

3.1.2.1 Development of the SEL

The objective was to develop a list of equipment (and associated structures) that will provide safe shutdown of the reactor and maintain a safe stable state after a beyond design basis earthquake. The IPE success criteria, and the IPPSS analysis, were used to guide this selection.

Initiating Events and Consequential Events

Switchyards, transformers, and associated ceramic insulators are not generally designed for large seismic events. Experience has shown the ceramic insulator stacks to be among the first pieces of equipment likely to fail in an earthquake. Therefore, the Loss Of Offsite Power event tree was the initial model used for the seismic PRA. The systems used to mitigate this event encompass those used in the mitigation of general transients.

With increased earthquake magnitudes, there is the potential for instrument lines connected to the NSSS to be damaged or broken, resulting in a small LOCA. Therefore, the small LOCA event tree and mitigating systems were also used in the seismic PRA. Since larger NSSS piping is very rugged and overdesigned, it would be very unlikely to fail. The capacity of the reactor coolant system (RCS) and associated major equipment (reactor vessel, steam generators, reactor coolant pumps, pressurizer) were reviewed and evaluated by the seismic fragilities engineers, and determined to have high seismic capacity. Based on these evaluations, and guidance in the NRC and EPRI seismic margins procedures (References 3-5 and 3-7), large/intermediate LOCA was screened from further analysis. Main steam line breaks up to the MSIVs were similarly screened out, as were main feedwater line breaks inside the containment, and seismic-induced steam generator tube rupture (SGTR).

Seismic-induced ATWS is considered in the analysis, but no credit was included for mitigation of ATWS using the boration system. From a practical viewpoint, this conservatively results in most seismic-induced ATWS events leading to consequential core damage.

The electric power and auxiliary system event trees were also appropriate to the analysis. For example, the SWS or CCW system pumps (or strainers, heat exchangers or structures) may all fail at some acceleration. These support system event trees were examined to determine what systems are critical for the safety functions.

Review Of Event Tree Modeling Assumptions

The seismic IPEEE model is an extension of the plant model generated for the IPE. Therefore, many of the systems and components considered in the IPE are included in the IPEEE. Assumptions made about the need for various support systems (such as instrument air or HVAC) were reviewed to verify that they are valid for the IPEEE. Systems that were considered in the IPE, but whose impact was not explicitly modeled, were reviewed to determine if the assumptions were valid for a seismic event. Also, since a severe earthquake may result in offsite power being lost for one or more days, assumptions related to offsite power recovery were carefully reviewed and revised. The seismic PRA from the amended IPPSS (Reference 3-8) was also reviewed with respect to event tree assumptions. For example, the gas turbines (GT1, 2, and 3) were retained in the seismic equipment list as potential alternative power systems in the event of diesel generator failure. However, following the walkdown the gas turbine generators were found to have relatively low capacity, and were not included for accident mitigation given a seismic event. The availability of offsite power from the grid was determined to have a significant availability following a seismic event, and its potential success was appropriately included in the analysis.

The top event models and equations for these selected event trees were reviewed. The assumptions used for these system models were also reviewed to make sure that they were consistent with a large seismic event and an extended loss of offsite power. All components included in these top event models were evaluated for seismic failure in the IPEEE. All support system components necessary to support these top event functions were also included. These components formed the initial IPEEE seismic equipment list. These components were identified using the same scheme (Tag Number) as that used in the plant. This facilitated the location and identification of the equipment during the walkdown.

For air-operated components, the "normal position" and the "failed position" were identified. At Indian Point 2, loss of normal instrument air as a support system failure is not significant due to local passive back up supplies (accumulators) and the fail-safe nature of the components. However, if air was required to obtain the desired position, then the local component accumulator and associated solenoids were added to the SEL.

Components That Maintain System Pressure Boundary Integrity

The P&IDs for all of the systems identified above were reviewed to include all relevant components (such as tanks) which may have been excluded from the associated system equations by the assumptions made in the IPE models. Additionally, components that if seismically failed could result in a flow diversion were added to the SEL. The following items are typical examples added to the seismic equipment list:

- Tanks, heat exchangers, filters, strainers, receivers, accumulators (such as nitrogen tanks to back up instrument air). These generally passive components may not have been included in the IPE based on low random passive failure probabilities, but during a seismic event, their failure could fail the pressure boundary or flow path of a system.

- Components that could inadvertently change position during a seismic event (such as an MOV or AOV due to relay chatter), and cause a flow diversion or blockage. Manual valves and check valves do not need to be included. Special attention was paid to portions of systems that should be isolated, such as the non-critical CCW components.

- Systems connected to the NSSS were reviewed for potential seismic-induced interfacing systems LOCA. As a result, CVCS heat exchangers such as letdown, regenerative, and excess letdown were added to the list.

Instrumentation, Control, And Power Cabinets And Panels

Items such as instrumentation transmitters, instrumentation racks, electrical cabinets, power supplies, transformers, switchgear cabinets, motor control centers, and buses that provide essential signals, power, or control room indication for IPEEE equipment were added to the list. This included the control room and panels. Individual breakers and cable trays are generically evaluated, and were not individually listed.

Based on the EPRI guidance and previous seismic PRAs, the following criteria for instrumentation and control were followed:

a. Include equipment needed to provide the instrumentation and control requirements necessary to achieve and maintain the plant in a safe shutdown condition and to adequately monitor its shutdown status. Instrumentation which is confirmatory in nature does not need to be listed.

b. The safety functions needed for safe shutdown are:

   1. reactor subcriticality
   2. reactor inventory makeup
   3. reactor pressure control
   4. decay heat removal
   5. containment isolation and integrity

c. Although a loss of offsite power will result in an automatic SCRAM, the reactor protection system instrumentation should be included to ensure reactor subcriticality.

Each safety function was reviewed to understand the actuation systems and associated instrumentation required to fulfill that safety function. The internal events IPE was reviewed to determine what instrumentation and actuation equipment was selected for the IPE. The loss of offsite power procedure was reviewed to determine what instrumentation and actuation equipment was included in the procedure.

The control room instrumentation displayed on the flight panels, supervisory control panels, emergency DG control panels, HVAC control panels, and ventilation panels are not separately listed. These major control panels are included in their entirety. Instrumentation equipment which is associated with SEL individual equipment items, such as containment isolation valve position indication or pump operational status, and is on the above control panels, is not listed separately. This is acceptable since the individual equipment is evaluated including the associated instrumentation devices, the logic cabinets are evaluated, and the control panels are evaluated.

Relays associated with instrumentation, actuation, and control are evaluated separately in the relay evaluation task, and are therefore not listed separately for this evaluation.

Based on the above criteria and evaluation steps, the following instrumentation items were listed separately on the IPEEE SSEL:

CVCS instrumentation Logic Racks A5 and A6
Supervisory control panels and flight panels
EDG and EDG building HVAC control panels
Reactor protection channel logic racks
Reactor trip breakers and bypass
RWST level transmitters
CST level transmitters
RCS pressure transmitters and racks
SG level transmitters and racks
Containment pressure transmitters
SWS header pressure transmitter
VCT level controller
Thermostats for DG building HVAC

Components Critical For The Containment Performance Analysis (Level 2)

The IPE containment performance analysis was reviewed to gain background information on the systems and components critical to prevention of early or large releases from containment, and the necessary components were added to the IPEEE list as described below.

- Containment isolation, and potential relay chatter which could open containment isolation valves that interface directly with the containment atmosphere. All of the isolation valves for the potentially significant pathways (including the large purge lines, pressure relief lines, post accident vent system lines, and air or gas lines) were found to be isolated by either fail closed AOVs or check valves. The normally closed containment purge and pressure relief lines and valves were added to the SEL.

- Containment isolation actuation system components and associated cabinets.

- Main steam isolation valves were reviewed. The main steam isolation valves do not require air or nitrogen to close. The MSIVs are included in the SEL.

- The containment hatch seals were reviewed, and do not have inflatable seals, so air supply is not required.

- Containment penetration cooling, isolation valve water system, weld channel system, and containment penetration pressurization systems were reviewed. These systems are not credited for post-accident mitigation purposes and were therefore not included in the equipment list.

- Interfacing systems LOCA valves, such as the hot leg suction MOVs for shutdown heat removal were reviewed. These components were identified from the IPE interfacing LOCA analysis and are included in the SEL.

<u>Remove Generically Rugged/Passive Components</u>

Some components are considered generically rugged based on the material presented in EPRI NP-6041 and associated references. These components include check valves, manual valves, backdraft dampers, and simple relief valves. These were removed from the IPEEE walkdown list.

<u>Seismic Systems Walkdown</u>

Sometimes called a pre-walkdown, the seismic systems walkdown was used to accomplish the following items:

a. Identify any cabinets or equipment that should be on the list of IPEEE components, but was not identified from the systems analysis or the P&IDs. For example, the exhaust lines and silencers for the three emergency diesel generators were added to the IPEEE listing.

b. Identify multiple equipment items that are mounted on a skid so that the "rule of the box" can be used for the seismic capability walkdown. These items were coalesced into one item on the walkdown list.

c. Identify any obvious spatial interactions (such as a block wall) in order to alert the fragilities analysts. This includes the control room ceiling panels and supports.

d. Identify any seismic-fire or seismic-flood interactions, and add to the walkdown list to allow the fragility analysts to provide seismic capacities for these items.

For seismic-induced fires, any flammable liquid or gas storage tanks that could affect safety equipment were itemized. The IPEEE fire analysis task furnished a list of potential fire sources that contain flammable liquids or gases.

For seismic-induced floods, the primary items are potential failure of sprinkler heads or firewater piping, and spraying on safety equipment. These sources were identified by the seismic walkdown team during the walkdown and any potential interactions were then added to the list.

Structures and Unique Features

All structures housing critical equipment and any buildings adjacent to these critical structures that could potentially interact with the identified critical structures were identified. These structures, such as the Unit 1 superheater stack, were added to the walkdown. Potential seismic failure and impacts from the natural gas pipeline which crosses the Indian Point site was evaluated separately.

Verification With the A-46 SSEL

A cross-check with the SSEL which was developed separately for the A-46 program was performed to verify that the IPEEE list was comprehensive.

The final result of this task was a documented list of the plant components and location for the seismic IPEEE walkdowns.

3.1.3 Walkdown

The objectives of the seismic walkdown were to:

- Verify assumptions used in developing the seismic risk model and component list.
- Screen out high ruggedness components from the component fragility list.
- Review and gather detailed information and measurements on equipment and structures required for developing seismic fragilities, search for potential seismic vulnerabilities, and review potential spatial system interaction concerns.
- Search for seismic/fire and seismic/flood interaction concerns.
- Perform a liquefaction and slope stability screening.

3.1.3.1 Preparation for Walkdown

Seismic Walkdown Team

The IP2 seismic walkdown team consisted of the systems engineers and seismic capability engineers possessing the following qualifications:

- Knowledge of the failure modes and performance of structures, tanks, piping, process and control equipment, active electrical components, etc. during strong earthquakes.
- Knowledge of nuclear design standards, seismic design practices, and equipment qualification practices for nuclear power plants.
- Ability to perform fragility evaluations including structural/mechanical analysis of essential elements of nuclear power plants.
- Understanding of the PRA models, system analysis, and conclusions.
- Knowledge of the plant system functions and operator procedures.

The IP2 seismic walkdown team consisted of the following members:

Systems Engineers - The primary responsibility of the systems engineers was to identify all components and structures for which fragility estimation would be required. The systems engineers were knowledgeable about the power plant equipment, normal and emergency operational procedures, and operator response to abnormal situations.

Seismic Capability Engineers - The main activity for the seismic capability engineers was to review all components and structures identified by the systems engineers and establish whether the components could be screened out during the walkdown or if field data needed to be obtained to perform a fragility analysis on the component.

Utility Participation - Con Edison personnel from both the plant operating organization and the Engineering support organization participated in the seismic walkdown both as part of the systems engineer team and as members of the seismic capability engineer team. The Con Edison members provided plant systems, operations, design and PRA expertise. The participation of the utility engineers was also intended to assure that insights into plant behavior when subjected to beyond design basis seismic events would be understood and carried forward after completion of the IPEEE review.

Coordination with A-46 Program

As discussed, many components in the IPEEE review are also on the A-46 Safe Shutdown Equipment List. These components were subjected to a thorough walkdown and review for A-46 prior to the IPEEE seismic capability walkdown. The essential information on this equipment had been assembled into data files containing SQUG GIP SEWS sheets, anchorage calculations, outlier sheets, photographs, drawings, test reports and other background documentation.

Because the screening rules for the A-46 walkdown per the SQUG GIP are similar to the rules for seismic margin walkdown per EPRI NP-6041, the components which are common to both A-46 and IPEEE did not need an additional detailed walkdown for IPEEE. The IPEEE seismic capability team reviewed the A-46 equipment data files and then did a walk by of the equipment for seismic/fire, seismic/flood and spatial interactions applicable to beyond design basis seismic events, such as block walls upgraded under IEB 80-11. Several members of the IPEEE seismic capability team had participated in the A-46 review and were familiar with the equipment.

Review of Plant Information

The seismic capability team reviewed the equipment list prepared by the systems team, collected the necessary seismic qualification information, and developed specific walkdown data sheets for each component. The following plant seismic design documents were reviewed by the walkdown team members to better understand the plant layout and system operation:

- Indian Point Probabilistic Safety Study (IPPSS)
- Indian Point 2 A-46 data files
- Updated Plant Final Safety Analysis Report (UFSAR)
- Structural drawings
- Sample equipment qualification reports
- Representative equipment anchorage calculations
- Selected equipment specifications

The review of the UFSAR requirements, constructions drawings, and equipment installation specifications provided the seismic walkdown team members with understanding of the approach used and the consistency in equipment anchorage provided when the plant was constructed. Furthermore, a review of the level of existing plant documents prior to the walkdown enabled the walkdown team members to determine the extent of field data collection during the walkdown. A significant portion of the plant-specific information had been collected, reviewed, and used in the previous IPPSS PRA and IP2 A-46 program.

Pre-Walkdown Screening and Worksheets

Seismic Evaluation Work Sheets (SEWS) were prepared for use in documenting the seismic capability walkdown. For components also on the A-46 Safe Shutdown Equipment List, the SEWS forms from the SQUG GIP were used for documentation. For other components, the SEWS forms from EPRI NP-6041 were used. Structures and major NSSS components were not documented on SEWS forms since they are primarily assessed by review of drawings and other plant documentation.

3.1.3.2 General Walkdown Procedures

Structures

Information necessary for seismic evaluation of civil structures is normally obtained from design drawings rather than walkdowns. Rigorous seismic walkdown was not performed for the containment structure and other Seismic Category I buildings during the IPEEE seismic capability walkdown since a detailed structure walkdown was performed by EQE in the previous IPPSS PRA study and all walkdown observations and findings were recorded. However, the findings of the previous walkdown were confirmed and verified during this walkdown.

Structures were reviewed in the original IPPSS and fragilities calculated. The original calculations were retrieved and reviewed prior to the walkdown. It was decided that new structural response factors would be calculated because of differences between what was used in the IPPSS and more recent criteria in EPRI NP-6041. The new structural response factors and the EPRI uniform hazard spectra were used to compute new structural fragilities and to scale design spectra for use in computing equipment fragilities.

There were three structures which contain components on the equipment list which were not reviewed in the IPPSS: the containment concrete internal structure, the intake structure and the diesel generator building. These structures required calculation of response factors for use in fragility evaluation.

Equipment

The walkdown team reviewed all components on the SEL. For equipment covered by the A-46 review, the walkdown team reviewed the A-46 data files and performed a walk by inspection. All other components received a complete inspection per EPRI NP-6041.

The walkdown team did not review 100% of the distribution systems such as piping, cable trays, conduit, and HVAC ducting. The walkdowns of selected subsystems were handled on a sampling basis. The sample size depended upon the design basis, as determined during the preparatory work, and the number of concerns expressed by the walkdown team.

The issue of relay and contactor chatter was not addressed in this walkdown; however, the walkdown team spot checked a large sample of relays and determined that relay mountings and orientations were proper and cabinets/panels were not too flexible nor contained large cutouts which would affect relays. A thorough relay spot check walkdown, in accordance with the GIP, was also conducted for the A-46 review.

The following describes the review of different classes of equipment inspected during the IP2 walkdown:

Tanks Design drawings for the tanks and their foundations and/or supports were reviewed to obtain a general understanding of the tank configurations and anchorage details. Walkdown procedures for the tanks included the following:

- Verification that the overall tank configuration and anchorage details conform with the design drawings.
- Review of piping flexibility and other attachments to identify any potential sources of damage due to seismic movement.
- Inspect any unique features, which are not common to tanks, but were identified during a review of the drawings.
- Identify and inspect potential sources for seismic interaction.

Pumps Historical performance during past earthquakes of horizontal and vertical pumps have shown high capacities. The walkdown procedures concentrated on:

- Verifying pump and motor anchorages, including type of anchorage, foundation configuration and integrity.
- Reviewing potential nozzle loads and piping flexibility.
- Identifying interaction potential from attached or adjacent components.

This review was aimed at a confirmation of judgements about the high capacities of pumps as well as documenting the pump configuration and anchorage via the SEWS forms and photographs.

Heat Exchangers Walkdown procedures for heat exchangers concentrated on:

- Reviewing the supports including support saddles and anchorage details between the saddles and the concrete piers.
- Reviewing nozzle loads and piping flexibility.
- Identifying interaction potential from attached or adjacent components.

SEWS sheets were used to record configuration and dimensional data from the walkdown for heat exchangers support, anchorage, and attached or adjacent component interaction details that were not available from the plant data reviewed prior to the walkdown.

Diesel Generators Past performance of diesel generators demonstrates lower bound median capacity levels higher than 0.5g pga. The walkdown procedures concentrated on:

- Reviewing anchorage and support integrity, noting if any vibration isolators were present.

- Review of the peripheral equipment such as engine control panel, diesel day tank, fuel oil lines, air intake and exhaust ducting, and starting air receiver for positive anchorage.

SEWS sheets were developed and used during the walkdown to record any problem areas encountered.

Electrical Distribution Equipment Walkdown procedures for electrical distribution equipment included:

- Reviewing and collecting anchorage details of the cabinet or enclosures for subsequent analytical review.
- Verifying that the internal instruments and components are positively attached to the cabinet framing or enclosure walls and that the device mountings are not excessively flexible.
- Identifying any system spatial interaction problems or flood or spray concerns.

Past performance of electrical distribution equipment during earthquakes suggests lower bound median seismic capacities exceed 0.5g, providing the equipment and internals, instruments, breakers, contactors, etc., are properly anchored.

The smaller (wall-mounted distribution cabinets and transmitters) equipment items were reviewed for positive anchorage, but typically very few details were recorded. These smaller items were judged to have high capacities during the walkdown review. Walkdown data sheets and photographs were used to record and document the walkdown findings.

HVAC Two procedures for reviewing the HVAC equipment were used:

- For HVAC equipment found mounted on vibration isolators, a detailed walkdown review was performed.
- For HVAC equipment found positively anchored to a supporting structure, an engineering judgment evaluation was performed and documented during the walkdown.

HVAC equipment positively anchored, as well as vibration isolator supported equipment with positive lateral restraints, have performed well during past earthquakes.

The review for HVAC equipment mounted on vibration isolators included recording dimensional data and support configuration sufficient to perform an analytical evaluation after the walkdown. Photographs were also used to record the walkdown findings.

The review of components in the second case included air intake and exhaust dampers and exhaust fans. The walkdown review assessed anchorage and any seismic deficiencies present in order to judge that the component had a high seismic capacity. The predominant form of documentation for these components was the use of photographs to record the walkdown findings.

HVAC Ducting The walkdown procedures consisted of two approaches:

- Inspect the ducting in close proximity to the HVAC equipment components to be reviewed. This includes:
  - Vertical and lateral load resisting members of the ducting
  - Any possible anchor point displacements that could impart significant loads to connected ducting.
- Inspect samples of the ducting systems selected during the walkdown.

Documentation consisted of noting any anomalies and taking photographs.

Valves Walkdown procedures consisted of a review of valves identified in the equipment list. Areas of concern reviewed during the walkdown included observing for interaction potential between the valve operator and adjacent structure or components, evaluation of oversized or eccentric operators, and reviewing possible anchor point displacements between piping and valve. SEWS were used to document the walkdowns, and similar valves were reviewed by a less detailed walk by to verify similarity.

Piping Past seismic PRA studies and earthquake experience data have shown that welded steel piping systems have a very high resistance to seismic loads. Two piping failure modes that were addressed during the walkdown included:

- Impacting failures of valve operators
- Damage of piping caused by the failure of anchorage of attached equipment.

The valve clearance issue and the equipment anchorage issue are addressed in the evaluation of the specific equipment component and not as a part of the piping review. Particular attention was placed on evaluation of non seismic piping, such as fire protection piping, and potential impacts on critical components.

Cable Trays Inspection of the cable trays was performed with a general survey of cable tray systems in the plant. The general survey was performed to obtain an overview of cable tray construction throughout the plant. This included a review of the variety of cable tray system layouts, support configurations, and construction details. The inspection also considered items identified as being of potential concern, including failure of taut cables due to large relative displacement, severing of cables caused by sharp edges at the ends of cable trays, and weld failure.

Instrument Racks Walkdown procedures of the IP2 instrument racks consisted of:

- Reviewing and collecting anchorage details of instrument racks supporting instruments on the IPEEE component list.
- Reviewing and verifying positive attachment of the instruments and components to the racks.
- Identifying seismic spatial interaction concerns to instrument tubing or air lines due to seismic failure of adjacent equipment.

Control Room Ceiling The ceiling system was inspected during the walkdown to verify that the light fixtures and ceiling grid are safety wired.

3.1.3.3 Walkdown Results

The seismic walkdown of IP2 was conducted in two parts. Components inside containment were inspected in February 1993 during the plant refueling outage. This inspection was done concurrently with the A-46 review. The remaining components were inspected during July 1993 with a small number of followup items resolved during the 1995 refueling outage. The A-46 evaluations had been mostly completed by the time of the July inspection.

Walkdown Documentation

Walkdown documentation for equipment consisted of recording the findings using SEWS forms and photographs. The SEWS were from the SQUG GIP for equipment also in the A-46 review and from EPRI NP-6041 for equipment only in the IPEEE review. The SEWS are included with the A-46 documentation.

Photographs were used to supplement the information recorded on the SEWS. Photographs provided a permanent record of what was reviewed and support any notes or details taken during the walkdown. System interaction concerns were typically documented with photographs. Additionally, photographs were used in the fragility evaluation to confirm details or to provide additional clarification. Photographs from the walkdown have been numbered and included in a binder with the A-46 documentation. Photograph numbers are noted on the SEWS.

Walkdown Screening

Fragility descriptions must be developed for IPEEE. The information for development of these fragility descriptions and the identification of components and structures for which the fragility descriptions are developed come from three sources:

- The original IPPSS.
- A-46 walkdown observations and seismic capacity calculations.
- IPEEE walkdown observations and new capacity calculations to be performed.

It is not practical to develop fragility descriptions for all structures and equipment nor is it necessary if the capacities are large, since the contribution to risk will be negligible. Therefore, only components that are estimated to have a median capacity of less than 1.5g peak ground acceleration or a high confidence of low probability of failure (HCLPF) capacity of less than 0.5g will be considered. HCLPF is defined as 95% confidence of less than 5% probability of failure. Note that these values for median capacity and HCLPF are consistent given a combined uncertainty, random and modeling, of 0.67. The unscreened components are derived from the following:

- In the original IPPSS, specific fragilities were computed for major safety related structures, ground mounted storage tanks, and selected equipment for which design information was obtained from Westinghouse and UE&C. The calculations for these structures and components were revisited to take into account a new definition of the spectral shape of the earthquake hazard defined for the site, newly calculated in-structure response spectra, and more current methodology for computing fragilities.

- Components which were identified in the A-46 program as outliers or which had a calculated demand/capacity ratio greater than about 0.5 will have HCLPFs calculated.

- Non-A-46 components identified during the IPEEE walkdown for which fragility calculations should be conducted.

Structures and components in these categories with HCLPF less than 0.5g pga (i.e., not screened out) require specific fragilities for the PRA quantification. Screened out structures and components may be represented by surrogate fragilities.

The following structures and components were not screened out and were forwarded to the fragility analysts for investigation in more detail. For some items, screening calculations or test data would be sufficient to screen them out from further analysis. Others would require plant-specific fragility curves to be developed.

<u>From original IPPSS:</u>

Containment Shell	Primary Auxiliary Building
Control Building	Turbine Building
Superheater Building and Stack	Masonry Walls
Reactor Vessel Internal Structure	Pressurizer Support
RHR Pump	Condensate Storage Tank
Buried Service Water Piping	Diesel Fuel Oil Storage Tanks (Buried)
Refueling Water Storage Tank	Spray Additive Tank
Containment Fan Coolers	Diesel Generator
Cable Trays	Batteries
Offsite Power	120V Distribution Panels (DC Bus 21, 22, 23, 24)

From A-46:

Charging Pumps
Instrument Rack 20
Volume Control Tank
CCW Heat Exchangers
SOV 1139-1 Rack
480V Bus 2A, 3A, 5A, 6A
Diesel Generator Jacket Water Expansion Tank
MCCs 26A, B, C, 26AA & BB, 27, 27A, 28, 29
Excess Letdown Heat Exchanger
Regenerative Heat Exchanger
Instrument Stanchions (Generic)

From IPEEE Walkdown:

Diesel Generator Building
Intake Structure
Service Water Pumps
DC Bus 23 and 24 (masonry wall)
Diesel Generator Control Panel
Instrument Rack for PT 455 and 456
Boric Acid Storage Tank
Containment Spray Header
Diesel Generator 22 Exhaust Pipe
Containment Concrete Internal Structure
Fuel Storage Building
MCC EPA 77 and 78 (anchorage)
Solatron Transformers 21 and 24 (masonry wall)
Flux Monitoring Cart (GI-131)
Containment Recirculation Pump
CCW Surge Tank
Gas Turbine Generators

Based on the walkdown, the gas turbine generator facilities and the connection to the vital bus had several points which were of relatively low seismic capacity. The gas turbines were therefore considered to have no more capacity than the offsite power sources.

3.1.3.4 Seismic Induced Fire/Flood Interactions

The potential for seismic induced fire interactions was evaluated during the walkdown. Sources of flammable gases and liquids were identified by the systems engineers prior to the walkdown, and from previous fire walkdown experience, and the seismic capacity of these flammable sources was evaluated by judgment. Seismic interactions which could affect these flammable sources were also identified and evaluated by judgment for seismic capacity. If a flammable source could not be screened out on the basis of high capacity, then it was documented with an evaluation in the seismic or fire analysis depending on specific circumstances. The only potential seismic induced fire interactions that could not be screened out at the time of the walkdown were:

- The reactor coolant pump lube oil collection tank, located on the 46 ft elevation of the containment building outside of the crane wall. Anchorage details and configuration were not sufficient to confirm seismic capacity. This tank was designed to provide standby capacity and does not normally contain large amounts of lube oil. It was subsequently determined that this tank was seismically installed. The installation details and analysis were reviewed and was determined that the tank as utilized had a substantial seismic capacity and did not require a detailed fire risk evaluation.

- Hydrogen bottles stored near the alternate shutdown panel. Since as stated above, however, the gas turbine facilities were conservatively assumed in the detailed analysis to have no greater seismic capacity than offsite power sources. Alternate shutdown was therefore, not credited in the seismic analysis and this potential impact was not significant to that analysis.

The potential for seismic induced flooding and spray interactions was evaluated in a similar way. Potential sources of flooding and spray interactions were identified by the walkdown team and evaluated by judgment during the walkdown. Special consideration was given to fire protection sprinkler heads in proximity to structural steel or other hard objects. Consideration of flooding from non-seismic tanks was based on input from the systems engineers and the internal flooding analysis. There were no potential seismic induced flooding or spray interactions identified as needing further consideration.

3.1.3.5 Liquefaction/Slope Failure

The liquefaction and slope stability review during the walkdown assessed the potential for liquefaction and slope failure due to a seismic event under the IPEEE using the EPRI NP-6041 procedures for assessing soil liquefaction. EPRI NP-6041, Table 2-3 addresses screening of civil structures for soil failure modes, soil liquefaction and slope instability. It refers to Section 7 and Attachment C within that document for screening criteria.

Indian Point 2 is a rock site. Section 7 of EPRI NP-6041 states, "Plants constructed at rock sites generally do not have soil failure issues. Exceptions might be earthen dams, pipe and tanks buried in overburden of steep cuts in surrounding hillsides". The plant site was screened for the above conditions during the seismic walkdown. The walkdown team reviewed the plant site and reviewed several pertinent references (see References 3-9, 3-10 and 3-11).

The liquefaction potential of a soil deposit depends on the depth of ground water, the type and density of the soil, and the intensity and duration of ground shaking. Soils susceptible to liquefaction are saturated, uniformly graded sandy soils in a loose to medium dense condition. When liquefaction occurs, the sand loses its strength completely and is transformed into a liquid state. Large ground movement would result from liquefaction.

IP2 is founded on rock which is typical of the area and consists primarily of fractured, seamy limestone and dolomite. Rock excavation for the entire plant was carried out until firm rock was uncovered, and fill concrete was added to bring the excavated areas to proper grade. Because the structures bear directly on rock, there is no liquefaction potential for major structures. Reference 3-9 shows site topography. The only steep slopes are next to the superheater building (east of GT 1), between the PAB and containment, and on the north side of the containment. These slopes were made by excavating the rock. Since there are no saturated sands involved, the slopes are very stable. Only the landscaped surface soil north of the containment would be subject to movement and no safe shutdown structures would be affected. The CST is located at the top of the slope but well back from the edge and would not be affected by movement of loose surface soil on the slope. The other two slopes are bare rock or faced with concrete.

Buried pipelines inside the plant fence are run in trenches excavated from rock and backfilled. The details of the trenching and backfill cannot be found. Since backfill would be compacted and would be granular in nature, as opposed to uniformly graded sand, liquefaction leading to failure of buried piping is not a concern. Some settlement could possibly occur but the amount of backfill beneath the pipe was expected to be small. Consequently, any seismically induced settlement would not be of sufficient magnitude to fail the buried pipes.

The only important buried tanks are the diesel fuel oil tanks. These were judged not of concern for the same reasoning as for buried piping. The seismic capacity of these tanks was judged to be controlled by sliding with subsequent failure of the tank hold down straps and grouted rock anchors. This mode of failure was evaluated as part of the fragility evaluation.

The electrical lines from the gas turbines located near the city water tank run underground to the plant. The exact location and construction of these feeders were not determined. Also, the soil conditions under the city water tank and the gas turbine fuel tank were not determined. There may be a potential for damage resulting from soil failure; however, other seismic vulnerabilities in the emergency offsite power trains had been noted and liquefaction would not the determining factor in the capacity of these trains.

A special review and evaluation was performed for the natural gas pipelines and pig stations which are co-located near the Indian Point site. There are two natural gas transmission pipelines passing through the Indian Point site, about 1000 feet from the nearest Unit 2 plant structures. Three pig launch sites and the manual shutoff valves are located by the river crossing, about 1700 feet from the nearest Unit 2 structures. The pipelines did not use the relatively weaker method of "chill rings" for weld backing, and random X-raying of joints was performed for quality assurance. Both pipelines have a coating (two coats of coal tar enamel, fiberglass wrap, and a third coat of enamel), and a cathodic protection system to prevent corrosion. The pipeline routes are surveyed often, using aerial, vehicular, and walking surveys to detect gas leaks, dead vegetation (due to gas leaks), and undesired construction activities. A Supervisory Control and Data Acquisition (SCADA) system provides instant flow and pressure information, so that a leak can be quickly detected. The older pipeline (26-inch diameter) has been inspected several times recently with "smart pigs" to ensure its integrity.

Earthquake experience in high seismicity regions has demonstrated that well-designed pipelines fail due to lack of support or slope failures rather than the lateral seismic forces. The pipelines are buried on a sand pad in a rock trench excavated about 3 feet deep. On slopes, sand bag breakers were used to stabilize the soil around the piping.

Pipeline slopes were reviewed by examination of the site development plan, and photos were taken to document a site survey of the steepest portion of the route. Most of the route is on relatively flat land with slopes less than 20 percent. Based on these mild slopes and the construction of the pipelines, there is judged to be no potential for soil liquefaction or settling that would cause any significant loss of support to the pipeline. Therefore, based on the earthquake experience database, these sections of the pipelines would have high capacity, and are not of further concern to the seismic analysis.

In one area, about 1200 feet from the nearest Unit 2 plant structures, there is a 40 foot elevation drop in about 100 linear feet, or about a 40 percent slope. The slope is covered with soil and vegetation, with some rock outcroppings. The pipelines and sand bag breakers cannot be seen. While this section of piping might be screened if more information were available, it cannot be screened based on the available data. Therefore, the following factors were used to evaluate the impacts of a potential pipeline failure. The potential failure impacts are a fire at the pipeline, an explosion, or a vapor gas cloud.

a) Fire at the pipeline:	A fire starting at the pipeline itself would not impact the plant, or spread to the plant because there is a wide firebreak (approximately 100 feet) around the plant.
b) Potential explosion:	Although there is an old stack (chimney) which could collapse onto the control room, extensive studies by the US Bureau of Mines and others have demonstrated that natural gas does not detonate, unless confined, and therefore a severe shock wave is not credible.
c) Vapor cloud and: potential fire	The remaining hazard is an unignited vapor gas cloud traveling to the plant, with either the potential for ignition or asphyxiation. The distance from the section of the pipeline to IP2 is 1200 feet. Natural gas is lighter than air, and readily rises and disperses into the atmosphere. While dispersion modeling was not performed for this analysis, it is unlikely that weather conditions would form a gas cloud which could travel 1200 feet.

A conservative bounding calculation using the SEISMIC software and the LLNL seismic hazard curve was made to evaluate the potential for the pipeline to fail, for the wind to be in the direction of IP2, and for the gas cloud to not ignite until reaching critical safety systems and structures. The calculated mean frequency of this bounding scenario was 6E-7/year. Note that the above scenario does not include the presence of the redundant and diverse safety systems at IP2. Multiple systems would have to be rendered inoperable to cause core damage. Since this calculation is conservative, and the frequency is below the criterion of 1E-6/year, it is judged that this scenario can be screened from further analysis. Therefore, based on the above discussion and bounding calculations, it was concluded that the gas pipelines and associated facilities crossing the plant property are not a seismic vulnerability.

It was concluded that liquefaction and slope stability could be screened out from the seismic PRA.

3.1.4 Analysis of Plant System and Structural Response

Structural response for the plant structures was originally conducted during the plant design stage. As part of the A-46 program, Con Edison contracted Altran Corporation (Reference 3-12) to reanalyze the structural response for the design basis earthquake and develop in-structure spectra. No new analyses were conducted in support of IPEEE, thus the Altran analysis was scaled to develop loads and spectra for use in IPEEE. Since a PRA was utilized for IPEEE a structural response factor of safety, F_{SR}, was developed by comparison of the spectral accelerations for the DBE design analysis spectra and damping to the uniform hazard spectrum and median centered damping used for IPEEE. This factor and its variability were then used to scale design loads and spectra and to define the uncertainty in these loads and spectra. The scaling process used for structures and equipment is the same, however, some differences exist due to the fact that the analysis methods for developing structural loads is different from that for developing spectra.

The structural response factor, F_{SR}, is determined from a number of variables which include:

1. The response spectra used for design compared to the median-centered spectra for the site (F_{SS})
2. Damping used in the design analysis compared with damping expected at failure (F_δ)
3. Modeling accuracy (F_M)
4. Modal combination methods (F_{MC})
5. Soil-structure interaction and wave incoherence effects (F_{SSI}).
6. Earthquake directional components (F_{ED})

The overall factor of safety, F_{SR}, for building response is then:

$$F_{SR} = F_{SS} \bullet F_\delta \bullet F_M \bullet F_{MC} \bullet F_{SSI} \bullet F_{ED}$$

and the associated variability is:

$$\beta_{SR} = \left[\beta_{SS}^2 + \beta_\delta^2 + \beta_M^2 + \beta_{MC}^2 + \beta_{SSI}^2 + \beta_{ED}^2\right]^{1/2}$$

The structure response factor and associated variability affects both the structure fragilities and the equipment fragilities for equipment located within the structure. Slightly different structure response factors were used for building and equipment fragility evaluations, however. This occurs because a time history record was used to generate the in-structure response spectra which were used to obtain the equipment response, whereas a response spectrum analysis was conducted for development of structural loads. The response spectrum of the time history exceeds the response spectrum used to determine the loading in the buildings, thus F_{SR} for equipment is greater than for structures.

Median factor of safety, F_m, and variability, β_R and β_U, estimates are made for each of the parameters affecting the capacity and response. These median and variability estimates are then combined using the properties of the lognormal distribution in accordance with the above equations to obtain the overall median factor of safety and variability estimates.

For each variable affecting the factor of safety, the random variability, β_R, and the uncertainty, β_U, must be separately estimated. The differentiation is based on the following guidelines. Essentially, β_R represents those sources of dispersion in the factor of safety which cannot be reduced by more detailed evaluation or by gathering more data. β_R is due primarily to the variability of an earthquake time-history and, therefore, of a structure's response when the earthquake is only defined in terms of the peak ground acceleration. β_U, represents those sources of dispersion which could be reduced only through better understanding or more knowledge of the behavior of the item. β_U is due to such items as inaccuracies in mass and stiffness representations, uncertainty as to the actual damping and use of engineering judgment in the absence of plant-specific data. The guidance of EPRI TR-103059 (Reference 3-13) is used in developing the structural response factors and is consistent with past practice in previous seismic fragility development including the Diablo Canyon Long Term Seismic Program.

3.1.4.1 Structural Response Factor for Structures

<u>Spectral Shape</u> F_{SS}

Most of the Indian Point Unit 2 concrete structures were designed using 5% of critical damping. The reactor building and concrete internals structure were designed using 2% of critical damping, and 2.5% was used for most of the steel frame structures. Spectral shape factors were determined from the ratio of spectral acceleration at design damping to the 5% damped median spectral acceleration with both spectra normalized to 0.15g pga. When modal participation factors for the individual structure modes were available, the overall spectral shape factor was determined from the ratios of design spectral acceleration to median spectral acceleration at the modal response frequencies weighted by the modal participation factors.

$$F_{SA} = \frac{Sa_{1Design}}{Sa_{1Median}} \frac{\varphi_1}{\Sigma\varphi_i} + \frac{Sa_{2Design}}{Sa_{2Median}} \frac{\varphi_2}{\Sigma\varphi_i} + \cdots\cdots$$

where: $Sa_{iDesign}$ = Spectral acceleration for the i-th mode at design damping for the design spectrum.

$Sa_{iMedian}$ = Spectral acceleration for the i-th mode at 5% damping for the median spectrum.

φ_i = Modal participation factor for the i-th mode.

Where the modal participation factors were not available, the spectral shape factor was determined from the ratio of the design spectral acceleration to the median spectral acceleration at the fundamental frequency of the structure. For the current evaluation, the spectral shape factor includes the effect of the change in structural damping used in design to 5% of critical.

As shown in Figure 3.1-1, the expected variability about the median spectrum varies over the frequency range. Lognormal standard deviation in the amplification factor varies from zero in the rigid range to more than 0.8 at one hertz. Variability in the response spectrum shape was assumed to be all randomness, β_R, and was found by weighting the ratio of the 85th percentile/medial spectral acceleration at the individual response frequencies by the modal participation factors in a similar manner as shown above for the spectral shape factor.

Structure Damping, F_δ

As noted above, the majority of the Indian Point Unit 2 concrete structures were designed using 5% of critical damping with 2% for the reactor building and concrete internals. At response levels where the structure is at or near yield, NUREG/CR-6011 (Reference 3-14) indicate estimates of median damping of 7% of critical for concrete and 10% for steel structures are somewhat conservative. Corresponding minus one standard deviations of 5% of critical for concrete and 7% for steel were used in the current evaluation. The damping factor accounts for the change in expected damping from 5% (included in the spectra shape factor) to the expected median damping at structure response approximately equal to yield.

Spectra for damping ratios other than 5% of critical are not available for the UHS used to evaluate the Indian Point structures in the current evaluation. Consequently, spectral accelerations at higher damping ratios were estimated using amplification factors from Housner spectra. The Housner spectra were typically used for the design of the Indian Point structures. The shape and amplification of Housner spectra more closely approximate the UHS than other standard spectra. The ratios of spectral accelerations were used to determine the damping factors and associated variabilities for the Indian Point structures. Thus:

$$F_\delta = \frac{S_a \text{ 5\% damping}}{S_a \text{ median damping}}$$

and $$\beta = \ln \frac{S_{a5\%}}{S_{a7\%}} \text{ for concrete, and}$$

$$\beta = \ln \frac{S_{a7\%}}{S_{a10\%}} \text{ for steel structures.}$$

Soil-Structure Interaction and Wave Incoherence, F_{SSI}

The Indian Point structures are founded on very stiff rock. Fixed-base models were used for design and were reevaluated (Reference 3-12), and it is expected that the overall effect of compliance functions representing the rock would result in negligible changes in the structure response characteristics when compared to the fixed base models. Therefore, a factor of safety of unity with negligible variability was assigned to this aspect of the analysis.

However, it is known from limited recorded data that some reduction in average input for structures founded on a large stiff base slab can be expected compared to a point location (Reference 3-15). This occurs due to the spatial incoherence in the input wave motion. The reduction in input is a function of both the plan dimensions and building frequency. For a 150 foot plan foundation, the reduction is:

Frequency (Hz)	Reduction
5	1.0
10	0.9
25	0.8

A linear interpolation or extrapolation can be used for base plans with other dimensions and structures with other frequencies. For Indian Point steel structures, the fundamental frequencies are less than 5 Hz so that no benefit is obtained from this effect. However, for the stiffer concrete structures this effect was included in the response factor. In general, a reduction of unity was assumed to correspond to a -2β response for this parameter.

Modeling, F_M

The dynamic models used in the Indian Point design were typically determined in the Altran review to be adequate to predict the seismic response. Therefore, median modeling factors of unity typically were used in the current fragility evaluation. Variability in modeling predominantly influences the calculated mode shapes and modal frequencies. For concrete structures, the concrete strength and, consequently, the stiffness of the structures is above the design values, and calculated design frequencies would be expected to be somewhat less than actual values, at least for low-to-moderate levels of response. At response levels approaching failure, softening of the structures due to concrete cracking occurs, and for structures analyzed using uncracked section properties, some decrease in the actual frequencies compared to the calculated values is expected. For steel structures, there is somewhat less uncertainty in the stiffness. However, uncertainty in the calculated masses still exists. The Indian Point calculated mode shapes were assumed to be approximately median-centered.

Modeling uncertainties from both the mode shapes and modal frequencies enter into the uncertainty on calculated modal response as defined by β_M thus:

$$\beta_M = \sqrt{\beta_{MS}^2 + \beta_{MF}^2}$$

where β_{MS} and β_{MF} are estimated logarithmic standard deviations on structural response of a given point in the structure due to uncertainties in mode shape and due to uncertainties in modal frequencies, respectively. Logarithmic standard deviations on modeling were typically estimated in the 0.05 to 0.2 range with the lower values being associated with simple structures which can be adequately modeled with single degree of freedom models with frequencies in a range of the amplified portion of the response spectrum where a nominal shift in frequency does not result in a large change in response. Variability in modeling is normally assumed to be essentially all uncertainty, β_u

<u>Modal Combinations,</u> F_{MC}

In the seismic design analysis conducted on the Indian Point Class I structures, the individual modal responses were combined by the square-root-of-the-sum-of-the-squares (SRSS). Closely spaced modes were combined by the absolute sum method. This is the current recommended practice of the USNRC given in Regulatory Guide 1.92 (Reference 3-16).

Many studies have been conducted to determine the degree of conservatism or non-conservatism obtained by use of SRSS combination of modes. Except for the very low damping ratios, these studies have shown that SRSS combination of modal responses tends to be median-centered. The median modal combination factor of safety was therefore taken to be 1.0.

For simple structures with essentially single mode response, a β_R of about 0.05 was estimated for the mode combination factor with higher values for multi-degree of freedom systems.

<u>Combination of Earthquake Direction Components,</u> F_{ED}

The design of the Indian Point structures was based on the absolute addition of one horizontal and the vertical load component. Current recommended practice is to combine the responses for the three principal directions by the SRSS method. Alternatively, it is recommended by Newmark and Hall (Reference 3-17) that directional effects be combined by taking 100% of the effects due to motion in one direction and 40% of the effects from the two remaining principal directions of motion.

The effect of SRSS combination of three components compared to the direct addition of two depends on the relative magnitudes of the two horizontal load components together with the vertical component and the geometry of structure. For instance, if the two horizontal load components are approximately equal, and the vertical component is small, the SRSS method results in an increase in stress of approximately 40% for a square structure but 0% for a circular structure. Combining the effects by the 100%, 40%, 40% method for the same case results in the same 40% increase in stress as for the SRSS method and an increase in approximately 8% for a circular structure such as the reactor building. If the two horizontal load components are approximately equal and result in stresses approximately equal to that from the vertical component, all stress combinations from either the SRSS or 100%, 40%, 40% method are less than the absolute sum of one horizontal plus vertical as was used in the design of Indian Point.

Depending on the geometry of the particular structure under consideration together with the relative magnitude of the individual load or stress components, the expected variation in stresses due to either the SRSS or the 100%, 40%, 40% method of load combinations is from -30% to +40% when compared with the original design method. For shear wall structures where the shear walls in the two principal directions act essentially independently and are the controlling elements, the two horizontal loads do not combine to a significant degree except for the torsional coupling. Thus, only the vertical component affects the individual shear wall stress. A moderate amount of vertical load increases the ultimate shear load carrying capacity of reinforced concrete wall slightly. However, there is an equal probability the vertical seismic component will add to or subtract from the deadweight loads at the time of maximum horizontal load. Consequently, for concrete shear wall structures, the factor of safety is not strongly influenced by the directional component assumptions except for torsional coupling.

For asymmetric Indian Point structures, an estimate of the torsional coupling was made using the 100%, 40%, 40% method. However, no three dimensional structure analyses were conducted as part of the current evaluation.

3.1.4.2 Structural Response Factor for Equipment

The Structural Response factor, F_{SR}, for equipment defines the effect of the conservatism or unconservatism of the structural analysis and the development of floor spectra on the actual equipment response. The variables pertinent to the structural response analyses used to generate floor spectra for equipment design are the only variables of interest relative to equipment fragility. The applicable variables for equipment from those analyses include:

1) Spectral Shape resulting from the time-history input vs. median spectral shape
2) Damping
3) Modeling
4) Mode Combination
5) Soil-Structure Interaction and Wave Incoherence effects
6) Earthquake Directional Combination
7) Inelastic Structural Response

Therefore:

$$F_{SR} = F_{SS} \bullet F_{\delta} \bullet F_{M} \bullet F_{MC} \bullet F_{SSI} \bullet F_{ED} \bullet F_{IR}$$

Spectral Shape, F_{SS}

When time-history analyses are conducted, the resulting spectra are required to envelop the design basis earthquake ground motion spectra, thus there is conservatism relative to the design requirement. For Indian Point Unit 2, several different time histories were used for these different structures. Figure 3.1-2 shows the spectra resulting from a Taft earthquake time history, the El Centro 1941 earthquake, synthetic time histories developed to envelop the Housner design basis earthquake spectrum and the Design Basis Earthquake.

Superimposed upon Figure 3.1-2 is the EPRI median uniform hazard spectrum, anchored to the DBE of 0.15g. The spectral shape factor which is applicable to the Altran floor response spectra is the ratio of the spectrum resulting from the time-history input motion to the median centered uniform hazard spectrum.

The spectral shape factor is developed on a mode-by-mode basis as described for structures in

Section 3.1.4.1 for cases where the mode participation factors are available.

$$F_{SS} = \frac{S_{a1_{Design}}}{S_{a1_{UHS}}} \frac{\varphi_1}{\Sigma\varphi i} + \frac{S_{a2_{Design}}}{S_{a2_{Median}}} \frac{\varphi_2}{\Sigma\varphi i} + \cdots \frac{S_{an_{Design}}}{S_{an_{UHS}}} \frac{\varphi_n}{\Sigma\varphi i}$$

where:

- $S_{ai\ Design}$ is the spectral acceleration of mode *i* from the DBE time-history spectrum.
- $S_{ai}UHS$ is the spectral acceleration of mode *i* from the 50 percentile uniform hazard spectrum.
- i is the mode participation factor for mode *i*.

It can be seen from Figure 3.1-2 that at low frequencies, the factor F_{SS} is significantly greater than unity where at higher frequencies, the factor is less than unity. For soft structures, the floor spectra used for design are very conservative relative to floor spectra that would result from the UHS.

The random variability in the spectral shape factor may be derived by comparing the 50th and 85th percentile UHS. Figure 3.1-3 plots the 10,000 year, 15th, 50th, and 85th percentile UHS for Indian Point. The random variability, β_R is defined as the logarithm of the ratio of the 85th percentile response to the 50th percentile response, at each modal frequency and weighted by the participation factors.

<u>Damping</u>, F_δ

The damping factor, F_δ, is computed by comparing the ground motion spectral acceleration at median structural damping to the spectral acceleration at design damping. Since only 5% damped spectra are available for the UHS, the DBE spectra were used for this comparison.
The damping factor and its variability are computed as described for structures.

<u>Modeling</u>, F_M

As described for structural loading, the modeling factor and its uncertainty are composed of two parts, mode shapes and modal frequencies. The Altran structural models are considered to be adequate to predict seismic response and the modeling factor is unity. The modeling uncertainties, β_U varied from about 0.05 to 0.2, depending upon the complexity of the model.

Mode Combination, F_{MC}

Mode superposition time-history analysis was conducted to develop floor spectra, thus the phasing of modes is calculated directly. However, there are an infinite number of earthquakes that will result in the same response spectrum but which will result in different modal responses, so there is a random variability which must be considered for mode combination.

The mode combination variability depends on the number of degrees of freedom which significantly contribute to response. The upper bound, considered to be approximately a 3β limit, is considered to be a case where all significant modes are in phase.

Earthquake Component Combination, F_{ECC}

This is discussed in Section 3.1.4.1 as it relates to the governing stress or load in a structure. For in-structure spectra, the earthquake component factor and its variability represents the effects from directional coupling. Two dimensional (horizontal plus vertical) models were used to develop floor spectra, whereas there is some torsional coupling arising from the two horizontal directions of motion.

Torsional coupling variability was estimated by studying the models and their response. No three-dimensional structural analyses were conducted.

Soil Structure Interaction and Wave Incoherence, F_{SSI}

Major structures at Indian Point are founded in stiff rock, hence, there is no strong influence or response from soil-structure interaction. The soil-structure interaction factor was considered to be unity and a small variability was assigned to acknowledge very small effects of the underlying rock foundation.

As discussed in Section 3.1.4.1, the effect of wave incoherence is based upon the structural frequency and the size of the foundation. For stiff structures with long basemat plan dimensions, the wave incoherence factor removes the conservatism associated with the analysis assumption of spatially coherent ground motion. As noted in Section 3.1.4.1, the factor for low frequency steel structures at Indian Point was determined to be unity. Stiffer concrete structures had a factor greater than unity.

Inelastic Structural Response Factor, F_{IR}

As a civil structure approaches yield and begins to exhibit nonlinear behavior, the spectral acceleration for frequencies near the peak of the floor spectra tend to decrease relative to the scaled linear spectra. Several studies have shown that this is not the case at higher frequencies, however, and the Structural Inelastic Response factor, F_{IR}, addresses this phenomenon. Depending upon the structural characteristics and the frequency content of the ground motion, spectral accelerations in the higher frequency regions may be either higher or lower than the scaled linear floor spectra.

The structures that contain safety-related equipment at Indian Point 2 were found to have a high capacity relative to the weaker equipment items, thus the structures remain elastic at the failure level of the governing equipment. Hence, it was not necessary to develop a factor for inelastic structural response.

Applicability of Structural Response Factors

It should be noted that the structural response factors associated with the behavior of the building are not appropriate for equipment located at the basemat. In such cases, only the Spectral Shape and wave incoherence effects are included. It should also be noted that the wave incoherency factor is only appropriate for failure modes driven by the horizontal earthquake components and are not included for failure modes resulting from the vertical component of earthquake.

RESULTING STRUCTURAL RESPONSE FACTORS AND VARIABILITY

Table 3.1-1 summarizes the structural response factors developed for Indian Point 2 equipment. Note that in the table, the factors for low frequency structures such as the reactor building, control building and fuel storage building are significantly greater than unity, but for some of the stiffer structures such as the reactor building concrete internals and the intake structure, the factor is less than unity. This can be easily understood by examining Figure 3.1-2, where it is shown that the ground input spectral amplitude for low frequency structures greatly exceeded the UHS spectral amplitude, but at higher frequencies, the reverse is true.

3.1.5 Evaluation Of Fragilities And Failure Modes

3.1.5.1 Methodology and Review Process

The evaluation of structural and component fragilities and failure modes followed the guidance and procedures of EPRI TR-103059 (Reference 3-13), which are consistent with past practice including the procedures used in the Diablo Canyon Long Term Seismic Program. For structures, existing calculations performed for the IPPSS were revised to reflect the use of UHS for defining the ground motion spectral shape plus incorporation of refinements in methodology since the original IPPSS.

For equipment, a combination of methodologies were used. Some of the original IPPSS calculations were updated to reflect the use of a UHS. Most components on the SSEL were screened out on the basis of generic calculations, review of A-46 calculations, review of test reports, or by judgment based upon walkdown observations and generic ruggedness. For most cases, where fragilities were calculated, the A-46 calculations served as the basis for the development of fragilities.

3.1.5.2 Screening Results

Screening was done on the basis that the HCLPF capacity should be at least 0.5g pga and the median capacity equal to or greater than 1.5g. Thus for screened out components it was assumed that the fragility was defined as:

Am = 1.5g
$\beta_R = 0.30$
$\beta_u = 0.36$
HCLPF = 0.50g

This surrogate fragility when convolved with the seismic hazard results in a very small probability of failure (less than 1E-6 per year). The median capacity of equipment was generally estimated on the basis of anchorage capacity. The equipment itself is quite rugged and, based upon the walkdown and application of the screening guidelines in EPRI NP-6041, the HCLPF of the equipment can be stated to be greater than 0.5g as long as the anchorage HCLPF is at least 0.5g. Screened out components are listed in Table 3.1-2 including the basis for screening. In response to GI-131, calculations for the seismic upgrading of the flux monitoring cart were reviewed and it was concluded that it also could be screened out.

All of the important structures were analyzed to develop seismic fragilities. Their fragilities are presented in Table 3.1-3. It can be seen from Table 3.1-3 that many structures can also be screened out. Referring to Table 3.1-3, the only structural failures that need to be retained are the fuel storage building, superheater stack and the turbine building.

3.1.5.3 Detailed Fragility Results

Structural fragilities are tabulated in Table 3.1-3. The median acceleration capacity is the value at which the conditional probability of failure is 50 percent and is indexed to the peak ground acceleration defined at rock. β_R is the logarithmic standard deviation defining the random variability about the median capacity and β_u is the logarithmic standard deviation defining the uncertainty in the capacity. High Confidence of Low Probability of Failure (HCLPF) values are also tabulated. The HCLPF is defined as 95% confidence of less than 5% probability of failure and is computed as:

$$\text{HCLPF} = (\text{Median Capacity}) (\text{Exp}) [-1.65(\beta_R + \beta_u)]$$

Equipment fragilities for unscreened components are provided in Table 3.1-4. Some equipment had low capacity and upgrades were recommended for A-46 and IPEEE. Fragility values are provided for the as-built conditions and for upgrade conditions.

3.1.6 Analysis of Plant Systems and Sequences

This section describes the quantification of seismic risk for Indian Point 2, and includes the following topics:

- development of the seismic event tree and seismic damage states
- definition of the seismic failure nodal equations
- combination of the seismic hazard curve, the structural and equipment fragilities, and the seismic event tree using the SEISMIC software
- quantification of the seismic core damage frequency, including non-seismic failures and operator actions
- sensitivity and uncertainty

Traditional event tree techniques were used to delineate the potential combinations of seismic-induced failures and the resulting scenarios, which were termed "seismic damage states" (SDSs). The frequencies of these seismic damage states were quantified by convolving the earthquake hazard curve with the structure and equipment seismic fragility curves. This quantification included dependent and correlated failures, and appropriate success states. The SDS results were used in the seismic sequence analysis, which uses the IPE internal events models to incorporate random failures of equipment and operator actions. Sensitivity studies were performed for critical items, and a qualitative uncertainty assessment was performed.

3.1.6.1 Development Of The Seismic Event Tree

The seismic event tree (SET) depicted in Figure 3.1-4 is used to delineate the potential successes and failures that could occur due to a seismic event. The seismic-induced failures that are incorporated into the SET were obtained from the seismic fragility evaluation, as documented in Section 3.1.5. These fragilities are summarized in Table 3.1-5, and include the median fragility from the IPPSS if calculated. Seismic-induced failures of redundant components were conservatively assumed to be completely correlated by treating redundant components as if they were one component in the SET model.

Most structures and components that were included on the walkdown list were screened out based on their high seismic capacity. The conservative screening criteria were:

- median acceleration greater than 1.5 g

  and
- HCLPF greater than 0.5 g

These criteria are conservative when compared to the 0.3 g seismic margins HCLPF criterion for the Indian Point 2 site. In addition to the plant systems providing "level 1" safety functions, the walkdown list and seismic capacity evaluations included the structures, equipment, and actuation component necessary for the "level 2" functions of containment integrity, containment pressure suppression, containment heat removal, containment radioactivity removal, and containment isolation.

Note that some components and systems are not included in the seismic model and SET, and are conservatively assumed to be unavailable during a seismic event. Examples of these systems are:

- the city water system, which can be used to supply cooling to the charging pump seals to continue RCP seal cooling if CCW is lost, to provide an alternate source of suction to the AFW pumps and to provide alternate cooling to the RHR and SI pumps
- the primary water system which can be used to supply cooling to the charging pumps
- the three gas turbine generators, which can provide alternate station power
- the boric acid system, which could be used to achieve subcriticality in the event that the control rods did not insert

They are not included in the SET because other systems provide the same function, and have significantly higher seismic capacity.

In the event of a seismic failure of plant instrumentation and control due to the collapse of the superheater stack onto the control building, or impact of the turbine building on the control building, it may be possible to credit the Alternate Safe Shutdown System (ASSS). However, due to the potential impact on plant operations personnel given such an event, any credit for the ASSS was conservatively ignored.

Also note that only the seismic-induced impacts are treated in the SET. Success of equipment in the SET does not imply success from non-seismic causes. Non-seismic failure, such as random failure of a pump or an operator error, are included in the overall quantification, but not in this SET evaluation.

The definitions of the top events in the SET are as follows:

Top Event	Success/Failure Description
S	**Seismic event greater than 0.05 g:** Since the HCLPF of offsite power is 0.09 g and the design basis of the plant is 0.15 g, any lesser seismic event would very likely have offsite power and all safety systems available.
OP	**Offsite power remains available:** Failure of offsite power would generally be dominated by the failure of ceramic insulator columns in the switchyard or incoming transformers. However, failures of instrumentation and control (IC) and

1E 480 vac electric power (EP), discussed below, could also cause failure of offsite power to the 1E 480 vac buses. Therefore, the success of top event OP also requires the success of IC and EP, and is modeled as one event in the success branch. However, due to the different impacts, the failures of OP, EP, and IC are modeled separately.

RV **Reactor vessel internals are not damaged, and the control rods are successfully inserted:** Success implies that the reactor is scrammed. Failure implies that the RV internals and control rods are so badly misaligned that they are obstructed from insertion, and an ATWS occurs. Since the Boric Acid Storage Tank has a lower capacity than the RV internals, it is conservatively assumed that the boric acid transfer system is not available for ATWS mitigation. The availability of the RWST, although of lower seismic capacity, is included in the accident sequence delineation. Also, other systems may be available to prevent containment failure.

IC **Instrumentation and control remains available:** Success implies that the operators are able to control equipment from the main control room. Failure implies severe loss of instrumentation and control leading to core damage with no systems working. The loss of control is also considered to have the same impact on offsite power as the loss of OP event, and is included as a direct contributor to the failure of OP. Therefore, although top event IC is not explicitly questioned if OP is a success, it is included in the nodal equation for success of OP.

The two seismic failures leading to IC failure are the superheater stack collapsing onto the control room or the collapse of the Turbine Building frame damaging the control room. The term "TRAJ" was introduced into the equations to account for the probability that if the superheater stack fails, it would impact one of the critical structures. A probability of 0.18 is assigned based on the subtended angle for which the impact can occur. Note that the collapse of the superheater stack onto the emergency diesel generator building is also included in this event for ease of quantification, although the turbine driven AFW pump train (AFW TDP) may continue to operate. However, a RCP seal LOCA is postulated to eventually occur, leading to core damage since injection systems are not available.

EP **Emergency electric power (480 vac) is available to the equipment served by**

the emergency diesel generators (EDGs): Success of emergency electric power implies that power is available to run all of the loads required for safe shutdown after a seismic event. Failure implies a station blackout (SBO), although the AFW TDP may be available for some time. Eventually an RCP seal LOCA is postulated to occur, with consequential core damage. Containment systems are not available.

Based on the dominant failure mechanisms, the loss of 480 vac emergency power is also considered to cause loss of offsite power, and is therefore included in the OP nodal equation as a direct contributor to the failure of OP. Therefore, EP failure is not explicitly questioned if OP is a success.

Seismic failure of EP is conservatively postulated if the cable trays fail, or if the MCCs (26A, 26B, 26C, 27A, 27B, 26AA, or 26BB) fail.

SW **Essential and Nonessential Service Water is available:** Failure implies that the cooling for the EDGs is lost, leading to a SBO. Although the AFW TDP may be available for some time, eventually an RCP seal LOCA is postulated to occur, with consequential core damage. Containment systems are not available. Seismic failure of SW is caused by the loss of the intake structure due to sliding, the failure of the service water system pumps, or the failure of the CCW heat exchangers resulting in a breach of the SW system.

CT **AFW and the condensate storage tank (CST) are available:** Failure implies that the CST fails, and AFW is therefore lost. Bleed and Feed is a potential success path, but its probability of seismic induced failure is high due to the relatively low seismic capacity of the RWST (evaluated later on in the SET).

CW **Component cooling water (CCW) is available:** Success implies that the RCP seal thermal barriers are cooled adequately, as well as cooling to various safety related pumps. Failure implies the loss of RCP seal cooling, including the charging pump seal cooling (note that primary water and city water are conservatively assumed to be unavailable after a seismic event), as well as cooling to the RHR, SI, and recirculation pumps which are required in the recirculation mode. While AFW and containment sprays may be available, core damage due to an unmitigated RCP seal LOCA is assumed. The potential for continued injection by providing make-up to the RWST is not considered, which is a further conservatism in the model. The containment fan coolers may be available.

Seismic failure of CW can occur by failure of the CCW surge tank, which could result in excessive leakage from the closed system. It was also initially assumed that failure of the Fuel Storage Building would cause failure of the fuel pool heat exchangers and associated CCW piping, thus failing the CCW system. This later assumption is conservative since the failure mode of the Fuel Storage Building is collapse of the metal superstructure, which would be unlikely to severely impact the CCW piping contained in the lower concrete portion of the building.

S2 **No seismic-induced small LOCA occurs:** The fragilities evaluation of the primary system screened out the possibility of a Large or Medium LOCA. Success implies that the plant is in a transient condition, although an RCP seal LOCA might occur due to the loss of seal cooling (evaluated in other top events). Failure implies a small LOCA (less than 2" equivalent diameter) has occurred due to the seismic event. This could be caused, for example, by multiple failures in the small instrument lines connected to the reactor coolant system (RCS), or by small seismic-induced RCP seal leakage. The safety injection function, including the RWST, is required to mitigate a seismic-induced small LOCA.

R **RWST available:** Success implies that the RWST is available to provide a source for safety injection to mitigate a SLOCA or RCP seal LOCA, or for bleed and feed operations. Failure implies the loss of these functions as well as the loss of the containment sprays. Although the seismic capacity of the RWST is less than the seismic capacity of the RCS piping and instrument lines, the RWST may still be available to mitigate a SLOCA or RCP seal LOCA, and this is reflected in the SET.

FC **Containment fan coolers are available:** Success implies the capability to prevent containment overpressurization. Failure implies loss of this means of containment heat removal. In sequences evaluated to be less than 1E-7 frequency in the SET (based on the initial quantification) the branch point for FC was not questioned in order to reduce the overall number of sequences. It was conservatively assumed for these sequences that the fan coolers were not available.

The column labeled "Sequence" denotes the failures in the accident sequence and the sequence number, which is used as the seismic damage state number. The "STAT" column designates the status of the sequence as follows:

STAT	Description
OK	Sequence does not end in core damage, and no significant seismic damage has occurred at the plant. No further analysis is required.
OK-X	Sequence does not directly end in core damage, but transfers (X) to the designated IPE event tree for analysis of the associated non-seismic failures. Seismic failures from the SET sequence are included as house events or guaranteed failures for the remainder of the sequence analysis.
CD	Sequence results in core damage, and no containment systems are available to prevent overpressure failure of the containment. Generally this is a station blackout (SBO) sequence with or without AFW, an ATWS sequence, or a loss of instrumentation and control sequence. No further analysis is required because the end state is already delineated and quantified.
CD-X	Sequence results in core damage, but containment systems may be available to prevent containment overpressurization. Therefore, the sequence is transferred to the designated IPE event tree for analysis of non-seismic failures. Seismic failures from the SET sequence are included as house events or guaranteed failures in the remainder of the sequence analysis.

The COMMENT column usually indicates the IPE event tree that is used to analyze the sequence for non-seismic failure (if appropriate) or the general type of accident sequence. The abbreviations are:

COMMENT	Description
minor quake	The event was a minor earthquake, with no loss of offsite power. Because the event is no worse than an anticipated plant transient, and the

frequency is much lower than transients analyzed in the IPE, this sequence is considered insignificant to risk and not analyzed further.

LOP	Loss of offsite power.
SLOCA	Small LOCA (less than 2" equivalent diameter break).
Seal LOCA	Reactor Coolant Pump (RCP) seal LOCA. These are analyzed as a SLOCA event.
Feed & Bleed	Feed & Bleed must be used to mitigate these transient sequences, since the CST is unavailable.
SBO	Station blackout. These sequences result in core damage with no containment systems available for overpressurization mitigation. In addition, some of these sequences do not have AFW available (no AFW) so they result in an earlier core damage.
ATWS	Anticipated Transient Without SCRAM. This sequence results from seismic-induced misalignment of the reactor vessel internals with the control rods, resulting in a mechanical failure to SCRAM. The RWST and containment systems may be available in some sequences, and these are analyzed for non-seismic failures. Some ATWS sequences do not have AFW, or are SBO sequences as well.
NA	Core damage with no containment systems available. No further quantification of core damage frequency is required.

3.1.6.2 Seismic Event Tree Sequence Quantification

Boolean equations were developed for each of the SET top events based on the logic and seismic fragility information discussed above. Table 3.1-5 provides a cross reference between the abbreviations used in the equations, the structure/component description, and the fragility information. The failure equations for each top event are:

S	=	(No equation needed since this is the seismic event)
OP	=	SWYD + IC + EP
		(where IC and EP represent the equations below)
RV	=	RV
IC	=	STACK * TRAJ + TURB
		(where TRAJ represents the likelihood of the stack impacting the identified critical structures)
EP	=	TRAYS + MCC
SW	=	CCWHX + SWINT + SWP
CT	=	CST
CW	=	CCWST + FSB
S2	=	SLOCA
R	=	RWST
FC	=	FC

These equations, which represent the seismic failure of structures and components, were then combined into the seismic sequence equations as delineated by the SET. Both failure and successes were included in these seismic sequence equations. Each seismic sequence equation represents the Boolean logic associated with its corresponding seismic damage state (SDS). As mentioned above, the SET was first quantified without fan cooler failures. For SDSs with frequencies greater than 1E-7 the branch point for fan coolers (FC) was then questioned by adding two equations, one with FC failure and one with FC success. Note that some SDSs greater than 1E-7 do not question FC because it is a guaranteed failure, such as EP sequences with loss of all ac power.

The seismic hazard information, structural/component fragilities, and SDS equations were then input to the SEISMIC code to quantify the frequency of the SDSs. In essence, the SEISMIC code uses a Monte Carlo sampling process at each seismic magnitude interval to combine the seismic hazard frequency information with the seismic fragility information for each structure/component in the SDS equation. Successes, failures, and Boolean intersects are properly treated in this calculation. The code repeats this process for each seismic magnitude, and then sums the results to obtain the SDS frequency. This process is then repeated for each SDS equation until all equations are quantified.

The SDS results are presented in Table 3.1-6, including the mean value and the distribution (in terms of the 5%, the mean value, and the 95%) for each of the 47 sequences in the SET. The quantification of non-seismic failure used these SDS frequencies as initiating event frequencies including seismic failures as guaranteed failures.

The mean frequency of an inconsequential earthquake, as denoted by sequence 1, was found to be 1.6E-3 per year. This sequence has offsite power and all safety systems available, and would be similar to a plant trip with or without main feedwater. Since it is several orders of magnitude lower in frequency that the corresponding IPE internal events Loss of Main Feedwater initiating event, it is not significant to risk, and is not quantified further. Similarly, several of the other seismic damage states have insignificant frequency, and are classified as negligible (NEG). However, most of the SDSs were retained for quantification of non-seismic failures.

3.1.6.3 Incorporation of Non-Seismic Failures and Human Interactions

The internal events IPE model was used to calculate the impact of non-seismic failures and human errors for each of the non-negligible seismic damage states. The core damage and plant damage state frequency resulting from each SDS was quantified by modifying the plant logic model embodied within the RISKMAN software, accounting for the frequency of each SDS and the resulting structural or equipment damage.

In addition to the guaranteed failures from the SDS analysis, the following changes were made to the logic models:

- The EDG and fuel oil pump run times were increased from 6 hours to 24 hours to reflect the increased difficulty of restoring offsite power and making repairs following a seismic event.
- Due to the relatively low capacity of the Gas Turbines and supporting systems, power recovery from these sources was assumed to fail if offsite power failed (event OP).
- Loss of CCW is assumed to result in a non-recoverable RCP seal LOCA, and consequential core damage, since alternate sources of City Water and Primary Water are assumed to be unavailable after an earthquake.
- Supply of City Water to the AFW pumps is assumed to be unavailable.
- For SDSs with frequency less than 1E-7 per year, the fan coolers were conservatively assumed to be unavailable.
- For ATWS events, emergency boration and manual scram were assumed unavailable.

Human Interactions

Operator error probabilities were reviewed to determine if the seismic event would impact their probabilities. Several different methods have been used in other studies to evaluate the impacts of a seismic event on post-accident human interactions. These methods were evaluated, and, for the Indian Point 2 seismic PRA, the following guidance was judged to be realistic in terms of timing and error probabilities.

1) If events must be diagnosed and action taken within an hour of the seismic event, multiply the IPE human error probability by the following factors to account for the confusion, distraction, and potential difficulty in movement:

IPE HEP Range	Multiplication Factor
0.1 to 1.0	2 (maximum HEP of 1.0)
0.01 to 0.1	5 (maximum HEP of 0.2)
<0.01	10

2) Operator actions for which greater than one hour is available use the HEP from the IPE since the confusion and other factors will have decreased significantly.

Table 3.1-7 provides a summary of the revised operator action HEPs. No unique operator actions were added to the IPE for the seismic PRA.

Some operator actions may not be possible after a seismic event, and were therefore excluded. The action to use city water to cool the charging pumps if CCW is lost is not possible since the city water will likely not be available after a seismic event that fails CCW. Similarly, offsite power recovery and main feedwater recovery was not credited for the analysis. Also, manual scram of the reactor and operator action to use emergency boration during a seismic-induced ATWS were not credited.

3.1.6.4 Core Damage Frequency Results

The results of the analysis of seismic damage state frequencies and non-seismic failures and human interactions were combined using the IPE internal events models, and the results are presented in Table 3.1-8. The total seismic core damage frequency for the base case, using the LLNL seismic hazard curve, is 1.46E-5 per year. The dominant contributors, and their significant SDSs, are discussed below.

Loss of Instrumentation and Control (SDSs 37 and 47)

Approximately 45% of the seismic core damage frequency is caused by loss of instrumentation and control sequences, which are assumed to lead directly to loss of all power, and consequential core damage. The failure of the turbine building frame, and assumed consequential failure of the control building contributes 54% toward this dominant sequence, while the collapse of the Unit 1 superheater stack onto the control building or the DG building contributes the remaining 46%.

Loss of Component Cooling Water (SDSs 25 and 6)

About 29% of the seismic core damage frequency is related to failure of the CCW, which causes loss of cooling to the RCP seals and to the charging, RHR, and SI pumps. A consequential seal LOCA is assumed to occur, and, without safety injection for mitigation, core damage will result. The dominant contributor, representing about 75% of the seismic sequence, is the failure of the CCW surge tank, causing loss of the integrity of this closed cooling water system. The secondary contributor is the failure of the steel superstructure of the fuel storage building. For the base case it was very conservatively assumed that this failure would damage the CCW piping, valves, or heat exchangers to the fuel pool cooling system. This issue is discussed again in the sensitivity section.

Loss of 480 VAC Electric Power (SDS 36)

About 9% of the seismic core damage frequency is caused by failure of the 480 vac emergency electric power system, which causes station blackout, and eventual failure of decay heat removal, with consequential core damage. The two equally dominant contributors are the seismic failure of cable trays, which is assumed to be sufficiently widespread to cause loss of all electric power, and the seismic failure of the 480 vac MCCs. It was conservatively assumed that the MCC failures are totally correlated, such that if one fails, they will all fail.

Loss of Service Water (SDS 35)

About 9% of the seismic core damage frequency is caused by failure of the SW system, which provides cooling to the EDGs, and to the CCW. Loss of the SW will quickly result in loss of the DGs, causing station blackout, with consequential core damage. Seismic failure of the SW pumps is the dominant contributor, followed by seismic failures of the CCW heat exchangers failing system piping integrity, and sliding of the intake structure failing the SW pumps.

Other Sequences

The OP sequence (SDS 19), contributing about 3% of the seismic core damage frequency, is the only other sequence that contributes more than about 1%. It consists of a seismic-induced loss of offsite power, with subsequent non-seismic failures resulting in core damage. Other sequences contributing about 1% each are loss of the CST and RWST (SDS 29), unmitigated ATWS caused by failure of the reactor internals (SDS 38), and ATWS with seismic failure of the RWST (SDS 40), which prevents mitigation. None of these sequences contributes more than 5E-7 per year core damage frequency, and are thus not significant overall contributors to seismic core damage.

3.1.6.5 Sensitivity and Uncertainty Assessments

The following assessments were performed to provide more insight into the seismic PRA results:

- Modification of the CCW surge tank capacity
- Impact of Small LOCA fragility estimate
- Non-seismic failures and human error sensitivity
- Seismic hazard curve variability and uncertainty
- Contribution of the acceleration ranges to CDF
- Comparison with the IPPSS results

CCW Surge Tank Saddle Bolt Sensitivity Case

A sensitivity study was performed to examine the potential core damage frequency reduction if several bolts on the CCW surge tank supports were replaced with high strength bolts. Such a modification would strengthen the surge tank such that it would be screened out of the analysis based on high seismic capacity (greater than 1.5g median acceleration and 0.5g HCLPF). In addition, the failure of the superstructure of the fuel storage building was assumed not to fail the CCW, which is more realistic than the baseline case. The following table provides a comparison of the significant results.

		BASE CASE		SENSITIVITY CASE	
SDS	Seismic Failures	SDS Freq	CDF	SDS Freq	CDF
1	S	1.6E-3	negl	1.6E-3	negl
6	CW	9.1E-7	9.1E-7	0.0	0.0
19	OP	8.0E-5	4.6E-7	8.2E-5	4.7E-7
21	OP-R	4.3E-6	1.4E-8	5.2E-6	2.2E-8
25	OP-CW	2.7E-6	2.7E-6	0.0	0.0
26	OP-CW-FC	1.3E-7	1.3E-7	0.0	0.0
33	OP-CT-CW	1.8E-7	1.8E-7	0.0	0.0
42	OP-RV-CW	1.7E-7	1.7E-7	0.0	0.0

The sequences that previously included failure of CCW (SDSs 6, 7, 12, 16, 25, 26, 33, 34, 42, and 43) are no longer significant contributors. In the base case, these sequences resulted in core damage frequency of about 4.2E-6. Those sequences that include CCW success increased by this amount, with most of the increase going to sequence 1 (no seismic failures), sequence 19 (seismic-induced LOP), and sequence 21 (LOP with seismic failure of RWST). Other sequences increased by less than 1E-7, which is not significant. Since the sequences that increased (SDS 1, 19, and 21) do not directly result in core damage, and other non-seismic failures would have to occur, the overall effect of this sensitivity study is to decrease core damage frequency by about 4E-6 per year. This is approximately 29% of the baseline seismic core damage frequency.

Seismic-Induced Small LOCA Sensitivity Case

The fragility used for the seismic-induced small LOCA event was based on a conservative estimate of the seismic design margin of the piping with respect to the reactor building response spectra. During the walkdowns, samples of the small bore piping and impulse lines were examined, and judged to have a high seismic capacity. However, in accordance with EPRI/NRC guidelines and to reduce radiological exposure, only a sample of the LOCA sensitive piping and impulse lines were examined during the walkdowns. While it is unlikely, there is some chance that an undetected construction flaw in field run piping or impulse lines could have occurred. In the NUREG/CR-4840 (Reference 3-18), it is stated that piping failures should be neglected in general since typical piping runs, designed to nuclear power plant standards have margins of safety of 10-25 over the SSE design level. However, Figure 3.6 of NUREG/CR-4840 provides a generic curve of the conditional probability of small LOCA versus peak ground acceleration. The acceleration corresponding to a 50% probability of small LOCA is about 0.92g. For a sensitivity study, the median acceleration capacity for a small LOCA was reduced from the baseline value of 1.5g to approximate value of 0.92g. All of the seismic sequences were recalculated, with the overall results about the same as the base case. The only significant changes were:

		BASE CASE		SENSITIVITY CASE	
SDS	Seismic Failures	SDS Freq	CDF	SDS Freq	CDF
4	S2	2.7E-8	1.0E-10	4.8E-7	1.8E-9
23	OP-S2	9.2E-8	1.5E-9	1.1E-6	1.8E-8
24	OP-S2-R	7.0E-8	7.0E-8	5.1E-7	5.1E-7

As can be determined, the overall increase in seismic core damage frequency is less than 4% when the NUREG generic small LOCA fragility is used. There is no significant difference in the plant damage states, or containment performance issues. Therefore, this sensitivity analysis demonstrates that the overall seismic core damage frequency is not very sensitive to the selection of different small LOCA fragility parameters.

Non-Seismic Failures and Human Errors Sensitivity

Only a few significant seismic damage state sequences required additional non-seismic failures or human errors to occur to result in core damage. SDS 1 and SDS 2 are sequences where offsite power is not lost, and most of the safety systems (and likely the non-safety systems) remain available to mitigate the seismic damage. Based on the relatively low seismic acceleration level, and minimal damage to equipment, the uncertainties and special seismic influences on non-seismic failures and human errors is judged to be insignificant for these seismic damage states.

The only other SDSs with frequency greater than 1E-6 are SDS 19, loss of offsite power (8E-5 per year), and SDS 21, loss of offsite power and failure of the RWST (4.3E-6 per year). The core damage probabilities for these SDSs are 4.6E-7 and 1.4E-8 per year, respectively. Thus, the availability of safety systems and operator actions provides a reduction factor of more than 100 between the SDS frequency and the resulting core damage frequency. The dominant failures are primarily associated with emergency diesel generator failures. As discussed in the previous sections, operator error probabilities were increased to reflect increased stress and other associated performance shaping factors.

Since these SDS sequences contribute less than 5% to the overall seismic core damage frequency, these sequences are not significant to the overall seismic risk.

Uncertainty

Uncertainty in the seismic PRA generally comes from the three primary inputs: the hazard curve, the fragilities, and the non-seismic failures and human errors. Each of these was assessed, either qualitatively or quantitatively.

Hazard Curve Uncertainties: Both the LLNL and EPRI mean hazard curves were used to quantify the seismic damage states. As discussed in the seismic hazard Section (3.1.1), the LLNL mean hazard curve was used for the baseline analysis. Use of the EPRI hazard curve would result in a 10% decrease in seismic core damage frequency.

NUREG-1488 shows that the difference between the Indian Point mean hazard and the 85% upper bound is about a factor of 2 over the entire range of accelerations. Therefore, if the 85% upper bound had been used for the hazard curve, which would be very unrealistic, the seismic core damage frequency would have increased by about a factor of 2. Alternatively, the 15% lower bound is a factor of 5-100 lower than the mean hazard curve. While a quantitative uncertainty analysis of the seismic hazard was not performed, the results would show that the uncertainty in the hazard curve impacts the CDF by no more than a factor of 2.

The uncertainty in the uniform hazard spectra (UHS) were directly included in the estimation of structural response factors, and thus were included in the fragility estimates.

Also as discussed in Section 3.1.1, extrapolation of the hazard curve to 1.5g would result in an increase in core damage frequency, but by no more than 1.75E-6 per year, which is about 10% of the baseline CDF. A qualitative examination of the impact of truncating the hazard curve at

1.0g shows that the ranking of the dominant sequences, and their dominant contributors, remains about the same. Finally, any extension of non-linear, composite hazard curves into low frequency, high acceleration regions of the earthquake hazard would be rough estimates at best. Since there could easily be upper bounds on the magnitudes of the earthquake sources, the hazard curve may decrease very quickly. A simple extrapolation with no geotechnical basis may misrepresent the actual hazard. Based on these observations, it was determined that hazard curve extrapolation would provide no additional insights into seismic risk, uncertainty, or potential vulnerabilities for Indian Point 2.

Structural and Component Fragilities Uncertainties: While mean values were used for the seismic hazard curve, the full set of fragility parameters, including both random and modeling uncertainty, were used in the quantification process. Estimates of the SDS uncertainties are given in Table 3.1-6. For the dominant SDSs, the ratio between the mean and the 95% upper bound are factors of 2 to 5, and between the median and 95% are factors of 2-10 (which correspond to error factors if the distribution were lognormal). For the overall seismic core damage frequency, a quantitative estimate of the overall impact of the fragilities uncertainties provided the following results:

Mean CDF:	1.46E-5 per year
Median CDF:	1.3E-5 per year
95% Upper Bound:	2.8E-5 per year
5% Lower Bound:	6.7E-6 per year

This uncertainty analysis demonstrates that there is a factor of about 2 between the mean CDF and the 95% upper bound, based on the uncertainties associated with the fragilities assessments.

Non-Seismic Failures and Human Error Uncertainties: Quantitative estimates of the uncertainties associated with the non-seismic failures and human errors were not performed. These model inputs were not significant to the overall risk, since they impacted less than 5% of the sequences that caused core damage. Therefore, even if a full uncertainty analysis of non-seismic failures and human errors were performed, the overall results would not change significantly.

Contribution of Acceleration Ranges to CDF

The following table presents the percent contribution, and cumulative percent contribution, of the different hazard acceleration ranges to the total seismic core damage frequency. This analysis was performed using the dominant seismic failure contributors.

Acceleration Range (g)	Percent Contribution	Cumulative Contribution
0.05 - 0.075	0.1 %	0.1 %
0.075 - 0.15	0.8 %	0.9 %
0.15 - 0.25	5 %	6 %
0.25 - 0.3	8 %	14 %
0.3 - 0.4	10 %	24 %
0.4 - 0.5	16 %	40 %
0.5 - 0.65	20 %	60 %
0.65 - 0.8	19 %	79 %
0.8 - 1.0	21 %	100%

As can be discerned, the lower acceleration levels contribute very little to plant seismic risk.

Comparison with the IPPSS Results, Amendment 2

The baseline seismic CDF for this IPEEE analysis is 1.46E-5 per year, compared to the IPPSS estimate of 7.6E-6 per year, about a factor of 2 lower. While detailed comparisons were not made, the primary differences are:

- Use of LLNL seismic hazard curve versus IPPSS hazard curves
- Changes in the fragilities estimates due to:
  - different shape of the EPRI UHS versus the NUREG-0098 spectra
  - large spread between the median and 84% for the lower frequencies of the spectra, resulting in large uncertainty parameters for the structures, particularly the turbine building and the superheater stack
- Inclusion of the CCW surge tank failure mode in the seismic analysis

Other changes were relatively minor. As shown in the CCW sensitivity study above, removal of the CCW surge tank failure results in a 29% decrease in overall seismic CDF, which is more similar to the IPPSS results. Overall, the two studies have very similar results and conclusions.

3.1.7 Analysis of Containment Performance

NUREG-1407, Section 3.2.6, provides guidance on the content of the seismic containment performance analysis. The purpose is to identify vulnerabilities that involve early failure of containment functions, including containment integrity, containment isolation, prevention of bypass functions, and some specific systems depending on containment design. The IP2 IPE and IPPSS were used to determine the scope of systems for the examination, with the following results.

Structures and Major Components

The major structures and systems whose failure could result in early failure of containment were evaluated through walkdowns and seismic capacity calculations. This included the containment building, internal structures, the reactor coolant system (reactor vessel, coolant pumps, pressurizer, and steam generators), RCS supports, primary piping, main steam lines, and nearby structures. No issues or potential for failure of these items was noted in the walkdowns. Particular attention was paid to the adequacy of seismic gaps between major structures. The fragility calculations demonstrated that all of these structures and items had high seismic capacity, and could be screened from the analysis, except the fuel storage building superstructure, and the reactor vessel internals. The potential collapse of the fuel storage building steel superstructure, although it was modeled to fail component cooling water, would not impact the containment integrity or damage containment systems. Failure of the reactor vessel internals was modeled to cause an ATWS, but this would not cause failure of the containment integrity or safety functions.

Containment Isolation

Mechanical and electrical penetrations were included in the walkdown to ensure that there would not be failures of the mechanical penetrations or piping, electrical penetration assemblies, isolation valves and associated cables, piping supports, anchorages, or spatial interactions or differential motion which could cause failure of containment isolation or integrity. The list of containment isolation valves was based on the IPE analysis, with special consideration for valves directly connected with the containment atmosphere or systems with non-seismic category piping inside containment. Additional valves were added to the walkdown list based on boundary integrity considerations. Although cooling is provided to steam and feedwater penetrations to preclude long-term degradation, loss of this cooling would not jeopardize penetration integrity within the period considered in this analysis. No isolation valves depend on air to provide closure capability.

On the basis of the walkdowns, and capacity judgments, there are no vulnerabilities in the mechanical and electrical penetration systems, or the containment isolation valves and piping.

Containment Bypass

The potential for seismic-induced interfacing systems LOCAs (ISL) involves the failure of the RCS pressure boundary leading to a LOCA outside the containment boundary. The internal events IPE has identified all potential ISL paths, and was used as the initial basis for this seismic analysis. Valves in each of the ISL paths were reviewed for inclusion on the seismic equipment list (SEL), and then included in the seismic capacity walkdown. Paths with check valves and normally closed manual valves for isolation have high capacity, and these paths were not evaluated further. Power operated valves, such as MOVs and AOVs, were included in the SEL and walkdown. These valves were also determined to have high seismic capacity, and were not evaluated further. Particular attention was placed on the shutdown cooling lines and valves, and the CVCS letdown lines. The relays associated with these valves, including isolation actuation systems, were included in the relay chatter evaluation. Based on the ISL evaluation, there are no seismic vulnerabilities associated with these paths, or with the valves and associated relays. No additional containment performance modeling is necessary.

Containment Hatches

The personnel and equipment hatches were reviewed both during the walkdown, and through capacity evaluations. The plant does not have inflatable seals on the hatches, so this is not an issue. Based on the walkdown and capacity review, there were no vulnerabilities associated with the hatches.

Containment Isolation Actuation

The sensors, transmitters, logic and relay cabinets, and power supplies for the containment isolation actuation system were included in the walkdown. All components had high capacity, and were screened from further evaluation.

Containment Pressure Suppression and Heat Removal

The seismic PRA included containment pressure suppression and heat removal functions and systems, such as the containment sprays and the fan coolers. Most of the components for these systems were determined to have high capacity, and were screened from further analysis. The containment fan coolers had a median capacity of 1.11g, with a HCLPF of 0.47g, and were included in the seismic event tree and the PRA model. However, the direct seismic failure of the fan coolers was not significant to the containment performance results and plant damage states. Other failures, such as loss of instrumentation and control or electric power, were more important to containment performance.

Containment Failure Modes

Based on the results of the seismic PRA, approximately 65 percent of the core damage frequency results in plant damage states with initial loss of containment pressure suppression and heat removal functions. If these functions are not regained, these sequences would lead to long-term containment overpressure and failure. However, none of these sequences lead directly to early failure of containment or to containment bypass.

Containment Performance Results

In summary, containment performance systems and equipment were explicitly included in the walkdowns and seismic PRA. No vulnerabilities which could cause early failures of containment, or containment bypass were identified.

3.2 USI A-45, GI 131, AND OTHER SEISMIC SAFETY ISSUES

This section discusses the following NRC safety issues with respect to seismic risk:

USI A-45	Shutdown Decay Heat Removal Requirements
GI-131	Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System Used in Westinghouse Plants
USI A-46	Verification of Seismic Adequacy of Equipment in Operating Plants
USI A-17	System Interactions in Nuclear Power Plants

USI A-40	Seismic Design Criteria: Seismic Capability of Large Safety-Related Above-Ground Tanks
	Eastern US Seismicity (Charleston Earthquake) Issue
GI-57	Effects of Fire Protection System Actuation on Safety Related Equipment

3.2.1 USI A-45: Decay Heat Removal

The USI A-45 issue is concerned with reliability and potential vulnerabilities in the decay heat removal systems, both for internal and external events. For Indian Point 2, the safety-related decay heat removal systems for the A-45 issue include the auxiliary feedwater system, the charging, safety injection, RHR, and recirculation systems, and the PORV system. Support systems include electric power, cooling water (CCW and SW), air/nitrogen, and room cooling and ventilation. Containment heat removal and pressure suppression can be performed by the containment spray and fan cooler systems.

For the case of a transient or small LOCA, the AFW system removes decay heat through the steam generators to the atmosphere through the atmospheric dump valves or secondary side safety valves. If AFW is unavailable, bleed and feed operations can be performed by the charging and SI pumps, using the PORVs. Long-term decay heat removal is provided through the closed loop residual heat removal system, utilizing the RHR pumps and RHR heat exchangers. In case of a LOCA, or bleed and feed operations, the charging, SI, RHR, and/or recirculation systems can provide primary inventory makeup, and decay heat removal during recirculation. Containment heat removal is also available from the containment sprays and fan coolers for the LOCA events.

Each of these systems were included in the analysis of potential earthquakes for the IPEEE. Generally, the sequences leading to potential core damage involve the seismic initiating event, and either failure of a critical structure, or multiple failures of redundant support system equipment. Based on the relatively low CDF from earthquakes at Indian Point 2, and the conservatisms included in the seismic modeling process, there are no identified vulnerabilities in the decay heat removal systems. The individual decay heat removal failures are discussed below.

<u>AFW and Injection Functions</u>

While the AFW system is important for decay heat removal, the system components have high seismic capacity. All of the AFW equipment screens out of the seismic analysis, with the exception of the condensate storage tank (median capacity of 1.13g). Bleed and feed may also be available as a diverse system for decay heat removal. The front-line equipment associated with bleed and feed also have high capacity, with the exception of the RWST (median capacity of 0.61g). Sequences with seismic failure of the CST, and combined with failure of the RWST or other bleed and feed failures, contributed about 3E-7 per year to the overall CDF, which is about 2% of the overall seismic CDF.

While a seismic-induced LOCA would be rare, it was analyzed in the seismic IPEEE analysis. The injection systems (charging, SI, and RHR) all have high seismic capacity, with the exception of the RWST discussed above. Small LOCAs, with failures of injection or recirculation, contributed less than 1% to the overall seismic core damage frequency.

Support Systems and Structures

Systems that support the front-line decay heat removal systems also have generally high seismic capacity. The dominant seismic failures were discussed in previous sections, with the two dominant functional failures involving the loss of instrumentation and control assumed if the turbine building (median capacity of 1.5g) or superheater stack (median capacity of 0.73g) severely damaged the control building, and failure of the CCW due to surge tank failure (median capacity of 0.9g) or fuel storage building failure (median capacity of 1.37g). These functional failures contributed about 45% and 29% respectively to the seismic core damage frequency. Seismic failures of the 480 vac electric power and the SW system contributed about 9% each to seismic CDF. Since the overall Indian Point 2 seismic risk of 1.46E-5 per year is relatively low, and since the largest single contributors only contribute about 3E-6 per year, there are no identified decay heat removal vulnerabilities.

In summary, a plant-specific systematic evaluation has been performed for Indian Point 2 to identify any potential vulnerabilities in the decay heat removal systems. No vulnerabilities were identified for seismic initiating events.

3.2.2 GI-131: Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System Used in Westinghouse Plants

GI -131 was identified by NRC IE Information Notice 85-45 in June 1985 because portions of the in-core flux mapping system that were not seismically analyzed are located directly above the seal table. Failure of this equipment during a seismic event could cause multiple failures at the seal table and could produce an equivalent small break LOCA. The reason for including this GI in the IPEEE is to evaluate the potential seismic interaction of the movable in-core flux mapping system used at Indian Point 2.

Based on the IE notice, the flux monitoring cart has been modified to brace the cart in two directions. A review of the design by the fragilities engineers concluded that the HCLPF for the revised design is in excess of 0.5g, and may be screened out. Therefore, based on this high capacity, this issue can be considered closed for Indian Point 2.

3.2.3 USI A-46: Verification of Seismic Adequacy of Equipment in Operating Plants
USI A-17: System Interactions in Nuclear Power Plants
USI A-40: Seismic Design Criteria: Seismic Capability of Large Safety-Related Above-Ground Tanks

The A-46 program has developed an alternative method and acceptance criteria (to current licensing requirements) to verify the seismic adequacy of equipment in plants with a construction permit application docketed before 1972, including Indian Point 2. The scope of A-46 has been expanded by the NRC to include the seismic spatial system interaction of USI A-17 and the concern of USI A-40 for the seismic capability of large safety-related above-ground tanks.

The IPEEE and A-46 programs were conducted in a coordinated manner at Indian Point 2, with the A-46 walkdown and capacity information being used by the IPEEE program. As discussed in Section 3.1.3, the A-46 walkdowns were performed in advance of most of the IPEEE walkdowns. Joint equipment on both A-46 and IPEEE equipment lists was given a walkby by the IPEEE staff to verify the A-46 SEWS and conclusions, and perform the additional walkdown steps requested by EPRI NP-6041. Caveats and interactions (such as the IPEEE flooding issue) were carefully observed by the IPEEE staff. Several members of the IPEEE seismic capability team had participated in the A-46 review and were familiar with the equipment.

Spatial interactions were specifically addressed in the seismic capacity walkdowns and checklists, and the large safety-related yard tanks were demonstrated in the A-46 and IPEEE analyses to have adequately high seismic capacity.

Therefore, all of these issues have been adequately addressed by the Indian Point 2 A-46 program, the IPEEE seismic program, and by the seismic capacity walkdowns. These issues can be considered closed for Indian Point 2.

3.2.4 Eastern US Seismicity (Charleston Earthquake) Issue

This issue is directly resolved by the seismic IPEEE analysis for Indian Point 2, and can be considered closed.

3.2.5 GI-57: Effects of Fire Protection System Actuation on Safety Related Equipment

Seismic induced fire/flood interaction issues, including spurious actuation of the fire protection systems, were evaluated in detail as discussed in Section 3.1.3.4. These evaluations included issues such as fires due to potential sources of flammable liquids or hydrogen, and floods due to multiple actuations of fire suppression systems. The overall result is that any potential seismic-induced fires or floods will not affect safety equipment needed for shutdown during or after a seismic event, and the issues are considered closed.

Based on the above discussions, all of these issues can be considered closed for Indian Point 2.

3.3 RELAY CHATTER REVIEW

3.3.1 Scope

As proposed in Reference 3-19, in addition to the performance of a full USI A-46 relay review effort for the A-46 program, Con Edison has performed a low ruggedness ("bad actor") relay review for those relays that are associated with IPEEE-only equipment (that is, not on the A-46 SSEL). For a limited number of secondary circuit relays we have performed a relay chatter impact evaluation.

Other types of electrical circuits devices, such as motor starters, circuit breaker coils and auxiliary switches, limit switches and manual switches, are inherently rugged and are therefore not considered as potential bad actors (Reference 3-20).

3.3.2 General Approach and Implementation

The basic steps involved in performing this effort were as follows:

1. Identify those IPEEE components not considered within the scope of the A-46 evaluation.

2. For those components identified in step 1, identify the relays and contacts in the primary control and power circuits.

3. *Evaluate impact of chatter in secondary circuits.*

4. Perform a "bad actor" review of the relays and contacts in step 2 by comparing them to the low capacity relay list found in Appendix D of EPRI NP-7148-SL (Reference 3-20).

5. Disposition any bad actors identified

Identification of Non A-46 IPEEE Components

In order to determine which IPEEE components required evaluation, a list of IPEEE only equipment (i.e., non A-46) was compiled by removing any components in the IPEEE Seismic Equipment List which also appear in the A-46 Safe Shutdown Equipment List (SSEL). Due to the approach taken in developing the A-46 SSEL, the large majority of the components considered in the seismic IPEEE effort were already included in the SSEL.

Next, any components that do not rely on relays to perform their safety function were eliminated. These included components such as tanks, heat exchangers, manual valves, etc.

Identification of Relays

For the components identified in the previous step, electrical schematics and/or elementary wiring diagrams were collected and reviewed. Those relays and contacts in circuits that might cause a possible seal-in or lockout signal, inadvertent component actuation or loss of function due to seismic chatter were identified. Alarm and indication circuits were not considered. As mentioned earlier, motor starters and mechanically actuated switches (e.g., limit switches and manual control panel switches) which are known to possess a high inherent seismic capacity were considered not to require additional review.

When identifying the relays that might impact the operation of an IPEEE component, care was taken to ensure that interlock and actuation circuits, which do not necessarily appear on the component's primary electrical schematic, were addressed within this evaluation or had previously been addressed within the A-46 relay evaluation. In order to illustrate the issue, consider the following example (see Figure 3.3-1):

> Let circuit "1" be controlled by the opening or closing of one set of contacts from relay "A"; however, relay "A" is not an integral part of circuit "1" (i.e., only one set of contacts are part of circuit "1", the relay is physically located in circuit "2"). In this case, one must first determine that relay "A" is not a bad actor. However, the fact that relay "A" is not a bad actor does not ensure that circuit "1" is not susceptible to chatter. One must also ensure that the circuitry controlling relay "A" (i.e., circuit "2") is not susceptible to chatter which could cause inadvertent energization of relay "A" (i.e., to chatter). That is, if relay "B" controls relay "A", and relay "B" is a bad actor, circuit "1" is subject to chatter.

For each non A-46, IPEEE component, all relays and contacts, as defined above, shown on the primary electrical schematic were uniquely identified by parent component, relay tag number, contact pair (if applicable), type, location and reference drawing number

For primary circuit relays and secondary circuit relays with contacts in primary circuits, considerable effort was made to identify the associated relay manufacturer and model number. The main sources of this information were twofold; the Con Edison PRIME/OE database (Reference 3-21) and the electrical drawings.

Evaluation of Secondary Circuit Chatter

For those relays which are part of the secondary interlock or actuation circuit (i.e., with only contacts shown on the primary drawing), further evaluation and screening was performed. Secondary circuit relays and their associated circuits were dismissed as having no significant degrading effect due to chatter if any of the following applied:

> <u>A-46 (A-46 Analysis)</u> - the circuit was already analyzed as part of the A-46 program, and thus the A-46 evaluation boundary has been reached.
>
> <u>CA (Chatter Acceptable)</u> - chatter was determined to affect the component, but

not adversely to a degree to which operation of the component is impaired.

NA (Not Applicable) - their is no secondary circuitry (i.e., either the relay coil is a part of the primary circuitry, or the relay receives direct physical input).

OA (Operator Action) - the affects of chatter can be reversed/reset within a reasonable period of time without affecting the safe shutdown function of the plant.

Bad Actor Review

Appendix E of EPRI NP-7148-SL (Reference 3-20) contains a list of known low seismic capacity relays; sometimes referred to as the "Bad Actor" list. These "low ruggedness relays" are characterized by the manufacturer and model number, as well as the operating mode. In order to determine if any of the relays on the "IPEEE Only" list were "bad actors", a simple comparison of manufacturer and model number was made. If any relays matched the manufacturer and model number they were deemed bad actors (regardless of operating mode).

Dispositioning of Bad Actors

Any bad actor relays identified during this review were evaluated for there potential impact on systems credited in the IPEEE seismic analysis and the potential for recovery.

3.3.3 Results of Review

Non A46 IPEEE Components identified for review

In total, 170 IPEEE components which were beyond the scope of the A-46 effort were identified. Following further review only 83 components were determined to employ relays in their control and/or actuation circuits. This included 49 air or motor operated valves, 4 pumps, 5 fans, 12 circuit breakers, 8 buses and 5 transformers.

Bad Actor Review and Dispositioning

There were a total of 116 primary circuit relay coils identified. None of the primary circuits were found to contain any bad actor relay coils.

In addition, 201 secondary circuit (interlock/actuation) contact pairs were identified in the primary circuits. Four interlock/actuation relay contacts were found to originate from bad actor relays. Those contacts are associated with relays, 50NP/138, 50P/138, 50NBU/138 and 50BU/138, which are all Westinghouse Model SC over-current relays used for protection of the Station Auxiliary Transformer. Since chatter of these specific relays can at most result in a recoverable loss of offsite power (which would be lost for other reasons anyway during significant seismic events) no remedial action was considered necessary.

Secondary Circuit Chatter Review

The potential for secondary circuit relay chatter resulting in component loss of function was dispositioned as discussed above in section 3.3.2.

Of the 201 secondary circuit relays associated with the identified IPEEE primary relays, 123 secondary circuit relay contact pairs were determined to be associated with relays already included in the A46 review; 13 contact pairs were determined to have no adverse affect on the associated component in the event that chatter occurred; 29 relay contacts were determined to be associated with primary circuit relays or receive direct input which was not derived from a secondary circuit (e.g. switch, sensor); and 36 relay contacts were dispositioned on the basis of operator recovery action.

Those contacts dispositioned on the basis of recovery action (OA) can affect only the offsite power supply and containment spray function. The issue of recoverable loss of offsite power was discussed and dismissed above. Given the need to consider no more than a small LOCA event following a seismic event, short term loss of the containment spray function will have little or no impact on the core damage frequency, and an extended time window will be available for recovery without impacting containment performance issues. The loss of the associated equipment is easily recognizable from, and can be recovered from, the control room.

3.4 SUMMARY OF SEISMIC ANALYSIS RESULTS

In conformance with NRC Generic Letter 88-20, Supplement 4, and NUREG-1407, the Indian Point 2 seismic IPEEE analysis used the NRC-approved seismic PRA approach to respond to the information request.

A comprehensive seismic walkdown, discussed in Section 3.1.3, was performed in conjunction with the A-46 program, and documented in accordance with procedures in the GIP and EPRI NP-6041. Structural response, Section 3.1.4, and detailed fragility analysis, Section 3.1.5, provided capacity screening or fragility estimates for the Indian Point 2 structures and equipment. The baseline PRA analysis used the LLNL mean seismic hazard curve, plant-specific fragilities, and the appropriately modified internal events IPE model to calculate seismic core damage frequency. Sensitivity and uncertainty analyses were performed to provide insights into seismic risk. A qualitative containment performance analysis examined key issues related to containment integrity, containment isolation, containment bypass, and containment heat removal/pressure suppression functions. A low ruggedness relay review was performed in addition to the extensive A-46 relay evaluation.

During the course of the seismic IPEEE effort, it was determined that, although the Component Cooling Water Surge Tank met its design basis, the capacity of the tank to withstand beyond design basis seismic events was limited by the capacity of the hold down bolts. As a result of this IPEEE finding, those hold down bolts were replaced by higher tensile strength bolts.

The baseline seismic core damage frequency was 1.46E-5 per year. With the higher tensile strength bolts on the CCW surge tank, the CDF is reduced to 1.1E-5 per year. The dominant sequences result from collapse of the turbine building or superheater stack onto the control building, which is assumed to fail instrumentation and control for the plant systems, resulting in core damage. Non-seismic failures and human interactions were included in the seismic assessment, but were not significant to the overall results. Additional detail on these results, including sensitivity and uncertainty analyses, is presented in Section 3.1.6.5. The containment performance analysis, Section 3.1.7, demonstrated that there are no unique failures or failure modes which would cause an early, large release due to the seismic event. The low ruggedness relay evaluation, Section 3.3, demonstrated that potential relay chatter does not have adverse impacts on the safe shutdown functions and equipment.

Based on these results, there are no potential seismic vulnerabilities identified for the Indian Point 2 plant. The associated seismic safety issues, including A-45, GI-131, A-40, A-17, Eastern Seismicity, and GI-157, have been addressed through the IPEEE and A-46 programs, and can be considered closed for Indian Point 2.

3.5 REFERENCES

3-1 NUREG-1407, Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, Final Report, June 1991.

3-2 EPRI NP-6395-D, Probabilistic Seismic Hazard Evaluation at Nuclear Plant Sites in the Central and Eastern United States: Resolution of the Charleston Issue, April 1989.

3-3 NUREG-1488, Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains, April 1994.

3-4 Seismic Qualification Utility Group (SQUG), Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment, Revision 2, Corrected 2/14/92, February 1992.

3-5 EPRI NP-6041-SL, A Methodology for Assessment of Nuclear Power Plant Seismic Margin (Revision 1), Electric Power Research Institute , Final Report, August 1991.

3-6 EPRI NP-7148-SL, Procedure for Evaluating Nuclear Power Plant Relay Seismic Functionality, December 1990.

3-7 NUREG/CR-4482, Recommendations to the Nuclear Regulatory Commission on Trial Guidelines for Seismic Margin Reviews of Nuclear Power Plants, March 1986.

3-8 Consolidated Edison Company, Indian Point Unit 2 Probabilistic Safety Study (IPPSS), including Amendments 1 and 2, 1982 and 1983.

3-9 IP2 Survey Drawing. A-91-1779 showing area topography.

3-10 IP2 UFSAR pages 1.11-32, 1.11-33, 1.11-40 and 1.0-4, 1.0-5.

3-11 UE&C, Report on Seismic Evaluation of IP2 & 3 Structures, September 1976.

3-12 ALTRAN, 1992, Indian Point Unit 2 Licensing Basis In-Structure Response Spectra, Technical Report No. 92128-TR-01, October 1992.

3-13 EPRI-TR-103059, Methodology for Developing Seismic Fragilities, June 1994.

3-14 NUREG/CR-6011, Review of Structure Damping Values for Elastic Seismic Analysis of Nuclear Power Plants, prepared by EQE, March 1993.

3-15 NUREG/CR-3805, Engineering Characterization of Ground Motion Task 1: Effects of Characteristics of Free-Field Motion, on Structural Response, prepared by Structural Mechanics Associates, May 1984.

3-16 USNRC Regulatory Guide 1.92, Combining Modal Responses and Spatial Components in Seismic Response Analysis, Rev. 1, February 1976.

3-17 Newmark N.M. and W.J. Hall, Development of Criteria for Seismic Review of Selected Nuclear Power Plants, 1978.

3-18 NUREG/CR-4840, Procedures for the External Event Core Damage Frequency Analyses for NUREG-1150, November 1990.

3-19. Letter dated December 24, 1991, from S. Bram (Con Edison) to Document Control Desk (USNRC), Response to Generic Letter 88-20, Supplement 4 (189 day Response)

3-20 "Procedure for Evaluating Nuclear Power Plant Relay Seismic Functionality," EPRI NP-7148-SL, Project 2925-8, Final Report December 1990.

3-21 Con Edison PRIME/OE equipment database.

Table 3.1-1

INDIAN POINT UNIT 2 STRUCTURE RESPONSE FACTORS*

STRUCTURE		F.S.	R	U
Reactor Building		3.04	0.31	0.10
Reactor Bldg. Conc. Int.		0.85	0.19	0.12
Control Building	N-S	8.07	0.53	0.18
	E-W	6.51	0.59	0.16
Prim. Aux. Bldg.	N-S	1.14	0.21	0.11
	E-W	1.15	0.19	0.10
Boric Acid Bldg.	N-S	0.97	0.13	0.10
	E-W	0.95	0.10	0.10
Fuel Storage Bldg	N-S	5.08	0.50	0.14
	E-W	4.89	0.57	0.14
Intake Structure	N-S	0.69	0.24	0.12
	E-W	0.61	0.20	0.11
Shield Wall	N-S	0.65	0.19	0.10
	E-W	2.31	0.40	0.12
Fan House	N-S	1.05	0.27	0.12
	E-W	1.23	0.35	0.12
Nuclear Service Bldg.	N-S	1.15	0.25	0.12
	E-W	1.52	0.30	0.11
Superheater Bldg.	N-S	6.36	0.63	0.17
	E-W	7.81	0.59	0.16
Diesel Gen. Bldg.**		1.25	0.09	0.05
Turbine Bldg.**		1.25	0.09	0.05
F.S. Includes:		Response Spectra Damping Wave Motion Incoherence Earthquake Directional Components Mode Combination Modeling Soil-Structure Interaction		
F.S. and Variability		Based on EPRI 10^{-4} UHS		

* For equipment above base slab using ALTRAN in-structure spectra.

** Housner Ground Spectra x 1.5 used for In-Structure Response Spectra

Table 3.1-2
INDIAN POINT 2 SUMMARY OF SCREENED COMPONENTS

I.D.	NAME	LOCATION*	BASIS
Various	All Valves	Various	Generic Calc
Various	All Pipe	Various	Generic Calc
21ELHX	Excess L.D.H.X.	RBI	A-46 Calc
RRHX21, 22	RHR HX	RBI	A-46 Calc
	Instrument Rack 4A & 4B	RBI	A-46 Calc
	Reactor Pressure Vessel	RBI	NUREG/CR-3660
	Steam Generators	RBI	NUREG/CR-3660
	Reactor Coolant Pump	RBI	NUREG/CR-3660
AT 21-24	Accumulator Tanks	RBI	W Calc
Various	Pressure & Level Transmitters	RBI	Generic Test
BATP 21, 22	Boric Acid Transfer Pumps	PAB	A-46 Calc
21 SWHX	Seal Water HX	PAB	A-46 Calc
RHRP 21, 22	RHR Pumps	PAB	W Calc
SIP 21, 22, 23	SIS Pumps	PAB	W Calc
	Boron Injection Tank	PAB	W Calc
A5, A6	CVCS Inst. Logic Rack	CCR	Generic Test
PE 6, 7, 8, 9	118 VAC Instrument Bus	CCR	Generic Test
PNL SF, SA, SBF2, SG	Supervisory Control Panels	CCR	Generic Test
PNL FB, FBF, FBR, FC, FDF	Flight Panels	CCR	Generic Test

* RBI = Reactor Building Internal Structure
RB = Reactor Containment Shell
PAB = Primary Auxiliary Bldg.
AB = Aux. Feed Pump Bldg./Shield Wall
CCR = Central Control Room
CTLB = Control Building
EDGB = Emergency Diesel Generator Building
TH = Turbine Hall
IT = Intake Structure

Table 3.1-2 (CONTINUED)
SUMMARY OF INDIAN POINT 2 SCREENED COMPONENTS

I.D.	NAME	LOCATION*	BASIS
A1, A2, A3, A4, A6, A9, A10, A11, A12	RPS Logic Racks	CCR	Generic Test
B1, B2, B3, B9, B10	RPS Logic Racks	CCR	Generic Test
LI 920, LI 5751	RWST Level Indication	CCR	Generic Test
Auxrel 1-Auxrel 10	Aux. Relay SIS Relays	CCR	Generic Test
Fuse	Master Relay Fuse	CCR	Generic Test
MR Relay	Master SIS Actuation Relays	CCR	Generic Test
Selswitch	SW Selector Switches	CCR	Generic Test
Batt. 21, 22, 23, 24	Battery Banks	CTLB	Calc
EDD 1, EDD 2, EDD 3, EDD 4	Transfer Switches	CTLB	Generic Test
EDB 1, 5, 6, EDC1	Static Inv. Man. Bypass Sw.	CTLB	Generic Test
EGA 1, 2, 4, 8	10KVA Static Inverters	CTLB	Generic Test
RTA, RTB, RTA-B, RTB-B	Reactor Trip Breakers	CTLB	Generic Test
SLUGTE-N	Sluice Gates	Dock	Not Req.
EDGSAT 21, 22, 23	Air Start Tanks	EDGB	A-46 Calcs

* RBI = Reactor Building Internal Structure
RB = Reactor Containment Shell
PAB = Primary Auxiliary Bldg.
AB = Aux. Feed Pump Bldg./Shield Wall
CCR = Central Control Room
CTLB = Control Building
EDGB = Emergency Diesel Generator Building
TH = Turbine Hall
IT = Intake Structure

Table 3.1-2 (CONTINUED)
SUMMARY OF INDIAN POINT 2 SCREENED COMPONENTS

I.D.	NAME	LOCATION*	BASIS
EDG 21, 23	Emergency Diesel Generators	EDGB	A-46 Calcs
EDG 22**	Emergency Diesel Generator	EDGB	Review of Design Calcs.
EDG Panel ***	Air Receiver Vent. Plenum Control Panel	EDGB	Judgment
DMPR 318-323	EDG Building Exhaust Damper	EDGB	Judgment
L-21 - L-25	EDG Louver	EDGB	Judgment
ELJ 10-ELJ 16	Thermostats for Fans	EDGB	Judgment
EVY15	Solenoid Valve	EDGB	Judgment
EP-1	Electro-Pneumatic Valve	EDGB	Judgment
ADM 1-ADM 10	Air Motors for Louvers	EDGB	Judgment
	Air Cylinders for Fan Louvers	EDGB	Judgment
	Solenoid Valves for Fan Louvers	EDGB	Judgment
PT-1191	SWS Nuclear Header Pressure Transmitter	TH	Judgment
21HDR	Containment Spray Headers	RB	Generic Calc.
CONTSMP	Containment Sump & Recirc. Sump		RBI ****

* RBI = Reactor Building Internal Structure
RB = Reactor Containment Shell
PAB = Primary Auxiliary Bldg.
AB = Aux. Feed Pump Bldg./Shield Wall
CCR = Central Control Room
CTLB = Control Building
EDGB = Emergency Diesel Generator Building
TH = Turbine Hall
IT = Intake Structure

** EDG 22 has no lateral support at exhaust bellows. A review of the design calculations reveals that the displacement of the exhaust pipe at the bellows is sufficiently small to screen out.

*** Has been replaced by SOV and pressure switch

**** Part of Reactor Building Internal Structure

Table 3.1-2 (CONTINUED)
SUMMARY OF INDIAN POINT 2 SCREENED COMPONENTS

I.D.	NAME	LOCATION*	BASIS
RECP 21,22	Containment Recirculation Pump	RBI	Calc.
21,22,23 CHP	Charging Pumps	PAB	Calc(1)
0021NRH	Non-Regenerative HX	PAB	Calc
	Fuel Oil Day Tank	EDGB	Calc
	Regenerative Heat Exchanger	RBI	Calc
MCC 29A,29B	Motor Control Centers	CTLB	Calc
BWS 2A,3A,5A,6A	480V Switchgear	CTLB	Calc(2)
	Component Cooling Pump	PAB	Judgment(3)
	Containment Spray Pump	PAB	Judgment(4)
	Pressurizer	RBI	Judgment(5)

* RBI = Reactor Building Internal Structure
RB = Reactor Containment Shell
PAB = Primary Auxiliary Bldg.
AB = Aux. Feed Pump Bldg./Shield Wall
CCR = Central Control Room
CTLB = Control Building
EDGB = Emergency Diesel Generator Building
TH = Turbine Hall
IT = Intake Structure

(1) Specific bolt torque must be applied to base anchorage for screen.
(2) Contingent on verification of anchorage; 3/4" dia. plug welds assumed at each of 4 corners.
(3) Capacity greater than CCW surge tank with fix.
(4) Capacity greater than RWST.
(5) Based on review of original IPPSS calcs and removal of conservatism.

Table 3.1-3
SEISMIC FRAGILITIES OF IP2
STRUCTURES AND STORAGE TANKS

Building/ Component	Median Acceleration	β_R	β_U	HCLPF (g)
Containment	3.4	0.31	0.38	1.1
Concrete Internals	1.79	.20	.28	.81
Fuel Storage Bldg.	1.37	0.51	0.23	0.41
Superheater Bldg. Frame	3.5	0.62	0.26	0.82
Superheater Bldg. Stack	0.73	0.62	0.21	0.19
Control Bldg. Frame	3.45	0.52	0.22	1.02
Vent Room Wall (S.H. Bldg.)	4.8	0.64	0.3	1.0
Battery Room Block Walls	5.7	0.61	0.3	1.3
P.A.B. Steel Frame	2.98	0.33	0.44	0.84
P.A.B. Infill Panels	2.2	0.20	0.26	1.0
P.A.B. Concrete Structure	3.18g	.22	.30	1.35
Turbine Bldg. Steel Frame(1)	1.5	0.69	0.25	0.32
D.G. Bldg. Steel Frame	8.0	0.51	0.48	1.6
D.G. Buried Fuel Tanks	3.3	0.33	0.41	1.0
Intake Structure	1.52	.33	.24	.59
RWST	0.61	0.29	0.32	0.22
Condensate Storage Tank	1.13	0.29	0.32	0.41
Buried Concrete Ducts	1.90	0.22	0.23	0.91

(1) Base Column Anchor Bolt Failure NS

Table 3.1-4
INDIAN POINT 2 SEISMIC FRAGILITIES OF EQUIPMENT

Building/ Component	Median Acceleration	β_R	β_U	HCLPF (g)
Service Water Pumps	1.23	0.26	0.33	0.46
MCC 26A,B,C, 27, 27A	1.44	0.26	0.32	0.55
0021 Volume Control Tank	1.48	0.36	0.26	0.53
0021, 0022 CCW Heat Exchanger	1.43	0.29	0.34	0.51
Containment Fan Coolers	1.11	0.31	0.21	0.47
0021, 0022, CCW Surge Tank(1)	.90	.30	.37	.30
0021, 0022 CCW Surge Tank(2)		screened out		
21, 22, 23 EDG Control Panels(3)	.65	.28	.44	.20
21, 22, 23 EDG Control Panels(4)		screened out		
MCC 26AA, 26BB(5)	.65	.28	.44	.20
MCC 26AA, 26BB(6)	1.49	0.26	0.43	0.48
Reactor Vessel Internals	1.08	.24	.30	.44
Cable Trays	1.23	.30	.28	.47
Boric Acid Storage Tank	0.8	0.28	0.30	0.31
Switchyard(7)	0.3	0.25	0.50	0.09

(1) Recommended to change to A-449 bolts in saddle.
(2) With addition of A-449 bolts in saddle.
(3) Recommended to be fixed in A-46 program.
(4) With anchorage fix.
(5) Assumed to be no better than EDG Panels. Recommended to be fixed in A-46 program.
(6) With top bracing added.
(7) Historic value for loss of offsite power.

Table 3.1-5
SUMMARY OF INDIAN POINT 2 SEISMIC FRAGILITIES

	Building/Component	Abbrev	Median Acc. (g)	Br	Bu	HCLPF (g)	IPPSS Am	Comments
1	Switchyard	SWYD	0.30	0.25	0.50	0.09	.2-.3	
2	RWST	RWST	0.61	0.29	0.32	0.22	0.70	
3	Superheater Building Stack	STACK	0.73	0.62	0.21	0.19	0.72	
4	Boric Acid Storage Tank		0.80	0.28	0.30	0.31		not in model-CRDs have more capacity
5	CCW Surge Tank	CCWST	0.90	0.30	0.37	0.30		
6	Reactor Vessel Internals	RV	1.08	0.24	0.30	0.44	1.04	
7	Containment Fan Coolers	FC	1.11	0.31	0.21	0.47	1.16	
8	Condensate Storage Tank	CST	1.13	0.29	0.32	0.41	1.28	
9	Service Water Pumps	SWP	1.23	0.26	0.33	0.46		
10	Cable Trays	TRAYS	1.23	0.30	0.28	0.47	1.54	
11	Fuel Storage Building	FSB	1.37	0.51	0.23	0.41	0.92	roof and superstructure-may not fail CCW
12	CCW Heat Exchanger 21,22	CCWHX	1.43	0.29	0.34	0.51		
13	MCC 26A, B, C, 27 & 27A	MCC	1.44	0.26	0.32	0.55	1.65	IPPSS for chatter only
14	Volume Control Tank 21		1.48	0.36	0.26	0.53		not in model-not adequate for SLOCA

Table 3.1-5
SUMMARY OF INDIAN POINT 2 SEISMIC FRAGILITIES

	Building/Component	Abbrev	Median Acc. (g)	Br	Bu	HCLPF (g)	IPPSS Am	Comments
15	MCC 26AA, 26BB	MCC	1.49	0.26	0.43	0.48	1.65	IPPSS for chatter only
16	Turbine Building Steel Frame	TURB	1.50	0.69	0.25	0.32	1.40	
17	Intake Structure (Sliding)	SWINT	1.52	0.33	0.24	0.59		
18	Small LOCA due to Seismic Event	SLOCA	1.50	0.30	0.36	0.50		NUREG/CR-4840 approx. Am=0.92, Bc=0.7
	RANDOM FAILURES							
1	Trajectory of stack hits control room or DG building	TRAJ	0.18					modeled as a constant

Table 3.1-6
SEISMIC DAMAGE STATE RESULTS

SDS	SEISMIC FAILURES	FREQUENCY				STATUS	TRANSFER TO
		MEAN	5 %	MEDIAN	95%		
1	S	2.95E-04	2.61E-04	3.00E-04	3.16E-04	OK	NA
2	R	4.77E-07	9.51E-12	4.69E-08	2.41E-06	OK	GEN TRANSIENT
3	R-CF	6.48E-09	3.78E-16	5.58E-11	2.65E-08	OK	GEN TRANSIENT
4	S2	8.96E-09	2.42E-18	2.41E-12	1.98E-08	OK	SLOCA
5	S2-R	4.61E-09	4.68E-19	8.79E-13	1.01E-08	CD	SLOCA
6	CW	2.85E-07	3.70E-11	2.15E-08	1.28E-06	CD	Seal LOCA
7	CW-FC	5.36E-09	1.06E-16	2.64E-11	2.24E-08	CD	NA
8	CT	2.89E-08	1.62E-16	7.70E-11	9.29E-08	OK	GEN TRANSIENT
9	CT-R	2.10E-08	1.36E-17	2.09E-11	5.73E-08	CD	GEN TRANSIENT
10	CT-S2	6.36E-10	9.69E-22	1.11E-14	5.20E-10	OK	SLOCA
11	CT-S2-R	7.73E-10	9.68E-22	1.36E-14	8.19E-10	CD	SLOCA
12	CT-CW	9.69E-09	7.18E-17	8.73E-12	3.02E-08	CD	Seal LOCA
13	SW	5.38E-08	1.42E-14	4.63E-10	2.16E-07	CD	Loss of SW

Table 3.1-6
SEISMIC DAMAGE STATE RESULTS

SDS	SEISMIC FAILURES	FREQUENCY				STATUS	TRANSFER TO
		MEAN	5 %	MEDIAN	95%		
14	RV	1.40E-08	5.73E-18	1.04E-11	3.89E-08	OK	ATWS
15	RV-R	8.58E-09	1.16E-18	4.47E-12	2.51E-08	CD	ATWS
16	RV-CW	7.92E-09	6.69E-19	3.34E-12	2.07E-08	CD	ATWS
17	RV-CT	5.51E-06	9.68E-08	3.14E-06	1.82E-05	CD	ATWS
18	RV-SW	5.01E-09	3.21E-20	6.01E-13	1.10E-08	CD	ATWS
19	OP	1.78E-05	1.66E-07	9.76E-06	6.05E-05	OK	LOP
20	OP-FC	6.39E-08	2.21E-10	1.47E-08	3.10E-07	OK	LOP
21	OP-R	1.58E-06	4.22E-08	9.89E-07	5.13E-06	OK	LOP
22	OP-R-FC	5.55E-08	3.49E-10	1.93E-08	2.35E-07	OK	LOP
23	OP-S2	3.58E-08	2.74E-13	8.14E-10	1.64E-07	OK	SLOCA-LOP
24	OP-S2-R	4.17E-07	1.23E-12	2.10E-09	1.80E-07	CD	SLOCA-LOP
25	OP-CW	1.08E-06	3.38E-08	5.36E-07	4.09E-06	CD	Seal LOCA-LOP
26	OP-CW-FC	7.71E-08	6.72E-10	2.69E-08	3.32E-07	CD	Seal LOCA-LOP

Table 3.1-6
SEISMIC DAMAGE STATE RESULTS

SDS	SEISMIC FAILURES	FREQUENCY				STATUS	TRANSFER TO
		MEAN	5 %	MEDIAN	95%		
27	OP-CT	1.04E-07	1.61E-11	9.92E-09	5.09E-07	OK	LOP-Feed & Bleed
28	OP-CT-FC	5.02E-09	8.00E-13	4.08E-10	2.14E-08	OK	LOP-Feed & Bleed
29	OP-CT-R	9.96E-08	5.97E-11	1.53E-08	4.71E-07	CD	LOP
30	OP-CT-R-FC	1.12E-08	5.50E-12	1.54E-09	4.86E-08	CD	NA
31	OP-CT-S2	2.93E-09	7.07E-15	2.87E-11	8.25E-09	OK	SLOCA-LOP
32	OP-CT-S2-R	7.19E-09	7.70E-14	1.85E-10	2.46E-8	CD	SLOCA-LOP
33	OP-CT-CW	9.45E-08	6.76E-11	1.74E-08	4.31E-07	CD	Seal LOCA-LOP
34	OP-CT-CW-FC	1.79E-08	9.40E-12	2.77E-09	8.21E-08	CD	NA
35	OP-SW	4.91E-07	8.66E-09	2.29E-07	1.83E-06	CD	NA-SBO
36	OP-EP	5.71E-07	5.38E-09	2.30E-07	2.21E-06	CD	NA-SBO
37	OP-IC	6.23E-06	2.20E-06	5.60E-06	1.25E-05	CD	NA
38	OP-RV	9.43E-08	2.98E-12	5.39E-09	4.55E-07	OK	ATWS-LOP
39	OP-RV-FC	5.91E-09	3.13E-13	3.27E-10	2.68E-08	OK	ATWS-LOP

Table 3.1-6
SEISMIC DAMAGE STATE RESULTS

SDS	SEISMIC FAILURES	FREQUENCY				STATUS	TRANSFER TO
		MEAN	5 %	MEDIAN	95%		
40	OP-RV-R	1.03E-07	3.23E-11	1.50E-08	4.92E-07	CD	ATWS-LOP
41	OP-RV-R-FC	9.00E-08	1.81E-11	1.06E-08	4.57E-07	CD	NA
42	OP-RV-CW	3.83E-07	8.85E-09	1.60E-07	1.43E-06	CD	ATWS-LOP
43	OP-RV-CW-FC	1.88E-08	1.42E-10	5.58E-9	8.13E-08	CD	NA
44	OP-RV-CT	6.23E-08	2.19E-11	7.99E-09	2.97E-07	CD	ATWS-LOP
45	OP-RV-SW	5.60E-08	5.94E-11	1.16E-08	2.57E-07	CD	NA
46	OP-RV-EP	1.70E-07	3.69E-10	4.59E-08	7.41E-07	CD	NA
47	OP-RV-IC	3.55E-07	1.16E-09	1.53E-07	1.36E-06	CD	NA

Table 3.1-7

MODIFIED HUMAN ERROR RATES

Human Interaction ID	Human Interaction Description	IPE Operator Error Rate	Multiplying factor applied in Seismic IPEEE
EPMCC---OPERR (IPOPFO)	Reset MCCs (Locally) following LOSP	3.7E-05	x 10
RCMUV---OPERR-SR (IPOPB4)	Secure ATWS pressure relief	1.0E-01	x 2
RSPMS-HE-RHR--SM (IPOPR1)	Align RHR to recirculation given SLOCA and failure of Recirculation Pumps	1.5E-03	x 1
RSMOV-HE-LPR__LL (IPOPR6)	Switchover to low pressure recirculation phase following LLOCA or SLOCA with successful depressurization	1.7E-03	x 1
CSMOV-HE____889S (IPOPR9)	Align recirculation to provide Containment Spray	3.7E-04	x 1
AF_OPERR_L14 (IPOP01)	Establish flow from Turbine Driven AFW pump (TDAFWP) prior to SG dryout	4.0E-03	x 10
AF_OPERR_L13 (IPOP02)	Reset Turbine Driven AFW pump (local control)	2.9E-02	x 5
AF_OPERR_L16 (IPOP03)	Establish flow from TDAFWP prior to SG dryout given failure of high head injection	1.1E-02	x 5
AF_OPERR_L13 (IPOP04)	Establish flow from TDAFWP prior to SG dryout for ATWS events	1.3E-02	x 5
HPI_PORV_HENATWS (IPOPFB)	Establish primary bleed & feed following loss of AFW	7.1E-03	x 10
RSMOV_HE_RECIRCHH (IPOPR3)	Switchover to recirculation following MLOCA	2.3E-05	x 1
RSMOV_HEHPRECIRCRS (IPOPRA)	Switchover to high head recirculation following SLOCA	3.7E-04	x 1
RSPMS_HE_____RHR (IPOPR1)	Align RHR to recirculation given SLOCA and failure of Recirculation Pumps	1.5E-03	x 1
HPI_PORV_HEOATWS (IPOPSB)	Initiate primary bleed only following ATWS	1.0E-01	x 2
RCMOV___OPERR_PV (IPOPB1)	Close PORV block valve during a transient	4.0E-03	x 10

Table 3.1-8
SEISMIC QUANTIFICATION RESULTS

SDS	SEISMIC FAILURES	SDS FREQUENCY (PER YEAR)	CORE DAMAGE FREQUENCY (PER YEAR)
1	S	1.6E-02	negl
2	R	1.6E-05	7.8E-09
3	R-FC	1.6E-07	1.6E-07
4	S2-(FC)	2.7E-07	1.0E-09
5	S2-R-(FC)	9.2E-08	negl
6	CW	9.1E-06	9.1E-06
7	CW-FC	1.3E-07	1.3E-07
8	CT	8.2E-07	6.9E-08
9	CT-R-(FC)	3.5E-07	3.5E-07
10	CT-S2	8.4E-09	negl
11	CT-S2-R	1.3E-08	negl
12	CT-CW-(FC)	1.9E-07	1.9E-07
13	SW	1.2E-06	1.2E-06
14	RV-(FC)	5.6E-07	5.0E-07
15	RV-R-(FC)	2.3E-07	2.3E-07
16	RV-CW-(FC)	2.0E-07	2.0E-07
17	RV-CT-(FC)	6.3E-08	negl
18	RV-SW	7.1E-08	negl
19	OP	8.0E-04	4.6E-06
20	OP-FC	1.6E-06	1.3E-09
21	OP-R	4.3E-05	1.4E-07
22	OP-R-FC	1.3E-06	1.1E-09
23	OP-S2-(FC)	9.2E-07	1.5E-08
24	OP-S2-R-(FC)	7.0E-07	7.0E-07

(FC): fan cooler failure is conservatively assumed for these low frequency sequences

Table 3.1-8
SEISMIC QUANTIFICATION RESULTS
(continued)

SDS	SEISMIC FAILURES	SDS FREQUENCY (PER YEAR)	CORE DAMAGE FREQUENCY (PER YEAR)
25	OP-CW	2.7E-05	2.7E-05
26	OP-CW-FC	1.3E-06	1.3E-06
27	OP-CT	2.6E-06	6.4E-07
28	OP-CT-FC	1.1E-07	2.2E-08
29	OP-CT-R	2.1E-06	2.1E-06
30	OP-CT-R-FC	2.3E-07	2.3E-07
31	OP-CT-S2-(FC)	6.3E-08	negl
32	OP-CT-S2-R-(FC)	1.0E-07	1.0E-07
33	OP-CT-CW	1.8E-06	1.8E-06
34	OP-CT-CW-FC	2.9E-07	2.9E-07
35	OP-SW	9.6E-06	9.6E-06
36	OP-EP	1.1E-05	1.1E-05
37	OP-IC	6.2E-05	6.2E-05
38	OP-RV	2.2E-06	2.0E-06
39	OP-RV-FC	1.1E-07	9.2E-08
40	OP-RV-R	1.8E-06	1.8E-06
41	OP-RV-R-FC	2.0E-07	2.0E-07
42	OP-RV-CW	1.7E-06	1.7E-06
43	OP-RV-CW-FC	3.1E-07	3.1E-07
44	OP-RV-CT-(FC)	1.0E-06	1.0E-06
45	OP-RV-SW	1.6E-06	1.6E-06
46	OP-RV-EP	2.0E-06	2.0E-06
47	OP-RV-IC	3.6E-06	3.6E-06
		TOTAL CDF	1.46E-05

(FC): fan cooler failure is conservatively assumed for these low frequency sequences

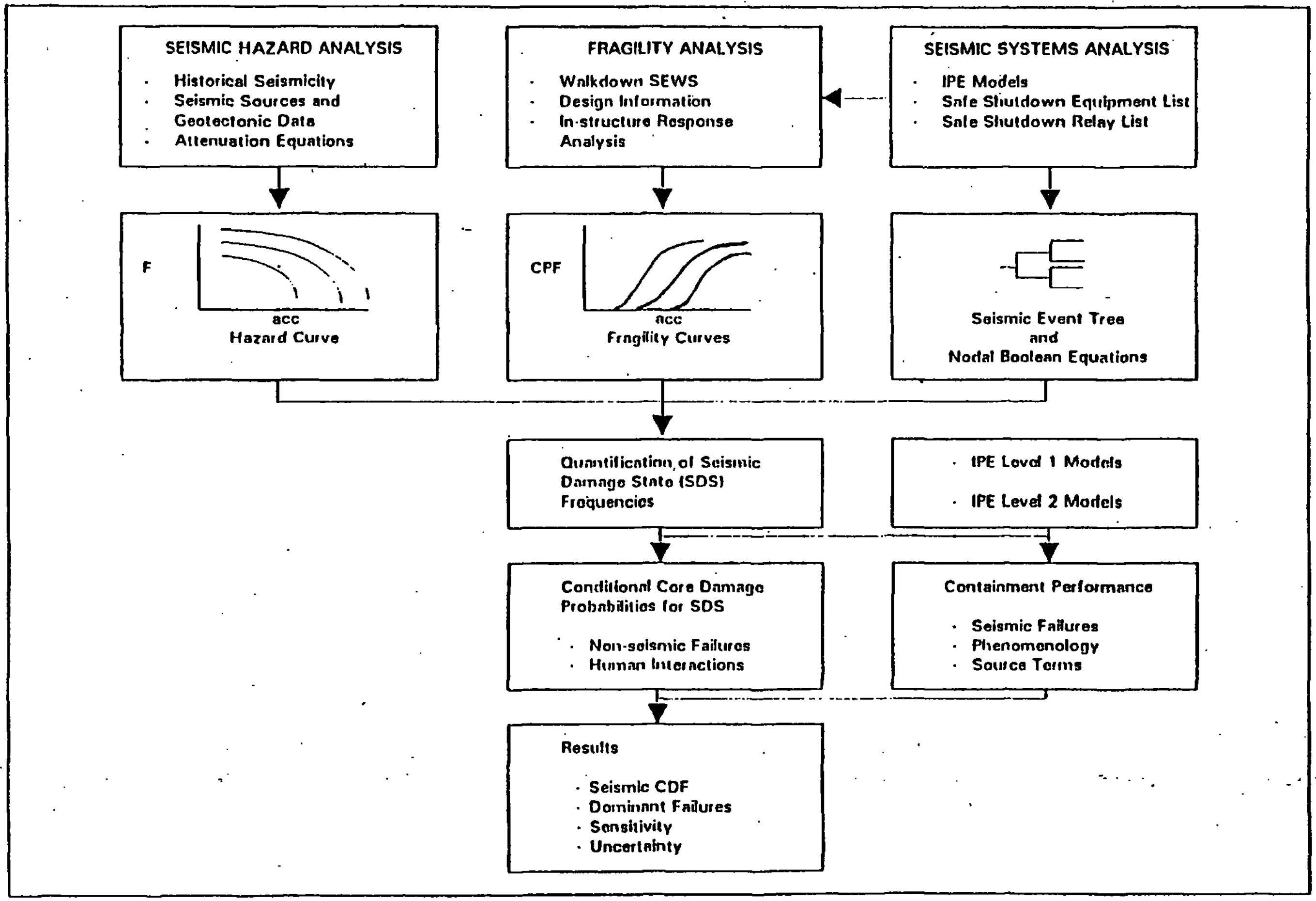

Figure 3.0-1
Seismic Analysis Overall Methodology

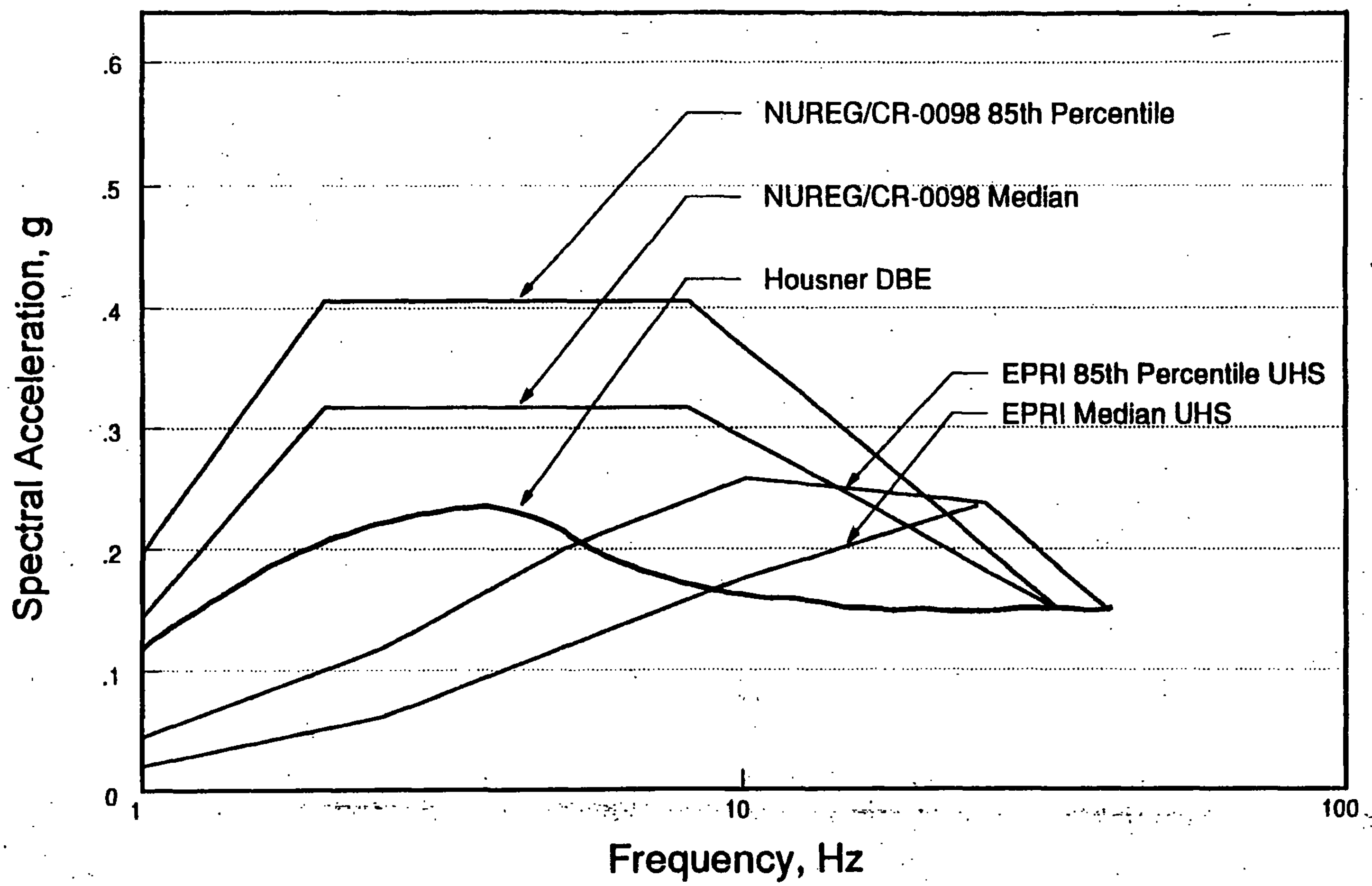

Figure 3.1-1
Comparison of Housner DBE Spectrum, NUREG/CR-0098 Median and 85th Percentile Spectra and EPRI Median and 85th percentile UHS, 5% Damping, Normalized to 0.15g

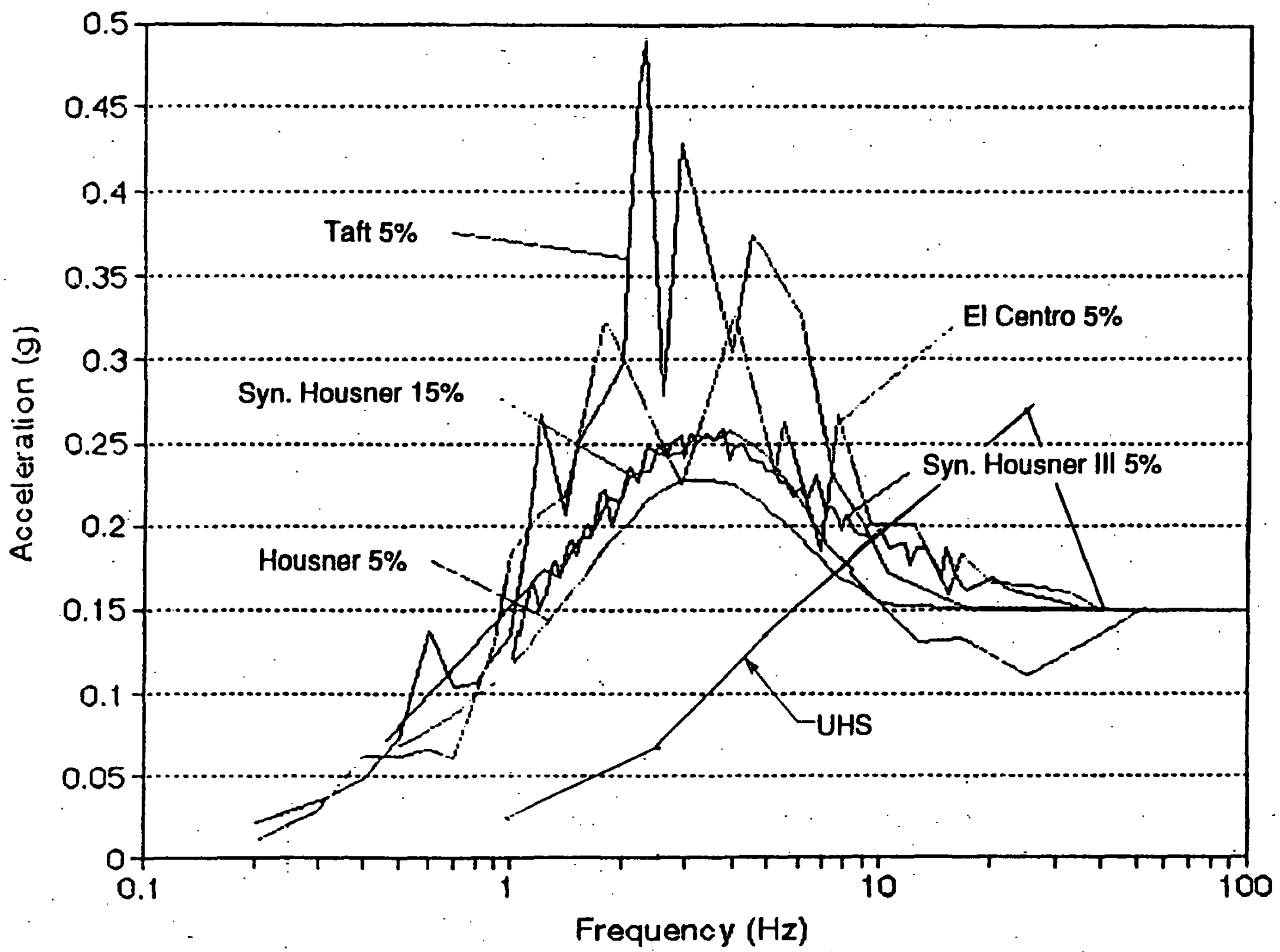

Figure 3.1-2
Indian Point Unit 2 Time-History Input Response Spectra at 5% Structural Damping

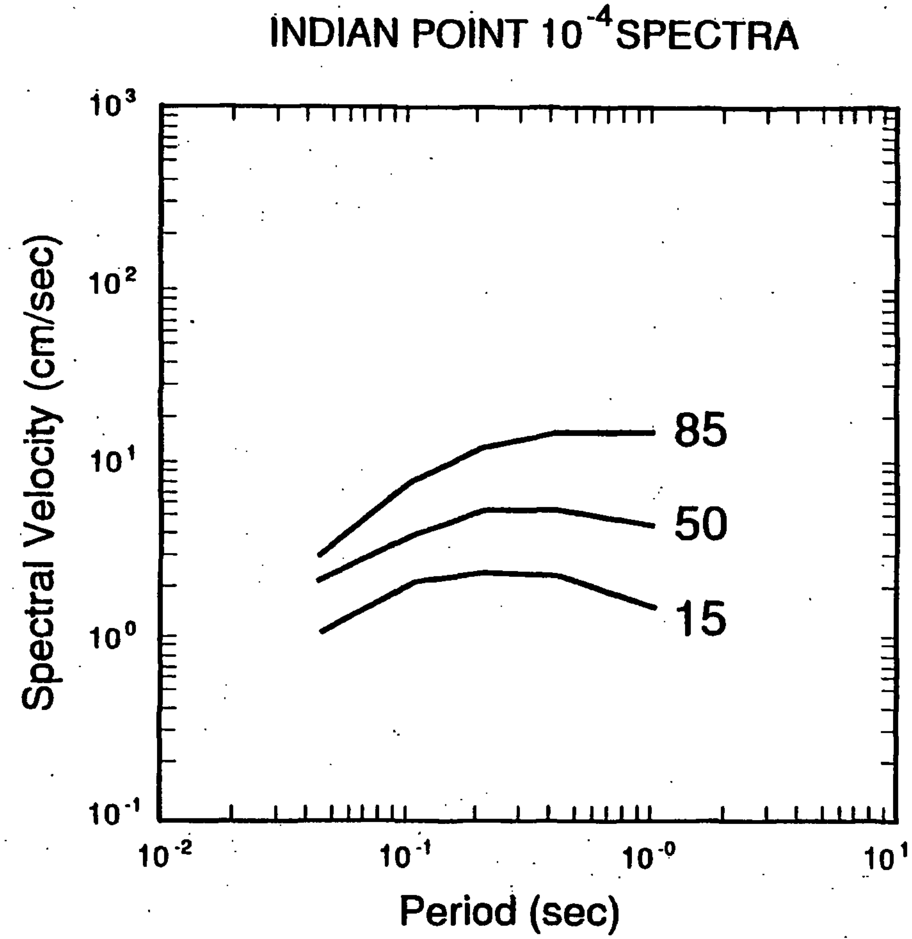

Figure 3.1-3
Uniform hazard spectra for the 10^{-4} annual probability of exceedance: Indian Point site. Spectra shown for three percentiles: 15th, 50th, and 85th

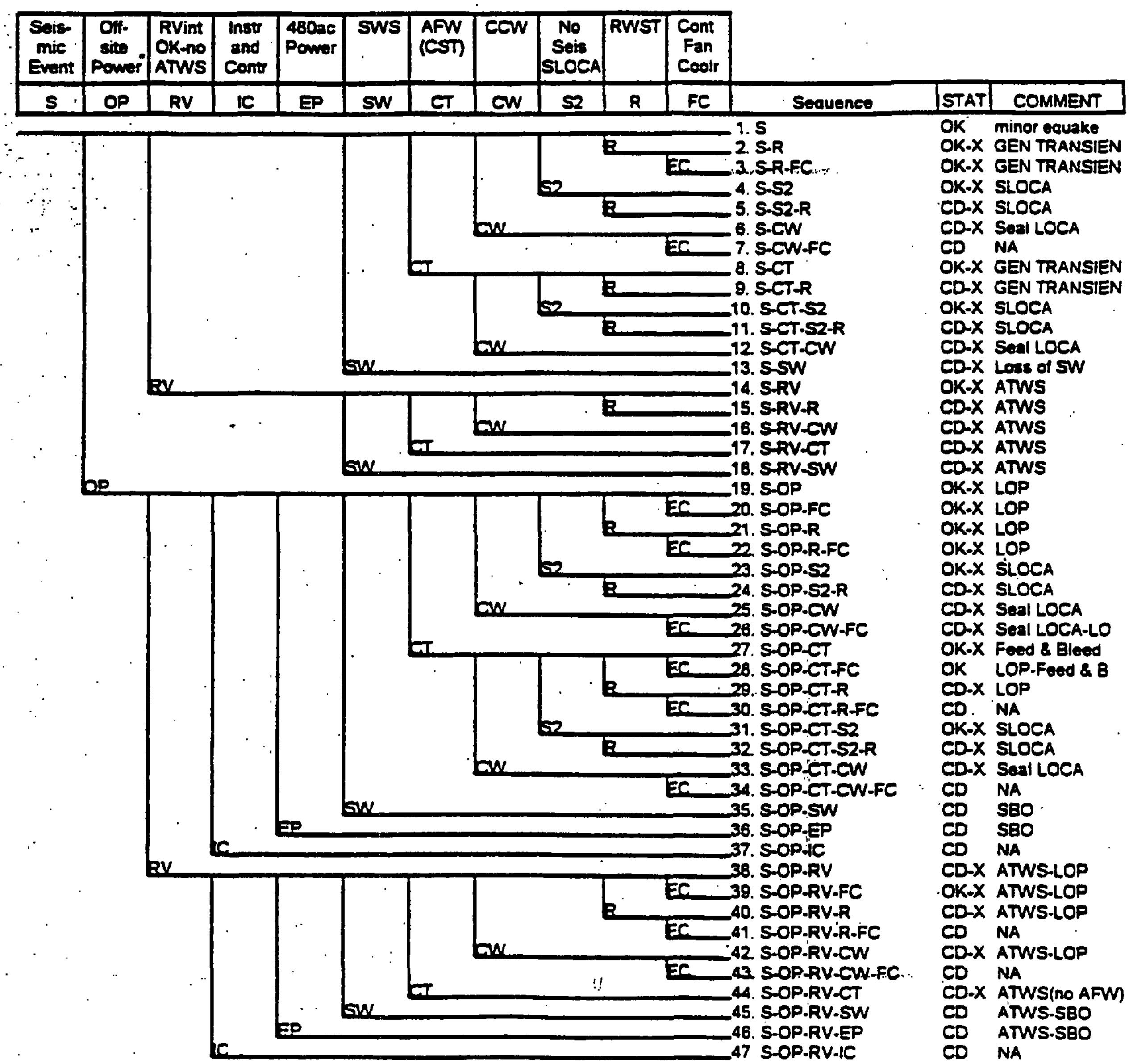

Figure 3.1-4
Indian Point 2 Seismic Event Tree

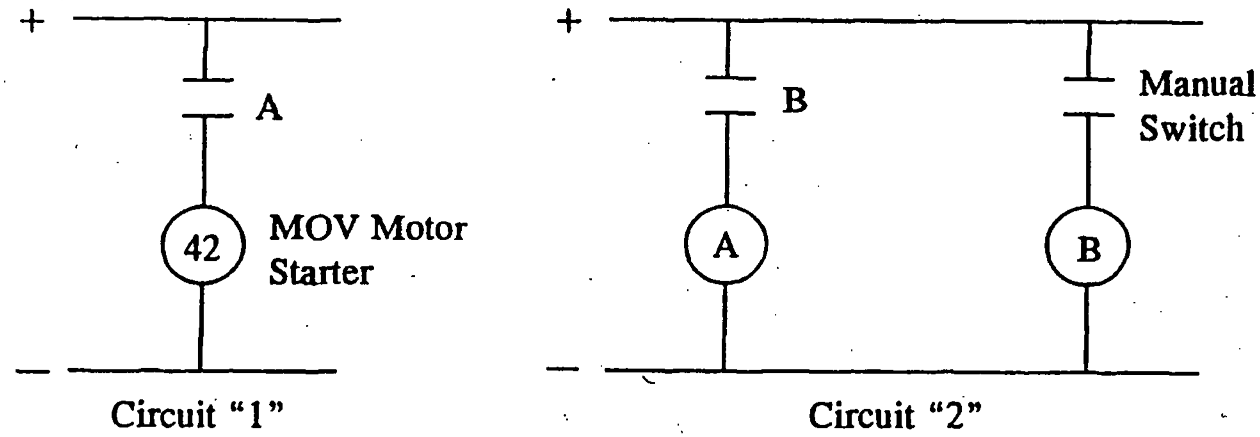

Figure 3.3-1
Secondary Circuit Relay Chatter Dependency Example

INTERNAL FIRES ANALYSIS

4.0 METHODOLOGY SELECTION

Acceptable methodologies for analyzing internal fires are specified in NUREG-1407, Section 4 (Reference 4-1). Of those methods, a Fire PRA was selected for IP2. Specific fire PRA issues raised in NUREG-1407 were addressed as follows:

Fire compartments of potential risk significance were identified using the initial qualitative and quantitative screening steps defined in the FIVE methodology document (Reference 4-2).

Those fire compartments which did not screen out were subject to detailed modeling described in various procedure guides such as NUREG-2300 (Reference 4-3), NUREG-2815 (Reference 4-4), NSAC/181 (Reference 4-5) and EPRI NP 3385-01 (Reference 4-6). The COMPBRN IIIe code (Reference 4-7) together with simplified methods prescribed in the FIVE methodology were used for all deterministic modeling of fire growth and damage. Inter-area and compartment fire propagation analysis was not required based on the review of the fire area and compartment boundaries performed to address the Fire Risk Scoping Study, NUREG/CR-5088 (Reference 4-8) issues.

Fire frequencies in particular locations accounted for both U.S. plant generic experience (Reference 4-9) and area specific fixed ignition sources. The contribution of transient fuels and sources was accounted for by addressing plant specific procedures for the control of combustibles and ignition sources, as well as by considering periodic inspections for transients.

Coincident failure of accident mitigating equipment was modeled, accounting for random component failures and human error.

Uncertainties in the fire modeling input parameters were propagated using the monte carlo simulation option of the COMPBRN code to predict overall probability of damage and mean time to damage for specific source/target. Point estimate values were used for all other input parameters.

Fire Risk Scoping Study Issues were addressed through specifically tailored walkdowns as defined in the FIVE methodology, including seismic fire interactions, effects of fire suppressants on safety related equipment, fire fighter effectiveness, fire barrier effectiveness and control systems interactions.

4.1 REVIEW OF PLANT INFORMATION AND WALKDOWN

4.1.1 Plant Information Sources

For this analysis, IP2 plant information was obtained from plant drawings, plant procedures, and other documents such as the Individual Plant Examination (IPE) (Reference 4-10) and the Fire Protection Program Plan (FPPP) (Reference 4-11).

The FPPP defines the post fire safe shutdown methodology including the definition of the fire area and zone boundaries, as well as safe shutdown (SSD) and safety related (SR) systems components. This report also addresses associated circuits and the Alternate Safe Shut Down System (ASSS) capability which was specifically installed to mitigate transients and equipment loss due to fires. In addition, assessments for individual fire zones and fire areas are provided. This document also contain a complete discussion of the plant's fire protection program including: organizational responsibilities; fire prevention abilities (control of combustibles and ignition sources, and control of fire protection system impairments); employee training; fire brigade manning, response, training, drills, and equipment; and fire protection systems (detection, alarm and suppression systems).

Implementation of the fire protection program is governed by specific plant procedures which were also reviewed as part of this IPEEE project. Examples include; SAO-704, Removal/Re-installation of Fire Rated Assemblies and SAO-702, Control of Ignition Sources.

The above reports provide information on the method of Appendix R compliance, combustible loading analysis, exemption requests and engineering analyses. The existence of these reports is pre-supposed by the FIVE methodology. They were used to obtain the fire area boundary definitions, the safe shutdown and other safety related functions which may be disabled in each fire zone, and the combustible loading characteristics, including cable tray loadings and transient material inventories.

For compartments requiring detailed analyses, specific power and control wires were identified through reviews of electrical schematics and control wiring diagrams. Cable routes were then obtained from the IP-2 cable database. Plant cable tray and conduit drawings were utilized to identify physical locations.

Plant drawings were also used for locating equipment to obtain information about the number and type of ignition sources and targets in each fire area. The plant specific data were used to relate generic fire frequency data obtained from the EPRI fire events database to specific IP2 fire zones.

Post fire safe shutdown procedures embodied within the Emergency Operating Procedures and Abnormal Operating Procedure A27.1.9, "Shutdown Procedure for Inaccessibility of the Control Room" were utilized in defining applicable recovery actions and in evaluating the Human Error Probabilities (HEPs).

4.1.2 Outstanding Modifications

Generic Letter 88-20, Appendix 4, section 4.3 requires licensees to provide a discussion of the status of Appendix R modifications. All Appendix R modifications at IP2 have been completed.

4.1.3 Plant Walkdowns

Several plant walkdowns were performed for the IP-2 fire analysis. The main objective of these walkdowns was to gather plant data which cannot be readily derived from documented sources in order to perform the screening and detailed analyses, as well as complete the evaluation of Fire Risk Scoping Study issues. Another objective was to confirm that information which was obtained from documented sources is consistent with the as-built, as-operated plant. The main walkdown activities are discussed below.

Walkdowns were carried out to verify plant conditions for the Fire Risk Scoping Study evaluation. Information pertaining to potential seismic-fire interactions (seismically induced fires from hydrogen, or from storage of diesel oil, fuel oil or lubricating oil; or seismic actuation of fire suppression systems) were obtained.

A walkdown was also performed primarily to verify the information in the qualitative and quantitative screening analyses and obtain specific information on the type and location of ignition sources in each compartment.

Several additional walkdowns were performed on an as-required basis with the aim of obtaining information regarding specific plant configurations. For example, information was obtained on:

(i) The type of sealing and venting of electrical cabinets;
(ii) The type of confinement provided for potential oil spills;
(iii) The separation of redundant components/wireways provided within control room cabinets;
(iv) The type and proximity of fire detectors to specific fire sources; and
(v) The proximity of exposed combustibles to ignition sources.

All walkdowns were carried out by NUS and/or Con Edison personnel. The participants were either fire protection engineers or PRA specialists who, between them, possessed the following qualifications:

(i) Familiarity with the Appendix R Safe shutdown paths, equipment and cable raceway layouts and Appendix R Shutdown Procedures,

(ii) Familiarity with the plant fire protection design and standards, including fire barrier characteristics, fire detection and suppression systems and fire prevention measures, and

(iii) Understanding of PRA models and assumptions made in fire PRA analysis.

4.2 FIRE HAZARD ANALYSIS OVERVIEW (METHODOLOGY)

4.2.1 Overview

The IP2 plant has already undergone an extensive deterministic fire hazards and safe shut down review conducted under the 10 CFR 50 Appendix R program and was demonstrated to be in full compliance. Although the plant information contained within the Appendix R submittals and supporting documentation provided much of the input to this IPEEE fire analyses, the underlying bases for the two studies are substantially different. Consequently, any findings or conclusions reached concerning potential fire vulnerabilities in no way contradicts or compromises the existing Appendix R analyses. Differences in the Appendix R and fire IPEEE methodologies include:

Issue	*Appendix R*	*Fire IPEEE*
Extent of equipment damage	Generally assumes all equipment in fire area is damaged	Uses fire modeling to determine extent of damage from specific sources
Likelihood of fire	Assumes fire may occur regardless of sources present	Evaluates fire frequency as a basis for estimating actual risk
Coincident equipment failures	Assumes equipment unaffected by the fire will be available for plant shutdown	Considers random failures of unaffected equipment coincident with fire damage
Operator reliability	Assumes operators will take actions directed by procedures having demonstrated adequate time and access is available	Considers potential operator error and associated reliability
Offsite power	Assumes offsite power unavailable	Only assumes offsite power unavailable if shown to be damaged by the fire, otherwise considers random failure probability coincident with the fire
Fire protection systems	Has specific requirements regarding installation and operability depending upon fire hazard	Only addresses and credits fire protection system operability for risk significant fire scenarios

In theory the contribution to core damage frequency from fires anywhere in the plant may be assessed in detail. However this is impractical, due to the large number of possible scenarios, and also unnecessary, since fires in many plant areas are incapable of causing significant damage no matter how severe they become. Consequently, the first stage in performing a fire analysis was to perform a systematic screening of all fire areas to identify those plant locations where fires may present a significant hazard.

The FIVE methodology qualitative and quantitative screening procedures were applied, as described below. The results of this screening are presented in Sections 4.2.3 of this report.

4.2.1.1 Qualitative Screening Analysis of Fire Areas

Steps 1-6, below, apply to all plant areas with the exception of containment. For various reasons, principally low fire potential, FIVE permits a less stringent criteria to be applied to the screening of containment fires. Step 7 describes this approach. Further details of the methodology can be found in Sections 5.3 and 6.3.1 of the FIVE methodology document (Reference 4-2).

The purpose of this task was to identify the boundaries of the plant fire areas, together with the location of equipment and cables which, if damaged by fire, would cause a plant shutdown and degradation of shutdown paths identified in the plant's safe shutdown analysis and IPE. That information was then initially used in this subtask as a basis for systematically screening out fire areas from further consideration using the non-probabilistic criteria developed in the FIVE methodology document. Further use was made of the information in subsequent tasks.

Step 1: Identify Plant Safe Shutdown Systems

The safe shutdown analysis described in the FPPP, and PRA models were reviewed to identify the IP2 safe shutdown systems. Both front line and support systems were listed, including balance of plant as well as safety related equipment. In the FIVE methodology, the target shutdown mode of operation selected should be consistent with the plant's PSA (FIVE, Section 2-10). In general, the IP2 event trees were constructed to model success paths which lead to hot shutdown. The combination of systems required to achieve this stable condition for a period of 24 hours, following various types of initiating events, is discussed in Section 3 of the IPE (Reference 4-10).

Step 2: Identify Fire Areas

The plant was initially divided into fire areas which are physically separated from one another and the boundaries must comply with the requirements of the FIVE methodology (definition 2.2). That is, fire area boundaries must have at least a two hour rating with all penetrations sealed with assemblies which have an equivalent rating, or an engineering evaluation must have been performed to determine whether the boundary can withstand the fire hazards within the area and protect important equipment in the area from a fire outside the area.

Step 3: Identify Safe Shutdown Equipment in Each Fire Area

Safe shutdown (SSD), other safety related equipment and the associated cabling for the required components are identified in the IP-2 FPPP (Appendix B) for each fire zone. Based on the above information, a summary of the affected safe shutdown equipment in each fire zone and area were documented.

Step 4: Perform Fire Area vs Safe Shutdown System Screening

Using the information from step 3, and a review of the potential fire induced initiating events (e.g., loss of offsite power, LOCA) those fire areas which do not contain safe shutdown equipment (components, cables, etc.) required to achieve stable hot shutdown in any of the associated zones were screened out as risk insignificant.

Step 5: Perform Fire Area vs Safe shutdown Function Evaluation

For each fire area which is not screened out after step 4, the following evaluation was performed:

(i) All SSD equipment considered affected as a result of fire in the area are assumed failed.

(ii) The normal alternate shutdown SSD equipment are assumed unavailable (Due to some random failure unrelated to the fire).

(iii) Then, given the above conditions (not Appendix R assumption of the coincidental loss of off-site power event), the following determination is made:

   (a) Is there a requirement for plant trip/shutdown within 8 hours (manual or automatic)?

   (b) Does the shutdown require the use of equipment assumed to be damaged or unavailable (i.e. another path may exist which is independent of these paths)?

If the answer to (a) or (b) is "NO", then the area is screened out.

(Note: This screening criteria, which is consistent with that defined in the FIVE methodology, is more severe than the Appendix R acceptance criteria since it requires at least two paths to be unaffected by the fire whereas Appendix R requires only one. A later amendment to the FIVE methodology (Reference 4-12), incorporated more conservative criteria. However, this was issued following the completion of this phase of the IP2 analysis. Its application would not have had a significant impact on determining the fire locations requiring detailed analysis.)

Step 6: Compartment Identification, Interaction and Screening

At this stage the FIVE methodology also provides the option of sub-dividing an area into compartments, which are locations within an area separated by non-combustible barriers. Such barriers, although not necessarily fire rated, may provide a significant degree of independence with respect to fire propagation. A fire compartment interaction analysis was performed in this step to determine if such propagation could be shown to be ruled out. The evaluation of fire spread between compartments was performed with aid of the screening criteria presented in section 5.3.6 of the FIVE methodology. Factors such as the characteristics of the inter compartment barrier, combustible loading, and installed fire detection and suppression systems were considered.

Where all boundaries of a compartment could be screened out (i.e. risk of propagation is insignificant) then the screening criteria applied in step 5 was re-applied considering only the potential for damage within the compartment.

Those compartments not screened out at this stage were analyzed further in the quantitative analyses.

Step 7: Containment Fire Evaluation

FIVE indicates that containment fires are generally not expected to be risk significant and consequently does not provide data for quantitative evaluation. Several reasons are provided, namely;

a) a hot gas layer is unlikely to form in most areas which can damage cables

b) the small number of historical events during plant operation, a large percentage of which were RCP fires which are unlikely to occur in the future due to oil collection system design improvements.

c) previous fire PRAs did not show containment fires to be risk significant

Consequently FIVE recommends a qualitative assessment to determine if there are any unique plant features which make the plant more susceptible than those plants examined previously. Specific issues to be addressed are; (1) plant experience which might indicate fires have occurred frequently, and (2) the potential for redundant trains of critical equipment to be exposed to the same fire plume or be in a confined space subject to damage by a hot gas layer.

4.2.1.2 Fire Frequencies

The purpose of this task was to evaluate the fire frequency for compartments which were not screened out in the qualitative screening process described above. These frequencies are intended for use in the quantitative screening evaluation and detailed fire analysis.

For IP2, the fire frequency calculations were performed using the methods provided in the FIVE methodology, Phase 2, step 1, and generic fire data information provided in the Fire Events Data Base (Reference 4-9). The approach requires the analyst to weight generic fire data according to the specific types and quantity of ignition sources present in the area being evaluated. FIVE provides detailed guidance for determining both "Location Weighting Factors" and "Ignition Source Weighting Factors" and a formalized documentation process for recording input data and calculating fire frequencies.

The number, type and location of each ignition source was initially evaluated from IP-2 drawings and the IP-2 Operating Equipment (OE) data base. The information was modified as necessary as a result of plant walkdowns.

The area/compartment ignition sources and the fire frequency calculations were documented according to the FIVE Attachment 10.2, Table 3, Ignition Source Data Sheet (ISDS). These are included in the tier 2 documentation together with the analysis assumptions and data used.

4.2.1.3 Quantitative Screening Analysis

The FIVE methodology permits screening of a fire area/compartment when either of the following can be shown to be less than 1E-6/year:

(i) the total area/compartment fire ignition frequency

(ii) the fire ignition frequency multiplied by the conditional core damage probability given loss of all equipment/cable in the compartment

At this screening stage, the PRA model was used to determine the conditional core damage probability.

4.2.2 Assumptions and Other Modeling Considerations for Screening

4.2.2.1 Success Criteria

The Appendix R analysis included equipment necessary to achieve cold shutdown. The IPEEE fire analysis was limited to achieving a stable hot shut down state for general transients and loss of offsite power. using the same success criteria identified in the IPE. LOCAs are not able to be mitigated with Appendix R equipment alone and consequently areas where such an event may be induced by a fire due to spurious operation of hi-lo interface valves were not screened out.

The first step of the FIVE methodology is to identify plant safe shutdown systems [FIVE page 5-3]. This analysis primarily takes credit for the same shutdown systems as defined in the FPPP Report for IP-2 to achieve stable hot shutdown since the location of equipment and cable associated with these systems is known [IP2 FPPP Section 10.2.3 and Figure 10.2-1]. However, experience has shown that it is also advantageous at this stage in the analysis to be able to take credit for offsite power supplies to the emergency buses. (This function is assumed to be unavailable for Appendix R purposes). Specific analyses were therefore performed to identify and locate the necessary components and cables to support offsite power.

In summary the following safety functions are required for achieving stable hot shutdown:

Reactivity Control - In both the Appendix R and the IPE models short term reactivity control is accomplished through insertion of control rods. In addition the Appendix R model addresses long term reactivity control which is achieved by increasing the boron concentration of the Reactor Coolant System (RCS) in order to maintain sufficient shutdown margin. However, since this boration capability would not be required before 24 hours after shutdown it is not addressed in this IPEEE analysis. Furthermore, the effect of a fire will most likely cause rod insertion, through de-energization of the RPS, rather than inhibit its operation. There are also several proceduralized methods to manually de-energize the RPS by taking action either within or outside the control room. The potential for fire events to prevent adequate reactivity control is therefore insignificant.

Core Heat Removal - Core heat removal for hot shutdown is accomplished through natural circulation, pressure control and inventory control. Natural circulation is achieved by fulfillment of pressure control, inventory control and secondary heat removal. RCS pressure control is achieved by initial actions to isolate RCS letdown and/or other leakage paths, and by control of secondary heat removal rate. RCS inventory make up would not be required for 30 hours given successful letdown isolation and secondary side heat removal although it has been considered an essential function for establishing stable hot shutdown in the Appendix R analysis. In the IPE, and in this IPEEE analysis, charging is not considered to be an essential function for inventory control in order to achieve hot shutdown (given a non-LOCA condition). The potential for fires to degrade letdown isolation capability is discussed in Section 4.2.2.2.

Primary System Integrity - RCS system integrity is required to aid core heat removal and secondary heat removal functions to assure that natural circulation, pressure control, and inventory control can be maintained and heat removed through a steam generator. This function can be achieved by maintaining the high/low pressure interface integrity and RCP seal integrity. Reliability of the high/low pressure integrity sub-function is discussed in Section 4.2.2. RCS seal integrity can be achieved through operation of either component cooling water for thermal barrier cooling or seal injection from a charging pump. Both methods are credited in the IPE and in this IPEEE fire analysis.

Secondary Heat Removal - Upon reactor shutdown, the cooling requirements are short term removal of stored energy in the RCS as well as the effects of delayed neutrons, and long-term removal of heat due to the decay of the fission products. Stable hot shutdown may be maintained indefinitely by supplying water from one or more of the Auxiliary Feedwater pumps and venting the steam generators (SG) to atmosphere via the safety valves. Feedwater may be obtained from the Condensate Storage Tank or the City Water Tank. In addition to supplying water to the SGs, secondary side inventory maintenance requires isolation of at least one steam generator which is being feed by the AFW. Generally, this involves automatic closing of the main steam isolation valves (MSIVs).

If the MSIVs do not automatically close, EOP E-2 and AOP 27.1.9 provide guidance for local manual MSIV closure. In the event that local fires prevent local manual closing of the MSIVs, SG isolation should still be achieved since the turbine stop and throttle valves close when the turbine is tripped. *Note that if SG isolation is provided by the turbine stop* and throttle valves, operation of the steam dumps must be monitored to ensure the cooldown rate is not excessive.

Long-Term Heat Removal - Long term removal of heat using the RHR system is not addressed in this IPEEE analysis since its function (given a non LOCA condition) is to provide cooldown below hot shutdown conditions.

Process Monitoring - Instrumentation required in order to assure a makeup supply to the RCS and steam generators include pressurizer level, RWST level, steam generator level and pressure, and condensate storage tank level. Pressurizer level and steam generator level are available in the fan house as part of the Alternate Safe Shutdown System. The indication is pneumatic and does not rely on any power sources. Piping associated with ASSS is not susceptible to fire damage. RWST and CST tank levels and steam generator pressure are available locally through mechanical devices.

Support Systems - Essential service water is required to support the emergency diesel generators. Non essential service water and component cooling water provides cooling to the charging pumps, RHR pumps and RHR heat exchangers. The charging and RHR pumps may also be cooled by manually aligning a city water supply.

Alternate Safe Shutdown System (ASSS) - If the normal shutdown method is available, power is provided to at least one train of the above equipment from the diesel generators via the 480v switchgear. If the normal shutdown power or control is disabled by a fire, the ASSS is used to provide independent power supplies from IP-1 auxiliaries to specific components associated with the systems described above. These power supplies are hardwired through transfer switches, generally located in close proximity to the equipment being served. The IP-1 auxiliaries receive power from gas turbines 1, 2 or 3 in the event of a loss of offsite power from the grid. Plant shutdown using the ASSS is directed according to Abnormal Operating Procedure A.27.1.9, "Control Room Inaccessibility Safe Shut Down Control".

Passive mechanical components - Valves, heat exchangers, and piping systems, which are exposed to the fire, remain structurally intact as a pressure barrier or structural member of a system. Mechanical components that are exposed to a fire may be actively operated after the fire is extinguished if a local operational capability exists (i.e., handwheel). However, if there are restrictions for entering the fire affected location (e.g. restriction due to severe smoke levels), then the restrictions on performing the local operation noted in the FPPP were also accounted for in this analysis.

In addition to the above functions, two additional support functions have to be provided during a fire event, namely emergency lighting and communication. These support systems will not be included in this analysis since emergency lighting is located in each fire area with sufficient Appendix R analysis to establish reliability. Portable lighting can also be utilized. Emergency communication can be achieved by utilizing portable communication systems.

4.2.2.2 Fire Initiated Events

Consistent with the FIVE methodology, it has been assumed that a fire will cause a demand for plant shutdown unless it can be shown with confidence that the damage sustained will not result in an automatic plant trip, and the degradation of safety related equipment is such that a shutdown would not be required within 8 hours in order to meet technical specifications.

The analysis utilizes the IP-2 IPE initiating event categorization except for those initiating events which cannot be induced as a result of fire (e.g. steam generator tube rupture or steam line break). In summary, the categories of fire inducing initiating events which are evaluated include:

1- General Transient (GT)

2- Loss of Offsite Power (LOSP)

3- Small Break Loss of Coolant Accident (SLOCA)

<u>General Transients</u>: A transient can occur as a result of many different fire induced faults and may even be initiated by the operator in response to spurious signals or technical specification limitations. A general transient is assumed to occur given a fire in an area unless specific discussion is provided which excludes any type of fire induced initiating event or identifies a more onerous event (i.e., LOCA or loss of offsite power).

Loss of Offsite Power: Areas where the fire may result in a loss of offsite power have been specifically identified. These fire areas include area A (zones 11, 14 and 15), J (zone 43A) and an unclassified outside area containing the auxiliary transformers (zones 57A and 58A).

Loss of Coolant Accidents: Fire induced LOCA events may occur as a result of loss of RCP thermal barrier cooling and seal injection, or as a result of electrically operated valves in the RCS spuriously operating. LOCAs associated with the RCPs seal failures are addressed in the FPPP analysis and in this analysis by questioning the availability of Component Cooling and charging pumps. In the FPPP, an evaluation is also performed to demonstrate that the RCS integrity will not be compromised as a result of spurious valve operations resulting from fire induced electrical shorts.

Since the FIVE methodology requires the consideration of random equipment failure in addition to fire induced faults (whereas the Appendix R analysis does not), the FPPP analysis of LOCAs was reviewed in order to identify any specific areas where the conclusions reached in the Appendix R study may not necessarily satisfy the IPEEE requirements.

A systems review (FPPP, section 10.2.4.1) of the interfaces which use electrically controlled valves to isolate the primary coolant system pressure boundary identified the following interfaces:

PATH DESCRIPTION	ORIGINATION	MOV OR AOV
1. RHR Letdown	RCS Loop 2	731, 730
2. Letdown (CVCS)	RCS Loop 1	459, 200A, B, C, 201, 202
3. Excess Letdown (CVCS)	RCS Loop 1	213, 123
4. RCS Pressure Control (PORV)	Pressurizer	535, 536, 455C, 456
5. Reactor Vessel Head Vent	Reactor Vessel Head	3100, 3101

Excluded from consideration were injection lines containing check valves in the high pressure portion of the piping and lines that are normally isolated and can only be opened by manually operated valves.

Each of these paths was considered in terms of the number of simultaneous hot shorts required to cause a LOCA, possible mitigating actions that might be taken to terminate the event and other design and operational precautions. The conclusion of this review was that the only potentially risk significant, fire induced LOCA pathways are associated with the Pressurizer PORV and Reactor Head Vent paths. A hot short of the associated control or power cables in fire areas A and F (fires zones 1A, 2A, 74A and 7A) were identified as possible causes in the screening analysis. Fire in these locations could both cause the event and prevent subsequent isolation. (Damage to three phase power cable was later eliminated as a potential cause during the detailed analyses -see section 4.4.2. COMPBRN fire modeling confirmed FPPP analyses that damage to Reactor Head Vent power and control cables in fire zone 7A was not credible, thus eliminating the potential for fire induced LOCAs in fire Area F).

4.2.2.3 Self Ignited Cable and Junction Box Fires

All electric cable construction utilized at IP-2 station satisfies the requirements of Branch Technical Position D.3(f) which requires the electrical cable construction to pass the IEEE No.383 flame test or be covered with an approved flame retardant coating and properly derated [Reference 11, page A-59]. Although the IP-2 cables were not specifically tested to the IEEE 383 flame test, the cables did pass the ASTM-D-470-59T vertical flame test, as well as certain other tests developed by Con Edison. The NRC concluded that this was sufficient to meet the requirements of the BTP and that no further testing to the IEEE 383 criteria was required.

The cable installed at IP2 meets the intent of the IEEE 383 criteria and thus can be considered as qualified for the purposes of applying the FIVE methodology. Thus there is no contribution to fire frequency from self ignited fires in non qualified cable or associated junction box fires at IP2.

The FIVE methodology also identifies a small contribution from self ignited fires in qualified cable junction boxes. However, sustained combustion from such fires is deemed to be not credible and fires of this type are not considered further. This is consistent with assertions made in previous PRA studies in particular the EPRI PRA Requantification Studies, NSAC/181 (Reference 4-5).

4.2.3 Analysis Results

4.2.3.1 Qualitative Screening of Fire Areas

The FPPP designates inter-area fire barriers at IP2 as Type I. Such barriers are required to be 3 hour rated or can be of a lesser rating if justified by an exemption. All such exemptions are justified on the basis of engineering evaluations and have been accepted by the NRC. Consequently, the fire area definitions defined within the FPPP comply with the requirements of the FIVE methodology. A list of fire areas and associated fire zones is included as Table 4.2-1.

The qualitative screening analysis was completed using the FIVE methodology as discussed in Section 4.2.1 and includes all plant fire areas and zones addressed in the FPPP. The results and the screening rationale are shown in Tables 4.2-2 and 4.2-3. The following fire areas screened out:

Fire Area B	RHR Pump Room 21
Fire Area D	Fuel Storage Building
Fire Area E	No 21 Charging Pump Room
Fire Area G	Diesel Generator Building
Fire Area F	PAB Upper Elevation and Fan House
Fire Area H	Containment
Fire Area J	Alternate Safe Shutdown Cable and Equipment Area
Fire Area K	Steam feedwater Piping Area
Fire Area L	IP-1 Screen well Pump House
Fire Area Q	Penetration H-20
(Outdoor)	Rad Monitoring Building
(Outdoor)	Main Transformer 21
(Outdoor)	Main Transformer 22
(Outdoor)	Unit Auxiliary Transformer
(Outdoor)	Station Auxiliary Transformer
(Outdoor)	Corridor and Open Floor Area of Chem Systems Bldg.
(Outdoor)	Oil And Mixed Waste Room

4.2.3.2 Sub-Division of Areas into Compartments and Fire Compartment Interaction Analysis

Of the remaining (non screened fire areas) identified in Table 4.2-3, fire areas C, I, N and P (auxiliary boiler feed pump room, intake structure, manhole and component cooling water pump room) were not amenable to sub-division. However, fire area A, which includes the control building electrical and piping tunnels and penetration areas, portions of the PAB and the tank farm, was subdivided into 4 fire compartments, designated A1, A2, A3 and A4. The fire zones included within each compartment are listed in Table 4.2-4. The interfacing boundaries of these compartments were subsequently examined using the FCIA approach and in the majority of the cases were found to meet the screening criteria. In the few cases where this was not the case, an engineering evaluation was performed and the potential for inter compartment fire propagation was deemed to be negligible based on factors such as low combustible loading and no combustible continuity at the boundary or lack of safe shutdown equipment or cable in the proximity of the boundary.

4.2.3.3 Qualitative Screening of Fire Compartments

Fire compartments A2 and A4 were screened out due to the lack of any safe shutdown equipment or cable within the compartment boundaries.

4.2.3.4 Fire Ignition Frequencies for Quantitative Screening

For each fire zone located within the fire areas and compartment that were not screened out in the previous steps, estimates of fire ignition frequency were prepared for use in the quantitative screening and detailed analyses. These estimates were based on data from the Fire Events Database for US Nuclear Power Plants from the Electric Power Research Institute (EPRI, 1992b) and adjusted for Indian Point 2 using information from plant arrangement drawings or other documentation and equipment databases. A summary of the database appears in the FIVE methodology document. The frequencies were then updated based on the plant walkdowns that were performed for this purpose. Table 4.2-5 contains a summary of the fire zone ignition frequencies obtained from the individual Ignition Source Data Sheets (ISDS).

Fire area N (Manhole) was the only fire area or compartment screened solely on the basis of ignition frequency (i.e. ignition frequencies below the 10^{-6} per year criteria). This is a small enclosure, in which the only potential ignition source and combustible is IEEE rated or equivalent electrical cable.

4.2.3.5 Quantitative PRA Screening Analysis

The FIVE methodology includes a second level of screening which provides for a conservative estimation of the contribution to core damage frequency. All equipment cable in a compartment was assumed to fail due to a fire. Using an event tree representative of the most significant failure, the contribution to the core damage frequency was calculated. The initiating event frequency was set equal to the frequency of fire in the compartment. If this contribution was less than 10^{-6}/yr the compartment was screened out. For this analysis, fault tree and event tree models from the PRA were used.

None of the remaining fire areas or compartments were screened in this step.

4.2.4 Detailed Fire Modeling

The second part of the fire analysis deals specifically with the potentially significant fire areas and compartments which could not be eliminated as part of the qualitative and quantitative screening process.

As previously stated, the initial quantifications assumed all vulnerable equipment in the fire zones was damaged. This can obviously be very conservative in many cases. For example, fire damage to an elevated cable tray from a small to medium size fire, on the opposite side of a room, with no intervening combustibles, is highly unlikely if not impossible. Using fire damage calculations, many of the fire sources can be shown to be benign based on their size and target range, and can be screened from further consideration. Furthermore, if a fire compartment is protected by an automatic fire suppression system the initial estimate of the probability of equipment damage due to fires can often be substantially reduced. Through a process of eliminating many of the ignition sources as potential causes of significant equipment damage or reducing the estimated probability of such damage, a more realistic (less conservative) estimate of the fire induced risk can be obtained. The analysis discussed in sections 4.3 to 4.6. The control room analysis uses a somewhat unique approach, which is discussed in sections 4.6.3. The evaluation of the effects of the fire on the containment systems are described in Section 4.7.

4.3 FIRE GROWTH AND PROPAGATION MODELING

4.3.1 Fire Scenario Identification and Evaluation

The following general steps were performed for each unscreened fire area/compartment:

1. A qualitative fire scenario assessment was made for each individual fire ignition source identified in the ignition source data sheets (see section 4.2.3.2) considering the spatial relationship of the ignition sources to: equipment required for safe shutdown, intervening combustibles and the size of the enclosure as well as the fragility of the targets in question. Ignition sources which were incapable of causing significant damage to safe shutdown equipment were screened out.

2. COMPBRN models were developed for those fire scenarios identified in Step 1. The models were developed using plant layout drawings, cable tray and conduit layout drawings and schedules, combustible loading calculations, lube oil maintenance procedures and/or any other information needed to accurately describe the geometric and pyrotechnic characteristics of the fire scenario.

3. For those fire scenario models developed in step 2, the point estimate module of COMPBRN was run using worst case values (e.g., highest heat release rates, and lowest damage and ignition temperatures) to determine what, if any, shut down equipment/cables may be damaged, and if fire propagation occurs.

4. For those runs made in step 3 which indicated a potential for significant equipment damage, the uncertainty module of the COMPBRN program was run to predict the probability distribution of the time to damage. Where appropriate, floor area ratios (i.e., critical fire damage area divided by total floor area) were also be calculated at this point.

5. An assessment of the probability of fire suppression prior to damage was made based on the type of fire detection and suppression available, and the time available for fire brigade response.

6. Fire scenario frequencies were then evaluated based on three factors for fixed sources and four factors for transient sources:

$$Fi = F_{IG} \times p(Di) \times p(FS) \times A_r$$

Where: F_{IG} is the frequency of ignition associated with a particular source p(Di) is the cumulative probability of the damage which defines the scenario i given no suppression prior to the fire self extinguishing

P(FS) is the probability of failing to extinguish the fire (manually or automatically prior to damage

A_T is the critical area ratio for transient fires (i.e. the probability that a transient fire within a room is located within the damage range of the target) .

7. The core damage frequency associated with a particular fire scenario was evaluated using the updated IPE model embodied within the RISKMAN code. Each fire scenario was defined as an initiating event and the appropriate event tree requantified setting the probability of failure of the damaged equipment to 1.0 (i.e. failure guaranteed). Credit was taken for recovery following damage to normal power supplies or spurious component operation, using hard wired the alternate safe shutdown (ASSS) power and manual realignment of valves and electrical breakers where adequate time is available to take such actions.

The method used to evaluate control room fires is unique with respect to that used for other plant areas in that it requires the analyst to consider the potential for fire propagation within cabinets as well as the probability and consequences of evacuation. The approach adopted for IP2 follows that described in NSAC 181 (Reference 4-5) and suppression data from EPRI 3385-01 (Reference 4-6). The analysis is described in Appendix A.

4.3.2 Fire Modeling including the use of COMPBRN

4.3.2.1 COMPBRN Code

COMPBRN IIIe is a deterministic code which follows a quasi-static approach to simulate the process of fire growth and spread during the pre-flashover period in an enclosure. COMPBRN breaks a postulated fire environment into three sectors: flame/plume sector, hot gas layer sector, and ambient sector. Fire and heat transfer models and correlations are used to predict the thermal environment as a function of time. The thermal response of the specified targets for a given fire scenario are used to calculate the time to damage or ignition. The COMPBRN manual (Reference 4-7) discusses the modules of the code and the parameters used for defining a fire scenario. The uncertainty module in COMPBRN can be used to estimate the probability distribution of the damage time.

COMPBRN was used as part of a detailed evaluation to predict the possibility and/or the probability of equipment and/or cable within an enclosure sustaining damage due to the direct radiant or convective heat. In addition, the possibility and/or probability of fire propagation along cable trays or between adjacent equipment can be predicted. It should be noted that the COMPBRN code does not take into account the possibility of damage due to smoke or soot. However, this limitation is not considered to have a significant impact on the analysis results since, the detrimental short-term effects of smoke on equipment are not believed to be significant (Reference 4-6).

As indicated in section 4.3.1, the general approach was to first investigate the possibility of fire damage and/or propagation. Then, if the possibility for damage and/or propagation exists, determine the probability distribution of the damage time.

4.3.2.2 Characterization of Ignition Sources

Pump. Compressor and Fan Fires

Two types of ignition can arise from pump and compressor fires; the motor windings can ignite due to some electrical fault or bearing grease and oil burn. In either case the heat release rates are not easily defined. For motor fires a conservative bounding heat release rate equivalent to a small electrical cabinet is recommended (ie. 69 kW) (Reference 4-6). In this the heat release rate was assumed to 100kW. Such fires are assumed to burn at this rate for 30 minutes.

For oil fires the burning rate must be determined on a case by case basis, using COMPBRN The spill area accounts for the total oil inventory of the pump reservoirs and any confinements, including trays, dikes, floor slopes and drains, etc. Based on the Fire Events Data Base, 18% of pump motor fires and 2% of compressor fires involved oil spills (References 4-9 and 4-6). These fractions will be factored into the fire scenario frequencies.

Electrical Cabinet Fires

An HRR history similar to that of the No. 23, 24, and 25 tests of the Sandia National Labs (SNL) cabinet fire tests (4-12), was assumed for the electrical cabinets. The modeled maximum HRR history, is presented along with No. 23, 24 and 25 SNL cabinet fire test HRR histories in Figure 4.3-1. The modeled HRR history generally envelopes the SNL test fire HRR histories, and has a maximum HRR of approximately 1200 kW. This is a conservative heat release rate history on the basis that the SNL cabinet fire tests included nine other tests involving cable in vertical cabinets which produced significantly lower heat release rates. For uncertainty analyses the surface controlled burning rate was distributed normally with a lower bound fixed to give a minimum heat release rate of approximately 800kW.

The base of the fire was fixed at the top or just below the top elevation of the cabinet being modeled.

Small cabinets, containing minimal combustibles, are represented by 100kW fires which exceeds to the heat output from small cabinet fires (69kW) observed during the Sandia fire tests.

In one particular case (electrical penetration area, fire zone 74A) a small cabinet fire was found to be potentially significant. In this case a more realistic model was developed assuming a uniform heat release rate distribution with upper and lower bounds of 100kW and 50kW respectively. The total combustible loading of the source was estimated at 1.2E5kJ (about 5kG of cable)

No fire propagation was assumed to be possible if cabinets were not ventilated and all cable entries were via continuous conduit.

Small Electrical/Electromechanical Sources There are several types of relatively small electrical fire sources which contain minimal amounts of combustible material and as such are incapable of releasing large quantities of energy in the event of a fire. These sources include small transformers (50- 100KVA) battery chargers, inverters and electric motors which do no contain significant amounts of bearing oil or grease. In such cases major combustible is motor or transformer winding. For fires involving pump winding only EPRI 3385-01 (Reference 4-6) recommends a heat release rate of 69kW. For this analysis a heat release rate of 100kW has been selected to bound motor fires as well as the other similar types of source described here.

Engineering judgement used to screen these low combustible ignition sources is based on the proximity of the ignition source to the target (i.e., either safe shutdown equipment or intervening combustibles), and the presence of structures/equipment which could impede fire spread or provide radiant shielding (e.g., walls, non-essential, non-combustible equipment, curbs, etc.).

Cables Fires As indicated in section 4.2.2, self ignited cable fires at IP2 were previously screened out due to cables being IEEE 383 rated or equivalent. For similar reasons significant junction box/cable splice fires and welding induced cable fires which do not involve transient materials were not considered in the detailed analysis. In the FEDB two such events are reported; however, in neither case did sustained combustion or propagation occur (Reference 4-9). This approach is consistent with the approach adopted in NSAC 181 (Reference 4-5).

Fans: Fans are treated the same as pumps.

Large Transformers: All transformers of concern in this analysis are dry type. Transformers are treated the same as electrical cabinets.

Transient Fires: Transient fires, including those welding fires defined in Reference 4-5 as Plant Wide Ignition Source category #2 "Welding/Ordinary Combustibles", are generally placed in the "worst case" realistic location. For example, a trash can fire may be placed directly under sensitive equipment at an elevation consistent with the height of trash cans used in the compartment given that it is physically possible for the trash can to occupy that location (i.e., if an electrical cabinet occupied the "worst case" location for a trash can fire with respect to overhead cable trays, the trash can should be placed next to (realistic), not on top of or superimposed on the cabinet).

A previous review of EPRI's Fire Events Database (documented in NSAC-178L) has been performed to characterize the severity of transient fires in nuclear power plants. Three heat release rate (HRR) bins were selected, one for liquids and two for Class "A" materials labeled small and medium. Based on a survey of Class "A" fires, the following values were chosen to describe a normal distribution of the fire sizes to characterizing transient Class "A" fires:

	Min. Value	Mean Value	Max. Value
Small Class "A" Fires	10 BTU/s	137 BTU/s	400 BTU/s
Medium Class "A" Fires	340 BTU/s	380 BTU/s	600 BTU/s

The upper bound of 600 BTU/s (630kW) encompassed somewhat larger amounts of wood (up to 100 lb.), or moderate amounts of other materials with higher HRRs than wood (e.g., foam rubber). Only fires involving liquid combustibles were judged likely to exceed 600 BTU/s.

Class "A" transient fires were therefore all conservatively chosen to be "medium" sized fires with HRRs described by a normal distribution with 5th and 95th percentiles of about 340 BTU/s (about 360 kW) and 600 BTU/s (about 630 kW), respectively. The HRRs were varied by assigning a distribution to the specific burning rate, while holding the heating value constant thereby allowing fires with smaller HRRs to burn longer for a given combustible loading.

COMPBRN was allowed to predict the HRRs of liquid transient fires. The HRRs of liquid pool or container fires is dependent upon the physical characteristics of the liquid and the exposed surface area.

Class "A" transient fire durations, including welding/ordinary combustible fires, were determined on a case by case basis dependent upon the expected transient combustible loading as defined in the IP2 Fire Protection Program Plan (Reference 4-11), burning at a rate of 340 to 600 BTU/s. Lower HRR fires will burn longer. COMPBRN is allowed to predict the duration of flammable liquid spill fires. The duration of flammable liquid spill fires is a function of the HRRs predicted by COMPBRN, and the quantity of flammable liquid available for consumption.

Station Administrative Order (SAO) 701 states that unattended storage of combustible oil or other combustible fluids shall be prohibited in the following locations:

a) Containment spray pump room (fire zone 2)
b) Primary Water Make Up Pump Room (fire zone 2A)
c) Waste Storage and Drumming Area (fire zone 6A)
d) 480v Switchgear Room (fire zone 14)
e) Component cooling water pump room (fire zone 1)
f) Auxiliary boiler feed pump room (fire zone 23)
g) Electrical piping and tunnel, piping and penetration area (fire zone 1A)
h) Electrical penetration area (fire zone 74A)
i) Valve room (fire zone 13A)
j) Stairwell and corridor (fire zone 18A and 13A)

k) Cable spreading room (fire zone 11)
l) Electrical tunnel (fire zone 32A)

Therefore, transient combustibles fires in these zones were limited to class "A".

Hydrogen fires

External Sources

With one specific exception the main hydrogen supply tanks and piping for the turbine generator, volume control tank, etc. are located in fire compartments which were previously screened out and are thus not a threat to targets being considered in this detailed analysis. Neither are small hydrogen gas bottles which used for analytical purposes positioned in the fire zones under evaluation.

The exception is the VCT hydrogen supply which is routed through the pipe chase fire zone 30A. However, the hydrogen piping is designed to seismic category 1 standards and there are no pipe fittings (valves, etc) which may the usual sources of potential leakage. In addition there is no safe shut down equipment or cable which is susceptible to fire damage in the zone.

External sources of hydrogen are therefore not a risk significant fire source.

Plant Generated Sources

Plant generated hydrogen is present in the Waste Gas System piping and equipment which is located in various parts of the PAB. A review of the location of piping and equipment associated with the waste gas system indicated that it was confined to the large and small gas decay tank cells (zone 14A), the spent resin storage cell (zone 16A), a valve gallery (zone 15A), the CVCS pipe chase (zone 31A), the waste gas compressor room (zone 10A) and the pipe penetration area (1A). With the exception of the pipe penetration area, none of these locations contain any safe shutdown equipment which is vulnerable to fire damage and the combustible content is negligible.

Historically, three miscellaneous hydrogen fires have occurred in PWR Auxiliary Buildings lasting from 1 to 9 minutes. The damage severity in all cases was minimal and did not impact any safety related equipment. The sources appear to have been associated with a leaking regulator, leaking swage lock fitting and other equipment problems.

Thus, generally it may be concluded that a PAB hydrogen ignition located at the source of the leak would not be capable of causing any significant local damage (no vulnerable safe shutdown equipment nearby) or spreading to other areas due to the lack of combustibles in the vicinity of the flame). Even in the event of local hydrogen detonation due to the accumulation of hydrogen in the room where the leak occurs, damage to safety related equipment is unlikely due to the heavy concrete construction of those rooms. Furthermore any hydrogen escaping into the main auxiliary building would be quickly dispersed due to its buoyancy and the open layout of the PAB.

As inferred above these arguments do not apply to the pipe penetration area (fire zone 1). However, the waste gas piping in this area is minimal and is constructed to seismic class 1 standards. The only equipment which represents a potential source of leakage is a valve (1787). which is located in the penetration area, well away from any significant amount of exposed combustible or vulnerable safe shutdown equipment. If hydrogen were to leak and not immediately ignite, it would be quickly dissipate into the fire zone which is a large volume open to the remainder of the PAB.

Plant generated hydrogen does not therefore represent a risk significant fire hazard at IP2.

4.4 EVALUATION OF FIRE COMPONENT FRAGILITIES AND FAILURE MODES

4.4.1 Fire Damage Criteria for Potential Targets

Cables

The thermal properties of cable insulation are subject to significant uncertainty. Based on a review numerous published data sources the following input parameters were selected as representative of the properties of the various types of cable installed at IP2 which include; silicone insulated /asbestos jacketed, EPR insulated/neoprene or lead jacketed, PVC insulated /asbestos jacketed and cross linked polyethylene cable/neoprene jacketed:

	Low Value	High Value
Piloted Ignition Temperature	576 K	1029 K
Spontaneous Ignition Temperature	705 K	880 K
Damage Temperature	623 K	789 K

These input ignition temperature parameters are all described by a uniform distribution. A negative lognormal distribution is used for the damage temperature.

Consistent with other fire PRAs (e.g., Reference 4-14) cables in conduits or armored cables are assumed to be incapable of igniting. However, it is assumed that damage is still possible. Hence, the piloted and spontaneous ignition temperatures for these cables is artificially increased to prevent ignition.

Electrical Equipment

Electrical equipment, such as cabinets and motors, are generally located just above floor level and is not subjected to the high temperatures associated with fire plumes or hot gas layers. However, damage may occur due to direct radiant heat or, in special circumstances, by a descending hot gas layer. Electrical equipment is assumed to fail if the impinging heat flux exceeds $10kW/m^2$ (Reference 4-2) or if it's temperature is elevated above it's damage threshold. The damage temperature assumed are as follows (Reference 4-6):

Sensitive electrical components (e.g. solid state subject to set point/signal output drift)	150°F (339K)
Electric Motors (20% above operating limit)	150°F (339K)
Relays, switches	320°F (433K)

4.4.2 Fire Induced Failure Mechanism for Electrical Cable

Two classes of failure mode are evaluated. The first class is an "open circuit", which generally results in a loss of component functionality, unless the component (e.g. valve) fails to its accident position. That is, the damage results in a circuit discontinuity caused directly by the fire or as a result of the circuit grounding. In the latter case a protection device (fuse or circuit breaker) ll open producing the same effect. The second class, "hot short", consists of failures that cause inadvertent action; for example spurious valve operation leading to opening of hi-lo interface pathways.

An evaluation of the relative likelihood of the different failure modes (NUREG/CR-2258) (Reference 4-15) determined that, for a multi-conductor cable that contains both wires, the frequency of a hot short is .068. For the IP2 fire analysis, a value of 0.1 is assumed and is applied in all cases regardless of whether the wires are in the same multi-conductor. However, the potential for hot shorts is only applied in the case of single phase, AC control circuits or DC power/control circuits. The potential for multi-phase (cable to cable) hot shorts (in the absence of grounding) in power circuits is considered to be negligible.

4.5 FIRE SUPPRESSION

Automatic fire suppression system failure rates were developed in NSAC-179L (Reference 4-16) and are as follows:

CO2	.04
Wet Pipe Sprinkler	.02
Deluge or Pre Action Sprinklers	.05

Automatic pre-action sprinkler actuation has been credited for fires in the electrical tunnel.

In this case timely actuation is guaranteed since the heat detectors and sprinklers are located alongside the trays which they protect and actuate well below the damage temperature of the cable.

Generally, manual fire suppression, prior to damage, can only been credited if the manual response time during unannounced IP2 fire drills can be shown to be shorter than the time for cable damage predicted by COMPBRN (less the detector response time). If the maximum drill response time is less than the mean damage interval the probability of non response, FS can be assigned a value of 0.1. (Reference 4-2). If the mean damage time falls within the range of the drill response times, p(FS) is assigned a value of 0.5 (i.e. there is a 50% chance of successful manual suppression]. Manual fire suppression was credited for fires in the cable spreading room, the switchgear room, the control room and one specific, slow developing fire, in the electrical penetration area.

For cases where a fire watch is present credit can be taken for a much faster response time, as in the case of ordinary combustible fires initiated by welding and cutting. Station Administrative Order SAO 702 requires a fire watch, equipped with an appropriate extinguisher, during and 30 minutes after completion of any work involving open flames. Historically, all welding and cutting fires in the fire events data base (Reference 4-9) were detected and extinguished within a few minutes by either a fire watch or the welder. Figure 4-4 of Reference 4-6 provides a cumulative probability distribution with respect to time, for welding/ordinary combustible fire being extinguished. Realistically, it will take several minutes for a fire to develop to the point where significant damage can result. Conservatively it was assumed that 3 minutes are available for the fire watch or welder to extinguish a fire without the potential for significant damage. The cumulative probability of the fire being extinguished during this period is 0.85. Therefore, a manual non suppression probability (p(FS)) of 0.15 may be applied to welding/ordinary combustible fires. In fact this was only applied in evaluating the risk from fires in the cable spreading room (fire zone 11) after a preliminary analysis indicated a significant contribution to risk from such fires.

4.6 ANALYSIS OF PLANT SYSTEMS SEQUENCES AND PLANT RESPONSE

4.6.1 Modeling of Fire Induced Core Damage Sequences

The fire sequence analysis model is developed from the Indian Point updated IPE model (designated IP2ET) currently in service at Con Edison and maintained in the computer code RISKMAN version 5.11.

The IP2ET model was cloned and renamed FIRE. The core damage frequencies resulting from each fire scenario (and associated fire damage state) were quantified by modifying the event and fault tree logic models to reflect the frequency of each fire scenario and the associated impact on equipment and operator error probabilities.

The modifications to the plant model were of three basic types:

> *Creation of one additional top event*: One additional top event was created to model the unavailability of the Alternate Safe Shut Down (ASSS) which was not credited in the IPE model.

Creation of additional split fractions: Additional split fractions were developed to model new the new ASSS top event and reflect new boundary conditions arising due to fire damage.

Changes to the event tree structure - only one such change was made to reflect the use of the ASSS in the EPS tree.

Changes to the split fraction logic- new top boundary event conditions arising due to fire damage were reflected in the model by creating "macros". Each "macro" represents a specific type of fire damage to a given system and is used to select the appropriate split fractions when quantifying the risk from fire scenarios which cause the corresponding level of damage. The macros are inserted in the split fraction logic so that combinations of fire damage and random equipment failures, including support systems, are properly accounted for.

The most significant changes to the event trees and their associated split fraction logic and system models are described below.

4.6.1.1 Basic Modeling Changes to Reflect Fire Damage

Use of ASSS power

Station Blackout or Control Room Evacuation

In order to take credit for using the alternate safe shutdown system (ASSS) in the event of a loss of power from the 480v busses or control room evacuation, the EPS event tree structure was modified. A new top event (SS) "ASSS power available" was included. The split fraction logic was defined such that this may only be successful when power is lost to a combination of busses which would cue the operators to enter the station blackout procedure (ECA-0.0) and thereby utilize AOI 27.1.9 (i.e. no power on bus 5A or Bus 6A or Bus 2A and 3A). The auxiliary systems event tree and the general transient event tree were also modified such that if "SS" is successful new split fractions developed for top events SB (split fraction SBS), SC (split fraction SCS), CC (split fraction CCS) and L1 (split fraction L1S) would be challenged. These split fractions correspond to the successful alignment and operation of ASSS components.

These split fractions are used in quantifying fire scenarios in the control room. cable spreading room and switchgear room.

No Station Blackout or Control Room Evacuation

Failure of the ASSS supply given no station blackout or control room evacuation is modeled in the individual system split fractions, since the cues for aligning such power will be on a system by system basis. Since their is no loss of offsite power to the unit 1 switchgear in such cases the split fractions availability of power from the IP-1 switch gear will be controlled by the human error to properly align the supplies to individual components. In this case new split fractions developed for top events SB (non essential service water, split fraction SBS1), SC (essential service water, split fraction SCS1), CC (component cooling water, split fraction CCS1), LS (RCP seal injection, split fraction) LSSl and L1 (auxiliary feedwater, split fraction L1S1) would be challenged. These split fractions correspond to the successful alignment and operation of ASSS components.

With no station blackout or control room evacuation SS will be a guaranteed failure. This is a modeling facet and does represent a failure of the ASSS power supply, it merely that the blackout or control room evacuation entry conditions into A27.1.9 were not satisfied.

These split fractions are used in quantifying fire scenarios in the PAB, as well as less severe fires in the control room, cable spreading room and switchgear room.

<u>Fire induced LOCA due to stuck open valve</u>

A fire which damages power or control cables associated with the PORVs, PORV block valves or Reactor Head Vent valves may induce a LOCA and/or prevent one being isolated. the potential for fire induced LOCA is particularly important since additional systems are required to mitigate the accident and LOCA mitigation is not part of the ASSS design function.

Existing and new split fractions were used to model the eleven separate fire conditions which may lead to an enhanced LOCA probability. Credit was given for the ability of the operators to close the PORV block valves from the MCCs in the event that breaker control cables were damaged. (A screening HEP value of 0.1 was assigned).

For all fire events the PORV random challenge rate was assumed to be that corresponding to a loss of main feedwater which presents the highest challenge rate of all transients. in the IPE model.

High Pressure Injection

Fire damage to the power cables associated with all three pumps is modeled as a guaranteed system failure (split fraction HPF)

All the valves in the safety injection system are normally aligned in their operating position. Therefore loss of power to specific valves or MCCs does not degrade the system. However fires which damage control cables associated with MOVs 887A or B may result in a loss of suction to SI pump 22. Similarly damage to control cables associated with MOVs 851A or B may result in a loss of the discharge header crosstie. Such damage is reflected in the model by creating new split fractions HP3S, HP4S and HP5S. No credit is taken for manually re-aligning these valves..

Bleed

Fire damage to the PORV cables, block valve or their associated power supplies is assumed to lead to failure of bleed. The block valves were assumed to be initially closed. No credit is given to operation of the block valves from the MCCs in the event of control cable damage due to the limited time.

Fan Coolers

Fire damage to the Fan Cooler Unit power was reflected as a guaranteed system failure (split fraction FCF). Damage to the service water supply control or power cables was assumed to have no impact on the system unavailability. All valves are outside containment and can be operated manually since many hours are available following an accident (fire induced transient or LOCA) before this system is required to operate.

Recirculation System and Containment Spray

Damage to the RHR, Recirculation or Containment Spray power cables is assumed to lead to loss of those pumps (split fractions HRF, HRG and CSF)

Damage to power cables for valves inside containment is assumed to lead to loss of the flow path. In such cases only one path is available, i.e. from the RHR pumps via RHR HX 21. (split fraction HRG).

Damage to the power cables for valves outside containment or any control recirculation system MOV is assumed to have no impact on system availability. The valves can be operated manually since many hours are available following an accident (fire induced transient or LOCA) before this system is required to operate.

Loss of the auxiliary component cooling water pump power or control cables is assumed to lead to loss of the pumps and subsequent failure of the recirculation pumps (split fraction HRG).

<u>RHR Heat Removal</u>

Damage to the RHR heat exchanger CCW discharge valve power cables or MCCs 26A and 26B power supplies is assumed to lead to loss of recirculation cooling (split fraction RHF).

4.6.1.2 Treatment of Instrument and Human Error

All instrumentation that monitors vital plant parameters and provides input signals to the engineered safety feature actuation system and reactor protection system is supplied from 118vac instrument busses. However, loss of power to the sensors or instrument logic, as might occur due to fire damage, generally puts the associated channel in a tripped mode simulating an input to initiate the RPS or safeguards system. The exceptions to this "de-energize to operate principle" are the initiation of containment spray and main steam isolation on hi-hi containment pressure which, irrelevant with respect to accidents induced as a result of fires.

Thus damage to instrument cables or power supplies is not considered to degrade automatic actuation of safeguard systems.

Damage to instrument cables or power may degrade the ability of the operators to monitor the plant status from the control room. However, in addition to the control room instrumentation, various local instrumentation panels are available to perform shutdown throughout the plant. These are either pneumatic (i.e. do not rely on a power source) or are powered from the ASSS system. In summary the following alternate instrumentation is provided.

Instrument	Location
Pressurizer Level and Pressure	Fan Building
Steam Generator Level	AFW Pump Room Fan Building
Steam Generator Pressure	AFW Pump Room
AFW Pump Suction and Discharge Pressure	AFW Pump Building
CST and RWST level	At tanks
RCS temperature	Fan Building
CCW flow to RCPs	Pipe penetration area
RCP seal injection flow	Pipe penetration area

Since the local monitoring station in the fan building is well away from any potentially significant fire locations, the key plant parameters, steam generator level and pressurizer pressure and level, are available to the operators for all fire scenarios considered in the detailed analysis.

There were five categories of operator action to consider with respect to the potential impact of fires on operator reliability:

(1) Short term control room operator actions (within first 4 hours) modeled in IPE, necessary to mitigate a transient or transient induced LOCA.

Establish Flow from Turbine Driven Pump
Switch over from CST to City Water
Reset MCCs following LOSP
Close PORV Block Valve
Initiate Bleed and Feed

(2) Short term local operator actions modeled in IPE necessary to mitigate transients and LOCA.

Align City Water Cooling to Charging
Reset Turbine Driven Pump

(3) Long term operator actions taken in control room modeled in IPE

Align RHR in recirculation cooling mode
Switch over to high head recirculation following small LOCA
Inadvertently switch off high pressure injection pumps
at conclusion of recirculation switchover

(4) Short term local actions added to the model to account for specific, post fire recovery.

ASSS	Align ASSS power from IP-1 switchgear
TDP-VALVES	Align turbine driven AFW TD pump and Valves
ASSS-21AFP	Align ASSS power to AFW pump 21
CC-VALVES	Realign CCW thermal barrier supply MOVs
ASSS-23CCP	Align ASSS power to CCW pump 23
CH-VALVES	Re-align RCP seal injection supply MOVs
ASSS-CHP	Align ASSS power to charging pump 23
ASSS-SWP	Align ASSS power to SW pump 23 or 24
BV	Operate block valve or reactor head vent valve from MCC to isolate LOCA

(5) Long term actions added to the model or implicitly assumed to account for specific, post fire recovery

Operate Recirculation/CCW/SPRAY Valves inside Containment from MCC
Manually Operate FCU SW/RECIRCULATION/SPRAY
Locally operate 480VAC breakers in switchgear room

Not all of the above actions are credited in modeling all of fire scenarios. For example, some actions are not relevant in specific scenarios because the equipment which they actuate has been damaged by the fire or because other actions have an overriding influence.

Each short term action has been evaluated in the context of the scenarios in which it is credited in order to ensure that adequate indication for the need for action is available (i.e. proper cues are present), procedural guidance and/or training is available, the action is not prohibited by the presence of the fire and the response times used in determining the reliability of the action are reasonable actions credited in modeling each sequence and justifies their use. The actual quantification of human error probabilities was performed using the Human Cognitive Response Model in an identical fashion to that described in the IPE.

The impact of the fire on long term operator actions modeled in the IPE is considered to be negligible given the extended time available to prepare for and execute such actions (usually more than 10 hours). This also includes, if feasible, the execution of any long term recovery actions listed above.

4.6.2 Individual Compartment Evaluations

The fire compartments remaining for further analysis following the qualitative and quantitative screening processes were evaluated using the approach summarized in sections 4.3, 4.4 and 4.5. Specifically the following compartments were examined in this way:

Fire Compartment A1:	Electrical Piping and Penetration Area
Fire Compartment A3:	Control Building and Electrical Tunnel Entrance
Fire Compartment C:	Auxiliary Feedwater Pump Room
Fire Compartment I:	Intake Structure
Fire Compartment P:	Component Cooling Pump Room

Fire scenarios associated with individual fire zones within each compartment were first examined. For the multi-zone compartments namely; A1 and A3, the potential and additional risk resulting from interzone fire propagation was then examined. However, in no case was interzone propagation determined to be a risk significant concern for two reasons:

1) For fire compartment A1, the boundaries at the fire zone interfaces are vertical (fire zones are at the same elevation); horizontal cables trays represent the only combustible continuity between trays. COMPBRN modeling has demonstrated minimal lateral fire propagation along horizontally orientated trays.

2) The three major fire zones in compartment A3 are arranged one above the other, with the switchgear room at the bottom (elevation 15'), the central control room at the top (53' elevation) and the cable spreading room at the intermediate level (elevation 33'). The floor/ceiling fire zone boundaries are classified as Type II barriers and consisting of 7-1/2" thick concrete with all penetrations sealed with fire stops. All penetrations are periodically inspected and maintained as necessary (see Section 4.8.3.1). The cable tunnel zone boundary interfaces with the cable spreading room and, although completely open, fire propagation is not an issue for the same reasons described above for fire zones in compartment A1.

Representative examples of the detailed fire evaluations, including the specialized control room analysis, are included in Appendix A. The results are presented in Section 4.6.3.

4.6.3 Results Analysis

The total frequency of core damage due to fires is predicted to be 1.85E-05 per year. The core damage frequency contribution from individual fire scenarios is summarized in Table 4.6-1. For each scenario this table identifies the fire source and targets and gives the fire scenario frequency, as well as the total core damage frequency contribution. The contribution to core damage frequency from each fire zone is summarized in Table 4.6-2. The top ten fire induced sequences are summarized below:

The most significant scenario (A3-10, CDF 1.72E-6/yr) occurs due to a fire in the 480 V Bus 6A which in turn damages the power supply to Bus 3A, AFW pump 21 power cable (plus other equipment which is not significant with respect to this scenario). As a consequence both AFW motor driven pumps are without 480v-ac power and primary bleed is unavailable due to failure of power to the block valves 536 (which is assumed to be closed). A subsequent random failure of the AFW turbine driven pump, failure to align ASSS to AFW pump 21, results in core damage.

The second ranked sequence (fire scenario A3-17, CDF 9.63E-07/yr) occurs due to a fire in any of the control room cabinets which cannot be extinguished prior to the control board being obscured and the control room being uninhabitable. A subsequent failure of the operators to align the ASSS system in a timely fashion results in core damage.

The third ranked sequence (fire scenario A3-16C, CDF = 7.81E-07) occurs due to a fire in the western region of the supervisory panel which cannot be extinguished in the pre-growth phase. Consequently the SH-Electrical Distribution section of the panel is damaged). This is assumed to result in a loss of all normal and emergency power to all of the 480 busses. Subsequent failure of the ASSS alignment due to random faults results in core damage.

The fourth ranked sequence (fire scenario A3-16C, CDF = 7.08E-07) occurs due to a fire in the western region of the supervisory panel which cannot be extinguished in the pre-growth phase. Consequently the SH-Electrical Distribution section of the panel is damaged). This is assumed to result in a loss of all normal and emergency power to all of the 480 busses. Unlike the previous sequence, ASSS alignment is successful, however the transient results in a stuck open PORV which cannot be isolated since power is unavailable to MCCs 26A and 26B which supply the block valves.

The fifth ranked sequence (fire scenario A3-5, CDF 6.26E-07) occurs due to a floor based transient fire in the cable spreading room which damages or (possibly ignites) vertical cable trays or damages multiple chargers. This is assumed to result in a loss of all normal and emergency power to all of the 480 busses. Subsequent failure of the ASSS alignment due to random faults results in core damage.

The sixth ranked sequence (fire scenario A1-1B, CDF 6.21E-07) occurs due to a fire in Region 1 (interface of fire zone 1A and 74A) of piping and penetration area. The fire results in damage to the AFW pumps and valve control, Fan Cooler Units, PORVs and block valves and loss of power to valves inside containment. A fire induced PORV opening coupled with an inability to cool the containment due to loss of power to the Fan Coolers and RHR heat exchanger CCW valves, leads to core damage.

The seventh ranked sequence (fire scenario A1-8, CDF 5.97E-07) occurs due to a floor based transient fire in the primary water make up area. The fire results a loss of power to the charging and CCW pumps, possible misalignment of valves in the seal injection and thermal barrier cooling water supplies and loss of power to MCCs 26A and 26B. Operators subsequently fail to align the ASSS system resulting in an RCP seal LOCA. Random failure of the degraded containment recirculation system results in core damage.

The eighth ranked sequence (fire scenario A3-17, CDF 5.51E-07) occurs due to a fire in any of the control room cabinets which cannot be extinguished prior to the control board being obscured and the control room being uninhabitable. Fire causes or increases probability of LOCA via PORVs or Reactor Head Vent. Since the ASSS system is not designed for LOCA mitigation core damage occurs.

The ninth ranked sequence (fire scenario A1-18B, CDF 5.42E-07) occurs due to a cabinet fire in the electrical penetration area which is not extinguished prior to damaging the west wall cable tray stack. The fire results in damage to the AFW pumps and valve control, Fan Cooler Units, PORVs and block valves and loss of power to valves inside containment. A fire induced PORV opening coupled with an inability to cool the containment due to loss of power to the Fan Coolers and RHR heat exchanger CCW valves, leads to core damage.

The tenth ranked sequence (fire scenario A3-15J, CDF 5.1E-07) occurs due to a fire in the supervisory panel SH which is not extinguished in the pre-ignition phase. This is assumed to result in a loss of all normal and emergency power to all of the 480v busses. Subsequent failure of the ASSS alignment due to random faults results in core damage.

4.7 CONTAINMENT PERFORMANCE

The evaluation of containment performance following core damage resulting from fires requires the consideration of mechanisms which may lead to containment by-pass (via hi-lo interfaces), failure of containment isolation or degradation of the availability of heat removal systems. NUREG 1407, Section 4.1.4 indicates that the focus should be on identifying containment failure modes which are significantly different from those found in the internal events IPE.

Containment Bypass

Containment bypass was evaluated in the IPE, and the two significant mechanisms identified were the interfacing system LOCA (large containment bypass) and the unisolated steam generator tube rupture (small containment bypass). Mechanical failure or spurious valve operation is the cause of both of these events. Fire induced mechanical failures are not considered credible. Spurious valve operation due to control and power circuit damage caused by fires was examined, as discussed in Section 4.2.2. No significant by-pass mechanisms were identified. In addition, accident sequences resulting from fire events will not cause more excessive RCS pressures than those addressed in the internal events accident sequence analysis, and thus no new induced steam generator tube rupture events. Therefore the containment bypass conclusions presented in the

IPE are not altered by the fire analysis.

Containment Isolation

Containment isolation failure was also considered in the IPE for IP-2, the principal mechanism being associated with isolation valve failure to close. Containment penetration pathways determined to be a potential concern in the IPE analysis are isolated by mechanical check valves or air operated valves which fail closed on loss of air supply or power to their solenoid valves. Fire damage will not impact the operation of the former and is likely to lead to actuation of containment isolation in the case of the latter. However, in the event of fire induced hot shorts which cause the valves to open or prevent closure, manual recovery actions may be taken. Since fire induced accidents do not lead to early vessel failures, several hours would be available to take such action. Furthermore, the most risk significant fire scenarios are located in the switchgear room, cable spreading room and control room which are well separated from the containment penetration areas where the isolation valves are located. Thus access to the containment isolation valves would not be impaired due to the effects of the fire. Thus the likelihood of failure of containment isolation following fire scenarios is not significant and no new mechanisms were identified.

Containment Pressure Suppression and Heat Removal

The availability of containment heat removal systems following core damage was explicitly modeled in the IPE event trees, and their status reflected in the plant damage state binning process. Since the fire IPEEE analysis was mainly limited to evaluating the impact on core damage frequency rather than containment system status following core damage (plant damage state) recovery actions were not specifically included if they did not lead to a reduction in CDF.

The IPEEE model does not therefore provide a representative indication of plant damage state in the same way that the IPE model did. However, several general observations can be made:

The highest ranked fire scenario (A3-10) comprises about 9% (1.7E-06 /yr) of the CDF due to fires. Although core damage occurs, manual operation of breakers associated with the Bus 3A would permit containment system recovery in the long term.

Fires in the first and second ranked fire zones, namely the control room and cable spreading room comprise 61% (1.1E-05/yr) of the total core damage frequency due to fires. Since these fire only impact control power cables, power may be restored to containment systems in the long term by manually operating breakers.

Containment heat removal via fan coolers would not be affected by fires in the primary water make up pump area which contribute 6% (1.1E-05 /yr) of the fire induced core damage.

Thus, only about 24% (4.44E-06/yr) of the fire induced core damage occurs with non recoverable loss of containment systems. This compares with the IPE result in which the contribution to core damage frequency with coincident loss of containment systems was 1.07 E-05/yr (CDF with loss of Containment Heat Removal (CHR) and Containment Sprays = 2.2 E-06 and CDF with loss of CHR only = 8.5 E-06/yr). If these functions are not regained, these sequences would lead to long term overpressurization of containment. None of these sequences, however, lead directly to early failure of containment.

In conclusion, no new mechanisms associated with loss of containment heat removal were identified and the frequency of scenarios resulting in non-recoverable loss containment heat removal systems is not significantly increased due to fires.

4.8 TREATMENT OF FIRE RISK SCOPING STUDY ISSUES

4.8.1 Background

Under the NRC-sponsored Fire Protection Research Program, Sandia National Laboratories developed the "Fire Risk Scoping Study: Current Perception of Unaddressed Fire Risk Issues" (NUREG/CR-5088, Reference 4-8), hereafter referred to as the "FRSS". The objectives of this study were to:

(1) Reassess certain fire risk scenarios, in light of the availability of enhanced fire event databases and improved fire modeling techniques.

(2) Identify significant fire risk issues that may not have been addressed adequately (or at all) under earlier fire risk assessments, and to attempt to quantify the impact of these issues.

(3) Review current regulatory criteria and guidance, and plant fire protection programs, to assess whether the identified risk scenarios are adequately enveloped by these programs.

The issues identified and addressed by the FRSS include six categories:

(1) Potential seismic/fire interactions.
(2) Fire barrier qualification issues.
(3) Manual fire fighting effectiveness.
(4) Total environment equipment survival.
(5) Potential control systems interactions.
(6) Improved analytical codes.

The above issues, which were not addressed by earlier "fire" probabilistic risk assessments (PRAs), are required to be assessed as an integral part of the Individual Plant Examination for External Events (IPEEE). A structured approach to addressing the first five of these issues is presented in the Fire-Induced Vulnerability Evaluation (FIVE), EPRI Report TR-100370. The FIVE report provides an overall methodology for addressing the "fire" portion of the IPEEE process; the FRSS issues are but one element of the IPEEE process. The sixth FRSS issue, concerning analytical codes, does not require a plant-specific evaluation or response, as the use of current-day analytical codes (i.e., COMPBRN IIIe) is incorporated as an integral part of the FIVE (Phase II) methodology. Accordingly, this analysis is limited to an Indian Point 2 specific assessment of only the first five issues.

4.8.2 Seismic Fire Interactions

This issue involves three concerns:

(1) The potential for seismically-induced fires.

(2) The potential for seismically-induced actuation of fire suppression systems.

(3) The potential for seismically-induced failure or rupture of fire suppression systems.

The above events have obvious implications on both postulated fire scenarios and potential for disruption of the safe-shutdown capability.

4.8.2.1 Seismically Induced Fires

This issue considers the potential leakage or rupture of flammable/combustible liquid or gas lines or tanks/containers in areas containing seismic safe shutdown or safety equipment, during a seismic event. The potential hazards to be addressed include:

(1) Hydrogen piping and volume control tank
(2) Diesel fuel oil piping, day tanks, and storage tanks.
(3) Turbine lubricating oil storage tank(s) and associated piping.
(4) Turbine generator (hydrogen envelope).
(5) Hydrogen seal oil unit and associated piping and tanks.
(6) Hydrazine storage tanks and associated piping.
(7) Waste Gas System Piping and Equipment

The specific location of these and similar hazards are identified through the Fire Walkdown Phase of the IPEEE process, and the seismic ruggedness of each identified component is addressed under the Seismic Walkdown Phase. No potential vulnerabilities were identified (see Section 3.1.3.4 of this report).

4.8.2.2 Seismic Actuation of Fire Suppression Systems

This issue considers the potential for inadvertent actuation of suppression systems during a seismic event, and the resultant effects on safety/safe-shutdown related components and systems. The effects of concern include both flooding and wetting effects caused by runoff/spray.

Fixed fire suppression systems located in areas containing safety/safe-shutdown related equipment include the following:

- Cable Spreading Room (Fire Zone 11; total-flooding Halon)
- Electrical Tunnel (Fire Zone 32A; pre-action sprinkler)
- Diesel Generator Room (Fire Zone 10; wet-pipe sprinkler)

As stated by the FPPP, in response to BTP APCSB 9.5-1, Item A.5, "Fire Suppression Systems", "fixed fire suppression systems have not been installed where their operation or failure could cause unacceptable damage to safety-related equipment."

Con Edison internal correspondence dated 6/29/83 and 10/5/83 (Item No. 83-565), documents the review of the Information Notice 83-41 issues. This review concluded that adequate consideration of suppression system actuation effects on safety-related equipment has been integrated into the existing Fire Hazards Analysis, as discussed above. Consequently, this determination is considered to adequately envelope the issue of seismically-induced actuation of Indian Point 2 fire suppression systems.

4.8.2.3 Seismic Degradation of Fire Suppression Systems

This issue addresses the seismic installation of suppression system piping and appurtenances, and the potential for seismically-induced mechanical failure of these systems. The issue is focused on the potential effects on the safe-shutdown capability caused by suppression system equipment dislodged during a seismic event, and falling onto the subject equipment.

The potential for seismic induced flooding and spraying from all sources including fire protection systems was examined during the seismic walkdown and all potential sources were identified and evaluated by the walkdown team. No potential seismic induced flooding vulnerabilities were identified (see Section 3.1.3.4 of this report).

4.8.3 Fire Barrier Qualifications

This issue is primarily concerned with the installation and maintenance of fire barriers and fire barrier penetration seals, including electrical and mechanical seals, as well as fire doors and fire dampers.

4.8.3.1 Fire Barriers

The FPPP provides a description of the fire protection equipment periodic surveillance requirements and "impairment criteria" (operability requirements and compensatory measures). Periodic surveillance of all fire barriers (including Types I, II, and III) and penetration seals is conducted at least once per 18 months, and prior to declaring a penetration seal/fire barrier functional, following repairs or maintenance. Applicable procedures for the control of fire barrier/penetration seals are contained in SAO 703 and 704.

Specific inspection methodology and acceptance criteria are provided by several plant procedures. Procedures PI-V17-1 through PI-V17-8 address barrier inspections. Surveillance of fire dampers is addressed by PT-EM 9 and PT-EM28. Fire doors are addressed by PT-M55 and PT-Q41. Special barriers (Separation Fire Barriers and Transite Fire Barriers) are addressed by PI-Q 1, PI-R 1, PI-SA 1, and PI-SA 1A.

4.8.3.2 Fire Doors

Fire doors are also subject to inspection on an 18-month interval, or prior to return to service following repair or modification work. Surveillance of fire doors is addressed by PT-M55 and PT-Q41.

4.8.3.3 Penetration Seals

Penetration Seal Inspection and Surveillance Program

The surveillance of fire barrier penetration seals is addressed under 4.8.2.1.

Evaluation and Implementation of Applicable NRC I&E Notices

The FIVE methodology identifies three NRC I&E Information Notices which have specific applicability to fire barrier penetration seals:

(1) 88-04, "Inadequate Qualification and Documentation of Fire Barrier Penetration Seals."

(2) 88-04 Supplement 1, "Inadequate Qualification and Documentation of Fire Barrier Penetration Seals."

(3) 88-56, Potential Problems With Silicone Foam Fire Barrier Penetration Seals."

NRC Information Notice 88-04 has been addressed by Con Edison's Penetration Seal Evaluation Program. Dow-Corning 3-6548 silicone foam is one of the principal IP2 penetration seal materials, used at IP-2 and as such IN 88-56 is applicable and a program has been put in place to ensure that adequate installation procedures, inspection requirements and QA controls exist to address the concerns.

4.8.3.4 Fire Dampers

Fire Damper Inspection and Maintenance Program

The surveillance of fire dampers is considered in conjunction with overall fire barrier and penetration seal surveillance, and is addressed under 4.8.3.2. Periodic surveillance of fire dampers is addressed by PT-EM 9 and PT-EM28.

Evaluation and Implementation of Applicable NRC I&E Notices

The FIVE methodology identifies two NRC I&E Information Notices which have specific applicability to fire dampers:

(1) 83-69, "Improperly Installed Fire Dampers at Nuclear Power Plants."
(2) 89-52, "Potential Fire Damper Operational Problems."

Con Edison internal correspondence dated 11/13/83 and 4/17/84 (Item No. 83-734), documents the review of the Information Notice 83-69 issues. The review effort included several walkdowns and concluded that adequate consideration of fire damper rating requirements and installation criteria had been incorporated into the Indian Point 2 design and installation effort. A comprehensive evaluation of all fire walls included the assessment of existing fire dampers and requirements for new dampers. No improperly installed dampers were identified, although a number of dampers with indeterminate rating were found and addressed.

The principal issue associated with Information Notice 89-52 is the inability of curtain-type fire dampers to close under air-flow conditions through the associated ductwork. An internal response addressing IN 89-52, indicated that consideration had been given to ensuring the use of non-deficient fire dampers. As part of the current review, it was reconfirmed that the design features of the existing fire dampers address the issues raised in this Information Notice.

In summary, Con Edison Engineering practice is to apply appropriate consideration to the applicable HVAC fire damper procurement, installation, and operational criteria in the design, installation, and/or modification of HVAC fire dampers at IP2.

4.8.4 Manual Fire Fighting Effectiveness

This issue is focused on the adequacy of training and preparedness of the plant fire brigade, and on the general orientation of appropriate plant personnel to fire response requirements. The objective of this issue is to determine the adequacy of the plant's manual fire suppression capability, and thereby determine the degree to which this capability should be credited in the

IPEEE Fire PRA.

4.8.4.1 Reporting Fires

Orientation of Plant Personnel to the Use of Portable Fire Extinguishers

A program is in place to indoctrinate selected plant personnel and other personnel, as appropriate, in the administrative procedures that implement the IP2 Fire Protection Program. SAO-707 (Fire Emergency) is the procedure applicable to all plant personnel with respect to fire reporting. The FPPP and SAO-707 indicate that any individual discovering a fire is to attempt to extinguish the reported fire with "available portable extinguishing equipment."

Orientation of plant personnel in the use of fire extinguishers is accomplished under the General Employee Training program.

Availability of Portable Extinguishers Throughout the Plant

Fire extinguishers are visually inspected once per 24 months for general plant areas, and once per refueling interval, for extinguishers in containment. Fire extinguishers are distributed throughout the plant and the extinguisher availability is periodically verified through procedure PI-M7.

Plant Procedure for Reporting Fires

The reporting of fires is addressed by Station Administrative Order (SAO) 707, "Fire Emergency", with subsequent notification of the Fire Brigade under SAO-706, "Fire Brigade."

Communication System to Allow Contact With the Control Room

Station Administrative Order 707 stipulates the use of the plant telephone system for reporting of fires to the control room, with the plant PA system ("party phone") as a backup.

4.8.4.2 Fire Brigade

Size of Fire Brigade

As stipulated in SAO-706 ("Fire Brigade"), a fire brigade of at least five members (including the fire brigade leader) is maintained on site at all times.

Brigade members Knowledgeable in Plant Systems and Operations

In accordance with SAO-706, at least four members of the fire brigade on each shift are Operations personnel.

Annual Physical Examinations for Brigade Members

In accordance with SAO-706, brigade members must satisfactorily complete an annual physical examination, including a respiratory examination.

Minimum Equipment Provided/Available to Fire Brigade

The equipment available to the fire brigade is consistent with the FRSS criteria, and the equipment complement is verified periodically under Procedure PI-M4.

4.8.4.3 Fire Brigade Training

The fire brigade classroom training program, hands on training, drills and record keeping are described in SAO-706. No inconsistencies with the FIVE /FRSS criteria were identified.

4.8.5 Total Environment Equipment Survival

4.8.5.1 Potential Adverse Effects on Plant Equipment by Combustion Products

The FIVE/FRSS methodology does not provide criteria for assessment of the potential effects of non-thermal products of combustion on safety/safe-shutdown related equipment. However, for the relatively short duration of the fire event and early recovery period, these effects are considered to be insignificant by FIVE.

4.8.5.2 Spurious or Inadvertent Fire Suppression Activity

The potential effects of spurious/inadvertent suppression system actuation are enveloped by Section 4.8.2.2.

4.8.5.3 Operator Action Effectiveness

Post-Fire Safe-Shutdown Procedures

Abnormal Operating Instruction 27.1.9, "Shutdown Procedure for Inaccessibility of Control Room", provides operating instructions for a fire that renders the control room inaccessible, or renders normal controls and indication in the control room unreliable. As stated in the FPPP, this procedure is generic, in that it also addresses required shutdown functions for a fire that occurs in any fire area that results in damage to safe-shutdown equipment or cables.

Operator Training in Post-Fire Safe-Shutdown Procedures

Periodic operator training in post-fire shutdown procedures is conducted in accordance with Job Performance Measures for both licensed and non-licensed plant operators.

Operator Reentry Into Affected Fire Area: Respiratory Protection

The FPPP does not specifically address operator effectiveness in smoke-filled areas, but the following apply:

(1) SCBA equipment is provided in the control room and at strategic locations throughout the plant.

(2) Fixed, battery-backed emergency lighting units are installed along post-fire shutdown access/egress routes and at equipment operating stations.

4.8.6 Control Systems Interactions

A top-level assessment of credited IP2 post-fire alternative shutdown features was performed, to determine the design/operational characteristics applied to the "normal" and "alternative" equipment trains. The assessment addressed principal components supporting safe-shutdown functions including RCS Inventory and Pressure Control, Secondary System Cooling, Service Water, Component Cooling, and required primary and secondary system instrumentation. In this assessment, particular attention was given to any alternative shutdown equipment trains that rely on a control transfer and/or shared equipment scheme, rather than on the use of completely independent equipment trains.

A review of selected safe-shutdown equipment elementary and control wiring diagrams, and the FPPP, in conjunction with interviews of cognizant design personnel, indicates the following:

(1) Equipment with alternate features, implemented to circumvent the effects of a control complex fire, does not exhibit the design features that are generally considered susceptible to the defined control systems interactions issues. Typically, the alternate (post-fire) operating configurations for pumps have the one or more of the following characteristics:

- The alternate shutdown operating mode utilizes a completely separate and independent power source, switchgear/MCC, and control configuration. The only common equipment between the normal and post-fire alignments is the pump motor itself and the three-phase power cable, up to a manual transfer switch. Therefore, no common components, capable of causing fire-induced interactions between the normal and emergency control configurations, exist.

  Where the transfer switch is located in the same area as the pump served (e.g., Auxiliary Boiler Feed Pump), and all capability is subject to being rendered inoperable by a fire in that area, completely independent alternate equipment trains, located outside the area, (e.g., safety injection pumps) are credited.

  In the context of this discussion, the use of the term "independent" is not intended to imply that common power supply or common enclosure associated circuits are not located in fire areas common to both the normal and alternate shutdown equipment trains. However, where such circuits exist, they have been dispositioned by associated circuits analyses, and determined to have no adverse effect on the operability of the credited equipment train.

- A manually-operated transfer switch provides complete isolation between the normal and alternative controls, indicators, power sources, and associated cables. No reliance is placed on common power sources or over current devices, which could be rendered inoperable by a common fire. For fires occurring in the area/zone containing the transfer switch itself, the use of alternate electrically independent equipment, located outside the specific area, is credited.

- Cables associated with the normal and alternative power and controls are routed in accordance with 10CFR50, Appendix R, Section III.G separation criteria, or in accordance with approved exemptions.

(2) Alternative instrumentation channels, for use in monitoring key plant parameters during the post-fire scenario, are composed of (1) completely separate and independent channels from those used during normal plant operation (e.g., pneumatic, mechanical, or powered by IP1 power sources), and (2) shared channels, for which fire protective features are provided for cables/instrument tubing, to ensure their post-fire operability. Transfer or isolation schemes, in which a common sensor is shared between normal and alternative channels, are not utilized. Separation from instrument channels credited for normal plant operation is in accordance with the separation criteria of 10CFR50, Appendix R, Section III.G, or has been specifically justified by exemption. In several cases where redundant instrument lines are routed through common fire areas, separation, in the form of fire-protective envelope wrap, is provided. In other cases, where local mechanical gauges are credited as alternative instrumentation, the gauges are located in the same fire area affecting the credited "normal" channel. For these fire areas, the post-fire instrumentation capability is addressed by granted exemption(s).

Accordingly, the alternative instrument channels are not susceptible to spurious indications, actuations, or other fire-induced failures that would simultaneously impact the channels credited during normal plant operation.

Evaluation and Implementation of Applicable NRC I&E Notices

Information Notice 92-18, "Potential for loss of remote shutdown capability during a control room fire", pertains to motor operated valves used in safe shutdown systems operated from remote panels whose control circuits can be susceptible to hot shorts that impair their ability to properly operate. Such hot shorts can bypass torque and limit switches and at the same time mis-position the valve, possible causing mechanical damage to the valve which would hinder manual operation. This scenario is plausible when thermal overload protection devices have been purposefully bypassed to resolve operational reliability issues.

Since all MOVs at IP-2 have operational thermal overload protection this is not a concern at IP-2.

In conclusion, the IP2 alternative shutdown features provide independent remote control and monitoring features. Therefore, the design of the IP2 alternative shutdown capabilities is generally immune to the effects of "control systems interactions" as defined within the scope of the FIVE methodology.

4.8.7 Conclusions

The results of the topical assessments performed under the FIVE Fire Risk Scoping Study indicate that the FRSS issues have been adequately addressed by IP2, and the applicable aspects of the IP2 Fire Protection Program therefore are in conformance with the intent of the FRSS guidelines, as tabulated in Attachment 10.5 of the FIVE methodology:

4.9 USI A45

The total contribution to core damage frequency from internal fires is 1.85E-05/yr which is about the same as the contribution from loss of decay heat removal (DHR) sequences reported and deemed acceptable in the IPE. Thus, fires as a whole are not a significant DHR issue at IP2. As discussed in the IP2 IPE submittal, loss of decay heat removal is inherently considered in a PRA evaluation of core damage frequency. In the fire analysis, significant fire areas were identified on the basis of their contribution to core damage frequency. The significance of an area is not tied to the decay heat removal issue per se; however, resolution of any issues arising from identification of any of these areas as significant would resolve any issues related to USI A-45.

4.10 REFERENCES

4-1 "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities", NUREG-1407, U.S. Nuclear Regulatory Commission, June 1991.

4-2. "Fire-Induced Vulnerability Evaluation (FIVE)," EPRI TR-100370s, by Professional Loss Control, Final Report, April 1992.

4-3 "PRA Procedures Guide", NUREG/CR-2300, U.S. Nuclear Regulatory Commission, 1983 American Nuclear Society and Institute of Electrical and Electronic Engineers, January, 1983.

4-4 "Probabilistic Safety Analysis Procedures Guide, NUREG/CR-2815 Vols. 1 and 2, NRC, U.S. Nuclear Regulatory Commission, August 1985.

4-5 "Fire PRA Requantification Studies," NSAC-181, Final Report March 1993.

4-6 "Fire PRA Implementation Guide" ERP3385-01, Electric Power Research Institute, January 1994 (Draft).

4-7. "COMPBRN IIIE: An Interactive Computer Code for Fire Risk Analysis," EPRI NP-7282, by V. Ho, et al., Final Report, May 1991.

4-8 "Fire Risk Scoping Study", U.S. Nuclear Regulatory Commission, NUREG/CR-5088, January 1989.

4-9 "Fire Events Database for U.S. Nuclear Power Plants," NSAC-178L, Final Report June 1992.

4-10 "Individual Plant Examination for Indian Point Unit No. 2 Nuclear Generating Station," Consolidated Edison Company of New York, Inc., August 1992.

4-11 "Indian Point Nuclear Generating Station No. 2 Fire Protection Program Plan (FPPP)," Consolidated Edison of New York, Inc., Revision 7, November 30, 1992.

4-12 "Revision 1 to EPRI Final Report, dated April 1992, TR-100370, Fire-Induced Vulnerability Evaluation Methodology", Letter from William H. Rasin, NUMARC, Nuclear Management and Resource Council, September 29th 1993.

4-13 "An Experimental Investigation of Internally Ignited Fires in Nuclear Power Plant Control Cabinets: NUREG/CR-4527, Part I : Cabinet Effects, published April 1987, & Part II: Room Effects Tests," November 1988.

4-14 "Analysis of Core Damage Frequency: Surry Power Station, Unit 1 External Events," NUREG/CR-4550, December 1990.

4-15 "Fire Risk Analysis for Nuclear Power Plants," NUREG/CR-2258, M. Kazarians and J. Apostalakis, September 1981.

4-16 "Automatic and Manual Suppression Reliability Data for Nuclear Power Plant Fire Risk Analyses," NSAC-179L, Final Report February 1994.

Table 4.2-1

Identification of Fire Areas
Indian Point Nuclear Generating Unit 2

(b)(7)(F)

Page 4-55 thru 4-61

(7 pages)

Table 4.2-2a

Fire Area Qualitative Screening Evaluation

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Table 4.2-2b

Fire Area Qualitative Screening Evaluation

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Table 4.2-2c

Fire Area Qualitative Screening Evaluation

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Table 4.2-2d

Fire Area Qualitative Screening Evaluation

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Table 4.2-2e

Fire Area Qualitative Screening Evaluation

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Table 4.2-2f

Fire Area Qualitative Screening Evaluation

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Table 4.2-2g

Fire Area Qualitative Screening Evaluation

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Table 4.2-2h

Fire Area Qualitative Screening Evaluation

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Table 4.2-2i

Fire Area Qualitative Screening Evaluation

(b)(7)(F)

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(1 page)

Table 4.2-2j -FIRE AREA QUALITATIVE SCREENING EVALUATION	
Fire Area Designation: J	**Fire Area Description: Alternate Shutdown Cable and Equipment Area**
Fire Zone Number(s): See Table 4.2-1	
Does area contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No Yes. ASSS switchgear and power to CCW pump #23, AFW pump #21, Charging pump #23, SRM, T_H, T_C instrumentation, in addition to ASSS 13.8 kV and 480V power distribution equipment are located in this fire area.	
Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No Yes. A fire in the Unit 2 turbine building which forms part of this fire area may result in a loss of offsite powe the 6.9 kv and 480v busses.	
Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No No. Even when one of the emergency diesel generators is assumed to be unavailable coincident with fire damage to offsite power and the ASSS, either one of the two remaining diesel generators is sufficient to achieve stable hot shutdown. The normal instrumentation is also unaffected by the fire in area J.	
Area Screened Out? Yes. Using screening criteria presented in step 5 of the FIVE methodology (see item 3), this area is screened out based on the consideration that a plant shutdown induced by a fire in this fire area, would not require operation of the equipment postulated to be damaged or to be unavailable.	

Table 4.2-2k - FIRE AREA QUALITATIVE SCREENING EVALUATION	
Fire Area Designation: K	**Fire Area Description: Steam/Feedwater Piping**
Fire Zone Number(s): 60A, 61A, 62A, 65A	

Does area contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No

Yes. S.G. safety valves, and cables for AFW regulator valves are located in this compartment (zone). The AFW regulator valves may be operated locally in area C. Damage to the safety relief valves or local control of all ARV's is not credible.

Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No

Assumed yes. Damage to cables and equipment (SSD equipment and/or balance of plant) is assumed to require a plant shutdown.

Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No

No. Damage to the cables for AFW regulator valves would prevent remote operation of these valves. However, these valves controllers are equipped with a backup nitrogen system for remote operation from zone 23. These valves can also be operated locally with the handwheels. These valves fail open upon loss of power or air.

Area Screened Out?

Yes. Using screening criteria presented in step 5 of the FIVE methodology (see item 3), this area is screened out based on the consideration that a plant shutdown induced by a fire in this fire area, would not require operation of the equipment postulated to be damaged or to be unavailable.

Table 4.2-21 - FIRE AREA QUALITATIVE SCREENING EVALUATION	
Fire Area Designation: L	**Fire Area Description: IP-1 Screenwell Area**
Fire Zone Number(s): 600 and 610	
Does area/compartment contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No Yes. Unit 1 substation 12RW3 and associated electrical cables for feeding SWS pump 23 and 24 are located in this area	
Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No Yes. The River Water System pumps are located in this fire area. These pumps provide cooling to normally operating balance of plant equipment and consequently their failure would result in a plant shutdown.	
Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No No. Normal power to all the service water pumps would be available.	
Area Screened Out? Yes. Using screening criteria presented in step 5 of the FIVE methodology (see item 3), this area is screened out based on the consideration that a plant shutdown induced by a fire in this fire area, would not require operation of the equipment postulated to be damaged or to be unavailable.	

Table 4.2-2m -FIRE AREA QUALITATIVE SCREENING EVALUATION	
Fire Area Designation: M	**Fire Area Description: Gas Turbine #1**
Fire Zone number(s): 650	
Does area contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No Yes. Emergency power supply for alternate safe shutdown supply includes breakers and load centers.	
Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No No. GT2 and GT3 provide alternate power sources to GT2 for the ASSS. In the event that either GT1 or GT2 were inoperable coincident with a fire that disabled GT1, technical specifications Section 3.7.c permit continued plant operation (only one GT needs to be operable). Neither is there any other fire induced mechanism that might initiate or require plant shut down in this area.	
Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No Not applicable	
Area Screened Out? Yes. Using screening criteria presented in step 5 of the FIVE methodology (see item 3), this area is screened out based on the consideration that no plant shut down would be required due to equipment postulated to be damaged or to be unavailable.	

Table 4.2-2n -FIRE AREA QUALITATIVE SCREENING EVALUATION	
Fire Area Designation: N	**Fire Area Description: Manhole #21**
Fire Zone Number(s): 630	
Does area contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No Yes. The normal power cables for the service water pumps run through manhole #21.	
Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No Yes. Technical Specifications (3.3.F.1.a and b) state that three service water pumps must be operable on the designated essential header, and if one is inoperable, start shutdown within 12 hours. Re-routing power to the service water pumps via ASSS only provides power to two service water pumps, 23 and 24. Hence, the plant would have to shut down as directed by Technical Specifications.	
Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No Yes. ASSS, which is the alternate power supply to service water pumps 23 and 24, must be assumed in this initial screening to be unavailable, as per step 5 of the FIVE methodology.	
Area Screened Out? No. Based on the evaluation described above, this fire area can not be screened out at this level and requires further evaluation.	

Table 4.2-2p -FIRE AREA QUALITATIVE SCREENING EVALUATION	
Fire Area Designation: P	**Fire Area Description: Component Cooling Pump Room**
Fire Compartment Number(s): 1	
Does area contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No Yes. Component Cooling Pumps No. 21, 22, and 23 in addition to the ASSS and normal electrical cables (power) are located in this area.	
Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No Yes. CCW is required for normal plant operation and therefore loss of all three CCW system pumps would require a plant shut down. trip. Also, per plant technical specification (section 3.3.E.2) loss of two CCW pumps would require the reactor to be placed in hot shutdown conditions if at least one of the two inoperable pumps is not restored to operable status within 24 hours.	
Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No Yes. RCP seal integrity can be maintained by cooling the thermal barriers using CCW or by seal injection from a charging pump. The charging pumps require CCW or city water cooling. Thus in the event that a fire damages the CCW pumps coincident with the city water being inoperable, the integrity of the RCP seals may be compromised and safe shut down may not be achieved.	
Area Screened Out? No. Further evaluation of this area is required.	

Table 4.2-2q -FIRE AREA QUALITATIVE SCREENING EVALUATION	
Fire Area Designation: Q	**Fire Area Description: Penetration H-20 and Cabling**
Fire Zone Number(s): 74B	
Does area contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No Yes. Source Range Monitor and T_H and T_C cable for the ASSS are located in this area.	
Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No Yes. Assume manual shutdown is required.	
Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No No. All normal process monitoring capabilities required for shutdown would be available.	
Area Screened Out? Yes. Using screening criteria presented in step 5 of the FIVE methodology (see item 3), this area is screened out based on the consideration that a plant shutdown induced by a fire in this fire area, would not require operation of the equipment postulated to be damaged or to be unavailable.	

<table>
<tr><th colspan="2">Table 4.2-2r -FIRE AREA QUALITATIVE SCREENING EVALUATION</th></tr>
<tr><td>Fire Area Designation: None</td><td>Fire Area Description: Individual outside fire zones</td></tr>
<tr><td>Fire Compartment Number(s): 55 55A 56A 57A 58A 700 710</td><td></td></tr>
<tr><td colspan="2">Does area contain Appendix R SSD equipment/cable required for hot shutdown per IPE Success Criteria? Yes/No

No.</td></tr>
<tr><td colspan="2">Is there a requirement for plant shutdown given fire damage and normal alternate equipment unavailable? Yes/No

N/A</td></tr>
<tr><td colspan="2">Does shutdown require equipment postulated to be damaged or unavailable (i.e. no other path available)? Yes/No

N/A</td></tr>
<tr><td colspan="2">Area Screened Out?

Yes</td></tr>
</table>

Table 4.2-3: Results of Qualitative Screening Analysis				
Fire Area	**Fire Zone**	**Screened Out**	**PRA Accident Sequence Selected**	**Rationale**
A (Control Building, Tunnels, Penetration Areas, Lower PAB, Tank Farm)	1A,2,2A,3,3A,4A,6A,9,11,12,12A,13,13A,14,14A,15/115,15A,16A,17A,18A,19A,24,29A,30A,31A,32A,74A,94A,95A,96A,97A,98A,99A,100A,101A,105A,106A	No	General Transient (except where LOCA or LOSP may occur)	LOCA may occur due to a fire in zone 1A, 2A or 74A causing spuriously open PORV or RVHV. LOSP may occur due to a fire in zone 11, 14 or 15/115.
B (RHR No. 21 Pump Room)	4	Yes	N/A - area screened out	No equipment required for achieving a stable hot SSD is located in the location
C (Aux. Feedwater Pump Room)	23	No	General Transient	-
D (Fuel Storage Building)	90A,91A	Yes	N/A - area screened out	No equipment required for achieving a stable hot SSD is located in the location
E (No. 21 Charging Pump Room)	5	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.

Table 4.2-3: Results of Qualitative Screening Analysis				
Fire Area	**Fire Zone**	**Screened Out**	**PRA Accident Sequence Selected**	**Rationale**
F (PAB Upper Elevation and Fan House)	5A,6,7,7A,8,8A,9A,10A, 11A,20A,21A,22A,23A, 24A,25A,26A,27A,28A,33A, 59A	Yes	N/A	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.
G (Diesel Generator Room)	10	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.
H (Containment)	70A,71A,72A,75A,76A, 77A,78A,80A,81A,82A, 83A,84A,85A,86A,87A	Yes	N/A - area screened out	Low fire frequency & No potential for exposure of all SSD trains fire damage to both
I (Intake Structure)	22,63A,66A	No	General Transient	
J (Alternate Safe Shutdown Cable and Equipment Area	16,17,18,19,20,21,25, 39A,40A,41A,42A,43A, 44A,45A,46A,47A,48A, 49A,50A,51A,52A,53A, 64A,130,Unit 1 areas	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.

Table 4.2-3: Results of Qualitative Screening Analysis				
Fire Area	**Fire Zone**	**Screened Out**	**PRA Accident Sequence Selected**	**Rationale**
K (Steam/Feedwater Piping)	60A,61A,62A,65A	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.
L (IP-1 Screenwall Area)	600,610	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.
M (Gas Turbine)	650	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.
N (Manhole No. 21)	630	No	General Transient	
P (Component Cooling Water Pump Room)	1	No	General Transient	
Q (Penetration H-20 and Cabling)	74B	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.

Table 4.2-3: Results of Qualitative Screening Analysis				
Fire Area	**Fire Zone**	**Screened Out**	**PRA Accident Sequence Selected**	**Rationale**
Others	55,55A,56A,57A,58A,700,710	Yes	N/A - area screened out	Plant shutdown induced by a fire in this location, would not require operation of the equipment postulated to be damaged or to be unavailable.

Table 4.2-4: Fire Compartment Interaction Analysis Results

Fire Compartment	Fire Zones	Screened (Yes/No)
A1	1A, 2, 2A, 6A, 74A	No
A2	3, 3A, 4A, 9, 12A, 13A, 14A, 15A 16A, 17A, 18A, 19A, 29A, 30A, 31A	Yes
A3	11, 12, 13, 14, 15/115, 24, 32A	No
A4	94A, 95A, 96A, 97A, 98A, 99A, 100A 101A, 105A, 106A	Yes

Table 4.2-5: Fire Area Ignition Frequency Calculations		
Fire Area	**Fire Zone**	**Ignition Frequency**
A	1A	4.17E-03
	2	1.81E-03
	2A	3.40E-03
	3	1.13E-03
	3A	3.17E-03
	4A	4.54E-04
	6A	4.13E-04
	9	3.35E-03
	11	1.42E-02
	12	1.30E-03
	12A	1.34E-04
	13	1.30E-03
	13A	5.17E-04
	14	1.18E-02
	14A	4.13E-04
	15/115	9.50E-03
	15A	5.17E-04
	16A	0.00E-00
	17A	5.17E-04
	18A	5.17E-04
	19A	1.13E-03
	24	1.30E-03
	29A	4.54E-04
	30A	9.11E-04
	31A	4.54E-04

Table 4.2-5: Fire Area Ignition Frequency Calculations		
Fire Area	**Fire Zone**	**Ignition Frequency**
	32A	5.04E-04
	74A	2.90E-03
	94A	5.17E-04
	95A	5.17E-04
	96A	5.17E-04
	97A	5.17E-04
	98A	5.17E-04
	99A	5.17E-04
	100A	5.17E-04
	101A	5.17E-04
	105A	5.17E-04
Fire Ignition Frequency for Fire Area "A"		7.09E-02
C	23	2.50E-03
Fire Ignition Frequency for Fire Area "C"		2.50E-03
F	5A	1.14E-03
	6	1.20E-03
	7	1.20E-03
	7A	1.14E-03
	8	2.19E-03
	8A	5.17E-04
	9A	5.17E-04
	10A	1.69E-03
	11A	5.17E-04
	20A	4.13E-04

Table 4.2-5: Fire Area Ignition Frequency Calculations		
Fire Area	**Fire Zone**	**Ignition Frequency**
	21A	4.77E-04
	22A	1.14E-03
	23A	9.11E-04
	24A	5.54E-04
	25A	1.06E-04
	26A	5.17E-04
	27A	5.01E-03
	28A	4.13E-04
	33A	3.94E-03
	59A	4.88E-03
Fire Ignition Frequency for Fire Area "F"		2.85E-02
I	22	2.10E-03
	63A	2.10E-03
	66A	5.04E-04
Fire Ignition Frequency for Fire Area "I"		4.70E-03
N	630	0.00E-00
Fire Ignition Frequency for Fire Area "N"		0.00E-00
P	1	3.17E-03
Fire Ignition Frequency for Fire Area "P"		3.17E-03

Table 4.6-1a: Fire Zone 1A: Auxiliary Building Electrical Tunnel/ Pipe Penetration Area

Scenario ID.	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A1-1A	Floor based transient combustible fire damages lower trays in region 1 (cable trays T01D, T53C/ C3, C4, C5, C6, D400, J3, J4)	7.5E-06	REC pumps (P) FCUs (P)	None None	1.69E-10
A1-1B	Floor based transient combustible fire or welding fire damages all trays in region 1 (cable trays T41 C3, C4, C5, C6, D400, J3, J4, K2, J2, J1, K1, K1B, K2B)	3.23E-06	As A1-1T plus AFS pumps (C) AFS FCVs etc (P/C) LCV 112B (RWST supply to charging) REC/RHR HX CCW Valves inside containment fail closed (P) PORVs (P/C) (spuriously open/fail to operate) PORV BVs (P) will not open/close	 ASSS Power to MDP 21 TDP Manual Control Local Valve Operation Local valve realignment None None None	6.84E-07

Table 4.6-1a: Fire Zone 1A: Auxiliary Building Electrical Tunnel/ Pipe Penetration Area

Scenario ID.	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A1-2B	Floor based transient combustible fire or welding fire damages lower trays in region 2 (cable trays T8/D, K1B, K2B, F, D)	3.66E-05	PORV BVs (P) fail open/closed REC/RHR HX CCW Valves inside containment (P) fail closed	None None	2.68E-08

Table 4.6-1a: Fire Zone 1A: Auxiliary Building Electrical Tunnel/ Pipe Penetration Area

Scenario ID.	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A1-3	Floor based transient combustible fire damages all trays in region 3 ((cable trays T02C/C3, C4, K1, K2, J4, D4, & T01C,F, K1B, K2B) & cable trays T02C/C3, C4, K1, K2, J4, D4 & T52B/C3,C4, K1, K2, J4, D400).	5.47E-06	RCP seal injection valve alignment (P,C)	Local valve re-alignment	2.98E-08
			Charging Pumps 21, 22, 23 (C)	Align ASSS power to charging Pump 23	
			CCW thermal barrier valves (P,C) (mis-align)	Local valve re-alignment	
			CCW Pump 21, 22 (P)	Align ASSS power to CCW Pump 23	
			REC/RHR HX CCW MOVS inside containment (P) (fail to open)	None	
			HPI MOVS outside containment (C) (spuriously close)	None	
			MCCs 26A, 26B & 27A (P)	None	
			PORV BVs (P,C) fail open or closed	None	
			RHV MOVs (P,C) fail open	None	

Table 4.6-1a: Fire Zone 1A: Auxiliary Building Electrical Tunnel/ Pipe Penetration Area

Scenario ID.	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A1-4A	Floor based transient combustible fire damages lower trays in region 4 (cable trays T53B, T41C /C3, C4, C5, C6, D400, J3, J4).	2.23E-05	REC Pumps (P) FCU (P) RHR Pumps (P) SI Pumps (P) Charging Pumps (P)	None None None None Align ASSS Power to Pump 23	9.78E-08
A1-4B	Floor based transient combustible fire damages all trays and lower trays in region 4 (cable trays T53B, T41C /C3, C4, C5, C6, D400, J3, J4, K2, J1, J2, K1).	9.57E-06	As A1-4A PLUS AFS pumps (C) AFS FCVs etc (P/C) LCV 112B (RWST supply to charging) PORVS (P,C) will not open, spuriously opens	ASSS Power to MDP 21 TDP Manual Control Local Valve Operation in accordance with A27.1.9 Local valve realignment in accordance with A27.1.9 None	5.93E-08

Table 4.6-1a: Fire Zone 1A: Auxiliary Building Electrical Tunnel/ Pipe Penetration Area

Scenario ID.	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A1-5A	Floor based transient combustible fire damages all lower trays in region 5 (cable trays T45C, T52C /C3, C4, C5, C6, D400, J3, J4).	5.93E-05	REC pump (P) FCU (P) Charging Pump 21, 22, 23 (P) CCW Pumps 23 (P)	None None Align ASSS power to charging pump 23 in accordance with A27.1.9 None	4.97E-09
A1-5B	Floor based transient combustible fire damages all trays in region 5 (cable trays T41C/C3, C4, C5, C6, D400, J3, J4, K2, J1, J2, K1).	2.54E-05	AS A1-5A PLUS AFS pumps (C) AFS FCVs (etc) (P,C) LCV 112B (RWST supply to charging) (P,C) will not open PORVS (P,C) (spuriously open/ fail to operate)	 ASSS Power to MDP 21 TDP Manual Control Local Valve Operation in accordance with A27.1.9 Local Valve Operation in accordance with A27.1.9 None	5.06E-08

Table 4.6-1b: Fire Zone 2A: Primary Water Make Up Pump Area

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
A1-8	Floor based transient combustible fire damages all trays in region 1 (cable trays T01C/K1B, K2B, F & T02C/C3, C4, K1, K2, J4, D4) T14C/K1B, K2B, F T15C/C3, C4, K1, K2, J4, D4) T07C/C3, C4	1.24E-04	RCP seal injection valve mis-alignment (C)	Local valve operation in accordance with A27.1.9	6.84E-07
			Charging Pump 21, 22, 23 (C)	Align ASSS power to CHP 23 in accordance with A27.1.9	
			CCW thermal barrier valve mis-alignment (C)	Local Valve Operation	
			CCW Pump 21, 22, (P)	Align ASSS power to CCW pump 23 in accordance with A27.1.9	
			PORV Block Valve (P,C) (spurious open/fail to operate)	None, (MCC 26A/B power cable damage prevents operation from at MCC)	
			RHR Hd. Vent Valve (P,C) (spurious open)	None, (MCC 26A/B power cable damage prevents operation from at MCC)	
			Containment Spray Pumps 21, 22 (P)	none	
			MCC26A/26B (P)	none	
			HPI MOVs Outside Containment	none	
			REC/RHR HX CCW MOVs inside containment	none	

Table 4.6-1b: Fire Zone 2A: Primary Water Make Up Pump Area

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
A1-9	Floor based transient combustible fire damages all trays in region 2 (cable trays T01C/K1B, K2B, F T02C/C3, C4, K1, K2, J4, D4) T07C/C3, C4 T08C/C3, C4	3.00E-04	CCW Pump 21, 22, (P) Containment Spray Pumps 21, 22 (P) MCC26A/26B (P)	Align ASSS power to CHP 23 none none	3.63E-07

Table 4.6-1c: Fire Zone 6A: Drumming and Storage Station

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
A1-10	Floor based transient combustible fire damages all Charging Pump Power Conduits	2.64E-05	Charging Pump 21, 22, 23 (P)	Align ASSS power to CHP 23	1.53E-09

Table 4.6-1d: Fire Zone 11: Cable Spreading Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-1A	Fire originating in Rod Control Switchgear damages cross- over trays between main N & S stacks which serve Flight Panel (cable trays T51F/K1 T54F/K1, K2, T60F/J1-D, J2, J3, J4 & T57F/D) Note: Although other cross over trays may be affected no significant damage to accident mitigating systems was identified i.e. T21H/F (serving lighting), T62F/J1-K1, J2-K2, J3, J4. D (serving "D" rack)	1.43E-04	PORV (P,C) (spurious open, fail to operate) PORV BV (spurious open/close) Offsite Power to 6.9kV buses	None Close from MCC26A/26B to isolate LOCA in accordance with A27.1.9	1.51E-07
A3-1B	Fire originating in Rod Control Switchgear damages cross over trays between main N & S cable tray stacks which serve Flight Panel (cable trays T51F/K1, T54F/K1, K2, T60F/J1-D, J2, J3, J4 & T57F/D) and main north cable tray stack (cable trays T46B/K1, K2, J1, J2, J3, J4, D400, D800) Note: Although other cross over trays may be affected no significant damage to accident mitigating systems is assumed i.e. T21H/F (serving lighting), T62F/J1-K1, J2-K2, J3, J4. D (serving "D" rack)	2.90E-07	As A3-1A plus AFS pumps (C) AFS FCVs etc (P/C) LCV 112B (P,C) (RWST supply to charging)	ASSS Power to MDP 21 TDP Manual Control Local Valve Operation in accordance with A27.1.9 Local valve realignment in accordance with A27.1.9	4.29E-10
A3-2A	Fire originating in west end of Rod Drive Cabinet damages N-S cross over trays which serve the flight panel (cable trays T52F, T53F /K1, K2, J1, D T55F/J, K2 T58F/J, K2). Note: although damage to other trays in stack (i.e./ J4) may be damaged no resulting loss of accident mitigating systems was identified.	1.21E-04	PORVS (P) (spuriously open, fail to open) PORV BVS (C) (spuriously open/fail to open or close)	Close from MCC26A/26B to isolate LOCA in accordance with A27.1.9	2.58E-07

Table 4.6-1d: Fire Zone 11: Cable Spreading Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-2B	Fire originating in west end of Rod Drive Cabinet damages south cable trays stack (cable trays T33B, T41B/K1A, K2A,K1,K2, J4, D400) and N-S cross over trays which serve the flight panel (cable trays T52F, T53F /K1, K2, J1, D T55F/J, K2 T58F/J, K2).	1.75E-05	As A3-2A Plus All EDG Auxiliaries (C) Charging Pumps 21, 22, 23 (C) RCP seal injection valve (C) (mis-alignment) CCW thermal barrier valve (C) (mis-alignment) RECIRCULATION/RHR CCW MOVs (inside containment) (C) (Fail to Open) AUX CCW Pumps (C) HPI MOVs (C) (spuriously close)	As A3-2A plus none Align ASSS power to charging pump 23 Local valve re- alignment in accordance with A27.1.9 Local valve re- alignment in accordance with A27.1.9 Operate from MCC26A/26B none (given short time available) none (given short time available) None	5.57E-08

Table 4.6-1d: Fire Zone 11: Cable Spreading Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-3A	Fire originating in west end of Rod Drive Cabinet damages N-S crossover trays which serve "B" logic racks (cable trays T65F(or 66F) /J1-D, J3, J4, T68F(or 69F)/J3-D, J4.	1.21E-04	AFW TDP (C) AFW FCVs (C) PORV (C) (spurious open, fail to open)	TDP Manual Control Local Valve Operation in accordance with A27.1.9. None	2.79E-07

Table 4.6-1d: Fire Zone 11: Cable Spreading Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-3B	Fire originating in west end of Rod Drive Cabinet damages main south cable tray stack (cable trays T43B, T41B/K1A, K2A,K1,K2, J4, D400, F) and N-S crossover trays which serve "B" logic racks (cable trays T65F(or 66F) /J1-D, J3, J4, T68F(or 69F)/J3-D, J4.	1.75E-05	As A3-3A plus	As A3-3a plus	8.71E-08
			All EDG Auxiliaries (C)	none	
			Charging Pumps 21, 22, 23 (C)	Align ASSS power to charging pump 23	
			RCP seal injection valve (C) (mis-alignment)	Local valve re- alignment in accordance with A27.1.9	
			CCW thermal barrier valve (C) (mis-alignment)	Local valve re- alignment in accordance with A27.1.9	
			RECIRCULATION/RHR CCW MOVs (inside containment) (C) (Fail to Open)	Operate from MCC26A/26B	
			AUX CCW Pumps (C)	none (given short time available)	
			HPI MOVs (C) (spuriously close)	none (given short time available)	
				None	

Table 4.6-1d: Fire Zone 11: Cable Spreading Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-4	Fire originating in the RVLIS Cabinet damages main south cable tray stack (cable trays T45B(or 51B)/K1A, K2A,K1,K2, J4, D400, F) and N-S cross trays serving logic cabinet "A" (cable trays T71F(or72F)/J-D, J2)	1.18E-05	Identical to A3-3B	Identical to A3-3B	2.73E-08
A3-5	Transient fire damages vertical cable trays or multiple electrical cabinets	2.10E-05	Loss of off site power to 480v-ac busses Loss of EDGs	Use ASSS in accordance with A27.1.9	1.27E-06

Table 4.6-1e: Fire Zone 14: Switchgear Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-7	Fire originating in 480V switchgear 2A or associated station service transformer damages overhead cable tray	9.43E-04	All component powered from Bus 2A	none	1.65E-06
			All components powered from Bus 5A (Breaker controls for Bus 5A normal and emergency EDG power)	none	
			480 v power to MCC26C (P)	none	
			EDG 22 Supply breaker to Bus 3A (C). (normal power source unaffected)	none	
			125V dc power from power panel 21 to Bus 3A (backup source unaffected)	none	
			SW pump 22 and 25 (C)	none	
			Charging Pump 22 and 23 (C)	Align ASSS power supply to charging pump 23	

Table 4.6-1e: Fire Zone 14: Switchgear Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-8	Fire originating in 480V switchgear 3A or associated station service transformer damages overhead cable tray.	8.31E-04	All components powered from Bus 3A		1.15E-07
			FCU 23 (P)	none	
			MCC 29A (P)	none	
			Battery Charger 22 (P)	none	
			SI Pump 22 (C)	none	
			FCU 25 (C)	none	
			SW Pump 25 and 23 (C)	Align ASSS power supplies as necessary for SW pumps	
A3-9	Fire originating in 480V switchgear 5A or associated station service transformer damages overhead cable tray.	8.31E-04	All components powered by Bus 5A	none	6.19E-07
			SI Pump 22 (P)	none	
			CCW Pump 22 (P)	none	
			MCC26C (P)	none	
			Charging Pump 23 (C)	none	
			125V dc power from power panel 21 to Bus 3A (backup source unaffected)	none	

Table 4.6-1e: Fire Zone 14: Switchgear Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-10	Fire originating in 480V switchgear 6A or associated station service transformer damages overhead cable tray.	9.43E-04	All components powered from Bus 6A AFW pump 21 (P) Charging Pump 22 (P) Battery charger 22 (P) FCU 23 and 24 (P) RHR Pump 21 (P) All components powered from Bus 3A (Breaker controls for Bus 3A normal and emergency EDG power)	none none none none none none none	2.44E-06
A3-11	Fire originating in SW/FCU local control cabinet damages internal wiring	2.84E-04	All SW pumps (C) All FCUs (C)	Align ASSS power supply to SW pumps in accordance with A27.1.9 None	5.67E-10
A3-12	Lube Oil fire originating in Air Compressor 22 damages Bus 6A and overhead cable tray (T27B)	1.18E-05	Bus 6A CCW Pump 22 SI Pump 22 Battery Charger 22 MCC26A and 26C DG Bldg ventilation panel 22	none	3.99E-07

Table 4.6-1e: Fire Zone 14: Switchgear Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency (per year)
A3-13A	Floor based transient fire damages all 480v busses	6.62E-06	All 480v Buses	Align ASSS power supply to all ASSS equipment in accordance with A27.1.9	5.17E-07
A3-13B	Floor based transient fire damage bus 5A and 6A	1.23E-05	Bus 5A and 6A	none	4.74E-07
A3-13C	Floor based transient fire damages bus 2A and 3A	1.23E-05	Bus 2A and 3A	none	1.61E-09
A3-13D	Floor based transient fire damages bus 2A and 5A	2.21E-06	Bus 2A and 5A	none	1.85E-09
A3-13E	Floor based transient fire damages bus 3A and 6A	2.21E-06	Bus 3A and 6A	none	1.08E-09
A3-13F	Floor based transient fire disables bus 2A and 3A and the SW/FCU local control cabinet	9.52E-06	Bus 2A and 3A All SW pumps (C) All FCUs (C)	none Align ASSS power supply to SW pumps in accordance with A27.1.9 none	8.19E-09

Table 4.6-1f: Fire Zone 15: Central Control Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency
A3-15C	Fire confined to supervisory panel, section SB-1	2.39E-05	All SW Pumps (C)	Align ASSS power to SW pumps in accordance with A27.1.9	3.86E-10
A3-15D	Fire confined to supervisory panel, section SB-2	1.79E-05	All FCUs (C) HPI Suction and Crosstie valves (C) spuriously close MCC 26A, 26B and 26C supply bkrs (C) spuriously open	none none Close breakers locally at MCC	2.33E-08
A3-15E	Fire confined to supervisory panel, section SC	2.39E-05	AFS Pumps (C) AFS FCV etc (C)	ASSS Power to MDP 21 TDP Manual Control Local Valve Operation	3.61E-07
A3-15H	Fire confined to supervisory panel, section SF	1.79E-05	LCV 112B RWST (supply to charging) (C)	Local valve re-alignment in accordance with A27.1.9	1.42E-10
A3-15I	Fire confined to supervisory panel section SG	1.79E-05	RHR Pumps (C) REC/CCW Valves inside cont (C). CCW Pumps (C)	none Operate from MCC Align ASSS power to Pump 23 in accordance with A27.1.9	5.97E-10

Table 4.6-1f: Fire Zone 15: Central Control Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency
A3-15J	Fire confined to supervisory panel, section SH	1.79E-05	Offsite power supply breakers to associated with all 6.9kV and 480v all buses (C) EDG supply breakers to 480v ac buses All SI Pumps (C)	Align ASSS power to all ASSS components	1.89E-06
A3-15K	Fire originating confined to supervisory panel, section SJ	1.79E-05	All SW pumps (C)	Align ASSS to SW pumps in accordance with A27.1.9	5.37E-10
A3-16A	Fire originating in eastern region of supervisory panel damages sections SB-1 SB-2 and SC	2.17E-05	All SW Pumps (C) All FCUs (C) HPI Suction and Crosstie valves (C) spuriously close MCC 26A, 26B and 26C supply bkrs (C) spuriously open RVHV Valves (C) spuriously open AFS Pumps (C) AFS FCV etc (C)	Align ASSS power to SW pumps in accordance with A27.1.9 none none Close breakers locally at MCC Close MOVs at MCC ASSS Power to MDP 21 TDP Manual Control Local Valve Operation	4.30E-09

Table 4.6-1f: Fire Zone 15: Central Control Room

Scenario Id	Fire Scenario Description	Fire *Scenario* Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited *for Accident Mitigation*	Core Damage Frequency
A3-16B	Fire originating in center region of panel damages all functions controlled from supervisory panel	1.26E-05	Offsite Power supply breakers to 480 V busses (C) EDG power supply breakers to 480v Busses (C) RVHV Valves (C) spuriously open (all other damage subsumed by above)	In accordance with ASSS A27.1.9: Align ASSS to AFS, CCW & CHP, and SW Pumps Control AFS TDP locally Align AFS valves locally none	7.62E-07
A3-16C	Fire in originating in western region of supervisory panel damages sections SG SH and SJ.	2.65E-05	Offsite Power supply breakers to 480 V busses (C) EDG power supply breakers to 480v Busses (C) (All other damage subsumed by the above)	In accordance with ASSS A27.1.9: Align ASSS to AFS, CCW & CHP, and SW Pumps Control AFS TDP locally Align AFS valves locally none	5.96E-06

Table 4.6-1f: Fire Zone 15: Central Control Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency
A3-17	Fire originating in any CCR panel which results in CCR evacuation:	3.23E-05	Assume loss of control of all equipment from CCR PORVs may spuriously open (fires in Flight Panel only) RHR Head vent valves may spuriously open (fires in supervisory panel eastern and center section only)	In accordance with ASSS A27.1.9: Align ASSS to AFS, CCW & CHP, and SW Pumps Control AFS TDP locally Align AFS valves locally Close block valves at MCC (480v-ac power should be unaffected by supervisory panel fire even though CCR is evacuated)) none	2.55E-07
A3-18	Fire confined to flight panel	1.95E-04	PORVs (P/C) (Spuriously open/will not operated) PORV BVs (C) will not open/close Loss of offsite power to 480vac busses.	none Close block valves from MCC 26A/26B in accordance with A27.1.9 none	2.11E-07
A3-19	Fire confined to CVCS logic cabinet (JG6-JG7).	1.17E-04	All charging pumps (C)	Align ASSS power to CHG Pump 23 in accordance with A27.1.9	1.05E-09
A3-20	Fire confined to FW logic cabinet	1.17E-04	AFW Pumps (C) AFW Valve Control (C)	Align ASSS to Pump 21 Control AFS TDP locally Align AFS vales manually	5.62E-09

Table 4.6-1f: Fire Zone 15: Central Control Room

Scenario Id	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Recovery Actions Credited for Accident Mitigation	Core Damage Frequency
A3-21	Fire confined to pressure control logic cabinet: *JF6-JF8*	1.83E-04	PORVs (P/C) (Spuriously open/will not operated)	none	2.16E-08

Table 4.6-1g: Fire Zone 74A: Electrical Penetration Area

Scenario Designation	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
A1-14A	Floor based transient combustible fire damages lower trays in region 2 (cable trays T01D/C3, C4, C5, C6, D400, J3, J4)	6.04E-06	REC Pumps (P) FCUs	None	1.51E-10
A1-14B	Floor based transient combustible fire damages all trays in region 2 (cable trays T01D/C3, C4, C5, C6, D400, J3, J4, J2, J1, K1, K2, K1B, K2B)	2.59E-06	As A14A plus: PORV Block Valve (P) (fail to open/close) PORVs (P.C) spurious open or fail to open) REC/SPRAY/CCW MOVs inside containment (P) (fail to open) AFW Pumps (C) AFW FCVs (P,C)	 None None None Align ASSS Power to AFS MDP 21. Control TDP locally in accordance with A27.1.9. Align valves locally	3.83E-07
A1-15	Floor based transient combustible fire damages all trays in region 3b (cable trays T23D/C3 T23Z/C3	1.91E-05	RECP 22 (P) FCU 23 (P) PORV 456 (P,C) (spuriously opens/ fails to open)	none	2.09E-09

Table 4.6-1g: Fire Zone 74A: Electrical Penetration Area

Scenario Designation	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
A1-16	Floor based transient combustible fire damages all trays in region 3c (cable trays T30D/C3, T33Z/C3, T32D/K1B, T77B/K1B, T33D/K1B)	1.91E-05	RECP 22 (P) FCU 25 (P) PORV 455C (P,C) (spuriously opens/ fails to open) PORV BV 536 (P) fails open /closed REC/SPRAY/CCW MOVs 745B, 746, 822A, 889A, 1802A & HCV 640 inside containment (P) (fail to open)	none	7.35E-08
A1-17	Floor based transient combustible fire damages all trays in region 4 (cable trays T0F/K1, K2)	2.36E-05	AFW Pumps (C) AFW FCVs (P,C)	Align ASSS Power to AFS MDP 21. Control TDP locally in accordance with A27.1.9. Align valves locally	7.54E-08
A1-18A	Cabinet fire damages lower trays in west wall stack (cable trays T01D/C3, C4, C5, C6, D400, J3, J4)	3.13E-04	Identical to A1-14A	Identical to A1-14A	9.20E-09
A1-18B	Cabinet fire damages all trays in west wall stack (cable trays T01D/C3, C4, C5, C6, D400, J3, J4, J2, J1, K1, K2, K1B, K2B)	2.82E-06	Identical to A1-14B	Identical to A1-14B	5.68E-07

Table 4.6-1h: Fire Zone 32A: Electrical Tunnel

Scenario Designation	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
A3-22A	Floor based fire on south side of electrical tunnel damages all overhead cables on that side of tunnel (T51B F/K1A, K2A, D, C3, C2, C4, K1, K2, J4, D400)	1.1E-05	RCP seal injection valve alignment (C) Charging Pumps 21, 22, 23 (P, C) CCW thermal barrier valves (C) (mis-align) CCW Pump 21, 22 (P) Containment Spray Pumps (P) REC/RHR HX CCW MOVS inside containment (C, P) (fail to open) Auxiliary CCW pumps (C) HPI MOVS outside containment (C) (spuriously close) MCCs 26A, 26B & 27A (C, P) PORV BVs (C) fail open or closed RHV MOVs (C) fail open All EDG auxiliaries	Local valve re-alignment Align ASSS power to charging Pump 23 Local valve re-alignment Align ASSS power to CCW Pump 23 None None None None None None None None	6.02E-08

Table 4.6-1h: Fire Zone 32A: Electrical Tunnel

Scenario Designation	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
A3-22B	Floor based transient fire damages cables on north side of tunnel (T50B K1, K2, J1, J2, J3, J4, D, C3, C4, C5, C6)	1.1E-05	AFW Pump (C)	Align ASSS Power to AFS MDP 21. Control TDP locally in accordance with A27.1.9.	3.60E-08
			AFW FCVs etc (C)	Align valves locally	
			PORVs (P,C)	None	
			Recirculation Pumps (P)	None	
			SI Pumps (P)	None	
			RHR Pumps (P)	none	
			Fan Cooler Units (P)	none	

Table 4.6-1l: Fire Zone 23: AFW Pump Room

Scenario Designation	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
C-1	Floor based transient in region 1 damages AFW local control panel and ASSS transfer switch	2.72E-05	Both motor driven pumps 21 & 23 (including ASSS)	none	4.77E-08
C-2	Floor based transient in region 5 damages motor driven AFW pump FCVS	2.27E-05	FCVs 406A/B/C/D	none	3.96E-08
C-3	AFW local control panel fire damages panel internals	3.12E-04	Both motor driven pumps	Align ASSS Power to AFS MDP 21 in accordance with A27.1.9.	1.58E-08

Table 4.6-1J: Fire Zones 22 and 63A: SW/CW Intake Structure

Scenario Designation	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
I-2	Lube oil fire originates in SWP 22 or 23	4.81E-05	SW Pumps 21, 22, 23, 24 and 25	none	2.53E-08
I-3	Lube Oil fire originates in SWP 24	9.61E-05	SW Pumps 23 and 24	none	7.83E-10
I-4	Lube Oil fire originates in SWP 25	4.81E-05	SW Pumps 22, 23, 24, 25 and 26	none	8.90E-09
I-8	Lube Oil fire originates in SWP 23 or 24	9.61E-05	SW Pumps 21 and 26	none	7.83E-10

Table 4.6-1k: Fire Zone 1 : CCW Pump Room

Scenario Designation	Fire Scenario Description	Fire Scenario Frequency	Safe Shutdown Equipment Damage	Accident Mitigating Systems / Actions Credited	Core Damage Frequency
P-1	Lube oil fire originates in CCW pump 21 or 22	9.61E-05	CCW pumps 21, 22 and 23	Align ASSS power supply to CCW pump in accordance with A27.1.9	2.21E-09

Table 4.6-2
Summary of Core Damage Frequency Contributions from Fire Zones

Fire Zone	Fire Zone Description	Fire Scenario	Scenario Core Damage Frequency	Zone Core Damage Frequency
1A	Electrical Tunnel/ Pipe Penetration Area	A1X1B	6.50 E-07	
		A1X4A	9.78 E-08	
		A1X4B	5.93 E-08	
		A1X5B	5.06 E-08	
		A1X3	2.98 E-08	
		A1X2B	2.61 E-08	
		A1X5A	4.97 E-09	
		A1X1A	1.69 E-10	9.19 E-07
2A	Primary Water M/U Area	A1X8	6.84 E-07	
		A1X9	3.64 E-07	1.05 E-06
32A	Cable Tunnel	A3X22A	6.02 E-08	
		A3X22B	3.60 E-08	9.62 E-08
6A	Drumming & Storage Station	A1X10	1.53 E-09	1.53 E-09
1	CCW Pump Room	PX1	2.19 E-09	2.19 E-09
11	Cable Spreading Room	A3X7	1.65 E-06	
		A3X5	1.27 E-06	
		A3X9	6.19 E-07	
		A3X3A	2.79 E-07	
		A3X1A	1.51 E-07	
		A3X8	1.15 E-07	
		A3X3B	8.71 E-08	
		A3X2B	5.57 E-08	
		A3X4	2.76 E-08	
		A3X2A	2.58 E-08	
		A3X1B	4.29 E-10	4.28 E-06
14	Switchgear Room	A3X10	2.44 E-06	
		A3X13A	5.17 E-07	
		A3X13B	4.74 E-07	
		A3X12	3.99 E-07	
		A3X13F	8.19 E-09	
		A3X13D	1.85 E-09	
		A3X13C	1.61 E-09	
		A3X11	5.67 E-10	
		A3X13E	1.30 E-10	3.84 E-06

Table 4.6-2
Summary of Core Damage Frequency Contributions from Fire Zones (continued)

Fire Zone	Fire Zone Description	Fire Scenario	Scenario Core Damage Frequency	Zone Core Damage Frequency
15	Control Room	A3X17	1.95 E-06	
		A3X16C	1.89 E-06	
		A3X15J	1.86 E-06	
		A3X16B	7.62 E-07	
		A3X15D	3.61 E-07	
		A3X18	2.11 E-07	
		A3X21	2.16 E-08	
		A3X20	5.62 E-09	
		A3X16A	4.31 E-09	
		A3X15E	1.08 E-09	
		A3X19	1.05 E-09	
		A3X15I	5.97 E-10	
		A3X15K	5.38 E-10	
		A3X15C	3.86 E-10	
		A3X15H	1.43 E-10	7.07 E-06
22/63A	SW Intake	IX2	2.30 E-09	
		IX8	1.77 E-09	
		IX3	1.77 E-09	
		IX4	1.62 E-09	7.46 E-09
23	Auxiliary Feedwater Pump Room	CX3	2.65 E-09	
		CX2	1.79 E-09	
		CX1	1.71 E-09	6.15 E-09
74A	Electrical Penetration Area	A1X18B	5.68 E-07	
		A1X14B	3.83 E-07	
		A1X17	7.54 E-08	
		A1X16	7.35 E-08	
		A1X18A	9.20 E-09	
		A1X15	2.09 E-09	
		A1X14A	1.51 E-10	1.11 E-06
00			Total	1.84 E-05

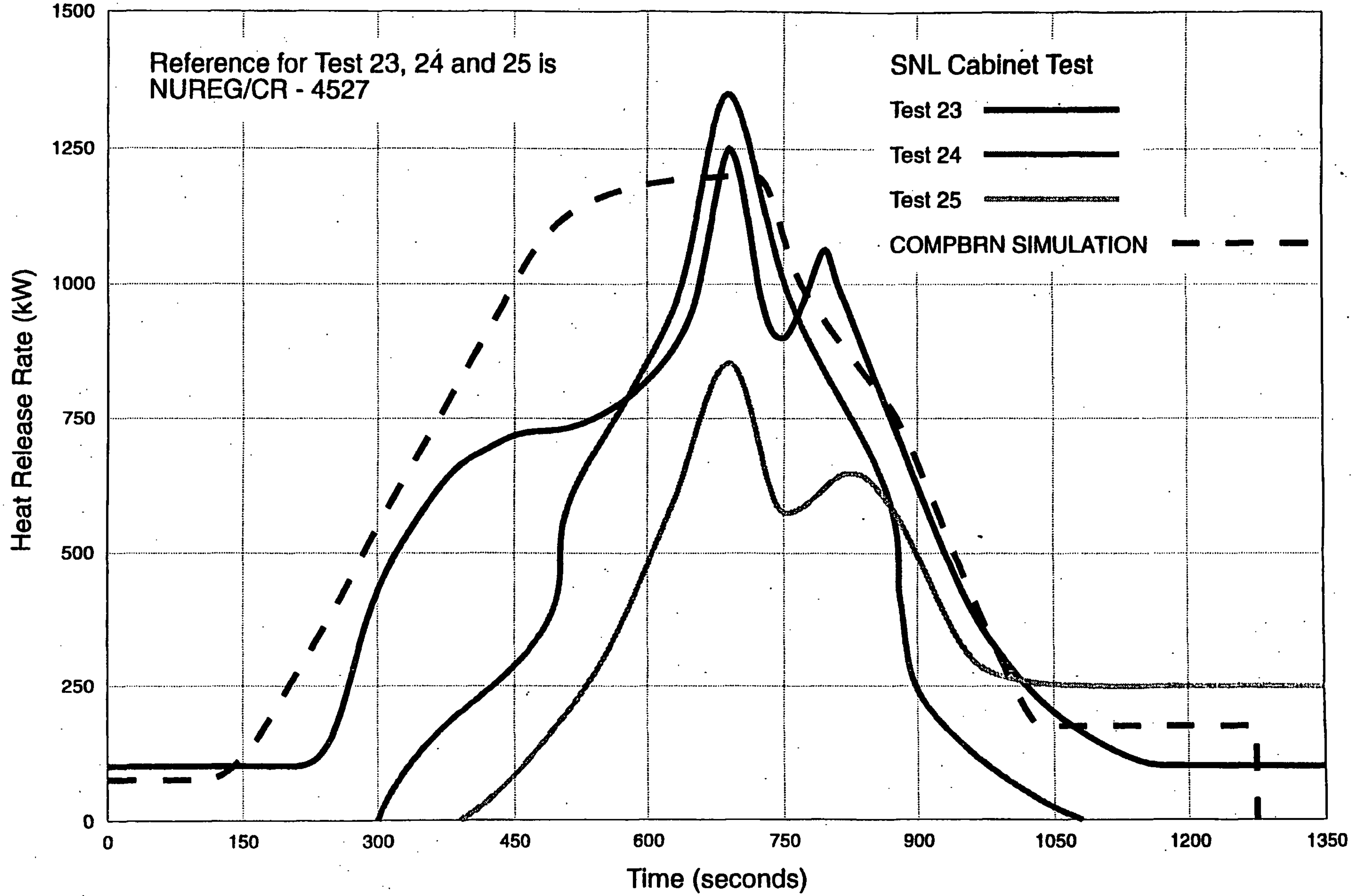

Figure 4.3-1 Actual SNL Cabinet Fire Test Heat Release Rates and COMPBRN Simulation

INTERNAL FLOODING

5.0 METHODOLOGY SELECTION

This portion of the IPEEE examined the potential for floods resulting from the failure, or incorrect operation or alignment of components within the plant. Internal plant flooding includes the effects from the accumulation and spraying of fluids, as well as adverse environmental conditions. The direct effect on system operation resulting from loss of its integrity is also taken into account. All potential internal flood sources and causes are considered in this analysis, with the exception of those that result in loss of primary or secondary reactor coolant outside the Containment (e.g., interfacing system LOCAs or steam line breaks with failure to isolate). Such events were considered in the IP2 Individual Plant Examination (IPE). This analysis utilized a progressive screening process based on bounding assumptions, followed by a detailed probabilistic risk analysis for those areas determined to be potentially significant at the completion of the screening process.

Plant familiarization is addressed in Section 5.1. The initial screening is discussed in Section 5.2 including the approach taken in performing the flood area screening, the partition of IP2 into the different independent flood areas and the qualitative analysis of each flood area. Section 5.3 describes the detailed analysis of remaining flood scenarios and the resulting flood damage states. Sections 5.4 and 5.5 describe the propagation of those flood damage states through the plant model and the quantification of core damage frequency.

5.1 REVIEW OF PLANT INFORMATION AND WALKDOWN

The flood analysis team included two Con Edison engineers who are located on the site and have direct, continuing access to plant facilities, equipment, procedures and staff. In addition, three engineers from NUS Corporation with extensive prior experience at the IP2 site were part of the team.

At the beginning of the analysis, a plant walkdown was performed by the entire flood analysis team. The plant walkdown was performed in two steps. In the first step, all currently available information such as plant system descriptions, P&IDs, previously performed flooding analyses and associated correspondence, and plant specific flooding events were examined. Following that, the actual walkdown of the IP2 plant by the five members of the internal flooding walkdown team was performed based on a pre-established walkdown plan. All accessible flood areas were inspected. Checklists and tables were prepared to document the information obtained during the walkdown. Ingress and egress paths were noted as were protection features such as sumps, alarms, moats and splash guards. Significant flooding sources were located and vital equipment locations were confirmed. Inter-area connections were examined to identify any potential flood propagation concerns.

5.2 FLOOD HAZARD ANALYSIS

Prior to performing flood area screening, the plant was divided into broad flooding areas, corresponding to the major plant buildings (e.g., turbine building, auxiliary feedwater building, diesel generator building etc.) which were identified as having a significant degree of independence with respect to all potential internal flooding effects. An area was considered independent if flooding outside the area could not intrude into the area without the failure of an enclosing flood barrier (wall, fire door, dike etc.). Flood barrier failure modes could include leakage through unsealed doors and hatchways, mechanical failures (e.g., failure of check valves or blockages in common drain lines) and failures of penetration seals, doors etc. due to an excessive head of water. In the absence of a flood barrier failure, flooding in an independent area would not be the direct cause of failures outside the area.

5.2.1 Qualitative Screening of Flood Areas

Initially, the plant was divided into a few large independent buildings, such as the Auxiliary Building, the Turbine Building and the Fuel Storage Building which could be easily identified as independent with respect to internal flooding, because they are distinct structures with only a few interconnecting pathways. A review of the plant design was performed to identify design features that would be expected to preclude or inhibit any significant propagation of water from one building to the other. In general, the collapse of walls or leakage through construction joints is not a significant issue with respect to plant flooding. Even though there have been instances of leakage through wall seams, the leakage rates have been minor and easily accommodated by installed drainage systems.

Flood scenarios which could not be demonstrated as benign, or bounded by other flooding or internal events scenarios, were identified. For each flood area in which such a flood could occur, flood susceptible equipment was identified and the potential for the flood to cause an initiating event was determined. The potential impact on accident mitigating systems was also examined. In the screening analysis, susceptible equipment is assumed to be damaged given that a flood occurs in an area unless damage can be easily ruled out on the basis of an inadequate maximum flood height and no possibility of spraying.

Although this phase of the screening was generally qualitative, in some cases the analysis required deterministic calculations to show, for example, that a particular flood source was well within the capacity of the drainage systems and therefore did not represent a flood accumulation hazard.

5.2.1.1 Flood Hazard Mechanisms

The flood hazard mechanisms considered for each flooding area were divided into two categories:

(1) hazard mechanism(s) as a result of loss of flood source, and
(2) hazard mechanism(s) as a result of the consequence of the flooding event.

For example, as part of category (1), if an RWST pipe rupture occurs, the hazard mechanism of concern is the direct impact of the loss of the RWST on the safety related systems. In category (2), the consequences of flooding caused by the rupture of RWST piping can be analyzed by considering the effects of water accumulation, water spraying, environmental conditions, and flood propagation (egress) if necessary.

The parameters of interest for determining the effects of water accumulation were the critical flood area volume, flood source inventory, the flooding rate, the flood egress rate, and the capacity of drains within the flood area. The most important parameters in determining the effects of water spraying were the proximity of the pipes to the safety related equipment, and whether this equipment is protected against splashing/spraying. The effects of environmental conditions were based on the determination of the effects of high pressures and temperatures on the safety related components within the area of interest due to a postulated pipe failure. The pressure buildup can occur as a result of failure of a high energy steam line, whereas temperature buildup can occur as a result of failure of the lines operating at a temperature far above the ambient temperature. The parameters of concern for determining the harsh environmental effects were pressure and temperature of the discharged fluids.

The effects of flood egress (flood propagation) were based on the determination of the flood propagation into the adjacent flood areas and the susceptibility of the safety related equipments in those areas. The elements of interest were the flooding paths, and the potential for flood accumulation, spraying effects if any, and harsh environmental conditions in the adjacent areas.

5.2.1.2 Flood Area Designations

The flooding analysis was performed for the following IP2 structures:

Primary Auxiliary Building (PAB)
Control Building (CTL)
Diesel Generator Building (DGB)
Auxiliary Feedwater Building (AFW)
Turbine Building (TBL)
Service Water Intake Structure (SWI)
Fuel Storage Building (FSB)

Flood sources within the Containment were not considered because their potential for causing core damage is already bounded by the LOCA analysis within the internal events analysis.

Based on a preliminary review of the above IP2 structures, it was apparent that the PAB, the Control Building and Auxiliary Feedwater Building could not be easily screened out because they contain too many components required for safe plant shutdown. Therefore, these structures were subdivided into smaller areas, each unique in terms of flood sources, flood accumulation and equipment affected by the flood. However, unlike the larger flood areas, these sub-areas are not independent with respect to internal flooding. Floods can propagate from one sub-area to the next through pathways like equipment hatches, openings under doors, piping penetrations, etc. In the screening analysis, flood propagation is assumed to occur if a given pathway exists, unless it requires the failure of a physical barrier whose failure probability is independent of flood height. In those cases, propagation was assumed to occur with a probability equal to the probability of the barrier failure. The flood areas corresponding to each plant building are shown in Table 5.2-1.

TABLE 5.2-1

Preliminary Independent Flood Area Designation

FLOOD AREAS	DESCRIPTION
PAB 15-1	Primary Aux. Building, RHR room El. 15'-0"
PAB 42-1	Primary Aux. Building, Els. 35'-0" & 42'-0"
PAB 59-1	Primary Aux. Building, Safety Injection Pumps room, El. 59'-0"
PAB 68-1	Primary Aux. Building, Component Cooling Pumps room, El. 68'-0"
PAB 68-2	Primary Aux. Building, Containment Spray Pumps room, El. 68'-0"
PAB 80-1	Primary Aux. Building, Charging Pumps rooms, and CC Heat Exchanger room, El. 80'-0"
PAB 98-1	Primary Aux. Building, CCW Heat Exchangers, Boric Acid Tanks, & MCCs, El. 98'-0"
CTL 15-1	Control Building, 480 Switchgear Room, El. 15'-0"
CTL 15-2	Control Building, Deluge Area, El. 15'-0"
CTL 33-1	Control Building, Battery rooms, MCCs & Panels, El. 33'-0"
CTL 53-1	Control Building, Control Room, El. 53'-0"
DGB 67-1	Diesel Generator Building, El. 67'-0"
AFW 18-1	Aux. Feedwater Building, AFW pumps room, El. 18'-6"
AFW 18-2	Aux. Feedwater Building, Main Steam Room, El. 18'-0"
AFW 32-1	Aux. Feedwater Building, El. 32'-0"
TBL 15-1	Turbine Building, El. 15'-0"
SWP 5-1	Service Water Valve and Strainer Pit, El. 5'-9"
FST 51-1	Fuel Storage Building El. 51'

5.2.2 Flood Hazard Analysis Results

The results of the flood hazard analysis for each of the areas examined is provided in the following sections.

5.2.2.1 Primary Auxiliary Building (PAB)

The PAB has several elevations (98', 80', 68', 59', 42', and 15'), and contains vital equipment including charging pumps, the boric acid tanks and transfer pumps, the containment spray pumps, the safety injection pumps, the component cooling heat exchangers and pumps, residual heat removal pumps, and safety related motor control centers and control panels. The design of the PAB is such that there are substantial open pathways (e.g. open stairwells, floor grating, equipment hatches and piping penetration) from the upper elevations to the lower elevation. The only exception to this is the component cooling water (CCW) pump room where there are no penetrations to the levels below. The lower elevation (Flood Area 15-1), contains the RHR pumps, and is susceptible to flooding from all water sources located within the PAB including the CCW, SI, CVCS, SW, FP sources. The flood mitigation features in this area include sumps, drains, and a door flap.

The environmental effects such as temperature and pressure buildup in the PAB were not explicitly analyzed since all areas of the PAB are sufficiently open and maximum flow from high energy lines are sufficiently limited. Several plant specific studies (References 5-1 and 5-2) confirmed this conclusion.

5.2.2.1.1 Evaluation of Flood Area PAB 98-1

This area represents the general PAB area at elevation 98'. The most significant safety related equipment in elevation 98' of the PAB are the motor control centers. There are many flooding sources in this area including the component cooling piping, auxiliary steam piping, boric acid tanks, fire protection, city water, seal water tank, upper portion of the CCW Heat Exchangers, SWS and CCW piping, CCW surge tank, and volume control tank.

Water accumulation/holdup within the area is not considered possible due to drainage pathways (via stairway, doors, drains and equipment hatch) to lower elevations of the

PAB. However, since the critical flood height is about 16", and with the existence of the drainage pathways discussed above, the critical height would not be attained. The only equipment subject to a potential spraying source is MCC 26A. However, this MCC is protected against spraying effects by the presence of splash guards.

Floods originating in this area will flow unrestricted to lower elevations of the PAB via stairwells and equipment penetrations. The propagation to the 68' elevation through the open grating around the CCW heat exchangers can potentially damage the CCW pumps. Propagation to other intermediate elevations via the stairwell or via the open grating is not considered a threat to other safety related components since water spray is not possible and water accumulation is not credible due to the existence of the open pathways mentioned previously. Water propagated to the 15' elevation will accumulate at this level. An egress path exists at this elevation via a door flap which may be effective for lower flow rates

It was concluded that flooding at the 98' elevation would not affect equipment at this elevation and it will not initiate a plant transient. However, this flood can propagate to lower levels and can impact the component cooling water pumps at elevation 68', and the RHR pumps at 15' elevation.

5.2.2.1.2 Evaluation of Flood Area PAB 80-1

PAB 80-1 is a multi-compartment area at 80' elevation, separated from each other by walls and doors. The charging pumps are the primary mitigation equipment located in this area. The flood sources in this area include CCW heat exchanger SW inlet lines, CCW, city water, CVCS, RWST, auxiliary steam, and fire protection systems. As discussed above water accumulation is not expected at this elevation. Water spray is not concern since the charging pumps are located in separate individual compartments. As discussed above, the only concern relative to other areas is propagation to the 68' elevation through the open grating around the CCW heat exchangers, which can potentially damage the CCW pumps and accumulation at the 15' elevation.

The loss of essential and non-essential SWS and CCW are the only potential direct consequences of piping component rupture in this area. Loss of Essential SW will not result in an automatic plant trip but could result in a manual shutdown because of technical specification requirements. Loss of Non-Essential SW or CCW could result in a plant trip. In addition cooling to the RCP thermal barriers, ECCS pumps and RHR heat exchangers would be lost.

The following scenarios were deemed to require further evaluation and are addressed in the detailed flood analysis:

(i) Effects of flooding in the component cooling pump room from propagation of flood due to rupture of CVCS lines, Service Water lines, or fire protection system lines.

(ii) Effects of flooding in the RHR pump area (PAB elevation 15') due to flood sources in PAB 80-1 (including the direct effects from the rupture of SW and CCW piping).

5.2.2.1.3 Evaluation of Flood Area PAB 68-1

PAB 68-1 represents the part of the PAB at elevation 68' that houses the component cooling water pumps. The water sources within this area include those from the non-essential SW, and CCW systems. Since this area is an enclosed area, there is a potential for flood water to accumulate if the flood rate exceeds the outflow rate from the drains and sump pumps. Should this happen, water will accumulate to the top of the pipe chase that separates this area from the containment spray area (PAB 68-2). Therefore, given sufficient flood volume, the equilibrium flood height in this area will be the height of the pipe chase (i.e., 5'). At this height, the CCW pumps are assumed to be disabled. While equipment damage due to water spray is possible in this area, the direct impact of the loss of the SW or CCW systems piping would bound the consequence of spray induced damage to the CCW pumps. At a flood height of 5', water will flow over the pipe chase to flood area PAB 68-2 and then to the lower levels as discussed above.

From the above, the following scenarios will require a more detailed analysis to determine flooding risk.

i) Rupture of non-essential SW piping leading to a loss of non-essential SW and a loss of CCW.

ii) Rupture of a CCW line leading to a loss of CCW.

iii) Flood propagation from upper elevations leading to a loss of CCW.

5.2.2.1.4 Evaluation of Flood Area PAB 68-2

PAB 68-2 represents the PAB areas at 68' and 51' elevations corresponding to containment spray pump room, the piping and electrical tunnel, the piping penetration area, and the steam generator blowdown tank area. The safety related equipment in this area include the containment spray pumps and their associated motor operated valves and the auxiliary CCW pumps. In addition, the piping penetration area contains power and/or control cables for the containment spray pumps, safety injection pumps, component cooling pumps, containment fan coolers, residual heat removal pumps, charging pumps, pressurizer relief valves, atmospheric relief valves, and auxiliary feedwater pumps. Significant flood accumulation in this zone is precluded by the existence of open pathways, as mentioned previously, which would direct the flow to the 15' elevation. Since the valves on the containment spray pump suction lines from the RWST are maintained in the locked open position, water splashing caused by a rupture of the pipe on the suction side can cause damage to both CS pumps. However, this scenario is bounded by the direct loss of the RWST as a suction source to the spray pumps. Spraying effects from pipe ruptures in the pipe penetration area could potentially be a problem because of the proximity and abundance of piping and electrical cables in this area. However, during the plant walkdown and subsequent walkdowns, it was noted that there were no cable splices within 10' of any piping. Therefore, it is concluded that spraying effects in the pipe penetration area would not be risk significant. The events of concern as a result of a pipe break in the PAB 68-2 flood area are rupture of the CS supply pipe causing loss of RWST inventory and water propagation to the 15' elevation which may affect the RHR pumps.

5.2.2.1.5 Evaluation of Flood Area PAB 59-1

This area is located at elevation 59', and contains the safety injection (SI) pumps. The major flooding source is the piping from the RWST, although other small lines also pass through the area. Floods originating within the PAB 59-1 flood area would propagate to lower elevations of the PAB via the stairway (located on the eastern boundary of the area) and piping penetrations, precluding any significant accumulation. Equipment damage due to spraying effects from SI piping ruptures is bounded by the direct effects of the loss of the RWST itself. Spraying effects from the rupture of the other piping were not considered risk significant based on the distance from the piping to the SI pumps, the relative low pressure of the piping, and the spatial separation of the SI pumps.

5.2.2.1.6 Evaluation of Flood Area PAB 42-1

This area represents the 42'and 35' elevations of the PAB. There are no vital equipment in this area. Water accumulation at the PAB 42-1 flood compartment is not possible since water can flow to lower elevations (15' elevation) unrestricted via the stairway, and piping penetrations. Spraying effects are not a concern since there are no vital equipment in this area. Flooding concerns are therefore limited to the potential damage to the RHR pumps due to water propagation to the 15' elevation.

5.2.2.1.7 Evaluation of Flood Area PAB 15-1

This flood area represents the PAB elevation 15'. The only significant equipment in this area are the RHR pumps. The significant flooding sources within this area include the piping from the RWST and fire protection piping. If the flooding rate exceeds the capacity of the two sump pumps present in the area, flood waters would accumulate at this level and some quantity of water would be eventually discharged to the outdoors via a door flap located on the west wall of the PAB. However, since the capacity of the door flap is limited, the RHR pumps can potentially be at risk if a large flooding event occurs in this area. No spraying effects are postulated that can fail both RHR pumps simultaneously since the RHR pumps are located in separate compartments. A single RHR pump will be sufficient to remove decay given a plant shutdown. The only egress path for floods originating in this area would be to the outdoors via a door located on the west wall of the PAB.

Since floods from most areas of the PAB can potentially threaten the RHR pumps, a more detailed analysis of flood risk in this flood area will be covered in the quantitative analysis.

5.2.2.2 Control Building (CB)

The control building consists of four elevations (15', 33', 53', and 72'). The control building is divided into five flood areas; namely the HVAC room (CTL 72-1), the control room (CTL 53-1), the battery rooms and the electrical tunnel (CTL 33-1), the 480V switchgear room (CTL 15-1), and the deluge station (CTL 15-2). The only significant flooding sources are from fire protection and service water piping. Flood mitigation features in this area include floor drains in all zones except the control room, and a large drain at the entrance to the cable tunnel.

5.2.2.2.1 Evaluation of Flood Area CTL 72-1

This area represents the HVAC room on 72' elevation. There are no significant water sources for in this area for flooding.

5.2.2.2.2 Evaluation of Flood Area CTL 53-1

This area represents the Unit 2 control room. The only flood source in this area is city water which is used in the wash rooms. The accumulation of water inside the control room is not expected to be significant since it is a small diameter, low pressure line, the control room is continuously occupied by operators, and the flooding source can be isolated quickly. Alternatively substantial time exists to open the CCR access doors if necessary to allow the water to flow out of the room into the adjacent open areas. Spraying is not a concern in this area since the above flooding source is located away from and is well shielded from the plant equipment. There are no significant flooding scenarios originating in the Control Room.

5.2.2.2.3 Evaluation of Flood Area CTL 33-1

This area represents the battery rooms, the cable tunnel, and the cable spreading room. The flood sources in this area are fire protection, city water, and instrument air closed cooling water. The plant batteries are located inside the three battery rooms separated by walls. Flood susceptible equipment in this area include battery chargers, emergency batteries, DC panels, and MCCs 26C and 29A. There is no susceptible equipment in the cable tunnel. The fire protection piping located in this area are dry. The water from the inadvertent actuation of fire sprinklers in the cable tunnel would flow down the sloped floor of the tunnel towards the cable spreading room. However, the drain at the end of the tunnel (the entrance to the cable spreading area) is sized large enough to mitigate the flood water. In addition, a 10" high curb is located in front of the drain to prevent flow to cable spreading room. Flooding from other sources do not present a significant flood accumulation hazard. IACCW system floods would be limited to the contents of the head tank (~150 gallons) plus the discharge from the 1.5" diameter CW make up line. The tank and piping are contained within a diked area equipped with a 4" floor drain. There are no significant sources in this area which could cause adverse environmental conditions or are close enough to vital equipment to represent a threat due to spraying. The only propagation path from this area into adjacent areas would be via a small door gap into the turbine building.

5.2.2.2.4 Evaluation of Flood Area CTL 15-2

This area represents the deluge station located at elevation 15' of the control building. There are no safety related equipment in this area. However, floods in this area can propagate into the adjacent 480V switchgear room or into turbine building. Flooding into the switchgear room can propagate through a gap under a 3' wide door or through the louver located in the lower section of the door. Flood propagation into the turbine building is through a gap under a separate (also 3' wide) door. The amount of water which could propagate into the turbine building through the door gap is not a concern since the turbine building is a large open area and the flow rate can easily be handled by the turbine building drainage system. However, a large break in the fire protection piping in CTL 15-2 could cause build-up of flood water in this area very quickly leading to the propagation of water into CTL 15-1 through the door gap as well as through the door louvers. In the case of the larger pipe breaks, the drainage capability of CTL 15-1 may not be sufficient to handle the propagating water, and thus the 480V switchgear could be threatened.

There are no safety related equipment in this area that would be affected by a flood. However, because of the large size of the piping in this area, its proximity to the switchgear room and the existence of a potential flooding pathway, this scenario was further evaluated in the detailed flood analysis.

5.2.2.2.5 Evaluation of Flood Area CTL 15-1

This area represents the 480V switchgear room at 15' elevation. The vital equipment in this area include the 480V vital buses (2A, 3A, 5A, and 6A), instrument air compressors and closed cooling water pumps. The water sources in this zone are the Essential and Non-Essential SW, IACCW heat exchanger piping, pumps and valves. The (3") service water system supplies the instrument air compressor closed cooling system heat exchangers. Drainage consists of two 4-inch floor drains, four 4-inch equipment drains with 4 inch lips, and one 4-inch equipment drain with a 1 inch lip.

There are two 3-inch service water supply and return lines in the vicinity of the closed cooling heat exchangers which are located about 32' away from the 480V switchgear buses. A break in the essential service water piping may lead to a plant trip due to loss of instrument air. A break in the non-essential service water piping in this area would have no immediate direct effect. In the event of a complete rupture in the essential SW pipe, the break flow rate would exceed the capacity of the drain system. The remaining IACCW flood sources do not present significant flood hazards due to their smaller pipe sizes and their limited capacity (a few hundred gallons) compared with the critical flood volume for the area. Since the service water line is approximately 32' away from the emergency switchgear, it does not represent a spray hazard. Also, the IACCW piping will not present any spaying hazard to the 480 switchgear since their operating pressure is low (8 psi) and the piping is located more than 8' away from the switchgear. There are no sources in this area which could create adverse temperature or humidity in this area.

Any flooding in excess of the drain capacity would flow into an adjacent stairwell and into the deluge area (CTL 15-2). The water propagating into the stairwell will further propagate into the IP 1 water factory room through a gap beneath the 3' door. The water factory room does not contain any safety related equipment and its drainage capability is adequate to handle the amount of water coming from the switchgear room. Water from the switchgear room can also propagate into the deluge area (CTL 15-2) through a gap below a 3' door. The deluge area does not contain any safety related equipment, thus flood propagation into this area would not cause any risk significant effects. The flooding water inside the deluge area can further propagate into the turbine building under another 3' door. However, water propagating into the turbine building from the deluge area would be easily removed by the drainage system in that area.

Failure of the service water piping in this area is a potential concern and was further evaluated in the detailed flood analysis.

5.2.2.3 Emergency Diesel Generator (EDG) Building

The diesel generator building contains the three emergency diesel generators (EDGs), day tanks, control panels, and their associated piping. Although the three EDGs are separated from one another by Appendix R fire barriers, these barriers will not prevent propagation of water from one EDG location to the others. Major flood sources in this area include the essential service water (ESW) piping and the fire protection (FP) piping. There are five drainage sumps covered by checkered plate with two 3" openings through backwater valves (which essentially are check valves to prevent backflow of water into the DG building). These drainage sumps are connected to a common 12" drain which runs to the site drainage system. The floor surrounding the diesel engines/generators and control panels is primarily metal grating such that this equipment is located at least five feet above the elevation at which water could begin to accumulate.

The fire protection system in the DG building consists of wet pipe automatic sprinklers in the sump area beneath the diesel engines and on the day tanks. Actuation of the fire protection system is annunciated and alarmed in the control room. However, operator action to protect the diesel generators from flooding is not required since the drains in the diesel generator building are sized sufficiently to preclude significant accumulation. If the flood source is from the service water pipe break, the effect of damage is bounded by the direct consequence of loss of essential service water which provides cooling to the EDG component coolers.

The only safety related equipment affected by spraying are diesel generators and control panels. There are two sources of spraying: (1) the inadvertent actuation of sprinklers or pipe rupture of the fire protection system, and (2) the rupture of the service water piping.

The fire protection system in the diesel generator building consists of wet pipe automatic sprinklers installed in the sump area beneath the diesel engines and on the day tanks.

The EDGs and their control panels will not be affected by the inadvertent actuation of the fire protection sprinklers, because they are located away from these sprinklers. Since the diesels are each separated by a distance of approximately 12 feet, it is also unlikely to that all three diesel engines could be affected by spray from a break in the fire protection or SWS headers.

(b)(7)(F)

(b)(7)(F)

5.2.2.4.2 Evaluation of Flood Area AFW 18-1

This area corresponds to the auxiliary feedwater pump room adjacent to the containment building at 18'6" elevation. This flood area is a concrete enclosure housing the two motor driven AFW pumps and one turbine driven AFW pump, their associated piping and control panels. An Appendix R remote shutdown panel is also located in this area for providing alternate power to AFW pump 21 and for monitoring steam generator level. The flood sources in this area are the main steam to the turbine driven auxiliary feedwater pump, and the city water and condensate storage tank (CST) feeds to the pumps. The drainage capabilities of this area include a door flap and a wide (8') roll up door to the transformer yard, a normal fire door with a small gap to AFW 18-2, two floor drains, and three equipment drains (inlet raised about 4"). Thus, significant water accumulation or holdup within this flood zone to reach the critical heights and to damage pumps, valves, or the safe shutdown panel is unlikely.

The AFW pumps are separated by a distance of approximately 6' from one another. It is very unlikely that spraying effects from a pipe break will disable all three of these pumps *or their controls, since the pipes in this area are all low pressure pipes. The one exception* is the steam line to the turbine driven pump. The turbine driven pump and motor driven pump 21 are susceptible to steam from steam line breaks located above the pumps. However, the fire barrier which exists between pumps 21 and 23 would prevent the failure of motor driven pump 23 by direct steam impingement. The environmental effects are discussed below. Rupture of the steam supply line to the turbine driven auxiliary FW pump has the potential for generating failure inducing environment in the AFW pump room (flood area AFW 18-1). However, the steam supply to the turbine contains redundant valves designed to isolate the steam supply following such a failure. The frequency of a rupture coupled with the probability of failure to isolate preclude this scenario from being a significant contributor.

Floods originating in this area would propagate to the transformer yard via the door flap and any gap under the wide (8') roll up door. Some flooding would also propagate to the AFW 18-2 flood area via the small gap under the interconnecting fire door. Based on this screening analysis, the scenario involving a rupture of the CST piping was determined to be potentially significant. Since, however, plant technical specifications will not allow for a shutdown with the CST unavailable, this case will be analyzed as a sensitivity analysis.

5.2.2.4.3 Evaluation of Flood Area AFW 18-2

This flood area is the portion of the AFW building which extends from elevations 18'6" to 80' and includes all areas in the Auxiliary Feedwater building not covered by AFW 32-1 and AFW 18-1. This area is used to house the main feed lines, the main steam piping, and the relief valves. Safety related equipment present in this flood area include the atmospheric relief valves, steam generator safety valves, main feedwater stop and check valves, and the main steam stop valves. This area is a major source of flooding and an accumulation of flood water can occur in this room with some propagation into the adjacent flood area AFW 18-1 via an interconnecting door. However, the small gap (about 1/2" wide) under this dividing fire door should make the propagation from flood area AFW 18-2 to AFW 18-1 minimal. In addition, the existence of a large drain, louvered wall openings and a door to the outside (with a 7" by 30" flap) will channel flood waters away from flood zone AFW 18-1. All vital components in this area are located at heights that would preclude failure from flood accumulation. The vital equipment located in this area is not susceptible to spray damage.

The effects of temperature, humidity, and pressure from steam line breaks in this area are addressed in Reference 5-2. The maximum calculated temperature is 242°F and the maximum calculated pressure is 0.25 psi and these last for a duration of only 10 minutes. Therefore, it was concluded in Reference 5-2 that high energy line breaks in this area present an insignificant risk to the plant.

5.2.2.5 Turbine Building

The turbine building contains no safety related equipment other than two motor control centers, the turbine stop valves and the turbine over speed protection. In addition, the 6.9kV switchgear, located on 15' elevation, provide normal power to the 480V vital buses but do not directly supply any safety related system components. For this analysis, the entire turbine building is lumped into a single flood area and designated as TBL 15-1.

5.2.2.5.1 Evaluation of Flood Area TBL 15-1

This area corresponds to the turbine building elevations 5', 15', 36'9", and 53'. The only safety related equipment inside the turbine building are the two vital MCCs (24 and 24A) located at elevation 15', and the turbine stop valves and turbine over speed protection located at the 53' elevation. The 6.9 kV switchgear (which is not safety related) is located on the 15' elevation.

A 12" flood dike surrounds MCCs 24 and 24A. Relatively large feedwater piping are located directly above these MCCs, however, splash guards have been installed above these MCCs making the effects of splashing and dripping minimal. The turbine stop valves and over speed protection are located on the 53' elevation and, and will not be subjected to flood submersion.

The turbine building is an open structure with multiple drainage paths to the lowest elevations (5' and 15'), consequently, water can only accumulate at these elevations. Flood accumulation at the upper elevations will be limited to the 4" curb heights where these curbs exist. There are several openings from the turbine building to the outside yard at elevation 15 feet. There are other flood mitigation features at the 5' and 15' levels, such as floor drains and flood alarms which annunciate in the control room.

Loss of the 6.9kV switchgear due to a large break in the turbine building would result in a unit trip and loss of normal power to the 480V buses. This is potentially more serious than the loss of offsite power due to other causes (e.g., loss of grid) since recovery of AC power from Gas Turbines, or offsite would be compromised by flood damage to the 6.9kV switchgear.

It should be noted that although the potential flood inventory from breaks in the Circulating Water system downstream of the condensers is very large, flood heights due to these breaks would be self limiting since the CW pumps are supplied from the 6.9kV switchgear and these pumps would stop should the switchgear be failed by the flood (or the pumps themselves could be failed by the flood).

The only significant potential spray damage identified in this area is associated with the 10" diameter fire protection system piping in the south east corner of the 15' elevation. The 6.9kV switchgear may be vulnerable to breaks in piping which runs to the west and south of the switchgear cabinets.

The 6.9 kV switchgear may also fail as a result of adverse temperature/humidity conditions resulting from major steam line or feedwater/condensate line breaks. The consequences are similar to those discussed under accumulation and spraying

One potential inter-area connection is a door to the deluge room in the south east corner of the 15' elevation, which is connected by a second door to the 480V switchgear room in the control building. Since the turbine building occupies a relatively large area and the volume of the condenser pits are sufficient to contain most turbine building flood sources, flooding from sources other than the circulating water system would not be significant when considering the flood propagation to the adjacent 480V switchgear room.

Flooding due to a break in a circulating water line could affect performance of the 480 volt switchgear of the control building (CTL 15-1). The 480V electrical system provides power to required safeguards equipment (e.g., safety injection pumps, component cooling pumps, residual heat removal pumps). As noted earlier, flood heights due to circulating water line breaks would be self limiting, thus the level of water would increase only few inches above the turbine building floor before the circulating pumps are failed. However, a limited amount of flood water can still propagate through the door gaps into the 480V switchgear room before the circulating water pumps are stopped.

In order to keep the flood level below the critical height (level at which 6.9kV switchgear fail), operator action would be required. This action may consist of shutting down the circulating water pumps from either the control room or locally at the 6.9kV breaker panel. In addition, flooding can also be relieved by locally opening the roll up doors to the yard.

Redundant level alarm switches installed in the Unit 1 condenser pit will be actuated within approximately three minutes after a break in a Unit 2 circulating water line. In addition, detection by plant operators is also very likely since there is an operator assigned on a 24-hour basis to this portion of the plant.

The flood propagation into the 480V switchgear room would be limited to the smaller of the two gaps under the connecting doors into the deluge room and subsequently into the 480V switchgear room and would be mitigated by normal drainage from those rooms.

Since various flooding mechanisms within the turbine building may both cause an initiating event and potentially degrade mitigating systems, the flooding scenario that may cause a plant trip and a loss of the 6.9 kV switchgear was further evaluated in the detailed flood analysis.

5.2.2.6 Service Water Intake Structure (SWIS)

The SWI structure includes the circulator water pump area, the service water pump area, and the service water valve and strainer pit. Major circulating water and service water piping are located below grade, whereas the pump motors are located above grade (El. 15').

In the event of a pipe break above grade in the intake structure, water would simply run off back to the river and would not present a flooding hazard to the circulating and service water pumps. However, there are also some small bore, screen wash water piping which are located above grade in the intake structure. A rupture in these piping may present a spray/splashing hazard to the Circulating Water or Service Water pumps. However, since the pump motor enclosures are designed for outdoor operation no damage is postulated. The only possible flood hazard present in the intake structure is from sources inside the SW valve and strainer pit area.

5.2.2.6.1 Evaluation of Flood Area SWI 5-1

The service water valve and strainer pit area is below grade (elevation 5'-9") and is located at the east end of the SW pumps. It can be accessed via a hatch. A 50 gpm sump pump leading to a 8-inch drain line provides a run off path to mitigate potential flooding. The only susceptible equipment located in the SW valve and strainer pit is the SW strainer motors. The failure of the strainer motors may accelerate pressure buildup on the strainers which may eventually fail the SW pumps in the absence of manual action.

This area is relatively small with dimensions of 27.5' by 19'. Since the drain flow rate is relatively small (50 gpm) when compared with the potential flood flow rates (approximately 5000 gpm), a pipe break here would cause water to accumulate very quickly. Accumulation of water beyond a 66" depth would cause damage to the Zurn strainer motors which could result in the failure of the SW system in the long term. Spraying of water due to a SW pipe rupture could also cause damage to the Zurn screen motors. This effect, however, is similar to the effect from water accumulation. Flood egress from the SW pit area can occur through the drain line or through the hatch when the pit is filled. The overflow would then propagate into the SW and circulation pump areas. However, the flood water would simply run off back to the river and would not present a flooding hazard to the circulating and service water pumps.

The results of the qualitative analysis of the SW intake structure shows that for substantial SWS pipe breaks, flooding inside the SW strainer pit area would bounded by the loss of the service water system. The loss of the essential service water header would result in a loss of SW to the emergency diesel generators and the fan cooler units, however, no plant trip mechanism has been identified for this loss. The loss of the non-essential service water header will cause a plant trip because of the resulting loss of the Component Cooling Water system. This transient was considered as part of the IPE (see Section 3.1.3.4.2.6). Since a SWS pipe break frequency in this area is substantially less than the frequency of the Loss of Service Water initiating event in the IPE and failure of the strainer motors is a long term issue which can be resolved by manual action, this event is concluded not to be risk significant.

5.2.2.7 Fuel Storage Building

The Fuel Storage Building (FSB) contains the spent fuel pit and the new fuel storage facility. The spent fuel pump pit heat exchangers, which are cooled by the Component Cooling Water System, and spent fuel pumps are located at the lowest (51') elevation. The sources of water include those from the component cooling, fire protection, and city water systems.

5.2.2.7.1 Evaluation Of Flood Area FSB 51-1

This area corresponds to the entire fuel storage building. There are no equipment in the FSB susceptible to damage by flooding that are required for safe shutdown of the reactor or mitigation of the consequences of an accident. Other than flooding effects, the most severe direct impacts from a piping failure in this building would be a loss of spent fuel pool cooling. Section 9.3 of the IP2 UFSAR addresses the loss of pool cooling and dismisses the risk as insignificant because of the large heat capacity of the pool and the slow heat up rate. Given a loss of cooling, Table 9.3-4 of the UFSAR shows a pool heat up to 212°F in 8.9 hours for a fuel assembly loading of one third of the core, and a time of 4.9 hours for a full core loading. Therefore, even if we do not add the time it would take for water to boil off to below the level of the fuel assemblies, we would have sufficient time for recovery actions to keep the fuel assemblies covered and/or cooled.

Apart from the Containment, the only building with which the Fuel Building interfaces is the PAB Fan House. However, the only potential flood pathway is a doorway located at the 95' elevation. Since the flood sources area FSB 15-1 are not large enough to fill the FSB up to the 95' elevation, there is no potential for significant flood propagation to the PAB. Thus, the risk significance of Fuel Building flooding with respect to both equipment damage within the Fuel Building itself and propagation to other plant areas is negligible and does not warrant further evaluation.

5.3 DETAILED FLOOD ANALYSIS

As a result of the qualitative analysis, many potential flood scenarios were screened out because they are not risk significant (core damage frequency were judged to be much less than 10^{-6} per year, or scenarios are already included as part of the internal events IPE). Scenarios not screened out are listed below and further analyzed as part of the quantitative evaluation in this section.

Flooding Scenarios Originating in the Primary Auxiliary Building:

i) Flooding of the component cooling water pump area (PAB 68-1) causing the failure of all three CCW pumps in addition to the direct effects of the failure of the flood source itself.

ii) Loss of RWST inventory due to rupture of its associated piping. This leads to the failure of RWST supply to the containment spray, RHR, and SI pumps. In addition, the backup to the charging pumps is lost. The initiating event would be a controlled plant shutdown with the RWST assumed unavailable.

iii) Flooding in the RHR pump area (flood area PAB 15-1) causing the failure of both RHR pumps in addition to the direct effects of the failure of the flood source itself. Flooding can be due to flood propagation from higher elevations of the PAB or from sources in this elevation itself.

Flooding Scenarios Originating in the Control Building:

i) Flooding in the 480V switchgear room (CTL 15-1) due to the rupture of the service water piping within the area.

ii) Flood propagation to CTL 15-1 due to the rupture of fire protection piping in the deluge room (CTL 15-2) and subsequent propagation to CTL 15-1.

Flooding Scenarios Originating in the Diesel Generator Building:

The only issue of concern here is whether there is a significant potential for water accumulation and subsequent propagation to the Control Building through the electrical tunnel.

Flooding Scenarios Originating in the Auxiliary Feedwater Building:

i) A break in the steam line to AFW pump 22 causing a plant trip coupled with the unavailability of pump 22. In addition, motor driven pump is assumed to be lost due to direct steam impingement.

ii) A break in the CST piping resulting in the possibility of a manual shutdown with CST inventory unavailable. (Since plant Technical Specifications will not allow for a shutdown with the CST unavailable, this case will be addressed as a sensitivity case.)

Flooding Scenarios Originating in the Turbine Building:

A general flooding event (source unspecified) causing a plant trip with consequences which are bounded by loss of the 6.9 kV switchgear.

Flooding Scenarios Originating in the Service Water Intake Structure:

A flooding event in the SW pit failing the Zurn strainer motors, thereby leading to potential blockage and loss of service water in the long term. One header of SW (either ESW or NESW will also be lost due to this flood).

Flooding Scenarios Originating in the Fuel Storage Building:

This area was screened out because it does not contain equipment required for safe plant shutdown and a flood in this area will not result in a plant trip initiator. In addition, the risk from flood egress from this area to other areas of the plant was shown to be insignificant. Therefore detailed analysis is not required for this area.

The approach for the detailed analysis and quantification is divided into five steps:

1. Determination of realistic frequency and size (flooding rate) of potentially significant flood sources.

2. Definition of flood damage stages.

3. Probabilistic evaluation of flood growth.

4. Realistic quantification of flood induced accident sequence frequencies.

5. Sensitivity/uncertainty analysis on critical input parameters.

5.3.1 Determination of Flood Frequencies and Size (Flooding Rate) of Potentially Significant Flood Sources

For flood areas found to be potentially significant in the screening analysis, flood frequencies from each individual source of flooding in the area were calculated. These frequencies include those from pipe, tank, valve, and expansion joint failures; major maintenance actions; or spurious activations of fire systems. The frequency of flooding from flooding sources was determined on the basis of industry data on component leakage and rupture and by the use of empirical correlations, which account for the effects of historical failure data and pipe and weld geometric factors. Similarly, industry data was used to determine the frequency of actuation of fire systems which disable plant systems and/or cause the initiation of plant transients. To estimate flood frequency from maintenance actions, plant data was used to determine the frequency of major maintenance on pumps and valves that might require the total disassembly of that pump or valve. This method of obtaining flood frequencies:

- Permits a discretized distribution of flood frequency versus flooding rate to be established, using hydraulic calculations when necessary.

- Permits flood sources which result in inadequate equilibrium flood heights to be dismissed (or at least their contribution to risk reduced).

- Allows the prediction of flood frequency at a particular location within a flood area, which is important if the equipment failure mode being evaluated is attributable to spraying.

Table 5.3-1 provides the frequencies and flow rates for those flood sources subjected to the detailed analysis.

Table 5.3-1
Flood Source Frequencies and Sizes

Flood Source	Frequency	Flow Rate
Non-essential Service Water Piping in PAB	1.6 E-5/yr	16,000 gpm
Essential Service Water Piping in PAB	2.1 E-5/yr	16,000 gpm
Component Cooling Water Piping in PAB	1.6 E-4/yr	(a)
City Water Piping in PAB	(b)	190 gpm
Fire Protection Piping in PAB		
(impacting CCW Pump area)	7.9 E-5/yr	2800 gpm
(impacting RHR Pump area)	1.3 E-4/yr	2800 gpm
RWST Piping to ECCS Pumps in PAB	4.8 E-4/yr	(c)
SWS Piping in 480V Switchgear Room		
Category 1	1.8 E-5/yr	1942 gpm
Category 2	5.4 E-5/yr	647 gpm
Category 3	1.1 E-4/yr	216 gpm
Fire Protection Piping in Deluge Room		
Category 1	1.5 E-5/yr	5700 gpm
Category 2	4.5 E-5/yr	1900 gpm
Category 3	9.0E-5/yr	633 gpm
Steam Supply to Turbine Driven Aux Feed Pump	2.1 E-5/yr	(d)
Turbine Building Floods	7.2 E-3/yr	(e)
SW Piping in EDG Building	1.6 E-4/yr	4500 gpm
Fire Protection Piping in EDG Building	6.1 E-5/yr	2800 gpm

(a) Closed system, capacity limited to 16,200 gallons
(b) Flow rate below damage threshold
(c) Flow rate not calculated, flooding impact limited to RHR pumps which are assumed failed by direct consequence of RWST pipe failure
(d) Spray issue
(e) Loss of 6.9kV Busses assumed

5.3.2 Evaluation of Maintenance Induced Floods

A potential initiator of internal flooding is the combination of major maintenance on a fluid system coupled with an event that provides a flow path through the system bypassing the required isolation.

The initiating event is the occurrence of major maintenance while the reactor is at power. Major maintenance is defined here as actions which would disassemble the system components, for example, pump impeller replacement or valve steam replacement. This maintenance action has to be coupled with the failure to remove power from the isolation valves (if the isolation valve is motor operated), and the possibility that there is a coincident demand on the system, thereby opening the isolation valves. This demand can either be automatic or manual in response to a transient challenge, or an operator error of inadvertently opening the isolation valve. Alternatively an isolation valve may rupture.

The frequency of maintenance errors F_{me} leading to the opening of the isolation valves is then defined as:

$$F_{me} = F_{mm} \times P_{pw} \times P_{dm}$$

Where

F_{mm} = Frequency of major maintenance during plant operation
P_{pw} = Probability of failure to remove power from the isolation valve
P_{dm} = Probability of demand from transient challenge or operator error

5.3.2.1 Frequency of Major Maintenance During Plant Operation

To calculate the frequency of major maintenance during operation at IP2, the IPE database was reviewed, and at-power maintenance events that required the breaking of system integrity were tabulated. The total number of maintenance events in the IPE database is 282 and it spanned a 3 year period. Of those events, there were a total of 57 events from the IPE database involving loss of system integrity. Of this total, 48 involved the Service Water Zurn strainers. Of the remaining nine events, four were Charging pumps, two were fire pumps in IP Unit 1, two were

AFW pumps, and one was a CCW pump.

In analyzing the maintenance events on the Zurn strainers, a number of considerations should be kept in mind. First, the outlet of the strainer is directly connected to the other two pump outlets for that SWS header. Since the system is operating at all times, any back leakage would be detected as soon as the disassembly of the strainer began (actually before, since the blowdown line is opened before disassembly to relieve any residual pressure). The inlet would only be subject to flooding if the associated pump was started without the Zurn strainer re-secured. This is highly unlikely considering the proximity of the strainer to the pump and the procedural requirement to have an operator at the pump/strainer location whenever a SWS pump is started. In addition, with the installation of the ristroph screens, the frequency of even cleaning the strainers will be substantially reduced. Finally, as described in Reference 5-1 and in Section 7 of this report, flooding in the SW Intake Structure is not risk significant. Therefore, maintenance actions on the Zurn Strainers need not be considered further.

Maintenance actions on fire pumps can also be discounted because these pumps are located in buildings that do not contain any safety related equipment or equipment required for plant shutdown.

Flooding potential from maintenance actions on the charging and CCW pumps is minimal because these systems are continuously operating and any leakages/floods would be immediately evident to the operating crew at the site of the maintenance.

This leaves two events, both for the maintenance of the AFW pumps. Although not present in the database search, maintenance actions on the other standby safety systems, i.e. the SI, RHR, and CS systems would also have to be considered. The frequency of maintenance actions on these systems can be estimated as follows:

Number of SI pumps	=	3
Number of RHR pumps	=	2
Number of Containment Spray pumps	=	2
Number of AFW pumps	=	3

The above total is 10 pumps. As mentioned previously, there were 2 maintenance actions over a 3 year period, or 2 events over a period of 30 pump-years. This yields an average frequency of 2/30 or 0.067 events per pump-year for all standby safe shutdown pumps. For just the AFW pumps, the maintenance frequency is 2 events over a period of 9 pump-years, or 0.22 per pump year.

5.3.2.2 Probability of Failure to Remove Power From the Isolation Valve(s)

The removal of power from equipment and the isolation valves bounding this equipment while it is being maintained is proceduralized at Indian Point 2. All maintained equipment and boundary valves (where applicable) must be electrically disconnected from their power supply by pulling and tagging the appropriate breaker at the MCC. The probability of failing to open the required breaker is further reduced by the fact that each step in the tag sequence must be initialed by the individual performing the work and be verified by an independent observer (OAD-6).

The HEP for this event can be conservatively estimated from NUREG/CR-1278 to be 0.01 ("failure to follow established procedures or policies in valve changes or restoration", page 20-23, Table 20-15, Item 5 of NUREG/CR-1278). This is clearly conservative because the IP2 procedures call for a check and verification of the implementation of the tagging order.

5.3.2.3 Probability of Demand From Transient Challenge or Operator Error

During maintenance operations with the system disassembled, the isolation valves need to be closed in order for maintenance to proceed. However, the operator could fail to maintain the isolation of these valves either by opening one or more of them locally or by remote opening. Motor operated valves can be opened remotely either at the MCC or in the control room. Due to the location of manually operated isolation valves near the area where the flood would occur, it is judged to be very unlikely that an operator would manually open an isolation valve locally, fail to notice the flood, and fail to reclose the valve.

Operation of the valve at the MCC requires the presence of power and command. For this to happen, the prerequisite is the failure of power isolation. Command of the MCC requires the valve operation circuit be jumped. Jumping of these valve controls is not anticipated at IP2. Due to the low probability of this event, it will not be considered in further calculations.

The remaining possibility is that the valve is opened from the control room. This operation would require the valve auto-function be available and that the appropriate panel switch be activated. The auto function would be active if the operator failed to remove power from the valve.

The panel switch could be activated if the operator mistakenly operates the tagged out switch. A value of 0.001 (NUREG/CR-1278 page 20-21, Table 20-14, Item 4) is used to include the possibility for the failure to tag and the use of multiple tags in the area. A command fault to the valve is expected to be small ($< 10^{-4}$) as long as the maintenance period is restricted to the technical specification limits. The probability of the inadvertently opening the panel switch (i.e. opening the switch accidentally) is dependent on the control room configuration and is hard to quantify. A value of 0.01 is conservatively used in this study.

In summary, the probability of demand from transient challenge or operator error can be calculated as follows:

Operator mistakenly operates tagged out switch	= 0.001
Operator accidently operates tagged out switch	= 0.01
Probability of transient challenge	= 10^{-4}
TOTAL	≈ 0.01

5.3.2.4 Frequency of Maintenance Actions Leading to a Flooding Event

From the above discussion, the frequency of maintenance actions that could lead to flooding events could be calculated as follows:

$$F_{mc} = F_{mm} \times P_{pw} \times P_{dm}$$

For SI, RHR and CS pumps, $F_{mc} = 0.067 \times 0.01 \times 0.01 = 6.7 \times 10^{-6}$

For AFW pumps, $F_{mc} = 0.22 \times 0.01 \times 0.01 = 2.2 \times 10^{-5}$

If we combine all the SI, RHR and CS valves together (a total of 7 valves), the flood initiating frequency from maintenance actions would be 4.7×10^{-5} per year ($7 \times 6.7 \times 10^{-6}$). The effects from this flood would be the spilling of the RWST inventory into the PAB. Since the initiating event frequency in this case is only 10 percent of the similar scenario initiated by pipe ruptures, the incremental risk from this contributor would not be significant.

Similarly, if we combine all three AFW pumps, the frequency of maintenance action induced flooding would be 6.6×10^{-5} per year ($3 \times 2.2 \times 10^{-5}$). Since this frequency was 33% of the corresponding scenario initiated by pipe rupture it is bounded by that scenario. It should be noted, however, that this scenario will not result in a direct plant trip, therefore, it can be screened out.

5.3.3 Determination of Flood Damage States

Each flood damage state is defined in terms of the time at which it would occur after the initial flooding incident together with a set of accident mitigating systems which would be damaged. Following a flood incident, damage to some equipment in the local vicinity may occur immediately, due to spraying and dripping. However, for a flood area of reasonable size, much of the equipment will not sustain damage until the flood level rises to a critical level (e.g., for MCCs this is generally 3 inches to 1 foot). Likewise, flood propagation to an adjacent area may not occur until the flood level rises above a curb for example, and then additional time will be required before the level reaches a critical height in that area. Therefore, there is usually a basis for defining a set of distinct flood damage states, each corresponding to a progressively increasing severity of equipment loss.

The evaluation of the frequency associated with individual flood growth stages is represented using an event tree approach. The first event on the tree describes the discretized flood frequency distribution and subsequent events represent the failure of various automatic, manual and passive flood protection measures which may prevent progressive flood growth stages being achieved by suppressing the flood source or isolating its pathway to other areas. When quantified, the end points of the event tree represent the frequency of each postulated flood damage state. Their contribution to core damage was then determined by treating each flood damage state as an initiating event and propagating it through the internal events model accounting for associated damage to plant equipment.

The growth (or rate of rise) of flood level was determined by taking into account the flooding rate, the free cross-sectional area of the flood area, and the capability of the drainage mechanisms (floor drains, and leakage pathways to adjacent areas under doorways). In some cases an equilibrium flood height may be established when the outgoing flow through the drains or under doors equals the flood rate. (In cases, where floor drain outflow is the dominant form of mitigation, drain obstruction due to check valve failure or blockage was addressed.) Flood growth may be halted at any time either by operator action leading to isolation of the flood source or by exhaustion of the flooding source itself. Factors considered in evaluating the probability of suppression included: the means of detecting occurrence of the flood (alarm, area occupancy, etc.); the means of detecting and isolating the source of the flood; and the time available for the operator to isolate the flood source before equipment damage occurs.

The flooding scenarios found in the qualitative screening analysis to require a more detailed analysis are discussed in the following sections. The flood damage state frequencies associated with those scenarios are provided in Table 5.3-3.

5.3.3.1 Primary Auxiliary Building

Based on the qualitative evaluation, floods originating at any elevation of the PAB will most likely propagate to the 15' elevation. Water accumulation at the 68' elevation at the component cooling pump area is also possible depending on the location of the pipe break in the upper elevations. Substantial accumulation at other areas have been ruled out because of numerous pathways like stairwells, floor grating, equipment hatches and piping penetration.

Potential flood sources are from the NESW system piping (elevations 80' and 68'), ESW system piping (elevation 80'), CCW system piping (elevations 98', 80' and 68'), City water piping (elevation 98') FPS piping (elevation 98') and lines from the Refueling Water Storage Tank. The frequencies and flow rates for these sources were provided previously in Table 5.3-1.

<u>Non-essential SWS Induced Flooding</u>

Non-essential SWS failure can result in a plant transient and loss of mitigating equipment and was considered as a flood induced initiating event:

Initiating Event (IE)	=	Total Loss of Non-Essential SWS
Flood Damage State (FDS)	=	PABNSW
Damaged Equipment	=	All 3 CCW pumps and both RHR pumps

The equivalent event in the IP2 IPE is the turbine trip (TTRIP) with loss of non-essential service water.

Essential SWS induced flooding

Essential SWS failure can result in a plant transient and loss of mitigating equipment and was considered as a flood induced initiating event:

Initiating Event (IE)	=	Loss of CCW
Flood Damage State (FDS)	=	PABESW
Damaged Equipment	=	All CCW and RHR pumps

CCW System Induced Flooding

Flooding induced by the failure of the CCW system components will not cause system/component unavailability other than those caused as a direct consequence of a CCW system failure (i.e. flood water generated will not cause unavailability of any other component in addition to the CCW system itself). Therefore, the consequences of the this failure scenario is considered to be identical to the consequences of the IPE initiating event LOCCW (loss of CCW system initiator). This piping failure frequency is equivalent to 1.6×10^{-4} per year which is less than 0.2 percent of the other failures (0.081 per year) that could result in a loss of CCW. Therefore, the contribution of the CCW induced flooding to the plant operational risk as measured by the core damage frequency (CDF) is considered to be negligible when compared to the base case IPE risk.

City Water System Induced Flooding

The city water system provides backup cooling to CCW for several systems including the AFW, SI and RHR systems. Loss of the city water system would not directly induce an initiating event. The location of city water piping in the PAB is such that the majority of potential break flow will drain toward the 15' elevation. At a flood flow rate of 190 gpm and a sump drain rate of 30 gpm, the RHR area critical flood volume of 18,250 gallons would not be attained until approximately 2 hours after the initiation of the flood (even if we conservatively assume all flooding will flow into the RHR area with no holdups in the upper elevations). Flooding will be annunciated by a RHR area flood alarm.

In the vicinity of the CCW area, the city water piping is 1" in diameter. Therefore the break flow rate from a complete rupture of the pipe is 46 gpm. With a critical flood volume of 10,260 gallons in the CCW area and a sump flow rate of 30 gpm, critical height will not be attained until more than 9 hours after the initiation of the flood. Flooding will be annunciated by a CCW area flood alarm.

Given the amount of time available, flood isolation will almost certainly occur prior to damage of either the CCW or pumps and this flood source was determined to be of low risk significance.

Fire Protection System Induced Flooding

Fire protection system (FPS) piping components are located at various elevation of the PAB. The primary inventory of water for this system is from the City Water tank. The maximum diameter of the FPS piping in the PAB is 4 inches. All automatic fire protection systems are monitored to alarm in the control room when a system has been actuated by a fire or inadvertently. Operators, on such a signal, will be dispatched to the area to isolate the water, if necessary, by manipulation of the manual valves.

The flooding effects can be divided into four end-states as follows:

1) The flood could be mitigated before any damage is done

2) The pipe break is located in an area in the PAB where propagation to the CCW area is not physically possible and flood flow will only be toward the bottom elevation of the PAB

3) The flood could flow to the CCW area and then accumulate to a point where the critical height is reached, failing the CCW pumps, before mitigation is achieved

4) The flood flows to the CCW area and there is no mitigation (or mitigation occurs too late), thus, flooding propagates all the way to elevation 15' of the PAB resulting in failure of all the CCW and RHR pumps.

To account for each of these possibilities, a flood damage state event tree approach was used in addressing fire protection system failures. This tree is shown in Figure 5.3-1. The seven endpoints can be lumped into the four end-states as defined by the systems which have failed:

1) Both CCW and RHR fails
2) Only CCW fails
3) Only RHR fails, and
4) Neither CCW nor RHR fails (None)

The four top events in this tree were:

Event FRAC-RHR: This event describes the fraction of floods that will flow to both the CCW and RHR areas.

Event CATEGORY: Three flood categories were defined for this flood source. Category 1 floods are for flood flow rates between 2800 gpm and 933 gpm, Category 2 floods for flow rates between 933 gpm and 311 gpm, and Category 3 floods for flow rates are less than 311 gpm.

Event ISO-CCW: For each category of flood, this event sorts the fraction of floods that will be isolated before critical height in the CCW area is reached and depends on the time available to perform isolation following flood initiation, as compared with the time it requires to actually detect and suppress the flood.

Event ISO-RHR: For sequences where the flood is not isolated before damage to the CCW pumps, this event determines the probability that the flood is isolated before the flood propagation will also damage the RHR pumps.

Event SUMMARY: This event summarizes the status of the failed components at each endpoint. Table 5.3-2 summarizes results from Figure 5.3-1 and provides the fire protection flood damage state frequencies.

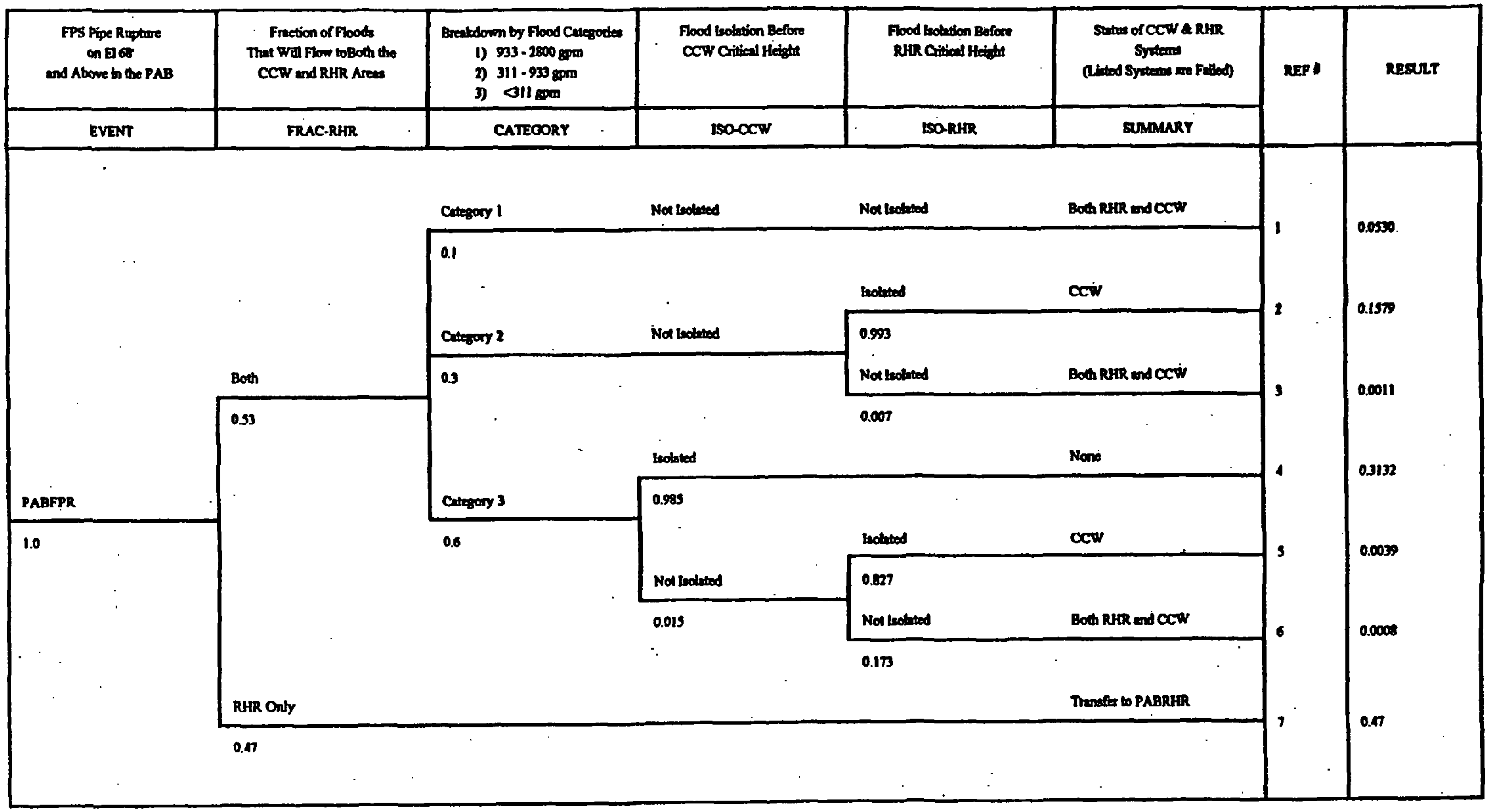

Figure 5.3-1
FPS Flood Damage State Event Tree

Table 5.3-2
Fire Protection Induced PAB Flood Damage States (FDS)

Assigned FDS Identifier	Relevant Endpoints From Figure 5.3-1	Failed Systems	Sum of Endpoint Probabilities	FDS Frequency	Initiator
N/A	4	None	0.31	4.1E-5	N/A
PABFPR-1	1,3,6	All RHR and CCW pumps	0.062	7.5E-6	Loss of CCW
PABFPR-2	2,5	CCW pumps	0.162	2.1E-5	Loss of CCW
PABRHR*	7	RHR pumps	0.47	6.1E-5	Manual Trip

* This sequence is transferred to and is quantified as part of Section 2.3.2 of this analysis file

<u>Flooding Caused by Failure of RWST Piping</u>

The RWST is the main source of water for many of the plant's safeguards systems (containment spray, RHR and SI pumps). The RWST has a minimum inventory of 345,000 gallons (governed by technical specification requirements) and is located in the yard at approximately 80' elevation. Flood induced as a result of failure of the lines from the RWST within the PAB will propagate to the lowest elevation of the PAB (i.e. 15' elevation). Rupture of the RWST piping at the 80' and 68' elevations will not lead to flood propagation to the CCW pump area (PAB 68-1) due to the location of these pipes. An RWST induced flooding will not result in a plant trip. However, due to technical specifications, a loss of RWST would require the plant to commence shut down (if RWST supply is not recovered) within a few hours. Therefore, as a conservative measure, the contribution of the this flooding scenario to the CDF can be quantified by considering the following:

Initiating Event = Manual trip with main feedwater available

Flood Damage State = PABRWF

Damaged Equipment = HHSI, RHR, containment spray

5.3.3.2 Control Building

From the qualitative analysis, it was determined that flooding risk in this building would be dominated by floods affecting the 480V switchgear room (CTL 15-1). The source of flood will most likely be due to the rupture of the service water piping within the area or from the rupture of fire protection piping in the deluge room (CTL 15-2). The frequencies and flow rates for these sources are provided in Table 5.3-1. Flood accumulation could result in a loss of all four emergency busses causing an automatic plant trip with feedwater/condensate and the related 480V safety related systems disabled or degraded. In addition, the instrument air system may be unavailable. A critical flood height of 4" was used for the switchgear based on measurements taken with limited accessability during the walkdown. This is conservative based on information obtained subsequently which shows that a 6" critical height was determined during previous analyses. Using the conservative 4" height as driving force, an egress rate of 522 gpm was calculated through existing drains and door gaps.

<u>Service Water Induced Flooding</u>

There are no flood alarms in this area, and the SW system header pressure may not be significantly affected by this relatively small break. If the break results in a loss of cooling to the Instrument Air Closed Cooling Water (IACCW) compressors, these will overheat and fail which would certainly alert the Control Room. However, depending upon the location of the break, cooling may not be lost (e.g. if break is on the discharge of the IACCW heat exchangers or in the supply pipe or valves not being utilized at the time of the break).

In order to isolate a pipe break upstream of the IACCW inlet valves would require tripping the SW pumps of the associated header which would effectively terminate SW to all safety related loads being supplied on that header. Furthermore, even if the break were downstream of the valves, operators may not be able to enter the zone in order to locally isolate the flood without first de-energizing all four emergency busses.

Given the lack of flood detection capability and the lack of an ready means of isolating the flood source probability of failing to isolate flood categories 1 and 2 is unity. (However, since the time window for Category 2 floods is relatively large, a sensitivity study was performed to calculate the flood damage state frequency given successful detection and mitigation of Category 2 floods.) The flooding rate associated with category 3 floods is well within the capacity of the drains and therefore not risk significant.

The contribution of this flooding scenario to CDF was quantified by considering the following:

Initiating Event (IE)	=	Loss of Offsite Power
Flood Damage State (FDS)	=	CBFSW
Damaged Equipment	=	All 4 emergency busses, IACCW compressors

Fire Protection Induced Flooding (in the Deluge Room)

The deluge station is located at elevation 15' of the control building adjacent to the 480V switchgear room. There are no safety related equipment in the deluge area. However, flood propagation from this area into the switchgear room is of concern. A large break in the FP piping in CTL 15-2 could cause build-up of flood water in this area very quickly. Flood water can propagate into the switchgear room or into the turbine building. Flooding into the switchgear room can propagate through a ½" gap under a 3' wide door or through the 13.5" high by 9.5" wide louvers located 9.5" from the bottom of the door. Flood propagation into the turbine building is through another 3' wide door with a 1" gap.

Operators in the Control Room will be alerted immediately when the flood occurs by the fire pump running alarm. Operators will be dispatched to determine the situation and report back to the control room. The flood can then be isolated in one of two ways; (i) by stopping the fire pumps which can only be accomplished locally in the Fire Pump

House, (ii) by closing the header isolation valve. In either case the time required to detect, investigate and isolate the flood source will almost certainly exceed the time window for the Category 1 and 2 floods. The probability of failing to mitigate the flood is therefore unity for these categories. For the Category 3 floods, a time window of 50 minutes was calculated.

The contribution of this flooding scenario to CDF was quantified by considering the following:

Initiating Event (IE)	=	Loss of Offsite Power
Flood Damage State (FDS)	=	CBFFP
Damaged Equipment	=	All 4 emergency busses, IACCW compressors

5.3.3.3 Emergency Diesel Generator Building

Direct flood accumulation effects is not a problem in this area because of the drains present and because of the height of the diesel generators above floor elevation. The worst case flooding induced effect in this area would be the loss of a ESW header. The CDF from this scenario is quantified as part of the IPE. The risk significant issue from flooding in this area is the potential for water propagation to the Control Building through the electrical tunnel.

The entrance into the electrical tunnel is through a penetration seal located near the west wall of the EDG building. Information on this seal was obtained from the IP2 Fire Barrier Penetration Seal Evaluation Program and includes the following:

Size of Opening = 6.3 ft^2 (907.2 in^2)
Seal Material = Dow Corning Sylgard Silicon Elastomer
Seal Density = 76 lbs/ft^3
Penetrating Objects = six 4" conduits
three 3/4" conduits
one 1" conduit
three 10"x9" bus ducts
Total penetration area = 347.7 in^2

The strength of these 6" silicone seals has been demonstrated in hydrostatic tests. One such test showed that the seal withstood a pressure of 2 psi (4.6' of water) for 2 hours, 5 psi (11.5' of water) for an additional 2 hours, and then 10 psi (23.1 ft of water) for one hour before substantially leaking. A guillotine rupture in the 10" SW line would result in a flood flow rate of 4500 gpm. Using a floor area of 2152 ft^2 and drain flow via the five floor drains, it was shown that a flood height of 4.6' (equivalent to 2 psi pressure) would not be reached until approximately 46 minutes after the break. At 2 hours, the flood height is 6.13' and the equilibrium height is at 6.5' (this does not account for flood egress through the door louvers located 5.25' off the floor elevation). If flooding was isolated, a flood height of 5' would completely drain in approximately 40 minutes.

Therefore, given the PCI/ICMS test data, and the flow rates given above, it can be seen that the operators have at least 4 hours to isolate the flood in the DG building before significantly leakage develops in the seal. This flooding would be indicated to the control room operators by a flood alarm in the control room, essential SWS header pressure drop alarms and detection by frequent personnel rounds in the DG Building. SW Header isolation can be achieved by isolation valves SWN-29 and SWN-30 located in the CCW pump area in the PAB. Given the presence of flood annunciation, the amount of time available for isolation, and the availability of specific isolation procedures, the frequency for this flooding scenario will be less than 10^{-6} per year. Therefore this scenario was screened out from further consideration.

The effects of a flood from a rupture of FPS piping would be less severe than that from a SW pipe rupture for several reasons. First, there are no direct effects from a FPS pipe rupture, i.e. there is no mechanism for immediate plant shutdown from this rupture. Second, the flow rate from a FPS pipe rupture is less than that from a SW pipe rupture (less than 2800 gpm versus 4500 gpm). Because of this lower flow rate, the timing considerations previously discussed for a sw break and the existence of similar indications, this flooding scenario was also screened out.

5.3.3.4 Auxiliary Feedwater Building

Based on the conclusions of the qualitative evaluation of the flooding hazard performed for this area, most flooding scenarios can be screened out because flood accumulation in this building is unlikely. Two scenarios were considered to require quantitative evaluation:

Rupture of the Main Steam Supply Line

A rupture of the main steam supply line to the turbine driven AFW pump (#22 AFP) would cause a loss of steam feed to the pump. Two temperature control isolation valves (PCV-1310A and PCV-1310B in series) would be signaled to close immediately upon detection of high temperatures in the AFW pump room which will prevent further damage. In either case, a plant trip will result with the turbine driven AFW pump not being available. In addition, Motor Driven pump 21 has also been conservatively assumed to fail due to direct steam impingement. The contribution of this flooding scenario to CDF was conservatively quantified by considering the following:

Initiating Event (IE) = Transient with main feedwater / condensate unavailable

Flood Damage State (FDS) = AFWMSB

Damaged Equipment = Auxiliary Feedwater pumps 21 and 22

Condensate Storage Tank (CST) Pipe Break Induced Flooding

A CST pipe break would lead to the loss of the primary supply for all auxiliary feedwater pumps. However, there will not be an automatic plant trip initiator. In addition, technical specification requirements will not allow a manual plant trip since AFW would be considered unavailable. Without a trip initiator, this flooding scenario can be screened out. However, because of the uncertainty on whether a manual plant shutdown will occur (because of low condenser hotwell levels or any other unspecified reasons) a sensitivity case was performed. This case is described in Section 5.5.

5.3.3.5 Turbine Building

The effects of most potential large flooding events which are confined to the turbine building would result in loss of Feedwater/ Condensate. However, the possibility of damage to the 6.9 kV Switchgear which supplies offsite power to all BOP and emergency loads, also exists. Operator actions to mitigate turbine building floods (by isolating the flood or by opening the roll up door to the outside) before propagation to the control building is spelled out in AOI 28.0.4.

Flood alarms will annunciate in the control room when level switches installed in the Unit 1 condenser pit are activated. This will occur within approximately three minutes after a break in a Unit 2 circulating water line. In addition, detection by plant operators is also very likely since there is an operator assigned on a 24-hour basis to this portion of the plant.

The worst case effects of flooding confined within the turbine building can be therefore be bounded by loss of offsite power transient (T1 initiator) with the probability of failure of AC power recovery being unity.

The frequency of the flood induced event is conservatively estimated by referring to generic flooding data in US plants. During the 829 years of operating experience there were 11 events with only 6 of these large enough to cause significant equipment loss. Therefore the frequency of significant turbine building floods is estimated to be 6/829 = 7.2×10^{-3} per year.

The contribution of this flooding scenario to the CDF was quantified by considering the following.

Initiating Event (IE)	=	Loss of offsite power with no recovery
Flood Damage State (FDS)	=	TBF
Damaged Systems	=	6.9 kV Buses

5.3.3.6 Service Water Intake Structure

The analysis in Reference 5-1 shows that the only possible flood hazard in the intake structure is the flooding of the SW valve and strainer pit area (SWI 5-1) and that the scenario can lead to excessive pressure buildup and long term failure of the Zurn strainers in the absence of manual action. Further analysis shows that failure of the strainers will not occur until at least ten hours after the failure of the Zurn strainer motors. In this period of time, recovery actions to isolate the flood, and restart the Zurn motors (or to manually rotate the Zurn strainers) would be very probable and this would prevent failure of the SW system. This scenario was therefore not considered to be risk significant.

TABLE 5.3-3
FLOOD DAMAGE STATE FREQUENCIES

Flood Damage State (FLDS)	Flood Induced Failures	Frequency (per year)
TBF	Offsite power from 6.9 kv busses	7.2E-03
CBFSW	All 480v-ac power	7.2E-05
CBFFP	All 480v-ac power	3.6E-05
AFWMSB	AFW MDP 21 and TDP 22	2.1E-05
PABNSW	NESW, RHR, CCW	1.6E-05
PABESW	ESW, CCW, RHR	2.1E-05
PABFP1	CCW, RHR	7.2E-06
PABRHR	RHR	1.4E-04
PABRWF	HHSI, RHR, CS, CVCS	4.8E-04

5.4 ANALYSIS OF FLOOD SEQUENCES AND PLANT RESPONSE

Following determination of flood induced damage states, the core damage and plant damage state frequencies resulting from each flood induced damage state were quantified by modifying the IPE event and fault tree logic models to reflect the frequency of each flood damage state and the associated impact on equipment and operator error probabilities. The IPE general transient event tree was used as the basis for quantifying all flood induced accident sequences. The following sections describe the plant model modifications made to reflect the specific flood damage states and present the core damage quantification.

5.4.1 Control Building

The two scenarios quantified for floods in the control building were failure of the service water piping in the 480V switchgear room and failure of the fire protection piping in the deluge room adjacent to the 480V switchgear room.

5.4.1.1 Service Water Pipe Break in 480V Switchgear Room (CBFSW)

Potential damage to all 480VAC switchgear was accounted for by modifying the Electric Power System (EPS) split fraction logic to select split fractions representing failure of each of the 480V buses given flood damage state CBFSW.

Due to the damage being confined to the switchgear room there is no significant impact on operator error probabilities for actions modeled in the control room or PAB or AFW building. There are no manual actions credited in the emergency switchgear room.

5.4.1.2 Fire Protection Pipe Break in the Deluge Valve Room (CBFFP)

The impact of this event is similar to the above scenario and potential damage to all 480VAC switchgear was again accounted for by modifying the Electric Power System (EPS) split fraction logic to select split fractions representing failure of each of the 480V buses given flood damage state CBFSW.

Similarly, the damage is confined to the switchgear room and there is no significant impact on operator error probabilities for actions modeled in the control room or PAB or AFW building. There are no manual actions credited in the emergency switchgear room.

5.4.2 Primary Auxiliary Building (PAB)

The two areas quantified for flooding impacts in the PAB were the CCW Pump room and the RHR pump room. The initiators of these flood scenarios were failure of the service water piping, CCW piping or fire protection piping.

5.4.2.1 Non Essential Service Water Flood in PAB (PABNSW)

Potential damage to the CCW pumps and RHR pumps was reflected in the model by modifying the auxiliary systems model logic to select split fractions representing guaranteed failure of CCW, and the general transient tree logic to select split fractions representing guaranteed failure of low pressure injection, low pressure recirculation and high pressure recirculation.

Since damage is confined to the PAB, there is no significant impact on operator actions modeled in the IPE requiring access to the control room or auxiliary feedwater building.

The only short term (i.e. within the several hours of the incident) operator action modeled in the IPE which require access to the PAB is associated with establishing alternate city water cooling to the charging pumps. This requires local alignment of manually operated valves located at the 80' elevation. Since accumulation is not expected at this elevation, no significant impact on the associated operator error is expected.

5.4.2.2 Essential Service Water Pipe Rupture in PAB (PABESW)

Potential damage to the CCW pumps and RHR pumps was reflected in the model by modifying the auxiliary systems event tree logic to select split fractions representing guaranteed failure of CCW, and the general transient tree logic to select split fractions representing guaranteed failure of low pressure injection, low pressure recirculation and high pressure recirculation.

Since the rupture will fail the supply from the ESW header, all systems supported by this system will be unavailable including the EDGs and Fan Coolers. This was reflected in the model by modifying the auxiliary systems event tree logic to select split fractions representing guaranteed failure of ESW, given flood damage state PABESW.

Similar to the discussion related to non-essential service water piping failures, no significant impact on operator actions modeled in the IPE requiring access to the control room, auxiliary feedwater building or PAB is expected.

5.4.2.3 Fire Protection Pipe Rupture in PAB (PABFP1)

Potential damage to the CCW pumps and RHR pumps was reflected in the model by modifying the auxiliary systems event tree logic to select split fractions representing guaranteed failure of CCW, and the general transient tree logic to select split fractions representing guaranteed failure of low pressure injection, low pressure recirculation and high pressure recirculation.

Similar to the discussion related to non-essential service water piping failures, no significant impact on operator actions modeled in the IPE requiring access to the control room, auxiliary feedwater building or PAB is expected.

5.4.2.4 Fire Protection Pipe Break in PAB (PABRHR)

Potential damage to the RHR pumps was conservatively reflected in the model by modifying the general transient tree logic to select split fractions representing guaranteed failure of low pressure injection, low pressure recirculation and high pressure recirculation. This is, in fact, conservative since the primary path for providing both high pressure and low pressure recirculation would be available using the Recirculation pumps located inside the containment.

Similar to the discussion related to non-essential service water piping failures, no significant impact on operator actions modeled in the IPE requiring access to the control room, auxiliary feedwater building or PAB is expected.

5.4.2.5 Refueling Water Storage Tank (RWST) Pipe Failure in PAB (PABRWF)

Potential damage to the core injection, recirculation and containment spray functions was reflected in the model by modifying the general transient event tree logic to select split fractions representing guaranteed failure of the RWST supply, given Flood Damage State PABRWF. Since the RWST is a support system for high pressure and low pressure injection (and by dependency high pressure and low pressure recirculation), all these functions are automatically disabled through the event tree logic.

In addition, loss of the RWST supply to the charging pumps is conservatively assumed to disable RCP seal injection from the charging pumps. This reflected in the model by modifying the general transient event tree logic to select split fractions representing guaranteed failure of RCP seal cooling, given Flood Damage State PABRWF and random failure of CCW.

Since damage is confined to the PAB, there is no significant impact on operator actions modeled in the IPE requiring access to the control room or auxiliary feedwater building. The only action modeled in the PAB is associated with establishing alternate cooling to charging, and high and low pressure injection pumps. These systems are already guaranteed failed, given the initiating flood.

5.4.3 Auxiliary Feedwater Building

The only base case scenario quantified for floods in the AFW building was failure of the main steam supply to the turbine driven auxiliary feedwater pump. An additional scenario representing failure of the Condensate Storage Tank supply to the AFW pumps was addressed as a sensitivity case (since failure of this line should not result in an automatic plant trip and Technical Specifications would preclude a manual shutdown) and is presented in Section 5.5.2.1.

5.4.3.1 Main Steam Line Rupture in Auxiliary Feedwater Building (AFWMSB)

In the event of damage to AFW pump 21 and 22, the only source of secondary side heat removal is motor driven feed pump 23. A new split fraction was created in the general transient event tree to reflect this condition and the event tree logic was modified to select this split fraction logic given flood damage state AFWMSB.

Since the damage is confined to the Auxiliary Feedwater Building there is no significant impact on operator errors for actions modeled in the control room or PAB. Actions in the AFW Building are associated with the turbine driven pump only and are irrelevant since the turbine driven pump is failed by the initiating event.

5.4.4 Turbine Building Flood (TBF)

In the event of a turbine building flood, the 6.9kV buses were assumed to fail, resulting in a loss of normal power to the 480v-ac busses. This was accounted for in the model by modifying the Electric Power System (EPS) split fraction logic to select split fractions representing failure of each of the 6.9kV buses given flood damage state TBF.

5.5 RESULTS ANALYSIS

5.5.1 Base Case Results

The contribution to core damage frequency resulting from the flood induced accident is given in Table 5.5-1. The total core damage frequency resulting from internal floods is 6.66E-06 per year.

The most significant contribution (CDF = 3.01E-06/yr) corresponds to flooding due to breaks in the 3" diameter service water piping located in the emergency switchgear room (FDS CBFSW). Of the three break sizes considered, only the smallest (< 216 gpm) can be accommodated by the various drainage paths and does not result in significant damage. The remaining two categories (1942 < FR< 647 gpm and 647 < FR< 216 gpm) were determined to cause damage after 4 minutes and 61 minutes respectively. No flood detection or isolation was credited due to the limited time available. In the latter category this approach is conservative since the emergency switchgear room is often surveilled or otherwise occupied by plant operations, security and other personnel. Flood egress into the turbine building would also be noticeable. A sensitivity case, which provides credit for operator action given the smaller flow rate, is presented in Section 5.5.2.2.

The second highest contributor arises from turbine building floods (CDF = 1.72E-06/yr) which are assumed to result in a non recoverable loss of normal power to the emergency buses due to damage to the 6.9 kV buses located at the turbine building 15' elevation (FDS TBF). Although the frequency of the flood damage state is based on industry experience with large flooding events in turbine buildings, given the large area of the IP-2/IP-1 turbine building and the many egress paths, such floods may not result in significant damage unless they are located in position where significant direct impingement can occur. Furthermore, even if the 6.9 kV buses were temporarily disabled, there is some possibility that the buses could be recovered following isolation of the flood source. A sensitivity case which considers the possibility of damage to the MCC 24A, which is also located at the turbine building 15' elevation and supplies power to one of the three EDG fuel oil pumps is presented in Section 5.5.2.3. Since, however, the MCC is protected by a curb and overhead spray shields, damage is highly unlikely.

The third highest contribution (CDF = 1.51E-06 /yr) comes from a fire protection pipe break in the deluge valve room located in the control building at the 15' elevation. Flood propagation to the emergency switchgear room occurs via the interconnecting door (FDS CBFFP). This flood scenario would be alarmed in the main control room by a fire pump running annunciator). No credit is taken for operator action in the highest flow rate of the three flood categories considered. In the second category some credit has been taken given the longer time available for isolation or mitigation prior to damage. The third category would result in a flow into the switchgear room which could be accommodated by the egress paths and therefore no damage is postulated to occur.

The remaining flood scenarios contribute less than 1E-06 to core damage frequency.

TABLE 5.5-1
FLOOD DAMAGE STATE CONTRIBUTIONS TO CDF

Flood Scenario/ Damage State (FLDS)	Flood Induced Failures	CDF Contribution (per year)
Major Flood from Turbine Building Source (TBF)	6.9 kv busses	1.72E-06
Service Water System Flood in Emergency Switchgear Room (CBFSW)	All 480v-ac power	3.01E-06
Fire Protection Header Flood in Control Bldg. Deluge Valve Room (elev. 15')	All 480v-ac power	1.51E-06
Steam Line Break in AFW Pump Room (AFWMSB)	AFW MDP 21 and TDP 22	2.37E-08
Non Essential Service Water Line Break in PAB (PABNSW)	NESW, RHR, CCW	8.59E-08
Essential Service Water Line Break in PAB (PABESW)	ESW, CCW, RHR	1.13E-07
Fire Protection Line Break in PAB (PABFP1)	CCW, RHR	3.86E-08
Fire Protection Line Break in PAB (PABRHR)	RHR	1.65E-08
RWST Line break in PAB	HHSI, RHR, CS, CVCS	1.27E-07
Total Contribution to Flood induced CDF (mean) =		6.66E-06

5.5.2 Sensitivity Analyses

This section presents several sensitivity cases performed to determine the effects of certain input parameters and modeling assumptions for which there is some uncertainty. The flood damage state frequencies associated with the sensitivity cases presented in this section were provided previously in Table 5.3-4.

5.5.2.1 Sensitivity Case 1: Manual Shutdown Given a CST Pipe Break in the AFW Building

A pipe break in the CST line within the AFW Building will lead to loss of inventory to all 3 AFW pumps. Although there is no automatic plant trip expected and technical specification requirements will not allow for a manual plant trip with AFW not available, this sensitivity study will investigate the potential CDF should a manual trip be necessitated for an unknown reason. The contribution of this flooding scenario to the core damage frequency can be conservatively quantified by considering the following:

Initiating Event (IE)	=	Manual shutdown with Main FW / Condensate available
Flood Damage State (FDS)	=	AFWCST
Frequency of IE	=	2.0×10^{-4} / yr
Disabled systems	=	All 3 AFW pumps

The quantified CDF contribution for this scenario would be 4.46 E-6 per year.

5.5.2.2 Sensitivity Case 2: Credit for Mitigation of Category 2 Floods for Flood Damage State CBFSW

In Section 3.1 no credit was taken for flood isolation for Category 2 floods for flood damage state CBFSW (even with a time window of 61 minutes) because it was felt that there was no mechanism for alerting the operators of a flood in this area. In this sensitivity case, the flood damage state frequency is recalculated assuming that a flood alarm is installed in the switchgear room.

With an alarm, and with a time window of 61 minutes, analysis file 9P32.IC/05 calculates the HEP to be 0.0093. The frequency for damage state CBFSW can ten be re-calculated as follows:

	Frequency (per year)	Te (mins)	HEP	Adjusted Frequency
Category 1	1.8E-5	4	1.0	1.8E-5
Category 2	5.4E-5	61	.0093	5.0E-7
Category 3	1.1E-4	ADR>FR	n/a	0.0

The sum of the adjusted frequencies is $1.9\text{x}10^{-5}$ per year. This is 26% of the base case frequency. The CDF from this flood sequence will be reduced by a similar percentage.

5.5.2.3 Sensitivity Case 3: Coincident Failure of Both the 6.9kV Buses and MCC 24A

This sensitivity case considers the possibility of damage during a turbine building flooding event to both the 6.9 kV buses and MCC 24A, which is also located at the turbine building 15' elevation and supplies power to one of the three EDG fuel oil pumps. It should be noted that since the MCC is protected by a curb and overhead spray shields, damage is highly unlikely.

The flood damage state is identical to base case turbine building flood analysis with the exception that the MCC 24A (which serves fuel EDG fuel oil pump no. 2), is damaged in addition to the 6.9 kV buses. The Electric Power System event tree logic was modified to include guaranteed failure of that fuel oil pump given the flooding event with no recovery action. The core damage frequency for the turbine building flood scenario increased for this sensitivity case from 1.72 E-6 per year to 2.90 E-6 per year.

5.5.2.4 Sensitivity Case 4: Breakup of Flood Damage State PABRHR into the Three Flood Severity Categories

The calculation of core damage frequency for flood damage state PABRHR in Section 2.3.2 was done using a flood damage state (FDS) frequency for this scenario of $1.4\text{x}10^{-4}$ per year which was based on a guillotine break of the fire protection piping in the PAB. This sensitivity case is intended to show the impact if this scenario was divided according to the three severity classes.

	Frequency (per year)	Time for Mitigation (mins)	Probability of Non Isolation	Adjusted FDS Frequency (per year)
Category 1 (2800 < FR > 933 gpm)	1.4E-5	6.6	1.0	1.4E-5
Category 2 (933 < FR > 311 gpm)	4.2E-5	20	0.16	6.7E-6
Category 3 (FR < 311 gpm)	8.4E-5	65	0.0086	7.2E-7

The sum of the adjusted flood damage state frequencies for the three categories above is 2.1×10^{-5}. This is 15% of the base frequency of 1.4×10^{-4} per year. The CDF would be reduced by a similar amount.

5.6 REFERENCES

5-1 IP2 Docket No. 50-247, "Analysis of High Energy Lines," April 9, 1973.

5-2 "Identification of Plant Areas Which Can be Subjected to Harsh Environmental Conditions as a Result of a LOCA or HELB and the Environmental Parameters for the Area - Indian Point 2", SE Technologies Inc., Report No. P803-01-3 Volume 1, Rev 4, July 1990.

HIGH WINDS, FLOODS AND OTHER EVENTS

6.0 METHODOLOGY SELECTION

The examination of Indian Point Unit No. 2 utilized the NUREG-1407 recommended progressive screening approach for high winds, external flood, and transportation and nearby facility accidents. Figure 6.0-1 shows the analytical steps of increasing detail, effort and resolution that are contained in this screening approach.

1. Review plant-specific hazard data and licensing bases.

2. Identify significant changes since the operating license (OL) was issued. This includes a review with respect to the following changes since the operating license was issued: (1) military and industrial facilities within 5 miles of the site, (2) onsite storage or other activities involving hazardous materials, (3) transportation, or (4) developments that could affect the original design conditions.

3. Determine if the plant and facilities design meets the 1975 Standard Review Plan (SRP) criteria.

After reviewing the information obtained in these three steps, a confirmatory walkdown of the plant is recommended in NUREG-1407, concentrating on outdoor facilities that could be affected by high winds, onsite storage of hazardous materials, and offsite developments. If the walkdown does not reveal any potential vulnerabilities not already considered in the original design basis analysis and the plant and facility design meets the 1975 Standard Review Plan, it is judged that the contribution from the hazard to core damage frequency is less than 10^{-6} per year and the IPEEE screening criterion is met.

If the review reveals that the 1975 SRP criteria will not be met, one or more of the following steps are taken to further evaluate the situation:

4. Determine if the hazard frequency is acceptably low.

   If the current design basis does not meet the regulatory criteria given in the 1975 Standard Review Plan requirements, the next step is to demonstrate that the current design basis hazard is sufficiently low - that is, less than 10^{-5} per year, and the conditional core damage probability is judged to be less than 10^{-1}.

If the current design basis hazard combined with the conditional core damage probability is not sufficiently low (i.e., less than the screening criterion of 10^{-6} per year), additional analyses should be performed.

5. Perform a bounding analysis

   This analysis is intended to provide a conservative calculation showing that either the hazard would not result in core damage or the core damage frequency is below the reporting criterion. The level of detail is that level needed to defend the above conclusion; judgment is needed for determining the proper level of detail and needed effort.

6. Perform a probabilistic risk assessment (PRA).

NUREG-1407 recognizes that the application of the above approaches involves considerable judgment with regards to the required scope and depth of the study, level of analytical sophistication, and level of effort to be expended.

Con Edison had previously performed a probabilistic safety study of Indian Point Unit 2 (IPPSS) which included consideration of external events (Reference 6-1). The external events examined in IPPSS in addition to seismic events, and internal fires and floods were:

- High Winds
- External Flooding
- Aircraft Accidents
- Transportation Accidents and Accidents from Onsite Storage of Hazardous Materials

The IPPSS analyses of the above events, which can be found in Sections 7.4 through 7.7 of that study, were reviewed to determine their continued applicability to this examination. The results of that review are included in the specific examination of those events in the following sections.

Section 6.1 briefly describes the site and plant as well as the plant walkdown and its findings. Section 6.2 describes the methodology and results of the high wind analysis. Section 6.3 contains the results of the external flood analysis. Section 6.4 contains the results of the transportation and nearly accident analysis. Section 6.5 addresses "other" external events. Section 6.6 addresses Generic Issue 103 (PMP). Section 6.7 contains a list of references for Section 6.

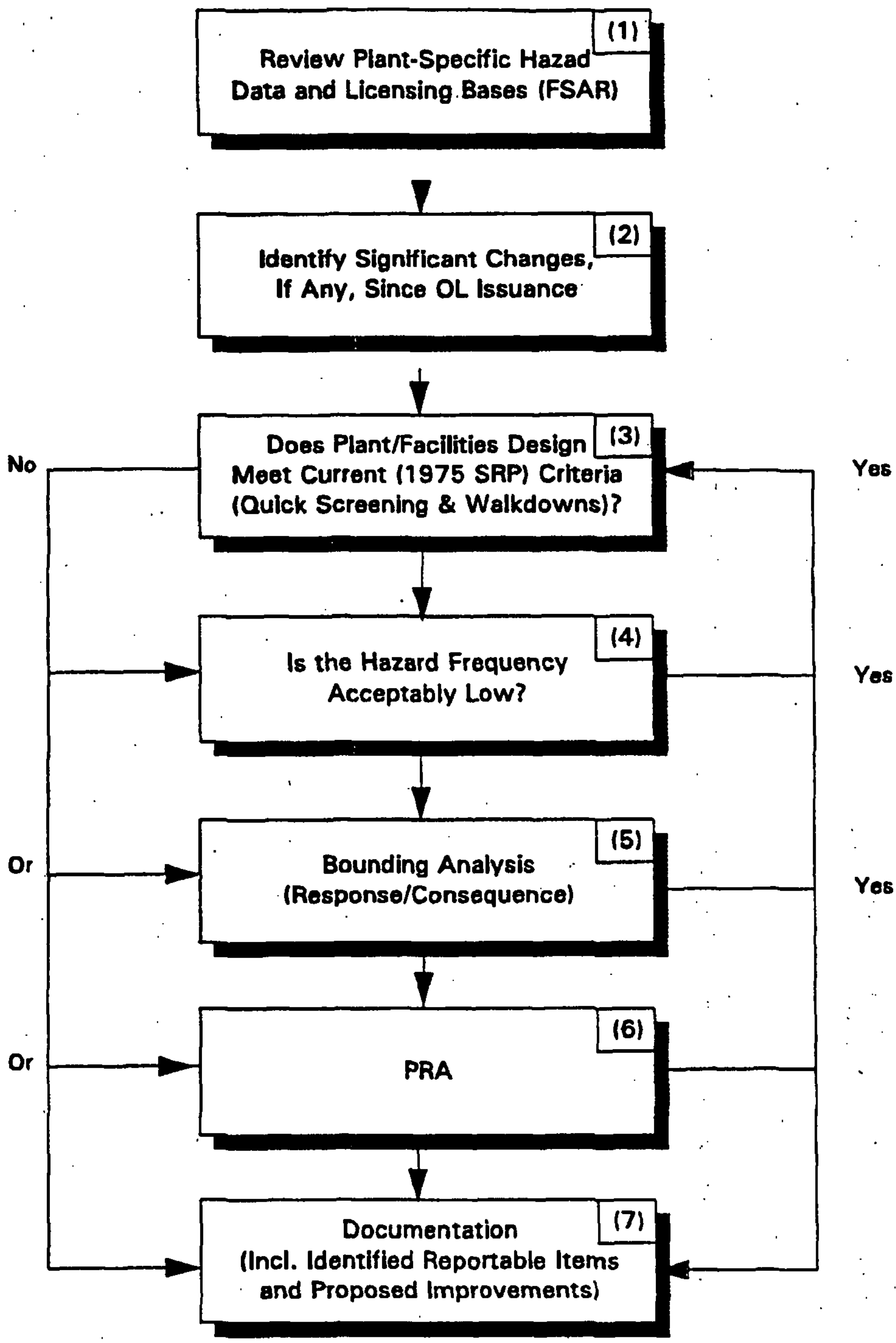

Figure 6.0-1: IPEEE Approach for Winds, Floods and Other Events

6.1 REVIEW OF PLANT INFORMATION AND WALKDOWN

6.1.1 General Description

6.1.1.1 Site

Indian Point Unit 2 is on the east bank of the Hudson River within the Village of Buchanan in upper Westchester County, New York. The site is about 24 miles north of the New York City boundary line. The nearest city is Peekskill, 2.5 miles northeast of Indian Point.

6.1.1.2 Plant

Indian Point Unit 2 is a pressurized water reactor supplied by Westinghouse Electric Corporation and has a rated capacity of 974 MWe. The plant began commercial operation in 1974. United Engineers and Constructors was the architect-engineer for this plant.

Figure 6.1-1 is a layout of the plant showing the location of major structures. Those structures which contain or may impact PRA equipment include:

- Auxiliary Feed Pump Building
- Control Building
- Unit 2 Intake Structure
- Emergency Diesel Generator Building
- Primary Auxiliary Building
- Piping Penetration/Fan House
- Fuel Storage Building
- Containment Building
- Turbine Building
- Superheater Building/Stack (IP1)
- Gas Turbine Generator Areas
- Yard Tanks

In addition to these structures, switchgear associated with the Appendix R Alternate Safe Shutdown capability is located on or in Unit 1 facilities. The reactor containment building is a steel-lined, reinforced concrete structure with vertical cylindrical walls and a hemispherical dome.

The Primary Auxiliary Building is constructed with reinforced concrete shear walls and floor slabs with steel frame construction at the upper elevations. The Control Building is a steel frame structure located immediately adjacent to the Unit 1 Superheater Building which is also a steel frame structure. The Emergency Diesel Generator Building and the Turbine Building are also of steel construction.

6.1.2 Plant Walkdown and Findings

A walkdown of Indian Point 2 was made with the objective of collecting information on the other external events being addressed in this section. Concurrent with the walkdown activities, a review was made of plant design documents, the updated FSAR, the Indian Point Probabilistic Safety Study (IPPSS) and recent meteorological data collected by Con Edison. The walkdown was performed to confirm that no significant changes to the plant and in the site region have occurred since the issuance of the operating license and the IPPSS. The walkdown concentrated on outdoor facilities that could be affected by the external events addressed in this section (with emphasis on high winds and onsite storage of hazardous materials), and on offsite developments. The walkdown was performed following procedures developed for this effort and included engineering and technical personnel from both the utility (four representatives) and the contractor team (three representatives).

Due to the importance of high winds identified in the original IPPSS, the onsite walkdown concentrated on outdoor tanks and equipment, entrances to concrete buildings, openings in buildings such as air intakes, diesel exhaust stacks, and louvers, block walls in structures with openings, structures which could collapse and impact buildings containing safety-related equipment, and availability of objects which could become missiles in a tornado or hurricane. Table 6.1-1 based on the Probabilistic Safety Analysis Procedures Guide (Reference 6-2) was used as guidance in the plant walkdown. The table shows the items to be examined and the specific observations made at IP2. The main purpose of the walkdown was to obtain an overall appreciation of the plant layout, location of structures, and the types of construction and generally confirm the validity of structural drawings for tanks and buildings from which most of the information for wind fragility evaluation was obtained. The walkdown activities also included inspection of the area surrounding the immediate site and contact with cognizant non-utility personnel with knowledge of current conditions and activities which could impact the examination.

(b)(7)(F)

Ex. 7F

Figure 6.1-1
Indian Point Units 1 & 2
Site Layout Plan

Table 6.1-1
Walkdown Inspection List and Observations

Item	Observation
Locate all safety related equipment and structures	Equipment located inside concrete buildings (i.e., reactor building and lower portion the primary auxiliary building and Auxiliary Feed Pump Building) are generally protected from wind loading and missile penetration. Equipment located within sheet metal clad structures are partially protected (i.e., top portions of the primary auxiliary building, Auxiliary Feed Pump Building, diesel generator building, control building, top portion of the auxiliary feed water structure, turbine generator building, superheater building Unit 1, and gas turbine generator building). Equipment in the yard (e.g., condensate storage tank, service water pump) are not protected from tornado or hurricane induced missiles
Verify thicknesses of concrete walls protecting equipment	Where observable, we did not find any significant variation from drawings; therefore, design drawings can be used in evaluating the structural capacities to resist wind loading and missile
Check if there are metal-sided structures	Structures housing equipment on the PRA list and whose failure may affect adjacent structures are: Top portion of Primary Auxiliary Building, Diesel Generator Building, Control Building, Auxiliary Feedwater Pump Structure, Turbine Generator Building, Superheater Building (Unit 1), Superheater Stack, and Gas Turbine Generator Building
Inspect entrances to concrete buildings	Openings shown on drawings were verified; no specific barriers around entrances were found
Inspect other types of openings to buildings such as air intakes diesel exhaust stacks, and louvers	No specific barriers around these openings found

Table 6.1-1 (Continued)
Walkdown Inspection List and Observations

Item	Observation
Note block walls in structures with openings which could fail and fall on safety-related equipment	Reactor Building and concrete portion of the primary Auxiliary Building do not have such openings
Look for structures which could fail, fall, and impact buildings which contain safety-related equipment (indoor or outdoor.)	Superheater Building, Unit 1 Turbine Building, Unit 2 Turbine Building and Superheater Building Stack were identified to be in close proximity to buildings containing equipment on the PRA list and could damage them in the event of wind induced collapse. These issues are addressed in the IPPSS and will be accounted for in the updated analysis. However, it was noted that the Superheater Building Stack was previously verified through analysis to show high wind resistance (IPPSS). The transmission tower by the side of the Diesel Generator Building was observed to be well anchored and therefore, we judge its falling on the Diesel Generator Building is less likely than the wind induced failure of the Diesel Generator Building itself.
Look for missile paths through weaker buildings, which could impact equipment	Wind fragility analysis for IP2 would conservatively assume that the missile penetration of sheet meta clad buildings results in damage to all equipment within the buildings
Inspect outdoor water storage tanks which are safety-related	Condensate storage tank, refueling water storage tank and city water tank are metal tanks with no special provision for missile protection (i.e., concrete barrier). The details shown on the drawings regarding anchorage were generally confirmed and the drawings will be used for wind fragility evaluation
Make an inventory of potential missiles within 1,000 ft of the site boundary	Tornado missile risk is evaluated in the IPEEE by using the insights and results obtained from generic studies performed by Twisdale et al (1981). The walkdown confirmed that the potential number of missiles available at IP2 is less than that used in the generic studies There is no significant construction activity at the site. The IP2 structures are closer to each other compared to the generic study plants so that there is additional missile protection inherent at IP2. Missile Potential noted around GT1 and CST

6.2 HIGH WINDS

6.2.1 Methodology

Indian Point No.2 (IP2) structures and systems were designed to the wind loading requirements of the building codes in effect in the early 1970s. They pre-date and do not meet the 1975 Standard Review Plan criteria. Also, some of the structures at IP2 housing safety related equipment are metal-sided steel structures offering limited resistance to tornado missiles. The extreme wind hazard analysis done in the IPPSS indicated that high winds could not be screened out on the basis of low frequencies of occurrence. Therefore, utilizing the NUREG-1407 screening approach, it was concluded that a detailed probabilistic risk assessment was needed to address the impact of high wind events at IP2.

The wind hazard and building fragility analysis performed in the original IPPSS analysis was reviewed and updated as necessary. A new event tree based approach was used to define a set of unique wind induced plant damage states. Since this is the same basic approach used for the seismic analysis, it was determined that the software developed for the seismic hazard analysis could be used for this wind analysis. The frequencies associated with the wind induced plant damage states were, therefore, quantified using the EQE Seismic Risk Analysis software (EQESRA). The core damage frequency resulting from each wind induced damage state was then quantified by modifying the internal event plant logic model embodied within the RISKMAN software, accounting for the frequency of each damage state and the wind induced equipment damage. In the case of hurricane events, the analysis accounts for the benefits of the Hurricane Technical Specification" which requires the plant to be in cold shut down prior to the possibility of any structural damage.

6.2.1.1 Treatment of Winds in the IPPSS

In Section 7.5.4 of the IPPSS, simplified fault tree models were developed to represent the various combinations of wind initiated events (including hurricanes, extratropical cyclones, tornados and tornado missiles) and resulting equipment failures which may lead to core damage. Three types of scenarios were initially considered; transients coupled with failure of decay heat removal, loss of RCP seal cooling (resulting in seal LOCA) coupled with failure of Safety Injection, and large LOCA coupled with failure of Safety Injection. Wind induced large LOCAs were subsequently ruled out.

In addition to addressing overall core damage frequency, the IPPSS also developed models for determining the impact of winds on containment systems thereby permitting an evaluation of the contribution to individual plant damage states and release categories.

In order to perform the quantification of the risk due to winds, simplified fault trees were used to derive boolean expressions for each scenario of concern. Using these boolean expressions, combined with building and component fragilities, a plant level family of fragilities curves were developed for core damage and each release category under each wind direction. These were subsequently combined with the wind and tornado hazard curves to obtain an overall frequency for core damage and each individual release category.

6.2.1.2 Modeling Changes Made for the IPEEE

Since the development of IPPSS wind analysis there have been several significant changes to the Level 1 and Level 2 internal event models as part of the IP2 IPE. In addition, plant design features and procedures have been modified, and there have been some general improvements in external events modeling. Specifically the following needed to be accounted for in developing a new plant logic model for wind events:

1) Abnormal Operating Instruction (AOI) 28.0.7 " Hurricane /Tornado/High Wind/ Severe Thunder Storm" requires operators to track approaching hurricane conditions and if necessary bring the plant to cold shutdown (Tavg < 200deg F) prior to hurricane winds in excess of 87 knots (100 mph) arriving on site. Since significant leakage out of the reactor coolant pumps seals occurs only at high temperatures and pressures sufficient to damage the elastomer seals, for hurricane events, providing heat removal capability were available, a RCP seal LOCA would not be expected.

2) In the event of Control Room inoperability, AOI 27.1.9 instructs operators to utilize Alternate Safe Shutdown capability. This permits offsite power, or power from any of three Gas Turbines to be fed to a minimum set of safe shutdown equipment via the Indian Point 1 switchgear and local transfer switches. These power sources are completely independent of the IP2 control building. Sufficient pneumatic plant monitoring instrumentation was installed at locations outside the control building to provide necessary information regarding primary conditions to the operators during performance of the alternate safe shutdown actions.

3) Although the IPPSS was one of the first comprehensive PRAs to consider external events,

it did not consider random equipment failures in combination with seismic or wind related events. Linking the hazard analysis to the RISKMAN plant model allows this consideration.

4) The IPE Level 1 internal event model addresses the potential for a LOCA induced by an unisolated stuck open PORV, as well as an RCP seal LOCA. Since the PORVs would not be challenged when the plant is shutdown, stuck open PORV type LOCA's are not an issue for hurricanes.

5) The simplified logic model in the IPPSS did not address the potential for damage to MCCs 26A and 26B, located at the 98' elevation in the PAB, which could preclude bleed and feed operation. The IPEEE model allows this consideration.

6) The original IPPSS success criteria for containment spray assumed successful recirculation given successful injection. This was modified within the IPE and now allows separate consideration of injection and recirculation capability.

7) The Level 1 plant damage state definitions have been revised to address new Level 2 issues which were not considered in the original IPPSS. Of particular relevance to the wind analysis is the RCS pressure at core damage, which is now defined within the plant damage states.

8) The Level 2 analysis was completely revised in the IPE, resulting in a new set of release category definitions.

There were two options for developing a high winds risk model which would account for both wind related and coincident random equipment failures. The first option was to expand the existing IPPSS fault tree logic model to include equipment random failures as well as wind related failures. The second option was to develop a "Wind Damage Event Tree" which includes as its headings each potential wind related failure. The end points of the event tree represent unique "wind damage states" which, when quantified, define plant initiating event types and frequencies together with degraded plant conditions. These "wind damage state initiating events" can be propagated through the existing IPE internal events model. The latter (wind damage event tree) approach has been used for this analysis.

6.2.2 Wind Hazard Analysis

Extreme winds at IP2 could result from tornadoes, hurricanes, and extratropical cyclones and thunderstorms. Data on occurrence of these meteorological events was reviewed and models developed to characterize them probabilistically in the IPPSS. The IPPSS analysis of the wind hazard from all these events was conducted in great detail and the results continue to be applicable to the current analysis. As a check on the tornado occurrence rate used in IPPSS, we reviewed the data reported in Ramsdell and Andrews (Reference 6-3). For the one degree box of latitude and longitude around the Indian Point site, the mean occurrence of tornado winds was calculated to be 1.6E-4 per year per square mile. This compares well with the value of 2.0E-4 per year used in the IPPSS. Since, based upon a preliminary quantification, the tornado induced mean frequency of core damage was significantly greater than that induced by hurricanes, *qualitative review of the IPPSS hurricane hazard analysis was deemed sufficient to confirm its* applicability for this study.

The contributions of tornado and "extratropical cyclones and thunderstorms" to the mean core damage frequency are about equal. Tornado hazard is based on a modeling of the phenomenon whereas the thunderstorm hazard is based on an extrapolation of 20 or more years of weather station annual maximum windspeed data. Since the contribution of thunderstorms to the core damage frequency comes mainly from windspeeds of less than 125 miles per hour, in this range, the extrapolation from observed windspeed data was judged to be reasonable. In Section 7.9.5 of the IPPSS, wind hazard curves are provided for each of the four principal directions for hurricane, tornado, and extratropical cyclones and thunderstorms. These were used in the wind damage state quantification.

In the IPPSS, the effects of hurricane, tornados and extratropical cyclones were combined in the quantification of core damage frequency, although the hazard curves for each of these events were derived in each of the four principal directions. By this process, the relative contributions of the hazard events were not displayed in the final core damage frequency results. The present study separates the effects of hurricanes from those of tornadoes and extratropical cyclones. At each windspeed, the windspeed exceedance probabilities for tornado and extratropical cyclones were added to obtain the wind hazard curves for the combined extratropical cyclone and tornado event (Table 6.2-1). Such addition is reasonable for low probabilities of exceedance encountered for these events.

Table 6.2-1 Combined Windspeed Exceedance Probabilities--Plant West Direction

Velocity Fastest Mile	Hazard Curve	Windspeed Exceedance Probabilities: Hurricane	Extratropical Cyclone	Tornado	Combined Extra-tropical Cyclone and Tornado
60	Lower	5E-4	4E-7	Note 1	4.0E-7
	Mid-Lower	3E-3	1E-4	-	1.0E-4
	Median	6E-3	2E-3	-	2.0E-3
	Mid-Upper	2E-2	1E-2	-	1.0E-2
	Upper	3E-2	4E-2	-	4.0E-2
80	Lower	2E-5	-	8E-7	8.0E-7
	Mid-Lower	1E-4	5E-7	2E-6	2.5E-6
	Median	3E-4	4E-5	9E-5	1.3E-4
	Mid-Upper	7E-4	5E-4	7E-5	5.7E-4
	Upper	1E-3	4E-3	5E-4	4.5E-3
100	Lower	2E-7	-	4E-7	4.0E-7
	Mid-Lower	1E-6	-	1E-6	1.0E-6
	Median	4E-6	1E-6	7E-6	8.0E-6
	Mid-Upper	1E-5	2E-5	4E-5	6.0E-5
	Upper	2E-5	5E-4	2E-4	7.0E-4
125	Lower	-	-	1E-7	1.0E-7
	Mid-Lower	-	-	5E-7	5.0E-7
	Median	-	-	3E-6	3.0E-6
	Mid-Upper	1E-8	5E-7	2E-5	2.0E-5
	Upper	1E-7	2E-5	7E-5	9.0E-5
150	Lower	-	-	5E-8	5.0E-8
	Mid-Lower	-	-	3E-7	3.0E-7
	Median	-	-	2E-6	2.0E-6
	Mid-Upper	-	-	7E-6	7.0E-6
	Upper	-	2E-6	3E-5	3.2E-5
200	Lower	-	-	-	-
	Mid-Lower	-	-	5E-8	5.0E-8
	Median	-	-	3E-7	3.0E-7
	Mid-Upper	-	-	7E-7	7.0E-7
	Upper	-	-	2E-6	2.0E-6
250	Lower	-	-	-	-
	Mid-Lower	-	-	-	-
	Median	-	-	2E-8	2.0E-8
	Mid-Upper	-	-	4E-8	4.0E-8
	Upper	-	-	1E-7	1.0E-7

Note 1: Less than 1.0E-8

6.2.3 Evaluation of Structural Fragilities and Failure Modes

In the IPPSS, wind fragilities of key structures were calculated by reviewing the building design drawings and calculations, and information obtained from the metal siding manufacturer. Various modes of failure were assessed for extreme wind loadings in each of the four principal wind directions. The analysis considered building shape factors, roofing and siding failures from impinging winds and negative pressures, and building frame and anchorage failures. Funneling and shielding effects on these buildings were also considered in the calculation of wind fragilities.

The methodology used in wind fragility evaluation has not changed significantly since that analysis was done. The review of plant drawings and plant walkdown performed for the IPEEE wind analysis did not reveal any structural modifications of IP2 buildings since the time of the IPPSS that would alter the fragilities. Therefore, it was concluded that the IPPSS wind fragilities (Amendment 2, Table 7.5-7) were appropriate for use in the current IPEEE.

Figure 6.2-1 shows a typical family of wind fragility curves for a structure (i.e., Diesel Generator Building). The fragility is defined as the conditional probability of failure of the structure as a function of the windspeed in miles per hour. Shown are the median fragility, 5% confidence and 95% confidence curves. Although the fragility values are not shown for windspeeds below 70 miles per hour, it was judged that engineered building frames and siding will not fail below 70 miles per hour and the fragility curves are therefore curtailed at windspeeds below this value in wind damage state quantification. In the IPPSS quantification, each failure mode was further examined to derive Boolean expressions (Table 7.5-10 of IPPSS Amendment 2). Also included in these Boolean expressions were the missile damage event for each structure. In the current analysis, missile damage probabilities for each wind damage state were considered in the RISKMAN calculations for wind induced CDF.

The variability of wind capacity estimated in the IPPSS was all assumed to be uncertainty in the median capacity. To be consistent with the fragility model of randomness and uncertainty (where fragility is displayed by a family of curves), we have divided the β values reported in IPPSS into β_R and β_U using judgement. Sensitivity studies showed that the final wind damage state frequencies are not sensitive to this assumption whether the variability is treated as all randomness or all uncertainty or a combination of the two. The key structures examined in the IPEEE wind analysis are shown in Table 6.2-2, along with their median capacity and β values.

In the IPPSS, wind fragilities were cutoff at wind speeds below 3 standard deviations from the median capacity of the structure under consideration. Although this implies that the gas turbine shelters (s1 and s14) could fail at windspeeds as low as 43 mph, engineered structures should not fail at such windspeeds. The 70 mph cutoff was judged to be a more reasonable level below which structural failures would not occur.

Building frame failures are conservatively assumed to cause failure of all equipment within the building. Impact of one building failing or falling on to an adjacent building is discussed in Section 6.2.4.1 under the development of wind damage event trees.

Table 6.2-2

Wind Fragilities of Key Structures for West Direction

Structure	Median Capacity mph	β_R	β_U
s1 - Gas Turbine 1 Shelter	83	0.15	0.20
s3 - Aux. Feed Pump Bldg.	222	0.10	0.16
s4 - Control Bldg.	167	0.10	0.10
s5 - PAB (metal portion)	174	0.10	0.05
s6 - Diesel Gen. Bldg.	132	0.10	0.12
s7 - Stack	360	0.10	0.12
s12 - Unit 1 Turbine Bldg.	200	0.07	0.07
s13 - Unit 2 Turbine Bldg.			
Interior Frame	119	0.10	0.07
Exterior Frame	132	0.10	0.07
s14 - Gas Turbine 3 Shelter	83	0.15	0.20

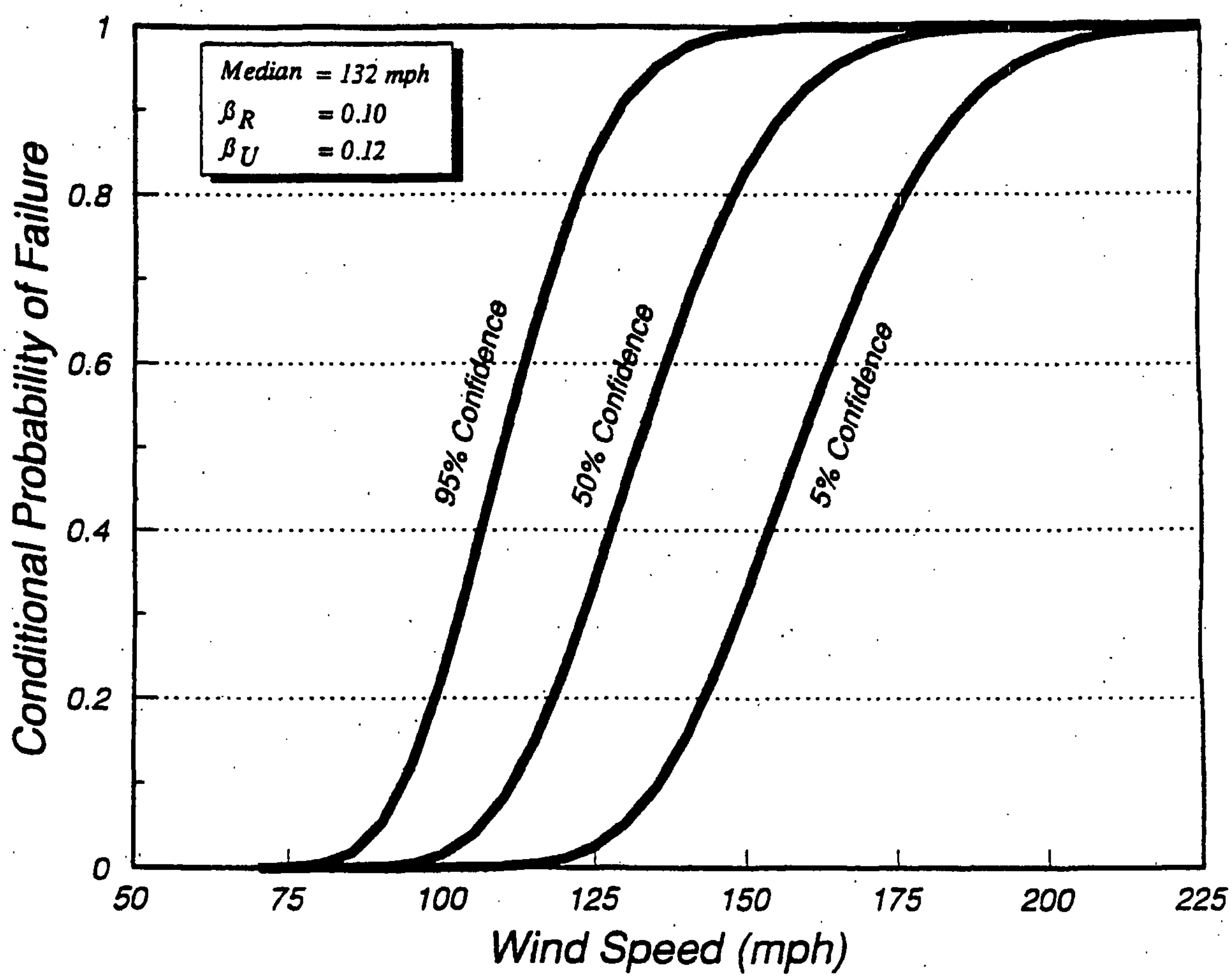

Figure 6.2-1
Example of Windspeed Fragility Curves

6.2.4 Analysis of Plant Systems and Sequences

6.2.4.1 Wind Damage Event Tree

In this examination, the wind induced failures were evaluated separately from random equipment failures, using an event tree logic approach. The aim was to identify and quantify a unique set of wind induced plant states. Each state was represented by one or more end points of a Wind Damage Event Tree.

Each heading on the Wind Damage Event Tree is a potential structural failure which may occur due to high winds. Most of these are listed in Table 7.5-10 of the IPPSS, although failure of the Gas Turbine 3 (GT3) shelter has been added in order to address the availability of power from the GTs. Those components (e.g. RWST) which are not susceptible to wind damage, but only susceptible to tornado missile damage, are excluded to simplify the event tree and minimize the number of scenarios which have to be quantified. The probability of tornado missile induced failure is independent of the magnitude of the wind hazard and could therefore be directly added to the internal events model.

In some instances, a particular structural failure can have a consequential effect of causing the loss of function of equipment located in another structure. This may occur either by one building collapsing onto another (which is assumed to cause the guaranteed failure of the equipment in that structure), or by loss of equipment in the damaged structure which is required to support the functioning of equipment in another. In such cases the event heading may not be challenged within the event tree structure. Due to the low capacity of the Gas Turbine Shelters, they were assumed to be failed given a preceding failure of a significantly stronger structure including the Unit 1 Super Heater Stack, the Control Building or the Auxiliary Feedwater Pump Building.

A separate Wind Damage Event Tree was constructed for each wind direction (north, south, east and west) since the consequential effects vary according to wind direction. As an example, Figure 6.2-2 shows the wind damage event tree for the west direction. The event tree headings are discussed below: The rationale is based on assumptions described in the original IPPSS analysis (IPPSS Table 7.5-9) which were reviewed and confirmed.

> <u>Event NW, (EW) (SW) (WW)</u>: <u>Wind Direction Plant North (East South West)</u>
> This represents the wind hazard.

Event s12: Unit 1 Super Heater Building and Turbine Building
The damage to the Super Heater building itself will disable the unit 1 Switchgear failing ASSS electrical feeds from GT 1, 2 and 3. For all wind directions this building will impact the Control Building. For North, East and West wind directions this building will impact the Gas Turbine 1 shelter. For a west wind direction there is a 50% chance this building will impact the Diesel Generator Building. However, this is of no significance since due the guaranteed failure of the Control Building.

Event s13: Unit 2 Turbine Building
The offsite power supply to the 480V buses and the ASSS power supply to the AFW pump 21 will fail due to damage within the turbine building. For all wind directions this building will impact the Service and the Control Building. For the north wind direction this building will also damage the Gas Turbine 1 shelter. This event is bypassed given failure of the Superheater building, since the Unit 1 switchgear has failed (loss of ASSS) and consequential failure of the Control Building results in loss of all power from the 480 v switchgear and normal plant control. For southerly winds this building is protected by the Unit 1 Turbine Building (IPPSS Table 7.5-7) and therefore is not challenged.

Event s7: Unit 1 Super Building Heater Stack
Damage to this building will not, itself, disable any mitigating functions, however it may cause consequential damage to other structures. For south winds this building will impact the control building. For south winds this building will also impact the diesel generator building with a 16% chance. However this is not significant since the damage to the control building is already guaranteed. For east winds there is a 50% chance that the control building will be damaged. For west winds there is a 50% chance the diesel generator building will be damaged. For north and east winds this building will impact the Gas Turbine 1 building with a 100% and 50% chance respectively. It is assumed that the Unit 1 switchgear will also fail due to damage within the Superheater Building. This event is a guaranteed failure given failure of the Unit 1 Superheater building.

Event s4: Control Building
This is a combination of events 4, 4a and 4b, (Control Building, Control Room and Control Building Siding) listed in Table 7.5-10 of the IPPSS. Since all events result in a loss of normal power or control to safety related equipment (see IPPSS Figure 7.5-20a) there did not appear to be any reason to treat these separately. This event may be a failure given a preceding failure of the Super heater Building or stack as described above

Event s6: Diesel Generator Building

This event results in loss of power from all three EDGs. This event is bypassed, given failure of the Control Building since the Unit 2 batteries and 480 switchgear are unavailable. In cases where the event is not bypassed there is a 50% chance of failure due to a West Wind and preceding collapse of the Super Heater Stack.

Event s3: Auxiliary Feed Pump Building

This event results in loss of all three AFW pumps. This event is always challenged since operation of the turbine driven pump is independent of any other structure

Event s5: Primary Auxiliary Building (top section):

This event results in the loss of Component Cooling Water (Heat Exchangers) and MCCs 26A, 26B, 26AA, 26BB. MCCs are required for valve operations including the PORV block valves. This event is bypassed given a failure of the Unit 1 Superheater Building, the Control Building, Diesel Generator Building due loss of all ac power.

Event s1: Gas Turbine 1 Shelter:

This event results in the loss of power from GT1. As discussed above, this event is assumed failed given a preceding structural failure of the Unit 1 Superheater Building, Superheater Stack, Control Building or Auxiliary Feedwater Building. The event is also bypassed given a failure of the Unit 2 Turbine Building since the 6.9 kV busses are failed, as is the power feed to the Alternate Safe Shutdown (ASSS) equipment and the service water system.

Event s14: Gas Turbine 2 and 3 Shelter:

This event results in the loss of power from GT2 and GT3. This event is assumed failed given the similar preceding conditions as those described for GT1.

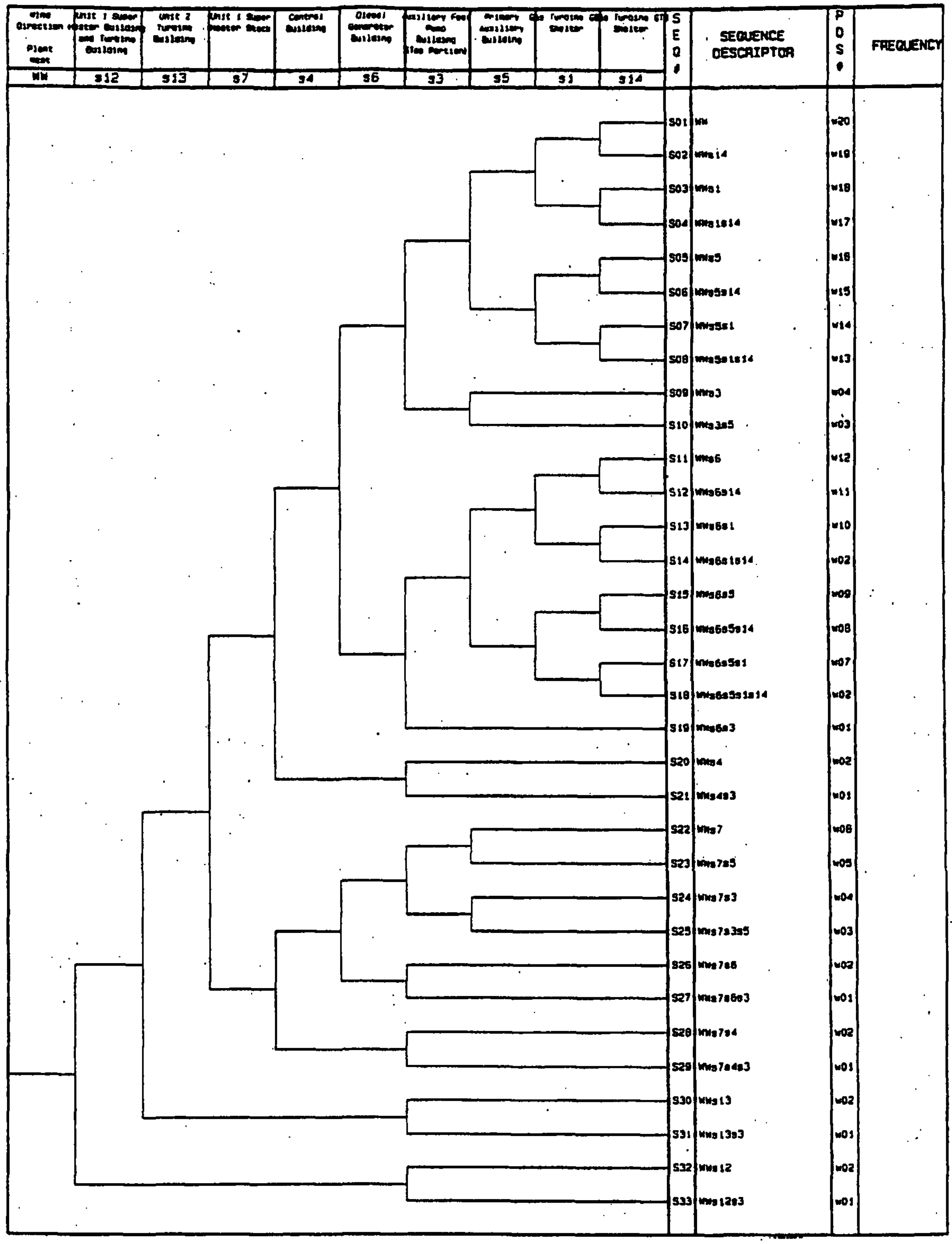

Figure 6.2-2
Typical Wind Damage Event Tree (West Direction)

6.2.4.2 Quantification of Wind Damage States

6.2.4.2.1 <u>Computational Methodology</u>

Wind damage state quantification was performed using EQESRA which computes the probability distribution of damage state frequency from information about component fragilities, Boolean expression for the wind damage state, and the wind hazard curves. EQESRA was originally developed for seismic risk evaluation and the computational scheme is equally applicable for wind risk analysis. The various elements of the risk analysis are described in the following:

- *Structure/Component Fragilities*: Fragilities are defined by a double lognormal model in terms of median capacity in miles per hour, logarithmic standard deviation β_R, and logarithmic standard deviation due to uncertainty in median, β_U.

- *System Logic*: The wind damage state is expressed in terms of a Boolean equation in which the basic events are the structural failures or successes.

- *Wind Hazard*: Expressed as the annual frequency of exceedance of various windspeeds at the site. To reflect the uncertainty in the modeling of extreme wind phenomena and in the parameters of such a model, the wind hazard is presented as a family of hazard curves with subjective weights assigned to each curve.

The risk quantification procedure first combines the component failures and successes according to the wind damage state Boolean equation using the component fragilities; resulting in damage state fragility curves. This damage state fragility is convolved with the wind hazard to yield probability distributions for the wind damage state frequencies.

An example of the wind damage state frequency calculation is given below. The Boolean equation for wind damage state w02 for west direction is derived from Figure 6.2-2 as:

$$\begin{gathered}
\overline{s3}*s12+\overline{s3}*s13*\overline{s12}+\overline{s3}*s4*s7*\overline{s13}*\overline{s12}+ \\
\overline{s3}*s6*\overline{s4}*s7*\overline{s13}*\overline{s12}+\overline{s3}*s4*\overline{s7}*\overline{s13}*\overline{s12}+ \\
s14*s1*s5*\overline{s3}*s6*\overline{s4}*\overline{s7}*\overline{s13}*\overline{s12}+ \\
s14*s1*\overline{s5}*\overline{s3}*s6*\overline{s4}*\overline{S7}*\overline{s13}*\overline{s12}
\end{gathered}$$

where basic events (structural failures) are denoted by s12, s13, etc. Success terms are denoted by the bar over the basic event. The wind fragilities for this direction were given previously in Table 6.2-2. The hurricane, tornado and extratropical cyclone hazard values were given previously in Table 6.2-1.

6.2.4.2.3 Detailed Quantification of Wind Damage States

The following sections describe the phased approach used for the detailed wind analysis quantification which allowed increasing focus on those aspects which represented significant contributors.

6.2.4.2.3.1 Identification of Dominant Wind Damage States

A review of the event trees (for example, Figure 6.2-2) shows that there are 20 plant damage states identified. Also, four principal wind directions for which wind hazard and fragility of structures are different are considered. As discussed before, three sources of extreme wind- hurricane, tornado and extratropical cyclones were evaluated. Therefore, there could essentially be 20 x 4 x 3 = 240 different analyses. By inspection of the wind hazard tables given in IPPSS (Tables V-1, 2, 3 and 4), it can be seen that the hazard from hurricanes and extratropical cyclones from the west direction is the highest of the four principal directions. Review of the wind fragilities showed that the wind capacities for critical structures (e.g., Gas Turbine Shelter, Control Building, Diesel Generator Building, and Unit 2 Turbine Building) are the lowest in the west direction among all the four directions. Therefore, in order to judge the relative contribution of different wind damage states to the overall wind induced core damage frequency, the mean annual frequencies of all 20 wind damage states for wind blowing from the west direction were calculated. Using these wind damage state frequencies as initiating event frequencies, core damage frequencies were calculated to conclude that the following nine wind damage states need to be examined further for all directions, hazard sources and fragilities since their contribution to core damage frequency exceeded 1.0E-08/yr:

w01, w02, w10, w11, w12, w17, w18, w19, and w20.

These wind damage states are described in Table 6.2-3. Of the wind damage states determined to be potentially risk significant, w01 and w02 can be assumed to lead directly to core damage. Consequently, the major contribution to core damage frequency would come from the wind damage state w02 of which about 50% comes from the west wind direction.

Table 6.2-3

Summary of Unique Wind Damage States

Wind Damage State	Description
w01	EDG Power and Control failed, GTs failed, AFW failed
w02	EDG Power and Control failed, GTs failed, AFW success
w03	AFW failed, PAB failed, GTs failed, EDG Power and Control success
w04	AFW failed, GT's failed, EDG Power and Control success
w05	PAB failed, GT's failed, EDG Power and Control success, AFW success.
w06	GT's failed, PAB success, EDG Power and Control success, AFW success.
w07	GT1 failed, PAB Failed, EDG Power failed, PAB failed, GT2 and 3 success, AFW success.
w08	GT2 and 3 failed, PAB Failed, EDG Power failed, GT1 success, AFW success.
w09	PAB Failed, EDG Power failed, GT1 success, GT2 and 3 success, AFW success.
w10	GT1 failed, EDG Power failed, PAB success, GT2 and 3 success, AFW success.
w11	GT3 failed, PAB Failed, EDG Power failed, PAB success, GT1 success, AFW success.

Table 6.2-3
Summary of Unique Wind Damage States
(continued)

Wind Damage State	Description
w12	EDG Power failed, PAB success, GT1 success, GT2 and 3 success, AFW success.
w13	GT's failed, PAB failed, EDG Power and Control success, AFW success.
w14	GT1 failed, PAB failed, EDG Power and Control success, AFW success, GT2 and 3 success
w15	GT3 failed, PAB failed, EDG Power and Control success, AFW success, GT1 success
w16	GT2 and 3 PAB failed, EDG Power and Control success, AFW success, GT1 success
w17	GT's failed, PAB success, EDG Power and Control success, AFW success.
w18	GT1 failed, PAB success, EDG Power and Control success, AFW success, GT2 and 3 success
w19	GT2 and 3 failed, PAB success, EDG Power and Control success, AFW success, GT1 success
w20	PAB success, EDG Power and Control success, AFW success, GTs success.

6.2.4.2.3.2 Identification of Dominant Structural Failures

A review of the fragilities of structures indicated that the following structures have relatively low wind capacities:

- s1 - Gas Turbine 1 Shelter
- s14 - Gas Turbine 3 Shelter
- s6 - Diesel Generator Building
- s13 - Unit 2 Turbine Building

The gas turbine shelter (s1 and s14) is of light sheet metal and steel frame construction. The median wind capacity of the siding was estimated to be 83 mph for west wind direction whereas the median wind capacity of the frame was calculated to be 104 mph.

The diesel generator building (s6) is a small steel-framed structure with approximate plan dimensions of 65 feet long in the east-west direction by 45 feet wide rising to a maximum height of 26 feet. Steel moment-resisting portal frames carry the lateral wind load in the north-south direction. Lateral wind loads in the east-west direction are resisted by 3/4-inch diameter cross-bracing which is provided in two bays of the structure along each side. The exterior of the diesel generator building is sheathed in corrugated metal siding with 26-gauge corrugated metal decking on the roof. Under suction wind loads, the siding capacity is controlled by failure due to pullover of the siding from the frame. Under impinging wind loads, torsional instability of the girt and subsequent tearout from the siding is considered to be the controlling failure mode. Loss of the exterior roofing occurs when the 26 gauge metal roofing is pulled away from the frame. The moment frames and braced frames have high wind capacities. The wind capacity of the roof is the lowest of all potential failure modes. Median capacity of the roof was estimated to be 132 mph; the siding capacity was calculated as 157 mph.

The Unit 2 turbine building (s13) is a steel structure; wind loads in the east-west direction are resisted by eleven moment resisting frames at 25 feet on center. Lateral loads in the north-south direction are carried by diagonal cross-bracing located in two bays along each side of the structure. The turbine building wind capacity was calculated as the combination of capacities of interior and exterior frames as described in IPPSS. The equivalent median capacity under this failure mode was calculated as 123 mph.

A review of the Boolean equation for w02 shown in Section 6.2.4.2.1 indicated that the following sequences may be dominant contributors to the w02 frequency:

$$Seq\ 30 = \overline{S3}*S13*\overline{S12}$$
$$Seq\ 20 = \overline{S3}*S4*S7*\overline{S13}*\overline{S12}$$
$$Seq\ 14 = S14*S1*\overline{S5}*\overline{S3}*S6*\overline{S4}*\overline{S7}*\overline{S13}*\overline{S12}$$

Sequence 30 is controlled by the failure of the Unit 2 Turbine Building (consequentially failing the control building) whereas sequence 14 is dominated by the failure of Gas Turbine Shelters and the diesel generator building. The control building failure by itself controls sequence 20 and contributes less than 1%.

6.2.4.2.3.3 Review of Building Failure Modes

Following the initial quantification, the failure modes of key structures, in particular the Unit 2 Turbine Building and EDG Building, were re-examined.

Unit 2 Turbine Building Failure s13: In IPPSS, the median capacities of turbine building frame (internal and external) was estimated by assuming the full siding intact; at windspeeds in excess of 100 mph, however, we could expect some siding will have been blown away reducing the loading on the frame. IPPSS Boolean equation for s13 (IPPSS Table 7.5-10) attempted to correct this by modeling the failure of the frames and the success of siding. This assumption is unrealistic and non-conservative at higher windspeeds; at very high windspeeds the probability of s13 goes to zero. As a result, the initial IPEEE turbine building failure analysis was adjusted such that part of the siding was assumed to be blown away at windspeeds below structural failure. The tributary area of loading on the frame was assumed to be 50% of the full siding area.

Diesel Generator Building Failure s6: In the initial IPEEE analysis, the diesel generator building capacity was assumed to correspond directly to the roof capacity under wind suction. Although suction failure of the roof would not necessarily failure the equipment in the building, this failure mode was included to bound the effect since wind damage is frequently accompanied by rain that may affect the electrical components inside the diesel generator building. Although this roof failure occurs at wind speeds less than those necessary for failure of the siding not all tornadoes are accompanied by rain. The 70% likelihood of complete Diesel Generator failure, given structural failure, used in the IPPSS was therefore judged to be applicable to this failure mode for tornado induced damage.

6.2.4.2.3.4 Modeling of Coincident Tornado Damage to the EDG and Gas Turbines

In the initial IPEEE quantification it was assumed that tornadoes which strike the EDG building invariably strike Gas Turbines 1, 2 and 3. Since Gas Turbines 2 and 3 are actually located approximately 0.5 miles from the main power complex and feed the Station through underground lines, the probability of coincident strike is actually considerably less than unity.

It can be seen from Ramsdell and Andrews (Reference 6-3) that the path length of most tornadoes exceeds 0.5 miles which is the distance between the EDG/GT 1 buildings and GTs 2 and 3. Therefore any tornado striking the EDG/GT 1 building and moving in the direction of the gas turbine shelters 2 and 3 would invariably strike them too. The relative frequency of the tornado path direction is derived by Twisdale et al (Reference 6-4) and is given in Table III-9 of the original IPPSS report. For the subregion around Indian Point 2, the relative frequency of tornado path direction varies from 0.54 in the east octant to 0 in the south west octants. The EDG building and GT2/3 are oriented in the north-south octants. The tornadoes with path directions in these octants have a relative frequency of occurrence of .022 + 0.014 = .04. The probability of tornadoes traveling in other directions is therefore .96. Of those, only tornadoes having path widths exceeding 0.5 miles will damage the EDGs and all three gas turbines. From Garson et al (Reference 6-5), the probability of a tornado path width exceeding 0.5 miles is 0.1.

The probability of a tornado passing through both the onsite EDG and GT 1 buildings and the offsite GTs 2 & 3, or a tornado wide enough to simultaneously damage the EDGs and all the GTs is .04 x 1 + 0.96 x 0.1 = .14

Tornado missile effects are not explicitly considered in this evaluation. A tornado may structurally fail the EDG building (and GT 1) and may throw missiles at GT2/3. Because of the distance between the EDG building and GT2/3 however, and the relatively higher probability of a random failure of the GTs (which is accounted for in the RISKMAN model) compared with a concurrent missile strike, this event was judged to be of negligible concern.

The total annual frequencies for each wind damage state (from all wind directions) for tornadoes, hurricanes and extratropical cyclone hazards is shown in Tables 6.2-4 through 6.2-6.

TABLE 6.2-4 ANNUAL FREQUENCIES OF WIND DAMAGE STATES RESULTING FROM TORNADOES

Wind Damage States	Wind Direction											
	North			East			South			West		
	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%
w01	9.03E-7	3.65E-9	3.80E-6	5.44E-7	1.92E-9	1.95E-6	5.24E-7	9.0E-10	1.52E-6	5.19E-7	1.71E-9	1.70E-6
w02	8.74E-6	5.56E-8	3.89E-5	8.37E-6	4.83E-8	3.59E-5	8.30E-6	4.80E-8	3.54E-5	9.37E-6	5.18E-8	4.02E-5
w10	5.80E-7	3.9E-11	1.63E-6	7.53E-7	5.0E-11	2.15E-6	7.06E-7	2.4E-11	2.01E-6	3.84E-7	2.47E-12	1.08E-6
w11	5.80E-7	3.9E-11	1.63E-6	7.53E-7	5.1E-11	2.15E-6	7.06E-7	2.5E-11	2.01E-6	3.84E-7	2.47E-12	1.08E-6
w12	2.45E-7	4.35E-12	8.28E-7	2.68E-7	4.9E-12	8.84E-7	2.59E-7	2.4E-12	6.63E-7	7.32E-8	8.35E-14	1.18E-7
w17	1.96E-5	7.07E-8	7.26E-5	2.15E-5	7.94E-8	7.87E-5	2.11E-5	6.45E-8	7.85E-5	3.85E-5	1.92E-7	1.39E-4
w18	1.88E-5	3.20E-8	6.00E-5	1.91E-5	3.21E-8	6.08E-5	1.90E-5	8.55E-9	5.45E-5	1.80E-5	8.57E-9	4.83E-5
w19	1.88E-5	3.20E-8	6.00E-5	1.91E-5	3.22E-8	6.08E-5	1.90E-5	8.55E-9	5.45E-5	1.80E-5	8.57E-9	4.83E-5
w20	2.78E-5	6.06E-8	8.90E-5	2.79E-5	6.07E-8	8.91E-5	2.81E-5	4.98E-8	8.92E-5	1.34E-5	1.02E-8	3.62E-5

TABLE 6.2-5 ANNUAL FREQUENCIES OF WIND DAMAGE STATES RESULTING FROM EXTRATROPICAL CYCLONES

Wind Damage States	Wind Direction											
	North			East			South			West		
	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%
w01	7.83E-9	1.3E-27	3.57E-8	1.86E-9	0	7.37E-9	7.9E-10	0	1.61E-9	3.0E-10	0	4.6E-11
w02	1.91E-6	7.6E-17	7.88E-6	4.48E-7	0	1.53E-6	2.45E-7	0	8.22E-7	4.96E-6	2.2E-16	1.16E-5
w10	6.20E-7	9.7E-17	5.68E-7	1.72E-7	0	1.75E-7	1.02E-7	0	7.22E-8	1.02E-6	1.8E-16	7.01E-7
w11	6.20E-7	9.7E-17	5.69E-7	1.72E-7	0	1.75E-7	1.02E-7	0	7.22E-8	1.02E-6	1.8E-16	7.01E-7
w12	4.49E-7	2.2E-16	2.52E-7	1.22E-7	0	9.19E-8	7.85E-8	0	3.01E-8	3.70E-7	2.3E-16	2.80E-7
w17	6.06E-5	1.0E-10	2.19E-4	1.66E-5	0	5.91E-5	1.15E-5	0	3.48E-5	3.242E-4	1.72E-9	1.60E-3
w18	1.39E-4	5.5E-10	5.23E-4	3.84E-5	0	1.43E-4	2.91E-5	0	1.06E-4	3.95E-4	2.75E-9	1.54E-3
w19	1.39E-4	5.5E-10	5.23E-4	3.84E-5	0	1.43E-4	2.91E-5	0	1.06E-4	3.95E-4	2.75E-9	1.54E-3
w20	4.93E-4	1.22E-8	2.90E-3	1.38E-4	0	8.12E-4	1.12E-4	0	7.48E-4	7.03E-4	1.66E-8	3.15E-3

TABLE 6.2-6 ANNUAL FREQUENCIES OF WIND DAMAGE STATES RESULTING FROM HURRICANES

Wind Damage States	Wind Direction											
	North			East			South			West		
	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%	95%
w01	3.07E-8	1.1E-14	1.12E-7	2.82E-13	0	1.88E-13	3.6E-13	5.3E-27	9.5E-14	2.81E-9	4.0E-17	2.29E-8
w02	1.48E-6	3.94E-9	5.20E-6	1.54E-9	3.8E-13	4.91E-9	9.43E-9	1.7E-11	2.43E-8	7.61E-7	4.5E-10	2.66E-6
w10	1.02E-6	5.7E-12	3.03E-6	1.05E-9	1.02E-16	3.44E-9	8.88E-9	1.8E-16	1.86E-8	3.19E-7	1.4E-12	6.76E-7
w11	1.01E-6	5.7E-12	3.03E-6	1.05E-9	1.02E-16	3.44E-9	8.88E-9	1.8E-16	1.86E-8	3.19E-7	1.4E-12	6.76E-7
w12	1.13E-6	1.1E-12	2.36E-6	1.35E-9	7.54E-17	3.21E-9	1.36E-8	1.2E-16	2.56E-8	1.99E-7	1.2E-13	2.63E-7
w17	2.28E-4	1.66E-7	9.97E-4	3.42E-7	1.64E-10	1.11E-6	4.52E-6	1.4E-10	2.10E-5	2.78E-4	1.30E-6	1.08E-3
w18	6.57E-4	4.73E-7	2.82E-3	1.10E-6	3.91E-10	3.62E-6	1.70E-5	3.8E-10	9.58E-5	4.25E-4	1.11E-6	1.65E-3
w19	6.57E-4	4.73E-7	2.82E-3	1.10E-6	3.91E-10	3.62E-6	1.70E-5	3.8E-10	9.58E-5	4.25E-4	1.11E-6	1.65E-3
w20	2.55E-3	6.03E-6	6.50E-3	4.52E-6	3.07E-8	1.81E-5	7.94E-5	7.76E-8	3.21E-4	8.22E-4	1.40E-5	2.62E-3

6.2.4.3 Quantification of Core Damage Frequencies

The final stage of the analysis is to determine the core damage and plant damage state frequencies resulting from each wind damage state taking into account equipment loss due to wind related structural damage, tornado missile damage as well as unrelated coincident random equipment failures. This section describes modifications which were made to the internal events IPE model embodied within the RISKMAN software, to reflect the wind and missile related damage.

Within the internal events model, the general transient event tree was selected for the purposes of modeling accident sequences resulting from wind induced initiating events. This model includes the potential for and mitigation of consequential LOCA events resulting from loss of RCP seal cooling or a stuck open PORV. Loss of offsite power was reflected in the support systems logic as was the recovery of power from the gas turbines.

The general transient tree, the electric power event tree and the auxiliary support systems event tree split fraction logic terms were modified to reflect the damage associated with particular wind damage states as discussed below.

The system fault trees were also modified to reflect the potential for damage to structures and associated equipment caused by tornado missiles. Specific system model changes to reflect wind induced damage are discussed in sections 6.2.4.3.5 and 6.2.4.3.6.

Separate quantifications for each wind damage states resulting from tornados, hurricanes and extratropical cyclones were performed. The results are discussed in section 6.2.5.

6.2.4.3.1 Initiating Event Frequencies

As discussed in the previous section, the total annual frequencies for each wind damage state (from all wind directions) for tornadoes, hurricanes and extratropical cyclone hazards are shown in Tables 6.2-4 through 6.2-6. These wind damage state frequencies were treated as initiating events and propagated through the internal events model with modifications as described in the following section.

6.2.4.3.2 Modifications Made to Internal Events Event Trees to Reflect Wind Damage Impact

The following paragraphs describe the major changes made to the internal events model to reflect the impact of particular wind damage states.

Offsite Power
In the event of either a hurricane, tornado or extratropical cyclone, it is assumed that offsite power would be unavailable.

Emergency Power and Control
The following wind induced damage states imply failure of the control building or diesel generator building; w01, w02, w10, w11 and w12.

Gas Turbines
In the original IPE model, recovery of power from the gas turbines was accounted for in the Loss of Offsite Power seal LOCA model rather than the Electric Power event tree. For the wind analysis the Electric Power event tree was modified to include a new top event which challenges the availability of the gas turbines following a station blackout. Due to the low capacity of the gas turbine shelters, the GTs are assumed to be damaged given a wind which is capable of damaging the higher capacity structures (e.g. Superheater building, Unit 2 Turbine Building or the Control Building). Thus the GTs are not useful for mitigating scenarios in which emergency power is lost due to wind damage to these structures. However, loss of emergency power may also occur following high wind events as a result of missile damage to the control building and (to a lesser extent) the EDG building. In such cases the GT shelters are not impacted, although, since the control building may be damaged the power must be supplied via the Alternate Safe Shutdown System (ASSS).

Service Water
As discussed above, in the event of a loss of power from the Emergency 480V Busses, ASSS components may be supplied from the gas turbines via switchgear located in the Unit 1 Superheater Building and local transfer switches. Such action is directed by the EOPs in the event of a station blackout. Service water pumps 23 and 24 may be supplied in this manner.

Component Cooling Water

In a similar manner to that described for service water, the CCW pump 23 may be powered via the ASSS from the gas turbines. In addition, wind damage state w02 implies damage to the PAB structure resulting in a failure of CCW piping.

The internal events General Transient event tree and split fraction logic was modified to reflect particular wind damage states as follows:

Stuck Open PORV

The IPE model for a stuck open PORV is dependent upon the challenge rate of the PORVs which in turn depends on the type of the initiating transient. For all tornado and extratropical cyclones, the PORV challenge rate was assumed to be that corresponding to a loss of offsite power transient (the highest challenge rate of all transient types). Stuck open PORVs are not considered given the plant has been shutdown prior to a hurricane striking the site.

RCP Seal LOCA

In a similar manner to that described above for the service water system, Charging Pump 23 may also be powered via the ASSS (given gas turbine availability) in the event of loss of power from the emergency buses.

Auxiliary Feedwater System

Wind damage state w01 implies damage to the Auxiliary Feedwater Building. In a similar manner to that described above for the service water system, Auxiliary Feedwater Pump 21 may be powered via the ASSS in the event of loss of power from the emergency buses.

Primary Bleed

Wind damage state w02 results implies damage to the PAB and loss of MCCs 26A, 26B, 26AA and 26BB located on the 98' elevation. This guarantees failure of Primary Bleed.

Emergency Diesel Generator Mission Times

The Emergency Diesel Generator and EDG Fuel Oil Pump mission times have been increased from 6 hours to 24 hours to reflect the increased difficulties in restoring offsite power and making repairs following high wind events.

6.2.4.3.3 Changes Made to System Models to Reflect Missile Damage

In IPPSS, tornado missile strike probabilities given the occurrence of a tornado were calculated using the extensive study done by Twisdale et al (1978) for EPRI. The missile strike (damage) event was included in the Boolean expression for each structure failure. In the current study, we have examined the results of the EPRI study in conjunction with the plant walkdown and concluded that it is appropriate for use in quantification.

In the current study, the missile damage probabilities for different structures or components are input directly into the fault trees in the same way as random unavailabilities since the missile damage probabilities have been calculated as conditional on the occurrence of the hazard event. The likelihood of missile strike was conservatively assumed to be independent of the intensity of the hazard.

Although hurricanes and cyclones could generate missiles, they would not be as energetic as the tornado missiles; since the number of objects picked up in a hurricane is smaller than in a tornado (because of pressure drop effects), their conditional probability of striking a structure is expected to be much smaller than that calculated for tornadoes. Random failure rates of equipment housed in structures are expected to be larger than the missile damage probabilities of structures from cyclones and hurricanes. Therefore, quantification of missile damage events has been limited to tornado events.

As stated above, system damage due to missile strikes has been input directly into the model as basic events in the same way as random failures. The new basic events modeled in the fault trees are listed in Table 6.2-7. New split fractions have been created where appropriate to reflect the potential for missile damage given each type of wind hazard.

TABLE 6.2-7: TORNADO MISSILE STRIKE EVENTS

Event Name	Description	Mean	Comment
CWTMIS	Missile strike on CST	1.4E-03	Input to AFW fault tree as contributor to CST failure
RWTMIS	Missile strike on RWST	1.4E-03	Input to RWST fault tree as contributor to RWST failure
CTBMIS	Missile strike on Control Building	1.1E-02	Input to Fuel Oil System fault tree as single contributor to fuel oil system failure. Note: fails power from EDGs thru model logic
EDGMIS	Missile strike on EDG Building	1.4E-03	Input to Fuel Oil System fault tree as single contributor to fuel oil system failure. Note: fails power from EDGs thru model logic
CWTMIS	Missile strike on City Water Tank	1.4E-03	Input as a single contributor to RCP Seal Cooling failure (top event LS) given failure of CCW. Input to AFW fault tree as a contributor to failure of back up supply from the city water tank.
PABMIS	Missile strike on PAB	1.3E-02	Input to the CCW fault tree as a single contributor to the failure of CCW. Input to the Primary Bleed fault tree as a single failure of primary bleed. (due to damage to MCCs 26A and 26B.
AFBMIS	Missile strike on Auxiliary Feedwater Building	1.3E-02	Input to the AFW fault tree as a single contributor to the failure of AFW.
SWSMIS	Missile Strike on Service Water Pumps	6.1E-04	Input to the essential and non essential service water fault trees as a single contributor for the failure of service water

6.2.5 Results Analysis

The contribution to core damage frequency from each wind damage state and wind hazard type was calculated. The total contribution to core damage frequency from all three wind hazard types is 3.03E-05 per year. The contribution to core damage frequency from each wind damage state and wind hazard type is given in Table 6.2-8.

Tornadoes and extratropical cyclones are the major contributors core damage frequency, contributing 1.68E-05 per year and 1.11E-05 per year respectively. Hurricane events contribute 2.43E-06 per year.

6.2.5.1 Dominant Sequences

The dominant sequences for tornado and extratropical cyclones occur due to wind damage state w02. In the case of tornadoes, failure of the turbine building (leading to consequential failure of the control building), the control building itself, and the combination of EDG/GT building failure all contribute significantly. In the case of extratropical cyclones, the EDG building failures are more important. The various structural failure modes are discussed in section 6.2.4. Due to the resulting station blackout, RCP seal cooling is lost resulting in a seal LOCA with no RCS make up capability.

There is also some contribution to core damage from scenarios which include missile damage (principally on the control and EDG building) and/or coincident random equipment failures (principally the gas turbines). In the case of tornadoes, this contribution is 3.76E-06 per year, whereas the contribution from extratropical cyclones is 3.45E-06 per year.

The contribution to core damage frequency from hurricane events (2.4E-06/yr) is less significant compared with the other two wind hazards. This is the case for two reasons. First, and of greater significance, the frequencies associated with hurricane windspeeds in the range which could cause severe plant damage are substantially lower than those associated with tornadoes and extratropical cyclones. Second, and of lesser significance, the implementation of the IP2 hurricane technical specification and implementing procedure requires the plant to be in a cold shutdown condition prior to the hurricane reaching the site. In this condition, the likelihood of an RCP seal LOCA is reduced and the plant may be maintained in a stable condition using the turbine driven auxiliary feedwater pump and pneumatic instrumentation.

6.2.5.2 Sensitivity and Uncertainty Analysis

In this study, the wind hazard analysis performed in the IPPSS was reviewed and determined to still represent the current state-of-the-art and be of use in this examination. Structural fragilities developed in the IPPSS were reviewed and modified, where appropriate, to reflect more realistic assumptions of failure modes and consequences. The event tree modeling has reflected these improvements in the methodology and has explicitly taken into account the impact of the technical specification on hurricane alert currently implemented at IP2. The quantification of wind damage states has explicitly included uncertainty analysis. Extrapolating to core damage frequencies, the 5% to 95% confidence range for the total contribution to core damage frequency from all high wind events is 3.3E-07 to 1.5 E-04 per year.

TABLE 6.2-8
CORE DAMAGE FREQUENCY (PER YEAR) FROM WIND DAMAGE STATES

Wind Hazard	Wind Damage State	Mean Core Damage Frequency/yr
Tornadoes	w01	Total: 2.49 E-06
	w02	Total: 1.06 E-05
	w10	Total: 7.47 E-07
	w11	Total: 8.65 E-08
	w12	Total: 1.67 E-07
	w17	Total: 2.99 E-07
	w18	Total: 1.09 E-06
	w19	Total: 7.72 E-07
	w20	Total: 5.82 E-07
		Total from Tornadoes 1.68 E-05
Hurricanes	w01	Total: 3.35 E-08
	w02	Total: 1.78 E-07
	w10	Total: 2.06 E-08
	w11	Total: 3.60 E-08
	w12	Total: 1.11 E-08
	w17	Total: 4.74 E-07
	w18	Total: 3.37 E-07
	w19	Total: 4.66 E-07
	w20	Total: 8.80 E-07
		Total from Hurricanes 2.43 E-06
Extratropical Cyclones	w01	Total: 1.08 E-08
	w02	Total: 7.56 E-06
	w10	Total: 4.33 E-07
	w11	Total: 7.01 E-07
	w12	Total: 1.44 E-07
	w17	Total: 9.38 E-07
	w18	Total: 3.76 E-07
	w19	Total: 2.70 E-07
	w20	Total: 6.80 E-07
		Total from Extratropical Cyclones 1.11 E-05
Total Contribution to CDF from High Winds		3.03E-05

6.2.6 Containment Performance

Generic letter 88-20, Supplement 4, Appendix 2 and NUREG 1407, section 3.2.6 provides guidance on the containment performance analysis. The purpose is to identify sequences that involve containment failure modes distinctly different from those found in the IPE and in particular those that lead to early containment failure. Failure of containment isolation, containment bypass pathways and containment systems are at issue.

<u>Structures and Major Components</u>

The containment itself is not susceptible to wind damage due to its massive reinforced concrete structure. Piping in the Pipe Penetration Area (Fan House) and the lower portion of the Auxiliary Feedwater Building which penetrates the containment is also protected by reinforced concrete structures which are not susceptible to wind damage. However the upper portion (above the second story) of the Auxiliary Feed Water building, and the pipe bridge crossing to the turbine building are steel framed with metal siding and roof decking. These structures house and support the main steam, feedwater and auxiliary feedwater lines. Failure of the main steam or feedwater lines at the containment could theoretically lead to a loss of containment should the pipe penetration sleeve or the closure plate between the pipe and the sleeve on the containment wall fail. An analysis was made of the load capacity of each of these pipes. Although hairline cracking could occur, the piping and pipe penetration would not fail at wind loadings considered to be credible.

Loss of containment integrity as a direct cause of high wind events is therefore not an issue.

<u>Containment Bypass</u>

Containment bypass was evaluated in the IPE, and the two significant mechanisms identified were the interfacing system LOCA (large containment bypass) and the unisolated steam generator tube rupture (small containment bypass). Mechanical failure or spurious valve operation is the cause of both of these events. Wind induced mechanical failures are not considered credible since critical piping is enclosed and supported by reinforced concrete structures. Spurious valve operation due to control and power circuit damage was addressed and determined not to be an issue in the fire analysis, as discussed in Section 4.2.2. In addition, accident sequences resulting from wind induced events will not cause more excessive RCS pressures than those addressed in the internal events accident sequence analysis, and thus there are no new induced steam generator tube rupture events. Therefore, the containment bypass conclusions presented in the IPE are not altered by the high wind analysis.

Containment Isolation

The containment penetrations determined to require more detailed analysis in the IPE are isolated by mechanical check valves or air operated valves which fail closed on loss of air supply or DC power to their solenoid valves. The valves of concern are located in the Pipe Penetration Area and are thus protected from direct wind damage, as discussed above. Wind damage to structures, valves or power supplies will therefore not degrade the reliability of the containment isolation function.

Containment Pressure Suppression and Heat Removal

The availability of containment pressure suppression and heat removal systems (containment spray, fan coolers, and RHR) following core damage was explicitly modeled in the IPE event trees, and their status reflected in the plant damage state binning process. Based on the results of the IPEEE analysis 87% (2.64E-05 per year) of the wind induced core damage sequences result from station blackout and also result in loss of all containment systems. (This compares with the IPE result where the contribution to core damage frequency with coincident loss of containment systems was 1.07E-05 per year (CDF w/loss of Containment Heat Removal (CHR) and Spray (CS) = 2.2E-06 per yr, and CDF w/loss of CS only 8.5E-06 per year). If these functions are not regained, these sequences would lead to long term containment overpressure and failure. However, none of these sequences lead to directly to early failure of containment

Containment Performance Summary

In conclusion, containment performance issues have been specifically addressed in the wind analysis. No vulnerabilities which could cause early failures of containment or containment bypass were identified.

6.3 EXTERNAL FLOODING

The grade elevation at the plant embankment adjoining the river is 14.0 feet and rises above this level at all other plant buildings and structures. The minimum critical flood height for Indian Point Unit 2 is in the 480V Switchgear Room and is Elevation 15 foot 6 inches. The probable maximum flood (PMF) analysis conducted in 1971-73 during licensing of the adjoining Indian Point Unit 3 facility concluded that the maximum sustained water surface elevation at the plant is 14.0 feet based on the extraordinary combination of a Hudson River maximum flood, probable maximum precipitation over the Esopus Creek Basin resulting in failure of the Ashokan Dam, and a hurricane at New York Bay. The IPPSS study estimated the annual frequency of the combination of these extreme events to be in the range of 10^{-12} to 10^{-8} per year. The IPPSS also estimated that a maximum hurricane surge during spring tides could result in a maximum water surface elevation of 12.4 feet above mean sea level. Since, as mentioned above, the minimum plant grade elevation (adjoining the river) is 14.0 feet, it was concluded in the IPPSS that the contribution of external flooding to core damage frequency of IP2 was extremely small.

The plant has not experienced flooding from the Hudson River that has exceeded the plant grade elevation. Information obtained from the US Army Corps of Engineers (1994) has confirmed that there is a stream gage on the Hudson River (at Greenland) and that the water level does not exceed 14 ft above MSL. Since the river is very wide, its water depth does not fluctuate much. The walkdown and review of the surrounding site showed that no major construction has taken place that may change the river regime upstream of the Hudson River since the IPPSS nor has there been any major changes to the terrain around the plant. Therefore, the response of the terrain to a hazard which could cause river flooding, as evaluated in the IPPSS is still valid.

With regard to hurricane induced river flooding, more recent hurricane inundation maps for Westchester County developed by the U.S. Army Corp of Engineers and the Federal Emergency Management Agency show that the maximum hurricane surge elevation for a Category 4 hurricane, were it to occur close to Indian Point, could reach 13.5 feet. Note that this maximum surge could only occur for the Category 4 hurricanes with windspeeds at the upper end of the range for the category. Since the water level associated with a spring high tide could rise to the 3.00 foot elevation, if a maximum Category 4 hurricane were to occur coincident with spring high tide, the maximum hurricane surge level could be as high as 16.5 feet which would exceed the critical flood level for IP2 and therefore require protective action. Category 4 hurricanes on the Saffir-Simpson damage potential scale have maximum sustained (1-minute) wind speeds ranging from 131 to 155 miles per hour. From Figure III-13 in the report by Twisdale and Dunn

(Reference 6-4), it can be seen that even the upper bound annual frequency of exceeding a windspeed of 131 mph is less than $5x10^{-7}$ per year. Combining this with the probability of a simultaneous high tide condition reduces the hazard frequency even further. Therefore, the frequency of a river flooding event, including hurricane induced flooding, at Indian Point Unit 2 is substantially below the hazard screening level (Screening Level 4 of Figure 6.0-1).

6.4 TRANSPORTATION AND NEARBY FACILITY ACCIDENTS

6.4.1 Aircraft Accidents

Airports and airfields within approximately 25 miles of Indian Point were considered in the IPPSS study. The three closest airports were identified as Mahopac, Ramapo Valley and Peekskill Seaplane Base out of which the Peekskill Seaplane Base was judged to pose the greatest hazard to the plant. Using the annual number of landing and take-off operations at the Seaplane Base and general aviation accident statistics, the annual probability of an aircraft hitting any of the plant structures was estimated as $2.4x10^{-7}$ per year. Federal airways in the vicinity of the plant were also examined. The annual probability of an aircraft using the federal airways in the vicinity of the plant at that time accidentally hitting IP2 structures was estimated as 4.6×10^{-8} per year.

For the IPEEE, a review was made of current information regarding airports and airways in the vicinity of Indian Point.

6.4.1.1 Airports Within 10 Miles

There are no airports within 10 miles of the plant except for the Peekskill Seaplane Base. Since the time of IPPSS, there has been a considerable reduction in the activity at the Seaplane Base. Based on direct contact with the owner of the Seaplane Base, it was determined that the annual number of take-offs and landings could be conservatively estimated as 360. The IPPSS had used an estimate of 4,000 take-offs and landings per year. Therefore, the revised estimate of aircraft hit probability from operations at the Seaplane Base is $2.4x10^{-7} \times 360/4000 = 2.1x10^{-8}$ per year. Since this value is far less than the screening criterion, the operations at the Seaplane Base are considered to not pose any significant hazard to IP2.

6.4.1.2 Airports Beyond 10 Miles

The airports beyond 10 miles from IP2 are listed in Table 6.4-1. Of these, the airports with the largest number of operations are Stewart International, Westchester County and Orange County airports. Table 6.4-2 shows the distance to Indian Point, the maximum number of operations per year and the Standard Review Plan criteria regarding the number of operations relative to the distance from the plant for each of these airports.

Since the number of operations at each of the airports is less than the Standard Review Plan criteria, it is concluded that the airports beyond 10 miles from Indian Point may be addressed at this screening level.

Table 6.4-1
Airport Within 10 Miles of Indian Point

Airport	Distance From Indian Point (miles)
Danbury, CT	26
Greenwood, Greenwood Lake, NJ	22
Mahopac, Mahopac, NY	12
Orange County, Montgomery, NY	22
Ramapo Valley, Spring Valley, NY	13
Stewart International, NY	17
Warwick, Warwick, NY	18
Westchester County, NY	18

Table 6.4-2

Airport	Distance to IP2 Miles (D)	Maximum Annual Number of Operations	SRP Criteria ($1000D^2$)
Stewart International	17	219,000	289,000
Westchester County	18	200,000	324,000
Orange County	22	86,000	484,000
Ramapo Valley	13	720	169,000

6.4.1.3 Military Training Routes

There are no military training routes within 5 miles of the Indian Point site.

6.4.1.4 Federal Airways

There are two federal airways whose nearest edge is within 2 miles of Indian Point as shown on the aeronautical chart for the IP2 region. These airways are designated V374 and V39-374. The number of flights per day on V39-374 was estimated as 20 based on recent correspondence with the Federal Aviation Administration (Reference 6-6). Although the number of flights on V374 was not available, it should be less than 20 since a number of the flights continue on V39. We have conservatively assumed the same number of flights on the two airways. The distances from the centerline of these airways to IP2 are 3.9 miles and 4.7 miles respectively. The standard width of airways is 9.2 statute miles. The probability of an aircraft using one of these federal airways accidentally hitting the IP2 can be calculated based on the Standard Review Plan procedure as follows:

$$P = (C \times N \times A) / W$$

where

P = probability of a hit by an aircraft, per year
C = in-flight accident rate, per mile flown
N = annual number of flights on the specified airway
A = effective area of the structures which could be hit, in square miles
W = width of the airway, in miles

The area "A" which could be hit, represented by all potentially vulnerable structures was estimated in the IPPSS as not to exceed 0.01 square miles including an allowance for the shadow and skid areas. There have been no changes to the plant since that time that would change this result.

The NRC Standard Review Plan suggests the use of an in-flight accident rate (C), of 3.0×10^{-9} per mile flown. The SRP also suggests that the width of the aircraft hit area (used to calculate aerial crash density) be taken as the width of the airway. This corresponds with the assumption of uniform hit density throughout the entire width of the airway. The standard airway width (W) is 8 nmi which is 9.2 statute miles.

Using these values, the probability of an aircraft hit resulting from accident on the airways was calculated as $3.0 \times 10^{-9} \times (20 + 20) \times 365 \times 0.01/9.2 = 4.8 \times 10^{-9}$ per year. Even if the aircraft impact is conservatively assumed to lead directly to core melt, the calculated probability of such aircraft impact is less than the NUREG screening criteria.

Based on the above, it is concluded that the aircraft impact does not contribute significantly to the IP2 core damage frequency and can be screened out in accordance with the NUREG criteria.

6.4.2 Other Transportation Accidents

No changes relative to the IPPSS analysis were observed regarding the location of rail, road and shipping routes or the traffic on these routes which might be carrying any hazardous materials. Therefore, the IPPSS conclusion that the potential transportation accidents do not significantly contribute to core damage frequency was expected to still remain valid.

6.4.2.1 Rail Transportation

The nearest rail facilities are located about 0.9 miles west and 0.6 miles east of the plant site. These Conrail lines carry freight, including a variety of hazardous chemicals and explosive materials such as propane. However, the safe stand-off distance for the railroad traffic from the plant structures is 2,282 feet, according to Regulatory Guide 1.91. The closest distance to the rail lines from the plant is 3,168 feet, which is larger than this stand-off distance. Therefore, IP2 meets the SRP requirements so far as the rail transportation is concerned and this event can be screened out (Screening Level 3 of Figure 6.0-1).

The hazard from transportation of toxic chemicals on Conrail near IP2 is addressed in Section 6.4.2.4.

6.4.2.2 Road Transportation

The nearest major road is New York Highway 9 extending north/south and located between one and two miles east of the plant site. Interstate I-684 and I-87, which are each more than 15 miles away from the plant serve to relieve industrial traffic from Highway 9. Highway 9 does carry some truck traffic which may, on occasion, transport hazardous materials. However, the distance to the road is much larger than the safe stand-off distance of 1,651 feet given in Regulatory Guide 1.91. Therefore, IP2 meets the SRP requirements so far as the road transportation is concerned and this event can be screened out (Screening Level 3 of Figure 6.0-1).

6.4.2.3 Barge Traffic

The potential consequences of accidents involving barges on the Hudson River are overpressure on IP2 structures, systems and components due to explosion, fire at the shoreline and release of toxic chemicals.

Petroleum products shipped on the Hudson River near IP2 were conservatively estimated in the IPPSS to be about 600 tankers and 2,600 barges on an annual basis. The annual probability of a large, rapid spill resulting in a fire at the shoreline was calculated as ranging from 1.0×10^{-9} to 1.0×10^{-6} per year. It was determined that such a fire would not affect any equipment that would preclude a safe shutdown and it was, therefore, concluded in the IPPSS that a fire due to a spill from a river vessel would not pose a credible threat to the plant.

Section 6.4.2.4 discusses the effect of toxic chemical release on IP2 control room habitability.

With respect to the potential for damage due to detonation of explosive gases contained in the vapor space of river vessels, Indian Point is located on the shore of the Hudson River. Therefore, potential explosions of barges on the Hudson River cannot be screened out using the safe standoff distance given by Regulatory Guide 1.91. Consistent with NUREG-1407, an analysis was then performed of the frequency of such explosions which could threaten the plant.

Data from the U.S. Department of Transportation (Reference 6-7) shows the total cargo ton-mileage carried on all U.S. domestic waterways during the years 1979 and 1984 to be about 9×10^{11} per year. The same reference gives the total number of accidents (i.e., marine casualties) involving tank barges as about 4,000 per year. It should be noted that Part 4.05 of 46 CFR defines a notice of marine casualty as whenever any of the following occur:

a) All accidental groundings and any intentional grounding which also meets any of the other reporting criteria or creates a hazard to navigation, the environment, or the safety of the vessel;

b) Loss of main propulsion or primary steering, or any associated component or control system, the loss of which causes a reduction of the maneuvering capabilities of the vessel. Loss means that systems, component parts, sub-systems, or control systems do not perform the specified or required function;

c) An occurrence materially and adversely affecting the vessel's seaworthiness or fitness for service or route, including but not limited to fire, flooding, or failure or damage to fixed fire extinguishing systems, lifesaving equipment, auxiliary power generating equipment, or bilge piping systems;

d) Loss of life

e) Injury causing a person to be incapacitated for a period in excess of 72 hours

f) An occurrence not meeting any of the above criteria but resulting in damage to property in excess of $ 25,000. Damage to cost includes the cost of labor and material to restore the property to the service condition which existed prior to the casualty, but does not include the cost of salvage, cleaning , gas freeing, drydocking or demurrage.

Therefore, not all the marine casualties lead to a loss of vessel integrity. In a study of ammonia barge accidents, NUS (1985) evaluated the conditional probability of tank rupture per marine casualty for tank barges of 1,000 tons and above as about 1×10^{-3}.

The frequency of barge accidents leading to tank rupture is therefore calculated to be:

$$\frac{4000 \text{ accidents/yr}}{9 \times 10^{11} \text{ ton miles/yr}} \times \frac{1 \times 10^{-3} \text{ ruptures}}{\text{accident}} = 4.4 \times 10^{-12} \text{ ruptures/ton-mile}$$

From the US Corps of Engineers Waterborne Statistics (Reference 6-8), total quantities of flammable material handled by the Port of Albany and presumably transported past IP2 on Hudson River are:

Gasoline	2,230,980	tons
Jet Fuel	216,413	tons
Naptha	40,307	tons
Kerosene	153,524	tons
Fuel Oil	3,187,833	tons

Specific data on the actual sizes of shipment and the number of shipments does not exist. None of the above material in liquid form is explosive. If there is a rupture of the tank barge, the most realistic scenario will be spill of these petroleum products. In a few instances, it could catch fire and burn. For an explosion to occur which could impact shoreline facilities, the vessel would have to contain a substantial inventory in vapor form in a confined space and be subjected to a sudden, high pressure impact. Empty tankers containing gasoline vapor may explode if involved in a collision; but the effect on shoreline structures would be minimal because the peak incident overpressure developed in such an explosion would be very small. Therefore, it would be extremely conservative to assume that the total quantity of gasoline shipped in tank barges near Indian Point, i.e., 2,230,980 tons could all result in an explosion which could threaten the plant. We have, instead, assumed that ten percent of these barges would be empty or partially full (with remaining space having gasoline in vapor form) and subjected to an event which could detonate a sufficient quantity of explosive vapor to threaten the plant (i.e. produce an overpressure of 1 psi at the plant site).

The maximum size of the vessel used in shipments along the Hudson River is not known; based on the 5,000 ton river vessel size which is specified in Regulatory Guide 1.91, we have determined a safe standoff distance of about 2 miles. Since the IP2 structures are close to the Hudson River, we have conservatively included barge explosions occurring anywhere along a stretch of 4 miles on the Hudson River near the plant in our calculation.

Using these assumptions, the frequency of barge accidents which could result in overpressures exceeding 1 psi at IP2 is calculated as:

$$4.4 \times 10^{-12} \frac{\text{ruptures}}{\text{ton-mile}} \times 2{,}230{,}980 \frac{\text{tons}}{\text{year}} \times 10^{-1} \frac{\text{explosions}}{\text{rupture}} \times 4 \text{ miles} = 3.9 \times 10^{-6} \frac{\text{events}}{\text{year}}$$

Exceedance of 1 psi overpressure at the plant structures does not lead directly to a core damage event. The structures housing vital equipment are largely shielded from direct exposure to the pressure wave. Therefore, the conditional core damage frequency resulting from barge explosions on Hudson River can be reasonably judged to be less than 10^{-1}, thus allowing this hazard to be addressed by use of previous analysis and NUREG-1407 Screening Level 4.

6.4.3 Gas Pipeline Accidents

There are two underground natural gas transmission lines (26-inch and 30-inch diameter) passing through the Indian Point site about 1,000 feet from the closest Unit 2 plant structures. Using actual industry data and information specific to these pipelines, the IPPSS conservatively calculated the frequency of a failure of these pipelines which could pose a hazard to the plant as about 5×10^{-7} per year. This value, if it remains valid for this examination is less than 1×10^{-6} and would allow this event to be screened out.

The Algonquin Gas Transmission Company which operates these pipelines was contacted as part of the IPEEE to obtain an update on the performance and service history of the pipelines. The response is provided in Reference 6-9 and is summarized below:

- The 26 inch pipeline that passes through the IP2 site was also retested after installation. (IPPSS stated that only similar sections of 26 inch line were retested.)

- Pressure relief valves are no longer used at valve sites and have been replaced with line pressure monitors at various locations. Automatic shutoff controls have recently been removed from all valve sites due to their history of false closures. With an effective emergency response plan in place and the use of a Supervisory Control and Data

Acquisition (SCADA) system, quick response to line breaks is expected, which is considered more reliable than the automatic shutoff controls previously in place.

- For the section of pipeline in the vicinity of IP2, vehicle patrol inspections of the pipeline near vehicle access points are now performed on a weekly basis. (At the time of IPPSS, the inspection frequency was once a month.)

Based on the updated information obtained during this examination, the analysis provided in the IPPSS was considered to remain applicable, and allows this postulated event to be screened out.(Screening Level 4 of Figure 6.0-1).

6.4.4 Release of Toxic Chemicals

A number of chemicals stored at the plant were identified in the IPPSS for their potential explosion, fire and toxic effects on the plant structures and control room personnel. The treatment in the IPPSS was qualitative and took credit for an ongoing evaluation and any resulting mitigating actions.

Subsequent to IPPSS, Con Edison conducted a toxic and hazardous chemical survey of both stationary facilities, and road, rail and waterborne shipping in a five mile radius of Indian Point Unit 2. A decrease in the number of manufacturing facilities using hazardous materials in the area was noted since the last survey made in 1981. The Kay-Fries facility in Stony Point was closed and the chemicals removed in 1988 eliminating potential sources of hydrogen cyanide and other hazardous chemical emissions.

Analysis of the survey results by Rudell & Associates (Reference 6-10) indicated that the two major potential hazardous chemical emission sources are a ten-ton carbon dioxide (CO_2) cylinder at Indian Point No. 3 and a one-ton chlorine (Cl_2) cylinder at Peekskill Sewage Disposal Plant. Using "worst case" chemical release conditions, a "puff" diffusion model was used to estimate the gas concentration over time at the control room air intake. With the control room normal air exchange rate of 0.6 volumes per hour, the estimated maximum control room gas concentrations are less than 1% of CO_2 and less than 1 ppm of Cl_2.

Rudell & Associates report also stated that Conrail no longer transports hazardous chemicals on the local rail routes. There is no evidence the waterborne shipments have changed since 1981, when the only chemical frequently transported was sodium hydroxide, which is not vapor-toxic.

Based on the Rudell & Associates' study and the plant walkdown, it can be concluded that no stationary or mobile hazardous chemical sources are present which could release airborne toxic chemicals in sufficient quantities to exceed the maximum two-minute concentration in the control room.

Per the requirements of Regulatory Guide 1.95, to protect the operators of a Type I control room against an accidental chlorine release, quick response chlorine detectors located in the fresh air inlets should be able to detect and signal a chlorine concentration of 5 ppm. The Cl_2 gas detectors would actuate low-leakage dampers installed on the upstream side of recirculation fans or other locations where negative systems pressure exists and where in-leakage from chlorine - contaminated outside air is possible.

The external event of toxic chemical release from onsite and offsite sources is not considered to pose any credible threat to IP2 and is screened out at screening level 3 (since RG 1.95 and hence *standard Review Plan is met) in Figure 6.0-1.*

6.5 OTHER EVENTS

The screening process followed in NUREG-1407 and the supporting documents (Budnitz and Kimura, 1987; Kimura and Prassinos, 1989, Ravindra and Banon, 1985) were reviewed in light of IP2 specific information. The objective was to determine if there was any known reason to believe that the generic screening of events done in NUREG-1407 is not applicable to IP2. In addition, any known external hazards that may have a potential to damage IP2 were examined. Examples of these are instances of high river debris and turbine missiles. The external hazards and the screening criteria listed in the PSA Procedures Guide (Reference 6-2) were used to ensure that all potential external hazards were considered. The generic basis and IP2 specific basis for each external hazard are described in Table 6.5-1.

Based on the above, the specific NUREG-1407 events were determined to be applicable and there were no other plant-unique external event found to pose any significant threat of a severe accident.

Table 6.5-1
Screening of External Events for Indian Point Unit 2

Event	Generic Basis	Specific Applicability for IP2
Seismic Events	NUREG-1407 requests a detailed examination for seismic events.	ConEdison is performing the IPEEE for seismic events using the seismic PRA method.
Internal Fire	NUREG-1407 requests a detailed examination for internal fires.	ConEdison is performing the IPEEE for internal fires using the PRA method.
High Winds and Tornadoes	NUREG-1407 requests that this event be examined in the IPEEE. A progressive screening approach is recommended. If the plant does not meet the NRC current criteria (described in the 1975 version of the Standard Review Plan), more detailed examination is required.	Previous study on IP2 indicated that wind design does not meet the Standard Review Plan criteria. This event was also studied in the IPPSS. Further examination is conducted in the IPEEE.
External Floods	NUREG-1407 requires that river flooding be evaluated if the plant design basis does not meet the current criteria described in Regulatory Guide 1.59; it also requires the use of the latest probable maximum precipitation (PMP) criteria which may result in higher site flooding levels and greater roof ponding loads than have been used in the previous design bases.	Previous study (IPPSS) indicated that the plant grade (Elevation 14.0' and higher) is well above the Probable Maximum Flood and Probable Maximum Hurricane surge levels on the Hudson River near IP2. This conclusion is reviewed and the effect of local PMP evaluated in the IPEEE.

Table 6.5-1 (Continued)
Screening of External Events for Indian Point Unit 2

Event	Generic Basis	Specific Applicability for IP2
Transportation and Nearby Facility Accidents	NUREG-1407 requires that older plants need systematic examination for plant-specific vulnerabilities from these events.	IPPSS had examined the impact of potential accidents on the transportation routes (i.e., Rail road, aircraft, highways, barge traffic, and gas pipelines) and concluded that their contribution to core damage frequency is negligible. The traffic and accident statistics were reviewed for any changes to this conclusion as part of the IPEEE.
Lightning	The primary impact of lightning on nuclear power plants is the loss of offsite power which is included as part of the internal events IPE. The NRC staff has judged that the probability of a severe accident caused by lightning (other than one due to loss of offsite power) is relatively low and further consideration of lightning effects should be performed only for plant sites where lightning strikes are likely to cause more than just loss of offsite power or a scram.	Experience with lightning events at IP2 is that they led to loss of offsite power and no other effects were observed. ConEdison has no additional information to revise the findings in NUREG-1407. Therefore, lightning does not need to be considered further in the IP2 IPEEE.

Table 6.5-1 (Continued)

Screening of External Events for Indian Point Unit 2

Event	Generic Basis	Specific Applicability for IP2
Severe Temperature Transients	The effects of these events are usually limited to reducing the capacity of the ultimate heat sink and loss of offsite power. The capacity reduction of the ultimate heat sink would be a slow process that allows plant operators sufficient time to take proper actions such as reducing power output level or achieving safe shutdown. The other potential impact on the plant, loss of offsite power, will be considered within the realm of the station black out rule. Therefore, the temperature transients need not be addressed in the IPEEE.	IP2 site is not exposed to temperature transients more severe than other nuclear power plants in the U.S. Therefore, the generic data used in screening this event is applicable to IP2. Also, technical specifications control plant operation should river water or ambient temperatures go beyond design basis.
Severe Weather Storms	The potential effects of severe weather storms are loss of offsite power and station blackout; these will be addressed in the internal events IPE. Thus, severe weather storms need not be examined further in the IPEEE.	ConEdison has no unusual experience with severe weather storms at IP2 The generic basis for screening of this event, therefore applies. Apart from hurricane, tornado; and external flooding which are analyzed separately, severe weather storm effects at IP2 are limited to, at most, causing a loss of offsite power which is already analyzed as part of the IPE.

Table 6.5-1 (Continued)
Screening of External Events for Indian Point Unit 2

Event	Generic Basis	Specific Applicability for IP2
External Fires	Potential effects on the plant could be loss of offsite power and forced isolation of the plant ventilation and possible control room evacuation. Usually, external fires are unable to spread onsite because of site clearing during construction stage. The effect of loss of offsite power will be addressed on the internal events IPE. The other effects have been evaluated during operating license review against sufficiently conservative criteria; thus, they do not need to be reassessed in the IPEEE.	Site in proximity to Plant buildings is generally cleared to preclude the possibility of external fires damaging critical equipment or impacting control room operations.
Extraterrestrial Activity	The probability of a meteorite or satellite strike is estimated to be negligibly small and the event is screened out from further consideration in the IPEEE.	The generic basis is applicable to IP2.
Volcanic Activity	Nuclear plants are generally too far away from active volcanoes to expect any effect at the plant; this event need not be considered in the IPEEE.	The generic basis is applicable to IP2.

Table 6.5-1 (Continued)

Screening of External Events for Indian Point Unit 2

Event	Generic Basis	Specific Applicability for IP2
Unusually High Levels of River Debris	Biological events such as periods of unusually high river debris are screened out in the external event PRA based on the observation that the events are slow to occur and provide adequate warning for remedial action.	Periods of unusually high levels of river debris in the Hudson River occur twice in a year and could increase the normal plugging rate of the service water pump Zurn strainers. ConEdison has recently installed Ristroph Screens in front of the SWS Pumps which significantly reduce plugging of the strainers. Recent experience seems to support a conclusion that with the new Ristroph screens in place, the generic basis for screening this event is applicable to IP2.
Turbine Missile	Based on the regular inspection of low pressure turbine discs and overspeed protection system followed by the utilities, the probability of turbine failure leading to missiles is considered acceptably small. Therefore, turbine missile need not be considered further in the IPEEE.	IP2 turbines have integral rotors and are maintained regularly. A Westinghouse Owners Group report (Rodibaugh and Tran, 1993) shows that the destructive overspeed probability is less than $1x10^{-5}$ per year and therefore the frequency of turbine missile damage to the plant leading to core damage is judged to be less than $1x10^{-7}$ per year. Screening out of turbine missiles from the IPEEE is applicable to IP2.

6.6 GENERIC ISSUE 103 - PROBABLE MAXIMUM PRECIPITATION (PMP)

6.6.1 Purpose

Section 6.2.2.3 of NUREG-1407 requested that licensees assess the effects of applying the new Probable Maximum Precipitation (PMP) criterion which is provided in Generic Letter 89-22 (Reference 6-11) to their plants in terms of onsite flooding and roof ponding to determine whether it would lead to severe accidents. Neither Generic Letter 89-22 nor NUREG-1407 provide guidance regarding frequencies to be applied to the PMP events, making it difficult to derive a true perspective on the risk associated with these events. Nevertheless, the following summarizes an analysis of these "worst case" scenarios.

6.6.2 Hazard

As defined in HMR No. 52, dated August 1982, PMP is "theoretically the greatest depth of precipitation for a given duration that is physically possible over a given size storm area at a particular geographical location at a certain time of the year. (This definition is a 1982 revision to that used previously ... and results from mutual agreement among the National Weather Service, the U.S. Corps of Engineers, and the Bureau of Reclamation.)".

Probable Maximum Precipitation is addressed in at least three documents by the U.S. Department of Commerce, National Oceanic and Atmospheric Administration, U.S. Department of the Army Corps of Engineers and U.S. Nuclear Regulatory Commission as follows:

> Hydrometeorological Report No. 51, Probable Maximum Precipitation Estimates, United States, East of the 105th Meridian, June 1978
>
> Hydrometeorological Report No. 52, Application of Probable Maximum Precipitation Estimates, United States, East of the 105th Meridian, August 1982
>
> Hydrometeorological Report No. 53, Seasonal Variation of 10-Square-Mile Probable Maximum Precipitation Estimates, United States, East of the 105th Meridian, April 1980

The Indian Point 2 site was evaluated for six storm events, one of which was a 100 year - 24 hour Storm Event which is intended to be used as a benchmark for comparison purposes. The six storms analyzed were as follows:

PMP (in.)	Duration (Min.)
6.0	5
9.3	15
13.3	30
17.5	60
33.0	24 Hours
8.0	24 Hours (100 Year - 24 Hour Storm Event)

The 1 hr PMP rainfall depth, as shown above, was derived from Figure 24 of HMR 52. This figure is the basis for calculating the shorter duration rainfall depths based on Figures 36 through 38 of HMR 52. The all-season PMP for a 24-hour period was derived from Figure 20, HMR 51. Each storm event had relevance to the study and unique characteristics. The five and fifteen minute storms, in most cases, created the greatest rate of run-off from the subcatchment areas. The storm event from which the peak flooding elevations were calculated varied from the thirty minute event to the 24 hour event.

The benchmark analysis and 24 Hour PMP analysis were accomplished using the USDA Soil Conservation Service TR-20 analysis method. The shorter duration analyses were completed using the Rational Method.

6.6.3 Method

The PMP analysis provides the locations and maximum depths of ponds which form on the roofs of various site structures, and in various areas around the site. The roofs were evaluated by converting the water depth to a loading and comparing with the allowable roof loadings. The effect of ponding in areas around the site were evaluated by first determining if water could potentially flood any safety related equipment given the maximum expect pond depths. This evaluation is provided in Section 6.6.4.1. Where the potential for such impacts existed, and were not clearly bounded by previous internal flooding risks, or otherwise able to be shown not to be risk significant, a more detailed evaluation was done. Only one area required this treatment and is discussed in Section 6.6.4.2. Results of the internal flooding analysis were used to determine the results of flooding areas containing safety related equipment.

The stormwater model accounted for subcatchments, reaches and ponds. Subcatchments are the land area and building surface area that collect rainfall and contribute runoff to a point of concentration. The drainage reaches represent culverts, drainage ditches and subsurface drainage. In most cases, a reach is either a culvert or a swale. Ponds are areas of significant water accumulation. The subsurface structures were considered to be no longer effective when the storm event exceeded the 100 year - 24 hour event.

6.6.4 Summary of Results

6.6.4.1 Roof Ponding

As mentioned above, the roofs were evaluated by converting the water depth to a loading and comparing with the allowable roof loadings. The buildings which contain safety related equipment and which were also considered to be susceptible to ponding are the Primary Auxiliary Building (PAB), the Auxiliary Feedwater Building (AFW), the IP2 Turbine Building (TB) and the Control Building (CB). Using the maximum allowable live loading for these buildings, an equivalent maximum allowable height of water accumulation was calculated and compared against the maximum height of accumulated rainfall on those buildings determined for each of the PMP storms. The results are shown in Table 6.6-1.

Table 6.6-1
PMP Roof Ponding

Building	Maximum Allowable Water Buildup (feet of water)	Worst Case PMP Buildup (feet of water)
Primary Auxiliary Building	1.1	0.4
Auxiliary Feedwater Building	1.1	0.9
Turbine Building	1.3	1.3
Control Building	1.6	**

** There is no significant parapet on the Control Building roof above the Unit 2 Control Room and electrical equipment and ponding is therefore precluded.

Although the Turbine Building roof could experience loading at or close to yield, given the conservatisms in the hazard calculation, the likelihood of yielding, if any, being localized and the remaining margin between yield and actual failure, it was judged that the structure would retain its integrity. All other buildings were well below their maximum allowable height.

6.6.4.2 Ponding at Grade

Based on the hazard analysis, the following areas experience ponding at grade due to one or more of the PMP situations:

Ponding in Transformer area:	Pond	#3	0.7 feet
Ponding in Transformer area exit:	Pond	#4	0.7 feet
Ponding NW of Unit 2 behind 4 Story Bldg & Retaining Wall	Pond	#5	0.7 feet
Depth of flow west of T/G Building:	Reach	#6	0.3 feet
Ponding NW of Unit 1, South of EDG Building:	Pond	#10	1.9 feet
Ponding SW of Unit 1:	Pond	#12	1.0 feet
Ponding East of Chemical Systems Building:	Pond	#13	1.8 feet

These areas were reviewed to determine the potential for affecting safety related equipment.

Pond No. 3 represents buildup of water in the area east of the Turbine Building containing the Station and Unit Auxiliary Transformers (Transformer Area). The following exterior building openings will see some head of water from this pond. The bottom of the openings are approximately at grade, or slightly above grade:

- Double doors on the west side of the PAB (columns 1 and C)
- Exterior door of the Radiation Monitor Enclosure
- Exterior door on the south side of the AFW building
- Double doors on the north side of the control building

Water which enters the PAB from leakage through the west side doors could potentially damage the RHR pumps which are below grade at elevation 15'-O". Since the PMP event is not postulated to cause an initiating event (except a possible plant trip) and the plant can be safely maintained in a hot shutdown condition without the RHR pumps for an extended period, this event is bounded by the not considered risk significant. No other critical equipment exists in the area below the top of the pond.

The radiation monitor enclosure does not contain any safety related equipment, therefore flooding in this area is not a concern.

The maximum allowable depth of flooding in the AFW building is 14" above the floor, governed by the bottom of the AFW pump motors. The floor level is approximately 2 inches above grade at the south end of the AFW Building. The maximum height of Pond No. 3 is 8.4 inches (0.7 feet). Therefore flooding from Pond No. 3 in the AFW building is not a concern.

Leakage could occur into the 480V Switchgear Room which is located at 15' Elevation of the Control Building through the double doors on the north side of the Control Building. Intrusion of water into this room is evaluated in Section 6.6.4.2.

Pond No. 4 represents the accumulation of water at the exit from the Transformer Yard leading to the roadway at the north end of the Turbine Building. The following exterior building openings will see some head of water from this pond:

- Exterior doors on the east side and north side of the turbine building.

- Exterior door on the west side of the enclosure in the north portion of the AFW building.

Egress from this pond area will flow down the road on the north side of the turbine building towards the river. Any leakage through the doors of the turbine building will spread out over the large area of the turbine building ground floor at elevation 15'-O". The only safety related items in this area that could be exposed to water leakage are MCC's 24 and 24A. These MCC's are protected by dikes which are adequate to protect from flooding. The only adverse consequences of the in-leakage could be flooding of the 6.9 kV switchgear which could result in loss of offsite power. This has already been addressed in the internal flooding analysis for a more severe event and is therefore not a concern.

Since the PMP analysis determined that the subsurface drainage structures will become surcharged for many of the analyzed events, water from this pond area would enter the AFW Building through drain backup as well as inleakage through the exterior door. The water level in the AFW Building could therefore reach the top elevation of Pond No. 4. As discussed previously, the maximum allowable depth of flooding in the AFW building is 14" above the floor, governed by the bottom of the AFW pump motors. The floor level is approximately 5 inches above grade at the exterior door leading to this pond area. The maximum height of Pond No. 4 is 8.4 inches (0.7 feet) above grade. Therefore flooding from Pond No. 4 in the AFW building is not a concern.

Pond No. 5 is located at the intersection of the Unit 2 reactor building and steel building enclosure which constitutes the north portion of the AFW building. There are two blocked off wall louver openings on the east side of the building. The bottom of the openings are 4" above grade at this location, based on field inspection. The pond would reach a height of approximately 4" above the bottom of the openings, and water could seep in through the blocked openings. The results of this water intrusion would not govern the level of water inside this area, however, since the water in the enclosure will reach the level of Pond No. 4 due to backup in Manhole No. 5 which is located within the enclosure.

Reach No. 6 represents the area west of the turbine building and is a large paved area which slopes to the west towards the Hudson River. It is expected that there will be sheet flow in this area and no significant ponding. The maximum depth of flow is approximately 4 inches. There are several exterior door openings on the west side of the turbine building that may be susceptible to leakage. The sheet flow, however, is in the direction away from the openings towards the river, therefore the leakage contribution from this area to the turbine building ground floor will not be significant. The path of the sheet flow going to the river is partially blocked by the intake structure which contains safety related equipment (service water pumps, strainers and associated electrical equipment). This area is protected by an exterior wall which is above the level of the sheet flow, therefore the intake structure will not be adversely affected.

Pond No. 10 represents the area south of the EDG Building. The only safety related equipment in this area is in the diesel generator building. The highest elevation of Pond No. 10 is 71'-11". Since the bottom of the exterior door openings are above this elevation, water from this pond will therefore not affect the diesel generator equipment.

The areas represented by *Pond No. 12* (Southwest of Unit 1) and *Pond No. 13* (East of Unit 1) do not contain any safety related equipment.

6.6.4.2.1 Pond No. 3 Impact on 480V Switchgear Room

On the basis of the foregoing PMP analysis, one area was identified for further evaluation. Water may enter the 480V Switchgear Room under the following scenarios:

a) Ingress through the gap under the exterior double doors could occur due to ponding in the transformer area.

b) Should the subsurface drainage system becomes surcharged and not allow free flow of Control Building roof drainage, some or all of the flow from the control building roof drains (which would normally exit through the manhole) could be diverted into the switchgear and deluge rooms through the floor drains (which are tied together for those two rooms).

Based on fluid flow calculations assuming both of the above conditions exist, (i.e. ingress through the double doors from a maximum PMP flood accumulation of 0.7 feet in the transformer yard and full diversion of roof drains into the switchgear room), the level in the switchgear room could reach a height where it could impact safety related equipment in approximately 68 minutes without operator action. It should pointed out that opening of either of the doors from the switchgear room into adjacent plant areas on the 15' elevation would provide a sufficient egress path to handle all inleakage. It is highly unlikely that a full hour would pass prior to operator presence in the room, and the probability of such a "theoretical maximum" event is believed to be low enough that failure of the switchgear due to an unmitigated flood in this room could be shown not to be risk significant. As pointed out previously, however, the frequencies of the postulated PMP events have not been provided, precluding a meaningful quantification of this scenario. We, therefore, intend to modify the double doors to minimize the gap. The remaining leakage, together with the maximum backup from the roof drains will result in a maximum steady state level in the room below the critical height.

One additional potential flooding scenario was postulated. The outlet drain for the combined control building roof and switchgear room/deluge room drains connect to a dedicated transformer yard manhole. The pipe into the manhole is furnished with a flapper valve. If the flapper valve on the drain outlet were to fail in the open position, and a PMP condition occur such that the drainage system were surcharged, water could back up into the switchgear and deluge rooms directly from the manhole. A physical inspection of the condition of the flapper valve was made and the valve was found to be fully functional, moved easily on its clevis pin and was free of obstruction. The valve normally sits firmly on its seat and opens only a slight amount for normal drainage. It was judged that the probability of the valve being substantially off its seat and sticking open such that substantial back leakage could occur is low enough to preclude this from being risk significant scenario. Nevertheless, this valve has now been included in the periodic surveillance schedule of the plant preventive maintenance program. In addition, screens are being placed over the four equipment drains in the room to preclude the possibility of foreign material entering the drain line which could act as an obstruction to valve closure.

6.7 REFERENCES

6-1 Consolidated Edison Company, Indian Point Unit 2 Probabilistic Safety Study (IPPSS), including Amendments 1 and 2, 1982 and 1983.

6-2 "Probabilistic Safety Analysis Procedures Guide, NUREG/CR-2815 Vols. 1 and 2," U.S. Nuclear Regulatory Commission, August, 1985

6-3 Ramsdell, J.V. and G.L. Andrews "Tornado Climatology of the Contiguous United States", NUREG/CR-4461, PNL-5697, Pacific Northwest Laboratory, Richland, Washington 99352, May, 1986

6-4 Twisdale, L.A. and Dunn, W.L. "Extreme Wind Risk Analysis of the Indian Point Nuclear Generating Station," Research Triangle Institute Report 44T-2491, Addendum to Report 44T-2171 March 1983 for Pickard, Lowe and Garrick, Irvine, California

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6-5 Garson, R.C., Catalan, J.M., and Cornell, C. A., "Tornado Designs Wind Based Risk," Structures Publication No 397, Department of Civil Engineering, MIT., August, 1974.

6-6 Letter, dated November 18, 1994, from John S. Walker, Manager Air Traffic Division, Federal Aviation Administration

6-7 U.S. Department of Transportation, "National Transportation Statistics Annual Report, 1986" DOT-TSC-RSPA-86-3, Research and Special Programs Administration, Transportation Systems Center, Cambridge, MA July 1986

6-8 U.S. Army Corps of Engineers (1989) "Waterborne Commerce of the United States," WRSC-WCUS-89-1

6-9 Letter dated February 21, 1994, from C. P. Fantasia, Algonquin Gas Transmission Company, Boston, Massachusetts

6-10 Rudell & Associates, Inc., "Control Room Habitability Study: Toxic Chemicals Impact," prepared for Consolidated Edison Company Indian Point No. 2 Nuclear Generating Station, June 10, 1991

6-11 "Potential for Increased Roof Loads and Plant Area Flood Runoff Depth at Licensed Nuclear Power Plants due to Recent Change in Probable Maximum Precipitation Criteria Developed by the National Weather Service,"USNRC Generic Letter 89-22, October 19, 1989

LICENSEE PARTICIPATION AND INTERNAL REVIEW TEAM

7.1 IPEEE PROGRAM ORGANIZATION

The organizational structure for the Indian Point 2 IPEEE effort is provided in Figure 7.1-1. Due to the close coordination between the IPEEE and the effort performed in response to Generic Letter 87-02 (USI A-46), the organizational structure shown represents this integrated approach. The prime objective was to foster a utility/consultant team effort while recognizing the need for unique expertise in some areas. The organizational structure addresses the need for a coherent assignment of the technical task responsibilities with overall coordination by the NUS project manager while overall project responsibility remained with Con Edison.

Utility personnel were involved to varying degrees in all aspects of the IPEEE effort. The utility IPEEE team included members of both the onsite and corporate staff. The onsite utility team members are part of the plant organization, are permanently located within the plant facilities and have direct, continuing access to plant facilities and equipment. The corporate project lead and most of the corporate members of the project team are members of the Nuclear Power Engineering organization which is solely dedicated to support of Indian Point Unit 2 and spend a significant portion of their time at the site. Several of those engineers were A-46 qualified seismic capability engineers. The ability of Con Edison and the contract support members to interface was enhanced by the proximity of the primary contract project manager's work location to plant site and his extensive personal IP2 experience prior to this project.

Utility personnel were full participants in the data gathering effort and the walkdowns performed for each of the external events. In addition, utility personnel performed a substantial portion of the modifications made to the internal events plant model to account for external event impacts.

It should also be pointed out that the IPPSS effort, which was the foundation for the IPEEE, was also a joint effort, with substantial utility participation throughout the project. Although not members of the primary Con Edison IPEEE 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 IPEEE effort.

The objective of utility participation in the IPEEE as discussed in NRC's guidance documents is to facilitate integration of the plant specific PRA insights into plant activities. It should be noted that the onsite Con Edison IPEEE 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 IPE efforts and provides a strong link to the primary use of a PRA approach in addressing the IPEEE. We believe that our efforts to date in applying existing PRA insights and our participation in the IPE and IPEEE efforts demonstrate a commitment to the NRC's objective.

7.2 IPEEE INDEPENDENT REVIEW

The IPEEE was subjected to a multi-pronged review process. All work was performed in accordance with approved quality control procedures which provided for formal review of all work products. This review was performed by Con Edison, NUS and EQE personnel and normally involved reviews by several individuals in addition to the individual specifically tasked with the review. All comments were documented and resolved utilizing an established process.

7.2.1 IPEEE Independent Review Team

In addition to the above project reviews, two independent reviews were included in the project scope. An independent review was performed by an in-house review team. This effort drew upon experienced personnel, separate from the project team, possessing extensive plant specific experience in operations, engineering, safety and risk analysis. This review team was provided with project and task plans, analysis files and other work products. Review meetings were held with this in-house review team during which methodology, analysis and results were discussed for all of the events within the scope of this examination. The Con Edison personnel who combined to provide the IPEEE independent review are shown in Table 7.2-1.

An additional review of work products was performed by a team of industry recognized outside experts. That team was comprised of the following individuals:

Paul Smith, President, The Readiness Operation
Mardy Kazarians, Principal, Kazarians & Associates
E. Robert Schmidt, Assistant General Manager, NUS Corporation

Plant walkdowns were also performed as part of this outside expert review.

7.2.2 Review Comments and Resolution

The independent review performed for the IPEEE included:

- Project Plan
- Task Plans
- Hazard Analyses
- Fragility Determinations
- Screening Analyses
- Walkdown Results
- Modified System Models
- 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 resulting from the independent review were documented and resolved utilizing the review 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 significantly impacting the IPEEE results and insights are provided in Table 7.2-2.

TABLE 7.2-1
Con Edison Personnel Providing Independent Inhouse IPEEE Review:

Reviewer	Primary Areas of Expertise
Manager, Independent Safety Review[a]	Safety Analysis, Risk Analysis, Licensing
Chief Nuclear Power Engineer	Engineering (Electrical Specialty), Nuclear Codes and Standards
Manager, Operator Training	Operations, Normal and Emergency Operating Procedures
General Manager (formerly Civil Engineering Division Manager)[a]	Structural Engineering, Seismic Analysis, Nuclear Codes and Standards
Manager, Generation Support	Operations, Normal and Emergency Operating Procedures
Senior Project Manager, Nuclear Power Engineering[a]	Nuclear Analysis, Licensing, Engineering
Senior Engineer, Nuclear Safety[a]	Safety Assessment, Transient Analysis, Risk Analysis

(a) These reviewers were also members of the Con Edison team during performance of the original Indian Point Probabilistic Safety Study (IPPSS).

TABLE 7.2-2
Examples of Independent/Inhouse IPEEE Review Comments and Resolution

Area of Review	Comment and Resolution
Seismic	COMMENT:The details of the Control Building bumper fix installed as a result of the IPPSS should be reviewed to assure that it provides the basis for screening out this building failure mode. RESOLUTION: The as built drawings for the bumper fix were reviewed. EQE confirmed that bumper fix as installed is appropriate and is adequate to allow this failure mode to be screened out.
Seismic	COMMENT: The structures with HPCLFs below .3g should be reviewed to determine if the analysis used generic assumptions rather than plant specific design information, and if so, whether use of plant specific information could show additional capacity. RESOLUTION: The two structures with calculated HPCLFs below .3g are the RWST and Superheater Stack. The stack is unique to Indian Point and the information used was therefore required to be plant specific. The RWST used plant specific information except for anchor bolts material which assumed standard bolts. A review of documents provided information which supported the assumption that standard material was used for anchor bolts. A field walk, performed by the Civil Section of the Con Edison Nuclear Power Engineering Department confirmed this.
Seismic / Fire	COMMENT: The risk associated with random failure of the Algonquin Gas Line has been evaluated in the IPEEE. The potential for damage due to seismic induced failure of the gas line should also be addressed. RESOLUTION: This gas line runs west to east through the plant site, south of the IP3 plant. A review of drawings, discussions with Algonquin Gas Transmission personnel and specific field walks were performed to address the potential for seismic induced gas line failure. Based on the information gathered through this process, EQE evaluated the the potential for seismic induced failure and demonstrated that this failure mode could be addressed by applying the screening guidance provided in NUREG-1407.

TABLE 7.2-2
Examples of Independent/Inhouse IPEEE Review Comments and Resolution
(continued)

Area of Review	Comment and Resolution
Seismic / Fire	COMMENT: The potential for seismic/fire interaction due to failure of the Waste Gas System should be specifically addressed. RESOLUTION: Although the Waste Gas System does not provide a direct mitigating function, the potential exists that failure of the system could release a mixture of gases including hydrogen, potentially impacting other systems. The waste gas system is a seismic Class 1 system. Nevertheless, the system configuration was reviewed, including equipment location and proximity to mitigating systems. Based on this review, it was demonstrated that failure of this system would not represent a significant risk contribution.
Seismic	COMMENT: Is there any value in considering additional strength provided by the gunite lining in the Superheater Stack when determining its seismic fragility? RESOLUTION: Although the existence of the gunite lining was recognized, taking any credit for the gunite lining in the stack required assurance that the gunite is fully intact and would remain intact during the seismic event. Since there was no practical way to verify this, no credit was taken for the lining in the analysis.
High Winds / Flooding	COMMENT: The impact of recent Army Corps of Engineers (ACOE) data regarding flooding from hurricanes should be evaluated. RESOLUTION: The most recent drawing prepared for the ACOE was obtained and reviewed. The only flooding level of potential risk significance based on the maximum flooding hazard shown on those maps is associated with a Level 4 Hurricane which is not indicated for the area surrounding Indian Point. In addition, the hurricane wind speeds associated with a Level 4 hurricane have probabilities well below 1E-6 per year at the Indian Point site which would allow them to be screened out.

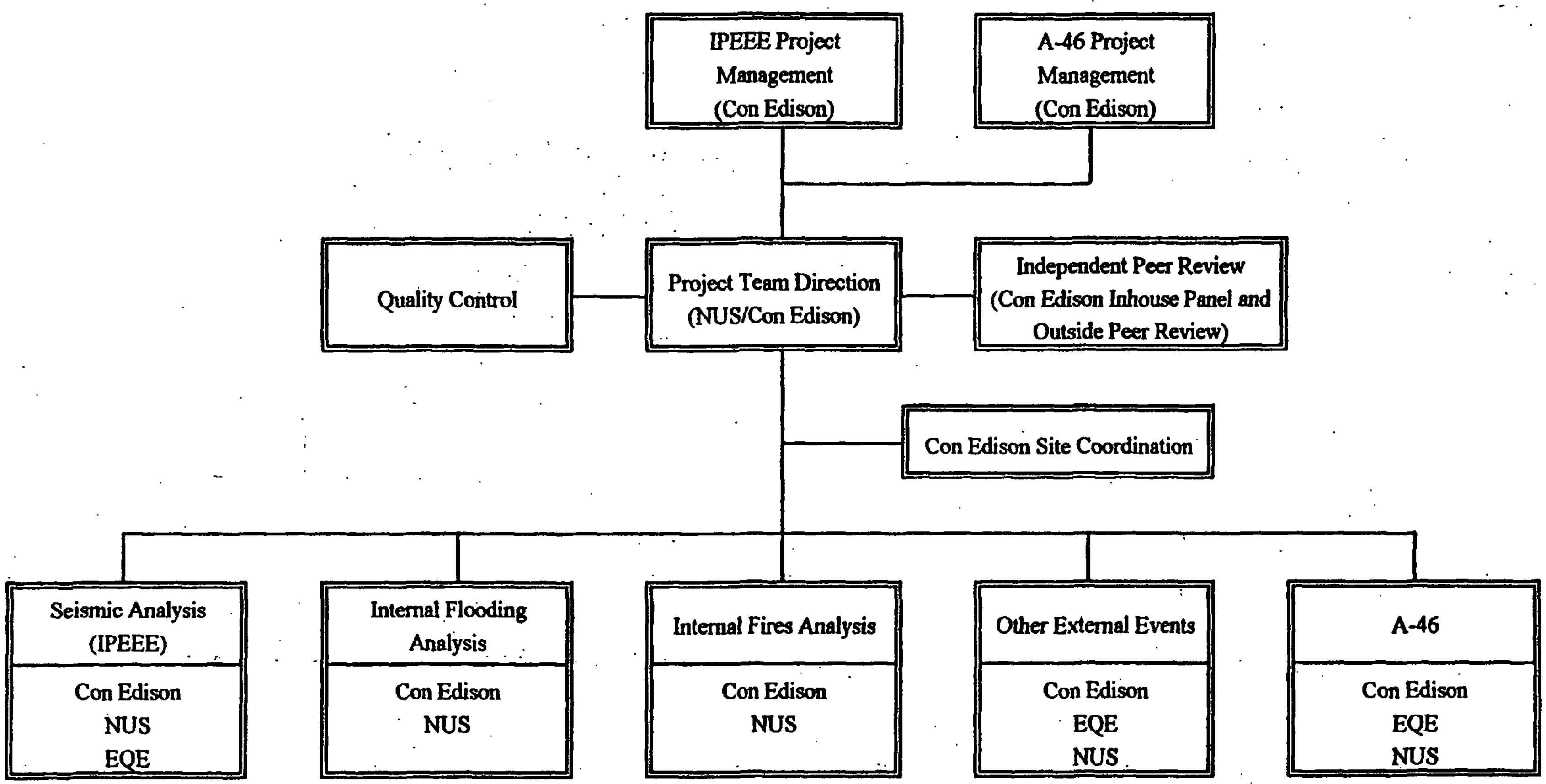
TABLE 7.2-2
Examples of Independent/Inhouse IPEEE Review Comments and Resolution (continued)

Area of Review	Comment and Resolution
High Winds	COMMENT: The potential for winds impinging on the AFW Building to damage the connections to Containment should be specifically addressed. RESOLUTION: The potential for winds impinging on the AFW Building to damage the connections to Containment was addressed in the Wind Analysis section of the original IPPSS. That analysis determined that this failure mode was not a concern. No plant or hazards changes have occurred since the IPPSS to invalidate this conclusion.
Internal Flooding	COMMENT: This analysis uses a critical height of four inches in the 480 Switchgear Room. This is not consistent with the plant design basis and should be re-evaluated. RESOLUTION: The critical height used for this room in the IPEEE was conservatively set at four inches based on a limited access field measurement and engineering judgement. The impact of using the actual critical height of six inches, was evaluated by performing a sensitivity study and determined not to change the major scenarios associated with internal flooding. The impact of the higher critical height is to provide additional time for mitigating action which would tend to improve the associated HRA values. Given the uncertainty associated with the mitigating actions, the conservative critical height was maintained in the base case analysis for this hazard.

TABLE 7.2-2
Examples of Independent/Inhouse IPEEE Review Comments and Resolution (continued)

Area of Review	Comment and Resolution
Seismic/ Flooding	COMMENT: Although the IP1 Condensate Tanks have no safety functions, they are essentially unanchored and are in the vicinity of the control building. The potential for their failure due to a seismic event impacting the control building or causing flooding damage should be addressed. RESOLUTION: The IP1 Condensate Tank design and location were evaluated. Based on this review, it was determined that the tanks could be subject to "elephant foot" type deformation at the base and potential shearing of the outlet pipe connection which is located at the center of the tank base. Movement of the tanks during a seismic event would not represent an impact threat to the adjacent structures. The tanks are in an eight foot high enclosed area, with a series of fixed IP1 ventilation louvers which lead to lower areas of the IP1 facility containing no safe shutdown equipment. Since catastrophic failure of the tanks is not expected, any water released from the tanks due to a seismic event would be directed through this path. In the unlikely event that the louvers were insufficient to relieve the tank contents, the water could rise and flow over the wall and into open areas of the IP1 facility.

Figure 7.1-1
IPEEE Organization Chart



PLANT IMPROVEMENTS AND UNIQUE SAFETY FEATURES

8.1 UNIQUE SAFETY FEATURES

Specific safety features in the design of 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. Many of those features were described in Section 6 of the Indian Point 2 Individual Plant Examination report (Reference 8-1) and included the existence of redundant systems capable of performing recirculation, the ability of the turbine driven auxiliary feedwater pump to provide secondary side cooling using manual action following loss of AC motive power or DC control power, the high capacity of the large dry containment design, and the existence of two systems, the Isolation Valve Seal Water System and the Weld Channel and Containment Penetration Pressurization System, which provide additional sealing of Containment penetrations, piping between isolation valves and Containment liner weld locations.

In addition, there are several unique features which enhance the mitigation capability of the plant following externally initiated events. The original Indian Point Probabilistic Safety Study (IPPSS, Reference 8-2) identified the value of upgrading the ability to respond to fires which could threaten the 480V buses through which power is supplied to vital equipment. As a result, the Alternate Safe Shutdown System (ASSS) was modified to more quickly and easily allow power to be provided to key shutdown equipment using power sources which bypass the IP2 control building areas which contain those buses. Although this capability was enhanced in response to a specific postulated internal fire event, this feature provides value following other events (e.g. flooding) which may threaten the 480 V buses but for which there is a potential for survival of the alternate power source.

In addition to the three Emergency Diesel Generators whose function is to provide power to vital equipment following loss of the normal offsite power feed, Indian Point 2 also has the ability to recover from a scenario where all three EDGs fail to operate following a loss of offsite power. There are three Gas Turbine Generators, one located directly on the site and two others located at an offsite facility some distance from the plant. All three of the Gas Turbines are available to the plant in the event of an emergency and can provide power to the plant through underground feeders. Power feeds from these Gas Turbines to the Indian Point 1 facility can bypass the Indian Point 2 Control Building and represent one of the alternate power sources mentioned in the previous paragraph. Since two of the three Gas Turbines are located some distance from the site, they also represent additional recovery potential for some localized tornado sequences which may damage both the incoming overhead power lines and the Emergency Diesel Generator Building.

8.2 PLANT IMPROVEMENTS

Section 9 of this report summarizes the results of the various events which were analyzed in detail in the Inian Point 2 IPEEE and evaluates the appropriate response to achieve closure by use of existing NEI guidance (Reference 8-3). Based on that evaluation, there are no outstanding vulnerabilities which merit physical modification or immediate procedural changes. The value of additional procedural changes will, however, again be reviewed as part of the Severe Accident Management Program development effort.

Since, similar to the IPE, an underlying objective of this effort is that these risk assessments be useful tools to the individual utilities, an effort was made as part of the IPEEE effort to identify areas of potential benefit. During the course of the seismic IPEEE effort, it was determined that, although the Component Cooling Water Surge Tank met its design basis, the capacity of the tank to withstand beyond design basis seismic events was limited by the capacity of the hold down bolts. As a result of this IPEEE finding, those hold down bolts were replaced by higher tensile strength bolts. As described in Section 3.1.6, this modification was primarily responsible (together with removal of a very conservative assumption regarding failure of the Fuel Storage Building), for a reduction of 29% in the calculated seismic core damage frequency. In addition, as part of the evaluation of Probable Maximum Precipitation, an additional opportunity for potential risk reduction was identified and is described in Section 6.6.4.2. Although as discussed in that section, it is believed that these scenarios would not represent significant risk contributors, since the lack of available frequency distributions for these events precluded a meaningful quantification of these scenarios, several changes were implemented to provide additional risk benefit. A drain flapper valve, located in the manhole to which the control building drains flow, has been added to the preventive maintenance surveillance inspection program. In addition, weather stripping is being added to the doors leading into the switchgear room from the transformer area to reduce the door bottom gap and screens are being placed on the equipment hub drains located in the 480V Switchgear Room to preclude foreign material intrusion.

8.3 REFERENCES

8-1 "Individual Plant Examination for Indian Point Unit No. 2 Nuclear Generating Station," Consolidated Edison Company of New York, Inc., August 1992.

8-2 Consolidated Edison Company, Indian Point Unit 2 Probabilistic Safety Study (IPPSS), including Amendments 1 and 2, 1982 and 1983.

SUMMARY AND CONCLUSIONS

9.1 INTRODUCTION

The Indian Point Unit 2 has already been the subject of a detailed comprehensive risk assessment, the Indian Point Probabilistic Safety Study (IPPSS) and associated amendments, published in 1982/83, which was reviewed extensively by the NRC and its contractors. This risk assessment included consideration of six external events, namely seismic, internal fires, internal floods, external floods, high wind, and nearby facility and transportation accidents. While accounting for the insights gained from that study, the IP-2 IPEEE represents a comprehensive revision of the external events analysis portion. Based upon the guidance provided in NUREG 1407, the most current methodology and hazard event data have been employed. Changes to the plant hardware and procedures have been identified and incorporated. The accident sequence development model presented in the IPE submittal together with updated system models have been used to calculate the resulting core damage frequencies.

In this section, the findings of the IPEEE study are summarized. The core damage frequency (Level 1) results are discussed in section 9.2. Sections 9.3 and 9.4 address the study's conclusions regarding " vulnerabilities" and the resolution of USIs and GIs, respectively.

9.2 CORE DAMAGE FREQUENCY RESULTS

Details of the core damage frequency results are presented in the preceding sections of the report pertaining to the analysis of individual external hazards. The total core damage frequency arising from each initiating event is shown in Table 9.2-1. It should be noted that the seismic core damage frequency presented represents the plant prior to the modification performed on the Component Cooling Surge Tank in which the hold down bolts were replaced with bolts possessing higher tensile strength. As discussed in Section 3.1.6 of this report, the seismic core damage frequency calculated in the sensitivity case, which includes the effect of this modification, is 1.1 E-05 per year. This would result in a revised total core damage frequency due to external events of 6.64 E-05 per year and a revised total plant core damage frequency, including internal events, of 9.49 E-05 per year.

Table 9.2-1
Summary of Core Damage Frequency Results

External Hazard	Core Damage Frequency (mean - per year)	Detailed Results Presented in IPEEE Section/Table
Seismic	1.46E-05	Section 3.1.6.4 Table 3.1-8
Internal Fire	1.84E-05	Section 4.6.3 Table 4-7 Tables 4-6a-j
Internal Flood	6.66E-06	Section 5.5.1 Table 5.5-1
High Wind	3.03E-05	Section 6.2.5 Table 6.2-11
External Floods	Screened Out	Section 6.3
Transportation and Nearby Facility Hazards	Screened Out	Section 6.4
Total CDF due to External Events	7.0E-05	
Total CDF due to Internal Events	2.85E-05*	
Total Plant CDF	9.85E-05	

* The internal events CDF is based on the current, updated plant PSA model used for this analysis and is slightly lower than the value (3.13 E-05) reported in the IPE (Reference 9-1).

9.3 VULNERABILITY SCREENING

A concise definition of "vulnerability" has not been provided in the NRC documentation associated with the performance and reporting of the IPEEE (Reference 9-2). In this study the external event induced sequences have been categorized and evaluated in accordance with the guidelines provided in the Nuclear Energy Institute (NEI) Severe Accident Closure Guidelines (NEI 91-04, Reference 9-3).

9.3.1 Seismic Hazard IPEEE Closure

The Indian Point 2 seismic induced core damage sequences have been grouped using the scheme provided in NEI 91-04, Table C-1. The description and frequency of each group is shown in Table 9.3-1. The accident sequence group frequencies have been compared to the criteria provided in Table 1 of the NEI document. The criteria provided in Table 2 of that document are not applicable in this case since no significant seismically induced bypass sequences were identified.

There are no IP2 seismic sequence groups which fall into either of the two highest frequency ranges [{>10^{-4} per year / > 50% of the total CDF} or {10^{-4} - 10^{-5} per year / 20 - 50 % of the total CDF}] which suggest the highest licensee consideration regarding potential risk reduction measures.

Indian Point 2 Seismic Sequence Groups S2 and S4 fall into the third frequency range {10^{-5} to 10^{-6}}. The suggested utility response is to incorporate this insight into the SAMGs with emphasis on prevention/mitigation of core damage or vessel failure or containment failure.

IP2 seismic sequence groups S1 and S5 fall into the lowest frequency range {< 10^{-6}} for which no specific action is required.

In conclusion application of the NEI guidelines indicates that there are no seismic sequences which require further attention at this time with respect to exploring additional mitigative measures.

9.3.2 Fire Hazard IPEEE Closure

The Indian Point 2 fire induced core damage sequences have been grouped on the basis of fire location as suggested in the NEI 91-04 guide, page 35. The description and frequency of each group is shown in Table 9.3-2.

The accident sequence group frequencies have been compared to the criteria provided in Table 1 of the NEI document. The criteria provided in Table 2 are not applicable in this case since no significant seismically induced bypass sequences were identified.

There are no Indian Point 2 Fire Sequence groups which fall into either of the two highest frequency ranges [{10^{-4} per year / > 50% of the total CDF} or {10^{-4} - 10^{-5} per year / 20 -50 % of the total CDF}] which suggest the highest licensee consideration regarding potential risk reduction measures.

Indian Point 2 Fire Sequence Groups 2A, 11, 14, 15, and 74A fall into the third frequency range {10^{-5} to 10^{-6}}. The suggested utility response is to incorporate this insight into the SAMGs with emphasis on prevention/mitigation of core damage or vessel failure or containment failure.

Indian Point 2 Fire Sequence Groups 1A, 32A, 6A, 1, 22/63A and 23 fall into the lowest frequency range {< 10^{-6}} for which no specific action is suggested.

In conclusion, application of the NEI guidelines indicates that there are no fire sequences which require further attention at this time with respect to exploring additional mitigative measures.

9.3.3 Internal Flood Hazard IPEEE Closure

No specific guidance is provided within NEI 91-04 for the grouping of internal flood core damage sequences although the document does indicate that, for all event types, any logical grouping scheme is acceptable. For this event however, sequence grouping is not necessary to demonstrate internal flood sequences do not present a vulnerability concern. Treating all flood induced sequences as a single group, the group frequency is 6.66 E-06 per year (see Table 5.5-1).

Comparing this accident sequence group frequency with the criteria provided in Table 1 of the NEI document, the utility response to the third frequency range {10^{-5} to 10^{-6} per year} is applicable. The suggested utility response is to incorporate this insight into the SAMGs with emphasis on prevention/mitigation of core damage or vessel failure or containment failure.

In conclusion, application of the NEI guidelines indicates that there are no flood induced sequences which require further attention at this time with respect to exploring additional mitigative measures.

9.3.4 High Wind Hazard IPEEE Closure

Again no specific guidance is provided within NEI 91-04 for the grouping of high wind induced core damage sequences although the document does indicate that, for all event types, any logical grouping scheme is acceptable. Since high wind hazards challenge the entire plant in a similar fashion to seismic events, it would appear logical to apply the seismic sequence grouping criteria (see Table 9.3-3). Applying these criteria to wind events, all sequences fall into either the transient with no station blackout group (W1), or the station blackout group (W2).

The accident sequence groups have been compared to the criteria provided in Table 1 of the NEI document. The criteria provided in Table 2 are not applicable in this case since no significant seismically induced bypass sequences were identified.

Indian Point 2 High Wind Sequence Group W2 falls into the low end of the second frequency range {10^{-4} to 10^{-5} per year}. The suggested utility response is to:

1) Find cost effective treatment in EOPs or other plant procedure or minor hardware change with emphasis on prevention of core damage.

2) If unable to satisfy above response, incorporate this insight into the SAMGs with emphasis on prevention / mitigation of core damage or vessel failure or containment failure.

Indian Point 2 High Wind Sequence Group W1 falls into the third frequency range {10^{-5} to 10^{-6}}. The suggested utility response is to incorporate this insight into the SAMGs with emphasis on prevention/mitigation of core damage or vessel failure or containment failure.

Thus application of the NEI guidelines suggests the need to further review the feasibility of additional mitigative measures to prevent station blackout (group W2) due to high wind events.

Reference to Table 9.3-3 indicates that 70% (2.08×10^{-5} per year) of the station blackout sequences group is as a result of damage to plant structures resulting from direct wind impingement effects (wind damage states w01 and w02). No minor plant modifications are feasible which would significantly change the capacity of the IP2 structures with respect to wind damage. With regard to procedural changes, given the lack of normal or emergency AC power, the operators are immediately directed to Emergency Procedure ECA 0.0 which clearly focuses the operators on:

1) Using the Turbine Driven Auxiliary Feedwater Pump to maintain the decay heat removal function

2) Attempting to restore power (although this would be clearly more difficult given these scenarios)

3) Shedding all unnecessary DC Power bus loads to maximize battery life

4) Ensuring successful containment isolation

Additional procedural guidance is also provided should AC power be restored (i.e. ECA-0.1 and ECA-0.2). For those cases where the control building is failed by the event, the ability of the operator to control the transient is lost, and additional procedural guidance would not increase the effectiveness of the response.

The remaining contribution to station blackout sequence group W2 (from wind damage states w10, w11, w12, w17, w18, w19 and w20) is 5.6×10^{-6} per year, which occurs as a result of wind damage coupled with missile impingement (principally on the control or EDG building) and/or coincident random equipment failures (principally of the Gas Turbines). Given the following considerations no further actions with respect to reducing the probability of these events is judged to be cost beneficial.

- o The model assumes that upon any structure being hit by a missile, all the equipment contained within that structure would be disabled. Given this simplifying assumption, the contribution from scenarios involving missile strikes is very conservative.

- A program to improve and track the availability of the gas turbines was already put in place as part of the resolution for the Station Blackout Rule for Indian Point 2. Gas Turbine Unit 2 has been upgraded to provide a black start capability.

- No minor plant modifications to defend the plant against missile strikes are feasible.

- Appropriate procedural guidance is already in place which directs operators to secure potential missiles in the site vicinity in the event of severe storm warnings (thus minimizing the probability of missile generation) and to utilize the gas turbines in the event of loss of normal and emergency AC power supplies.

9.3.5 Other External Event IPEEE Closure

The rationale for closure of this IPEEE element is to demonstrate acceptability by the process of progressive screening provided in NUREG-1407. If it can be shown that the 1975 Standard Review Plan criteria have been met or that the frequency of the original design basis hazard, combined with the conditional core damage frequency, is less than 10^{-6} the event can be considered fully addressed. For Indian Point 2, the remaining other external events were resolved as summarized in Table 9.3-4.

9.4 RESOLUTION OF USIs AND GIs

Based on the results of this IPEEE, there were no potential vulnerabilities identified for the Indian Point 2 plant. Resolution of various USIs and GIs have been addressed in the context of specific hazards throughout this study. As a consequence, the issues shown in Table 9.4-1 can considered resolved for Indian Point 2.

9.5 REFERENCES FOR SECTION 9

9-1 "Individual Plant Examination for Indian Point Unit No. 2 Nuclear Generating Station," Consolidated Edison Company of New York, Inc., August 1992.

9-2 "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities", NUREG 1407, U.S. Nuclear Regulatory Commission, June 1991.

9-3 "Severe Accident Issue Closure Guidelines", NEI 91-04 Revision 1 (formerly NUMARC 91-04).

TABLE 9.3-1
SEISMIC ACCIDENT SEQUENCE GROUP DEFINITIONS AND FREQUENCIES

Accident Sequence Group Definitions Derived From NEI 91-04 (Table C-1)		Corresponding Seismic Damage States		Seismic Accident Sequence Group Frequency
Accident Sequence Group	Definition	Seismic Induced Damage States (with corresponding structural failures)	Seismic Induced Core Damage Frequencies	
S1	Seismic Induced Accident Sequences Involving Non Station Blackout Transients	SDS 2 (R) SDS 3 (R-FC) SDS 8 (CT) SDS 9 (CT-R) SDS 19 (OP) SDS 20 (OP-FC) SDS 21 (OP-R) SDS 22 (OP-R-FC) SDS 28 (OP-CT-FC) SDS 29 (OP-CT-R) SDS 30 (OP-CT-R-FC)	7.76E-10 1.60E-08 1.03E-10 3.49E-08 4.56E-07 1.31E-10 1.44E-08 1.09E-10 2.23E-09 2.08E-07 2.24E-08	7.55E-07 (0.8% of plant CDF)
S2	Seismic Induced Accident Sequences Involving Station Blackout Transients (includes ATWS plus SBO)	SDS 35 (OP - SW) SDS 36 (OP - EP) SDS 37 (OP - IC) SDS 45 (OP-RV-SW) SDS 46 (OP-RV-EP) SDS 47 (OP-RV-IC)	9.57E-07 1.10E-06 6.20E-06 1.58E-07 2.00E-07 3.60E-07	8.98E-06 (9.1% of plant CDF)
S3	Seismic Induced Sequences Involving Medium and Large LOCAs	None	n/a	n/a

TABLE 9.3-1
SEISMIC ACCIDENT SEQUENCE GROUP DEFINITIONS AND FREQUENCIES

Accident Sequence Group Definitions Derived From NEI 91-04 (Table C-1)		Corresponding Seismic Damage States		Seismic Accident Sequence Group Frequency
Accident Sequence Group	Definition	Seismic Induced Damage States (with corresponding structural failures)	Seismic Induced Core Damage Frequencies	
S4	Seismic Induced Sequences Involving Small LOCAs	SDS 4 (S2)	1.00E-10	4.05E-06
		SDS 5 (S2-R)	9.17E-09	
		SDS 6 (CW)	9.07E-07	
		SDS 7 (CW-SC)	1.25E-08	(4.1% of plant CDF)
		SDS 10 (CT-S2)	NEG	
		SDS 11 (CT-S2-R)	NEG	
		SDS 12 (CT-CW)	1.89E-08	
		SDS 13 (SW)	NEG	
		SDS 23 (OP-S2)	1.52E-09	
		SDS 24 (OP-S2-R)	6.92E-08	
		SDS 25 (OP-CW)	2.69E-06	
		SDS 26 (OP-CW-FC)	1.28E-07	
		SDS 31 (OP-CT-S2)	NEG	
		SDS 32 (OP-CT-S2-R)	9.54E-09	
		SDS 33 (OP-CT-CW)	1.78E-07	
		SDS 34 (OP-CT-CW-FC)	2.87E-08	
S5	Seismic Induced Accident Sequences Involving ATWS events (incudes ATWS plus SLOCA sequences)	SDS 14 (RV)	5.03E-08	7.80E-07
		SDS 15 (RV-R)	2.29E-08	
		SDS 16 (RV-CW)	1.99E-08	
		SDS 17 (RV-CT)	NEG	(0.8% of plant CDF)
		SDS 18 (RV-SW)	NEG	
		SDS 38 (OP-RV)	2.00E-07	
		SDS 39 (OP-RV-FC)	2.22E-09	
		SDS 40 (OP-RV-R)	1.77E-07	
		SDS 41 (OP-RV-R-FC)	1.86E-08	
		SDS 42 (OP-RV-CW-FC)	1.67E-07	
		SDS 43 (OP-RV-CW-CT)	2.41E-08	
		SDS 44 (OP-RV-CT)	9.82E-08	

TABLE 9.3-1
SEISMIC ACCIDENT SEQUENCE GROUP DEFINITIONS AND FREQUENCIES

Accident Sequence Group Definitions Derived From NEI 91-04 (Table C-1)		Corresponding Seismic Damage States		Seismic Accident Sequence Group Frequency
Accident Sequence Group	Definition	Seismic Induced Damage States (with corresponding structural failures)	Seismic Induced Core Damage Frequencies	
S6	Seismic Induced Accident Sequences Involving Containment Bypass	None	n/a	n/a

TABLE 9.3-2
FIRE ACCIDENT SEQUENCE GROUP DEFINITIONS

Fire Zone #	Fire Zone Description	Fire Zone Core Damage Frequency
1A	Electrical Tunnel/Pipe	9.19E-07
2A	Primary Water MU Pump	1.05E-06
32A	Cable Tunnel	9.62E-08
6A	Drumming and Storage	1.53E-09
1	CCW Pump Room	2.19E-09
11	Cable Spreading Room	4.28E-06
14	Switchgear Room	3.84E-06
15	Control Room	7.07E-06
22/63A	SW Intake	7.46E-09
23	Auxiliary Feedwater Pump	6.15E-09
74A	Electrical Penetration Area	1.11E-06

TABLE 9.3-3
HIGH WIND ACCIDENT SEQUENCE GROUP DEFINITIONS AND FREQUENCIES

Accident Sequence Group Definitions Derived From NEI 91-04 (Table C-1)		Corresponding Wind Induced Damage States		High Wind Sequence Group Frequency
Accident Sequence Group	Definition	Wind Induced Damage States (with corresponding structural / random or missile failures)	Wind Induced Core Damage Frequencies	
W1	Wind Induced Accident Sequences Involving Non Station Blackout Transients	w10 (EDG Power, GT1 / AFW) w11 (EDG Power, GT2 & 3 / AFW) w12 (EDG Power / AFW) w17 (GTs 1, 2,& 3 / AFW) w18 (GT1 / EDG, AFW, Bleed & Feed) w19 (GT2 & 3 / EDG, AFW, Bleed & Feed) w20 (none / EDG, AFW, Bleed & Feed)	3.93E-06	3.93E-06 (3.99% of the plant CDF)

TABLE 9.3-3

HIGH WIND ACCIDENT SEQUENCE GROUP DEFINITIONS AND FREQUENCIES

Accident Sequence Group Definitions Derived From NEI 91-04 (Table C-1)		Corresponding Wind Induced Damage States		High Wind Sequence Group Frequency
Accident Sequence Group	**Definition**	**Wind Induced Damage States (with corresponding structural / random or missile failures)**	**Wind Induced Core Damage Frequencies**	
W2	Wind Induced Accident Sequences Involving Station Blackout Transients (includes ATWS plus SBO)	w01 (EDG Power and Control, GTs, AFW / none) w02 (EDG Power and Control, GTs / none) w10 (EDG Power, GT1 / GTs 2 & 3) w11 (EDG Power, GT2 & 3 / GT1) w12 (EDG Power / GTs 1 & 2) w17 (GTs 1, 2,& 3 / EDG Power and Control) w18 (GT1 / EDG power and Control, GTs 2 & 3) w19 (GT2 & 3 / EDG power and Control, GT 1) w20 (none / EDG power and Control, GT 1, 2 & 3)	2.54E-06 1.83E-05 5.54E-06	2.64E-05 (26.8% of plant CDF)
W3	Wind Induced Sequences Involving Medium and Large LOCAs	None	n/a	n/a
W4	Wind Induced Sequences Involving Small LOCAs	None	n/a	n/a

TABLE 9.3-3
HIGH WIND ACCIDENT SEQUENCE GROUP DEFINITIONS AND FREQUENCIES

Accident Sequence Group Definitions Derived From NEI 91-04 (Table C-1)		Corresponding Wind Induced Damage States		High Wind Sequence Group Frequency
Accident Sequence Group	**Definition**	**Wind Induced Damage States (with corresponding structural / random or missile failures)**	**Wind Induced Core Damage Frequencies**	
W5	Wind Induced Accident Sequences Involving ATWS events (incudes ATWS plus SLOCA sequences)	None	n/a	n/a
W6	Wind Induced Accident Sequences Involving Containment Bypass	None	n/a	n/a

Table 9.3-4
Resolution of Other External Events

Event	Basis for Screening	Reference IPEEE Section
External Flooding	PMF will not exceed plant grade. Frequency of hurricane surge combined with spring high tide < 10^{-6} per year	6.3
Aircraft Crash	Meets 1975 SRP Criteria	6.4.1
Rail Transportation	Meets 1975 SRP Criteria	6.4.2.1
Road Transportation	Meets 1975 SRP Criteria	6.4.2.2
Barge Traffic	Frequency of accident leading to core damage < 10^{-6} per year	6.4.2.3
Gas Pipeline Accidents	Frequency of accident leading to core damage < 10^{-6} per year	6.4.3
Release of Toxic Chemicals from Nearby Facilities	Meets R.G 1.95 and SRP Criteria	6.4.4
Other Plant Unique Events	Systematic Review Identified None	6.5

Table 9.4-1
Resolution of USIs and Gis

USI/GI	Summary of Resolution	Reference IPEEE Section
USI A45 Decay Heat Removal	Inherently considered in evaluation of all external hazards for which no vulnerabilities were identified	3.2.1 4.9 9.3
GI- 131 Potential Seismic Interaction Involving In-core Flux Mapping System	Flux mapping cart strengthened previously in response to Generic Issue. Review during IPPEE confirmed HPCLF in excess of 0.5g	6.4.1
USI A-17 System Interactions at Nuclear Power Plants	IPEEE and A46 walkdowns confirmed absence/resolution of interaction issues	3.1.3 4.1.3 5.1 6.1 IP2 A46 Effort
USI A-40 Seismic Capability of Large Safety-Related Above-Ground Tanks	IPEEE and A46 seismic walkdowns and fragility analyses demonstrated adequacy of tanks	3.1.3 3.1.5 IP2 A46 Effort
Eastern US Seismicity (Charleston Earthquake) Issue	Subsumed directly into IPEEE and addressed by use of appropriate seismic hazard curves	6.4.3
GI-57 Effects of Fire Protection System Actuation on Safety Related Equipment	Seismic plant walkdown and review of FRSS concerns	3.1.3.4 4.8.2
Fire Risk Scoping Study Issues (NUREG/CR 5088)	Application tailored checklist and walkdowns prescribed in FIVE methodology	4.8
GI 103 Design Probable Maximum Precipitation	Detailed evaluation of PMP criteria provided in GL 89-22 with respect to on site flooding and roof ponding	6.6

APPENDIX A

EXAMPLE OF DETAILED FIRE ANALYSIS

Fire Compartment A3 - Control Building and Electrical Tunnel Entrance

A1.1 Qualitative Review of Fire Zones, Sources and Targets for Fire Compartment (FC) -A3.

Fire Compartment A3 is comprised of:

Fire Zone 11 -	Cable Spreading Room,
Fire Zone 12 -	Battery Room (No. 21),
Fire Zone 13 -	Battery Room (No. 22),
Fire Zone 14 -	Switchgear Room,
Fire Zone 15/115 -	Central Control Room,
Fire Zone 24 -	Battery Room (No. 24) and
Fire Zone 32A -	Electrical Tunnel from 68' Elevation of the PAB to 33' Elevation of the Control Building.

A1.1.1 Fire Zone 11, Cable Spreading Room

Arrangement and fire protection

Fire Zone 11 is the Cable Spreading Room. This room, located on the 33' elevation of the Control Building, is rectangular in shape with an approximate floor area of 2926 sq. ft. This fire zone has common boundaries with all other fire zones within Fire Compartment A-3.. A more complete description of the geometry of this fire zone is found in Appendix B of the Fire Protection Program Plan (Reference A1-1). Fire detection for this zone includes ionization smoke detectors. The zone is equipped with manually initiated total flooding halon system. A hose station is available in the adjacent stairways and carbon dioxide extinguishers are located in the zone.

A simplified sketch of the zone is shown in Figure A1-1.

Targets

The targets in this fire zone include control power cables associated with all safety related pumps and valves as well as instrumentation cabling. At the very east end of the zone power cables associated with all safety related pumps except SW and AFW, the fan coolers and MCC 26A and B enter from the switchgear room below and exit into the cable tunnel. The static inverters, MG sets and battery chargers, with their associated wiring, are also located in this zone. The potential for a fire induced LOCA exists due to the presence of PORV control cables in the north cable tray stack and Reactor Head Vent control cables in the south cable tray stack.

Sources

The fixed fire ignition sources in Fire Zone 11 are listed in Table A1-1 and include 8 transformers, 3 ventilation system fans, 4 battery chargers, 2 MG sets and numerous electrical cabinets and panels; class A transient are also credible in this zone as discussed in Section 4.3.2. Due to the multitude and varying sizes and locations of the fixed sources, they must be individually analyzed using COMPBRN to determine if they require in depth analysis. This analysis will simultaneously consider the size of the source, as well as it's location with respect to targets or intervening combustibles. If a source is judged to be "small" with no combustible pathway to a critical target, the fire source is assumed to be insignificant.

The transformers in Fire Zone 11 are small (max. size 30 kVA) and are treated as small electrical sources (see Section 4.3.2).

The three ventilation system fans are associated with the battery room exhaust and are mounted on the north wall. The small fan motors are mounted inside their associated 12"/18" diameter ducts and are therefore judged incapable of threatening adjacent cables. No further analysis of the fans is required.

The four battery chargers and 4 inverters are treated as small electrical sources (see Section 2.1).

The bearings and coupling on the MG sets are all lubricated with insignificant amounts of grease. There are no other significant combustibles associated with the MG sets. These are also treated as small electrical sources.

The Rod Control Switchgear and Rod Drive and RVLIS cabinets are large ventilated cabinets and are thus treated as open cabinet fire sources. Many other cabinets are not ventilated and their associated cable entry is via continuous conduit. These cabinets were excluded as significant fire sources (see Section 4.3.2).

The transient combustible loads would be Class "A", (i.e. combustible fluids may not be left unattended) and by definition can be located anywhere in the zone. Detailed analyses using COMPBRN will determine the critical range for representative transient fires. Once the range of the representative transient fires is determined, floor area ratios can be calculated for areas which can and cannot cause damage.

The COMPBRN runs performed to support the analysis of this zone are summarized in Section A1.2 and A1.3. The fire scenarios are evaluated in Section A1.4.1.

A1.1.2 Fire Zones 12, 13 and 24, Battery Rooms

Arrangement and fire protection

Fire Zones 12, 13 and 24 are three of the four battery rooms. The fourth battery room, No. 23, is Fire Zone 25 located inside Fire Area J which was screened out during the qualitative analysis. These three fire zones are separate rooms located on the 33' elevation of the Control Building (i.e., same level as the Cable Spreading Room) with Fire Zones 12 and 13 sharing a common wall. The rooms are quite small, Fire Zones 12 and 13 about 200 sq. ft. each and Fire Zone 25 about 90 sq. ft., with either 8" concrete block or 12" brick walls, 2-1/2" concrete on open steelwork ceilings and 7-1/2" concrete floors.

No automatic fire protection is provided. Fire suppression may be achieved with CO_2 fire extinguishers or hoses located in the adjacent zones.

Targets

Each fire zone contains a safety related battery associated with one the four dc electrical division. There are no cable trays running in or through these battery rooms. Cable in conduit is used to connect the batteries to the DC buses in the cable spreading room (Fire Zone 11). Each room has one entry way with a 3 hour rated door which is locked during plant operation. There is no concentration of combustibles near the doors. Based on the discussion in this paragraph, fire spread from the battery room to any adjacent room is considered incredible due to the lack of combustible loading and continuity.

Sources

The batteries are also the only fixed ignition sources located in the rooms; transient fires are also credible in these rooms.

Conclusion

Fires in any of the battery rooms may disable one of four safety battery trains. Since this will not result in a plant trip, and only minimal equipment damage may be sustained, Fire Zones 12, 13 and 24 are screened from further quantitative analysis.

A1.1.3 Fire Zone 14, 480v-ac Switchgear Room

Arrangement and Fire Protection

Fire Zone 14 is the 480 VAC Switchgear Room; the room, located on the 15' elevation of the Control Building, is rectangular in shape with an approximate floor area of 2940 sq. ft. This fire zone is located directly beneath the Cable Spreading Room. A more complete description of the geometry of this fire zone is found in Appendix B of Reference A1-1 from pages 14-1 to 14-4.

Fire detection includes ionization smoke detectors. The zone is equipped with manually initiated total flooding halon system. A hose station is available in the adjacent stairways and a carbon dioxide extinguishers is located in the zone.

A simplified sketch of the zone is shown in Figure A1-2.

Targets

The targets in this fire zone include elevated power and control cables for all safe shutdown and safety related pumps. In addition, the 480 VAC switchgear, Station Service Transformers (SSTs) and a service water\containment fan cooler control panel are housed in the zone.

Sources

The fixed fire ignition sources in Fire Zone 14 include 8 transformers, 3 ventilation systems, 2 air compressors and various electrical cabinets and panels; transient and welding/cable fires are also credible in this zone.

A fire in any of the Station Service Transformers (SSTs) is assumed to result in loss of its respective bus, as well as some possible damage to overhead cables. Since these same results are expected for switchgear fires, and the likelihood of overhead cable damage from switchgear fires is expected to be greater than for the SSTs (since they are closer to the trays), the ignition source frequency for the SSTs will be included in that for the corresponding 480 VAC switchgear.

The Pressurizer Heater Transformers (PHTs) are located directly underneath the cable trays on the east side of the room carrying cables from both ESF divisions up to the Cable Spreading Room, Fire Zone 11. Due to the possibility of damaging both ESF divisions, detailed quantitative analysis using COMPBRN will be required to determine whether PHT fires will damage these overhead cables.

The three ventilation systems are three wall mounted exhaust fans, 213, 215 and 216; these fans are all located on the north wall approximately 12 feet (centerline) above the floor. This is about the same centerline elevation as the nearest targets in the room, cable trays 18B, 18X, 18Y and 19B. The horizontal distance from the fans to the nearest trays is approximately 2 feet. With respect to the horizontal separation between, and equal elevations of the fans and cable trays, fires from the 2 HP fan motors are judged to be insignificant based on their low quantity of combustible.

Two instrument air compressors, 21 and 22, are located in the southeast corner of the room. Air compressor 21 is located directly under cable tray 27B, which contains safe shutdown cable. Air compressor 22 is horizontally isolated from any safe shutdown cable or equipment by at least 10 feet. These air compressors are used as backup to the station air compressors, and are not normally operating.

There are many small electrical panels and junction boxes in Fire Zone 14. However, all are small in comparison to the 480 switchgear 2A, 3A, 5A and 6A, and would be expected to have much less of an impact on plant operations and accident mitigation. One exception to this may be the Service Water Pumps/Containment Recirculation Fans (SW/CFC) panel located on the west wall of the fire zone, which could have a severe impact due to a possible loss of all service water pumps.

Transient combustibles in this fire compartment will be limited to Class "A" fires (e.g., trash can fires). Although large spills from containers of lube oil left after maintenance activities are not considered likely (see Section 4.3.2), lube oil spill fires limited to the amount of lube oil in individual equipment reservoirs are credible.

By definition, the transient source can be placed anywhere in the zone. Detailed analysis using COMPBRN will be used to determine the critical range of a representative Class "A" transient fire. Once the range of the representative transient fire is determined, floor area ratios can be calculated for areas which can and can not cause damage.

COMPBRN analyses was performed for all non-screened fixed sources, and those damaging transient fires to determine the conditional damage probability for each source.

A1.1.4 Fire Zone 15/115, Central Control Room

Arrangement and fire protection

Fire Zone 15/115 is the Central Control Room (CCR). This room is made up of both the Unit 2 (Fire Zone 15) and Unit 1 (Fire Zone 115) Control Rooms. However the Unit 1 equipment has mostly been retired and de-energized. The CCR is located on the 53' elevation of the Control Building and is rectangular in shape with an approximate floor area of 6625 sq. ft. (3100 sq. ft. from Fire Zone 15 and 3525 sq. ft. from Fire Zone 115). The Unit 2 portion of the fire zone is located directly above the Cable Spreading Room; the Unit 1 portion is located above the terminal board room (i.e., Fire Zone 160).

The control room has a suspended ceiling composed of light fixtures and transite material. The space above the ceiling houses electrical wiring associated with the lighting.

There is no cable run in floor trenches or culverts through the control room

Fire detectors (ionization type) are installed in the supervisory panel boards and the flight panel.

Fire fighting capability includes portable CO_2 and water extinguishers, located in the CCR and a hose station located in stairwell No. 4 at the east end of the CCR.

A more complete description of the geometry of this fire zone is found in Appendix B of Reference A1-1, pages 15-1 to 15-4, and 115-1 to 115-4.

A simplified sketch of the zone is shown in Figure A1-3.

Targets

The targets in Fire Zone 15/115 include the supervisory panel, the flight panel, the auxiliary relay cabinets, the safeguards protection logic cabinets ("E" and "F"), the logic racks ("A" and "B") and auxiliary relay cabinet "G". However, unlike other plant areas, there are no exposed cable raceways.

Sources

The fixed fire sources in Fire Zone 15/115 are electrical cabinets/bench boards. Transient fire sources do not pose a significant a threat because the CCR is continuously manned and therefore the likelihood that a transient fire would not be detected and suppressed at the incipient stage is small. The general philosophy for fire evaluation of control room fires follows the approach suggested in NSAC 181 (Reference A1-2). This approach is somewhat different from that for other areas due to the need to evaluate intra cabinet fires and the question of habitability due to the production of smoke.

The analysis is discussed in Section A1.4.2.

A1.1.5 Fire Zone 32A, Electrical Cable Tunnel

Arrangement and fire protection

Fire Zone 32A is an electrical tunnel connecting the cable spreading room (Fire Zone 11) to the PAB and diesel generator room. The tunnel is approximately 10 feet wide, 8 feet high and 150 feet long, with a 90° bend about midway along the length. The tunnel begins on the 33' elevation where it connects to the Cable Spreading Room (Fire Zone 11), and gradually rises up to the 68' elevation in the PAB where it connects to Fire Zone 1A. Along the way, the diesel generator bus ducts and some conduit exit the tunnel to feed the diesel generator building. A more complete description of this fire zone is found in Appendix B of Reference A1-1.

Fire detection comprises of 5 ionization detectors in the roof of the tunnels and 76 temperature trip devices located in the cable trays. The tunnel is equipped with a closed head, pre-action sprinkler system. The deluge valve is actuated by the temperature trip devices at approximately 160 deg F (344K) and the spray nozzles are activated at 175 deg F (352K).

Targets

The targets in this fire zone include power cables for all safe shutdown and safety related components except the Auxiliary Feedwater (AFW) and Service Water (SW) pumps; and control cables for the charging (CH) pumps, AFW pumps as well as valves in safety related systems. In addition, the PORV power and control cables, and cables for safety related instrumentation run through the tunnel.

Sources

There are no fixed fire ignition sources in Fire Zone 32A; however, both transient and welding/cable fires are credible. The transient combustible loads are limited to Class "A" and by definition be placed anywhere in the zone; however, since the tunnel is basically symmetric along its length, the position of the fire is relatively unimportant.

COMPBRN was used to predict the probability of cable damage prior to suppression.

A1.2 COMPBRN Bounding (Point Estimate) Analysis for FC-A3

Case 11-SEF-1

This case was run to determine minimum vertical separation distance between the small electrical sources and cable trays located directly overhead. The analysis was performed assuming a constant 100kW source for 30 minutes and a conservative cable damage temperature of 623K. The source and target were situated in proximity to a wall for additional conservatism. The analysis indicated no damage will occur providing the source is located at least 1.7 meters (5.5') above the source.

Case 11-SEF-2

This case was run to determine minimum horizontal separation distance between the small electrical sources and a horizontal cable tray. The analysis was performed assuming a constant 100kW source for 30 minutes and a conservative cable damage temperature of 623K. The source and target were situated in proximity to a wall for additional conservatism. The target was located adjacent to the source at mid flame height. The analysis indicated no damage will occur providing the source is separated from the tray by at least 0.2 meters (0.7') (i.e. edge of source to edge of tray).

Case 11-TRN-1

This case served two purposes; (i) to determine minimum vertical separation distance between the transient fuel source and cable trays located directly overhead, and (ii) to determine the minimum horizontal separation distance between the source and electrical cabinet. The analysis was performed assuming a constant 600 Btu source for 10 minutes and a conservative cable damage temperature of 623K. The criteria for cabinet damage was assumed to be 10kW/m2. The source and target were situated in proximity to a wall for additional conservatism. The analysis indicated no damage to the overhead tray will occur providing the source is located at least 2.4 meters (7.9') above the source. No damage to the cabinet will occur providing the minimum separation distance is at least 1.0 meter (edge of fire to wall of cabinet).

Cases 14-AC-65 and 14-AC-2

These cases were run to determine the damage range of lube oil spill fires from the instrument air (IA) compressors. Both IA compressors lube oil sumps have an approximate capacity of 6.5 gallons. The IA compressors, Nos. 21 and 22, are located in the southeast corner of Fire Zone 14. They are physically separated from the 480 V switchgear, and most cable trays containing safe shutdown and/or safety related cables; however, cable tray 27B (which does contain safe shutdown and safety related cables) runs directly over compressor #21, and the area covered by postulated lube oil spills from either compressor may be sufficient to overcome the physical separation that currently exists between the compressors and the 480 V switchgear.

Case 14-AC-65 models a 6.5 gallon lube oil spill which is allowed to fully spread before it is ignited, thereby producing a pool of lube oil covering approximately 650 ft^2. A spill this size would have an effective radius of about 14-1/2 feet. Assuming that targets within this radius are damaged with a probability equal to unity, it can be shown that compressor #21 fires would damage SST 6 thereby conservatively failing switchgear 6A, and compressor #22 fires would not directly damage any equipment or cable serving safe shutdown systems.

Case 32A-2

This case was run to determine the potential for a class "A" transient combustible fire located in the center of the control building electrical tunnel to damage both cable trays stacks. The model is identical to that performed PAB electrical tunnel with the exception that a hot gas layer was allowed to form due to the confinement within this part of the tunnel. No damage was sustained to either cable tray stack.

A1.3 COMPBRN Uncertainty Analysis for FC-A3

Uncertainty analyses were performed for fires originating in the rod control switchgear, and the RVLIS cabinets in the cable spreading room and for the switchgear cabinets located in the switchgear room.

Case 11-RSG-T

The rod control switchgear cabinet has open ventilation ports and exposed cable entries at the top of the cabinet. Multiple cable trays are routed over the cabinet, the closest being only 2' above. The COMPBRN analysis used a ramped fire source having a maximum heat release profile as described in Section 4.3.2. The heat release rates associated with the cabinet fire is also modeled as a range of possible values between the maximum of 1150kW and a minimum of 575kW. The assigned parameter distributions allow cable ignition and damage temperatures to vary over a prescribed range.

The cumulative probability of damage and mean time for each target cable tray is given in Table A1-2.

Case 11-RCW1T

The rod control cabinet has open ventilation ports at the top of the cabinet. Multiple cable trays are routed over the cabinet, the closest being only 4' above. The cabinet fire source was identical modeled for the rod drive switchgear. The cumulative probability and mean time of damage for each target cable tray is given in Table A1-3.

Case 11-RVL-T

Both the back and front of the RVLIS cabinet are completely open and the south cable tray stack passes directly overhead approximately 5' above the cabinet. The north - south cross zone trays serving "A" logic racks may also be exposed. The cabinet fire source was identical modeled for the rod drive switchgear. The cumulative probability and mean time of damage for each exposed target cable tray is given in Table A1-4.

Case 32A-1

This case was developed to model the potential for damaging the cable trays located in the control building electrical tunnel when a class "A" fire is placed directly under one of the cable tray stacks. A hot gas layer was allowed to form in the zone due to the additional confinement in this in this part of the electrical tunnel. Damage and burning of the cables directly exposed occurred. However no damage was sustained to the cables in the opposite stack. The probability of damage to cables in the exposed stack ranged from 0.4 to 1.0 depending upon the elevation.

A1.4 Results of Detailed Fire Evaluation for FC-A3

The results of the detailed analysis performed for the cable spreading, switchgear room control room and electrical tunnel are presented below. Fires in other zones included in compartment A3 (battery rooms) were screened out judgementally after due consideration of the combustible loadings and potential fire impact (see Section A1.2).

A1.4.1 Fire Zone 11 Cable Spreading Room

Screening of transient and fixed sources

The arrangement of this fire zone was previously described in Section A1.1.1. The results of the bounding COMPBRN analyses for small electrical ignition sources and transient fuel sources are presented in Section A1.2. These results were used to screen out specific sources and targets based on the predicted damage range and a detailed survey of the location of sources with respect to targets. The results are follows:

(i) floor based transient sources are screened out with the exception of those located in proximity to critical electrical cabinets or vertical cable risers. The minimum height of the cable tray and conduit is 10' and 9' 6" respectively, both of which are greater than the critical vertical separation distance of 7' 9".

(ii) all fixed ignition sources with the exception of the Rod Control Switchgear, the Rod Drive Cabinet and the RVLIS cabinet (which are classified as large cabinet fires) were screened out on the basis that the sources are completely closed or the closest target is outside the damage range (see Table A1-1).

Evaluation of risk from unscreened transient sources:

The frequency of transient fires (including those initiated by welding and cutting) in the cable spreading room is 4.41E-04/yr. The general approach for evaluating transient fires is to determine the conditional probability of the fire being located in a critical location such that damage can occur:

Vertical cable tray risers passing through the floor of the CSR are as follows:

T56D (12" wide)	T58B (36" wide)	T82F (18" wide)
T02D (12" wide)	T32A (24" wide)	T48D (24" wide)
T49D (12" wide)	T64A (24" wide)	

The horizontal damage range for Class A transient fires exposing vertical trays was examined using COMPBRN (Section A1.2, Case 11-TRN-1). The critical horizontal separation distance is 4.3' (1.35m).

Assuming the tray is against a wall, the area in which the transient fire must be located in order to cause damage for a tray of width T_W is therefore:

$$T_W \times 1.35 + 2 \times (\pi)(1.35)^2/4$$

Therefore total critical location area for transient fires damaging cable trays in CSR is:

For 3 12" trays,	area =	$9.8m^2$
For 3 24" trays,	area =	$11.0m^2$
For 1 18" tray,	area =	$3.47m^2$
For 1 36" tray,	area =	$4.08m^2$
Total		$28.4\ m^2$

The horizontal damage range for cabinets is approximately 3.1' (1.0m) (see Section 3.2.2, case 11-TRN-1). The cabinets in the CSR which are required for safe shutdown include MCCs 29, 29A, and 26C, battery chargers 21, 22, 23 and 24 and DC power panels 21, 22, 23 and 24. Loss of a single cabinet is not significant and is bounded by the internal events analysis (e.g. loss of a DC bus initiating event). The total critical area for cabinet damage is estimated to 12.2 m^2. The total transient critical location area is, therefore, 28.4 + 12.2 = 40.6 m^2

The total unoccupied floor area of the cable spreading room is 272.5m^2. Therefore the conditional probability of a transient fire being located in a critical area based on an area ratio is 40.6 m^2 / 272.5 m^2 = 0.148

A preliminary, highly conservative analysis was performed assuming all such fires resulted in the worst case room damage. The bounding estimate of the total CDF due to transient combustible in the cable spreading room is 4.14E-04 x (0.148) x 4.0E-02 = 2.5E-06/yr. Since this very conservative approach yields a result which is not an insignificant contribution, a less conservative (more realistic) approach was desirable. One approach, defining the consequences more precisely at each possible transient location, would have involved predicting the extent and rate of fire spread in vertical cable trays, something which COMPBRN does not do very well. Another approach, which was implemented in this case, was to predict the likelihood of suppression prior to damage or secondary ignition. The transient fire contributions were broken down into those initiated by welding and cutting and those which were initiated by other mechanisms. In the former case case, there is a good chance that fires would be quickly extinguished by a fire watch or person performing the hot work. An evaluation of the probability of manual suppression in this case is given in Section 4.5 and a value of 0.15 assigned. The resulting frequency of transient fire scenarios is evaluated in Table A1-5. The subsequent core damage frequency evaluation assumes worst case fire damage scenario in the zone.

Evaluation of risk from unscreened fixed sources

The frequency of fire in electrical cabinets fires (excluding the battery chargers which are treated as separate source) in the cable spreading room is 1.6E-03. The frequency of fires in the unscreened cabinets was determined on the basis of the ratio of their base area relative to the base area of all cabinets in the room. The results are as follows:

FF(Rod Control Switchgear) = 2.9E-04/yr
FF(Rod Drive Cabinet) = 5.5E-04/yr
FF(RVLIS Cabinet) = 1.2E-04/yr

<u>Rod Control Switchgear Cabinet Fire Scenarios (A3-1A and A3-1B):</u>

Based on COMPBRN analysis for fires in the rod drive switchgear, which is summarized in Table A1-2, two distinct fire damage scenarios may be defined:

The trays closest to the switchgear, E07C and E08C (termed east-west trays) are damaged within the first 2-3 minutes and subsequently ignite. Damage to these trays is not significant since only SAS circuits may be disabled. The first scenario, designated A3-1A, occurs within the initial 8-9 minutes (predicted mean time) of the fire growth period and results in damage to north-south trays crossover trays which pass directly over the cabinet. The probability of damage given no suppression is 1.0. The resulting damage to safe shutdown components is limited to that equipment which is controlled from the flight panel including the PORVs and Block Valves. Although the charging pump speed controllers are located on the panel, in the event of damage the pump flow will decrease to the minimum setting which is sufficient to provide RCP seal injection. Offsite power may also be lost due to the failure of the DC power sources (D21A and D21B) to the auxiliary and startup transformers, which is located in the Flight Panel.

Based on drills the response time of the fire brigade to this fire zone is considered to in the range of 5-10 minutes. Fire detection may occur either as a result of the actuation of smoke detectors located in the cable spreading room and electrical tunnel, or more likely, as a result of a trouble alarm associated with a malfunction of the control rod drive system. An electrical fault may well precede fire growth by several minutes. Since the chance of early detection is deemed to be high and the time to damage falls in the range of brigade response times, 0.5 is assigned as the probability of successful suppression prior to damage for this scenario.

The second fire scenario, designated A3-1B, may occur in the event that the fire is sufficiently intense and not suppressed in time to prevent damage to the north cable tray stack. The probability of such damage is less than .01 (see Table A1-2). In addition to the damage sustained in fire scenario A3-1A, control power associated with the AFW pumps and valves as well as the charging system valve alignment may be disabled. In this scenario the mean time to damage is 11 minutes. Given the damage time is beyond the longest fire brigade response time, 0.9 will be assigned as the probability of successful fire suppression prior to damage.

The frequency of each scenario is evaluated in the fire growth event tree shown as Figure A1-4.

Rod Drive Cabinet Fire Scenarios (A3-2A, A3-2B, A3-3A and A3-3B)

The rod drive cabinet is approximately 27' long and runs east to west. The targets are the south cable tray stack which runs over the entire cabinet length, and a series of north to south cross trays run at right angles to the cabinet. The potential impact of fires on the south tray is identical regardless of where the fire occurs in the cabinet. However the specific north to south cross trays affected are highly dependent upon the location of the fire within the cabinet. The north to south cross trays can be grouped as follows:

East End	T52F, T53F, T55F, T58F T59F	Serve Flight Panel (damage may impact PORVs and Block valves)
Middle	T21H, T62F T65F, T66F	Serve Lighting Bus, "D" & "C" logic racks (no impact on safe shutdown)
West End	T68F, 69F T71F	Serve "B" logic rack (which may impact AFW and PORVs)

It was therefore assumed that 50% of the fires in the Rod Drive Cabinet are capable of exposing trays at the east end of the cabinet and 50% are capable of exposing trays at the west end. COMPBRN analysis again indicated that the ROD drive control cabinets at either end of the cabinet may be further subdivided.

Fire scenario A3-2A occurs at the west end of the cabinet and damages the vertical sections of the north-south cross trays within the initial 9 minutes (predicted mean time) of the fire growth period. The probability of damage given no suppression is 1.0. (see Table A1-3). This results in damage to the equipment controlled from the flight panel namely the PORV cables, as discussed earlier. Since the chance of early detection is deemed to be high (for reasons discussed under scenario A3-1A) and the time to damage falls in the range of brigade response times, 0.5 is assigned as the probability of successful suppression prior to damage for this scenario.

Within the initial 10-11 minutes of the initial fire growth period the north to south cross trays will also be damaged (given the fire is unsuppressed). The probability of damage given no suppression is .63. As a result the EDG auxiliaries, charging pumps and all components supplied from the MCCs 26A and 26B are assumed to be disabled. Since the time to damage exceeds the longest anticipated response time based on drills, a 90% probability of successful suppression prior to damage is assigned in this case. The frequency of fire scenarios A3-2A and A3-2B are evaluated in the fire growth event tree shown as Figure A1-5.

Fire scenario A3-3A occurs at the east end of the cabinet and damages the north-south trays in that region. The probability and timing is similar to that at the east end. However damage to trays in this region results in loss of AFW and PORV control (see Table A1-6). A second fire damage scenario may develop due to fires at the east of the cabinet (designated A3-3B). Given the fire is unsuppressed and sufficiently intense, the south cable tray stack serving EDG auxiliaries and MCCs 26A and B may also be damaged. The probability of damage given no suppression is again .63 and the mean time to damage is 10-11 minutes. A 90% chance of suppression prior to damage is assigned.

The frequency of fire scenarios A3-3A and A3-3B are evaluated in the fire growth event tree shown as Figure A1-6.

RVLIS Cabinet Fire Scenarios (A3-4A)

The south cable trays stack passes directly over the RVLIS cabinet and there is a small chance (less than 1%) that it may be damaged given a fire in this cabinet. There is also a small chance that north-south cross tray serving the "A" logic racks may be damaged. In both cases the mean time to damage exceeds the longest anticipated fire brigade response time by a considerable amount and therefore a 90% probability of successful suppression prior to damage is assigned. A single fire damage scenario A3-4A is evaluated with damage consequences identical to fire scenario A3-3B. The frequency of fire scenario A3-4A is evaluated in the fire growth event tree shown as Figure A1-7.

The cable spreading room fire scenario frequencies are summarized in Table A1-5 and their contribution to core damage frequency evaluated as discussed in Section 4.6 of the main report.

A1.4.2 Fire Zone 14 Switchgear Room

Screening of transient and fixed sources

The arrangement of this fire zone was previously described in Section A1.1.2.

The results of bounding COMPBRN analyses for small electrical ignition sources and transient fuel sources are presented in Section A1.2 and A1.3. These results were used to screen out specific sources and targets based on the predicted damage range and a detailed survey of the location of sources with respect to targets. The results are follows:

(i) Floor based transient sources are screened out with the exception of those located in proximity to critical electrical cabinets. The minimum height of the cable tray or conduit is 8' respectively, whereas the critical vertical separation distance based on a conservative evaluation is 7'9".

(ii) The fixed fire ignition sources in Fire Zone 14 include the four 480v-ac buses, 4 Station Service Transformers (SSTs), 4 Pressurizer Heater Transformers (PHTs), 3 wall ventilation fans, 2 air compressors and various small electrical sources. All fixed ignition sources with the exception of the 480v-ac busses and SSTs, and the compressors were screened out on the basis that the sources are completely closed or the closest target is outside the damage range.

Evaluation of risk from unscreened transient sources:

The frequency of transient fires in the switchgear room is 4.41E-04/yr.

The general approach for evaluating transient fires is to determine the conditional probability of the fire being located in a critical location such that damage can occur.

The horizontal damage range for cabinets is 3.1' (1.0m) (Section 3.2.2, case 11-TRN-1).

The cabinets in the CSR which are required for safe shut down include the SSTs, the emergency busses and the service water/fan cooler control cabinet. Loss of single cabinet, with the exception of the service water/fan cooler control cabinet is not significant and is bounded by the internal events analysis (e.g. loss of a 480vac bus). The location of a transient fire which is capable of damaging two or more cabinets was therefore determined and critical area ratios determined. Critical area ratios and resulting scenario frequencies were as follows:

Region	Scenario	Damage State	Critical Location Area Ratio	Scenario Frequency
1	A3-13A	Buses 5A,6A,2A,3A	42/2779 = .015	6.62E-06
2	A3-13B	Buses 6A and 5A	77/2779 = .028	1.23E-05
3	A3-13C	Buses 2A and 3A	77/2779 = .028	1.23E-05
4	A3-13D	Buses 2A and 5A	14/2779 = .005	2.21E-06
5	A3-13E	Buses 3A and 6A	14/2779 = .005	2.21E-06
6	A3-13F	Buses 2A, 3A and SW/Fan Coolers	60/2779 = .021	9.52E-06

The fire scenario frequencies are summarized in Table A1-5.

Evaluation of risk from unscreened fixed sources

The entire cabinet ignition source frequency for the switchgear room is divided between the 4 emergency busses and the SW/CFC control panel. Switchgear 2A and 6A are each made up of 7 sections, while 3A and 5A are each made up of 6 sections. Including the SW/CFC panel, there are a total of 27 cabinet sections. Assuming that a fire is equally likely to occur in any section, the electrical cabinet ignition source frequency can easily be divided into 5 fire scenarios. Switchgear 2A and 6A fires each receiving 7/27 (25.9%)of the fire frequency; 3A and 5A each receiving 6/27 (22.2%) of the cabinet; and the SW/CFC panel receiving 1/27 (3.8%) of the frequency. These percentages will be included as the area ratios in the calculation of the fire damage state frequencies for these scenarios.

Total cabinet fire frequency is 7.50E-03. The fire frequency for each source is therefore determined as follows:

Source	Area Ratio	Fire Frequency
Bus 2A	.259	1.94E-03
Bus 3A	.222	1.67E-03
Bus 5A	.222	1.67E-03
Bus 6A	.259	1.94E-03
SW/FCU Cabinet	.038	2.85E-04

A fire is assumed to be equally likely to occur in any one of the 8 transformers located in the fire zone. The total transformer fire frequency is 2.43E-03. Therefore the individual SST fire frequency is 3.04E-04. Two instrument air compressors, 21 and 22, are located in the southeast corner of the room. Their associated fire frequency is 5.9E-04.

480v-ac Bus and Associated SST (Fire Scenarios A3-7, A3-8, A3-9 and A3-10)

Fire originating in each bus/SST combination are treated as one fire scenario. The immediate impact of such a fire is possible loss of power from the bus itself. However, this damage is not significant and is bounded by the internal events analysis for loss of a single bus. However, if the fire is not extinguished additional damage to overhead trays may occur. The mean time to damage (of the lowest tray is 5-6 minutes) .. see case 14-W-C. Since this time falls within the anticipated response times of the fire brigade based on drills, 0.5 is assigned as the probability of successful suppression prior to damage. A fraction of the fires may also self extinguish. Based on the data provided in the FEDB, 3 of the 19 switchgear fires and none of the transformer fires self extinguished. Thus 16% of the switchgear fires are assumed to self extinguish.

In addition to loss of all components supplied from Bus 2A due to fire originating in that bus or SST2, damage to overhead trays may result in the following (Scenario A3-7):

- o Loss of power from BUS 5A
- o Loss of MCC26C
- o Loss of EDG 22 supply to Bus 3A
- o Loss of redundant control power to Bus 3A

- o Loss of control power for CHP 22 and 23
- o Loss of control power to SW pumps 22, 25

In addition to loss of all components supplied from Bus 3A due to fire originating in that bus or SST3, damage to overhead trays may result in the following (Scenario A3-8):

- o Loss of power to FCU23
- o Loss of MCC29A
- o Battery Charger 22.
- o Loss of EDG 22
- o Loss of control power for SI pump 22
- o Loss of control power for FCU 25
- o Loss of control power to SW pumps 22, 25 and 26

In addition to loss of all components supplied from Bus 5A due to fire originating in that bus or SST5, damage to overhead trays may result in the following (Scenario A3-9):

- o Loss of power to CCW Pump 22
- o Loss of MCC26C
- o Loss of redundant control power Bus 3A
- o Loss of control power for CHP 23

In addition to loss of all components supplied from Bus 6A due to fire originating in that bus or SST3, damage to overhead trays may result in the following (Scenario A3-10) (see Appendix D3):

- o Loss of power to AFW pump 21
- o Loss of power to CHP 22
- o Loss of power to battery charger 22
- o Loss of power to FCU 23 and 24
- o Loss of power to RHR pump 21
- o Loss of power from Bus 3A

<u>Service Water /Fan Cooler Control Panel (Fire Scenario A3-11)</u>

This is a small electrical cabinet which is not ventilated and has cable entries in conduit.

It does not represent a significant fire source to external targets. However, fires in this cabinet may disable control power for all SW pumps and Fan Cooler units.

Air Compressor 21 (Fire Scenario A3-12)

Two types of compressor fire can occur; motor winding fires and oil /grease fires. The former fire size is equivalent to a small electrical source and would not cause damage to other equipment since the separation distances exceeds the damage range (see case COMPBRN 11-SEF-1 and 11-SEF-2).

The compressor contains approximately 6.5 gals of oil and a fire involving an oil spill may result in damage to cable tray 27B located directly above as well as to Bus 6A (see case COMPBRN 14-AC-65). In addition to loss of equipment supplied by bus 6A, the following equipment may be lost due to damage to tray 27B.

- o CCW pump 22
- o SI pump 22
- o Battery charger 22
- o MCC 26A
- o MCC 26C
- o DG Bldg Ventilation Distribution Panel #2

The fraction of compressor fires involving lube oil is determined from the FEDB (Reference A1-3) to be .02 and thus the frequency of this scenario is 5.9E-04 x .02 = 1.18E-05 per year.

Air Compressor 22

Air Compressor 22 fires will not damage any equipment or cable serving safe shutdown systems and thus no scenario is assigned.

The switchgear room fire scenario frequencies are summarized in Table A1-5 and their contribution to core damage frequency evaluated as discussed in Section 4.6 of the main report.

A1.4.3 Fire Zone 15/15 - Central Control Room

The arrangement of the fire zone was previously described in Section A1.1.4

The approach follows that described in NSAC 181 and has the following unique characteristics compared with typical fire zone analyses:

1) Regardless of the level of damage which is actually sustained as a result of a fire, the production of smoke may necessitate the evacuation of the control room. Under such circumstances the operators will evacuate the CCR room and shutdown the plant using the alternate safe shutdown capability in accordance with Abnormal Operating Procedure 27.1.9.

2) Deterministic fire propagation modeling is not be performed since there are no available intra or inter cabinets computer fire models. Given no timely suppression the entire contents of a cabinet will be assumed damaged in the event of a fire. However, cabinet fires in the control room will not spread from the confines of the cabinet in which they originate to adjacent cabinets providing the cabinets have intervening double metal or fire resistant boundaries. This is supported by the results of the Sandia cabinet fire tests in which all test fires self extinguished, and by the reports of control room fires in the Fire Events Database.

The evaluation of control room fires requires the analyst to determine those cabinets or combination of connected cabinets in which enclosed fires might cause significant degradation of accident mitigating systems. In particular, the location of fires which might cause a LOCA due to spurious PORV operation must be identified. Fire scenarios in such cabinets are evaluated individually. Fires in the remaining cabinets are evaluated as a group for their potential to cause the operators to evacuate the control room and shutdown the plant using the ASSS. The methods for frequency analysis, propagation analysis and suppression analysis are discussed below:

<u>Frequency Analysis:</u> A list of major electrical cabinets was compiled from the CCR layout drawings. With the exception of the supervisory panel each cabinet listed is physically separated from the others according to the criteria defined in (2) above. Despite the fact that they are not physically separated from one another, individual sections within the supervisory panel are listed separately to facilitate more refined analysis which is discussed below.

The frequency of fire in each individual cabinet/section is then determined as a fraction of total cabinet fire frequency for the CCR (9.5E-3/yr). A weighting factor is applied for each cabinet based on the floor area it occupies relative to the total floor area occupied by all cabinets in the CCR. This approach attempts to account for the relative number of potential ignition sources in cabinets of different sizes.

Propagation Analysis: In the propagation analysis, three stages of fire growth are defined:

Pre-ignition

The only ignition sources present within the electrical cabinets occur due to electrical overload resulting from a faulted component. If the damage can be confined to the site of the overload (i.e. the faulted component or associated wiring) the resulting impact will be bounded by the random failure of the component itself, which has already been accounted for in the internal events IPE model. Despite the lack of physical separation of redundant components and wire ways within individual cabinets, the potential for significant damage is highly unlikely prior to flame ignition. Sandia cabinet fire tests (Reference A1-4) indicate a five minute time lapse between an in-cabinet fire detector detecting smoke to the point where actual flames were observed (see A1-7).

Thus for CCR cabinets which have in-cabinet detectors, namely the supervisory panel and the flight panel, an initial five minute time window for manual suppression is accounted for in modeling the risk from control room fires. No significant damage is postulated within this time period. During this phase ignition may be prevented by de-energizing the faulted component and /or applying CO_2 extinguishers located in the control room.

For other CCR cabinets (which do not have in-cabinet smoke detectors), no credit is given for detection or suppression during this period. (Historically, all 12 control room fires experienced at US plants have been extinguished without significant damage).

Pre-Fire Growth

Once ignition of a fire occurs in a particular section of a cabinet, it is generally assumed that all components served by that section of the cabinet are failed. Furthermore, components served by adjoining cabinet sections which are not physically separated according to the criteria described above are assumed to fail unless the fire can be extinguished prior to any significant fire growth and heat production.

Again the evidence from the Sandia cabinet fire tests can be used to establish the time required for the onset of fire growth. These tests indicate that between 8 to 10 minutes elapsed between initiation of the in-cabinet smoke detector and significant heat generation (10-20 kW). The tests also indicate that once fire growth begins it may progress rapidly, with an equally rapid rise in cabinet air temperature. Thus, credit will be given for preventing fire propagation to inter-connected cabinet sections within the first 9 minutes after the in-cabinet detectors initiate. Once the fire has propagated to other cabinet sections all functions associated with the cabinets are assumed to fail.

In the case of the supervisory panel, the individual cabinet sections are butted side-to-side with a corridor down the middle. Full height partial walls exist between neighboring sections separating the cables. Cables servicing each section come up through the floor of both the front and rear panels and traverse overhead. There are very few cables which cross over to other sections. Therefore, damage is assumed to be limited to components served by individual supervisory panel sections during this pre-growth phase. Propagation around the partial walls of the cabinet sections will only occur in the event that the fire is not extinguished within the 9 minute period after the in-cabinet detector alarms. Since the panel is 46' long it would be extremely conservative to assume that once the fire begins to grow, all equipment served by the panel would be disabled regardless of where the fire starts. Instead the cabinet is divided into 3 regions:

The western region which includes 3 cabinet sections (SJ, SH and SG) containing the controls for significant safe shutdown and safety related equipment.

The eastern region which also contains 3 cabinet sections (SC , SB-1 and SB-2) containing controls for significant safe shutdown and safety related equipment.

The center region which is 11' long and separates the east and west regions. This section includes SF, SE and SD which do not house any controls for significant safe shutdown and safety related equipment.

A growing fire in the western region is assumed to damage all components served by the cabinets in that region but not spread to the eastern region. Similarly a growing fire in the eastern region is assumed to damage all components served by the cabinets in that region but not spread to the western-eastern region. Since the center region adjoins both the eastern and western regions, fires in the center region are assumed to result in loss of control of all equipment controlled from the entire supervisory panel.

The flight panel consists of individual front sections which are partitioned from one another but open to the rear section. The rear sections are completely open to one another and many cables cross them. Thus, although the flight panel is fitted with in-cabinet detectors, due to the lack of clearly defined separation, all components served by the flight panel are assumed to be failed during the pre-growth period.

Since none of the other CCR cabinets have in-cabinet fire detection (and no attempt was made to establish whether any inter-section separation exists), all components served by the cabinets were assumed to be failed during the pre-growth period.

Obscuration of CCR due to Smoke

The Sandia cabinet fire tests indicate that fires could be self-sustaining and produce sufficient quantities of smoke to cause visual impairment with purge rates as high as 14 room changes per hour. All of the actual control room fires in the FEDB were small but this may have been because they were extinguished early. Since there are no tools available for assessing smoke production and the evidence from the historical fires is not conclusive, it will be assumed that any fire is capable of producing sufficient smoke given it is allowed to continue burning for a sufficient period of time.

The Sandia cabinet fire tests included two electrically initiated fire in large enclosures (48000ft^3). In both cases the control board was obscured 19.5 and 15.5 minutes after smoke was first observed (which corresponded to the actuation of the in cabinet detector) (see Table A1-7). The room ventilation rates in one case was 1 room change per hour, and in the other 8 changes per hour. The volume of IP-2 CCR is approximately 3 times as that of the test enclosure.

Thus, although detection of fires in the IP-2 cabinets which are not fitted with detectors may be slower than that achieved in the Sandia tests, the additional volume of the CCR compared with the test enclosure will more than compensate to ensure that at least 15 minutes is available to suppress a fire prior to a need for evacuation.

Having abandoned the CCR, it is assumed that safe shutdown will be attempted utilizing the ASSS system. (Note: Given a major fire in IP-2 control room portable smoke removal equipment and, if necessary, breathing apparatus would be utilized, which would most likely negate the need to abandon the control room completely.)

Suppression Analysis

The probability and extent of component damage is dependent upon the probability of non suppression during the pre-ignition, pre-growth and pre-control room evacuation phases. The probability of non suppression of control room fires as a function of time is obtained using a model to interpret the control room fire durations in the EPRI data base. Such a model is developed in the EPRI Fire PRA Implementation guide (Reference A1-5, Appendix J]. The probabilities of non-suppression derived from the model (case 1 is recommended) are as follows:

p(non suppression within 5 minutes) = 1.2E-01

p(non suppression within 9 minutes) = 2.2E-02

p(non suppression within 15 minutes)= 3.4E-03

Based on the above discussion fire scenarios were developed for control room cabinets using a simple fire growth event tree approach. Fire growth event trees are shown as follows:

Supervisory panel fires	Figure A1-8
Flight Panel	Figure A1-9
CVCS logic cabinet (JG6-JG7)	Figure A1-10
RCS Pressure Control Logic (JF6-JF8)	Figure A1-11
Feedwater Control Logic (JF4-JF5)	Figure A1-12
Fire in other CCR cabinets which do not contain safe shutdown equipment	Figure A1-13

Scenarios A3-15C, D, E, H, I, J and K represent fire scenarios in the individual supervisory panel sections which are successfully suppressed pre-fire growth. The only damage sustained is to equipment served by the particular section in which the fire originates (see Table 4-6f).

Scenarios A3-16A, B, C represent a fire in the tree regions of the supervisory panel (eastern western and center which is not suppressed prior to fire growth but is successfully suppressed prior to control room evacuation. In this case, all equipment served by the sections within the supervisory panel region is assumed to be disabled (see Table 4-6f).

Scenario A3-18 represents a fire in any of the flight panel sections which is not suppressed during pre-ignition or growth but is suppressed prior to control room evacuation. In this case, all equipment served by the flight panel is assumed to be disabled which is shown in Table 4-6f.

Scenarios A3-19, A3-20, A3-21 represent fires which originate in CVCS logic, RCS Pressure Control logic or Feedwater logic cabinets which are not suppressed during pre-ignition or growth but are suppressed prior to control room evacuation. In this case, all equipment served by the particular cabinet in which the fire originates is assumed to be disabled (see Table 4-6f).

Scenario A3-17 represents a fire in any cabinet in the CCR which is not successfully suppressed prior to the need for control room evacuation. In this case the only safe shutdown equipment assumed to be available is that associated with the ASSS.

The fire scenario frequencies are evaluated in the individual fire growth event trees and summarized in Table A1-7. The control room fire scenario frequencies are summarized in Table A1-5 and their contribution to core damage frequency evaluated as discussed in Section 4.6 of the main report.

A1.4.4 Fire Zone 32A Electrical Tunnel

Screening of transient and fixed ignition sources

There are no fixed ignition sources in located in this zone.

The cable tray arrangement is identical to that modeled for zone 1A. COMPBRN analyses of the class "A" transient fires placed in the center aisle of the tunnel between the north and south cable tray stacks (Case 32A-2) indicated no damage to cables in either stack. Subsequent analyses were performed placing the fire directly under one of the stacks. In this case damage and burning of the cables in the stack directly above occurred, however cables on the opposite side of the tunnel did not sustain damage 32A-1.UNC). Simultaneous damage to both cable tray stacks due to transient fires is therefore excluded.

Evaluation of risk from transient sources

The frequency of transient fires in this fire zone is 4.41E-04/yr.

COMPBRN uncertainty analysis indicates that the probability of damage to cables from transient fires located on the same side of the tunnel ranges from .4 to 1.0 depending upon the elevation of the tray. For simplicity in this case it is assumed that 50% of the transient fires in the tunnel may damage the north stack and 50% the south stack. However, automatic sprinkler systems coverage is provided for the trays in the tunnel which is activated 270K below the minimum damage temperature for the cables. Thus no cable damage is assumed if the automatic system operates successfully. The reliability of these sprinkler systems have been analyzed (see Section 4.5) and found to have a failure probability of 0.05.

Fire Scenario A3-22A Transients on south side of tunnel

Based on the above discussion the frequency of fire damage to the south cable tray stack is:

4.41E-04 x .5 x .05 = 1.10E-05/yr

This stack consists of cable trays: T51B F/K1A, K2A/D/C3/C2, C4/K1,K2/J4, D400 which serve the following safe shutdown components.

MCC26A, 26B and 27	All EDG Auxiliaries
SI MOVs	PORV Block Valves
RCP Seal Injection Valves	RHR Pumps and MOVs
Charging Pumps	Auxiliary CCW Pumps
CCW Pumps 21&22 and thermal barrier cooling valves	
Reactor Head Vent Valves	Containment Spray Pumps

Fire Scenario A3-22B Transients on north side of tunnel

Based on the above discussion the frequency of fire damage to the south cable tray stack is:

4.41E-04 x .5 x .05 = 1.10E-05/yr

This stack consists of cable trays T50B K1/K2/J1,J2/J3,J4/D/C3/C4/C5/C6 which serve the following safe shutdown components:

AFW Pump and Valve control
SI and RHR Pumps
PORVs
Recirculation Pumps
Fan Cooler Units

The electrical tunnel fire scenario frequencies are summarized in Table A1-5 and their contribution to core damage frequency evaluated as discussed in Section 4.6 of the main report.

A1.5 References

A1-1 "Indian Point Nuclear Generating Station No. 2 Fire Protection Program Plan (FPPP)," Consolidated Edison of New York, Inc., Revision 7, November 30, 1992.

A1-2 "Fire PRA Requantification Studies," NSAC-181, Final Report, March 1993.

A1-3 "Fire Events Database for U.S. Nuclear Power Plants," NSAC-178L, Final Report June 1992.

A1-4 "An Experimental Investigation of Internally Ignited Fires in Nuclear Power Plant Control Cabinets: NUREG/CR-4527, Part I : Cabinet Effects, published April 1987, & Part II: Room Effects Tests," November 1988.

A1-5 "Fire PRA Implementation Guide" ERP3385-01, Electric Power Research Institute, January 1994 (Draft).

TABLE A1-1: SUMMARY OF FIXED IGNITION SOURCES IN CABLE SPREADING ROOM							
IGNITION SOURCE	**ELECTRICAL NODE**	**SIZE (ins.) (L x W x H)**	**TYPE OF CABLE ENTRY**	**VENTILATION/ CABINET OPENINGS**	**CLOSEST EXPOSED CABLE TRAY**	**COMMENTS**	**BASIS FOR SCREENING SOURCE**
MCC29	CJ1-CJ6	80x10x88	Conduits	None	Tray 34B 30" above		A
MCC29A	ECE28-ECE31	104x15x88	Conduits	None	Tray 64A 30" above and 9" back	Tray drops down to floor behind panel	A
MCC26C		58x24x90	Conduit	None	Tray E08C/J4 24" above		A
Static Inverter 21	EGA1	36x30x77	Conduits	2 Top fans and openings	Trays 66B/J4 7' 6" above Tray (12" wide) 5' 6" above Tray E08C 3' above	E08C separated horizontally by 2'	B
Static Inverter 22	EGA2	36x30x77	Conduits	2 Top fans and openings	"	"	B
Static Inverter 23	EGA3	36x30x77	Conduits	2 Top fans and openings	"	"	B
Static Inverter 24	EGA4	36x30x77	Conduits	2 Top fans and openings	"	"	B
Battery Charger 21	EMG4	30x30x77	Conduits	2 Top fans and openings	Trays 66B/J4 7' 6" above Tray (12" wide) 5' 6" above Tray E08C 3' above	E08C separated horizontally by 2'	B
Battery Charger 22	MN3	30x30x77	Conduits	2 Top fans and openings	"	"	B

TABLE A1-1: SUMMARY OF FIXED IGNITION SOURCES IN CABLE SPREADING ROOM							
IGNITION SOURCE	ELECTRICAL NODE	SIZE (ins.) (L x W x H)	TYPE OF CABLE ENTRY	VENTILATION/ CABINET OPENINGS	CLOSEST EXPOSED CABLE TRAY	COMMENTS	BASIS FOR SCREENING SOURCE
Battery Charger 23	EPB3	36x30x77	Conduits	2 Top fans and openings	*	*	B
Battery Charger 24	EPA9	36x30x77	Conduits	2 Top fans and openings	*	*	B
125V DC Power Panel 21	PC1	38x10x90	Conduits	None	Tray 89F/90F 6' above		A
125V DC Power Panel 22	PC2	38x10x90	Conduits	None	Tray 89F/90F 6' above		A
125V DC Power Panel 23	EPB3	29x10x47	Conduits	None	Tray 89F/90F 9'6" above		A
125V DC Power Panel 24	EPA9	29x10x47	Conduits	None	Tray E18C 4' above		A
MG Set 21	GC1		Conduit	Small openings in casing	Tray E08C/J2 6' above Tray (12" wide) 10' above	E08C separated horizontally by 2'	B
MG Set 22	GC2		Conduit	Small openings in casing	*	*	B
Rod Control SWGR	AL6-AL9	110x58x87	Conduit	Side openings top and bottom	Tray E10C/J4 12" above		Not screened

TABLE A1-1: SUMMARY OF FIXED IGNITION SOURCES IN CABLE SPREADING ROOM

IGNITION SOURCE	ELECTRICAL NODE	SIZE (ins.) (L x W x H)	TYPE OF CABLE ENTRY	VENTILATION/ CABINET OPENINGS	CLOSEST EXPOSED CABLE TRAY	COMMENTS	BASIS FOR SCREENING SOURCE
Rod Drive Cabinet	PL8, PI9,PM2,PM3	173x47x96	Conduit	Grills on cabinet tops	Tray 43B 4' above		Not Screened
Rod Drive Cabinet	PL5, PD6	82x48x96	Conduit	Grills on cabinet tops	Tray 43B 4' above		Not Screened
Inverter 23 (RPI)	GD7	31x31x87	Conduit	Louvers side top and bottom	Tray (12" wide) 6' above		B
RVLIS Cabinet	EPH8	78x33x87	Conduit	Open back and front	Tray 43B 4' above and 2' to side		Not Screened
10 KVA Xfmr	BD3	15x15x18	Conduit	Side louvers	Tray 10' above		B
125V XFR Switch 23	DA6	10x35x42	Conduit	None	Tray 89F/90F 9'6" above		A
S.I. 24 Bypass Switch	EDB1	10x10x19	Conduit	None	Tray 89F/90F 10'6" above		A
S.I. 22 Bypass Switch	EDB6	10x10x19	Conduit	None	"		A

TABLE A1-1: SUMMARY OF FIXED IGNITION SOURCES IN CABLE SPREADING ROOM							
IGNITION SOURCE	**ELECTRICAL NODE**	**SIZE (ins.) (L x W x H)**	**TYPE OF CABLE ENTRY**	**VENTILATION/ CABINET OPENINGS**	**CLOSEST EXPOSED CABLE TRAY**	**COMMENTS**	**BASIS FOR SCREENING SOURCE**
S.I. 23 Bypass Switch	EDC1	10x10x19	Conduit	None	"		A
S.I. 21 Bypass Switch	EDB5	10x10x19	Conduit	None	"		A
Emergency Lgt. Panel 29	PB7	19x6x36	Conduit	None	Tray 89F/90F 9'6" above		A
Lighting Panel 219	PH1	19x6x33	Conduit	None	"		A
Lighting Panel 219A	EPH1	14x6x16	Conduit	None	"		A
7.5KVA SOLA Xfmr 22	BF2	10x10x19	Conduit	None	Tray 89F/90F 9'6" above		B
7.5KVA SOLA Xfmr 23	EBA4	10x10x19	Conduit	None	"		B
7.5KVA SOLA Xfmr 24	EBA6	10x10x19	Conduit	None	"		B
Exhaust Fan 23	ERA7	12x12x12	Conduit	n/a	Tray 12" above	fan motor in duct	A

TABLE A1-1: SUMMARY OF FIXED IGNITION SOURCES IN CABLE SPREADING ROOM							
IGNITION SOURCE	**ELECTRICAL NODE**	**SIZE (Ins.) (L x W x H)**	**TYPE OF CABLE ENTRY**	**VENTILATION/ CABINET OPENINGS**	**CLOSEST EXPOSED CABLE TRAY**	**COMMENTS**	**BASIS FOR SCREENING SOURCE**
Exhaust Fan 22	ERA6	12x12x12	Conduit	n/a	Tray 14B 12" above	fan motor in duct	A
Exhaust Fan 21/22		15x15x12	Conduit	n/a	Tray 25B 12" above and 6" to side	fan motor in duct	A
15KVA Xfmr	BD6	19x12x12	Conduit	Side openings	Tray 35B 5'6" above		B
30KVA Xfmr	LE4	19x19x30	Conduit	Side Openings	Tray 14B 7'0" above		B
Strip Htr Panel 22	PJ4	19x6x40	Conduit	None	Tray 14B 4' above		A
PA Equipment Rack		108x36x84	Tray/conduit	None	Tray 97A 5' above	Unitstrut rack with 24 closed electrical boxes	A
15KVA SD Xfmr 21	EBB12	12x12x19	Conduit	Side openings	Tray 89F/90F 8' above		B
15KVA SD Xfmr 22	BC2	12x12x19	Conduit	Side openings	"		B
15KVA SD Xfmr 23	EBA1	12x12x19	Conduit	Side openings	"		B
15KVA SD Xfmr 24	EBA5	12x12x19	Conduit	Side openings	"		B

TABLE A1-1: SUMMARY OF FIXED IGNITION SOURCES IN CABLE SPREADING ROOM							
IGNITION SOURCE	**ELECTRICAL NODE**	**SIZE (ins.) (L x W x H)**	**TYPE OF CABLE ENTRY**	**VENTILATION/ CABINET OPENINGS**	**CLOSEST EXPOSED CABLE TRAY**	**COMMENTS**	**BASIS FOR SCREENING SOURCE**
SOLATRON Xfmr	BE9	27x19x51	Conduit	Opening in back and front	Tray 5'6" above		B
	EZF1,2,3,9	4'x6"x6'	Conduit	All boxes totally enclosed	Tray 6' above	Unistrut frame with 10 small electrical boxes	A
CCR Gas Monitor		36x48x48	Conduit	None	Tray 8' above		A
Tunnel Fan Control 21		12x6x15	Conduit	None	Tray 4' above		A
Tunnel Fan Control 22		12x6x15	Conduit	None	Tray 4' above		A

Explanation of Screening Basis:

A. No cabinet ventilation or open cable entries (fire does not propagate)

B. Closest target beyond damage range

Table A1-2

Results of COMPBRN Analysis for Fires in Rod Drive Switchgear

Target Tray	Probability of Damage	Mean Time to Damage (sec)	Safe Shutdown Equipment Loss
East to West trays passing over or to the south of source			
T67B J3 (87F) J4	.0005	720	None - SAS and Bistable circuits (1)
T91F J1 (72B) J2	.0	n/a	None - SAS and Bistable circuits (1)
T33B F (41B) K1A,K2A,D200 (43B) K1,K2, J4, D400	0	n/a	n/a
TE08C J2,J4	1.0	288	None - SAS Circuits (1)
TE07C J1,J3	1.0(2)	148	None - SAS Circuits (1)
North Cable Tray Stack			
T46B K1 (37B)	0(2)	n/a	PORV 455C, CHP 21, AFWP 21 (9)
T46B J1,J2 (37B)	0005(6) *	660	Monitoring Instrumentation
T46B K2 (37B)	.0005	660	PORV 456, AFWP 23, HCV- 645(9)
T46B J3,J4 (37B)	.0005	660	Monitoring Instrumentation
T46B D400 (37B)	.0005	660	None(9)
T46B D800 (37B)	0	n/a	

Table A1-2

Results of COMPBRN Analysis for Fires in Rod Drive Switchgear

Target Tray	**Probability of Damage**	**Mean Time to Damage (sec)**	**Safe Shutdown Equipment Loss**
Cross Trays between North and South of Room			
T60F J1-D J2-J3,J4	.99 .73	756 514	Trays serve flight panel- Assume all equipment served by FA, FB, FC and FD lost (i.e. PORVs, BVs and OSP) [1]
T57F D	.69	525	
T21H F	.99	525	None- only contains lighting panel circuits [1]
T62F J1-K,J2-K2 J3,J4 D	.99 .73	756 514	None - only serves "D" logic racks which support in-core inst., rad monitoring and steam dump. [1] [4]
T64F	0	n/a	n/a
T65F	0	n/a	n/a

Table A1-3

Results of COMPBRN Analysis for Fires in Rod Control Cabinet

Target Tray	**Probability of Damage**	**Mean Time to Damage (sec)**	**Safe Shutdown Equipment Loss**
South Cable Tray Stack			
T33B F (41B) (43B)	.54	645	n/a
T33B K1A,K2A,D200 (41B) (43B)	.53	630	All EDG Auxiliaries (1)
T33B K1 (41B) (43B)	.55	610	CHP 21 (4) All valves supplied by MCC26A and Cont. Recirc Pump 21
T33B K2 (41B) (43B)	.55	610	CHP 22 (4) All valves supplied by MCC26B and Cont. Recirc. Pump 22
T33B J4 (41B) (43B)	.63	609	Instrumentation Channel
T33B D400 (41B) (43B)	.63	609	CHP 23 (4)

Table A1-3

Results of COMPBRN Analysis for Fires in Rod Control Cabinet

Target Tray	Probability of Damage	Mean Time to Damage (sec)	Safe Shutdown Equipment Loss
Cross Trays between North and South of Zone exposed to Fires at West End of Cabinet			
T52F K1 (53F)	.25	795	Trays serve flight panel- Assume all equipment served by FA, FB, FC and FD lost (i.e. PORVs, BVs and OSP) [1]
T52F J1 (53F)	.97	567	
T52F D (53F) J4	.97	567	
T55F J, K2	.75	684	
T58F J,K2 (59F)	.62	648	
T62F (63F)	not modeled	n/a	None only serves " D" logic racks which support NIS, Rad monitoring and steam dump [1] [5]
Cross trays between north and south of room exposed to fires at east end of cabinet			
T65F J1-D,J2 (66F)	.75	684	None Only contain circuits associated with "C" logic rack which serve gross failed fuel detector, NIS and rod position indication [1] [5]
T65F J3,J4 (66F)	.97	567	
T68F J3-D (69F) J4	.97	567	Cables associated with "B" logic racks which serve FW control and RCS pressure control. Assume AFW control from CCR is lost and possibility of spurious PORV opening [1] [5]
T71F J1-D (72F) J2	0	n/a	n/a

Table A1-4

Results of COMPBRN Analysis for Fires in RVLIS cabinet

Target Tray	Probability of Damage	Mean Time to Damage (sec)	Safe Shutdown Equipment Loss
South Cable Tray Stack			
T45B K1A, K2A	.0043	920	All EDG Auxiliaries(1)
T45B K1-K2	.0055	872	CHP21, CHP22.(4) All valves supplied byMCC26A 26B and Containment Recirc Pumps 21 and 22
T45B, J4,D400	.057	709	Instrumentation and CHP23(4)
Cross trays between north and south of zone			
T71F J-D (72F)	.0025	1056	Cables serve logic rack "A". Assume control from the CCR is lost for all equipment served by these racks (1) (3)
T71F J1 (72B) J2	.0025	1032	

Table A1-5

Fire Damage State Frequency for Fire Compartment A3

Fire Zone	Scenario #	Ignition Source Frequency F(if)		Cond. Damage Prob.	F.S. x Area Ratio	Fire Damage State Freq
		Source	Frequency			
11	A3-1A	Rod Control SWGR	2.90E-04	1.0	0.5	1.43E-04
	A3-1B	Rod Control SWGR	2.90E-04	.01	0.1	2.90E-07
	A3-2A	Rod Drive Control Cabinet (West)	2.77E-04	1.0	0.5	1.21E-04
	A3-2B	Rod Drive Control Cabinet (West)	2.77E-04	.63	0.1	1.75E-05
	A3-3A	Rod Drive Control Cabinet (West)	2.77E-04	1.0	0.5	1.21E-04
	A3-3B	Rod Drive Control Cabinet (East)	2.77E-04	.63	0.1	1.75E-05
	A3-4	RVLIS Cabinet	1.18E-04	0.01	0.1	1.18E-07
	A3-5	Transient	9.38E-05	1.0	0.148	
		Welding /Ordinary Combustible	3.20E-04	1.0	0.148 x .15	
		Total	4.14E-04			2.10E-05
12	A3-6A	All	1.30E-03	1.00	1.0	1.30E-03
13	A3-6B	All	1.30E-03	1.00	1.0	1.30E-03

Table A1-5

Fire Damage State Frequency for Fire Compartment A3

Fire Zone	Scenario #	Ignition Source Frequency F(if)		Cond. Damage Prob.	F.S. x Area Ratio	Fire Damage State Freq
		Source	Frequency			
14	A3-7	Switchgear 2A	1.94E-03	1.0	0.5 x 0.84	8.14E-04
		SST 2	3.04E-04	1.0	0.5	1.52E-04
	Totals		2.24E-03			9.67E-04
	A3-8	Switchgear 3A	1.67E-03	1.0	0.5 x 0.84	7.01E-04
		SST 3	3.04E-04	1.0	0.5	1.52E-04
	Totals		1.97E-03			8.53E-04
	A3-9	Switchgear 5A	1.67E-03	1.0	0.5 x 0.84	7.01E-04
		SST 5	3.04E-04	1.0	0.5	1.52E-04
	Totals		1.97E-03			8.53E-04
	A3-10	Switchgear 6A	1.94E-03	1.0	0.5 x 0.84	8.14E-04
		SST 6	3.04E-04	1.0	0.5	1.52E-04
	Totals		2.24E-03			9.67E-04
	A3-11	SW/CFC Panel	2.85E-04	1.00	1.0	2.85E-04
	A3-12	Air Compressor 21	1.18E-05	1.0	1.0	1.18E-05
	A3-13A	Transient	4.41E-04	.015	1.0	6.62E-06
	A3-13B	Transient	4.41E-04	.028	1.0	1.23E-05
	A3-13C	Transient	4.41E-04	.028	1.0	1.23E-05
	A3-13D	Transient	4.41E-04	.005	1.0	2.21E-06
	A3-13E	Transients	4.41E-04	.005	1.0	2.21E-06
	A3-13F	Transients	4.41E-04	.021	1.0	9.52E-06

Table A1-5

Fire Damage State Frequency for Fire Compartment A3

Fire Zone	Scenario #	Ignition Source Frequency F(If)		Cond. Damage Prob.	F.S. x Area Ratio	Fire Damage State Freq
		Source	Frequency			
15/ 115	A3-15C	Supervisory Cabinet SB-1	2.66E-04	1.0	0.12	2.39E-05
	A3-15D	Supervisory Cabinet SB-2	1.99E-04	1.0	0.12	1.79E-05
	A3-15E	Supervisory Cabinet SC	2.66E-04	1.0	0.12	2.39E-05
	A3-15H	Supervisory Cabinet SF	1.99E-04	1.0	0.12	1.79E-05
	A3-15I	Supervisory Cabinet SG	1.99E-04	1.0	0.12	1.79E-05
	A3-15J	Supervisory Cabinet SH	1.99E-04	1.0	0.12	1.79E-05
	A3-15K	Supervisory Cabinet SJ	1.99E-04	1.0	0.12	1.79E-05
	A3-16A	Supervisory Cabinet (eastern region)	1.14E-03	1.0	0.022	2.17E-05
	A3-16B	Supervisory Cabinet (center region)	6.64E-04	1.0	0.022	1.26E-05
	A3-16C	Any Supervisory Cabinet (western region)	1.39E-03	1.0	0.022	2.65E-05
	A3-17	Any CCR Cabinet	9.50E-03	1.0	0.0034	3.23E-05
	A3-18	Flight Panel	1.67E-03	1.0	0.12	1.95E-04
	A3-19	CVCS Logic Cabinet	1.17E-04	1.0	1.0	1.17E-04
	A3-20	Feedwater Logic Cabinet	1.16E-04	1.0	1.0	1.16E-04
	A3-21	RCS Pressure Control Logic	1.83E-04	1.0	1.0	1.83E-04
24	A3-21	All	1.30E-03	1.0	1.0	1.30E-03
32A	A3-22A	Transient (south)	4.41E-04	1.0	0.025	1.10E-05
	A3-22B	Transients (north)	4.41E-04	1.0	0.025	1.10E-05

Table A1-6

Summary of Pertinent Data from Sandia Cabinet Fire Tests (Reference A1-4)

	EVENT	Test PCT 5	Test 24 [3]	Test 25 [4]
1.	Smoke first observed coming from cabinet	10:00	10:30	9:30
2.	Smoke detector gives alarm	n/a	n/a	10:00
3.	Ignition	15:33	15:40	15:40
4.	Significant Flame Spread	21:00	22:00	18:00
5.	CCR View Obscured	23:30	26:00	29:00
	Time Interval			
1.	Smoke being observed and ignition	5:33	5:10	6:10
2.	Ignition and flame spread	5:27	6:20	2:20
3.	Flame spread and CCR being obscured	2:30	4:00	11:00

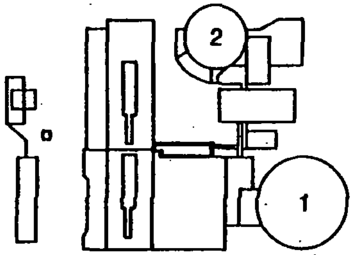
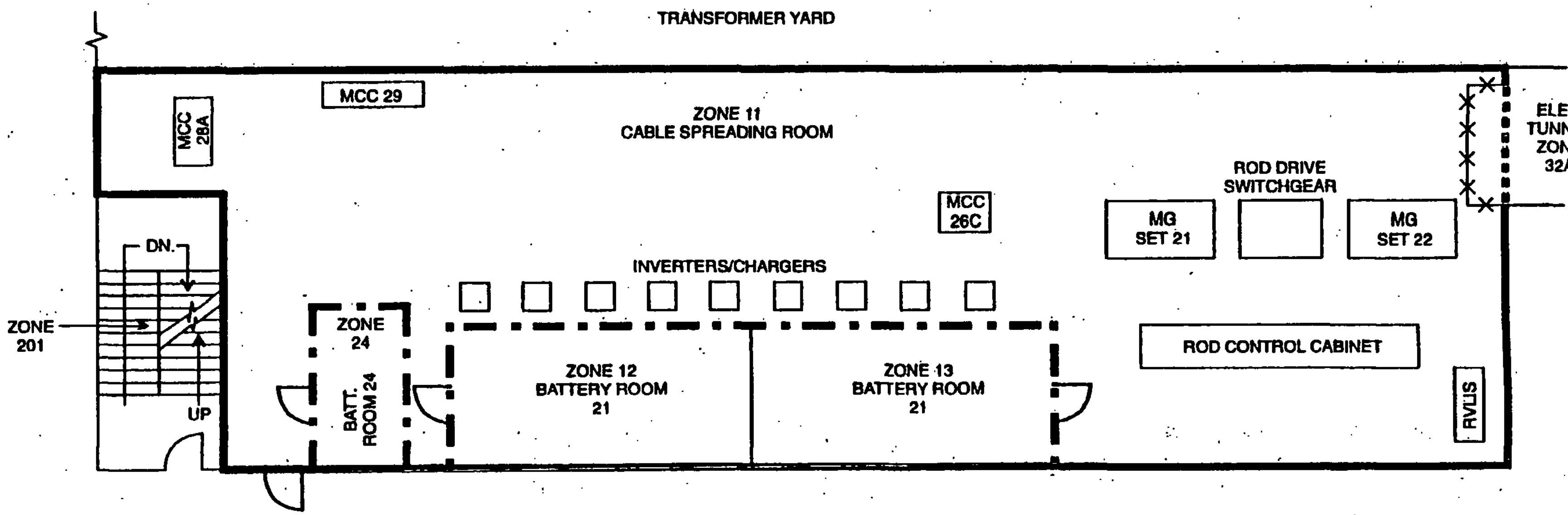


Figure A1-1
Control Building - Cable Spreading Room
Elevation 33' - 0"
Zone 11 Cable Spreading Room



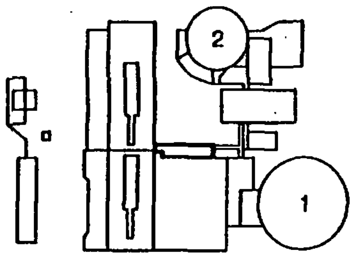
ADJACENT ZONES

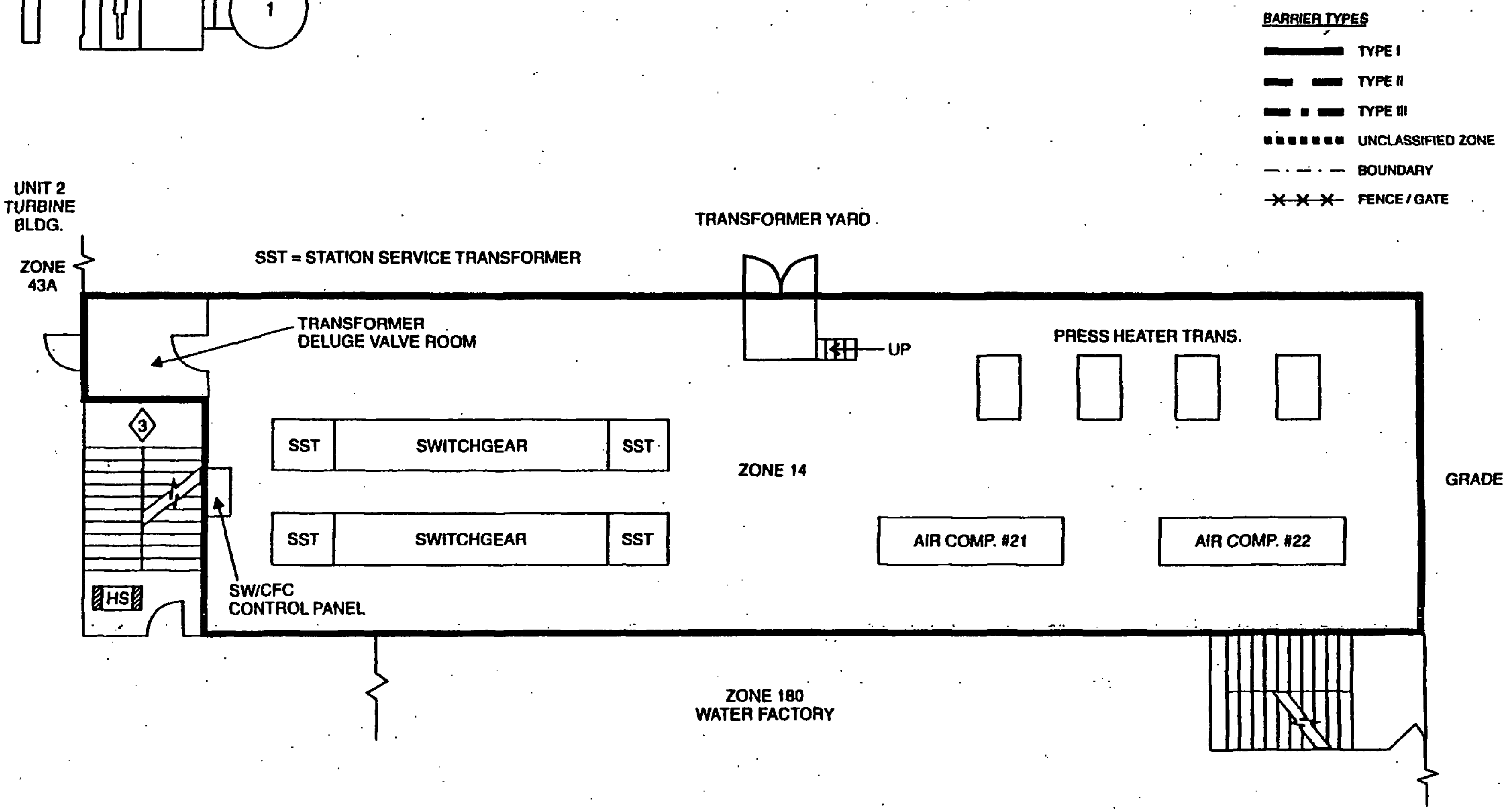
ABOVE - 15 (CONTROL ROOM)
BELOW - 14 (SWITCHGEAR ROOM)

BARRIER TYPES

TYPE I
TYPE II
TYPE III
UNCLASSIFIED ZONE
BOUNDARY
FENCE / GATE

Figure A1-2
Control Building
Elevation 15' - 0"
Zone 14 - Switchgear Room

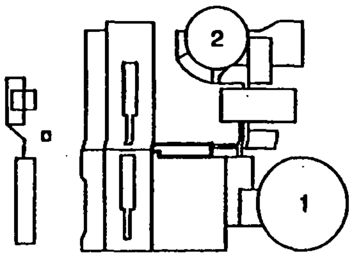




ADJACENT ZONES

ABOVE - 15, 12 AND 13
BELOW - NONE

Figure A1-3
Control Building
Elevation 53' - 0"
Zone 15 - Central Control Room



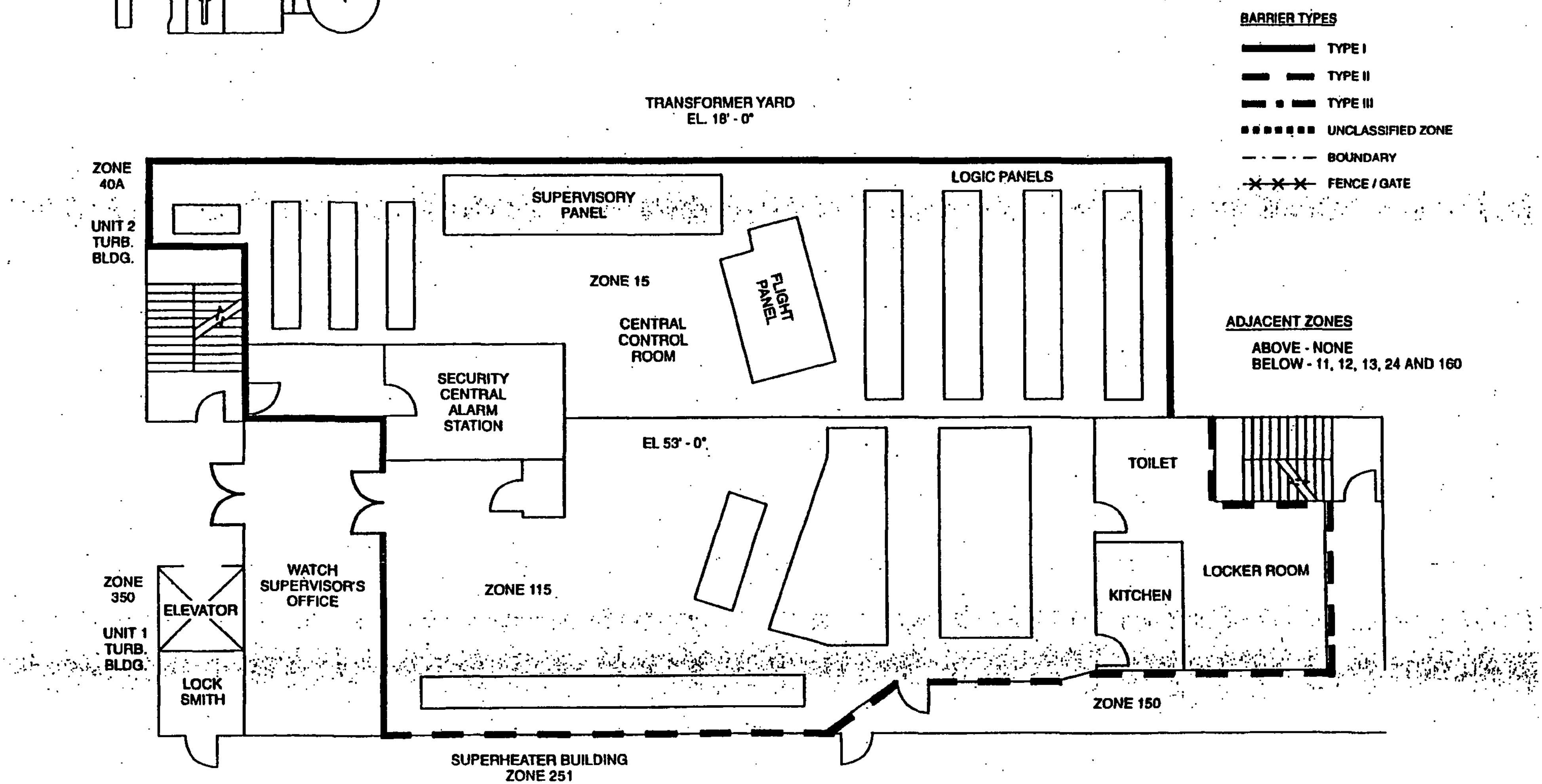
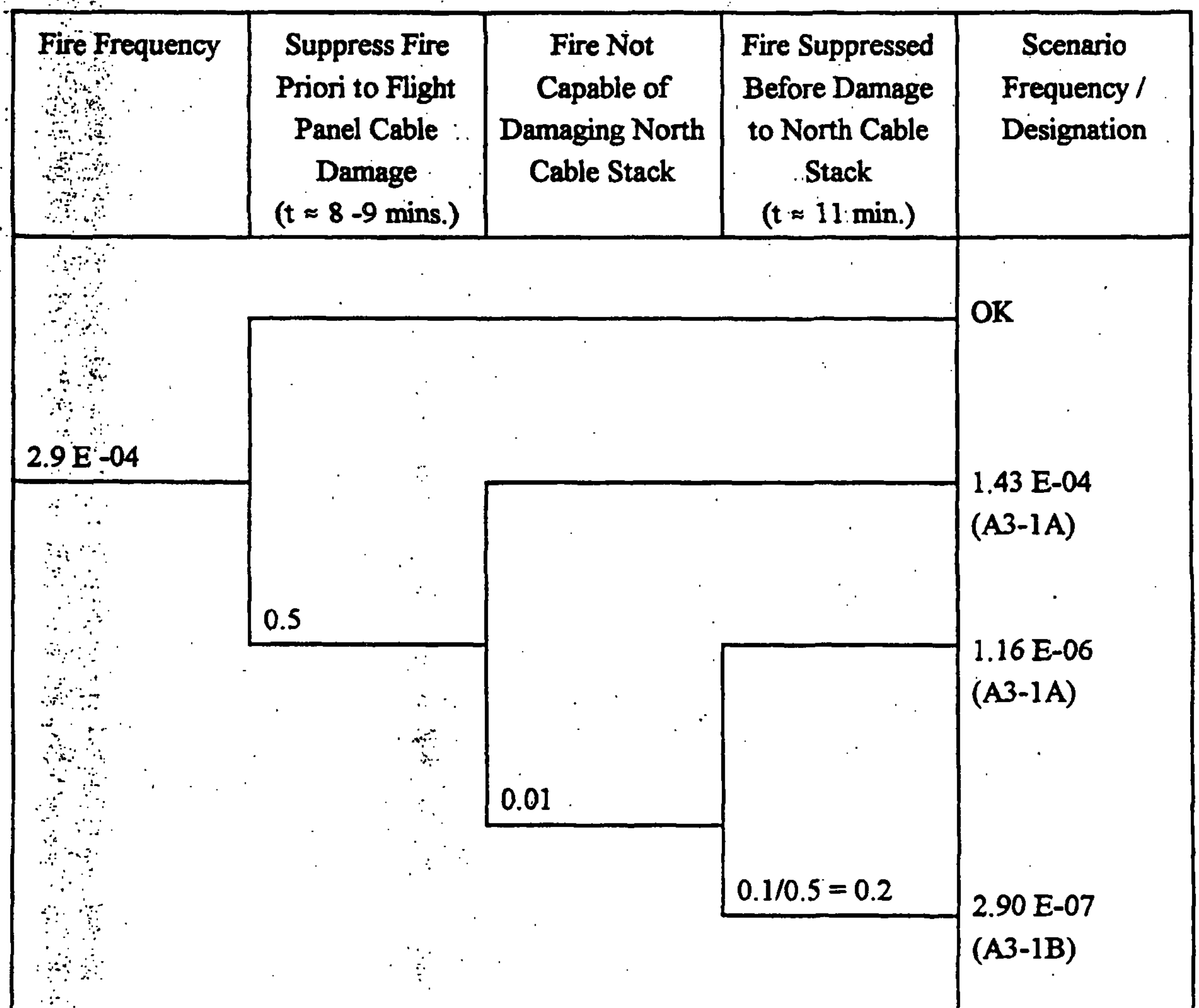
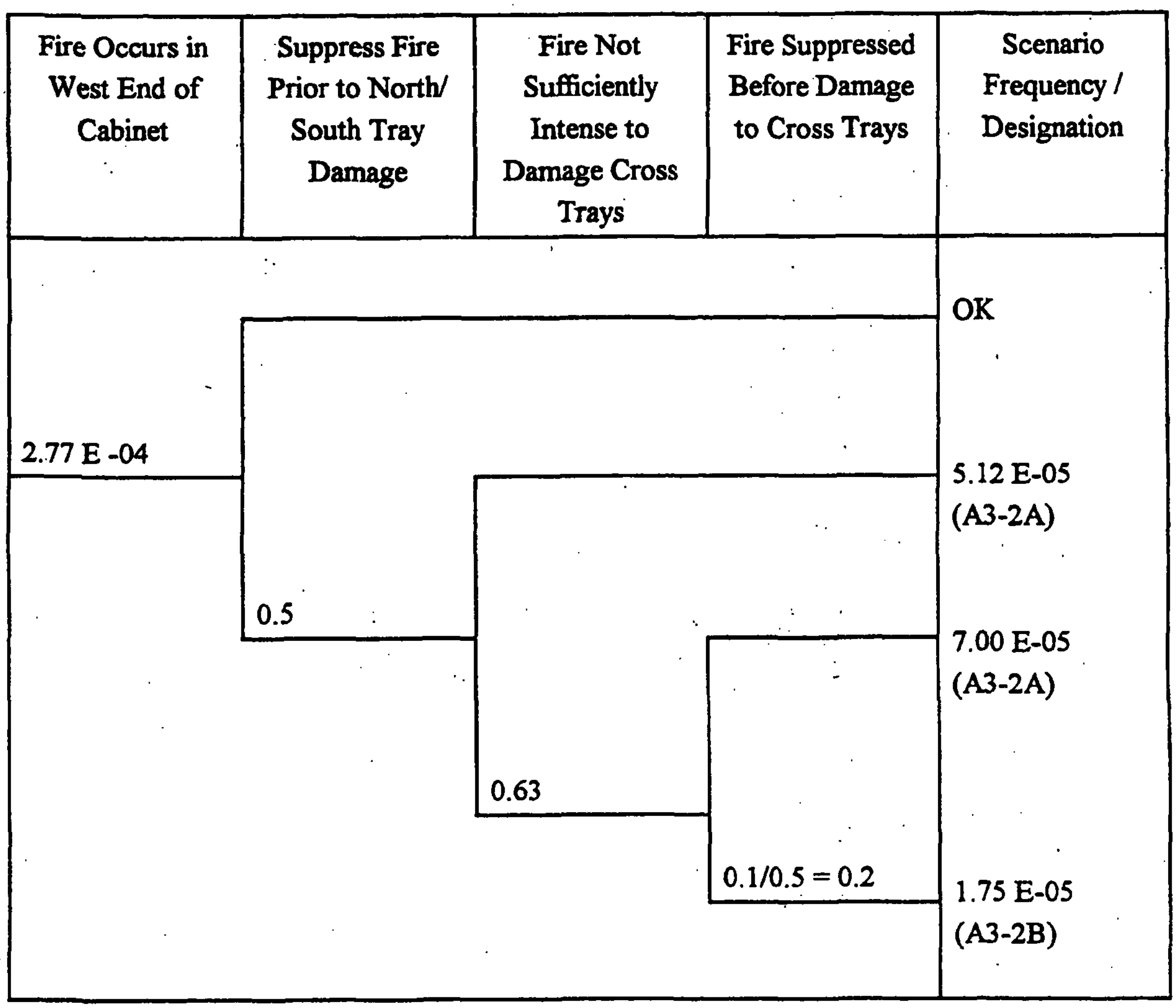


Figure A1-4
Fire Growth Event Tree for Rod Control Switchgear Scenarios



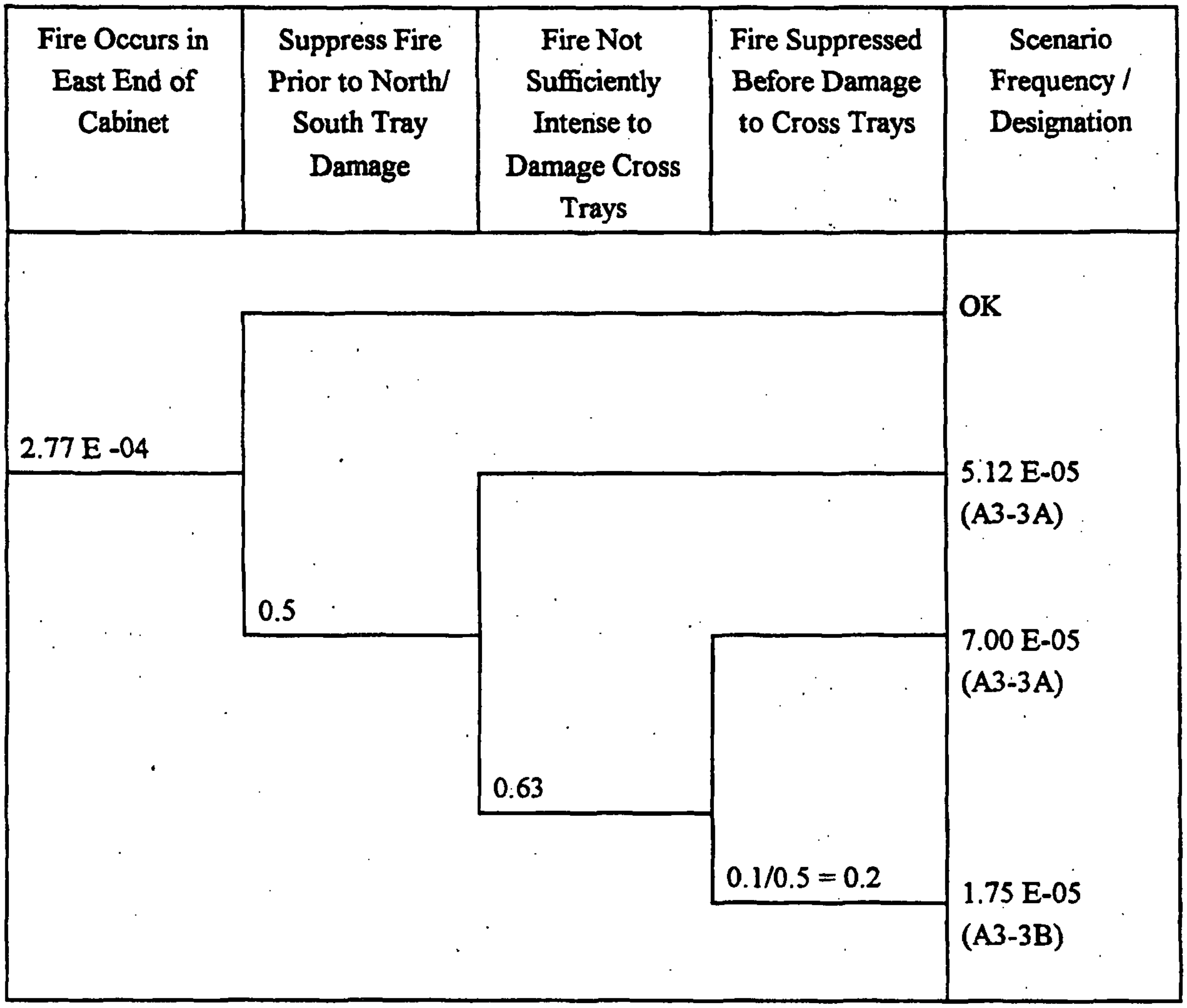
Total Frequency of Scenario A3-1A = 1.44 E-04 /yr
Total Frequency of Scenario A3-1B = 2.90 E-07 /yr

Figure A1-5
Fire Growth Event Tree for Rod Drive Control Cabinet Fires
(West End of Cabinet)



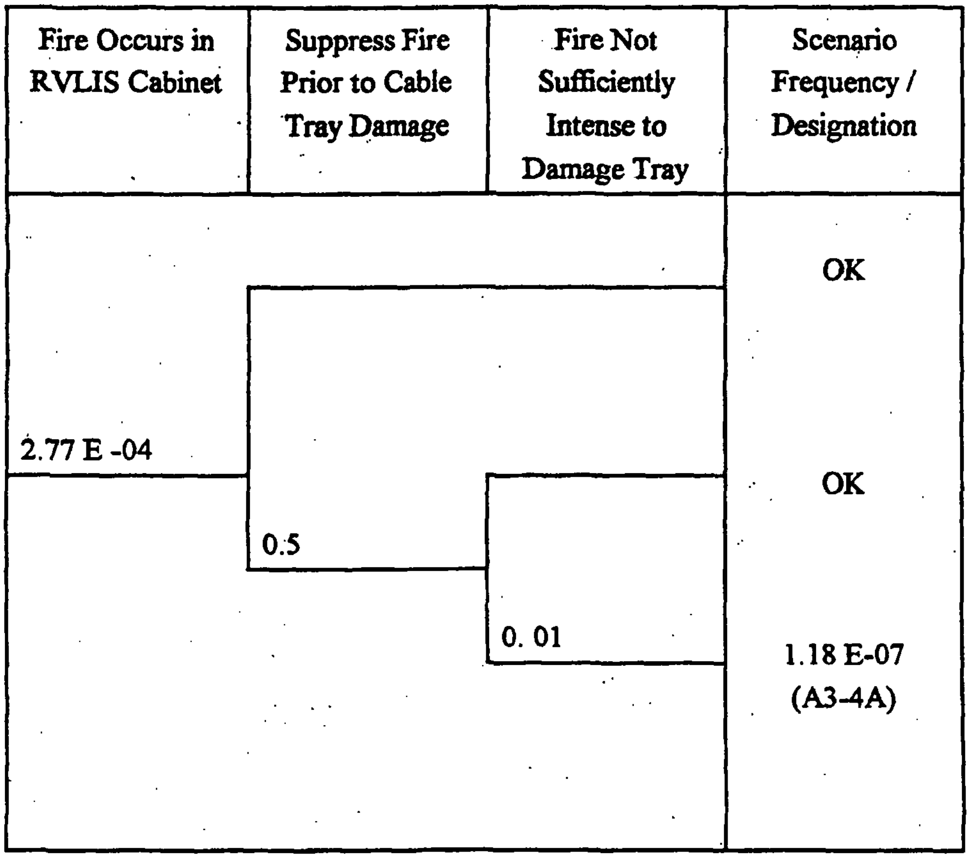
Total Frequency of Scenario A3-2A = 1.21 E-04 /yr
Total Frequency of Scenario A3-2B = 1.75 E-05 /yr

Figure A1-6
Fire Growth Event Tree for Rod Drive Control Cabinet Fires
(East End of Cabinet)



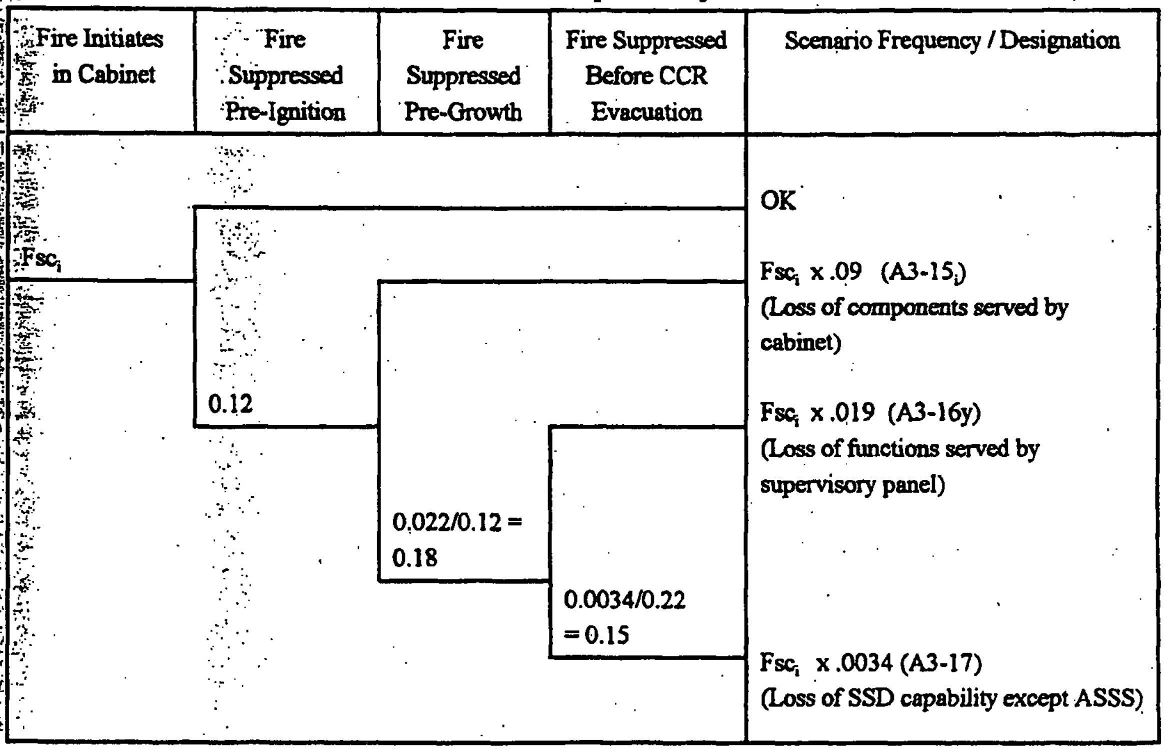
Total Frequency of Scenario A3-3A = 1.21 E-04 /yr
Total Frequency of Scenario A3-3B = 1.75 E-05 /yr

Figure A1-7
Fire Growth Event Tree for RVLIS Cabinet Fires



Total Frequency of Scenario A3-4A = 1.18 E-07 /yr

Figure A1-8
Fire Growth Event Tree for Supervisory Panel Cabinet Fires

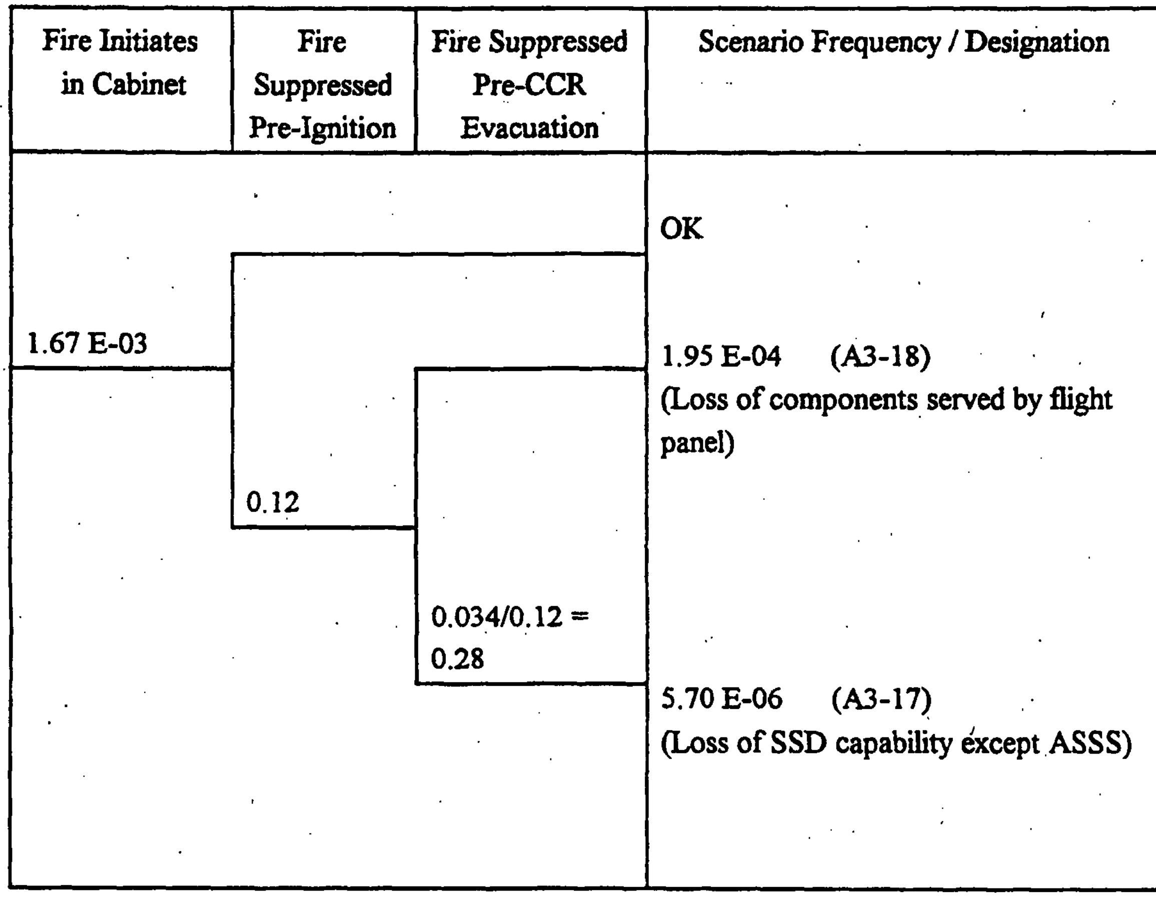


Supervisory Panel	(i)	Ignition Frequency Fsc_i	Damage State and Frequency		Comment
SA-1	(a)	2.12 E-04	A3-15A	1.91 E-05	no significant SSD equipment
SA	(b)	1.99 E-04	A3-15B	1.79 E-05	no significant SSD equipment
SB-1	(c)	2.66 E-04	A3-15C	2.39 E-05	
SB-2	(d)	1.99 E-04 E-04	A3-15D	1.79 E-05	
SC	(e)	2.66 E-04	A3-15E	2.39 E-05	
SD	(f)	1.99 E-04	A3-15F	1.79 E-05	no significant SSD equipment
SE	(g)	2.66 E-04	A3-15G	2.39 E-05	no significant SSD equipment
SF	(h)	1.99 E-04	A3-15H	1.79 E-05	
SG	(i)	1.99 E-04	A3-15I	1.79 E-05	
SH	(j)	1.99 E-04	A3-15J	1.79 E-05	
SJ	(k)	1.99 E-04	A3-15K	1.79 E-05	
SK	(l)	1.66 E-04	A3-15L	1.49 E-05	
SL	(m)	1.99 E-04	A3-15M	1.79 E-05	no significant SSD equipment
SM	(n)	1.66 E-04	A3-15N	1.49 E-05	no significant SSD equipment
SN	(o)	1.33 E-04	A3-15O	1.20 E-05	no significant SSD equipment
SO	(p)	1.33 E-04	A3-15P	1.20 E-05	no significant SSD equipment
	$\sum Fsc_i$	3.2 E-03	A3-16y	see sheet 2	
			A3-17	1.09E-05	Contribution from Supervisory Panel

Figure A1-8
Fire Growth Event Tree for Supervisory Panel Cabinet Fires
(continued)

Supervisory Panel Region	Supervisory Panel Section	Section Ignition Frequency	Region Ignition Frequency	Fire Damage State	Fire Damage Frequency
Eastern	SA-1	2.12 E-04	1.14 E-03	A3-16A	2.17 E-05
	SA	1.99 E-04			
	SB-1	2.66 E-04			
	SB-2	1.99 E-04			
	SC	2.66 E-04			
Center	SD	1.99 E-04	6.64 E-04	A3-16B	1.26 E05
	SE	2.66 E-04			
	SF	1.99 E-04			
Western	SG	1.99 E-04	1.39 E-03	A3-16C	2.65 E-05
	SH	1.99 E-04			
	SJ	1.99 E-04			
	SK	1.66 E-04			
	SL	1.99 E-04			
	SM	1.66 E-04			
	SN	1.33 E-04			
	SO	1.33 E-04			

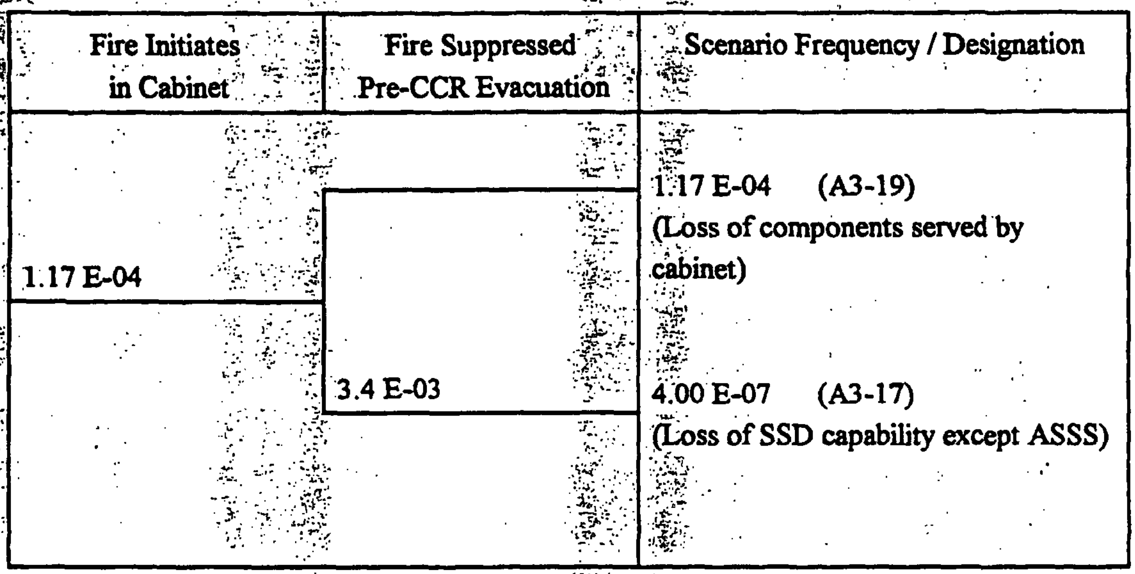
Figure A1-9
Fire Growth Event Tree for Flight Panel Fires



Damage State Frequency:
(Contribution from flight panel only)

Scenario A3-18	1.95 E-04
Scenario A3-17	5.70 E-06

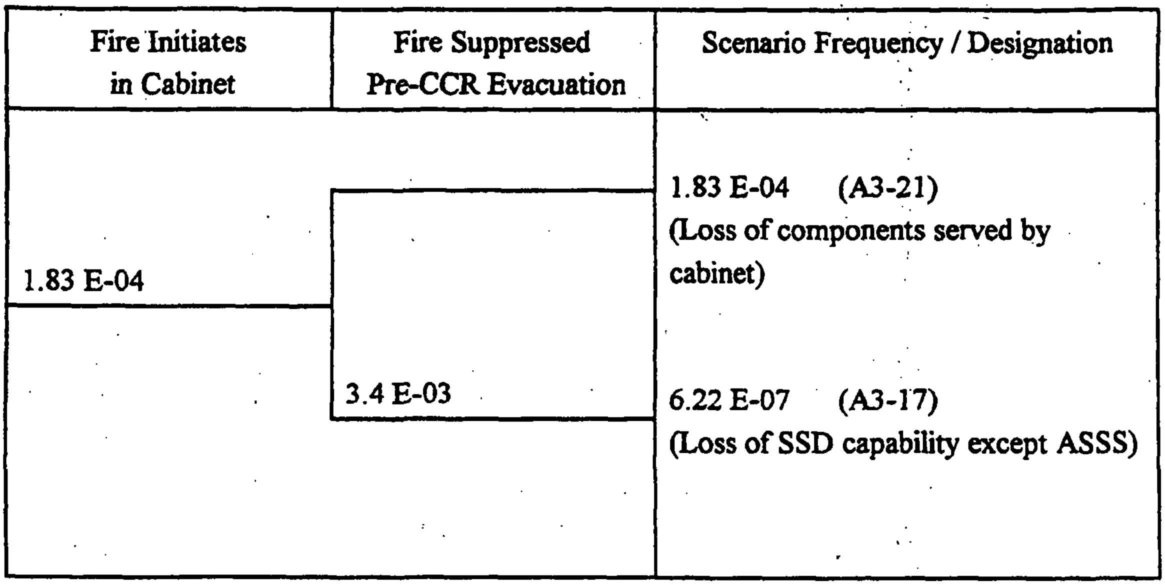
Figure A1-10
Fire Growth Event Tree for CVCS Logic Cabinet (JG6-JG7) Fires



Damage State Frequency:
(Contribution from CVCS logic cabinet only)

Scenario A3-19	1.17 E-04
Scenario A3-17	4.00 E-07

Figure A1-11
Fire Growth Event Tree for Pressure Control Logic Cabinet (JF6-JF8) Fires



Damage State Frequency:
(Contribution from Pressure Control logic cabinet only)

Scenario A3-21	1.83 E-04
Scenario A3-17	6.22 E-07

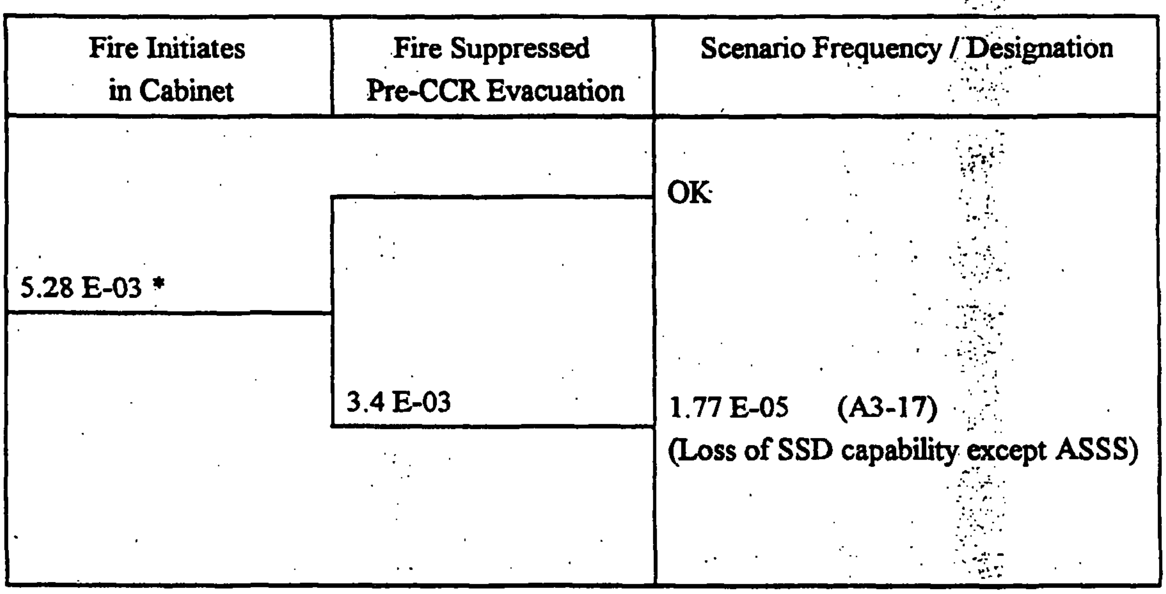
Figure A1-12
Fire Growth Event Tree for Feedwater Control Logic Cabinet (JF4-JF5) Fires

Fire Initiates in Cabinet	Fire Suppressed Pre-CCR Evacuation	Scenario Frequency / Designation
1.16 E-04		1.16 E-04 (A3-20) (Loss of components served by cabinet)
	3.4 E-03	3.94 E-07 (A3-17) (Loss of SSD capability except ASSS)

Damage State Frequency:
(Contribution from feedwater control logic cabinet only)

Scenario A3-20	1.16 E-04
Scenario A3-17	4.00 E-07

Figure A1-13
Fire Growth Event Tree for All Cabinets Which Do Not Serve Components Required for Safe Shutdown



* (Total cabinet frequency in CCR) - (Fire frequency of cabinets considered separately) =
(9.50 E-03) - (3.2 E-03 + 1.67 E-03 + 1.17 E-04 + 1.83 E-04 + 1.16 E-04) = 5.28 E-03

Damage State Frequency:

Scenario A3-17 1.77 E-05