Shearon Harris Nuclear Power Plant
Unit No. 1

Individual Plant Examination for External Events Submittal

CAROLINA POWER & LIGHT COMPANY

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SHEARON HARRIS NUCLEAR POWER PLANT
UNIT NO. 1

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LIST OF ACRONYMS

ACP	auxiliary control panel
AFW	auxiliary feedwater
AHU	air handling unit
ASCE	American Society of Civil Engineers
BOP	balance of plant
Btu	British thermal unit
CAFTA	Cutset and Fault Tree Analysis (Software)
CCDP	conditional core damage probability
CDF	core damage frequency
COMPBRN	computer code for fire analysis
CP&L	Carolina Power & Light (Company)
CSIP	charging/safety injection pumps
CVCS	chemical and volume control system
CWS	chilled water system
ENE	east northeast
EOP	emergency operating procedure
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EQE	Earthquake Engineering International Consulting Company
ESE	east southeast
ESW	emergency service water
ESWS	emergency service water system
FCIA	fire compartment interaction analysis
FDS	fire damage state
FHA	fire hazards analysis
FIVE	fire induced vulnerability evaluation
FRSS	fire risk scoping study
FSAR	final safety analysis report

GERS	generic equipment ruggedness spectra
GET	general orientation and general employee training/retraining
GIP	generic implementation procedure
HCLPF	high confidence of low probability of failure
HEP	human error probability
HRR	heat release rate
HVAC	heating, ventilation and air conditioning
IBM	international business machines
IPE	individual plant examination
IPEEE	individual plant examination of external events
ISDS	ignition source date sheets
LOCA	loss of coolant accident
LPG	liquified petroleum gas
MCC	motor control center
MFW	main feedwater
mph	miles per hour
NNE	north northeast
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	nuclear steam supply system
OPT	operation periodic test
PHP	pressurizer heater panels
PMF	probable maximum flood
PMH	probable maximum hurricane
PMP	probable maximum precipitation
PORV	power operated relief valve
PRA	probabilistic risk assessment
PSA	probabilistic safety assessment

LIST OF ACRONYMS (continued)

RCS	reactor coolant system
RHR	residual heat removal
RLE	review level earthquake
PWR	pressurized water reactor
S	south
SAROS	Safety & Reliability Optimization Services
SCBA	self-contained breathing apparatus
SEWS	screening and evaluation worksheet
SHNPP	Shearon Harris Nuclear Power Plant
SI	safety injection
SMA	seismic margin assessment
SNL	Sandia National Laboratory
SRT	seismic review team
SSD	safe shutdown
SSEL	safe shutdown equipment list
TNT	tri-nitro toluene
WNW	west northwest
WSW	west southwest

SECTION 1

EXECUTIVE SUMMARY

1.0 BACKGROUND AND OBJECTIVES

This report was developed in response to the Nuclear Regulatory Commission (NRC) request for each licensee to perform an Individual Plant Examination of External Events (IPEEE) for each of its nuclear plants, as detailed in Generic Letter 88-20, Supplement 4, issued in April 1991 (NRC, 1991a). With the performance of the work described in this report, Carolina Power and Light Company (CP&L) has fulfilled all the objectives of the generic letter for its Shearon Harris Nuclear Power Plant, Unit No. 1 (SHNPP). The principal objectives of the IPEEE as outlined in the generic letter are, for the case of external initiating events:

- to develop an appreciation of severe accident behavior,
- to understand the most likely severe accident sequences that could occur at the plant under full power conditions,
- to gain a qualitative understanding of the overall likelihood of core damage and fission product releases, and
- if necessary, to reduce the overall likelihood of core damage and fission product release by modifying, where appropriate, hardware and procedures that would help prevent or mitigate severe accidents.

In NUREG-1407 (NRC, 1991b), the NRC specifically identified the following external events as those to be included in the scope of the IPEEE:

- seismic events,
- internal fires,
- high winds and tornados,
- external floods,
- transportation and nearby facility accidents.

In addition, it was requested that a search for unique and plant specific events be made.

This document summarizes the results of the IPEEE for SHNPP in a manner consistent with the submittal guidance provided in the generic letter and in NUREG-1407.

In response to the original Generic Letter 88-20, published in November 1988 (NRC, 1988), CP&L submitted its Individual Plant Examination (IPE) for SHNPP (CP&L, 1993), which

addressed the risk from internal initiating events including internal flooding. This report builds upon the plant models created for that study, and the subsequent updates to those models.

The information provided in this submittal is based on the plant configuration as of September 1, 1993, and is backed by extensive documentation in the form of analysis notebooks. The organization of the documentation is designed to support a detailed review of the analysis, and ease of modification as changes are made to the plant design and operating practices.

This executive summary provides a brief description of the study and its results. Section 2 of this report is a description of the overall scope of the IPEEE and a summary of the methods used for the analysis. Section 3 provides a summary of the analysis of seismic events, and a more detailed description of the analysis is provided in Appendix A. Section 4 describes the analysis of the risks from fires, and section 5 the analysis of the risks from other external events. Section 6 describes CP&L participation in the project. Section 7 discusses the plant improvements that have been identified as a result of this investigation, and section 8 provides a summary and overall conclusions. References are provided separately at the end of each section.

1.1 PLANT FAMILIARIZATION

SHNPP is a single unit plant located near New Hill, North Carolina, approximately 16 miles southwest of Raleigh, North Carolina. The unit began commercial operation in 1987. The nuclear steam supply system (NSSS) is a three loop pressurized water reactor of Westinghouse design, and is rated at 2775 megawatts thermal. The NSSS is enclosed by a large, dry, reinforced concrete, steel-lined containment.

The performance of the IPEEE requires additional knowledge of the plant over and above that which was required for the performance of the IPE. In particular, the physical characteristics of the plant, including detailed knowledge of the location of equipment and details of its anchorage is required. This plant familiarization was brought into the project by involving engineers with detailed specialized knowledge, for example fire protection engineers, structural engineers, and also by performing walkdowns. Several walkdowns with different objectives were performed, some to address seismic issues, others to address fire related issues, and one to confirm the general characteristics of the plant and the site.

1.2 OVERALL METHODOLOGY

The IPEEE for SHNPP was performed using methods identified in NUREG-1407.

1.2.1 Seismic Analysis

The analysis of seismic events was performed using the seismic margins approach. This method, unlike that used in the IPE, and that used for the analysis of fires, does not result in estimates of core damage frequency. Instead, it is an analysis to assess whether the plant is

designed and constructed so that it can be safely shut down following what is known as a review level earthquake (RLE). The methodology for performing the seismic margin analysis has been described in EPRI NP-6041 (EPRI, 1991), and is briefly summarized here. A set of equipment that will be sufficient to safely shut down the plant is defined. A walkdown is performed to identify items on that list that do not appear to be sufficiently seismically rugged. Items which are not screened out by the walkdown are dispositioned in one of several ways:

- resolved through housekeeping or maintenance
- resolved through repair or modification
- resolved through further investigation
- resolved through a demonstration that the acceleration corresponding to the HCLPF (High Confidence of Low Probability of Failure) is higher than that of the RLE.

1.2.2 Fires

The analysis of the impact of fires was performed using a fire PRA approach. This method provides an estimate of core damage frequency for a set of limiting fire initiated scenarios, identified using a systematic screening approach. The analysis considers the likelihood of fire occurrence in each plant area and its subsequent impact on plant systems. Equipment damage resulting from the thermal effects of fire (conductive, radiative and convective) are considered as well as the degradation of operation reliability. Potential vulnerabilities raised in the Sandia Fire Risk Scoping Study (NRC, 1989) related to seismic/fire interactions, effects of suppressants on safety equipment and control system interactions are addressed through specifically tailored walkdowns, as defined in the EPRI FIVE methodology (EPRI, 1992).

The fire evaluation was performed on the basis of fire areas which are plant locations completely enclosed by rated fire barriers. The fire area boundaries were assumed to be effective in preventing a fire from spreading from the originating area to another area based on the implementation of a satisfactory fire barrier surveillance and maintenance program. The fire area boundaries recognized in this study are identical to those identified in the plant's Safe Shutdown Analysis (SSA) (CP&L, SSD). In some cases, these fire areas were further subdivided into compartments, and for analysis purposes for the more significant compartments, fire damage states within those compartments were defined that identified subsets of the equipment within the compartments as being damaged due to the fire.

The analysis was conducted in three main stages as follows:

Stage 1 is a systematic qualitative and quantitative screening analysis of all plant fire areas/zones. The screening analysis was based largely on information already available in the plant's SSA and the IPE study. At this stage all equipment and cable in an area/compartment was assumed to be damaged. The damage was assessed qualitatively to determine if the effects were significant; that is, whether the fire would cause a plant shutdown or trip, or lead to loss of safe shutdown equipment. Areas/compartments not screened out qualitatively were then subject to a determination of their associated fire frequency (F_1) and conditional core damage

frequency (P_2), given loss of all functions which may be impacted by the fire. If the resulting fire induced core damage frequency ($F_1 \times P_2$) was less than 1E-6 per year, the area/compartment was screened out.

Stage 2 was a detailed evaluation of the fire areas/compartments which did not previously screen out, using fire PRA techniques as well as methods and data provided in the FIVE technical report. The principal difference in this stage of the analysis is that the resulting impact of intermediate fire growth stages within each fire area/compartment was assessed rather than assuming the contents are immediately damaged.

Stage 3 was an evaluation of the Sandia Fire Risk Scoping Study issues using a tailored walkdown approach.

1.2.3 Other External Events

The analysis of the remaining group of external events, the other external events, was performed by a demonstration that the plant meets the 1975 Standard Review Plan (NRC, 1975) criteria. As specified in NUREG-1407, if this is the case, no estimate of core damage frequency is required.

1.3 SUMMARY OF MAJOR FINDINGS

1.3.1 Seismic Events

The result of the seismic margin study is that there are no significant seismic concerns at SHNPP. The results of the seismic margins assessment are grouped in three categories as follows:

- Housekeeping/Maintenance Issues:

  Thirteen items had minor interaction, housekeeping or maintenance issues that were to be resolved through routine maintenance activities via work request/job orders. Work was completed on all these issues on March 31, 1995.

- Repairs/Modifications:

  Six items were identified for potential modifications or repairs. These items will be completed prior to startup from refueling outage 7, currently scheduled for Spring 1997.

- Analysis:

  The lowest HCLPF was determined to be 0.29g without removing additional conservatism. Therefore, the overall HCLPF for the plant was judged to be 0.3g.

The removable equipment platform spanning between the containment inner structure to the exterior structure required further review for acceptance of building displacements at the RLE.

Two HVAC duct spans required further investigation to accept seismic loadings/displacements at the RLE.

Fifty-one low ruggedness relays were identified and accepted based on additional analysis considering relay configuration, relay function, system configuration and consequences of chatter.

1.3.2 Fires

Only four fire scenarios, one in each switchgear room and two in the control room, were identified as having a contribution to core damage frequency greater than 1E-6 per year. These are described below:

1.3.2.1 Switchgear Rooms A and B

These fire areas are located at the 286' elevation of the Auxiliary Building. Each room contains equipment and cabling associated with their respective safety train, as well as other non-safety equipment and cabling for their respective division. In addition, the turbine-driven auxiliary feedwater pump is powered from a safety train B DC bus, so a loss of this pump would also occur following a fire in Switchgear Room B upon depletion of the batteries. A fire in Switchgear Room B could lead to a loss of offsite power to division A if operator recovery actions are not successful.

Safety train A equipment, powered by equipment located in the Switchgear Room A fire area, will be relied upon for plant shutdown in case of a fire in Switchgear Room B. Significant fire ignition sources for this area include electrical cabinets, transformers, and battery chargers. Cable insulation is the primary source of combustible material for this area. The transient combustible loading for this area is negligible. Fire protection consists of early warning ionization detection located throughout the fire area. Hose stations, fire extinguishers and manual alarm stations are located in and adjacent to the area.

The total core damage frequency contribution from a fire in Switchgear Room B was determined to be 4.0E-6 per year.

The analysis is considered to be conservative, particularly in the assumption of the loss of all train B equipment for any postulated fire that is not suppressed in the cabinet in which it originates.

The most significant fires in Switchgear Room A lead to loss of the entire safe shutdown division A path. The total core damage frequency contribution from a fire in Switchgear Room A was determined to be 3.1E-6 per year.

1.3.2.2 Control Room

The SHNPP control room is located at 305' elevation of the Auxiliary Building, and contains control panels, computer consoles, radiation monitoring panels, alarms, incore instrumentation, desk relay panels, exhaust fans, a component cooling water surge tank and associated controls, wiring in conduit, a kitchen, and an office area.

Ionization-type fire detectors are provided in the control room and inside the panels of the main control board. A hose station, a manual alarm station, and portable extinguishers are provided. No automatic fire suppression systems exist in the area, other than a single sprinkler head located in the kitchen area to mitigate small local fires. Floor water surcharge is not considered significant, and floor water drainage is not required; excess water can overflow to adjacent areas. Plant equipment subject to water damage is mounted on floor pedestals.

Fire hazard combustibles include limited amounts of cable insulation within control cabinets and panels as well as limited quantities of ordinary combustibles necessary for control room computer and instrumentation operation. Transient materials such as paper and rags may be brought into the area during normal operations, for normal facilities maintenance and repair, or during plant shutdown. The quantity of combustible materials which may be involved in area fires (and consequently, the magnitude of these fires and the resultant damage to plant facilities) is reduced by limiting the permanent quantities of ordinary combustibles (class A) and controlling the introduction of transient combustibles through administrative procedures.

The fire postulated for this area assumes ignition and subsequent development into the most severe single fire expected in the area of localized concentrations of combustibles permanently present in the area. The postulated fire is not considered to have sufficient potential for spread to cause failure of redundant safety-related plant equipment and associated cabling and controls. This is based on several facts:

- the control room is permanently occupied; thus manual response can be promptly initiated.
- the control cabinets are of the self-ventilated type.
- any products of combustion will quickly migrate to the ceiling of the room, where the automatic detection system will sound an alarm and alert the control room operators.

The two control room fire scenarios that are not screened out are assumed to require control room evacuation with control of safe shutdown components from the auxiliary control panel (ACP).

- Scenario 1D1

  This scenario results in loss of control for the auxiliary feedwater and emergency service water systems from the main control room. In addition, control functions for many train A components are unavailable in the control room. Shutdown from the ACP is assumed to be necessary. The human error probability for failing to take control at the ACP is dominant. The core damage frequency is estimated to be 1.25E-6 per year.

- Scenario 6B

  This scenario involves a fire in any cabinet in the control room that is not suppressed within 15 minutes. The effects of smoke will necessitate control room evacuation and plant shutdown is assumed from the ACP. This scenario does not involve damage to any equipment, but requires an orderly shutdown from the ACP. The core damage frequency is estimated to be 3.0E-6 per year.

1.3.3 Other External Events

As expected, since SHNPP is a Standard Review Plan plant, none of the other external events is of concern. No unique plant-specific external events were discovered.

1.3.4 Resolution of Unresolved Safety Issues

By performing this IPEEE, CP&L has not only addressed the requirements of the Generic Letter 88-20, Supplement 4, but has also addressed other regulatory requirements.

Three programs, i.e., (1) the external event portion of Unresolved Safety Issue (USI)-A-45, (2) Generic Issue (GI)-131, and (3) the Eastern U.S. Seismicity Issue, are subsumed in the IPEEE.

Any vulnerabilities associated with decay heat removal (USI-A-45) would have been revealed and resolved during this process. By virtue of the fact that no seismic vulnerabilities were uncovered in the seismic margin study, and that the safe shutdown paths analyzed in that study included equipment for decay heat removal, there are no seismic vulnerabilities specific to decay heat removal. Two of the scenarios identified during the fire analysis involve loss of control or power to the auxiliary feedwater system, and therefore, are relevant to the USI-A-45 resolution. In one case, that of Switchgear Room B, the loss of power to the complete B division is a conservative assumption. In the second case, the frequency of the scenario has

been assessed to be 1.25E-6 per year, and when compared with the overall core damage frequency, is not a significant contributor.

The Eastern U.S. Seismicity Issue is resolved by the seismic part of the IPEEE. Since CP&L exercised the seismic margins option, the resolution was achieved by an appropriate choice of RLE. GI-131 deals with the seismically induced failure of the flux mapping transfer cart that would lead directly to the rupture of instrumentation tubes at the seal table. Since this is applicable to Westinghouse plants, it is applicable to SHNPP. It has been addressed in the IPEEE. USI A-46 has subsumed USI-A-17, "Seismic Interactions in Nuclear Power Plants". Although SHNPP is not an A-46 plant, USI-A-17 was addressed through the seismic walkdown that was performed to meet the requirements of the IPEEE.

The Sandia Fire Risk Scoping Study issues, NUREG/CR-5088, were examined through comparison to standardized checklist questions and through specifically tailored plant walkdowns according to the FIVE Methodology. The issues are discussed in section 4.8. The issue of seismic-fire interactions has been addressed and is discussed in section 3.1.6.

The revised "Design Probable Maximum Precipitation" criteria were addressed in Generic Letter 89-22 were assessed with the other external events as recommended in NUREG-1407. The conclusions are presented in section 5.4.

Information Notice 93-53, Supplement 1 (NRC, 1993), requested that the IPEEE address the lessons learned from the effects of Hurricane Andrew on the Turkey Point Nuclear Generating Station. This was addressed during the performance of a walkdown that was conducted to confirm the conclusions of the review of the plant design with respect to other external events, as discussed in section 5.

1.3.5 Resolution of Issues

All seismic related issues are minor, and are either completed or are being reviewed.

The four fire scenarios identified were subjected to review and screening in accordance with NUMARC 91-04 (NUMARC, 1991). In accordance with the criteria in NUMARC 91-04, it was unnecessary to evaluate modifications or administrative changes to address these items. A review of the control room fire scenarios did identify one enhancement to the procedure for remote shutdown (outside of the main control room). The procedure will be revised to specifically check the status of the pressurizer power-operated relief valves after transfer to the ACP to require closure of a block valve if necessary to isolate a failed open relief valve. The current results reported in this document do not credit this procedural enhancement. This procedure change will be implemented prior to startup after refueling outage 6, which is currently scheduled for fall 1995.

1.4 REFERENCES

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SECTION 2

EXAMINATION DESCRIPTION

2.0 INTRODUCTION

As part of the implementation of the Severe Accident Policy, the Nuclear Regulatory Commission (NRC) issued Generic Letter 88-20 (NRC, 1988) on November 23, 1988, requesting that each licensee conduct an individual plant examination (IPE) for internally initiated events including internal flooding. To comply with the generic letter, Carolina Power & Light Company (CP&L) submitted the IPE report for Shearon Harris Nuclear Power Plant Unit No. 1 (SHNPP) in August 1993 (CP&L, 1993). In supplement 4 to the generic letter (NRC, 1991a), the NRC requested that the licensee extend its examination to include what have become known as external initiating events. This report presents the Individual Plant Examination of External Events (IPEEE) for SHNPP in response to that request. The general objectives of the IPEEE are similar to that of the IPE, namely (1) to develop an appreciation of severe accident behavior, (2) to understand the most likely severe accident sequences that could occur at the plant under full power conditions, (3) to gain a qualitative understanding of the overall likelihood of core damage and fission product releases, and (4) if necessary, to reduce the overall likelihood of core damage and fission product release by modifying, where appropriate, hardware and procedures that would help prevent or mitigate severe accidents.

This section demonstrates that the analysis conforms with the NRC requirements for a response to supplement 4, and contains a brief description of the methodology and the information used in the course of the study.

2.1 CONFORMANCE WITH GENERIC LETTER AND SUPPORTING MATERIAL

CP&L has performed an IPEEE pursuant to 10 CFR 50.54, as invoked by Generic Letter 88-20, Supplement 4.

The IPEEE generic letter and report guidance document, NUREG-1407 (NRC, 1991b), requires licensees to consider five specific external events in performing their IPEEE: seismic events, internal fires, high winds, floods (external), and transportation and nearby facility accidents. Licensees are also required to confirm that no other plant unique external events, with potential for severe accidents, are being excluded. The IPEEE subsumes the external events aspects of several ongoing NRC programs, such as Unresolved Safety Issue (USI)-A-45 (decay heat removal); their resolution is also required to be explicitly addressed in the IPEEE response.

Consideration of the specific provisions of the generic letter is provided in the following sections.

2.1.1 Identification of External Hazards

The specific external hazards that should be addressed by the study are identified in the generic letter supplement as:

- seismic events
- internal fires
- high winds and tornados
- external floods
- transportation and nearby facility accidents

However, in addition to addressing these hazards, as required by the generic letter, a review has been conducted to confirm that there are no plant-specific hazards excluded by the IPEEE guidance that might initiate severe accidents.

2.1.2 Methods of Examination

The response to the IPEEE for fires has been met by performing a PRA. Portions of the EPRI Fire Induced Vulnerability Evaluation (FIVE) (EPRI, 1992) methodology have been adopted, particularly in the areas of location screening and fire frequency evaluation for the fire PRA. All other external events, with the exception of seismic events, have been analyzed using the approach discussed in NUREG-1407. This approach includes screening and bounding calculations as a substitute for detailed PRA analysis. The seismic hazard has been addressed utilizing the seismic margins approach (EPRI, 1991).

2.1.3 Coordination with Other External Event Programs

Three programs are subsumed in the IPEEE: (1) the external event portion of USI-A-45, (2) Generic Issue (GI)-131, and (3) the Eastern U.S. Seismicity Issue. Any vulnerabilities associated with decay heat removal (USI-A-45) would be revealed and resolved during this process. The Eastern U.S. Seismicity Issue is resolved by the seismic part of the IPEEE. Since CP&L is exercising the seismic margins option, the resolution is achieved by an appropriate choice of review level earthquake. GI-131 deals with the seismically induced failure of the flux mapping transfer cart that would lead directly to the rupture of instrumentation tubes at the seal table. Since this is applicable to Westinghouse plants, it is applicable to SHNPP. It is addressed in the IPEEE. USI-A-46 has subsumed USI-A-17, "Seismic Interactions in Nuclear Power Plants". Although SHNPP is not an A-46 plant, USI-A-17 is addressed through the seismic walkdown that is performed to meet the requirements of the IPEEE.

The Sandia Fire Risk Scoping Study (FRSS) issues, NUREG/CR-5088 (NRC, 1989a), were examined through comparison to standardized checklist questions and through specifically tailored plant walkdowns according to the FIVE Methodology. The FRSS issues are discussed in section 4.8. The issue of seismic-fire interactions has been addressed and is discussed in section 3.

The revised "Design Probable Maximum Precipitation (PMP)" criteria were assessed with the other external events as requested in Generic Letter 89-22, Supplement 4 (NRC, 1989b). The conclusions are presented in section 5.4.

2.1.4 Containment Performance

In accordance with Generic Letter 88-20, Supplement 4, Appendix 2, mechanisms that could lead to containment bypass, failure of containment to isolate, availability of and performance of containment systems under each external hazard have been evaluated to see if:

(i) they are different from those evaluated under the IPE, or

(ii) external events contribute significantly to the likelihood of containment failure.

Only fires are judged to have the capability of damaging individual components that could impact containment integrity, other than through support systems such as electric power or service water. However, in accordance with the FIVE methodology these issues were only addressed for areas where the core damage frequency is greater than 1E-6 per year. In such cases the following is required: (1) an assessment of the potential for fires to damage equipment or prohibit manual operator action used to accomplish the containment function, and (2) identification of a minimum set of equipment and manual actions necessary to achieve the containment function considering those lost in the fire. This is discussed further in section 4.7.

2.1.5 Accident Management—Vulnerability Screening

The evaluation of severe accident vulnerabilities was accomplished by reference to the Severe Accident Issue Closure Guidelines NUMARC 91-04 (NUMARC, 1991). Core damage sequences were grouped primarily on the basis of location (e.g., fire area/compartment) and also on the nature of the sequence, (non-LOCA, LOCA, fire induced containment bypass), and the group frequency compared to the closure guidelines which are provided in tables 1 and 2 of the NUMARC document.

2.1.6 Documentation of Examination Results

The documentation of the IPEEE study has three components. The first is this report which summarizes the results and findings of the IPEEE analyses given the current plant status, and constitutes the Tier 1 documentation. The second is the SHNPP PSA plant model, which is an updated IPE model, and was used to evaluate conditional core damage probabilities in the critical fire areas. The third is a set of analysis files which contain the supporting assumptions, plant walkdown records, calculations, reference information and QA records, all of which constitutes the tier 2 documentation.

This report follows the format specified in NUREG-1407, Appendix C as closely as possible. Information retained for audit corresponds to that specified in NUREG-1407, section 8.2.

2.1.7 Examination Process

The seismic margins study was performed by a team comprised of CP&L engineers and engineers from EQE International. A peer review was conducted by two engineers from Vecta Technologies Inc.

The fire analysis and the analysis of external events was, for the most part, performed by NUS at their Gaithersburg office. In order to ensure that CP&L personnel are fully conversant with the IPEEE methods used for the analysis of these hazards and are in a position to fully integrate the knowledge gained from performing the work into operating procedures, training programs and appropriate hardware changes, a cognizant CP&L engineer was appointed to be the point of contact throughout the study, and CP&L engineers performed an in-depth review of each of the separate analyses that make up the study.

In addition, CP&L engineers performed the quantification of the conditional core damage probabilities for the various plant damage states that were identified during the course of performing the fire analysis.

2.2 GENERAL METHODOLOGY

The following provides a brief overview of the approach used to evaluate seismic events, internal fires, and other and unique external events for SHNPP. Further details of the methodology and application are provided in sections 3, 4 and 5 of this report, respectively.

2.2.1 Seismic Analysis

The SHNPP seismic IPEEE was performed using the EPRI seismic margins methodology recommended by NUREG-1407 for a focused scope plant. The essence of the approach is a demonstration that sufficient equipment needed to safely shut down the reactor is capable of surviving the review level earthquake (RLE). The following discussion provides a summary of the general approach and its philosophy. The application to SHNPP is described in section 3.

A seismic margin assessment (SMA) consists of the following essential steps:

1. Selection of the RLE
2. Selection of assessment team
3. Preparatory work prior to walkdowns
4. Systems and equipment selection ("success paths") walkdown
5. Seismic capability walkdown
6. Subsequent walkdowns (as-needed)
7. SMA work
8. Documentation

Step 1 involves the specification of the earthquake for which the seismic margin assessment is to be conducted using the guidance provided in EPRI NP-6041 (EPRI, 1991).

The seismic review team (SRT) consisted of senior seismic capability engineers who are ultimately responsible for the seismic capability walkdowns and screening out components from further seismic margin assessment, and also for defining any required seismic margin assessment scope of work for those components not screened out.

The qualifications of the members of the SRT include:

- knowledge of the failure modes and performance of structures, tankage, 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/margin-type capability evaluations including structural/ mechanical analyses of essential elements of nuclear power plants
- some general understanding of seismic PRA conclusions and systems analysis
- some general knowledge of the plant systems functions.

The step 3 preparatory work prior to the walkdowns consists of gathering and reviewing information about the plant design and operation. During this step, the systems engineers define the candidate shutdown paths and the associated frontline and support systems and components. The seismic capability engineers gather information on the seismic design and equipment qualification. Information on locations of relays central to the selected success paths is obtained. Summaries of equipment design features and locations of equipment to be walked down is noted on walkdown data sheets for use by the SRT during the walkdown.

The primary objective of the step 4 walkdown is to assess the relative seismic ruggedness of the major equipment in the candidate success paths and select a preferred and one alternate success path. If weak links are observed that are not economically feasible to fix, then a success path that relies on the weak link component is avoided. Some support systems, such as emergency AC power, are required for all success paths and may be assessed during the step 4 walkdown or postponed until the step 5 walkdown. During the step 5 walkdown, fluid, electrical power and instrumentation systems that are required for the selected success paths were walked down to identify any potential weak links, including the potential for seismic spatial systems interactions (SI). The step 6 walkdown may not be necessary if all screening decisions and necessary data gathering is completed during steps 4 and 5. It is optional if selected components require a revisit to gather further information.

In the case of active electrical and control equipment, it may not be possible or cost effective to demonstrate operability on the basis of achieved test level or by use of generic equipment response spectra (SQUG). The systems engineers are required to evaluate the electrical circuits and operations procedures to assess the consequences and recovery action for relay chatter, breaker trip, etc.

2.2.2 Internal Plant Fires

The object of this task is to estimate the contribution of accident sequences induced by in-plant fires to overall core damage frequency. The analysis considers the likelihood of fire occurrence in each plant area and its subsequent impact on plant systems. Equipment damage resulting from the thermal effects of fire (conductive, radiative and convective) are considered as well as the degradation of operation reliability. Potential vulnerabilities raised in the Sandia FRSS related to seismic/fire interactions, effects of suppressants on safety equipment and control system interactions are addressed through specifically tailored walkdowns, as defined in the EPRI FIVE methodology.

The models were developed in a systematic manner which enables the specific strengths and weaknesses of plant defenses against fire to be clearly identified.

The fire evaluation was performed on the basis of fire areas, which are plant locations completely enclosed by rated fire barriers. The fire area boundaries were assumed to be effective in preventing a fire from spreading from the originating area to another area based on the implementation of a satisfactory fire barrier surveillance and maintenance program. The fire area boundaries recognized in this study are identical to those identified in the plant's Safe Shutdown Analysis (SSA) (CP&L, SSD). In some cases these fire areas were further subdivided into compartments and for analysis purposes, for the more significant compartments, fire damage states within those compartments were defined that identified subsets of the equipment within the compartments as being damaged due to the fire.

The analysis was conducted in three main stages as follows:

Stage 1 is a systematic qualitative and quantitative screening analysis of all plant fire areas/zones, following the methodology described in FIVE, Phase 1 and Phase 2, steps 1 and 2. The screening analysis was based largely on information already available in the plant's SSA and the IPE study. This resulted in the identification of fire areas and compartments in accordance with the FIVE methodology. At this stage all equipment and cable in an area/compartment is assumed to be damaged. The damage was assessed qualitatively to determine if the effects were significant; that is, whether the fire would cause a plant shutdown or trip, or lead to loss of safe shutdown equipment. Areas/compartments not screened out qualitatively were then subject to a determination of their associated fire frequency (F_1) and conditional core damage frequency (P_2), given loss of all functions which may be impacted by the fire. If the resulting fire induced core damage frequency ($F_1 \times P_2$) was less than 1E-6 per year the area/compartment was screened out.

Stage 2 was a detailed evaluation of the fire areas/compartments which did not previously screen out, using fire PRA techniques as well as methods and data provided in the FIVE technical report, phase 2, steps 3 – 5. The principal refinement in this phase of the analysis is that (i) the resulting impact of intermediate fire growth stages within each fire area/compartment are assessed rather than assuming the contents are immediately damaged, and (ii) the impact of fire on containment systems is evaluated. The initial exposure fires resulting from each potential ignition source are evaluated individually. Through the use of COMPBRN IIIe to predict burning rates, heat fluxes, secondary combustible ignition, hot gas layer temperature and target temperature, the fire duration required to cause initiation of fire detection and damage to specific targets is evaluated. The use of COMPBRN demonstrated that either:

(i) damage to equipment/cable in the immediate vicinity of the source occurred quickly such that initiation of fire detectors or auto suppression would not be effective, or

(ii) no damage was sustained by targets located a few feet from the fire source prior to the fire self extinguishing.

In theory, the probability of achieving a particular fire damage state (i) can be represented as:

$$Q(FDS_i) = \int f_{tg}(t) * (1 - F_{ts}(t))dt$$

Where $F_{ts}(t)$ is the probability of successful suppression before time (t), and $f_{tg}(t)$ is the probability that the fire duration required for achieving fire damage stage (i) is between t and (t+dt).

A simplified, discretized form of this equation was used.

The second stage required a substantial new data collection effort including identifying and locating subcomponents and cables associated with critical PRA components and the compilation of an electronic data base to efficiently record and search this data.

The third stage of the fire evaluation was an evaluation of the Sandia FRSS issues using the tailored walkdown approach provided in FIVE, section 7. This evaluation is presented in section 4.4.

2.2.3 Other and Unique External Events

The analysis of other external events was performed based on the progressive screening approach described in section 5 of NUREG–1407.

NUREG-1407 describes the screening process used to arrive at the list of potentially significant other external events: high winds, external floods, transportation and nearby facility accidents. Since this process used generic plant information, NUREG-1407 concludes that the first step in the IPE of other external events is to determine that there are no critical features of the plant or its surroundings that might invalidate the generic conclusions regarding potentially significant hazards (i.e., that their are no unique external events which should be addressed). For SHNPP this was achieved by reviewing the information available in the FSAR, by collecting supplemental information that might have changed since the last revision of the FSAR, and by performing a confirmatory plant walkdown.

For the specific other events called for in NUREG-1407, the analysis was conducted using the procedure recommended in NUREG-1407 as follows:

1) The specific hazard data was reviewed.

2) Significant changes since the operating license was issued were identified.

3) An evaluation was made to determine if the plant and facilities meet the 1975 Standard Review Plan (SRP) (NRC, 1975) criteria. If the review reveals that the 1975 design criteria has been met with respect to a particular hazard, it is judged that the contribution from the hazard is less than 1E-6 per year and the IPEEE screening criteria is met. For hazards where the SRP is not met, one or both of the following optional steps was taken:

4) A hazard frequency determination, or

5) A bounding analysis to show either the hazard could not cause core damage or the resulting core damage frequency is below 1E-6 per year.

In the case of SHNPP all the other external events were screened at step 3.

2.3 INFORMATION ASSEMBLY

The first step in the performance of the IPEEE tasks was the assembly and review of plant specific and generic data which would form the basis for the study. This consisted primarily of the FSAR, seismic design documentation, the SSA fire area layout drawings, SSA cable block diagrams, abnormal and emergency operating procedures, the SHNPP IPE study and SHNPP PSA models, and the EPRI FIVE methodology and supporting documents. The other external events analysis relied on the FSAR and the 1975 SRP for much of the needed information. These sources were supplemented by specific data collection when considered necessary. A precise description of how the information in each of these documents was used is provided in sections 4 and 5.

The analysts responsible for the analysis were already familiar with the techniques and methods of external events analysis at the onset of the study, having already completed other IPEEEs, and external event PRAs. The NUS fire protection engineers were very familiar with the plant through other projects performed for CP&L. The CP&L engineer assigned as the main point of contact was very familiar with the plant systems through his involvement with the IPE. Walkdowns were performed at various phases in the study to confirm the validity of information already used as well as to collect detailed data regarding cable raceway configurations and ignition source locations, etc. Walkdowns were performed according to a pre-determined plan and the results formally recorded.

2.4 REFERENCES

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SECTION 3

SEISMIC MARGIN ANALYSIS

3.0 INTRODUCTION

The SHNPP seismic IPEEE was performed using the EPRI seismic margins methodology recommended by NUREG-1407 (NRC, 1991), Methodology for Assessment of Nuclear Power Plant Seismic Margin, for a focused scope plant. The essence of the approach is a demonstration that the minimal set of equipment that is needed to safely shut down the reactor is capable of surviving the review level earthquake (RLE). This minimal set of equipment is called the safe shutdown equipment list (SSEL). For those items, and the structures that either contain them, or whose failure could cause their failure, an assessment is made of their capability. Those items capable of withstanding the RLE can be screened from further consideration. Any items that cannot be screened are identified and must be addressed in some manner.

Civil structures, equipment and subsystems were reviewed using the methodology provided in EPRI NP-6041 (EPRI, 1991) for a focused scope plant. Screening criteria are provided in Tables 2-3 and 2-4 of EPRI NP-6041 for civil structures, and equipment and subsystems, respectively. The criteria corresponding to 5 percent-damped peak spectral acceleration less than 0.8g were used for SHNPP, based on the definition of the RLE. The guidelines are supplemented by Appendix A of EPRI NP-6041, which provides the basis for the seismic capacity screening guidelines. A walkdown of the items on the SSEL was performed to confirm the as designed characteristics, and to address the seismic-systems interactions issues raised by the USI A-17, GI-131, and the Sandia Fire Risk Scoping Study issues (NRC, 1989).

The detailed seismic margin study is attached as Appendix A to this report. This section is a summary of the analysis and ite conclusions.

3.1 APPLICATION OF SEISMIC MARGIN METHOD TO SHNPP

3.1.1 The Review Level Earthquake for the SHNPP

3.1.1.1 The Safe Shutdown and Operating Basis Earthquakes

Based on historical seismicity, the maximum potential earthquake which might affect the site would be a recurrence of the Charleston, South Carolina earthquake of 1886 which was probably felt as an intensity VI on the Modified Mercalli Index at the site. The largest earthquakes in the site region which are not attributable to any particular geologic structure or seismic zone have been of intensity V. However, it is considered possible that some intensity VII earthquakes in the eastern Piedmont and the Coastal Plain may have been related to exposed or buried Triassic

Basins. Therefore, a shock of intensity VII occurring in the Deep River Basin is considered to be the maximum potential earthquake.

A small fault was discovered during excavation for the Waste Processing Building. The studies performed showed that this fault is not a capable fault, as documented in the SHNPP Fault Investigation Report submitted to the NRC in 1975.

The nearest known fault outside the site is one lying just west of Merry Oaks about three miles to the southwest of the site. Test borings showed nothing that would indicate the development of faults, joints, slickensides or other structural weakness since the late Triassic and early Jurassic time. FSAR section 2.5 provides more detailed discussion of geology and seismology.

On the basis of the seismology of the site area, the safe shutdown earthquake (SSE) is designated as an intensity VII earthquake occurring close to the site. The resulting maximum horizontal ground acceleration at foundation level within the competent bedrock at the site is estimated to be less than 0.12g. In order to provide an additional margin of conservatism, a value of 0.15g is assigned as the maximum horizontal ground acceleration. Safety related structures and systems are designed to assure safe plant shutdown for two horizontal excitations and one vertical excitation simultaneously. Seismic category I systems and components are designed for a minimum of 10 loading cycles under SSE conditions.

The operating basis earthquake (OBE) is designated as one with half the accelerations of the safe shutdown earthquake and equivalent to an intensity VI earthquake near the site. The corresponding horizontal acceleration at foundation level in the bedrock would be less than 0.075g.

3.1.1.2 Ground Response Spectra

The design response spectra used for seismic category I structures, systems, and components, except dams and dikes, were developed in accordance with Regulatory Guide 1.60. The horizontal and vertical design response spectra, normalized to 0.15g for the SSE and 0.075g for the OBE, are presented in Figures 2–3 through 2–6 of Appendix A.

The design response spectra used for the seismic category I dams and dikes were based on a modified form of a smoothed response spectra developed from the strong motion record of the 1935 Helena, Montana earthquake, normalized to the maximum horizontal ground accelerations of the safe shutdown earthquake and the operating basis earthquake. This record was obtained from a seismograph that was established on competent bedrock and is, therefore, considered appropriate for the proposed plant site. These response spectra are presented in Figures 2–7 through 2–10 of Appendix A.

3.1.1.3 Review Level Earthquake

For the seismic IPEEE program, the RLE is prescribed by NUREG-1407 as the NUREG/CR-98 median response spectrum anchored to 0.30g.

3.1.2 Identification of Components and Structures for Review

A preliminary walkthrough was performed by Safety and Reliability Optimization Services, Inc. (SAROS), CP&L, and EQE personnel to search for potential low seismic capacity components. Reference 3 was utilized in choosing the items and identifying boundary conditions and assumptions.

The SSEL is based on the identification of the equipment that is necessary to maintain operability of those frontline systems that provide the critical plant functions required to safely shutdown the plant and maintain it in hot or cold shutdown for seventy two hours. The relevant plant functions are:

- reactivity control,
- reactor coolant system inventory control,
- reactor coolant system pressure control, and
- decay heat removal.

In addition to the equipment in the frontline systems, equipment in the following support systems were identified as being essential for ensuring critical plant functions:

- safety and some non-safety related AC power
- safety related DC power
- HVAC for charging/safety injection pumps (CSIPs), emergency diesel generators, and control room
- emergency service water (ESW)
- chilled water

Success path logic diagrams (SPLDs) were constructed based on an understanding of available plant equipment function as well as the plant's normal and emergency operating procedures. The SPLDs were reviewed and agreed upon by SHNPP operations personnel. They were used as a basis for the identification of the equipment to be included on the SSEL. Equipment selected for inclusion on the SSEL was evaluated in a manner similar to that described in the SQUG Generic Implementation Procedure (GIP) (SQUG, GIP). Guidance from EPRI NP-6041 (EPRI, 1991) was also used in preparing the format for the list of components. The SSEL used for the IPEEE walkdown is presented in Appendix B of the full seismic IPEEE report for SHNPP (Appendix A of this report).

The assessment of the equipment necessary to maintain the identified functions is made under a set of boundary conditions. Offsite power is assumed to be lost. The success paths must be

capable of maintaining the plant in either hot or cold shutdown for a period of 72 hours. At least two success paths must be considered, one for a 1" LOCA, the other for a transient. Non-seismic failures are to be included in the assessment, and the potential for relay chatter must be addressed.

In addition to the components of the systems dsicussed above, the structures housing the components included in the above systems must be reviewed. Seismic Category I structures are cast-in-place reinforced concrete structures. The floors are supported on beams and girders which are in turn supported on interior columns and/or exterior walls. Where interior shear walls are installed, the beams and girders are supported on the shear walls. Interior shielding walls and partitions, other than shear walls, are either reinforced concrete or concrete block, and are not load bearing. The buildings are supported on separate foundation mats 10 feet thick which are founded on suitable rock.

For design purposes, the seismic analyses of the seismic category I structures were performed by using the normal mode time-history technique. The structures, considered as seismic systems and analyzed in this manner, are Containment, Reactor Auxiliary Building, Fuel Handling Building, Waste Processing Building, Tank Building, Diesel Generator Building, Diesel Fuel Oil Storage Building, ESWS Intake Structure, ESWS Discharge Structure and ESWS Screening Structure.

3.1.3 SEISMIC WALKDOWNS

3.1.3.1 Pre-screening

The seismic review team (SRT) had liberal access to plant design drawings, analyses and test reports to use in conjunction with the screening criteria. A considerable amount of information was reviewed and summarized in the screening and evaluation worksheets (SEWS) during a pre-screening. Pre-screening was enhanced by the use of the software program EHOST. EHOST is a database program which has been adapted specifically for use in performing Unresolved Safety Issue (USI)-A-46 and IPEEE evaluations. The program is set up so that the data is incorporated onto SEWS forms which are consistent with those recommended in EPRI NP-6041. In this manner the walkdown teams, using portable computers with the companion program EWALK were then able to work more efficiently by having access to SEWS that had already been partially completed.

The objective of pre-screening was to ensure efficiency in the walkdowns and evaluations with a goal of completing the maximum amount of data entry in advance of the walkdown. This was accomplished by incorporating existing data onto the seismic IPEEE documentation forms prior to the walkdowns. Data that was reviewed consisted of the FSAR, design criteria, stress reports, equipment qualification reports (testing and analysis), structures and equipment support drawings, equipment location drawings, anchorage calculations. and records from other related programs previously performed at SHNPP. The information is not intended as the sole basis for screening, but assists the SRT in their review. An initial walkdown was performed by CP&L

and EQE personnel as part of the pre-screening task to review the SSEL and to group items according to the "Rule of the Box" (SQUG, GIP).

Pre-screening was performed with three purposes in mind:

- to identify critical failure modes to be specifically reviewed on the walkdown.
- to assemble qualification and installation data for use as a basis for screening in the margins review.
- to provide data to be utilized in HCLPF (High Confidence of Low Probability of Failure) calculations.

3.1.3.2 Performance of Walkdowns

The SHNPP seismic margin walkdown was completed during the winter and spring of 1994 in two phases; a balance of plant (BOP) walkdown, and an outage walkdown. BOP walkdowns were completed in January 1994 prior to refueling outage RFO-5 in order to capture elements that could be reviewed during plant operation. Outage walkdowns were performed in March during RFO-5, capturing items located inside containment as well as electrical and control equipment that either needed to be de-energized for access, or were critical to plant operation.

The procedure for performing walkdowns is described in the SHNPP Project Plan (EQE, EPP). The walkdowns concentrated on the strength and load path of the equipment to the structure as well as function and integrity. The review of equipment anchorage was a prime objective for the walkdown teams. The walkdown addressed the physical attributes of the anchorage installation. Anchorage capacities were addressed in the pre-screening, as most of the components already had been evaluated for seismic capacities. The anchorage calculation for the transfer panels was the only calculation that was not found during the reviews. The transfer panels were included as a component for HCLPF evaluation based on the anchorage configuration and the fact that the calculation was not reviewed. The walkdown teams also verified that the anchorage was generally in accordance with the design configuration. The anchorage of the components was screened based on the high capacity anchorage and the SRT walkdown.

Interaction reviews were performed to identify falling, impact, spray and flood issues that could affect success path items. Housekeeping issues were also identified, e.g., compressed gas cylinder not sufficiently secured, fuel board not restrained, storage cabinets that were unrestrained, etc. Thirteen items were identified that had minor interaction, housekeeping or maintenance issues. No spray or flood issues were noted during the SRT walkdown.

Suspended systems, such as conduit, cable trays and ductwork were evaluated on a sampling basis in the plant. A general survey was performed to obtain an overview of the suspended system construction throughout the plant. This included a review of the variety of system layouts, support configurations, and construction details. The inspection also included known concerns for suspended systems, such as taut cables, sharp edges, or overloading of cable trays

and supports, and potential anchor point displacements. The ceiling above the control room was also reviewed to verify if the light fixtures and ceiling grid were adequately supported, and to evaluate the potential for ceiling panels to fall.

Containment penetrations were reviewed on an area basis to identify anomalies that might affect containment performance. Concerns such as falling and differential building displacement were considered. Also reviewed were displacement concerns between the containment shell and internal structure. Containment isolation valves were also reviewed on a walk-by basis based on the caveats listed on the valve SEWS.

3.1.3.3 Results of Walkdown

Seismic margin walkdown results are summarized for structures and equipment and subsystems in Appendix A, Tables 5-1 and 5-2, respectively.

Table 5-1 lists civil structures, following the format of EPRI NP-6041, Table 2-3, along with screening results for SHNPP. All SHNPP civil structures were screened from further review based on the EPRI NP-6041, Table 2-3, screening criteria and Section 3.8 of the SHNPP FSAR.

Table 5-2 lists equipment and subsystems following the format of EPRI NP-6041, Table 2-4, along with screening results for SHNPP. At the conclusion of plant walkdowns, SRT members, including senior level participants from CP&L and EQE, convened to complete the ranking and screening task. SRT members reviewed SEWS and categorized components into the following resolution categories:

- screened out by the SRT
- housekeeping or maintenance issue
- repairs or modification required
- specific issues require clarification
- candidate for HCLPF evaluation

3.1.3.4 Resolution of Issues Arising from the Walkdown

Following the initial screening, SRT members re-walked items not screened out and revisited existing design and qualification documentation. SRT members that performed the initial walkdowns presented and discussed issues with remaining SRT members. Categorization was refined by group consensus.

Equipment and subsystems that were not screened were grouped into 5 categories:

- Thirteen items had minor interaction, housekeeping or maintenance issues that were to be resolved through routine maintenance activities via work request/job orders.

These items are listed in Appendix A, Table 5-3 along with the corresponding work request number. Work was completed on these issues on March 31, 1995.

- Six items were identified for potential modifications or repairs, and are listed in Appendix A, Table 5-4 along with the description of the modification required for the item. These items will be completed prior to startup from refueling outage 7, currently scheduled for Spring 1997.

- One potential interaction issue was identified due to relative building displacement. This issue is addressed in Appendix A, section 9.

- Two components were identified due to interaction issues with HVAC ducts. These items are addressed in Appendix A, section 5.8.2.

- Several other items were identified as candidates for HCLPF evaluation. These are discussed below.

The first pass through SSEL items categorized about 45 items representing about 15 specific issues for HCLPF evaluation. Following these group walkdowns and followup discussion, 16 items were selected for HCLPF evaluation to address five issues. Several of the unscreened components were unique issues, such as no top supports on residual heat removal (RHR) heat exchangers, while others, such as low voltage switchgear located relatively high in the structure, were selected to represent a group of equipment. These five issues are considered to represent the most vulnerable issues observed by the SRT. Other items may have comparable seismic capacity but are considered representative of the selected items.

The five issues are:

Group 1: six panels having anchorage with 45° Nelson studs
Group 2: four low voltage switchgear
Group 3: two RHR heat exchangers
Group 4: two flat bottom storage tanks
Group 5: two ESW pumps

HCLPF evaluations are summarized in Appendix A, section 6. With the exception of the RHR heat exchangers, all the groups have a HCLPF capacity above the RLE. That of the RHR heat exchangers is calculated to be 0.29g. It is considered that further refinement of the associated piping analyses to eliminate any unnecessary conservatism in the nozzle loads may raise the HCLPF capacity above the RLE. This was not done however, because the capacity is essentially the same as the RLE.

3.1.4 Relay Evaluation

As described in NUREG-1407, for the focused-scope plants, which includes SHNPP, the evaluation of relay chatter emphasizes the consideration of relays with known low seismic ruggedness. Such relays are to be evaluated for their potential plant impact. Fifty-one such low-ruggedness relays were identified. Further review of these 51 relays resulted in the following conclusions:

- Twelve of the relays were determined not to be low-ruggedness relays because they were not in a configuration that had been determined to be subject to chatter for the relevant model.

- Twenty-nine of the relays were determined to be non-essential relays in which chatter is not a concern.

- Four of the relays were determined to be essential. However, chatter of these four relays would not produce any unacceptable consequences.

- The remaining six relays were determined to be essential relays. These are the differential relays (one for each phase) that would actuate the lockout relays on the two 6.9kv emergency buses (switchgear units). These relays are all General Electric model 12PVD21B1A relays. The equipment tag numbers for these six relays are 87SA-A-1738, 87SA-B-1738, 87SA-C-738, 87SB-A-1739, 87SB-B-1739 and 87SB-C-1739. The relays are mounted in the doors of cubicle 10 and 6 on the emergency buses 1A-SA and 1B-SB, respectively. The relays are mounted within 18 inches of the floor. The tripping of the bus would require two of three relays to chatter simultaneously. A detailed analysis of the seismic qualification of the buses has identified that sufficient margin exists.

3.1.5 Containment Integrity

The main objective of the containment analysis is to identify vulnerabilities that involve early failure of containment functions. This includes consideration of containment integrity, containment isolation, and other containment functions.

The guidance provided in NUREG-1407 states that "generally containment penetrations are seismically rugged; a rigorous fragility analysis is needed only at review levels greater than 0.3g, but a walkdown to evaluate for unusual conditions (e.g., spatial interactions, unique penetration configurations) is recommended." With regard to containment systems, the guidance provided is that "seismic failures of actuation and control systems are more likely to cause isolation system failures and should be included in the examination." The major concern deals with relay chatter, which is addressed in section 7 of Appendix A to this report.

A review of seismic capacities for containments of similar design to SHNPP indicates that the containment structure is expected to have a seismic capacity far above the RLE (Summitt, 1990). In addition to the containment structure, NUREG-1407 suggests that certain considerations could require some additional study. Hatches that employ inflated seals is one potential area for concern. The SHNPP design does not employ this type of seal. Another concern is the post-operation of penetration cooling that is present in some designs. SHNPP, however, does not employ this design feature. Finally, air-closed valves used for isolation are also listed as a possible concern. SHNPP does not utilize air-operated valves for containment isolation that require a supply of air to function. Thus, failures in containment isolation would not be expected due to seismic failures of the isolation valves.

The containment walkdown consisted of looking/evaluating unusual conditions/configurations (e.g., spatial interactions, unique penetrations, piping hard spots, items/components bridging the seismic gap between the containment liner and interior structure, and etc.). The containment walkdown was performed by the SRT (see section 3 of Appendix A).

No unusual conditions/configurations where noted except for the platform in the equipment hatch at elevation 286 ft. The platform is supported/welded to the liner at the equipment hatch barrel and is anchored to the floor of the interior structure at elevation 286 ft. Therefore, the platform bridges between the interior and exterior containment structures. This interaction issue is evaluated in calculation HNP-C/PLAT-1023 and is determined not to be detrimental to the containment integrity.

As stated previously, the main objective of the containment analysis is to identify vulnerabilities that involve early failure of containment functions. The SRT reviews and walkdown performed of the containment did not identify any vulnerabilities. Therefore, the HCLPF for the containment is greater than 0.3g, based on the results of this analysis.

3.1.6 Seismic Induced Fire and Flood Evaluation

Seismic/fire interactions, effects of suppressants on safety equipment, and control system interaction are addressed in the IPEEE. As discussed in Section 8 of Appendix A, failures of the fire protection system that lead to a release of water will not have a detrimental effect on the capability to safely shut down the reactor.

Other system interaction issues relate to the potential for the earthquake to result in a fire. Consequently, a review of the potential fire sources was performed to identify any vulnerabilities. As discussed in section 8 of Appendix A, none was found.

3.2 COORDINATION WITH OTHER PROGRAMS

Three programs, i.e., (1) the external event portion of USI-A-45, (2) GI-131, and (3) the Eastern U.S. Seismicity Issue, are subsumed in the IPEEE. The decay heat removal issue (USI-A-45) is addressed by the fact that the SSEL contains the equipment necessary to maintain

decay heat removal for a period of 72 hours. Since CP&L is exercising the seismic margins option, the resolution of the Eastern U.S. Seismicity Issue is achieved by an appropriate choice of RLE. GI-131 deals with the seismically induced failure of the flux mapping transfer cart that would lead directly to the rupture of instrumentation tubes at the seal table. Since this is applicable to Westinghouse plants only, it is applicable to SHNPP. It is addressed in the IPEEE in section 5.9.1 of Appendix A. USI-A-46 has subsumed USI-A-17, "Seismic Interactions in Nuclear Power Plants". Although SHNPP is not an A-46 plant, USI-A-17 is addressed through the seismic walkdown that is performed to meet the requirements of the IPEEE.

3.3 CONCLUSIONS

The principal conclusion is that there are no seismic vulnerability concerns at SHNPP. The results and conclusions of the SHNPP IPEEE seismic project are discussed in more detail in Appendix A.

3.4 REFERENCES

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SECTION 4

INTERNAL FIRES ANALYSIS

4.0 METHODOLOGY SELECTION

Acceptable methodologies for analyzing internal fires are specified in NUREG-1407, section 4 (NRC, 1991b). Of those methods, a fire PRA was selected for SHNPP. Specific fire PRA issues raised in NUREG-1407 were dealt with as follows:

- Fire areas of potential risk significance were identified using the initial qualitative and quantitative screening steps defined in the FIVE methodology (EPRI, 1992a) document.

- Those fire areas which did not screen out were subject to detailed modeling described in various procedure guides such as NUREG-2300 (NRC, 1983), NUREG-2815 (NRC, 1985f) or NSAC/181 (EPRI, 1993). The COMPBRN IIIe code (EPRI, 1991) was used for deterministic modeling of intra-area fire propagation. Inter-area fire propagation analysis was not required based on the review of the fire area boundaries performed to address the Sandia Fire Risk Scoping Study (FRSS), NUREG/CR-5088 (NRC, 1989b) issues.

- Fire frequencies in particular locations accounted for both generic experience (US plant experience obtained from the EPRI Fire Event Database (EPRI, 1992b)) 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 for periodic inspections for transients.

- A qualitative review of the input and modeling uncertainties has been performed. However, no formal propagation of those uncertainties through the model was performed or considered of value in terms of providing additional insights.

- FRSS issues were addressed through specifically tailored walkdowns as defined in the FIVE methodology, including seismic fire interactions, effects of fire suppressant on safety related equipment, fire barrier effectiveness and control systems interactions.

4.1 FIRE HAZARD ANALYSIS

4.1.1 Overview

In theory the contribution to core damage frequency (CDF) from fires anywhere in the plant may be assessed in detail. However this was impractical due to the large number of possible

scenarios, and was also unnecessary, since fires in many plant areas are incapable of causing significant damage. Consequently the first stage in performing the SHNPP fire analysis was to perform a systematic screening of all fire areas.

The FIVE methodology qualitative and quantitative screening procedures were applied, as described below. The results of this screening is presented in section 4.5 of this report.

4.1.1.1 Qualitative Screening Analysis of Fire Areas

The major steps are briefly summarized below. Further details of the methodology can be found in section 5.3 of the FIVE methodology document.

Essentially the purpose of this task was to identify the boundaries of the plant fire areas and their respective compartments, together with the location of equipment and cables which, if damaged by fire, would cause a plant shutdown or degradation of shutdown paths identified in the SHNPP Safe Shutdown Analysis (SSA) (CPL, SSD) and the PSA. 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 Fire Areas and Compartments

The plant was initially divided into fire areas which are physically separated from one another by fire rated walls, floors and ceilings which comply with the requirements of the FIVE methodology (definition 2.2). 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. Although the boundaries of such compartments may not be fire rated and may have openings, they will significantly confine heat and combustion products. The purpose of identifying separate compartments was to better locate equipment and cables and to provide a basis for a refined screening if required later on in the analysis. In the interests of efficiency, compartments were only identified if corresponding component and cable locations were readily available within the Safe Shutdown Analysis or easily ascertained by a plant inspection.

Step 2: Identify Plant Safe Shutdown Systems

In step 2, the SSA and PSA models were reviewed to identify the SHNPP 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 2–3). In general, the SHNPP PSA event trees were constructed to model success paths which lead to hot shutdown. The combinations of systems required to achieve this stable condition for a period of 24 hours, following various types of initiating events, are discussed in Section 3 of the IPE (CP&L, 1993).

Step 3: Identify Safe Shutdown Equipment in Each Fire Area or Compartment

Safe shutdown components and the associated cabling for the required components, i.e. components in the required safe shutdown (SSD) division, are identified in the Safe Shutdown Separation Analysis Report for SHNPP. Equipment/cables in the non-required train as well as cabling for the automatic actuation of auxiliary feedwater (AFW) and emergency service water (ESW) were then obtained from the cable database and from plant drawings. Based on the above information, a summary of the affected SSD equipment in each fire area was documented. In addition, the offsite power cabling and components were also added to this list.

Step 4: Perform Fire Area Safe Shutdown Function Evaluation

Each plant area was first evaluated to ascertain whether it contained any susceptible safe shutdown equipment. If so, a demand for shutdown was assumed unless it was shown with confidence that the fire would not cause an automatic trip, and plant operating conditions or technical specifications would not require a shutdown within eight hours.

The SHNPP fire analysis incorporates a revision of the FIVE methodology (NUMARC 1993) which requires that fire areas or compartments not be screened out unless it was shown that safe shutdown equipment was not damaged and there was no demand for shutdown. (Note: It was not necessary to assume a loss of offsite power as was required for the Safe Shutdown Analysis, unless there is some potential for the postulated fire inducing such an event as identified in step 3).

Step 5: Compartment Identification, Interaction and Screening

The screening approach up to this point conservatively assumed that a fire would disable all equipment and cable in the fire area being evaluated. As mentioned previously, fire compartments within some fire areas were identified based on plant drawings and walkdowns. A fire compartment interaction analysis (FCIA) was performed in this task to determine the potential and consequences of fire spread between compartments using the screening criteria provided in section 5.3.6 of the FIVE methodology document. Factors such as the characteristics of the barrier, combustible loading and installed fire detection and suppression systems were considered.

Where all boundaries of a compartment (or the perimeter of a group of compartments) could be screened out (i.e., risk of propagation is insignificant) then the screening criteria applied in steps 4 and 5 above were re-applied considering only the potential fire damage within the compartment (or compartment group).

4.1.1.2 Fire Frequencies

The purpose of this task was to evaluate the fire frequency for areas and compartments which were not screened out in the qualitative screening process described in Section 4.1.1.1. These

frequencies are intended for use in the quantitative screening evaluation and detailed fire analysis.

For SHNPP, 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 Database. The approach requires the analyst to weigh 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 SHNPP drawings. The information was modified 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.

4.1.1.3 Quantitative Screening Analysis

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

(i) the total area/compartment fire ignition frequency, or

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

At this screening stage, simple PSA models were used to determine the CCDP.

4.1.2 Analysis Results

4.1.2.1 Qualitative Screening Analysis

The qualitative screening analysis was completed using the revised FIVE screening methodology as discussed in section 4.1.1.1. Table 4-1 is a summary of the screening performed during the qualitative analysis. It includes fire plant areas that addressed in the SSA.

Two screening questions are asked in the table. A "Yes" answer to either of the questions, (i.e. there are SSD equipment in the area or a plant shutdown is required given a fire in the area) indicated that further analysis of the area was required. A "No" in the table to both these questions indicated that the fire area was screened at this level and no further analysis was required. As indicated in Table 4-1, only one SHNPP fire area (5-W-BAL, Waste Processing Building Balance) was screened out by this process.

4.1.2.1.1 Sub-Division into Compartments and Fire Compartment Interaction Analysis

There are two fire areas in the Auxiliary Building (1-A-BAL-A and 1-A-BAL-B) that are relatively large. Each of these were subdivided into smaller sub-areas (or compartments) for this analysis. In this way, a more realistic screening of the areas can be carried out since the subset of safe shutdown components in the compartments is smaller. However, to qualify as compartments certain requirements have to be met. A FCIA was carried out to determine the potential for, and consequences of, fire spread across compartment boundaries, using the screening criteria provided in section 5.3.6 of FIVE. A fire compartment barrier can be screened from further consideration based upon the following criteria:

1) Boundaries between two compartments, neither of which contain SSD components nor plant trip initiators, on a basis that fire involving both compartments would have no adverse effect on safe shutdown capability,

2) Boundaries that consist of a 2-hour or 3-hour rated fire barrier, on the basis of fire barrier effectiveness,

3) Boundaries that consist of a 1-hour rated fire barrier with a combustible loading in the exposing compartment <80,000 Btu per ft^2, on the basis of fire barrier effectiveness and combustible loading.

4) Boundaries where the exposing compartment has very low combustible loading (<20,000 Btu per ft^2) and automatic fire detection, on the basis that manual suppression will prevent fire spread to the adjacent compartment.

5) Boundaries where both the exposing compartment and exposed compartment have a very low combustible loading (<20,000 Btu per ft^2), on the basis that a significant fire can not develop in the compartment.

6) Boundaries where automatic fire suppression is installed over combustibles in the exposing compartment, on the basis that this will prevent fire spread to the adjacent compartment.

To define compartment boundaries, the existing fire zones within fire areas 1-A-BAL-A and 1-A-BAL-B were used as starting points. Other compartments were then added using observations from plant walkdowns. Usually, these other areas are individual walled-off rooms like the charging pump rooms or storage rooms.

A list of compartments that meet one of more of the above criteria is provided in Table 4-2. The screening of the compartment boundaries is documented in FCIA worksheets which are included in the tier 2 report. Note that compartment identifications that begin with a numeral are fire zones as defined by the SHNPP fire protection program. Identifications which begin with a letter are areas within the fire zones that also meet the FCIA criteria.

4.1.2.1.2 Qualitative Screening Analysis for the Compartments

A qualitative screening analysis (similar to that performed for the fire areas) was then carried out for each compartment. The results of this screening are included in Table 4-2 which shows that 14 of the 43 compartments can be qualitatively screened out because they do not contain components or cabling that will impact plant risk in terms of CDF.

4.1.2.2 Fire Ignition Frequencies for Quantitative Screening

For each area that was not screened out in the previous step, estimates of fire ignition frequency were prepared for use in the quantitative screening analysis. 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 SHNPP 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 4-3 contains a summary of the fire area ignition frequencies obtained from the individual ISDS for each SHNPP area. (Individual area ISDS are included in the tier 2 report.) As can be seen from Table 4-3, SHNPP fire areas do not screen out based solely on fire ignition frequency (i.e. none of the ignition frequencies were below the 1E-6 per year criteria).

It should be noted that in later, more detailed analyses, not all events in the EPRI database are included. The types of events which could be removed are these which do not cause damage, those occurring during plant commissioning, and those which are self-extinguished. Some fire frequencies determined using FIVE methodology have been adjusted to reflect only these significant fires. Frequencies modified in this manner are discussed in the following sections.

4.1.2.3 Quantitative PRA Screening Analysis

The FIVE methodology includes a second level of screening which provides for a conservative estimation of the contribution to CDF. The equipment in an area is assumed to fail due to fire. Using an event tree representative of the most significant failure, the contribution to the CDF is calculated. If this contribution is less than 1E-6 per year the area or compartment can be screened out. For this analysis, the PSA fault tree and event tree models were used.

4.1.2.3.1 Assumptions and Other Modeling Considerations for the PRA Screening

The following assumptions were made:

- Unlike the SSA, offsite power is assumed to be available following a fire unless cabling or equipment for offsite power is present in the fire area. Based on the equipment and cable routing location analysis for offsite power systems, it can be postulated that a fire in fire areas 1-A-BAL-A, 1-A-BAL-B, 1-A-BAL-C, 1-A-BATA, 1-A-BATB, 1-A-CSRA 1-A-CSRB, 1-A-SWGRA, 1-A-SWGRB,

1-D-DGA, 1-D-DGB, 12-A-CR, 12-A-CRC1, as well as in the Turbine Building roof and the switchyard area, could result in a loss of offsite power to 6.9kV emergency buses 1A-SA and/or 1B-SB.

In addition, the SHNPP IPE identified an initiator where the loss of a non-vital DC bus (DP-1A) would result in a plant trip due to effects on the secondary plant equipment. This trip is complicated by a loss of offsite power due to a loss of control power to the breakers which must reposition to transfer plant electrical buses from the main generator to offsite AC power through the startup transformers. Since non-vital bus DP-1A is located in area 1-A-5-BATN, a fire in this area could result in a loss of offsite power.

- The PSA success criteria were used to determine the minimum combinations of equipment necessary to mitigate core damage. This, in general, is less restrictive than the success criteria used in the SSA. In addition, consistent with the PSA, a successful end state is defined as reaching and maintaining a safe, stable state as characterized by a constant RCS temperature, pressure, and inventory. This criteria is equivalent to the SSA conditions for hot standby.

- In the PSA model, rod insertion is considered achievable by any of several means for reactivity control. The effects of a fire are more likely to cause rod insertion through deenergization of the reactor protection system (RPS) (with subsequent rod drop into the core) than to inhibit RPS operation. Also, there are procedures available which instruct operators to manually deenergize RPS equipment from within or from outside the control room if automatic deenergization fails. The potential for fire events to prevent adequate reactivity control by designed means is therefore considered to be insignificant; boration from the boric acid tank via the normal charging path to control reactivity is not considered in the IPEEE analysis.

- Passive mechanical components (for example, valves, heat exchangers and piping) exposed to fire were assumed to remain structurally intact as pressure barriers or structural members of a system. Other mechanical components that are exposed to a fire were assumed to be operable after the fire is extinguished if a local operational capability exists (for example, a handwheel in a valve).

- Since the SSA study did not consider the routing of cables required for the automatic actuation of emergency systems, no credit was taken for such actuations with the exception of the actuation of the AFW and ESW systems. For the AFW and ESW systems, cable tracing was performed to determine routings throughout the plant.

- All PSA components that are not also SSA components were also assumed to be failed in the screening analysis except as noted above for offsite power components and for AFW and ESW actuation components.

For the screening quantification, the PSA transient event tree was used except for areas where there is a potential for fire induced LOCA due to a breach of the high-low interface boundary. This scenario would require both of the following:

(i) the fire must cause a sufficient number of electrical faults to cause the spurious opening of valves at a reactor coolant system (RCS) high-low pressure boundary, and

(ii) failure of the operator to isolate the LOCA prior to loss of significant RCS inventory.

The Safe Shutdown Separation Analysis identifies high-low pressure interface valves which have the potential to spuriously open because of fire-initiated hot shorts. Many of the valves are pneumatic or solenoid operated, and fail closed on loss of air or DC power. Furthermore, both pre- and post-fire procedures are in place to either deenergize individual component power supplies or to isolate flow paths with redundant valves given fires in certain plant areas. However, within the framework of the IPEEE, the possibility of the operator failing to isolate the appropriate circuits, as well as coincident random equipment failures, must be addressed. Given the former event, the potential may exist for a fire to cause spurious valve operation via hot shorts. Once the high-low interface pathway has been aligned (due to such a short), subsequent isolation valve closure would be required which introduces the potential for a hardware failure leading loss of isolation capability.

The high-low interface pathways can be divided into three categories:

- Pathways which are protected by a mechanical check valve, as well as a fail closed isolation valve. These include the normal charging and auxiliary spray lines. The probability of the check valve failing to reseat coincident with operator failure to deenergize the circuit and hot shorts leading to spurious valve operation was judged to be negligible. The hot leg low head safety injection pathway with two check valves in series and a normally closed motor-operated valve (MOV) also fall into this category. Fire-induced LOCAs via these pathways were therefore discounted.

- Pathways for which the control circuits of the associated valves are normally deenergized prior to plant start up. These include the residual heat removal (RHR) suction and the reactor head and pressurizer vent paths. The probability of operator error leading to these control circuits not being deenergized, the fault remaining undiscovered until the time of the fire, and the fire causing control circuit hot shorts which open at least two valves in series was considered to be extremely low. Fire-induced LOCAs via these pathways were thus discounted.

- Pathways for which the control circuits of the associated valves are normally energized, but are required to be deenergized according to dedicated shutdown procedures following a fire. These include the chemical and volume control system

(CVCS) letdown, CVCS excess letdown, and the pressurizer power-operated relief valve (PORV) paths. In these cases, internal hot shorts may result in an unisolated LOCA given the following:

(i) operator fails to deenergize control circuit prior to core uncovery, or
(ii) operator successfully deenergizes circuits, but the isolation valves fails to close.

In the case of the CVCS letdown and excess letdown, the line sizes (1" or less) are such that, even with no charging flow, sufficient time is available to deenergize the valve control circuits and isolate the LOCA before the loss of RCS inventory would jeopardize core cooling. Furthermore, since redundant, fail closed isolation valves are located in each line, the likelihood of not isolating the LOCA due to valve failures is also small. Consequently, the possibility of an unisolated LOCA in the CVCS letdown or excess letdown paths was discounted.

In the case of the pressurizer PORV paths, the line sizes are such that the loss of RCS inventory may jeopardize the core within a relatively short period of time. Given this time window available for successful operator action, the probability of error may be significant. Furthermore, the cable associated with the PORV block valves may also be damaged by the fire, leaving the PORV as the only means of isolating the LOCA. Therefore, failure to isolate the LOCA due to random valve failure may also be significant.

In conclusion, the only potentially significant mechanism for a fire to induce an unisolated LOCA was judged to be as a result of an internal hot short associated with a pressurizer PORV circuit.

4.1.2.3.2 Individual Area PRA Screening

For this screening, the SHNPP PSA models were modified so thatcomponents (or components with cables) within a fire area/compartment are failed by the fire. In addition, the assumptions described in the section 4.1.2.3.1 were applied. A summary of the screening analysis results is presented in Table 4-4. Based on this analysis, the following 33 areas/ compartments were screened out.

1-A-5-BATN	1-O-PA	1-O-PB
1-A-BATA	1-A-BATB	1-D-DGA
1-D-DGB	1-D-DTA	1-D-DTB
5-O-BAL	5-F-BAL	5-S-BAL
12-O-TA	12-O-TB	12-A-BAL
12-A-HV&IR	12-I-ESWPA	12-I-ESWPB
1-A-4-CHF A	1-A-4-COM I	Chg Pump 1A-SA Area
Chg Pump 1C-SAB Area	Chg Pump 1B-SB Area	1-A-34-RHXB
1-A-1-PA	1-A-1-FD	1-A-1-ED
1-A-1-PB	1-A-3-TA	1-A-5-HV3
1-A-4-COR	1-A-46-ST	Valve Gallery A

4.1.3 Detailed Fire Analysis

The second part of the fire analysis deals specifically with the potentially significant fire areas which could not be eliminated as part of the qualitative and quantitative screening process. The principal difference in this analysis is that the likelihood and resulting impact of intermediate fire growth stages within each fire area are assessed (rather than assuming the contents of the entire compartment are immediately damaged). The approach described sections 4.3 through 4.6 uses aspects of the FIVE Methodology (sections 6.3 - 6.9) but aims to develop a comprehensive model of the various fire scenarios leading to core damage. These sections contain discussions of each major aspect of fire modeling: fire growth and propagation, component fragilities, fire detection and suppression, and human error analysis. The control room analysis, which uses a methodology that is somewhat different than the COMPBRN analyses is described in section 4.6.3, and the evaluation of the effect of fires on containment systems are described in section 4.7.

4.2 REVIEW OF PLANT INFORMATION AND WALKDOWN

4.2.1 Plant Information Sources

For this analysis, SHNPP plant information was obtained from plant drawings, plant procedures, and other documents like the IPE, the FSAR and the SHNPP Safe Shutdown Separation Analysis report. The specific sources of information are discussed below.

The SHNPP fire protection procedures contain a complete discussion of the plant's fire protection program including: the organizational responsibilities; its 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). Specific examples include: FPP-001, Fire Protection Conduct of Operations; FPP-013, Fire Protection—Minimum Requirements and Mitigating Actions; and FPP-014, Fire Protection Surveillance Requirements.

The SHNPP SSA defines the post fire safe shutdown methodology including the definition of the safe shutdown functions, systems and components. This report also addresses associated circuits and alternate shutdown capability. In addition, fire area assessments forfire areas containing safe shutdown equipment is provided.

The SHNPP FSAR defines the fire area boundaries within the plant and evaluates each of the fire barriers. It also documents the in-situ and transient combustible loading in each fire area. In addition, the fire protection systems and ventilation systems for the areas are provided.

The above reports provide information on the method of compliance with applicable regulations, combustible loading analysis, exemption requests and engineering analysis. The existence of these report is pre-supposed by the FIVE methodology. They were used to obtain the fire area boundary definitions, the safe shutdown equipment/cables located in each fire area, and the

combustible loading characteristics, including cable tray loadings and flammable liquid inventories.

The SHNPP cable database was used to identifythe cabling that runs through specific fire areas. Plant electrical drawings were utilized to provide the cable routing within an area in the cable tracing effort.

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

Plant procedures were utilized in the evaluation of the human error probabilities (HEPs) to analyze how the operators would respond to a fire in various areas of the plant.

4.2.2 Plant Walkdowns

The walkdowns performed for the SHNPP fire analysis were confirmatory in nature. The main objective of these walkdowns was to gather data which cannot be derived from documented sources to perform the screening and detailed analyses, as well as complete the Fire Risk Scoping Study Evaluation. Another objective was to confirm that information and assumptions used while performing the screening and detailed analyses are consistent with the as-built as-operated plant. The main walkdown activities are discussed below.

4.2.2.1 Verification of As-Built, As-Operated Conditions

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) was obtained. A general inspection of the fire area barriers, penetrations, dampers etc., was also carried out.

A two-day walkdown was performed primarily to verify the information in the qualitative and quantitative screening analysis files. This walkdown took place following the completion of the screening analyses and prior to the start of the detailed analysis effort. It was performed under the guidance of a procedure which included appropriate check-off lists.

Walkdowns were also used to help perform the fire compartment interaction analysis. To be specific, walkdowns were used to verify that the 1-A-BAL-A and 1-A-BAL-B plant areas could be compartmentalized into smaller fire-independent areas as defined by the EPRI FIVE document. Compartment boundaries and the potential spread of fire across these boundaries were evaluated.

Several additional walkdowns of an informal nature were performed with the aim of obtaining information regarding a specific area of the plant. Examples include walkdowns to verify the inputs to the COMPBRN models.

All walkdowns were carried out by NUS and/or CP&L personnel. The participants were either fire protection engineers or PRA/IPE specialists who, between them, possess the following qualifications:

(i) Familiarity with the SSA safe shutdown paths, equipment and cable raceway layouts and 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.

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

4.2.2.2 Verification Of Cable Routing and Other Parameters for COMPBRN Modeling

As part of the walkdown effort, attempts were made to visually verify the cabling to ensure that cable routing used in the analyses represents the as-built plant. However, given the congestion of conduits in the ceilings of many plant areas, it was not feasible to field-verify the cable routes visually. Instead, cable routing obtained from drawings were verified against the SHNPP cable routing database which provides routing by fire area and by raceway.

4.3 FIRE GROWTH AND PROPAGATION

4.3.1 Fire Scenarios

The first step in performing the fire growth and propagation modeling was the identification of the potential fire scenarios. The arrangement of the area being evaluated was mapped out, including the specific location and function ofcables and equipment associated with safe shutdown functions and containment systems. These items are targets for damage in the event of an exposure fire and also may represent fire sources in themselves. Second, the location and characteristics of potential fire sources within the compartment were identified. The sources include the permanent or fixed combustibles (e.g., electrical cabinets, electric motors, cables), transient combustible (e.g., trash, used protective clothing) and flammable liquids or gas storage vessels. The location of targets and fixed combustible fire sources were then represented on simplified compartment layout drawings.

Having determined the location of shutdown components in relation to each potential fire source, the next step was to review the area to determine if there were obvious compartments in which the fire damage may be confined both physically and with respect to the extent of loss of safe shutdown functions. Fire propagation modeling was then used to confirm the independence of the compartments with respect to fires.

The final step was to define damage states within each compartment. If a worst case fire was calculated to result in minimal damage, then it was assumed that all compartment fires would be bounded by this worst case fire and no further fire modeling was required. If redundant systems were located in the compartment, multiple damage states were defined. For example, in a compartment where two shutdown trains are present, three damage states may be defined; loss of train A, loss of train B, and loss of both trains. Fire modeling techniques were then used to identify which ignition sources might result in each damage state, taking into account the likelihood of fire suppression prior to damage.

The frequency of each damage state was then determined based on the number of ignition sources within the target range and the likelihood of suppression. Finally, the sequence frequencies were calculated using the PSA model modified to account for fire damage.

4.3.2 COMPBRN Analysis

The COMPBRN IIIe computer code (EPRI, 1991) was used in fire areas where detailed fire analysis is required (one exception is the Control Room). COMPBRN IIIe was developed specifically for use in nuclear power plant fire PRAs and has been approved by the NRC for use in IPEEE fire analyses. For a given fire scenario, the code calculates the time to damage specific targets. Specific targets in this analysis are usually components and the power and/or control cabling for components. The PSA and the SSA were important documents used to focus the selection of specific targets for analysis.

COMPBRN is a deterministic code which follows a quasi-static approach to simulate the process of fire during the pre-flash-over period in an enclosure. It breaks a postulated fire environment into three sectors: flame/plume sector, hot gas layer sector, and finally 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 is used to calculate the time to damage or ignition. The COMPBRN IIIe manual (EPRI, 1991) discusses the modules of the code and the parameters used for defining a fire scenario.

4.3.2.1 COMPBRN Modeling Considerations, Inputs and Assumptions

The assumptions and other modeling considerations that were made during COMPBRN modeling are given below.

1. The non-plant specific input parameters were taken from the sample input file for COMPBRN IIIe unless otherwise stated.

2. For a given fire ignition source, the position for a postulated fire was assumed as follows:

   Electrical Cabinets (e.g. motor control centers (MCCs), switchgear, transformers): For objects located above an electrical cabinet, the top of the cabinet was chosen as the location of a postulated fire (EPRI, 1992b, page 6-13). For the objects located at the same elevation or at elevations below the top of the cabinets (i.e. the fire source), a location which would induce the most thermal stress on the target object, was chosen as the location of the fire source. These assumptions would yield the most conservative results.

   Pumps: Pump fires were treated as combustible liquid lubricant spill fires. The location of the spilled fuel area was, conservatively, selected such that the fire would be closest to the target objects. However, location specific data was factored into the analysis.

   Compressors: Compressors were treated the same as pumps (i.e. lube oil was considered to be the combustible material and the compressor motor was the ignition source).

3. Consistent with the other fire PRAs (for example, see page 5-18 of NUREG/CR-4550 Volume 3 Part 3 (NRC, 1990c)), cables in conduits (in metal sleeves) or armored cables were assumed to be incapable of igniting and do not contribute to the heat release in the area. However, they were assumed to be damaged if the damage temperature is exceeded.

4. The following heat release rates for the fire ignition sources were used:

   Electrical Cabinets: In general, based on Sandia National Laboratory (SNL) cabinet fire tests 23, 24, and 25 (NRC, 1987c), a heat release rate of 1,200 kW was assumed for the electrical cabinets. Any diversion from this assumption is addressed in the analysis for that particular case.

Pumps: As stated previously, pump fires were postulated as a combustible liquid lubricant spill fires. The parameters of the liquid used for the COMPBRN model were based on the data postulated for oil fires in NUREG/CR-4550 page 5-19, Table 5.7 and are as follows:

Density:	900 kg/m^3
Specific Heat:	2100 J/kg-K
Heat of Combustion:	4.67E7 J/kg

The surface area of the spilled oil was calculated assuming pool thickness provided in FIVE Table 3, page 10.4-69. However, evaluation of the surface area of the spilled oil for each specific enclosure, was performed based on the layout of the enclosure (i.e. defenses such as dikes, drains, floor grates, etc. were taken into account).

5. The duration of a fire was estimated as follows:

Electrical Cabinets: As stated earlier, SNL cabinet fire tests 23, 24, and 25 were used as the basis for the electrical cabinet induced fires in this analysis. Using the heat release rate profile fires for these tests and using a heat release rate of 1200 kW, the duration of a fire was estimated to be approximately 6 minutes. Based on this information and on the results of several COMPBRN runs, an equivalent fire having a heat release rate of 1200 kW and lasting for 6 minutes can be characterized as follows:

Fire Source: Length = 0.7m, Width = 0.7m, Depth = 0.01m
Pilot: Mass = 8.5 kg

Pumps: COMPBRN will calculate the duration of a fire based on the mass of the postulated fuel and the surface area of the fire. The mass was calculated by multiplying the oil volume by a density of 900 kg/m^3.

6. Electrical cabinets were modeled as barriers having reflectivity value of 0.7 on the following basis:

$\varrho = 1 - \varepsilon$ where ϱ = reflectivity and ε = emissivity
and $\varepsilon = 0.3$ from Table 5.3 of NUREG/CR-2289 (NRC, 1981). Thus, $\varrho = 0.7$

7. Only one pilot fire was modeled on the basis that the frequency of independent simultaneous multiple fire events is negligible.

8. Based on the object modeling recommendation of the COMPBRN manual (page 4-18, item 32), the shape of a pool fire object was modeled as a square.

9. Consistent with recent PRAs (for example, NSAC/181), self ignited cable fires, and cable fires due to welding were not considered on the basis that cables in the fire areas of

concern meet the qualification requirements of the IEEE 383. The basis for this assumption are test results which indicate that these types of fires would only last for a very short period of time (40-240 seconds) and would not propagate beyond the cable tray of origin, see Section 3.4.2 of NUREG/CR-5384 (NRC, 1989g). In addition, consistent with NSAC/181, fires originating from junction boxes were also ruled out.

4.3.2.2 General Observations

Independent of the geometry of the modelled area or characteristics of the fire, the following COMPBRN results were noted.

1. The COMPBRN IIIe model predicts that it is very difficult to ignite cables unless the cables are within the flames. This is consistent with the findings of other fire PRAs that have utilized the COMPBRN computer code. See page 5-18 of NUREG/CR-4550, and section 6.3 of NUREG/CR-6144 (NRC, 1994). This finding was applied in the analysis of several SHNPP areas where ignition of overhead cables from pump or cabinet fires was assumed not credible unless these cables were within the flames. For example, in the case of well sealed electrical cabinets where cabling enters and exits through metal sleeves or conduits, the probability of fire propagation was assumed to be negligible.

2. For any enclosure without an opening, irrespective of the enclosure size or the ventilation rate, COMPBRN predicts that, at the first time step, a hot gas layer would be formed with a thickness equal to the height of that enclosure. This prediction was not affected by the duration of the time step used. This COMPBRN prediction stems from the fact that COMPBRN assumes a one zone model for closed room fires. This is not an accurate representation, and based on available experimental data from Sandia, it was concluded that during the initial stages of fire spread, temperatures at lower levels of the enclosure (where SSD equipment could be located) are less than those predicted by COMPBRN. However, temperatures at the ceiling where the heat detectors are located will be approximately those calculated by COMPBRN. Thus, in many cases, it was concluded that there was time for detection (and therefore suppression) before predicted failure of equipment at lower levels of the enclosure.

3. COMPBRN predicts that those cables which are immersed in the flames will ignite very quickly (less than 1 minute). However, the induced cable fires would not propagate laterally. Experimental data show this to be an accurate representation (NRC, 1989a). Therefore, the SHNPP analyses assumed fire propagation in a vertical direction when cables are immersed in flames.

4.3.2.3 Generic COMPBRN Models

In most cases, significant fire scenarios originating from fixed fire ignition sources involve either an electrical cabinet or an oil spill. Based on this observation, two sets of generic models were developed. The first set of models was developed to be a generic representation of fires

originating from electrical cabinets. An additional model was developed to address fires originating from a small oil spill. This modeling approach would limit the number of models that would be required to complete the analysis.

Note that these models are considered to be generic (i.e. are not plant or location specific). Thus, the physical characteristics used for the objects in these generic models (e.g. cable tray size) are not meant to represent the physical characteristics of the objects present in SHNPP. However, in most cases, the selected physical characteristics are judged to bound the physical characteristics of the objects found in the plant. In any case, when applying the results of these generic models, the location specific physical characteristics of the objects were compared with that of the objects modeled in these generic models to ensure that the generic models can be used as a bounding case.

4.3.2.3.1 Generic Electrical Cabinet Induced Fire Models

The following generic fire events were addressed:

- large fires—These are fire events that originate from a large electrical cabinet and expand (enlarge) by igniting cable insulation contained in multiple cable trays routed directly above it.

- medium fires—These are fire events that originate from a large electrical cabinet and expand by igniting cable insulation contained in two cable trays routed directly above it.

- small fires—These are fire events that can be represented by a fire originating in an electrical cabinet and the fire does not spread beyond the cabinet itself.

An enclosure approximately 68'x 68'x 19', having a 9.5' by 10' opening (to other plant enclosures) was selected to represent a typical enclosure in the plant. A 10' section of stacks of 4 and 2 cable trays are assumed as the source of in-situ combustible loading for the large and medium fires, respectively. The postulated intervening cable trays were assumed to be 30" wide, containing cable insulation of 37.0 lb/ft.

Based on the results of COMPBRN runs, the impact of a large fire in an enclosure can be represented by the impact of a fire lasting for 11 minutes and having a heat release rate of 10,000 kW. The impact of a medium fire in an enclosure can be represented by the impact of a fire lasting for 11 minutes and having a heat release rate of approximately 5000 kW. The impact of a small fire (i.e. a fire that is confined to a cabinet) in an enclosure can be represented by the impact of a fire lasting for 6 minutes and having a heat release rate of 1200 kW.

In the large fire event, cables more than 8' away from the edge of the fire source would not sustain damage. Furthermore, the maximum hot gas layer temperature was predicted to be approximately 618 K (653°F).

In the medium fire event, cables more than 3' away from the edge of the fire source would not sustain damage. Also, the maximum hot gas layer temperature would be 486 K.

In the small fire event, only cables routed close (less than 1') to the edge of fire source would be damaged and the hot gas layer temperature would be 371 K (208.4° F).

Note that inthe above described models, it is assumed that the flame can project freely from the fire source.

4.3.2.3.2 Generic Oil Spread Induced Fire Model

The objective of this model was to establish the vertical distance above which a small oil spill induced fire would not damage cables routed above the center of the postulated fire pool. For this model, the dimensions of the room were selected such that the room is considered to be representative of a typical enclosure in a nuclear power plant. Furthermore, a typical cable tray was also included in the model that runs directly above the postulated fire pool. The height of the cable tray above the pool was adjusted in the model until such time that COMPBRN does not predict damage.

The following assumptions are made during the development of this fire scenario:

1. The pool size was assumed to be the same as the size of the NUREG/CR–4550 postulated small oil fire scenario. That is, it was assumed that a typical small oil spillage would have a pool diameter of 0.61m (2'). Conservatively, this oil pool was represented by a square shaped pool of 0.61m in length.

2. The room was assumed to have dimensions of 52' x 33' x 16'.

3. A room opening, 10' high and 4' wide was included in the model.

4. Combustible loading of a typical small oil spill was assumed to consist of 1.5 gallons of oil.

5. Conservatively, room ventilation was assumed to be unavailable.

The results from COMPBRN showed that a hot gas layer with the thickness of approximately 3.5 m (11') and maximum temperature of 430K (314°F) will be formed. In addition, the COMPBRN model predicted that a tray located 9' above the center of the pool and a cabinet more than 5' away from the edge of the pool would not sustain damage.

4.4 EVALUATION OF COMPONENT FRAGILITIES AND FAILURE MODES

For the COMPBRN analysis, the following are considerations used to determine component fragilities and fire damage criteria for postulated targets.

- For the most part, COMPBRN input parameters were obtained from the EPRI generated sample input file unless otherwise stated.

- All SHNPP cables related to safe shutdown components have properties similar to IEEE 383 qualified cables.

- The damage criteria chosen were as follows:

  For cables: With reference to Table 5.7 of NUREG/CR-4550 (NRC, 1990c), the following input values were used.

  - Pilot ignition temperature: 773 K
  - Spontaneous ignition temperature: 773 K
  - Damage temperature: 623 K

  These data represent the SNL interpretation of its cable fire tests. It can be seen that, with these input parameters, cable damage would be predicted before cable ignition.

  For electrical equipment: If any of the following conditions were predicted, an electrical component was assumed to fail:

  1) For switchgear, electrical cabinets, and MCCs, a critical radiant heat flux of 10 kW/m^2 (1 $Btu/s/ft^2$) was used as the damage criterion as recommended on page 6-14 of FIVE.

  2) An electrical component was assumed to fail if the environmental temperature of the postulated enclosure containing the component, was predicted to exceed 320° F (433 K). This damage criterion is based on the relay thermal damage tests conducted by SNL. The test program results indicated that Agastat GPI relays failed between 320° F to 410° F and General Electric HMA relays failed in temperatures in excess of 662° F (NRC, 1986). This is consistent with damage criterion used for electrical cabinets in NSAC 181 (EPRI, 1993).

- Consistent with the other fire PRAs (for example, see page 5-18 of NUREG/CR-4550 Volume 3 Part 3), cables in conduits (in metal sleeves) or armored cables were assumed to be incapable of igniting and do not contribute to the heat release in the area. However, they were assumed to be damaged if the damage temperature is exceeded.

The damage criteria have been selected in a conservative fashion using the guidance provided in FIVE. Finally, the location of targets, sources and spills from sources have been chosen to yield conservative results.

4.5 FIRE DETECTION AND SUPPRESSION

The detailed fire analysis involves the evaluation and merging of two competing processes, namely fire progression and fire suppression. Before fire suppression can be possible, successful detection is required. The degree of fire damage is therefore dependent on the timing of detection/suppression as compared to the rate of fire growth and progression.

The detection of a fire event was evaluated based on two parameters: i) the type of fire detection systems available in the compartment under consideration; and ii) the expected environmental changes resulting from the fire. In general, the time to detect an electrical cabinet induced fire by smoke detectors was estimated based on the available experimental data presented in NUREG/CR-4527 (NRC, 1987c). The time to detect a fire by heat detectors is estimated using COMPBRN predictions of the environmental temperature increase, the detector set points, and available experimental data.

Given successful detection, the probability of successful suppression is dependent on:

i) the time available for such actions. This in turn is dependent on the time it takes to reach a particular fire damage state which is estimated based on the results of COMPBRN models and on experimental data where applicable,
ii) the type of automatic fire suppression systems available, and
iii) the availability of manual suppression.

Reliability data for automatic suppression was obtained from NSAC 179L (EPRI, 1994) and are as follows:

CO_2	0.04
Halon	0.05
Deluge or Pre-Action Sprinklers	0.05
Wet Pipe Sprinkler Systems	0.02

In addition, for manual actions, the response time given a fire alarm was estimated based on a review of the plant fire drills and a walkdown of the site.

4.6 ANALYSIS OF PLANT SYSTEMS, SEQUENCES AND PLANT AND OPERATOR RESPONSE

4.6.1 General Discussion

Given a fire damage scenario, an evaluation of accident sequences is required. This evaluation includes consideration of fire induced initiating event types, components failed by the fire, degraded mitigating system hardware impact on operator response actions modeled in the PSA, as well as additional recovery actions.

Using the results of COMPBRN analyses which determined the extent and frequency of fire damage for each fire damage state, the CDF was calculated using the SHNPP PSA models modified to account for the fire induced unavailabilities. Consistent with the IPE and PSA, the event trees and fault trees were solved using the CAFTA computer code. This code solves Boolean equations using the linked fault tree approach. Component failure probabilities were represented in the fault trees as basic events (i.e., fail-to-start, fail-to-open, etc.). If a component could be affected by a fire, a flag was added to the fault tree. The flag was assigned a value of one for components in the fire damage state being analyzed. The accident sequences were then re-solved with the revised fire-induced unavailabilities and modified HEPs. The resulting cutsets thus contains the appropriate combination of random failures, human errors and failures due to fires. (It should be noted that the PSA models used to support this IPEEE fire analysis are updated versions of the IPE models.)

As mentioned above, HEPs were evaluated to determine the effects of the postulated fire on operator actions. These actions included activities such as manual operation of motor operated valves when a fire in another area disabled the valve and operator actions necessary to establish control using the auxiliary control panel (ACP). These actions are essentially post-fire recovery actions and they are discussed further below.

The following are guidelines used for calculating the HEPs for the fire PRA.

1. For actions taken in the control room, the following applies:

   If the indications necessary to make the appropriate decisions are available, the HEP is not changed. This can be argued on the basis that the primary goal of the operators is to operate the plant according to the guidance of the emergency operating procedures.

   If adequate indication is not available, the HEP was increased by a factor of 10 if indications are degraded, and an HEP of 1 was used if indication is unavailable.

2. For local manual actions:

   If the time window is greater than two hours, the HEP from the PSA was used.

   If the time window is less than two hours, the HEP was evaluated on a case by case basis considering factors like the location of the equipment, time available, equipment available, etc.

3. For the manual recovery actions that were included in the model because they were called out in the post-fire operating procedures, the following considerations apply:

   The actions of concern are generally valve realignments associated with the AFW, ESW, and safety injection (SI) systems. For most of the scenarios in which they appear, there should be a reasonable amount of time to perform the function. Since the fire initiated

scenarios are not large LOCAs or ATWSs, there is at least 45 minutes for recovery for most scenarios.

A screening value of 0.1 was used for manual recovery actions. To account for HEP dependencies, only one HEP event was used per system/scenario.

4.6.2 Detailed Fire Evaluation of Remaining Areas

As mentioned in previous sections, a total of 14 fire areas/compartments were screened out qualitatively. An additional 33 were screened out based on conservative evaluations which showed that the CDF was below the 1E-6 per year criteria. Of the remaining 24 areas/ compartments, the two control room areas (12–A–CR and 12–A–CRC1) are evaluated in section 4.6.3. For the other 22 areas, a more detailed analysis was carried out to determine the extent of damage that could result from a fire in that area. In some cases, COMPBRN results provided arguments to show that fires can only affect a limited set of components and thus these fires were not risk significant (CDF < 1E-6 per year) and were screened out. For the fires that could still not be screened out, a set of fire damage states was defined. Using the fire damage state frequencies, and CCDPs obtained by using the SHNPP PSA models modified to account for the fire damage (i.e. the components/systems failed by the fire), the CDF from a fire in the area was calculated.

In this detailed analysis, the answers to the following questions were determined.

1) Given the fire ignition sources identified in the ISDS for an area, what fixed or transient fire ignition sources are potentially capable of causing damage beyond the fire source?

2) What would the severity of a fire be from the fire sources identified as a result of answering question 1?

3) What would the impact of the fire be on the equipment required for the safe shut down of the plant?

4) Can a fire be suppressed before damage occurs?

5) What is the frequency associated with the potential damage?

Table 4–5 summarizes the results of the detailed analysis in terms of the above questions. To assist in answering questions 3 and 4, the COMPBRN IIIe computer code was utilized. The expanded writeups for the analysis of three typical areas are provided below.

4.6.2.1 Electrical Penetration Room A (1-A-EPA)

4.6.2.1.1 General Description

This fire area is located at 261' elevation of the Auxiliary Building and it mainly houses SSD division 1 cabling and components. The fire area is protected by multiple-cycle sprinklers which can be actuated by thermal detectors and early warning ionization detection which are provided throughout the fire area.

Based on the fire ignition source data sheets, significant contributors to this area's fire frequency are:

1. Electrical cabinets = 2.64E-3 per year
2. Transients = 7.83E-5 per year
3. Welding/Ordinary Combustibles = 9.30E-5 per year
4. Welding/Cables = 1.53E-5 per year
5. Junction Boxes = 3.86E-5 per year

Consistent with recent PRAs (for example, NSAC 181), fires originating from cable junction boxes (FIVE, page 3-5), and cable fires due to welding were not considered significant sincethe cables at SHNPP meet the qualification requirements of IEEE 383. Test results show that these types of fires would last for a very short period of time (40-240 seconds) and would not propagate beyond the cable tray of origin (NUREG/CR-5384, section 3.4.2). Thus the only ignition sources of concern are the electrical cabinets, transients, and welding and cutting fires.

4.6.2.1.2 Evaluation

A walkdown of this fire area was performed to evaluate the characteristics of the remaining fire ignition sources and combustibles. The purpose of this evaluation was to ascertain the likelihood for occurrence of fire events with potential to cause damage to multiple targets (components and cabling) based on the characteristics of the ignition sources, passive defenses in the area, and relative location of the ignition sources with respect to the combustibles. Results of this evaluation are described in the following subsections.

Electrical Cabinets

The plant walkdown identified two types of electrical cabinets, namely motor control centers (MCCs) and pressurizer heater panels (PHP) in this fire area.

The MCCs do not have ventilation louvers. The top of these cabinets are covered, the cables to these cabinets enter through sealed penetrations from the top, and all cables are routed through conduits. Additionally, the cabinets are divided into several sub-panels and each sub-panel has only a few cables routed through it (i.e. the combustible loading in each sub-panel is not significant). Therefore, it was postulated that fires originating in these cabinets would not propagate outside the cabinet (i.e. no flames would extrude from the cabinets). This is supported by the results of electrical cabinet fire tests reported in the Limerick Accident Risk Analysis (PECO, 1983) and is consistent with NSAC 181 evaluations.

Furthermore, it was concluded that a fire originating from one of these MCCs would not spread by igniting any intervening combustibles. This conclusion was based on COMPBRN results which show that it is very difficult to ignite cable insulation unless the cables are in the flames. As discussed in the above paragraph, the flames from fires originating in these MCCs would not impinge on any cable insulation located outside the cabinet.

Additionally, due to the separation of the MCCs, the relatively large size of the room, and routing of the cables in conduits a fire originating in and confining within a MCCs will not result in damage to multiple targets.

The PHPs have small ventilation louvers near the top of the panels. However, the tops of these cabinets are covered, the cables to these cabinets enter through sealed penetrations from the top, and all cables are routed through conduits. Additionally, no cable trays are routed above the PHPs. Based on these observations it was judged that a fire originating from the PHPs would not spread by igniting cable insulation and potential floor based transient combustibles in the area. Additionally, the PHP induced fires would not damage cables associated with other targets, since the only cables close to the PHPs are the cables in the panels themselves.

Based on the above discussion, it was judged that the impact of fires originating in electrical cabinets located in this fire area would be limited to the loss of the fire source itself with no additional damage expected.

Loss of the PHPs was not considered to be risk significant since their loss would not impact any safe shutdown equipment. Based on the ISDS, only one of the five cabinets located in this area is an MCC (MCC-1A24). Thus, the frequency of fires originating in the MCC panel is 20% (1/5) of the total frequency of fires attributed to all electrical cabinets. Furthermore, as stated above, the MCCs are divided into several sub-panels. Fires originating in any sub-panel that are self extinguished before any significant development (i.e. are self extinguished during their incipient stage) were assumed to have limited impact on the safe shutdown capability and are risk insignificant. Thus, only that fraction of electrical cabinet induced fires that originate in MCCs and are developed beyond the incipient stage were considered potentially risk significant. Frequency of such fires, F_{sf}, is given by:

$$F_{sf} = F_{cf} * F_c * 0.2$$

where F_{cf} = 2.64E-3 is the frequency of fires originating in an electrical cabinet located in this fire area (from the ISDS), F_c is the fraction of fires originating in an electrical cabinet that have the potential to go beyond the incipient stage, and 0.2 is the fraction of electrical cabinets located in this area which are binned in the MCC category.

To evaluate F_c, the electrical cabinet induced fires reported in the Fire Event Database (NSAC 178L) were reviewed. Table 4-6 presents a summary of the manner by which these reported fires were terminated. As can be seen from the data presented in this table, a total of 26 events were terminated either due to de-energization of the cabinet or self extinguishment. Thus, the fraction of electrical cabinet induced fires that will not be significant is:

$$F_c = 26/84 = 0.31$$

Thus,

$$F_{sf} = 2.64E\text{-}3 * (1\text{-}0.31) * 0.2 = 3.6E\text{-}4$$

Conservatively assuming that loss of the MCC would lead to the loss of all division A safe shutdown components, the CCDP from a transient was calculated to be 1.44E-3. The contribution of the electrical cabinet induced fires to CDF is therefore:

$$CDF_{EC} = 3.6E\text{-}4 * 1.44E\text{-}3 = 5.2E\text{-}7 \text{ per year}$$

Transient Ignition Sources

The ISDS was reviewed for potential refinements to the ignition frequency from transient sources. This review showed that the total frequency of transient induced fires includes contributions from overheating (factor of 2) and hot pipe (factor of 1). However, based on the plant walkdown, these factors were eliminated on the following basis:

1. There are no ignition sources (e.g. batteries) in this area with potential to overheat combustibles (e.g. batteries terminal grease) in the room.

2. There are no hot pipes routed in the area.

Thus, the total factors for transients in this area was reduced from 10 to 7. The frequency of transient ignition source induced fires in this area is then:

$$F_{TF} = 7.83E\text{-}5 * (7/10) = 5.5E\text{-}5 \text{ per year.}$$

A review of transient ignition source induced fire events, as presented in NSAC 178L, indicated that most of the combustibles ignited by these ignition sources were paper, rags, or protective clothing (i.e. transient combustibles). The review also showed that for the sources identified in this category (i.e. hot pipes, extension cords or portable heaters), the combustible loading of the source themselves is insignificant and will not cause a fire capable of causing significant damage

unless it were to ignite other combustibles. Since the only in-situ combustible loading in this fire area is cable insulation and the cables routed in this fire area meet the qualification requirements of IEEE 383, fires originated by and being confined to the above identified ignition sources were assumed not to cause significant damage (i.e. are not assumed to impact safe operation of the plant or safe shutdown equipment). Thus, for any transient ignition source to cause a significant fire, transient combustibles must also be present.

Therefore, areas where either transient combustibles 1) could be stored (e.g. areas in the Auxiliary Building where potentially contaminated protective clothing are kept), or 2) could be used during maintenance activities (e.g. pump areas where oily rags could be present) are areas where a transient ignition source induced fire could result in a significant fire. This assertion is supported by the fire ignition source data discussed in NSAC 178L which indicate that 30 out of 31 fire events placed in the transients ignition source bin occurred in the turbine building, the auxiliary building, and the reactor building, mostly in areas where at least one of the above stated conditions applies.

Based on the SHNPP FSAR, no transient combustible loading is allowed or stored in this fire area. Equipment located in the area is mostly electrical equipment. Thus, the frequency of significant fires induced by transient ignition sources, F_{tsf}, is given by:

$$F_{tsf} = F_{TF} * w$$

where F_{TF} is the frequency of transient fires and w is the probability of transient combustibles being present.

As discussed above, transient combustibles are not allowed in this fire area and if due to an error they were to be left in the area they will be removed during inspection.

The probability of transient combustibles being present between inspections (w) can be calculated as follows (FIVE, page 6-34):

$$w = x/2 * \ln 1/x$$

where

$$x = F_{cci}/F_w$$

F_{cci} is the critical combustible loading frequency (in this case frequency of transient combustibles being present)

F_w is the frequency of transient combustible inspections

F_{cci} may be determined by reviewing plant records and/or interviews with plant personnel to determine the number of times the critical combustible load was found present at plant locations in violation of the control procedures. The number of incidents is then divided by the number of years over which data was taken (EPRI, 1992a, page 6-30). FIVE indicates that F_{cci} cannot

be set lower than one event per year per compartment. Discussions with plant personnel indicate that this is appropriate for SHNPP.

F_w is based on the frequency of inspections that actually look for transient combustibles per year (EPRI, 1992a page 6-31). Twice daily, a survey of transient combustibles in safety-related areas/rooms will be performed as part of the daily fire protection rounds. Therefore, F_w is 2 * 364 = 728 in this case.

Substituting values in equations above:

$$x = (1 / 728) = 1.37E\text{-}3$$

$$w = 1.37E\text{-}3/2 * \ln (1/1.37E\text{-}3) = 4.5E\text{-}3$$

Therefore, frequency of significant fires induced by transient ignition sources is:

$$F_{tsf} = 5.5E\text{-}5 * 4.5E\text{-}3 = 2.5E\text{-}7 \text{ per year}$$

Thus, fire induced risk for this fire area from this source of fires was screened out and no further evaluation was necessary.

Welding and Cutting Fires (Welding/Ordinary Combustibles)

The frequency of welding and cutting induced fires was calculated using data obtained from the Fire Event Database. Review indicates that the frequency of welding and cutting fires is based on the occurrence of 24 fires. These fires were all manually suppressed. The duration of twelve of the reported fires were three minutes or less; six fires burned between 5 and 15 minutes and the duration for the other ten is unknown. These fires were quickly suppressed due to presence of the personnel performing the welding as well as due to fire watches being posted (EPRI, 1992b, page 3-43). Conservatively assuming that the next welding and cutting induced fire would not be manually suppressed and using the FIVE methodology for calculation of fire frequency (EPRI, 1992b, page 3-42), then the frequency of an unsuppressed welding/ordinary combustible induced fire, F_{UW}, is given by:

$$F_{UW} = (1/1264.7) / 0.62 = 1.3E\text{-}3 \text{ per year.}$$

That is, the frequency of welding/ordinary combustibles induced fires which are not manually suppressed and are capable of causing damage is approximately 20 times smaller than the frequency of small welding fires (3.1E-2/1.3E-3 where 3.1E-2 is the frequency of small welding fires given in FIVE).

Thus, using the same fire area weighing factor as used in the ISDS, the fire frequency of an unsuppressed welding/ordinary combustible induced fire in this fire area, F_{UW}^{EPA}, is given by:

$$F_{UW}^{EPA} = 1.3E\text{-}3 * 3.0E\text{-}3 = 3.9E\text{-}6 \text{ per year}$$

Conservatively assuming that such an unsuppressed welding/ordinary combustibles induced fire would result in the total loss ofequipment in this area (i.e. all division A powered components) in addition to a fire induced spurious opening of a PORV, the contribution of this fire source to the CDF, CDF_{WF}, is given by:

$$CDF_{WF} = 3.9E\text{-}6 * 5.9E\text{-}3 = 2.3E\text{-}8 \text{ per year}$$

where 5.9E-3 is the CCDP for a small LOCA with division A electrical power unavailable.

Total Screening CDF for the Area

The total contribution to the CDF from fires in this plant area is given by:

$$CDF_T = CDF_{WF} + CDF_{EC} = 2.3E\text{-}8 + 5.2E\text{-}7 = 5.5E\text{-}7 \text{ per year.}$$

4.6.2.2 Fire Area 1-A-SWGRB (Switchgear Room B)

4.6.2.2.1 General Description

This fire area is located at 286' elevation of the Auxiliary Building. It houses equipment and cabling associated with the safety train B and other non-safety equipment. Significant fire ignition sources for this area include electrical cabinets, transformers, and battery chargers. Cable insulation is the primary source of combustible material for this area. The transient combustible loading for this area is negligible.

Fire protection consists of early warning ionization detection located throughout the fire area. Hose stations, fire extinguishers and manual alarm stations are located in and adjacent to the area. Safety train A, powered by equipment located in the Switchgear Room A fire area, will be relied upon for plant shutdown in case of a fire in this fire area.

4.6.2.2.2 Evaluation

A plant walkdown of this fire area was performed and all the electrical cabinets were examined. Based on this walkdown and the results of generic COMPBRN models, the following conclusions were made:

Electrical Cabinets

Cabinets for the 6.9 kV and 480V switchgear can be divided into two enclosure types, front enclosures, where the breakers are located, and the rear access panel enclosures, where the cabling associated the equipment is routed. The ventilation louvers are installed on the rear access panels. The two enclosures are separated by an internal metal wall. Additionally, each access panel is separated from the adjacent panel by a metal wall. It was noted that only a limited number of cables (two to three cables) are routed through the back access enclosures for these buses (both safety and non-safety). Additionally, the top of these cabinets are covered, and the cables to these cabinets enter through sealed penetrations from the top. Therefore, the following engineering determinations were made:

1. Fires originating from the breaker enclosures will be confined within the enclosures.

2. Fires originating from the access panel enclosures will have substantially lower heat release than that postulated for the generic cabinet-induced fires for the COMPBRN analysis on the following basis:

   The heat release rate postulated for the electrical cabinet induced-fires in this analysis is based on SNL cabinet fire tests 23, 24, and 25. The cabinets in those tests had between 1.0E6 to 1.4E6 Btu of combustible loading, had ventilation grills, and the doors to these cabinets were left open. The ventilation louvers for the bench board cabinets (tests 23 and 24) were located at the bottom of the cabinets. For the vertical cabinet the louvers were located at the bottom and the top of the cabinet (test 25).

   As stated above, the combustible loading of the access panel enclosures is significantly less than that of the SNL's test cabinets. Additionally, the panel doors are normally closed, limiting the oxygen access. The results of other cabinet fire tests performed by SNL indicate that the heat release rate is influenced by the ventilation method (i.e. closed or open cabinet door). Closed cabinet doors will cause oxygen deprivation that appears to limit the burning rate (NRC, 1987c). Additionally, there are no ventilation louvers on the bottom end of the access panels of the buses further limiting the oxygen intake.

3. Flames from fires originating in the access panel enclosures may propagate to outside of the cabinet but the height of the flame will be restricted on the basis that the top of the cabinet is covered and the only path for flame extrusion is via the ventilation louvers. However, cables inside the cabinet are routed in the middle of the cabinet, away from these ventilation louvers. Thus, the flame propagation path to outside of the cabinet is torturous.

Based on the above determinations and the generic models developed, the following conclusions were reached:

1. A fire originating from the front enclosure of these buses will not produce flames that extend beyond the cabinets. Thus, the damage caused by such fires would be limited to the bus itself and will not spread or damage additional components or cabling.

2. Flames from a fire originating in the access panel enclosure of the buses may extend beyond the cabinet and ignite cable insulation routed in close vicinity to the buses.

Additionally, based on the description of the SNL cabinet fire tests, it was judged that the development of a postulated fire in the access panel would take place in two phases. During phase 1, a fire is started and develops inside the cabinet with little or no propagation to the outside. During phase 2, the fire is fully developed inside the cabinet and flames from the developed fire will impinge and ignite cable insulation in the cable trays routed directly above the cabinet. Thus, potential damage during both phases have to be assessed. Also, based on the results of SNL tests, it is judged that about 27 minutes is available for suppression of the fire before it could grow beyond phase 1.

Taking credit for the smoke detectors installed in the room as the most likely means of fire detection, it was judged that fire would be detected about 15 minutes after start of the localized fire (i.e. 15 minutes after start of phase 1 of the fire development). This judgement was made on the following basis:

The results of the SNL test 25 indicate that a smoke detector installed inside the cabinet in which the fire originated, alarmed approximately 1 minute after visual detection of smoke in the test enclosure. The cabinet door in this test was left open. The report postulates that if the cabinet door had been closed, allowing smoke to accumulate inside, the fire would have been detected earlier . Another detector in a remote cabinet actuated 25.5 minutes after the start of the localized fire.

In the fire scenario under consideration, the time for the actuation of the smoke detector was judged to be closer to that of a smoke detector inside the fire source cabinet (i.e. 10.5 minutes) on the following basis:

1. Smoke would escape from the cabinet early in the development of the fire. If the design was such that smoke could not escape, the fire would in all likelihood be starved of oxygen and self extinguish.

2. The smoke will rise towards the ceiling where the smoke detectors are installed. The remote smoke detector in SNL test 25 was installed in a bench board cabinet well away from the fire source. For that detector to actuate, smoke had to rise and then accumulate sufficiently to come down to the bench board level. Smoke then

had to enter the cabinet and accumulate inside the cabinet and actuate the smoke detector. Therefore, the 25 minutes actuation time is overly conservative for the configuration under consideration in this fire scenario.

As stated above, a fire was assumed to be detected 15 minutes into its phase 1 development stage. Thus, manual suppression of the fire is possible before it could advance to phase 2, if the fire brigade personnel could arrive at the scene in less than 12 (27 - 15) minutes after detection of the fire.

Based on the review of the data pertaining to the electrical cabinet induced fires and on the plant layout, it was judged that fire fighters will be able to get to the scene within the 12 minutes time period.

Given the above evaluation, the following scenarios are postulated:

Scenario 1—This scenario modelled fires originating in the 6.9 kV and 480V buses that are confined within the cabinets either due to the physical characteristics of the cabinet or due to the successful suppression of the fires before they can ignite/damage cables routed in close vicinity of the cabinets. The impact of these fires was limited to loss of the fire source (i.e. one cabinet). The most significant of these fires are those that are conservatively assumed to lead to loss of the 1B-SB AC emergency bus . The frequency of such fires is estimated as 7.3E-4 per year. The CCDP, given a loss of bus 1B-SB, is 1.49E-3, resulting in a contribution to CDF, CDF_{S1}, of 1.1E-6 per year for this scenario

Scenario 2—This scenario modelled fires originating in any bus that is not suppressed during phase 1 of its development. Such fires were, conservatively, assumed to be able to ignite substantial quantity of combustibles before they could be suppressed. The impact of such fires was assumed to be loss of the entire SSD division 2 (i.e. loss of 1B-SB and 1E buses and all equipment that are powered from these buses). In addition, bus 1D was assumed to be initially de-energized due to either loss of control power to or spurious opening of its supply breaker. Operator action to locally close the breaker and restore offsite AC power to bus 1D (and therefore to bus 1A-SA), as directed by emergency procedures, was credited.

The frequency of scenario 2 fires was estimated as:

$$F_{S2} = F_{sf} * P_{fs}$$

where F_{sf} = frequency of significant electrical cabinet induced fires = 3.5E-3

P_{fs} = probability of failure to suppress = 0.1 (EPRI, 1992b)

Therefore, F_{S2} = 3.5E-3 * 0.1 = 3.5E-4 per year.

For cases where operator recovery of offsite power to bus 1D (and hence to 1A–SA) is successful, the consequence of the fire is limited to the loss of the 1B–SB and 1E buses. The CCDP for this case is 7.1E-3 and the resultant CDF was estimated as:

$$CDF_{S2,1} = F_{S2} * CCDP_{S2,1} = 3.5E\text{-}4 * 7.1E\text{-}3 = 2.5E\text{-}6 \text{ per year.}$$

For cases where operator recovery of offsite power is not successful (from the IPE, this HEP is 1E-2), the CCDP is 7.5E-2, and the resultant CDF was estimated as:

$$CDF_{S2,2} = F_{S2} * HEP_{S2} * CCDP_{S2,2} = 3.5E\text{-}4 * 1E\text{-}2 * 7.5E\text{-}2 = 2.6E\text{-}7 \text{ per year.}$$

Thus the total contribution from scenario 2 electrical bus fires to CDF is:

$$CDF_{S2} = 2.5E\text{-}6 + 2.6E\text{-}7 = 2.8E\text{-}6 \text{ per year.}$$

The transformers in this location are dry transformers with a minimal combustible loading, and fires from this type of components tend to be smoldering small fires due to the overheating of the transformer coils. Thus, a fire originating from these transformers is not expected to spread further by igniting the intervening fixed combustible material (i.e. cable insulation) located in this area.

For cabinets containing the 125V buses, there are no ventilation louvers, the tops of these cabinets are covered, cables enter the cabinets via sealed penetrations, and their combustible loading is judged to be insignificant. As discussed previously, flame propagation outside a cabinet from fires originating in an enclosed cabinet is not credible. Thus, it was concluded that flames from fires originating in the 125V buses would not extrude outside the cabinet enclosure.

Furthermore, results from generic COMPBRN analyses for an enclosure having floor area of 3481 ft^2 show that the impact of fires originating in an enclosed electrical cabinet on equipment located in close vicinity of the cabinet is not significant. Since the floor area of this fire area is 5396 ft^2 and, as discussed above, fires originating in the 125V buses are considered to be confined within the buses, it is concluded that the impact of such fire events would be limited to the loss of the bus itself and no further evaluation of fires originating from the 125V DC buses was necessary.

The battery chargers were inspected and were found to contain little combustible material. Additionally, no additional combustible material (e.g. cable insulation) were seen in close vicinity of these chargers. Thus, consistent with other fire PRAs, propagation of the fire from the battery chargers is not considered credible (for example, see NSAC 181L, page 4–24).

In summary, the contribution of the electrical cabinet induced fires to CDF is equal to the sum of scenarios 1 and 2 bus fires, estimated to be 3.9E-6 per year.

Transient Ignition Source Induced Fires

The evaluation of transient ignition source induced fires for this area is similar to that for fire area 1-A-EPA (see section 4.6.2.1). Based on the SHNPP FSAR, no transient combustible loading is allowed or stored in this fire area. The frequency of significant fires induced by transient ignition sources, F_{tsf}, is given by:

$$F_{tsf} = F_{tf} * w$$

where F_{tf} is the frequency of transient fires and w is the probability of transient combustibles being present.

From the ISDS, F_{tf} is equal 1.41E-4. As discussed in the analysis for area 1-A-EPA, the parameter w was calculated to be 4.5E-3. Therefore the frequency of significant fires induced by transient ignition sources is:

$$F_{tsf} = 1.41E\text{-}4 * 4.5E\text{-}3 = 6.3E\text{-}7 \text{ per year}$$

Since this frequency is less than 1E-6 without taking credit for the CCDP, this source of fire is screened from further evaluation.

Welding and Cutting Fires (Welding/Ordinary Combustibles)

The evaluation of the generic frequency for welding and cutting induced fires is discussed in section 4.6.2.1 and this frequency is equal to 1.3E-3 per reactor year. Using the area weighting factor as defined in the ISDS, the fire frequency of an unsuppressed welding/ordinary combustible induced fire in this fire area, F_{UW}^{SWB}, is given by:

$$F_{UW}^{SWB} = 1.3E\text{-}3 * 0.01 = 1.3E\text{-}5 \text{ per year}$$

Conservatively assuming that such an unsuppressed welding/ordinary combustibles induced fire would result in the total loss ofequipment in this area, then the contribution of this fire source to the CDF, CDF_{WF}, is given by:

$$CDF_{WF} = 1.3E\text{-}5 * 6.23E\text{-}3 = 8.1E\text{-}8 \text{ per year}$$

where 6.23E-3 is the CCDP for this area given a spurious opening of a PORV and the unavailability of B division power.

Total Screening CDF for the Area

The total contribution from a fire in this area is thus:

$$CDF_T = CDF_{WF} + CDF_{S1} + CDF_{S2} = 8.1E\text{-}8 + 1.1E\text{-}6 + 2.8E\text{-}6 = 4.0E\text{-}6 \text{ per year.}$$

4.6.2.3 Chiller Room, Elevation 261' Fire Compartment (1-A-4-CHLR)

4.6.2.3.1 General Description

This fire compartment is located at the 261' elevation of the Auxiliary Building. The compartment contains cabling associated with both SSD divisions. Cables associated with alternate shutdown paths are protected by 1-hour barrier where they are routed within 20 feet of one another. Additionally, some redundant cables are protected by a 1-hour barrier throughout the area. The fire compartment is protected by multiple-cycle sprinklers which can be actuated by thermal detectors. Additionally early warning ionization detection are provided throughout the fire compartment.

Based on the ISDS, the significant contributors to the fire frequency are:

1. Electrical cabinets = 1.06E-3 per year
2. Pumps = 3.45E-3
3. Transients = 7.60E-5
4. Welding/Ordinary Combustibles = 7.43E-4 per year
5. Welding/Cables = 1.22E-4 per year
6. Ventilation Systems = 1.94E-4 per year
7. Junction Boxes = 3.43E-4 per year

Using arguments similar to that for area 1-A-EPA (section 4.6.2.1), fires originating from junction boxes and cable fires due to welding were not considered on the basis that all the cables in the fire compartments of concern meet the qualification requirements of IPEEE 383. In addition, it was also shown that fires from transient ignition sources could be screened out because of the low frequencies (<1E-6 per year) of significant fires from these sources.

4.6.2.3.2 Evaluation

A walkdown of this fire compartment was performed to evaluate the characteristics of the remaining fire ignition sources and combustibles. The purpose of this evaluation was to ascertain the likelihood for occurrence of fire events with potential to cause damage to multiple targets (components and cabling) based on the characteristics of the ignition sources, passive defenses in the area, and relative location of the ignition sources with respect to the combustibles. Results of this evaluation is described in the following subsections.

Electrical Cabinet Induced Fires

Electrical cabinets located in this fire compartment do not have ventilation louvers. The tops of these cabinets are covered, the cables enter through sealed penetrations from the top, and all cables are routed through conduits between the cable tray containing cables and the cabinets. Additionally, the cabinets are divided into several sub-panels and each sub-panel has only a few cables routed through it (i.e. the combustible loading in each sub-panel is not significant). Therefore, it is postulated that fires originating in these cabinets would not propagate outside the cabinet (i.e. no flames would extrude from the cabinets).

This fire compartment is relatively large (13,860 ft^2) and a fire originating in and being confined within the cabinet would not impact any other equipment located in the compartment.

None of the major electrical cabinets whose failures would impact SSD paths significantly are located in this area. Thus, a fire originating in and being confined within any one cabinet located in this fire compartment is not considered to be risk significant.

Pump Fires

Based on plant walkdown observations, the pumps located in this fire compartment are small pumps, with negligible combustible loading, not normally in operation. Additionally, no combustible materials are located in close vicinity of these pumps. Thus, fires originating from these pumps were considered insignificant and screened out from further evaluation. This is consistent with the NUMARC/EPRI Fire Risk Evaluation Training Course recommendation that, "For pumps in the Auxiliary Building . . ., count large pumps in core heat removal systems and associated support systems", implying that only the larger pumps should be considered as ignition sources.

Welding/Ordinary Combustibles

The evaluation of the generic frequency for welding and cutting induced fires is discussed in section 4.6.2.1 and this frequency is equal to 1.3E-3 per reactor year. Thus, using the same fire compartment weighing factor as used in the ISDS for this fire compartment (i.e. 2.4E-2), the fire frequency of a manually unsuppressed welding/ordinary combustible induced fire in this fire compartment, F_{UW}^{CHL}, is given by:

$$F_{UW}^{CHL} = 1.3E\text{-}3 * 2.4E\text{-}2 = 3.1E\text{-}5 \text{ per year}$$

The above frequency is an estimate of the frequency for welding/ordinary combustibles induced fires where the fire is not manually suppressed in its incipient stage.

Noting that:

1. cables for redundant SSD equipment routed in this area are partially or completely protected by 1-hour fire wrap;

2. the fire compartment is provided with multiple-cycle sprinklers which can be actuated by thermal detectors and early warning ionization detection which are provided throughout the fire compartment;

It was judged that sufficient time is available for automatic fire suppression system to actuate before damage to protected cables. It was therefore concluded that a fire in this area would not damage protected cables unless the automatic fire protection system (i.e. suppression and detection) were to fail. Thus, the following fire damage states (FDS) were postulated for welding/ordinary combustibles induced fires:

FDS CHLR1—This FDS represents fires which are manually suppressed in their incipient stage. The frequency of such fires was estimated by:

$$F_{CHLR1} = F_{WF} = 7.43E\text{-}4 \text{ per year}$$

Where F_{WF} is the frequency of welding/ordinary combustibles induced fires which are manually suppressed. The risk induced from this fire damage state is negligible.

FDS CHLR2—This FDS represents fires which are not manually suppressed (i.e. growth beyond the incipient stage) but are suppressed by the automatic suppression system. The frequency of such fires was estimated as:

$$F_{CHLR2} = F_{UW}^{CHL} * (1 - P_{FA}) = 3.1E\text{-}5 * (1 - 0.02) = 3.0E\text{-}5$$

where $P_{FA} = 0.02$ is the failure probability of the automatic wet pipe sprinkler suppression system.

The impact of this FDS was modelled as the loss of one division of power. Since loss of the B division power has greater adverse impact on SSD capability (i.e. its CCDP is higher than that for loss of the A division power, or for a transient with recoverable loss of offsite power), the contribution of this FDS to CDF was evaluated as:

$$CDF_{CHLR2} = F_{CHLR2} * 3.89E\text{-}3 = 3.0E\text{-}5 * 3.89E\text{-}3 = 1.2E\text{-}7 \text{ per year}$$

where 3.89E-3 is the CCDP for a transient with the loss of B division power.

FDS CHLR3—This FDS represents fires which are not manually or automatically suppressed. For a welding/ordinary combustibles induced fire to grow to such a significant degree, it has to occur in close vicinity to significant in-situ combustibles (i.e. cable insulation) or exposed

transient combustibles in the compartment. Cables in this area are generally routed in cable trays that are located about 20 to 30 feet above the floor elevation. Generic COMPBRN model for transient fires indicates that cables routed more than 9' 3" above the fire source will not sustain damage. Thus, transient fires originating at floor elevation of this fire compartment will not cause damage to the cables routed in this compartment. Conservatively assuming that the probability of welding/ordinary combustibles induced fires occurring close to significant combustibles in this area is 0.5 (i.e. 50% of floor area), then, the frequency of such fires was estimated as:

$$F_{CHLR3} = F_{UW}^{CHL} * P_{FA} * 0.5 = 3.1E\text{-}5 * 0.02 * 0.5 = 3.1E\text{-}7 \text{ per year}$$

The impact of this FDS was modelled as the loss of all SSD paths (CCDP = 1), and the CDF was evaluated as:

$$CDF_{CHLR3} = F_{CHLR3} * CCDP = 3.1E\text{-}7 \text{ per year}$$

Ventilation Systems

Several air handling units (AHUs) are located in this fire compartment. These units are enclosed within a metal enclosure and contain negligible combustible loading. During the walkdown of this compartment it was observed that there were typically no cable trays routed in close vicinity of these ignition sources. (One exception is AHU AH-19-1B-SB which has cable tray C1214 routed approximately 10' above it. For this case, fire propagation was determined to be very unlikely.) Based on these observations it was concluded that a fire originating in one of the AHUs would not ignite other combustibles in the compartment nor would it damage other potential targets by creating harsh environmental operating conditions. That is, the impact of fires originating in any AHU is considered to be limited to loss of the fire source itself. Since the loss of an AHU was not considered to be risk significant, no further evaluation of this fire source was required.

Fires Originating from Other Ignition Sources

Risk from fires originating from other ignition sources in this compartment (e.g. transient ignition source induced fires) were considered insignificant because of the passive (e.g. location of cable trays well above the floor elevation, fire wrapping of SSD related cabling) and active (e.g. automatic fire protection) defenses in the compartment, together with relatively small frequency of their occurrence.

Total Screening CDF for the Area

Based on the above evaluation it was concluded that the CDF for this area is 3.1E-7 + 1.2E-7 = 4.3E-7 per year which is below the screening value of 1E-6 per year. Thus, this area was quantitatively screened out.

4.6.2.4 Summary of Results from the Detailed PRA Evaluation

A detailed analysis was carried out to determine the extent of damage that could result from a fire in 22 plant areas. A summary of the analysis results is shown in Table 4.5. These results show that, in each area, the probability that a fire will disable all components in the area is very small. In most cases, COMPBRN results provided arguments to show that fires can only affect a limited set of components and thus these fires were not risk significant (screening CDF < 1E-6 per year). The only area where the CDF is above 1E-6 per year is the 1-A-SWGRB fire area. Here the CDF is 2.6E-6 per year.

4.6.3 Risk from Fires in the Main Control Room Area

This section identifies the potential fire damage scenarios in the SHNPP Main Control Room (12-A-CR) and the Control Room Complex (12-A-CRC1). The resulting contribution of these fire damage states on CDF is also evaluated. The general approach, which is similar to that adopted in NSAC 181, includes the following steps:

- Identify fire sources and evaluate associated frequencies.
- Evaluate extent of damage and likelihood of control room evacuation.
- Determine conditional accident sequence frequencies for each damage stage postulated by requantifying the internal events PSA model.

4.6.3.1 Description of Control Room and Associated Fire Protection

4.6.3.1.1 Description of Fire Area

The SHNPP control room area is located at elevation 305' of the Auxiliary Building. The area is actually comprised of two separate FSAR fire areas, each of which is fully bounded by three-hour fire barriers. Fire area 12-A-CR (Main Control Room) contains control panels, computer consoles, radiation monitoring panels, alarms, incore instrumentation, desk relay panels, exhaust fans, a component cooling water surge tank and associated controls, wiring in conduit, living quarters, and a visitor's gallery. Fire area 12-A-CRC1 (Computer Room/Control Room Complex) contains the plant computer room process instrument and control racks, auxiliary relay panels, communications room, rod control cabinets, reactor trip switchgear, motor generator sets providing DC power for the control rod drive, associated controls, wiring in conduit, and cable in trays.

In each of these fire areas, the walls, floor, roof, and structural columns supporting the area boundaries are made of reinforced concrete and have a fire rating of three hours. All openings in walls for personnel use, including stairwells, are protected by airtight, seismically-designed emergency doors with a fire rating equal to certified three-hour A label type fire rated doors.

4.6.3.1.2 Fire Detection Capability

Ionization-type fire detectors are provided in each of the two fire zones comprising fire area 12-A-CR and also in each of the four fire zones comprising fire area 12-A-CRC1.

A local fire detection control panel located in the terminal cabinet room covers all six of the fire zones comprising the two areas. Local zone indication and audible alarm of fire or trouble condition are provided at the local control panel. For a fire condition, an audible alarm sounds in the fire area. A manual alarm station also exists in the Termination Cabinet room.

4.6.3.1.3 Fire Suppression Capability

In area 12-A-CR, a hose station, a manual alarm station, and portable extinguishers are provided. No automatic fire suppression systems exist in the area, other than a single sprinkler head located in the kitchen area to mitigate small local fires. Floor water surcharge is not considered significant, and floor water drainage is not required; excess water can overflow to adjacent areas. Plant equipment subject to water damage is mounted on floor pedestals.

Portable fire extinguishers are located in area 12-A-CRC1. However, no automatic fire suppression systems exist in the area other than a single sprinkler head located in the kitchen to mitigate small local fires. Again, floor water surcharge is not considered significant and floor water drainage is not required.

4.6.3.1.4 Alternate Shutdown Capability

The ACP is located in Switchgear Room B at the 286' elevation of the Auxiliary Building. It is a free-standing, floor mounted, bench-type board constructed of carbon steel. Transition from main control board (MCB) control of plant functions to ACP control is governed by procedure AOP-004.

Specifically, AOP-004, section 4.0, item 1, dictates that:

> The SS-N (Shift Supervisor, Nuclear) will decide whether to evacuate the main control room. If a fire occurs in the main control room that affects habitability and/or control room equipment, the need to evacuate will be obvious. A fire in the main termination cabinet room or PIC cabinet room may not seem to be a threat to control room operators; however, a fire in these areas can seriously degrade protection functions, controls, or indications. In this situation evacuation will also be necessary to ensure operators can maintain plant control and safety.

4.6.3.2 Fire Hazard Review

4.6.3.2.1 Combustibles

The only significant combustible loading in either fire area exists in fire zone 12-A-6-PICR1 of fire area 12-A-CRC1. There are 860 running feet of control and instrumentation cable insulation in this zone, providing a fire loading of approximately 550 MBtu. The combustible loading for all other zones is assumed to be insignificant since there are no cables, trays, or any other combustible materials (in-situ or transient) present in these zones. Such negligible combustible loading includes small quantities of control and instrumentation cable insulation within cabinets, limited quantities of computer material transients, the plant operating manual residing in the control room, and a small amount of exposed PVC cable in the communications room.

4.6.3.2.2 Nature of Control Room Fires

In the Main Control Room (fire area 12-A-CR), fire hazard combustibles include limited amounts of cable insulation within control cabinets and panels as well as limited quantities of ordinary combustibles necessary for control room computer and instrumentation operation. Transient materials such as paper and rags may be brought into the area during normal operations, for normal facilities maintenance and repair, or during plant shutdown. The quantity of combustible materials which may be involved in area fires (and consequently, the magnitude of these fires and the resultant damage to plant facilities) is reduced by limiting the permanent quantities of ordinary combustibles (class A) and controlling the introduction of transient combustibles through administrative procedures.

The extent of damage within and beyond the fire area is further limited by controlled removal of heat, smoke, and other products of combustion. In this instance, the operating mode of normal ventilation systems is switched to the once-through mode, and the smoke purge systems are activated in areas of high smoke generation potential. Three-hour fire barriers enclose the fire area.

The fire postulated for this area assumes ignition and subsequent development into the most severe single fire expected in the area of localized concentrations of combustibles permanently present in the area. Propagation of the postulated fire will be reduced by early detection using ionization-type smoke detectors installed at the ceiling. The automatic detection system senses products of combustion generated by the incipient fire and alerts employees both at the location of the local fire detection control panel and in the control room via the communications room. As such, manual fire response can be initiated promptly; this fire area is permanently occupied. In addition, ready access is provided to the area from adjacent plant areas facilitating initial use of area fire extinguishers on incipient fires and supplemental use of standpipe hose lines on developing fires by employees responding to the fire.

The postulated fire is not considered to have sufficient potential for spread to cause failure of redundant safety-related plant equipment and associated cabling and controls. This is based on several facts:

- the control room is permanently attended;
- the control cabinets are of the self-ventilated type; and
- any products of combustion will quickly migrate to the ceiling of the room, where the automatic detection system will sound an alarm and alert the control room operators.

In the control room complex (fire area 12–A–CRC1), fire hazard combustibles include cable insulation in cable trays, trenches, and connection boxes; limited amounts of cable insulation within control cabinets; and minor quantities of permanent class A materials (ordinary combustibles). Transient materials, such as rags, wood, light lubricating oils, and cleaning solvents may be brought into the area for normal facilities maintenance and repair. The quantity of combustible materials which may be involved in area fires (and, consequently, the magnitude of these fires and the resultant damage to plant facilities) is reduced or minimized:

- by the use of IEEE 383 qualified cables;
- by limiting the continued spread of fire along cable surfaces by the provision of fire-breaks along cable trays and fire-stops at fire barrier penetrations; barriers consisting of covers are provided at safety- and non-safety cable trays at points of possible fire communication;
- by limiting the continued spread of any fire by the provision of fire dampers in HVAC duct work at fire barrier penetrations; and
- by limiting permanent quantities of ordinary combustibles (class A) materials to amounts actually required for normal operations and by controlling the introduction of transient combustibles through administrative procedures.

The potential propagation of a postulated fire will be reduced by early detection using ionization-type smoke detectors installed at the ceiling. This automatic system senses products of combustion generated by the incipient fire and alerts employees both locally and in the control room via the communications room so that manual fire response can be initiated promptly.

4.6.3.2.3 Derivation of Control Room Fire Frequencies

The Main Control Room fire frequency as evaluated in the ISDS is dominated by the contribution from electrical cabinets. From generic data (EPRI, 1992b) this frequency is equal to 9.5E-3 per year and is based on twelve fires which actually occurred in control rooms. Eleven were cabinet fires, and one was a kitchen fire. None of the fires appears to have been of significant severity and all were extinguished (or self-extinguished) within a few minutes. No control room fires to date have required evacuation of the control room. As there is a kitchenette just off the main control room, the "kitchen fire" is considered applicable to this

plant's control room area and is included in the total count to reflect the small (but non-zero) probability of contribution of kitchen and other non-cabinet fire ignition sources.

The remaining contribution to the ignition frequency evaluated for the control room comes from plant-wide ignition sources. NSAC 178L states that plant wide components are not generally applicable to the control room. Furthermore, NSAC 181 assumes that the only significant control room fires are those which occur in cabinets, and that transient fires do not pose a significant risk in the control room because it is continuously occupied and the likelihood that a transient fire would not be detected and suppressed in its incipient stage is very small. For these reasons, the contribution of plant-wide ignition sources to the control room fire scenario frequencies will be assumed included in the non-cabinet fire frequency discussed in the previous paragraph.

4.6.3.3 General Approach for Control Room Fire Evaluation

4.6.3.3.1 General Philosophy For Control Room Evaluation

The general philosophy for fire evaluation of control room fires follows the approach suggested in NSAC 181. It is similar to that adopted in other areas but differs in two respects:

- Regardless of the level of damage which is actually sustained as result of a fire, the production of smoke may necessitate the evacuation of the control room. Under such circumstances, the operators will isolate the main control room and shutdown the plant using the alternate shutdown capability.

- Detailed fire propagation will not be performed since there are no acceptable models for modeling propagation within and from cabinets. Instead, it will be generally assumed that cabinet fires in the control room will not spread from the confines of the cabinet in which they originate, assuming that the cabinet has solid metal or fire resistant boundaries. This supposition is supported by the results of the Sandia cabinet fire tests (NRC, 1986, and 1987c), in which all test fires were self-extinguished, and by the reports of control room fires in the data base.

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. Fire scenarios in such cabinets are evaluated individually.

The methods used for frequency analysis, propagation analysis, and suppression analysis are discussed below.

4.6.3.3.2 Fire-Induced Equipment Failures for Enclosed Cabinet Fires

The technique used to determine the effects of fire-induced equipment failures for enclosed cabinet fires includes the following primary steps:

1) Determine which of the cabinets are to be considered critical. Typically, this will be those which degrade any safety-related system required for hot shutdown.

2) Determine the likelihood a fire will occur in a critical cabinet. The frequency of fire in any individual cabinet or set of cabinets is proportional to the number of cabinets in the control room area. Since the total number of cabinets in the fire areas 12-A-CR and 12-A-CRC1 is 118, the frequency of fire associated with each cabinet in the two fire areas can be calculated as 9.5E-3 per year/118, or 8.05E-5 per year.

3) Determine how severe a fire would have to be to fail the critical functions supported by a cabinet or combination of connected cabinets. In this analysis, it will be assumed that all the equipment in the cabinet where the fire originates will fail. This is conservative based on the fire events reported in the data base, and correlates with NSAC 181 assumptions. If a solid intervening wall or barrier exists between cabinets, the fire will be assumed to remain entirely within that cabinet, and it will not affect the functionality of other cabinets if it does not progress beyond the incipient stage. If a fire is assumed to progress beyond the incipient stage, the fire will be assumed to affect its adjoining cabinets, even if the fire itself is not assumed to propagate to these cabinets. Conservatively, all functions will be assumed lost in the affected cabinets in these cases.

   Based on historical experience, all 12 control room fires in the Fire Events Database have been extinguished before the fire reached a level capable of causing significant damage. For the purposes of this evaluation, it will be arbitrarily assumed that the next fire to occur will be more severe. Using this assumption, the frequency of control room fires progressing beyond the incipient stage can be estimated as 1/13 = 0.077.

   In cases where cabinets are connected and a solid intervening barrier does not exist, inter-cabinet fire propagation is assumed to occur if the fire is not suppressed at the incipient stage. Once the fire has propagated to another cabinet, all functions associated with that cabinet are assumed to fail.

4.6.3.3.3 Adverse Effects of Smoke

The technique used to incorporate the potential effects of smoke generated by a control room fire includes the following primary steps:

1) Determine the level of smoke which will impair the effectiveness of the operators, and the likelihood that this amount of smoke will be generated by a cabinet fire. The Sandia cabinet fire tests (NRC, 1987c) indicated fires were self-sustaining and did produce

sufficient quantities of smoke to cause visual impairment. All of the fires in the data base 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.

2) Determine how much time is available to suppress the fire before the smoke concentration reaches the level of visual impairment (at which time the operators are assumed to evacuate the control room). The SHNPP control room envelope has a volume of approximately 138,000 ft^3, and an air flow rate of approximately 14,000 cfm. This means that the control room ventilation rate is about six full room changes of air per hour (rm ch/hr). At a ventilation rate of 1 rm ch/hr (800 cfm), Sandia tests performed in a simulated control room of 48,000 ft^3 indicated that about 15 minutes are available before the control board is obscured. The typical SHNPP ventilation rate is about six times higher than this value. Furthermore, a high ventilation rate test (8 rm ch/hr, or 6400 cfm) was performed, which indicated that about 30 minutes are available before the control board is obscured at this ventilation rate. Since 6 rm ch/hr lies in the range of the tests performed (1–8 rm ch/hr), the time to control board obscuration can be assumed to lie within the 15-30 minute range. For conservatism, the lower value was used, and the control room operators will be assumed to be forced to leave the control room due to smoke buildup no later than 15 minutes into the fire scenario for fires which are not suppressed by that time.

3) Derive the probability of detection and suppression prior to smoke level reaching level of visual impairment. The control room is well covered by smoke detectors strategically located throughout the fire area, and this area is continuously manned. It is therefore quite reasonable to expect that the fire would be detected very quickly, most likely well before developing beyond the incipient stage.

NSAC 181 describes a methodology by which a probability of control room evacuation due to smoke impairment can be derived from existing control room fire data. The model used to interpret the data was EPRI's human cognitive reliability correlation for interpreting measured operator action times in the control room. The model fits the fire durations to a lognormal curve to estimate the probability for failure to successfully act (here, failure to suppress the fire) for times greater than those observed. Since the fires that would result in evacuation would obviously have had to progress beyond the incipient stage, it is on this subset of postulated control room fires that the calculations are based.

The overall probability of non-suppression within the fifteen minute time window given by the Sandia testing was estimated using this methodology to be .0034. Given that this analysis treats incipient and "beyond incipient" fires as separate cases, the conditional probability of control room evacuation due to smoke impairment given a fire which has progressed beyond the incipient stage must be derived. Inherent in this derivation is the

assumption that fires that do not progress beyond the incipient stage will not require control room evacuation. This conditional probability is calculated as .0034/.077= .044. In other words, 4.4% of all control room fires that progress beyond the incipient stage and 0.34% of all control room fires will be assumed in this analysis to result in control room evacuation.

4.6.3.3.4 Assumptions Regarding Control Room Evacuation

1. Control room evacuation will be governed by procedure AOP-004.

2. Smoke generation due to fire in the control room complex/computer room (fire area 12-A-CRC1) or in fire zone 12-A-6-RT1 (Termination Cabinet Room) adjacent to the Main Control Room will not result in a required control room evacuation. AOP-004 only dictates evacuation for fires in the Main Control Room itself. The control room complex/computer room is physically separated from the control room, has access to the control room only through air lock passageways, and is enclosed by three hour fire barriers. The Termination Cabinet Room, while not isolated for fire propagation purposes from the Main Control Room, can be isolated for the purposes of smoke propagation by the closure of two doors on the only wall adjacent to the two rooms.

3. Physically connected sub-cabinets will be treated as single cabinets in terms of the effect of fires that are not suppressed early. In other words, a fire in one sub-cabinet that is not suppressed within 15 minutes will be assumed to impact any function for which cables are present in any sub-cabinet in the physical grouping. This is conservative, but is necessary due to the lack of fire resistant barriers between sub-cabinets.

4.6.3.4 Fire Scenario Identification and Frequency Determination

Potential fire scenarios were identified by assuming that a potential fire could initiate in each of the control room cabinets. The control and/or indication functions lost because of this fire is then determined based on SHNPP drawings and other documentation. Scenarios which involve cabinets that do not impact any safe shutdown functions are screened out, unless fire propagation to other cabinets is possible. In addition to single cabinet fires, scenarios are also postulated where fire propagation fails two or more cabinets. For these scenarios, the functions for all the affected cabinets are assumed to be lost.

A summary ofthe postulated control room fire damage states and the quantification of the screening CDF is provided in Table 4-7. The initiating event frequencies are based on the following:

- Frequency of a single cabinet fire = 8.05E-5 per year.
- Probability of fire propagation (progressing beyond its incipient stage) = 0.77
- Probability of non-suppression within 15 minutes = 0.0034
  (when evacuation becomes necessary)

For quantification purposes, the following were calculated using the SHNPP PSA models.

Conditional core damage probabilities

Turbine trip transient with loss of one power train	
1A-SA 6.9kV AC bus and 125V DC bus	1.44E-3
1B-SB 6.9kV AC bus and 125V DC bus	3.89E-3
125V DC bus A	6.10E-4
125V DC bus B	2.80E-3
Total loss of offsite power followed by a division power failure	
A Division	9.95E-2
B Division	7.46E-2
Division loss of offsite power and the same division power failure	
A Division	7.50E-3
B Division	7.13E-3
Small LOCA with loss of one power train	
1A-SA 6.9kV AC bus and 125V DC bus	5.86E-3
1B-SB 6.9kV AC bus and 125V DC bus	6.23E-3
Turbine trip transient with	
Chilled Water System (CWS) unavailable	1.85E-5
CWS and A Division Power unavailable	5.80E-3
CWS and B Division Power unavailable	2.40E-3

Functional Failure Probabilities

Loss of AFW	4.53E-4
Loss of AFW and main feedwater (MFW)	1.49E-5
Loss of feed and bleed cooling and recirculation	2.27E-2
Loss of early RCS integrity	2.58E-4

4.6.3.5 Summary of Results from Quantification of Control Room Fire Scenarios

Table 4-7 summarizes the screening quantification forthe control room fire damage states. It should be noted that the screening CDFs in this table are very conservative since the components assumed to be unavailable are a much larger subset of what is actually failed by the individual cabinet fire (This conservative assumption was made to simplify calculations). In addition, no credit was taken for fire detection and suppression. Even with these assumptions, the calculated CDF's for the majority of the fire scenarios are below the 1E-6 per year criteria. The exceptions are the following scenarios whose initiating event frequencies are noted.

- Scenario 1D1 (event frequency 5.57E-5 per year)—This scenario results in loss of control for the AFW and ESW systems from the Main Control Room. In addition, control functions for many train A components (including those for feed and bleed) are unavailable in the control room. Shutdown from the ACP is assumed to be necessary. A potential LOCA can be mitigated by the closing of the appropriate PORV Block valve from the ACP.

- Scenario 5A5 (event frequency 7.43E-5 per year)—This transient results in loss of control of the SIS from the main control room. It was conservatively assumed that 10% of the fires in this scenario will result in hot shorts which will cause the spurious opening of a PORV. In this case, SI is necessary and shutdown from the ACP is assumed. The LOCA can be mitigated by the closing of the appropriate PORV block valve from the ACP.

- Scenario 5D2 (event frequency 3.10E-5 per year)—This scenario is similar to scenario 5A5.

- Scenario 6B (event frequency 1.98E-4 per year)—This scenario involves a fire in any cabinet in area 12-A-CR that is not suppressed within 15 minutes. The assumption here is that the effects of smoke produced will necessitate control room evacuation. Plant shutdown is assumed from the ACP.

- Scenario 6H (event frequency 2.48E-5 per year)—This scenario involves a fire which disables all functions in the main control board. Shutdown from the ACP is assumed.

All the above scenarios involve control room evacuation with control of safe shutdown components from the ACP. Operator action at the ACP includes the closing of the appropriate PORV block valve to mitigate a potential LOCA.

4.6.3.6 Calculation of Core Damage Frequency for Control Room Fire Scenarios

This section summarizes the evaluation of core damage frequency for each of the scenarios identified in section 4.6.3.5.

4.6.3.6.1 Scenario 1D1

It was conservatively assumed that 10% offires in this scenario will result in hot shorts causing a PORV to spuriously open. Thus, the scenario results in a transient with a frequency of 5.01E-5 per year, and a small LOCA with a frequency of 5.57E-6 per year. Even though it is not explicitly identified as an entry condition into AOP-004, it was assumed that the inability to control AFW and ESW from the control room will lead the operators to the remote shutdown procedure. It was further assumed that, using the values for conditional core damage

probabilities given in section 4.6.3.4, the HEP for failing to take control at the ACP is dominant.

The approach to estimation of HEPs for the case of fires is to choose an appropriate similar HEP from the internal events PSA and to multiply it by 10, to allow for the stress of using a less familiar control panel layout, and the urgency of the situation. Thus, for the transient scenario, the chosen HEP is OPER-9 which is the initiation of shutdown cooling. Thus, the HEP for failing to control the removal of decay heat following a fire was estimated to be 1.5E-2.

For the LOCA scenario, there is an additional stress. While one train of SI should be available, it was assumed that in addition to the above, the PORV should be closed. Since the procedure does not explicitly direct the operators to close the block valve (although in Step 18, control of pressurizer pressure is addressed), the HEP, OPER-23, failure to close a block valve, is multiplied by a factor of 100, yielding 7.5E-2. Thus, the total HEP for the LOCA case is approimately 1.5E-2 + 7.5E-2 = 9E-2.

The total core damage frequency is estimated as

$$5.01E\text{-}5 \times 1.5E\text{-}2 + 5.57E\text{-}6 \times 9E\text{-}2 = 1.25E\text{-}6$$

4.6.3.6.2 Scenario 5A5

In this case, the scenario that results in a spurious open PORV will require shutdown from the ACP. The non-LOCA scenario can be mitigated from the control room using the unaffected AFW system. The scenario that requires control from the ACP has a frequency of 7.43E-6 per year. Steps 6, 7, 13, 14, and 15 of AOP-004 address the CSIP initiator. Therefore, the initial factor is that the operators realize that they need to go to the ACP to control the CSIP. Since there is no explicit guidance, but the use of the remote shutdown panel is a high profile option in the case of fire, a HEP of 0.1 was assumed. Thus, the scenario leads to a core damage frequency of 7.43E-7.

4.6.3.6.3 Scenario 5D2

This is similar to scenario 5A5, but with a lower frequency. A value of 3.1E-7 was the calculated CDF.

4.6.3.6.4 Scenario 6B

This scenario does not involve damage to any equipment, but requires an orderly shutdown from the ACP. Similar to the description in Section 4.6.3.6.1, the value of 1.5E-2 for the HEP was assumed as for scenario 6B. The frequency of core damage is 3.0E-6 per year.

4.6.3.6.5 Scenario 6H

This scenario was assumed to lead to a LOCA with frequency of 2.48E-6 per year, and a transient with a frequency 2.23E-5 per year. Using the same rationale as for Scenario 1D1, the core damage frequency is 5.56E-7 per year.

4.6.4 Summary of Results

A summary of the screening status for the SHNPP fire analysis for all areas analyzed is presented in Table 4-8. Areas were screened out from further consideration when the CDF calculated using conservative assumptions was below the value of 1E-6 per year. It should be noted that several levels of screening were carried out, each level more refined that the previous one. If at any level, a CDF of below 1E-6 per year was achieved, calculations are stopped and the area was screened from further analysis. Therefore, the screening CDFs presented in Tables 4-4, 4-5 and 4-7 are not directly comparable in some cases. The results in these tables only show that fires in certain plant areas are not risk significant.

The only unscreened scenarios involve fires in the A and B switchgear rooms and in the control room. The CDF from these scenarios are summarized below:

Area 1-A-SWGRA	3.1E-6 per year
Area 1-A-SWGRB	4.0E-6 per year
Control Room Scenario 1D1	1.3E-6 per year
Control Room Scenario 6B	3.0E-6 per year

From the above, a total CDF from fire events at SHNPP was evaluated to be 1.1E-5 per year. This CDF is considered to be conservative and more detailed/refined analyses would yield a lower CDF.

4.6.5 Uncertainty Analysis

No formal analysis and propagation of uncertainty has been performed for the fire results. However, each of the possible sources of uncertainty is addressed qualitatively below in the context of the modeling approach and fire risk estimate for SHNPP.

Deterministic fire modeling parameters

State of knowledge uncertainties about values of the parameters used in COMPBRN IIIe would give rise to uncertainties in the predictions (e.g., extent of fire growth and damage range). As explained below, this was addressed by choosing conservative values for the current analysis.

In performing the COMPBRN analysis, mean value input parameters were taken primarily from the sample input file for COMPBRN IIIe. However, cable pilot ignition, spontaneous ignition and damage temperatures reported NUREG/CR-4550 were selected for conservatism.

In most cases, the fire sources were electrical cabinets. As discussed in Section 4.3, the heat release rate and fire duration selected for modeling were based on the most severe fires resulting from cabinet fire tests performed by Sandia. Other tests performed produced heat release rates an order of magnitude lower.

Fire Ignition Frequency

Fire frequencies were based on generic data of fire events which occurred during power operation at US nuclear power plants coupled with weighting factors to reflect the fire protection programs in place at SHNPP and location specific ignition sources. A number of reviews of the issues associated with estimation of fire frequencies have resulted in the derivation of probability distributions associated with the frequency of fires in various nuclear power plant compartments (Apostolakis, 1985 and NRC, 1990c). Such studies have produced upper bound estimates (95%) which are a factor of 2 to 4 times higher than the best estimate value, and lower bounds which are in some cases more than an order of magnitude lower.

Undamaged System Failure

Based on the IPE results, the probability of random system failures have upper and lower bounds which are a factor of 5 - 10 greater/less than the best estimate value. However, in the case of the fire analysis, the dominant cutsets often include a single human error probability. In this case, the uncertainty is on the high end of the 5 - 10 range quoted above.

Overall Uncertainty

Based on the above discussion, and particularly because of the conservative assumptions in the COMPBRN analysis, had a formal uncertainty analysis been performed, it is anticipated that the

upper bound of the fire induced core damage frequency distribution would not have exceeded a factor of 5 greater than the point estimate value presented in this study.

4.7 CONTAINMENT EVALUATION

The requirements for a containment analysis are different for the IPEEE than they were for the IPE. For the IPEEE, it is necessary to discuss mechanisms that could lead to containment bypass mechanisms that could lead to failure of containment isolation and availability and performance of containment heat removal systems under each external hazard to see if they are different from those evaluated under the IPE. Thus there are essentially three areas of concern: bypass, isolation and heat removal.

Containment bypass was evaluated in the IPE, and the two significant bypass mechanisms identified were the interfacing system LOCA (large containment bypass) and the unisolated steam generator tube rupture (small containment bypass). Mechanical failure is the cause of both of these events. Since the components involved are piping and check valves, a fire would not be expected to initiate either of the events. The detailed fire analysis did not find any fire-related failure mechanism that would cause one of these components to fail. In addition, accident sequences resulting from fire events will not cause a higher than expected reactor coolant system pressure (when compared with the other IPE initiating events), thus, the likelihood of induced steam generator tube rupture events will not be increased. Therefore, the containment bypass conclusions presented in the IPE are not altered by the fire analysis.

Section 6.3.9 of FIVE provides guidance on the evaluation for the potential impact of a fire on containment heat removal and isolation. The fire effects on containment performance must be evaluated if the likelihood of loss of safe shutdown capability for a fire compartment is greater than 1E-6 per year after the screening process.

The PSA success criteria for the containment cooling function requires at least two out of four containment fan cooler (CFC) units or one of the two containment spray (CS) trains. Therefore, if no more than two CFC units and one CS train are impacted by a fire in a given fire area, the containment cooling function is considered to be preserved. For each of the unscreened scenarios described in section 4.6.4 (in areas 1-A-SWGRA, 1-A-SWGRB and in 12-A-CR), the impact of a fire was evaluated for loss of the CFCs, the CS pumps and valves, and the power supplies for these systems. In each scenario, no more than one train (2 containment coolers or one CS pump train) would be failed. Therefore, the containment cooling function would be preserved by the remaining CFC or CS train.

For the evaluation of containment isolation, the analysis presented in section 3.2.17 of the IPE was reviewed to determine if a fire event will invalidate any of the IPE screening criteria and to determine the effects of a fire on the unscreened isolation paths.

All 5 IPE isolation valve screening criteria were found to be unaffected by fire scenarios in areas 1-A-SWGRA, 1-A-SWGRB and 12-A-CR. In addition, a review of the components in the

unscreened fire areas showed that there are at least one non-fire-susceptible containment isolation valve in each of the unscreened penetrations. Therefore, containment isolation for all penetrations was considered to be preserved.

The above methodology for containment performance evaluation is considered to be valid and conservative since the random failure probability of either two CFCs and one CS train, or one containment isolation valve of any type is considerably less than 0.05. When this is multiplied by the CDF for each individual fire scenario of approximately 2.0E-6 per year, the frequency for a containment bypass scenario would be less than 1.0E-7 per year.

4.8 TREATMENT OF FIRE RISK SCOPING STUDY ISSUES

The purpose of this analysis was to perform a qualitative evaluation of the five issues identified in the Sandia Fire Risk Scoping Study. The issues were evaluated to determine if there are any aspects which had not been adequately addressed in the past at SHNPP. The discussion and guidance outlined in the FIVE methodology, section 7.0 and Attachment 10.5, was used to perform this analysis. The FIVE methodology provides specific questions to be reviewed, through both programmatic reviews and plant walkdowns.

No deficiencies were identified during this review.

4.8.1 Seismic Fire Interactions

This issue involves three specific concerns identified in FIVE, namely, seismic induced fires due to breakage of flammable liquid and gas vessels, seismic actuation of suppression systems, and seismic degradation of suppression systems. Each of these are discussed below.

Seismically-Induced Fires

This issue considered the potential leakage or rupture of flammable/combustible liquid or gas lines or tanks/containers during a seismic event, which could create fire hazards. The potential hazards include hydrogen, diesel oil/fuel oil, and lubricating oil. The location of these and similar hazards were identified and documented. The seismic ruggedness of each identified component is addressed as part of the IPEEE seismic evaluation.

Seismic Actuation of Fire Suppression Systems

This issue considered the potential for inadvertent actuation of suppression systems during a seismic event, and the resultant effects on safety/SSD related components and systems. The effects of concern include both flooding and wetting effects caused by runoff/spray. A plant walkdown identifiedthe fixed fire suppression systems which are located in areas containing safe shutdown related equipment. The effects from seismic events on these systems are addressed as part of the IPEEE seismic evaluation.

A review of plant documentation, for example the SHNPP FSAR, section 9.5.1.1.5, demonstrated that this issue had been adequately covered as part of the plant design and was a factor in the fire hazards analysis. The following are excerpts from the FSAR:

- "The evaluation of the consequences of inadvertent operation of the fire extinguishing system is addressed in the description of each respective system and in the detailed fire hazards analysis for each fire area."

- "The evaluation of the consequences of a crack in a moderate-energy line in the fire extinguishing systems has been performed to demonstrate compliance with the guidelines of NRC Branch Technical Position APCSB 3-1 and MEB 3-1."

- "Equipment that might be damaged by water was protected from the fire and/or water. Drains were provided to remove water used for fire suppression and extinguishment to ensure that water accumulation will not incapacitate safety-related equipment."

NRC Information Notice (IEN) 83-41 pertains to this issue. The CP&L responses and actions with regard to this IEN is discussed below.

- IEN 83-41—This IEN alerts licensees to some experiences in which actuation of fire suppression systems caused damage to, or inoperability of, systems important to safety. As noted in the FIVE methodology, an assessment of SHNPP against this IEN would acceptably address the issue of adverse operational effects caused by the failure or spurious actuation of fire suppression systems. CP&L had performed evaluations to demonstrate that the concerns discussed in the IEN had been sufficiently addressed. One action in response to the IEN was the re-design of the transformer area to provide flood protection.

This review concluded that adequate consideration of suppression system actuation effects on safety-related equipment has been integrated into the plant during design and construction as discussed above and no further action is required.

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 location of fire suppression piping with respect to SSD equipment was identified and documented. Potential effects from the impact of equipment falling onto SSD components is addressed under the seismic evaluation phase of the IPEEE.

4.8.2 Fire Barrier Qualifications

Fire barrier elements (barriers, doors, penetration seals and dampers) were reviewed in accordance with the six checklist questions identified in FIVE. All checklist questions were answered affirmatively, indicating that fire barrier elements are being maintained consistently and that the SHNPP Fire Protection Program provides adequate control measures consistent with the objectives of the FIVE methodology.

Fire Barriers

SHNPP procedure FPP-001 provides a general discussion with regards to barriers and refers to other procedures regarding controls and compensatory actions. The following procedures demonstrates that the installation and maintenance of fire barriers/seals (including doors and dampers) at SHNPP are controlled and consistent with industry practices.

- FPP-013—this procedure establishes the requirements for operability and the actions to be taken when fire rated assemblies are impaired.

- FPP-014—this procedure establishes requirements to ensure fire rated assemblies are surveillanced to ensure the operable status of the fire protection systems.

- FPT (Fire Protection Periodic Test) series procedures performs periodic tests to ensure fire dampers, doors, penetrations wraps and fire barrier panels are operation in accordance with FPP-014.

- CMP (Civil Modification Procedure) series procedures provides instructions for the installation of concrete/grout, thermolag, masonry block, fire wrap, penetration seals and doors.

Fire Doors

As discussed above for fire barriers, fire doors are included in both FPP-013 and FPP-014 with regards to controls and impairments. Surveillances are performed in accordance with the requirements of several periodic tests procedures.

Penetration Seal Assemblies

The surveillance of fire barrier penetration seals is similar to those for the other fire barriers and is addressed in the above sections.

The FIVE methodology identifies three NRC IENs which have specific applicability to fire barrier penetration seals:

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

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

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

On-site Nuclear Safety OEF evaluation packages have been assembled for each of the above IENs as discussed separately below:

- **IEN 88-04**—An attachment to the evaluation package responded to the various issues, which supports CP&L's position that SHNPP complies with the NRC guidance in the IEN.

- **IEN 88-04, Supplement 1**—This IEN pertains to problems caused by potential misapplication of silicone foam material, specifically when used around diesel generator exhaust pipes. As noted in the evaluation package, silicone foam was not used where temperatures exceeded 392°F and referenced the applicable penetration drawings for the design specification.

- **IEN 88-056**—As discussed in the evaluation package, fire barrier seals at SHNPP are inspected on a sample basis at 18-month intervals and procedures require wraps to be removed such that seals can be visually inspected so that any problems as identified in the IEN can be detected. Initially all wraps were removed to inspect each penetration seal. Subsequently, given the non-degraded status of the subject penetrations and the destructive nature associated with the removal of the wraps, this approach was discontinued. Currently, procedure FPT-3550 considers seals to be satisfactory if fire wraps are intact.

It was demonstrated by the above discussion that the three IENs have been recognized by CP&L, and that these concerns were addressed by appropriate plant procedures and other documents maintained in project files.

Fire Dampers

Fire dampers are included in both FPP-013 and FPP-014 with regards to controls and impairments. Surveillance of the dampers are performed every 18 months in accordance with the FPTs.

The FIVE methodology identifies two NRC IENs which have specific applicability to fire dampers:

(1) IEN 83-69, "Improperly Installed Fire Dampers at Nuclear Power Plants."

(2) IEN 89-52, "Potential Fire Damper Operational Problems."

An On-site Nuclear Safety OEF evaluation package has been assembled for IEN 89-52, however this program was not in use at the time IEN 83-69 was issued since the plant was not operating at the time. However, as discussed below, the concerns addressed by the IEN have been obtained by other site documentation:

- IEN 83-69—A review of internal CP&L correspondences demonstrated that the concerns discussed in the IEN had been sufficiently evaluated and addressed. As part of the effort, SHNPP fire protection personnel assisted startup engineers during turnover walkdowns to look for areas of concern.

- IEN 89-52—This NRC notice alerts holders of operating licenses to potential problems affecting the closing reliability of curtain-type fire dampers under air flow conditions. The notice sites a 10CRF21 notification to the NRC involving Ruskin Manufacturing and Northern States Power Company, but acknowledges that concern need not be limited to Ruskin since all stations use curtain-type fire dampers of similar design. The evaluation package response stated that a unique design of an air balance fire damper was tested and exempted from the flow testing by the NRC. Specifically, this type of damper was later marketed by Pullman Construction Industries, Inc. as an internal expansion fire damper assembly with certification for closure against air flows.

Therefore, it can be concluded that the above two IENs have been recognized by CP&L and that these concerns were addressed by appropriate upgrades to the plant.

4.8.3 Manual Fire Fighting Effectiveness

This issue is focussed 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 fire PRA.

Manual fire-fighting effectiveness was reviewed in accordance with the 16 checklist questions identified in FIVE. All checklist questions were answered affirmatively, indicating that the plant's fire fighter training and preparedness is consistent with standard expectations. In summary, the programmatic criteria for the fire brigade training, practice/drills, and equipment complement are consistent with the guidelines of the FIVE methodology.

4.8.3.1 Reporting Fires

Orientation of Plant Personnel to the Use of Portable Fire Extinguisher

As described in procedure FPP-001, section 5.11, each employee will receive fire protection training in accordance with procedure FPP-016. This procedure specifies that all plant personnel granted unescorted access will receive training as part of the General Orientation and General Employee Training/Retraining (GET), which includes "Extinguishers" as a course topic. As part of the GET classroom material, step-by-step instructions are provided with regards to the proper use of portable extinguishers. In addition, portable fire extinguishers are included as part of fire brigade team and fire watch training course. The GET material stipulates that the control room be notified first, then attempt to extinguish the fire, if possible, using the appropriate extinguisher.

Availability of Portable Extinguisher Throughout the Plant

FSAR section 9.5.1.2.3 states that portable fire extinguishers are selected and mounted in readily accessible locations throughout the plant. Periodic test procedures require the visual inspection of extinguishers on a monthly basis for general plant areas, including the containment during modes 5 and 6.

Plant Procedure for Reporting Fires

Procedure FPP-002 specifies actions to be carried out in case of fire. This procedure, as reiterated in the GET material and the Plant Conduct of Operations procedure (section 5.9, AP-002), requires any person discovering a fire to immediately notify the control room. Upon receipt of notice of a fire or annunciation of a fire alarm, the Shift Supervisor implements additional actions as defined by FPP-002. FPP-002 provides the appropriate actions for alerting plant personnel (i.e., fire brigade, security and radiation control personnel) and/or other actions as deemed necessary in accordance to the fire severity.

Communication System to Allow Contact With the Control Room

FSAR section 9.5.1.2.3 states that a dedicated radio system is provided for plant operation and maintenance. The system is powered from a non-class 1E uninterruptible power supply. In addition, a sound powered telephone system is also available which requires no external power source. Both the dedicated radio system and the sound powered phone systems are independent of other communication systems. The locations of both systems are identified on the appropriate pre-plans, FPP-012.

In summary, SHNPP programs and procedures with regards to the use and location of extinguishers, reporting fires and communication with the control room is in compliance with the FIVE/FRSS criteria.

4.8.3.2 Fire Brigade

Size of Fire Brigade

Procedure OMM-001, section 3.3.2 states that at least five fire brigade members are available for each shift.

Brigade Members Knowledgeable in Plant Systems and Operations

FSAR section 9.5.1.5.e states that the fire brigade consists of five persons, at least three of whom are knowledgeable in the effects of fire on plant operation and safe shutdown capability. The brigade leader possesses an operator's license or has demonstrated equivalent knowledge of safety-related systems. In addition, a licensed operator is assigned to each shift to be an advisor to the brigade.

Annual Physical Examinations for Brigade Members

Each brigade member must comply with the provisions of FPP-009, which establishes the physical requirements for brigade members, including a respiratory examination.

Minimum Equipment Provided/Available to Fire Brigade

Operations Reliability Test procedure, ORT-3001, provides for monthly inspections to maintain equipment in the fire brigade staging area in a readiness state, which includes the following:

- ten SCBA's
- ten spare air bottles
- three spotlights and spare batteries
- four 50 foot sections of 1-1/2 inch hose
- one 1-1/2 inch by 1-1/2 inch gated wye
- two 1-1/2 inch Turbo Jet/TFT nozzle
- one smoke exhaust fan and accessories
- one pike pole
- one pry bar
- one pick-head axe
- one braided nitrogen to HVAC line
- ten life guards
- one 1-1/2 inch foam nozzle and eductor

In addition to the below minimum equipment levels, each brigade member has been issued individual turnout clothing.

Accordingly, the SHNPP fire brigade size, plant and system knowledge, physicals and equipment levels are consistent with the FRSS criteria.

4.8.3.3 Fire Brigade Training

Initial Classroom Instruction Program

The fire brigade team training as outlined in section 5.3.b of FPP-016 is required for all brigade leaders and members. This initial course will be completed in its entirety prior to assignment to the fire brigade. Quarterly training sessions are held such that reviews, updates, or advanced training on major topics of the fire fighting course are repeated every two years. The following are topics of this initial training which is consistent with the FIVE evaluation methodology: duties and responsibilities of fire brigade members; chemistry and extinguishment of fire; portable fire extinguishers; fire hydrants and hose houses; fire protection systems; flammable liquids and gases; smoke, toxic gas, and radiological hazards; use of fire preplans for hazards, ventilation controls, and building layout; hands-on use of SCBA, portable fire extinguishers, fire hose and nozzles; and ventilation.

Practice

The fire brigade hands-on training program is included as part of the fire brigade team training course. Once per year each fire brigade team receives hands-on structural fire fighting.

Drills

The fire brigade drills, as described in section 8.1 of FPP-016 provides the following factors, which are consistent with the FIVE evaluation methodology:

(1) Each shift fire brigade team will be drilled at least once per calendar quarter.

(2) At least one fire drill per year for each shift fire brigade team will be unannounced.

(3) At least one fire drill per year for each shift fire brigade team will be conducted on other than day shift.

(4) At least one fire drill per year will include participation by the off-site fire company.

(5) Each fire brigade team member will participate in every drill for that team and must participate in at least two drills per year.

(6) Each fire drill will be preplanned and postcritiqued by the fire protection staff.

(7) Drills will be performed in the plant and varied such that the brigade members are trained in fighting fires in a variety of safety-related and high hazards areas.

(8) At 3 year intervals, a fire drill will be critiqued by qualified outside individuals.

(9) Fire preplans are part of the fire brigade training.

(10) Fire brigade equipment is routinely surveillanced in accordance with ORT-3001.

Records

In accordance with FPP-001, the manager of the SHNPP training unit is responsible for implementing and supporting the fire protection program detailed in FPP-016, including maintaining training records. Section 5.20 "Training" of AP-002 lists items that will be included in the training records. This instruction provides a uniform method of identifying, processing, and retrieving records by the SHNPP training unit. The fire protection staff, which provides the training, also reviews the records to ensure that all program training goals are being achieved for each fire brigade member.

In summary, the SHNPP fire brigade training program is in compliance with the FIVE/FRSS criteria.

4.8.4 Total Environment Equipment Survival

This issue is concerned with the potential effects on plant equipment by combustion products, spurious or inadvertent fire suppression system activation, and on operator action effectiveness given a fire at the plant. A summary discussion for each of these is provided below.

Potential Adverse Effects on Plant Equipment by Combustion Products

The FIVE/FRSS methodology does not provide criteria for assessment of the potential non-thermal effects of products of combustion on safety/SSD related equipment. For the relatively short duration of the fire event and early recovery period, these effects are considered to be insignificant by FIVE. However, the effects of smoke and other combustion byproducts have been considered in the evaluation of operator recovery actions in the fire PRA. (The potential effects of smoke, heat and toxic gases on operator effectiveness during post-fire shutdown scenarios are recognized at SHNPP and appropriate measures have been implemented accordingly. These include the availability of emergency lighting, SCBA apparatus for operations and fire brigade personnel, and smoke venting capabilities. Also, the handling of smoke is considered and is incorporated into the training).

Spurious or Inadvertent Fire Suppression Activity

Spurious or inadvertent operation of water-type fire suppression systems was reviewed. The topic of water spray/runoff has been addressed as an integral part of suppression system design as indicated by the installed protective features. Key safe shutdown components in areas provided with water suppression systems are typically protected by appropriate spray deflectors/baffles, floor drains or similar features where required.

Operator Action Effectiveness

1. Post-fire safe shutdown procedures

   Two AOPs have been developed regarding fires and safe shutdown. AOP-036 provides operator actions when a major fire in any plant area may require a plant shutdown, but may inhibit normal shutdown procedures. AOP-004 provides operators with remote shutdown actions when fire, smoke or toxic gas in the control room or adjacent areas impairs or may impair control room functions.

2. Operator training in post-fire safe shutdown procedures

   Periodic operator training in post-fire shutdown procedures is conducted in accordance with a procedure which is accredited by INPO. This program requires annual training with a two year cycle for all AOPs of which post-fire shutdown procedures are enveloped.

3. Operator Reentry Into Affected Fire Area: Respiratory Protection

   Operator effectiveness in smoke-filled areas are addressed in the following manner:

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

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

   (c) AOP-004, section 3.2, steps 25 and 26, addresses smoke with regards to the control room.

4.8.5 Control System Interactions

AOP-004 provides operators with remote shutdown actions when fire, smoke or toxic gas in the control room or adjacent areas impairs or may impair control room functions. This procedure was developed from information obtained from the SHNPP SSA, specific steps are provided to ensure circuits are physically independent of, or can be isolated from, the control room (or other area) due to fire. The AOP provides steps to transfer predetermined controls to the ACP. In addition, a specific caution is provided to transfer to the ACP as soon as possible to minimize spurious actuation due to control room fires.

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

4.9 USI A-45 AND OTHER SAFETY ISSUES

For fire induced small break LOCAs (stuck open PORV or RCP seal LOCA) and transients, the AFW system is relied upon to provide decay heat removal through the secondary side. The MFW system can also be used to provide for decay heat removal. Emergency operating procedures direct the operations staff to establish MFW flow or flow directly from the condensate system by depressurizing the secondary. In case of failure of both the AFW and MFW systems, feed and bleed operation is required to cool down from the primary side. This involves the operation of the CSIPs and the PORVs together with the RHR system in the recirculation mode.

The unscreened scenarios in this fire PRA result from fires in Switchgear Rooms A and B (1-A-SWGRA and 1-A-SWGRB) and in the Main Control Room (12-A-CR). The Switchgear Room A scenario involves the failure of A division powered components which includes one motor-driven AFW pump and one CSIP. The Switchgear Room B scenario involves the failure of B division powered components which includes one motor-driven AFW pump, one CSIP and also the turbine-driven AFW pump. The CDF from these scenarios is thus dominated by random failures of the opposite division components, notably the motor-driven AFW pump. In the control room scenarios, CDF is dominated by the HEPs to achieve alternate shutdown from the ACP. Therefore the importance of the decay heat removal functions is somewhat masked. However, given successful control from the ACP, potential failures in the decay heat removal functions are likely to be recovered by operator action.

Since the CDF from fire initiated sequences is relatively low when compared to that for the other internal event initiators, the contribution to total CDF from fire induced failures of the decay heat removal system components is not significant. Therefore, the fire PRA confirms the IPE conclusion that there are no particular vulnerabilities in the systems used to perform decay heat removal on the basis of the small relative contribution to CDF. Therefore, USI-A-45 is judged to be resolved.

The FRSS (NUREG/CR-5088) issues were addressed during the fire analysis (section 4.8). It was found that each of the issues has been adequately addressed at SHNPP.

4.10 REFERENCES

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TABLES

Table 4-1 Qualitative Screening Evaluation for Safe Shutdown Fire Area						
Fire Area	Fire Area Description	Q1	SSD aff'd	SSD avail	Q2	SCREENED?
1-0-PA	Diesel Oil Pump A Room	Y	1	2	Y	
1-0-PB	Diesel Oil Pump B Room	Y	2	1	Y	
1-A-BAL-A	Reactor Aux. Building Balance Area A	Y	1,2	1,2	Y	
1-A-BAL-B	Reactor Aux. Building Balance Area B	Y	1,2	1,2	Y	
1-A-BAL-C	Reactor Aux. Building Balance Area C	Y	1,2	1,2	Y	
1-A-BATA	Battery Room A	Y	1	2	Y	
1-A-BATB	Battery Room B	Y	2	1	Y	
1-A-CSRA	Cable Spreading Room A	Y	1,2,3	2	Y	
1-A-CSRB	Cable Spreading Room B	Y	1,2	1	Y	
1-A-EPA	Electrical Penetration Area A	Y	1,2	2	Y	
1-A-EPB	Electrical Penetration Area B	Y	1,2	1	Y	
1-A-SWGRA	Switchgear Room A	Y	1,2	2	Y	
1-A-SWGRB	Switchgear Room B	Y	1,2	1	Y	
1-D-DGA	Diesel Generator A	Y	1	2	Y	
1-D-DGB	Diesel Generator B	Y	2	1	Y	
1-D-DTA	Diesel Gen. Day Tank A Enclosure	Y	1	2	Y	
1-D-DTB	Diesel Gen. Day Tank B Enclosure	Y	2	1	Y	
5-0-BAL	Diesel Oil Storage Tank Area Balance	Y	1,2	2	Y	
5-F-BAL	Fuel Handling Building Balance	Y	1,2	1	Y	
5-S-BAL	ESW Intake Screening Structure Balance	Y	1,2	1,2	Y	
5-W-BAL	Waste Processing Building Balance	N	—	—	N	Y
12-0-TA	Diesel Oil Storage Tank A	Y	1	2	Y	
12-0-TB	Diesel Oil Storage Tank B	Y	2	1	Y	
12-A-BAL	Reactor Auxiliary Building Balance	Y	1,2	1	Y	
12-A-CR	Main Control Room	Y	1,2, 3,4	ACP	Y	
12-A-CRC1	Control Room Complex	Y	1,2, 3,4	ACP	Y	
12-A-HV&IR	Heating, Ventilating, and Instr. Repair	Y	1,2	ACP	Y	

Table 4-1 Qualitative Screening Evaluation for Safe Shutdown Fire Area						
Fire Area	Fire Area Description	Q1	SSD aff'd	SSD avail	Q2	SCREENED?
1-0-PA	Diesel Oil Pump A Room	Y	1	2	Y	
12-I-ESWPA	Emergency Service Water Pumps 1A	Y	1	2	Y	
12-I-ESWPB	Emergency Service Water Pumps 1B	Y	2	1	Y	
TG	Turbine Generator	Y	2	1	Y	

Screening Questions:

Q1: Does this area contain SSD equipment required to achieve hot standby?

SSD aff'd: Safe Shutdown Division(s) affected by fire in this area
SSD avail: Safe Shutdown Division available for shutdown in the event of fire in this area (ACP = Auxiliary Control Panel; see note B)

Q2: Is there a requirement for plant shutdown given an initiating fire event with normal alternate path unavailable?

Table 4-2: Qualitative Screening of Fire Compartments				
Fire Compartment	Elevation	Q1	Q2	Screened ? / Comments
1-A-BAL-A FIRE AREA				
1-A-4-CHF B	261'	Y	Y	No, however, see Note 1
1-A-4-CHF A	261'	Y	Y	
1-A-4-COM I	261'	Y	Y	
1-A-4-CHF C	261'	N	Y	No, however, see Note 1
1-A-3-COR	236'	Y	Y	
1-A-3-MP	236'	Y	Y	
1-A-34-RHXA	236'	Y	Y	
HP STORAGE RM A-467C	236'	Y	Y	No, however, see Note 1
CHARGING PUMP 1A-SA	236'	Y	Y	
CHARGING PUMP 1C-SAB	236'	Y	Y	
CHARGING PUMP 1B-SB	236'	Y	Y	
SPARE ROOM A-467	236'	Y	Y	No, however, see Note 1
1-A-34-RHXB	236'	Y	Y	
1-A-3-PB	236'	Y	Y	
BORIC ACID XFER PUMP	236'	Y	Y	No, however, see Note 1
1-A-3-COMB	236'	Y	Y	
LETDOWN HXCH AREA	236'	Y	Y	No, however, see Note 1
1-A-3-COM E	236'	Y	Y	
1-A-3-COM I	236'	Y	Y	
HV AREA	236'	Y	Y	No, however, see Note 1
MECH. PENETRATION AREA	236'	Y	Y	
1-A-2-MP	216'	Y	Y	
1-A-2-PT	216'	N	Y	No, however, see Note 1
1-A-1-PA	190'	Y	Y	
1-A-1-FD	190'	Y	Y	
1-A-1-ED	190'	Y	Y	
1-A-1-PB	190'	Y	Y	
1-A-3-TA	236'	Y	Y	
1-A-4-TA	261'	N	N	Yes

Table 4-2: Qualitative Screening of Fire Compartments				
Fire Compartment	Elevation	Q1	Q2	Screened ? / Comments
1-A-BAL-B FIRE AREA				
1-A-5-HVA	286'	Y	Y	
1-A-5-HV3	286'	Y	Y	
1-A-5-CEH	286'	N	N	Yes
1-A-5-BAT N	286'	N	Y	No, however, see Note 2
1-A-4-CHL R	261'	Y	Y	
1-A-4-COR	261'	Y	Y	
1-A-46-ST	261'-305'	Y	Y	
VOLUME CONTROL TANK	261'	Y	Y	No, however, see Note 1
1-A-4-COM B	261'	Y	Y	
BORIC ACID TANK AREA	261'	Y	Y	No, however, see Note 1
VALVE GALLERY-A	261'	Y	Y	
VALVE GALLERY-B	261'	N	N	Yes
1-A-4-COM-E-E	261'	Y	Y	
1-A-4-COM-E-W	261'	Y	Y	

Screening Questions:

Q1: Are there safe shutdown equipment located in the compartment?

Q2: Is there a plant trip initiator in the compartment?

Notes

1. The safe shutdown equipment present in this compartment are not risk significant in terms of PSA modeling. Therefore a fire in the compartment can be modeled as a transient with all SSD equipment (including offsite power) available. Since the fire frequencies in these compartments are very small when compared with the PSA turbine trip frequency, these scenarios can easily be bounded by the PSA transient initiators, and therefore fires in these compartments can be screened out.

2. Fires in this compartment can lead to a loss of a non-vital DC bus (DP-1A), which would result in a plant trip due to effects on the secondary plant equipment. This trip is complicated by a loss of offsite power due to a loss of control power to the breakers, which must reposition to transfer plant electrical buses from the main generator to offsite AC power through the startup transformers. However, this initiator is covered by the loss of offsite power initiator in the PSA and can therefore be screened out.

Table 4-3: Fire Ignition Frequencies for SHNPP Fire Areas and Compartments		
Fire Area	Description	Ignition Frequency (yr^{-1})
1-A-BAL-A	RAB Balance South—Area A	3.53E-2
1-A-BAL-B	RAB Balance South—Area B	1.03E-2
1-A-BAL-C	RAB Balance South—Area C	4.18E-3
1-A-5-BATN	Battery Room Neutral	1.19E-3
1-O-PA	Diesel Oil Pump Room A	1.34E-4
1-O-PB	Diesel Oil Pump Room B	1.34E-4
1-A-BATA	Battery Room A	1.19E-3
1-A-BATB	Battery Room B	1.19E-3
1-A-CSRA	Cable Spreading Room A	5.00E-4
1-A-CSRB	Cable Spreading Room B	3.85E-4
1-A-EPA	Electrical Penetration Area A	2.93E-3
1-A-EPB	Electrical Penetration Area B	1.49E-3
1-A-SWGRA	Switchgear Room A	1.33E-2
1-A-SWGRB	Switchgear Room B	1.26E-2
1-D-DGA	Diesel Generator A	3.06E-2
1-D-DGB	Diesel Generator B	3.06E-2
1-D-DTA	DG Day Tank Room A	1.34E-4
1-D-DTB	DG Day Tank Room B	1.34E-4
5-O-BAL	Diesel Oil Storage Tank Area Balance	1.70E-4
5-F-BAL	Fuel Handling Building Balance	7.82E-3
5-S-BAL	ESW Intake Screening Structure Balance	3.54E-3
5-W-BAL	Waste Processing Building Balance	Screened out in Phase 1
12-O-TA	Diesel Oil Storage Tank A	1.34E-4
12-O-TB	Diesel Oil Storage Tank B	1.34E-4
12-A-BAL	RAB Building Balance North	5.46E-3
12-A-CR	Main Control Room	5.88E-3
12-A-CRC1	Control Room Complex	1.13E-2

Table 4-3: Fire Ignition Frequencies for SHNPP Fire Areas and Compartments		
Fire Area	Description	Ignition Frequency (yr^{-1})
12-A-HV&IR	HVAC & Instrument Repair Shop	1.96E-3
12-I-ESWPA	ESW Pump Room A	3.36E-3
12-I-ESWPB	ESW Pump Room B	3.36E-3
TG	Turbine Building	6.35E-2
1-A-BAL-A	Compartment 1-A-4-CHF B	3.67E-4
1-A-BAL-A	Compartment 1-A-4-CHF A	4.75E-4
1-A-BAL-A	Compartment 1-A-4-COMI	2.05E-4
1-A-BAL-A	Compartment 1-A-4-CHFC	4.46E-4
1-A-BAL-A	Compartment 1-A-3-COR	2.39E-4
1-A-BAL-A	Compartment 1-A-3-MP	9.08E-4
1-A-BAL-A	Compartment 1-A-34-RHXA	2.61E-4
1-A-BAL-A	HP STORAGE RM A-467C	7.27E-5
1-A-BAL-A	CHG PUMP 1A-SA	9.36E-4
1-A-BAL-A	CHG PUMP 1C-SAB	9.75E-4
1-A-BAL-A	CHG PUMP 1B-SB	9.36E-4
1-A-BAL-A	SPARE ROOM A-467	4.06E-5
1-A-BAL-A	Compartment 1-A-34-RHXB	2.60E-4
1-A-BAL-A	Compartment 1-A-3-PB	7.32E-3
1-A-BAL-A	BORIC ACID TRANSFER PUMP	1.97E-3
1-A-BAL-A	Compartment 1-A-3-COMB	1.28E-3
1-A-BAL-A	LETDOWN HXCH AREA	1.30E-4
1-A-BAL-A	Compartment 1-A-3-COME	4.62E-4
1-A-BAL-A	Compartment 1-A-3-COMI	1.37E-3
1-A-BAL-A	HV AREA	1.37E-3
1-A-BAL-A	MECH PEN AREA	6.72E-4
1-A-BAL-A	Compartment 1-A-2-MP	3.53E-3
1-A-BAL-A	Compartment 1-A-2-PT	4.85E-4
1-A-BAL-A	Compartment 1-A-1-PA	2.05E-3
1-A-BAL-A	Compartment 1-A-1-FD	1.30E-4

Table 4-3: Fire Ignition Frequencies for SHNPP Fire Areas and Compartments		
Fire Area	Description	Ignition Frequency (yr^{-1})
1-A-BAL-A	Compartment 1-A-1-ED	1.30E-4
1-A-BAL-A	Compartment 1-A-1-PB	2.06E-3
1-A-BAL-A	Compartment 1-A-3-TA	4.85E-4
1-A-BAL-B	Compartment 1-A-5-HVA	4.30E-3
1-A-BAL-B	Compartment 1-A-5-HV3	7.52E-4
1-A-BAL-B	Compartment 1-A-5-CEH	2.60E-4
1-A-BAL-B	Compartment 1-A-5-BATN	1.30E-3
1-A-BAL-B	Compartment 1-A-4-CHLR	5.91E-3
1-A-BAL-B	Compartment 1-A-4-COR	2.56E-4
1-A-BAL-B	Compartment 1-A-46-ST	3.41E-4
1-A-BAL-B	VOL CTR TANK	9.45E-5
1-A-BAL-B	Compartment 1-A-4-COMB	3.34E-4
1-A-BAL-B	BORIC ACID TANK AREA	9.79E-5
1-A-BAL-B	VALVE GALLERY A	1.90E-4
1-A-BAL-B	VALVE GALLERY B	1.26E-4
1-A-BAL-B	Compartment 1-A-4-COME-E	6.53E-4
1-A-BAL-B	Compartment 1-A-4-COME-W	5.90E-4

Table 4-4: Summary Quantitative Screening Results for SHNPP Fire Areas and Compartments					
Fire Area	Ignition Frequency (yr^{-1})	Screening CCDP	Screening CDF	Comments	Screening Status
1-A-BAL-A	3.53E-2			Broken up into compartments	n/a
1-A-BAL-B	1.03E-2			Broken up into compartments	n/a
1-A-BAL-C	4.18E-3	4.3E-2	1.8E-4	CCDP dominated by the potential fire-induced spurious closing of AOV 1RH-20. If this valve fails in the fail-safe position, or if cabling for the valve is not affected, the CCDF drops to 7.0E-3	N
1-A-5-BATN	1.19E-3	1.07E-4	1.27E-7		Y
1-O-PA	1.34E-4	1.07E-4	1.43E-8		Y
1-O-PB	1.34E-4	1.22E-4	1.63E-8		Y
1-A-BATA	1.19E-3	6.1E-4	7.3E-7		Y
1-A-BATB	1.19E-3	2.8E-3	3.4E-6		N
1-A-CSRA	5.00E-4	5.86E-3	2.9E-6	CCDP conservatively assumes unisolated spurious open PORV with A division power failed	N
1-A-CSRB	3.85E-4	6.23E-3	2.4E-6	CCDP conservatively assumes unisolated spurious open PORV with B division power failed	N
1-A-EPA	2.93E-3	6.31E-3	1.85E-5		N
1-A-EPB	1.49E-3	8.99E-3	1.34E-5		N
1-A-SWGRA	1.33E-2			Too many components/cabling in area. Will not screen quantitatively	N
1-A-SWGRB	1.26E-2			Too many components/cabling in area. Will not screen quantitatively	N

Table 4-4: Summary Quantitative Screening Results for SHNPP Fire Areas and Compartments					
Fire Area	Ignition Frequency (yr^{-1})	Screening CCDP	Screening CDF	Comments	Screening Status
1-D-DGA	3.06E-2	7.2E-6	2.2E-7	A check of CWDs show that the only affect of 1A-SA cabling in the area is on EDG A and auxiliaries. The 1A-SA bus itself is not failed, and offsite power will still be available to the bus. The fire will probably not even result in a plant trip.	Y
1-D-DGB	3.06E-2	6.2E-6	1.9E-7	A check of CWDs show that the only affect of 1B-SB cabling in the area is on EDG B and auxiliaries. The 1B-SB bus itself is not failed, and offsite power will still be available to the bus. The fire will probably not even result in a plant trip.	Y
1-D-DTA	1.34E-4	1.07E-4	1.43E-8		Y
1-D-DTB	1.34E-4	1.07E-4	1.43E-8		Y
5-O-BAL	1.70E-4	1.07E-4	1.82E-8		Y
5-F-BAL	7.82E-3	3.64E-5	2.85E-7		Y
5-S-BAL	3.54E-3	1.45E-4	5.14E-7		Y
12-O-TA	1.34E-4	1.07E-4	1.43E-8		Y
12-O-TB	1.34E-4	1.07E-4	1.43E-8		Y
12-A-BAL	5.46E-3	3.64E-5	1.99E-7		Y
12-A-CR	5.88E-3			See section 4.6.3 for quantification	N
12-A-CRC1	1.13E-2			See section 4.6.3 for quantification	N
12-A-HV&IR	1.96E-3	1.13E-4	2.21E-7		Y

Table 4-4: Summary Quantitative Screening Results for SHNPP Fire Areas and Compartments					
Fire Area	Ignition Frequency (yr^{-1})	Screening CCDP	Screening CDF	Comments	Screening Status
12-I-ESWPA	3.36E-3	1.09E-4	3.66E-7	Calculation of CCDP assumed that operator would not actuate SI signal but would manually align and start all components to prevent charging pump suction failure	Y
12-I-ESWPB	3.36E-3	1.32E-4	4.45E-7	Calculation of CCDP assumed that operator would not actuate SI signal but would manually align and start all components to prevent charging pump suction failure	Y
TG	6.35E-2	8.43E-3	5.35E-4		N
1-A-4-CHF A	4.75E-4	1.7E-4	8.1E-8		Y
1-A-4-COM I	2.05E-4	1.7E-4	3.5E-8		Y
1-A-3-COR	2.39E-4			Too many components/cabling in area. Will not screen quantitatively	N
1-A-3-MP	9.08E-4	1.2E-2	1.1E-5		N
1-A-34-RHXA	2.61E-4	3.8E-2	9.9E-6		N
Chg Pump 1A-SA Area	9.36E-4	1.5E-5	1.4E-8		Y
Chg Pump 1C-SAB Area	9.75E-4	1.5E-5	1.5E-8		Y
Chg Pump 1B-SB Area	9.36E-4	1.5E-5	1.4E-8		Y
1-A-34-RHXB	2.60E-4	2.2E-4	5.7E-8		Y
1-A-3-PB	7.32E-3			Too many components/cabling in area. Will not screen quantitatively	N
1-A-3-COMB	1.28E-3	1.0	1.3E-3	Seal LOCA results with no injection source to mitigate	N

Table 4-4: Summary Quantitative Screening Results for SHNPP Fire Areas and Compartments					
Fire Area	Ignition Frequency (yr^{-1})	Screening CCDP	Screening CDF	Comments	Screening Status
1-A-3-COM E	4.62E-4	1.0	4.6E-4	Seal LOCA results with no injection source to mitigate	N
1-A-3-COM I	1.37E-3	1.7E-3	2.3E-6	Dominant failure is random failure of PORV block valve to close for isolation of spurious PORV opening. CCDP = 2.6E-4 (CDF = 3.6E-7 if no spurious PORV openings)	N
Mech Pen Area	6.72E-4	2.2E-3	1.5E-6		N
1-A-2-MP	3.53E-3	7.2E-4	2.5E-6		N
1-A-1-PA	2.05E-3	7.3E-5	1.5E-7		Y
1-A-1-FD	1.30E-4	1.5E-5	2.0E-9		Y
1-A-1-ED	1.30E-4	1.5E-5	2.0E-9		Y
1-A-1-PB	2.06E-3	5.9E-5	1.2E-7		Y
1-A-3-TA	4.85E-4	5.4E-4	2.6E-7		Y
1-A-5-HVA	4.30E-3	1.0	4.3E-3	Seal LOCA results with no injection source to mitigate	N
1-A-5-HV3	7.52E-4	2.0E-4	1.5E-7		Y
1-A-4-CHLR	5.91E-3			Too many components/cabling in area. Will not screen quantitatively	N
1-A-4-COR	2.56E-4	2.0E-4	5.1E-8		Y
1-A-46-ST	3.41E-4	1.4E-4	4.8E-4		Y
1-A-4-COM B	3.34E-4			Too many components/cabling in area. Will not screen quantitatively	N
Valve Gallery A	1.90E-4	1.3E-4	2.5E-8		Y

Table 4-4: Summary Quantitative Screening Results for SHNPP Fire Areas and Compartments					
Fire Area	Ignition Frequency (yr^{-1})	Screening CCDP	Screening CDF	Comments	Screening Status
1-A-4-COME E	6.53E-4	1.0	6.5E-4	Seal LOCA results with no injection source to mitigate	N
1-A-4-COME W	5.90E-4	5.5E-2	3.2E-5		N

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-EPA	See section 4.6.2.1 for details. The significant contributors to the fire frequency are electrical cabinets, transients, welding/ordinary combustibles, welding/cables, and junction boxes. Fire originating in junction boxes and in cables due to welding can be ruled out because of the use of IPEEE 383 cables. Electrical Cabinets: It was shown the risk significant electrical cabinets in this area are the MCCs. Because of the construction of the cabinets, it was concluded that damage from MCC fires in this area will be limited to the loss of the MCC itself, with no fire propagation postulated. The frequency of MCC fires that develop beyond the incipient stage is 3.4E-4. Conservatively assuming that a fire in a MCC would lead to loss of all A power division supported components, the CCDP is 1.44E-3. Thus screening CDF_{EC} = 5.2E-7 per year. Transients: The frequency of a significant fire induced by transient ignition sources was calculated to be 2.5E-7 per year. Therefore, even before accounting for the CCDP, this scenario was screened out. Welding and Cutting Fires: The frequency for a manually unsuppressed welding or cutting fire was calculated to be 3.9E-6 per year. Conservatively assuming that a fire in a MCC would lead to loss of all equipment in the area (all division A components), and assuming a fire induced spurious open PORV, the CCDP is 5.9E-3. Thus the screening CDF_{WF} = 2.3E-8 per year. Total Screening CDF: $CDF_T = CDF_{EC} + CDF_{WF}$ = 5.5E-7 per year	5.5E-7
1-A-EPB	This fire area is similar to area 1-A-EPA with the exception that the area contains two fire panels. However, these fire panels are well sealed and cables to the panels are routed through conduits and enter the panels through sealed penetrations. Thus, the frequency of fire induced damage was considered to be similar for that postulated for 1-A-EPA. The following fire damage states were postulated for this fire area: Loss of 1B24 MCC: The frequency for the loss of this MCC was calculated to be 3.6E-4. Given a CCDP of 9.3E-7, the CDF is: CDF_{EC} = 3.6E-4 * 9.3E-7 = 3.3E-10 per year Loss of All Components and Cabling in the Fire Area: As was in the case for fire area 1-A-EPA, unsuppressed welding and cutting induced fires was the only contributor to this fire damage state with a frequency of occurrence which is greater than 1E-6. The frequency of this fire damage state was estimated to be 3.9E-6 per year. It was conservatively assumed that this FDS result in the total loss of all equipment in this area with a CCDP of 9.0E-3. Therefore, the contribution to the CDF, CDF_{WF}, is: CDF_{WF} = 3.9E-6 * 9.0E-3 = 3.5E-8 per year Total Screening CDF: The total contribution of the FDS's in this fire area is: $CDF_T = CDF_{WF} + CDF_{EC}$ = 3.5E-8 + 3.3E-10 = 3.5E-8 per year.	3.5E-8

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-SWGRB	See section 4.6.2.2 for details. The significant contributors to the fire frequency are electrical cabinets, transients, and welding/ordinary combustibles. Electrical Cabinets: Electrical cabinet fires were divided into two scenarios. The first is one where fires originate in the 6.9 kV and 480V buses and are confined within the cabinets either due to the physical characteristics of the cabinet or due to the successful suppression of the fires before they can ignite/ damage cables routed in close vicinity of the cabinets. The impact of these fires is limited to loss of the fire source (i.e. one cabinet). The significant fires are those that lead to the loss of the 1B-SB AC Emergency Bus and the total frequency of such fires was estimated to be 7.3E-4 per year. The CDF contribution is 1.1E-6 per year. The second scenario consists of fires originating in any bus that is not suppressed during phase 1 of its development. The impact of such fires was assumed to be loss of the entire division B safe shutdown path. With an ignition frequency of 3.5E-3, a probability of suppression failure of 0.1, and a CCDP of 7.1E-3, the contribution of these fires to CDF was estimated to be 2.5E-6 per year. In addition, these fires could also result in loss of offsite power to bus 1A-SA if operator recovery actions are unsuccessful. For this case, the HEP was evaluated to be 1E-2, the CCDP to be 7.5E-2, and the resultant CDF to by 2.6E-7 per year. The total risk from electrical cabinet fires, CDF_{EC}, was therefore estimated to be 1.1E-6 + 2.5E-6 + 2.6E-7 = 3.9E-6 per year. Transients: The frequency of a significant fire induced by transient ignition sources was calculated to be 6.3E-7 per year. Therefore, even before accounting for the CCDP, this scenario can be screened out. Welding and Cutting Fires: The frequency for a manually unsuppressed welding or cutting fire was calculated to be 1.3E-5 per year. Conservatively assuming that a fire in a MCC would lead to loss of all B power division supported components, and assuming a fire induced spurious open PORV, the CCDP is 6.23E-3. Thus the screening CDF_{WF} = 8.1E-8 per year. Total Screening CDF: $CDF_T = CDF_{EC} + CDF_{WF}$ = 4.0E-6 per year	4.0E-6
1-A-SWGRA	From a fire hazard analysis point of view, this area is almost identical to area 1-A-SWGRB. The postulated FDS's for this area are: FDS ASG1: These are fires in the 6.9kV or 480V busses that are suppressed in the incipient stage. Damage is limited to the loss of the bus itself. The consequence of these fires was conservatively assumed to be the loss of the 1A-SA emergency bus and the total frequency of such fires was estimated to be 7.3E-4 per year. With a CCDP of 6.05E-4, the CDF for this scenario was calculated to be 4.4E-7 per year.	3.1E-6

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-SWGRA (continued)	FDS ASG2: These are fires originating in any bus that is not suppressed during phase 1 of its development. The impact of such fires was assumed to be loss of the entire division A of safe shutdown path. With a FDS frequency of 3.5E-4 and a CCDP of 7.5E-3, the contribution of these fires to CDF is 2.6E-6 per year. FDS ASG3: These are welding and cutting fires which are unsuppressed. The FDS frequency is 1.3E-5 per year. Fire damage to the worst case group of components would conservatively leadto a loss of all A power division supported components, and assuming a fire-induced spurious open PORV, the CCDP is 5.86E-3. Thus the screening CDF = 7.6E-8 per year. Total Screening CDF: $CDF_T = CDF_{ASG1} + CDF_{ASG2} + CDF_{ASG3} = 3.1E-6$ per year	
1-A-4-CHLR	See section 4.6.2.3 for details. The significant contributors to the fire frequency are electrical cabinets, pumps, transients, welding/ordinary combustibles, welding/cables, ventilation systems and junction boxes. Fire originating in junction boxes and in cables due to welding were ruled out because of the use of IPEEE 383 cables. Fires from transients were screened out because of the low frequency. Electrical Cabinets: Because of the construction of the cabinets, it was concluded that fire damage will be limited to the loss of the cabinet itself, with no fire propagation and hot gas layer effects postulated. Finally, fires in cabinets in this area were screened out because the cabinets contain only limited SSD functions and failure of a single cabinet was not risk significant. Pumps: The pumps in the area are small pumps with a limited combustible loading. In addition, there are no intervening combustibles in the vicinity of the pumps. Therefore, fires in these pumps are not risk significant. Welding and Cutting Fires: Three fire damage states were postulated: FDS CHLR1 with a frequency of 7.4E-4 consist of fires that are manually suppressed in the incipient stage. The risk from this FDS is negligible. FDS CHLR2 represent fires that are beyond the incipient growth stage and are suppressed by the automatic suppression system. The frequency for this FDS was calculated to be 3.0E-5 per year. Conservatively assuming that this FDS would lead to loss of all B division components, the CCDP is 3.9E-3. Thus the screening CDF_{CHLR2} = 3.0E-5 * 3.9E-3 = 1.2E-7 per year. FDS CHLR3 represents unsuppressed fires. COMPBRN models for transient fires show that cables routed more than 9' 3" above the fire source will not sustain damage. Since cables in this area are generally routed in cable trays that are located approximately 20 to 30 feet above the floor elevation,	4.3E-7

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-4-CHLR	transient fires originating at floor elevation of this fire compartment will not cause damage to the cables routed in this compartment. Conservatively assuming that the probability of welding/ ordinary combustible induced fires occurring close to significant combustibles in this area is 0.5 (i.e. 50% of floor area), the frequency of such fires was estimated to be 3:1E-7 per year. The CCDP was then assumed to be 1.0 based on the failure of all cabling in the area. Therefore, CDF_{CHLR3} = 3.1E-7 * 1. = 3.1E-7 per year Ventilation Systems: Since there are no cable trays within 10' of an AHU, fire propagation was ruled out. Also the effects of hot gas layer was deemed not credible. AHU fires were considered non-significant since fire damage is limited to the source of the fire itself. Total Screening CDF: $CDF_T = CDF_{CHLR2} + CDF_{CHLR3}$ = 4.3E-7 per year	
1-A-BATB	Based on the ISDS, the ignition frequency of 1.2E-3 per year is dominated by battery initiated fires. Data from NSAC 178L shows that all four cases of battery room fires were manually suppressed before there was significant damage to equipment in the room. Conservatively assuming that the next fire will be unsuppressed and will lead to unavailability of all components in the area (CCDP = 2.8E-3), the screening CDF was estimated as: CDF = 1.2E-3 * 0.2 * 2.8E-3 = 6.7E-7 per year.	6.7E-7
1-A-BAL-C	Based on the ISDS, the significant contributors to the ignition frequency (per year) for this area are: electrical cabinets (3.69E-3), fans/HVAC (1.54E-4), transients (7.83E-5), and welding/ ordinary combustibles (1.55E-4). Fires originating from junction boxes and cable fires due to welding were not considered since all area cables meet the qualification requirements of IEEE-383.	3.7E-7

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-BAL-C (continued)	Electrical Cabinets: Because of the construction of the cabinets, it was concluded that fires originating in these cabinets would not propagate to the outside and that the impact of fires originating in electrical cabinets located in this fire area would be limited to the loss of the fire source only. The risk from fires originating in and confined to a single cabinet was considered to be bounded by the risk calculated in the internal events PSA for the loss of important buses or MCCs. Thus, no further evaluation was considered necessary. Fans (HVAC): Based on information and data from NSAC/178L and NSAC/181, it was concluded that fires in ventilation subsystems located in this area would not be capable of propagating to overhead cable trays unless there are additional transient combustibles available to fuel the fire. Thus, the frequency of fires capable of propagating beyond the fans, F_{sf}, is given by: $F_{sf} = F_{ff} * U * P_{ct}$, where F_{ff} is the ignition frequency, U is the probability that a transient combustible will be located in an area close enough such that the heat from the fire can ignite the transient, and P_{ct} is the probability that the transient will be exposed. From NSAC 181, transient materials located within a radius of 2.8 feet of an AC unit will be ignited. Thus, U = (2.8*2.8*3.14)/(3591) = 6.9E-3, where 3591 is the total area of the 1-A-BAL-C fire area. The probability of a critical combustible loading being exposed was calculated based on the SHNPP combustible storage and handling program and FIVE recommendations and a value of 0.1 was obtained. Therefore, F_{sf} = 1.54E-4 * 6.9E-3 * 0.1 = 1.1E-7 per year. Since this frequency is less than 1E-6 per year, the risk from this type of fires was not considered any further. Transients and welding/ordinary combustibles: The core damage frequency, CDF_{tw}, is given by: $CDF_{tw} = F_{tf} * U * CCDP_{HVB}$, where F_{tf} is the ignition frequency, U is the probability that a fire will occur in a location such that the overhead cables could sustain damage, and $CCDP_{HVB}$ is the conditional core damage probability given the loss of cables and components located in this fire area.	

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-BAL-C (continued)	All transient ignition source induced fires were considered as severe. Thus, the frequency of transients induced fires is 7.83E-5. Based on the discussion presented in section 4.6.2.1.2, only those welding/ordinary combustibles induced fires that are not manually suppressed in their incipient stage are considered as being severe. Therefore the ISDS frequency can be reduced by a factor of 20 to 7.75E-6 per year. Thus, F_{tf} = 7.83E-5 + 7.75E-6 = 8.61E-5 per year. Based on the generic COMPBRN models, cables located 9' 3" above the largest transient combustibles induced fires would not sustain damage. Since SSD cables in this area are routed more that 15' above the floor elevation, an ignition source has to be located 5' above the floor elevation to be risk significant. Based on the layout of the fire area, occurrence of such a fire is not likely, however, a 10% probability (i.e. U=0.1) was assigned to this parameter. The CDF is thus: CDF_{tw} = 8.61E-5 * 0.1 * 4.3E-2 = 3.7E-7 per year, where $CCDP_{HVB}$ = 4.3E-2 was obtained from a PSA quantification which assumed that all equipment with cabling in the area are failed. <u>Total Screening CDF</u>: $CDF_T = CDF_{tw}$ = 3.7E-7 per year	
1-A-CSRA	The only significant ignition source in this fire area is a division A alternate shutdown transfer panel. With an ignition frequency of 1.6E-4 per year, the bounding CDF assuming the loss of all division A components (CCDP = 1.4E-3) is 2.2E-7 per year. The impact of self-ignited cable fires and cable fires due to welding as well as fires at cable junction boxes was not considered to be significant. The impact of these types of fires are limited to the loss of one cable, i.e. the ignition source itself. The impact of welding and cutting fires, as well as, impact of the transient fires on the cabling routed in this areas was also considered to be insignificant unless these ignition sources were to ignite transient combustibles. The impact of fires involving transient combustibles were screened out based on low frequency of such fires in the area (The ignition frequencies for both the transient and welding/ordinary combustible fires are less than 1E-6 per year, therefore, CDF is much lower than this.)	2.2E-7
1-A-CSRB	This area is similar to 1-A-CSRA. The bounding CDF from a transfer panel fire was calculated assuming the loss of all division B components (CCDP = 3.9E-3) as 1.6E-4 * 3.9E-3 = 6.2E-7 per year. Similar to 1-A-CSRA, the contribution from the other ignition sources was negligible.	6.2E-7

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
TG	If a fire fails all equipment in this area, PRA results show that the major contributor to the CDF is a fire induced loss of offsite power event. Based on the walkdown observations, fires originating from the condensate booster pumps, turbine oil reservoir, and the MFW pumps are the only major potential threats to the off-site power cabling. The automatic fire suppression system in the area will provide coverage for each of these ignition sources. The frequency of fires that will affect offsite power cabling was estimated from the ISDS as 5.0E-3 per year. Using a probability of failure to automatic suppression of 0.02 (NSAC 179L), and a CCDP of 8.4E-3 (PSA re-quantification assuming loss of all TG building components), the CDF was calculated as: CDF_{TG} = 5.0E-3 * 0.02 * 8.4E-3 = 8.4E-7 per year	8.4E-7
1-A-3-COR	The ISDS shows that the only contributors to ignition frequency in this area are transients (7.83E-5 per year) and welding/ordinary combustibles (1.21E-4 per year). The combustible loading for this compartment is negligible (about 6200 Btu/ft^2) and an area walkdown showed that the combustible materials are well scattered. The majority of cables in this fire compartment are routed more than 15' above the floor elevation and a significant quantity of these cables are contained within conduits. Cables for the 480V bus 1B3-SB and ESW pump B are wrapped and conduits containing cables for the 480V bus 1A3-SA are routed above a room in this fire compartment. Generic COMPBRN models show that the largest typical transient induced fires would not damage cabling routed more 9' 3" above the fire source. Thus, for reasons discussed above, the likelihood of cable damage from a transient induced fire in this area is negligible.	negligible
1-A-3-MP	The arguments presented for area 1-A-3-COR are also applicable for this area. One exception is the presence of ventilation system components located in this fire compartment. However, the combustible loading in these AHUs is minimal and area walkdowns show that are no cable trays located within 10' of them. Therefore the probability of fire propagation is negligible and the impact of fires originating in any AHU was considered to be limited to loss of the fire source only.	negligible

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-34-RHXA	Based on the ISDS, significant contributors to the ignition frequency in this area are: one fire protection panel (1.44E-4 per year); transients (7.83E-5 per year); welding/ordinary combustibles (2.48E-5 per year). A walkdown of the area showed that (based on the locations of the potential ignition sources and the location of the combustibles) only a very large fire induced by plant wide ignition sources and involving transient combustibles would be able to cause significant damage in this compartment. Because of the policy on transient combustibles in this area, the frequency of significant transient ignition source induced fires is negligible (approximately 1E-7 per year). Thus, transients ignition sources were also screened from further evaluation. The frequency of welding/ordinary combustibles induced fires, capable of spreading, was calculated to be 1.2E-6 per year. It was conservatively assumed that such a fire would disable all components with cabling in this compartment. The resultant CCDP is 3.8E-2, and the screening CDF was calculated as: CDF = 1.2E-6 * 3.8E-2 = 4.6E-8 per year.	4.6E-8
1-A-3-PB	According to the ISDS, the significant contributors to the ignition frequency for the area are: electrical cabinets (1.06E-3 per year), pumps (5.18E-3 per year), ventilation systems (2.32E-4 per year), welding/ ordinary combustibles (6.43E-4 per year), and transients (6.11E-5 per year). (continued on next page)	6.1E-7

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-3-PB (continued)	Electrical Cabinets: In this area, these consist of two electrical cabinets as well as several instrument rack cabinets. However, based on the physical characteristics (e.g. size, openings in the cabinets, etc.) of these cabinets and relative location of other combustibles (e.g. cable trays) with respect to these cabinets, none were judged to be significant fire hazards. Thus, the contribution of this ignition source was judged to be to be negligible and no further evaluation was performed. Pumps: Several pumps are located in this fire area. In most cases, dikes around the pumps will prevent spread of potential oil spills. A COMPBRN model developed to determine the impact of a fire originating from a pump on the safe shutdown related cabling routed in close vicinity of a pump predicted that cables routed in trays located 2' from the edge of the fire source will not sustain damage. Since there are no cable trays routed directly above the pumps in this area, it was concluded that the impact of a fire originating from a pump, that does not ignite any transient combustibles, would be limited to the loss of the pump only. The risk associated with the loss of a single pump was not considered to be risk significant and no further evaluation was performed for this cases. However, fires originating from a pump that spread by igniting transient combustibles can potentially damage cables routed in this fire compartment. The following scenario was postulated. It involves a fire originating at a pump which propagates by igniting exposed transient combustibles left in close vicinity. It was conservatively postulated that such fires will disable cables routed in the X1803 and P1803 cables trays (i.e. train B related cable trays) on the basis that these cables are routed close to the pumps. However, these fires were not postulated to damage division A related cabling or components if the automatic fire protection system successfully actuates. Detection and suppression of fires before spread to division A related cabling or components was deemed likely because: 1) cables related with division A of safe shutdown are routed at least 13' away from the division B cable trays and more than 15' away from the pumps. Therefore, direct effects will be unlikely and the major source of heat for the A division cable trays is from the hot gas layer formed as a result of the fire. This hot gas layer would be formed uniformly throughout the compartment and the temperature will be higher near the ceiling where the heat detectors are located. Since the damage temperature for cables is significantly higher than the actuation temperature of the heat detectors, fire will be detected well before division A related cabling could be damaged. 2) Division A and B pumps are either separated from each other by partial height partial width walls or are located at opposite ends of the fire compartment. Thus, it was again judged that the major source of heat for redundant pumps is the fire induced hot gas layer. Based on the same argument presented for the cables, it was concluded that fire detection and suppression system will take place before more than one pump is damaged. (continued on next page)	

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-3-PB (continued)	Based on the above discussion, the following FDSs were postulated: FDS 3PB1—This represents the impact of successfully suppressed fires originating from the AFW pump 1B-SB and involving transient combustibles. The impact of these fires is judged to be limited to the loss of the pump itself and cables associated with the B division of safe shutdown routed in this fire compartment. This impact is assumed to be represented by the loss of B division of power (CCDP=3.89E-3). Since there are 6 pumps in the area, the frequency of fires originating from a pump, F_{pf}, is = 5.18E-3 / 6 = 8.6E-4 per year. The frequency of propagation of these fires by involving transient combustibles, F_{pcf}, is: $F_{pcf} = F_{pf} * p * w * u_1$ where p is the probability of exposed combustibles being present, w is the probability that the presence of exposed combustibles is not detected between fire inspection (house keeping) walkdowns, and u_1 is the probability that a transient fire is located in range of that can be ignited by a pump. The parameter "p" was evaluated based on the SHNPP combustible storage and handling program and FIVE recommendations, and a value of 0.1 was obtained. Parameter "w" was assigned a value of 4.5E-5 based on the discussion on transient ignition sources provided in Section 4.6.2.1, and u_1 was conservatively assumed to be 1. Thus: F_{pcf} = 8.6E-4 * 0.1 * 4.5E-3 * 1 = 3.9E-7 per year Using a suppression probability of 0.02, the CDF from this fire damage state, CDF_{3PB1}, is given by: $CDF_{3PB1} = F_{pcf} * P_{ss} * CCDP$ = 3.9E-7 * (1-0.02) * 3.89E-3 = 1.5E-9 per year FDS 3PB2—This represents the impact of unsuppressed fires originating from the AFW pump 1B-SB and involving transient combustibles. These fires are conservatively assumed to result in the total loss of all SSD functions (CCDP=1). Thus, CDF_{3PB2} = 3.9E-7 * 0.02 * 1 = 7.8E-9 per year FDS 3PB3—This represents the impact of successfully suppressed fires originating from the AFW pump 1A-SA and involving transient combustibles. This FDS results in the loss of AFW pump 1A-SA and cables associated with the B division of safe shutdown (with an evaluated CCDP of 0.15). Thus, CDF_{3PB3} = 3.9E-7 * (1-0.02) * 0.15 = 5.7E-8 per year FDS 3PB4—This represents the impact of unsuppressed fires originating from the AFW pump 1A-SA. Similar to the description for FDS 3PB2, CDF_{3PB4} = 7.8E-9 (continued on next page)	

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-3-PB (continued)	FDS 3PB5—This represents the impact of successfully suppressed fires originating from the CCW pump 1B-SB and involving transient combustibles. The impact of these fires is judged to be limited to the loss of the pump itself and cables associated with the B division of safe shutdown routed in this fire compartment. This impact is assumed to be represented by the loss of B division of power (CCDP=3.89E-3). Thus, CDF_{3PB5} = 3.9E-7 * (1-0.02) * 3.89E-3 = 1.5E-9 per year FDS 3PB6—This represents the impact of unsuppressed fires originating from the CCW pump 1B-SB. Similar to the description for FDS 3PB2, CDF_{3PB6} = 7.8E-9 FDS 3PB7—This represents unsuppressed fires originating from either the 1A-SA or 1C-SAB CCW pumps (Fires originating from these pumps that are suppressed will only result in the loss of the pump since there are no major fixed combustible loading or targets in close vicinity to these pumps.) The impact of the unsuppressed fires is conservatively assumed to be the total loss of all SSD functions (CCDP=1). Therefore, CDF_{3PB7} = 2* 3.9E-7 * 0.02) * 1 = 1.6E-9 per year Ventilation Systems: Several AHUs are located in this fire compartment. Based on the construction of these units and the layout of the compartment, fires originating from these ignition sources were not considered to be risk significant. Welding/Ordinary Combustibles/Transients: These fires involve transient ignition sources and transient combustibles and therefore they can occur in any location within the compartment. A review of the data presented in NSAC\178L indicated that these fires tend to be small unless they are able to ignite a substantial amount of fixed combustibles (e.g. cable insulation). Thus, the location of the fire with respect to combustible materials is important. Since the SA and SB cable trays are separated by approximately 13', and since there are no intervening combustibles, it was judged that a transient fire that is suppressed early cannot damage both sets of cable trays (based on generic COMPBRN models). However, unsuppressed fires are assumed to damage both SA and SB cables. The following fire damage states are postulated: FDS 3PB8—These are transient fires that are suppressed. As a worst case scenario, it was postulated that these fires will occur in locations where they can damage cables routed in the SB related cable trays (the SB train was chosen since condition core damage probability due to the loss of B train is larger than that for the loss of A train). The CCDP for this FDS is thus 3.89E-3. The frequency for this FDS is: $F_{3PB8} = (F_{UW} + F_{TP}) * P_{ss} * u_2$, (continued on next page)	

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-3-PB (continued)	where F_{UW} is the frequency of manually unsuppressed welding fires, F_{TF} is the frequency of transient ignition source induced fires, and u_2 is the probability that a fire is located in range of target components. Based on the plant walkdown observations and the review of cable routing drawings, it was judged that u_2 = 0.2. Thus, F_{3PB8} = (6.43E-4/20 + 6.11E-5) * (1-0.02) * 0.2 = 1.8E-5 per year, and CDF_{3PB8} = 1.8E-5 * 3.89E-3 = 7.0E-8 per year. FDS 3PB9 - These are unsuppressed transient fires that damage the SB and the SA related cabling routed in this fire compartment. The impact of such fires was assumed to be the total loss of all SSD functions (CCDP=1). Therefore, CDF_{3PB9} = (6.43E-4/20 + 6.11E-5) * 0.02 * 0.2 * 1 = 3.7E-7 per year <u>Total Screening CDF</u>: The total CDF is the sum of the CDF from all the above FDSs and this is equal to 6.1E-7 per year	
1-A-3-COM B	Based on the ISDS the dominant contributors to the ignition frequency for the area are pumps (8.64E-4 per year), transients (6.50E-5 per year), welding/ ordinary combustibles (1.93E-4 per year) and ventilation systems (7.72E-5 per year). <u>Pumps</u>: The six pumps in the area are small (2 chiller pumps, two sump pumps and two others) and there are no fixed combustibles close-by any of these pumps. Since all SSD cable trays in the area are routed approximately 15' to 20' above the floor elevation, the risk from pump induced fires was judged to be insignificant and no further evaluation was performed. <u>Ventilation systems</u>: The AHUs are contained within a metal enclosure and contain negligible combustible loading. During the area walkdown, it was observed that there are no cable trays routed within 10' the AHUs. It was therefore concluded that a fire originating in an AHU would not ignite other combustibles in the compartment nor would it damage other potential targets by creating harsh environmental operating conditions. That is, the impact of fires originating in any AHU is considered to be limited to loss of the fire source only. Loss of an AHU was not considered to be risk significant and no further evaluation was required. (continued on next page)	1.8E-7

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-3-COM B (continued)	Transients: The following transient ignition source FDSs were postulated: FDS 3COMB1— It was assumed that "Transients" ignition source induced fires which are automatically suppressed will result in the loss of all B train SSD paths (CCDP = 3.89E-3). The FDS frequency is given by: $F_{3COMB1} = F_{tf} * u * P_{ss}$, where F_{tf} is the ignition frequency from the ISDS (= 6.5E-5), u is the probability that a transient fire is located in range to damage and was judged to be 0.1 based on compartment geometry, and P_{ss} is the probability of successful suppression (= 1 - 0.02 = 0.98). Thus, CDF_{3COMB1} = 6.5E-5 * 0.1 * 0.98 * 3.89E-3 = 2.5E-8 FDS 3COMB2—It was assumed that transient fires which are not automatically suppressed will result in the unavailability of all SSD paths (CCDP=1). CDF_{3COMB2} = 6.5E-5 * 0.1 + 0.02 * 1 = 1.3E-7 per year Welding/ordinary combustibles: As discussed previously, the frequency of "welding/ordinary combustibles" induced fires, capable of spreading, was estimated to be 20 times smaller than the ISDS frequency. Therefore, this frequency is 1.94E-4/20 = 9.7E-6 per year. Using similar reasoning as for the transients, the following FDSs were postulated. FDS 3COMB3—CDF_{3COMB3} = 9.7E-6 * 0.1 * 0.98 * 3.89E-3 = 3.7E-9 per year FDS 3COMB4—CDF_{3COMB4} = 9.7E-6 * 0.1 + 0.02 * 1 = 1.9E-8 per year Total Screening CDF: The total CDF is the sum of the CDF from all the above FDSs and this is equal to 1.8E-7 per year	1.8E-7
1-A-3-COM E	There are no major fixed ignition sources in this area with the main contributors to the fire frequency being transients (7.83E-5 per year) and welding/ordinary combustibles (2.85E-4 per year). Safe shutdown related cables are the only potential risk significant targets in this compartment. Plant walkdowns and cable tray drawings show that the cable trays are routed 25' above floor elevation. In addition, no pinch points were identified. In the one case where cable trays containing cabling for redundant SSD paths (i.e. cable trays P1300 and P1303 containing division A cables and cable trays P1803 and P1808 containing division B cables) are routed parallel to each other with about 10' separation between them, automatic detection and suppression systems have been installed above the cables. Based on COMPBRN results, cables routed more than 9' 3" above the largest postulated transient combustible induced fire will not sustain damage. Since the safe shutdown cables in this compartment are more than 25' above the floor elevation, the risk of damage from transient induced fires was considered negligible.	negligible

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-3-COM I	From the ISDS, the main contributors to ignition frequency (per year) are: electrical cabinets (1.06E-3), transients (2.35E-5), welding/ordinary combustibles (1.93E-4) and ventilation units (3.86E-5). Based on equipment construction, cable routing and area geometry, electrical cabinets and ventilation units were evaluated as insignificant fire sources. The sources analyzed were the transient and welding sources. Since cabling for RC-114, RC-116 and RC-118 are present in the area, the worst case fire in this area could result in the spurious opening of the PORVs leading to a LOCA if un-isolated. The CCDP for this sequence is 1.7E-3. Mutiplying this CCDP by the adjusted ISDS frequency for transient and welding ignition sources will yield a bounding CDF. Thus, CDF_{3COMI} = (2.35E-5 + 1.93E-4/20) * 1.7E-3 = 5.6E-8 per year.	5.6E-8
MECH PEN AREA	Based on the ISDS, the main contributors to ignition frequency (per year) are: electrical cabinet (5.28E-4), transients (7.83E-5), welding/ ordinary combustibles (6.42E-4), and ventilation units (3.86E-5). The electrical cabinets and ventilation units were evaluated to be non-significant fire sources based on equipment construction and room layout. The only potential sources considered were the transient and welding sources. It was conservatively assumed that these fires would disable all the equipment with cabling and/or components in this compartment (CCDP = 2.2E-4). The frequency of such fires was estimated by summing the adjusted frequencies from the ISDS (7.83E-5 + (6.42E-5/20)). Therefore, CDF_{2MP} = (7.83E-5 + 3.2E-6) * 2.2E-4 = 1.8E-8 per year	1.8E-8
1-A-2-MP	According to the ISDS, the main contributors to ignition frequency (per year) are: pumps (1.73E-3), electrical cabinet (5.28E-4), transients (7.83E-5), welding/ordinary combustibles (4.84E-4), and fire protection panels (7.72E-5). Pumps: There are 3 small pumps (condensate pumps 1A and 1B, and 1CC-E006) in this area. There are no fixed combustibles in the vicinity of these pumps. The majority of cables (i.e. in-situ combustibles and potential targets) in this area are routed in cable trays about 15' above floor elevation. Therefore, the risk from pump induced fires were judged to be insignificant. (continued on next page)	7.4E-8

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-2-MP	Fire protection panels: Based on the panel construction (no ventilation louvers, covered top, seal cable penetrations, and external cables in conduits) and on the area geometry, fires originating from these panels were judged to be insignificant. Electrical cabinet: Similar to the fire protection panel, fires originating from MCC-1E22 was judged to be insignificant based on the cabinet construction and on the area geometry. Transient and welding fires: It was conservatively assumed that a worst case transient induced fire would disable all the equipment with cabling and/or components in this compartment. The frequency of such fires was estimated by summing the frequencies of significant welding and transient ignition source induced fires. The CDF is given by: $CDF_{2MP} = (F_{tf} + F_{wf}) * CCDP_{2MP}$, where F_{tf} is the frequency of transient ignition source induced fires, (7.83E-5), F_{wf} is the frequency of welding ignition source induced fires (= 4.84E-4 / 20 = 2.4E-5 per year), and $CCDP_{2MP}$ is the conditional core damage probability given loss of all safe shutdown equipment in the area (= 7.2E-4 from PSA re-quantification). Thus, CDF_{2MP} = (2.4E-5 + 7.83E-5) * 7.2E-4 = 7.4E-8 per year	
1-A-5-HVA	Based on the ISDS, the significant contributors to the ignition frequency (per year) for this area are: electrical cabinets (3.69E-3), fans/HVAC (2.32E-4), transients (7.83E-5), and welding/ ordinary combustibles (2.26E-4). Fires originating from junction boxes and cable fires due to welding were not considered since all area cables meet the qualification requirements of IEEE-383. This area is very similar to area 1-A-BAL-C. Therefore, for the most part, the writeup for 1-A-BAL-C will also be applicable here. Electrical Cabinets: Using arguments similar to those for 1-A-BAL-C, these cabinets were shown not to be risk significant. Fans (HVAC): Similar to area 1-A-BAL-C, the frequency of fires capable of propagating beyond the fans, F_{sf}, is given by: $F_{sf} = F_{ff} * U * P_{et}$, where F_{ff} is the ignition frequency, U is the probability that a transient combustible will be located in an area close enough such that the heat from the fire can ignite the transient, and P_{et} is the probability that the transient will be exposed. (continued on next page)	1.3E-8

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-5-HVA (continued)	Again, similar to area 1-A-BAL-C, P_{et} = 0.1 and U = (2.8 * 2.8 * 3.14) / (4100) = 6.0E-3, where 4100 is the total area of the 1-A-5-HVA fire area. Thus, F_{sf} = 2.32E-4 * 6.0E-3 * 0.1 = 1.4E-7 per year. Since this frequency is less than 1E-6 per year, the risk from this type of fires was not considered any further. <u>Transients and welding/ordinary combustibles</u>: The core damage frequency, CDF_{tw}, is given by: $CDF_{tw} = F_{tf} * U * CCDP_{HVA}$, where F_{tf} is the ignition frequency, U is the probability that a fire will occur in a location such that the overhead cables could sustain damage, and $CCDP_{HVA}$ is the conditional core damage probability given the loss of cables and components located in this fire area. Similar to area 1-A-BAL-C, U= 0.1 and F_{tf} = 7.83E-5 + 1.13E-5 = 8.96E-5 per year. Although there are Division B power cables in this area, many of these cables are embedded in concrete. In the other cases, separarion is provided so that a fire will not fail both division A and B power. Therefore, the $CCDP_{HVA}$ = 1.44E-3 based on the unavailability of all Division A powered components. The CDF is thus: CDF_{tw} = 8.96E-5 * 0.1 * 1.44E-3 = 1.3E-8 per year. <u>Total Screening CDF</u>: $CDF_T = CDF_{tw}$ = 1.3E-8 per year	

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-4-COM B	Based on the ISDS and on the plant walkdown, the significant contributors to fire ignition frequency for the area are transients (6.3E-5 per year) and welding/ordinary combustibles (1.93E-4 per year). Cable trays in this area are routed approximately 20' above the floor elevation. Also, cable protection is provided by utilizing one-hour cable wraps, or by spatial separation of at least 20' to ensure that at least one SSD path will be available in this area. Therefore it was concluded that only a large fire would be able to disable more than one SSD path in this compartment. Transients: The following FDS's were postulated: FDS COMB1 - It was conservatively, assumed that transient ignition source induced fires which are manually or automatically suppressed would still result in the unavailability of all but one SSD path. The CCDP for this FDS was thus based on the failure of B power division (= 3.89E-3). The ignition frequency was calculated as 6.3E-5 * (1-0.02) = 6.3E-5. The CDF is: CDF_{COMB1} = 6.3E-5 * 3.89E-3 = 2.4E-7 per year FDS COMB2 - Since cables associated with one SSD path are protected by one-hour rated fire wrap, sufficient time will be available (before cable damage) for manual or automatic suppression. It was conservatively assumed that transient fires which are not suppressed would result in the unavailability of all SSD paths. With a suppression failure probability of 0.02, the FDS frequency is 6.3E-5 * 0.01 = 1.3E-6. Therefore with a CCDP of 1, CDF_{COMB2} = 1.3E-7 * 1 = 1.3E-7 per year Welding/ordinary combustibles fires: Using an argument similar to that discussed in section 4.6.2.1.2, the frequency of significant "welding/ordinary combustibles" induced fires was estimated to be 9.7E-6 per year. FDS's postulated for this fire area are: FDS COMB3 - It was conservatively assumed that fires which are suppressed in the incipient stage will still result in the unavailability of all but one SSD path. Therefore, CDF_{COMB3} = (9.7E-6 * 0.98) * 3.89E-3 = 3.7E-8 per year FDS COMB4 - It was conservatively assumed that fires which are not manually or automatically suppressed will result in the unavailability of all SSD paths (CCDP=1). Therefore, CDF_{COMB4} = (9.7E-6 * 0.02) * 1 = 1.9E-7 per year Total Screening CDF: $CDF_T = CDF_{COMB1} + CDF_{COMB2} + CDF_{COMB3} + CDF_{COMB4}$ = 6.0E-7 per year	6.0E-7

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-4-COME-W	Based on the ISDS, the total ignition frequency for the area is 5.90E-4 per year with the significant contributors being: electrical cabinets (5.28E-4 per year) and welding/ordinary combustibles (2.79E-5 per year). The electrical cabinet located in this compartment is MCC-1A35-SA. This cabinet does not have ventilation louvers. The top is covered and cables enter through sealed penetrations. All cables are protected by cable wrap. The cabinet is divided into several sub-panels and each sub-panel has only a few cables routed through it. Therefore, it was postulated that fires originating in these cabinets would not propagate outside the cabinet (i.e. no flames would extrude from the cabinets). Based on the SSA, cable protection in the area is provided by the use of one-hour cable wraps to ensure the availability of at least one SSD path. The following FDS's were postulated for this area: <u>FDS COME1</u>: This FDS represents fires originating in the MCC-1A35-SA. It was assumed that these fires will result in loss of all A division power (CCDP = 1.44E-3). CDF is calculated as follows: $CDF_{COME1} = F_{sf} * CCDP_{LDB} = F_{cf} * F_c * CCDP_{LDB}$ where F_{sf} is the frequency of fires capable of causing significant damage, F_{cf} is the ignition frequency and F_c is the fraction of fires originating in an electrical cabinet that have the potential to go beyond the incipient stage. In section 4.6.2.1.2, F_c was evaluated to be equal to 0.69. Thus, CDF_{COME1} = 5.28E-4 * 0.69 * 1.44E-3 = 5.2E-7 per year <u>FDS COME2</u>: The impact of incipient fires originating from the other identified ignition sources (including welding/ ordinary combustibles) are lumped together in this FDS. The sum of the ignition frequency for these sources is 6.2E-5 per year. The probability for suppression before damage to protected cables is (1 - 0.02 = 0.98). The worst case damage for this scenario would be bounded by the loss of all division A power (CCDP = 1.44E-3). Thus, CDF_{COME2} = 6.2E-5 * 0.98 * 1.44E-3 = 8.7E-8 per year <u>FDS COME3</u>: This is similar to FDS COME2 except that the fires in this case are unsuppressed. Here, the CCDP calculated assuming the failure of all components and cables in the area is 5.5E-2. Thus, CDF_{COME3} = 6.2E-5 * 0.02 * 5.5E-2 = 6.8E-8 per year <u>Total Screening CDF</u>: $CDF_T = CDF_{COME1} + CDF_{COME2} + CDF_{COME3}$ = 6.8E-7 per year	6.8E-7

Table 4-5: Summary Results for the Detailed Fire Evaluation		
Area/ Compartment	Summary Description of Analysis Findings	Screening CDF (per year)
1-A-4-COME-E	Based on the ISDS, the significant ignition sources in this area are: electrical cabinets (5.28E-4 per year) and welding/ordinary combustibles (6.98E-5 per year). Electrical Cabinet Induced Fires: Only one electrical cabinet is located in this compartment (1B35-SB MCC). The construction for this cabinet is similar to that for MCC-1A35-SA (in area 1-A-4-COME-W). Therefore, fires are not postulated to propagate beyond the cabinet and the impact of the fires originating in the MCC is limited to the loss of the MCC itself (CCDP = 7.19E-6). This is represented by the COME4 FDS. CDF is calculated as follows: $CDF_{COME5} = F_{sf} * CCDP_{COME5} = F_{cf} * F_c * CCDP_{COME5}$ where F_{sf} is the frequency of fires capable of causing significant damage, F_{cf} is the ignition frequency and F_c is the fraction of fires originating in an electrical cabinet that have the potential to go beyond the incipient stage. In section 4.6.2.1.2, F_c was evaluated to be equal to 0.69. Thus, CDF_{COME5} = 5.28E-4 * 0.69 * 7.19E-6 = 2.6E-9 per year Welding and Cutting Fires: Using an argument similar to that discussed in section 4.6.2.1.2, the frequency of significant welding/ordinary combustibles induced fires was estimated to be 3.5E-6 per year. FDS's postulated for this fire area are: FDS COME5 - It was conservatively assumed that fires which are suppressed in the incipient stage will still result in the unavailability of all but one SSD path. Based on equipment present in the area and on the cable protection available, the failed train was assumed to be components powered from the B division. Therefore, CDF_{COME5} = (3.5E-6 * 0.98) * 3.89E-3 = 1.3E-8 per year FDS COME6 - It was conservatively assumed that fires which are not manually or automatically suppressed will result in the unavailability of all SSD paths (CCDP=1). Therefore, CDF_{COME6} = (3.5E-6 * 0.02) * 1 = 7.0E-8 per year Total Screening CDF: $CDF_T = CDF_{COME4} + CDF_{COME5} + CDF_{COME6}$ = 8.6E-8 per year	8.6E-8

Table 4-6					
Mode of Fire Termination For Electrical Cabinet Induced Fires					
Building	No. Of Fires				
	De-Energ. or Self Extin.	Manually Supp. w/t Known Method	Manually Supp. w/t Unknown Method	Auto. Supp.	Total
AUX. BLD	4	5	6	0	15
REC. BLD	8	10	6	0	24
DG RM	6	0	0	0	6
SWGR	5	6	6	2	19
CSR	0	4	0	0	4
TB	3	10	2	1	16
TOTALS	26	35	20	3	84

Table 4-7: Screening Quantification of Control Room Fire Scenarios

Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
1A1	Fire in PIC-P1 with early suppression	AFW SR1/SPM ESFAS SR1 RCRPC SA/SR1/SPM	7.43E-5	Small LOCA. Division A powered components failed	5.86E-3	4.4E-7
1A2	Fire in PIC-P2 with early suppression	AFW SR2/SPM ESFAS SR2 RCRPC SB/SR2/SPM	7.43E-5	Small LOCA. Division B powered components failed	6.23E-3	4.6E-7
1A3	Fire in PIC-P4 with early suppression	ESFAS SR4 RCSPC SB/SR4/SPM	7.43E-5	Small LOCA. Division B powered components failed	6.23E-3	4.6E-7
1A4	Fire in PIC-C12 with early suppression	CWS SA/SB	7.43E-5	Transient. CWS failed	1.85E-5	1.4E-9
1A5	Fire in PIC-C14SB with early suppression	CWS SB HCRC SB HDGB SB	7.43E-5	Transient. CWS SB failed. (Per the PSA, HCRC and HDGB will not affect CDF)	<1.85E-5	<1.4E-9
1A6	Fire in PIC-C13SA with early suppression	CWS SA/SB HCRC SA HDGB SA	7.43E-5	Transient. CWS failed. (Per the PSA, HCRC and HDGB will not affect CDF)	1.85E-5	1.4E-9
1A7	Fire in PIC-C10SB with early suppression	AFW SB ESW SB	7.43E-5	Transient. Division B powered components failed	3.89E-3	2.9E-7
1A8	Fire in PIC-P3 with early suppression	AFW SR3/SPM ESFAS SR3 RCSPC SA/SR3/SPM	7.43E-5	Small LOCA. Division A powered components failed	5.86E-3	4.4E-7
1A9	Fire in PIC-C9SA with early suppression	AFW SA ESW SA PDSAC SA	7.43E-5	Transient. Division A powered components failed	1.44E-3	1.1E-7
1B1	Fire propagation between PIC-C5 and PIC-P1	AFW SR1/SPM ESFAS SR1 RCRPC SA/SR1/SPM	1.24E-5	Small LOCA. Division A powered components failed	5.86E-3	7.3E-8
1B2	Fire propagation between PIC-C7, PIC-P3 and PIC-C11	AFW SR3/SPM ESFAS SR3 RCSPC SR3/SA/SPM	1.86E-5	Small LOCA. Division A unavailable	5.86E-3	1.1E-7

Table 4-7: Screening Quantification of Control Room Fire Scenarios

Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
1B3	Fire propagation between PIC-C6, PIC-P2 and PIC-C16	AFW SR2/SPM ESFAS SR2 RCSPC SR2/SPM/SB	1.86E-5	Small LOCA. Division B unavailable	6.23E-3	1.2E-7
1B4	Fire propagation between PIC-C3, PIC-P4 and PIC-C12	CWS SA/SB	1.24E-5	Transient CWS failed	1.85E-5	2.3E-10
1B5	Fire propagation between PIC-C10SB and PIC-C14SB	AFW SB CWS SB ESW SB HCRC SB HDGB SB	1.24E-5	Transient Division B unavailable	3.89E-3	4.8E-8
1B6	Fire propagation between PIC-C15, PIC-C13SA and PIC-C9SA	AFW SA CWS SA/SB ESW SA HCRC SA HDGB SA PDSAC SA	1.86E-5	Transient CWS failed Division A unavailable	5.8E-3	1.1E-7
1C1	Fire in IC-1B1 with early suppression	RCSPC SB	7.43E-5	Small LOCA	2.9E-5	2.2E-9
1C2	Fire in IC-1B2 with early suppression	ESW SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7
1C3	Fire in IC-2B2 with early suppression	EDGS SB HCRC SB HCRM SB HDGB SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7
1C4	Fire in IC-3A with early suppression	AFW SA CWS SA ESW SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
1C5	Fire in IC-3B with early suppression	AFW SB ESW SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7
1C9	Fire in IC-1A1 with early suppression	RCSPC SA	7.43E-5	Small LOCA	2.9E-5	2.2E-9

Table 4-7: Screening Quantification of Control Room Fire Scenarios

Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
1C10	Fire in IC-1A2 with early suppression	ESW SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
1C11	Fire in IC-2A1 with early suppression	ESW SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
1C12	Fire in IC-2A2 with early suppression	EDGS SA HCRC SA HCRM SA/NON HDGB SA/NON	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
1D1	Fire propagation between Isolation cabinets 1B1B1, 1B1B2, 2B2B1, 2B2B2, 33A1 & 33A2, and Annunciator Cabinets 1 Bays 1, 2 & 3	AFW SA/SB CWS SA EDGS SB ESW SA/SB HCRC SB HCRM SB HDGB SB RCSPC SB	5.57E-5	Small LOCA No AFW No ESW, however NSW available Only have train A F&B	will not screen - more detailed analysis required	
1D2	Fire propagation between Isolation cabinets 1A1A1, 1A1A2, 2A2A1 & 2A2A2, and Annunciator Cabinets 1 Bays 4 & 5 and Cabinets 2 Bays 1 & 2	EDGS SA ESW SA HCRC SA HCRM SA/NON HDGB SA/NON RCSPC SA	5.57E-5	Small LOCA Division A unavailable	5.86E-3	3.3E-7
1E1	Fire in the SSPA Input sub-cabinet with early suppression	ESFAS SR1/ SR2/ SR3/ SR4	7.43E-5	ESFAS SB available		<<1E-6
1E2	Fire in the SSPA Logic sub-cabinet with early suppression	ESFAS SA	7.43E-5	ESFAS SB available		<<1E-6

Table 4-7: Screening Quantification of Control Room Fire Scenarios						
Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
1E3	Fire in the SSPA Output 1 sub-cabinet with early suppression	AFW SA EDGS SA ESFAS SA ESW SA RCSPC SA SIS SA SPRCP SA	7.43E-5	Small LOCA Division A unavailable	5.86E-3	4.4E-7
1E4	Fire in the SSPA Output 2 sub-cabinet with early suppression	CCW SA RCSPC NON	7.43E-5	Small LOCA Division A unavailable	5.86E-3	4.4E-7
1E5	Fire in the SSPB Input sub-cabinet with early suppression	ESFAS SR1/ SR2/ SR3/ SR4	7.43E-5	ESFAS SA available		<<1E-6
1E6	Fire in the SSPB Logic sub-cabinet with early suppression	ESFAS SB	7.43E-5	ESFAS SA available		<<1E-6
1E7	Fire in the SSPB Output 1 sub-cabinet with early suppression	AFW SB EDGS SB ESFAS SB ESW SB SIS SB SPRCP SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7
1E8	Fire in the SSPB Output 2 sub-cabinet with early suppression	CCW SB RCSPC SB/NON	7.43E-5	Small LOCA Division B unavailable	6.23E-3	4.6E-7
1E9	Fire in the auxiliary relay rack AR-1 with early suppression	RCSPC SA/SB	7.43E-5	Small LOCA	2.9E-5	2.2E-9
1E10	Fire in the auxiliary relay rack AR-2 with early suppression	RCSPC SB	7.43E-5	Small LOCA	2.9E-5	2.2E-9

Table 4-7: Screening Quantification of Control Room Fire Scenarios						
Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
1E11	Fire in the auxiliary relay rack AR-3 with early suppression	SPRCP SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7
1F	Fire propagation among the following SSPA cabinets: Demultiplexes, Input, Logic, Output #1, Output #2, Test # 1, & Test #2	AFW SA CCW SA EDGS SA ESFAS SA/ SR1/ SR2/ SR3/ SR4 ESW SA RCSPC SA/NON SIS SA SPRCP SA	4.33E-5	Small LOCA Division A unavailable	5.86E-3	2.5E-7
1G	Fire propagation among the following SSPB cabinets: Demultiplexes, Input, Logic, Output #1, Output #2, Test # 1, & Test #2, and AR-1, AR-2 & AR-3	ESFAS SR1/ SR2/ SR3/ SR4 RCSPC SA/SB SPRCP SB	5.57E-5	Small LOCA Division B unavailable	6.23E-3	3.5E-7
2A1	Fire in the auxiliary relay panel ARP-19SA with early suppression	AFW SA ESW SA HCRM SA RCSPC SA	7.43E-5	Small LOCA Division A unavailable	5.86E-3	4.4E-7
2A2	Fire in the auxiliary relay panel ARP-2ASA with early suppression	CWS SA HCRC SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
2A3	Fire in the auxiliary relay panel ARP-3ASA with early suppression	CWS SA HDGB SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
2A4	Fire in the auxiliary relay panel ARP-2BSB with early suppression	CWS SB HCRC SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7

Table 4-7: Screening Quantification of Control Room Fire Scenarios						
Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
2A5	Fire in the auxiliary relay panel ARP-3BSB with early suppression	HDGB SB	7.43E-5	Not an initiator according to PSA	n/a	
2A6	Fire in the auxiliary relay panel ARP-4BSB with early suppression	CWS SB HCRM SA	7.43E-5	Transient Division B unavailable Failure of HCRM is not risk significant	3.89E-3	2.9E-7
2B1	Fire propagation among panels ARP-1ASA, 19SA, 2ASA, & 3ASA	CWS SA HCRC SA HDGB SA OSP A	2.48E-5	Transient with Division A electric power (including offsite power) unavailable	7.50E-3	1.9E-7
2B2	Fire propagation among panels ARP-1BSB, 2BSB, 3BSB & 4BSB	CWS SB HCRC SB HCRM SA HDGB SB OSP B	2.48E-5	Transient with Division B electric power (including offsite power) unavailable. Loss of HCRM SA is not risk significant.	7.13E-3	1.8E-7
2C	Fire in ARP-19BSB. Propagation is not a factor because this cabinet is not physically attached to other cabinets	AFW SB ESW SB HCRM SB RCSPS SB	8.05E-5	Small LOCA Division B unavailable	6.23E-3	5.0E-7
2D1	Fire in the auxiliary relay panel ARP-4ASA with early suppression	CWS SA HCRM SA HDGB SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
2D2	Fire in MTC-11ASA with early suppression	HCRC SA	7.43E-5	Not an initiator according to PSA	n/a	
2D3	Fire in MTC-11BSB with early suppression	HCRC SB	7.43E-5	Not an initiator according to PSA	n/a	
2E1	Fire propagation between cabinets ARP-4ASA and MTC-11ASA	CWS SA HCRC SA HCRM SA HDGB SA	1.24E-5	Transient Division A unavailable	1.44E-3	1.8E-8

Table 4-7: Screening Quantification of Control Room Fire Scenarios						
Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
2E2	Fire propagation between cabinets MTC-11BSB and MTC-16	HCRC SB	1.24E-5	Not an initiator according to PSA	n/a	
3	Fire in the Computer Room multiplexer bank	RCSPC SB/NON	8.05E-5	Small LOCA	2.9E-5	2.3E-9
4	Fire in a cabinet in the Rod Control Cabinets Room		8.05E-05	A fire in any cabinet in this room will result in plant trip with all SSD equipment available. This scenario is bounded by the PSA transient initiating events.		n/a
5A1	Fire in MTC-1ASA with early suppression	RCSPC SA	7.43E-5	Small LOCA	2.9E-5	2.2E-9
5A2	Fire in MTC-2ASA with early suppression	CCW SA RCSPC SA SIS SA SPRCP SA	7.43E-5	Small LOCA Division A unavailable	5.86E-3	4.4E-7
5A3	Fire in MTC-3ASA with early suppression	ESFAS SA RTS SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
5A4	Fire in MTC-8ASA with early suppression	ESW SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
5A5	Fire in MTC-4 with early suppression	RCSPC SA/SB SIS SA/SB	7.43E-5	Potential small LOCA with SIS unavailable	will not screen - more detailed analysis required	
5A6	Fire in MTC-6 with early suppression	RCSPC SA/SB/NON	7.43E-5	Small LOCA	2.9E-5	2.2E-9
5A7	Fire in MTC-1BSB with early suppression	RCSPC SB SPRCP SB	7.43E-5	Small LOCA Division B unavailable	6.23E-3	4.6E-7
5A8	Fire in MTC-2BSB with early suppression	CCW SB RCSPC SB SIS SB SPRCP SB	7.43E-5	Small LOCA Division B unavailable	6.23E-3	4.6E-7

Table 4-7: Screening Quantification of Control Room Fire Scenarios						
Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
5A9	Fire in MTC-3BSB with early suppression	CCW SB ESFAS SB RTS SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7
5A10	Fire in MTC-8BSB with early suppression	ESW SB	7.43E-5	Transient Division B unavailable	3.89E-3	2.9E-7
5A11	Fire in MTC-5 with early suppression	RCSPC SA/SB	7.43E-5	Small LOCA	2.9E-5	2.2E-5
5A12	Fire in MTC-7 with early suppression	NIS SA/SB	7.43E-5	Minimal effect on safe shutdown	n/a	
5B	Fire propagation among MTC-10SB, MTC-9B, MTC-8BSB, MTC-1BSB, MTC-2BSB & MTC-3BSB	CCW SB ESFAS SB ESW SB RCSPC SB RTS SB SIS SB SPRCP SB	3.72E-5	Small LOCA Division B unavailable	6.23E-3	2.3E-7
5C1	Fire propagation among MTC-1ASA, MTC-2ASA & MTC-3ASA	CCW SA ESFAS SA RCSPC SA RTS SA SIS SA SPRCP SA	1.86E-5	Small LOCA Division A unavailable	5.86E-3	1.1E-7
5C2	Fire propagation among MTC-8ASA, MTC-9A & MTC-10ASA	ESW SA	1.86E-5	Transient Division A unavailable	1.44E-3	2.7E-8
5D1	Fire propagation among ARP-10, ARP-12, MTC-5, MTC-7 & MTC-13	NIS SA/SB RCSPC SA/SB OSP	3.10E-5	Small LOCA with OSP unavailable.	1.35E-2	4.2E-7
5D2	Fire propagation among ARP-9, ARP-11, MTC-4, MTC-6 & MTC-15	RCSPC SA/SB/NON SIS SA/SB	3.10E-5	Potential small LOCA with SIS unavailable	will not screen - more detailed analysis required	

Table 4-7: Screening Quantification of Control Room Fire Scenarios						
Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
5E2	Fire in the RVLIS/ICC-SB panel	RCSPC SB	7.43E-5	Small LOCA	2.9E-5	2.2E-9
5F1	Fire in IDP-1A-S1 with early suppression	CWS SA NIS S1 RCSPC SR1	7.43E-5	Small LOCA Division A unavailable	5.86E-3	4.4E-7
5F2	Fire in IDP-1A-S3 with early suppression	SIS SA	7.43E-5	Transient Division A unavailable	1.44E-3	1.1E-7
5F3	Fire in IDP-1B-S2 with early suppression	NIS S2 RCSPC SR2	7.43E-5	Small LOCA	2.9E-5	2.2E-9
5F4	Fire in IDP-1B-S4 with early suppression	CWS SB RCSPC SR4 SIS SB	7.43E-5	Small LOCA Division B unavailable	6.23E-3	4.6E-7
5G	Fire propagation between IDP-1B-S2 & IDP-1B-S4	CWS SB NIS S2 RCSPC SR2/SR4 SIS SB	1.24E-5	Small LOCA Division B unavailable	6.23E-5	7.7E-8
5H	Fire propagation between the RVLIS/ICC-SB panel and the H_2 Analyzer Remote Control Panel 1B-SB	RCSPC SB	1.24E-5	Small LOCA	2.9E-5	2.2E-9
5I	Fire propagation between the H_2 Analyzer Remote Control Panel 1A-SA, IDP-1A-S1 & IDP-1A-S3	CWS SA NIS S1 RCSPC SR1 SIS SA	1.86E-5	Small LOCA Division A unavailable	5.86E-3	1.1E-7
5J1	Fire in cabinet C10-1IH-0051ASA	AFW SA CCW SA ESWS SA SIS SA	8.05E-5	Small LOCA Division B unavailable	6.23E-3	4.6E-7
5J2	Fire in cabinet C10-1IH-0051BSB	ESWS SB SIS SB	8.05E-5	Transient Division B unavailable	3.89E-3	3.1E-7
5J3	Fire in cabinet NFMS-BSB	NIS S2	8.05E-5	Minimal effect on safe shutdown	n/a	

Table 4-7: Screening Quantification of Control Room Fire Scenarios						
Scenario	Scenario Description	Systems Affected	FDS Frequency	Transient Modelled	CCDP	Screening CDF
6A1	Fire in the NIS-1 cabinet with early suppression	NIS S1	7.43E-5	Minimal effect on safe shutdown	n/a	
6A2	Fire in the NIS-2 cabinet with early suppression	NIS S2	7.43E-5	Minimal effect on safe shutdown	n/a	
6B	A fire in any cabinet in Fire Zone 12-A-6-CR that is not suppressed within 15 minutes	--	1.98E-4	Shutdown from the ACP assumed		
6C1	Fire in the Auxiliary Equipment Panel AEP-1	CWS SA/SB HCRC SA/SB RCSPC SA/SB	8.05E-5	Small LOCA CWS unavailable	<1E-2	<1E-6
6C2	Fire in the RVLIS monitor cabinet	RCSPC SB	8.05E-5	Small LOCA	2.9E-5	2.3E-9
6H	CR EVAC	--	2.48E-5			

Table 4-8: Screening Status for SHNPP Fire Areas / Compartments				
Fire Area	Screened Out Qualitatively (Note 1)	Screened Out Quantitatively (Note 2)	Screened Out Using COMPBRN Arguments (Note 3)	CDF Calculated
1-A-BAL-C			✓	
1-O-PA		✓		
1-O-PB		✓		
1-A-BATA		✓		
1-A-BATB			✓	
1-A-CSRA			✓	
1-A-CSRB			✓	
1-A-EPA			✓	
1-A-EPB			✓	
1-A-SWGRA			✓	3.1E-6
1-A-SWGRB				4.0E-6
1-D-DGA		✓		
1-D-DGB		✓		
1-D-DTA		✓		
1-D-DTB		✓		
5-O-BAL		✓		
5-F-BAL		✓		
5-S-BAL		✓		
5-W-BAL	✓			
12-O-TA		✓		
12-O-TB		✓		
12-A-BAL		✓		
12-A-CR				see section 4.6.3
12-A-CRC1				see section 4.6.3
12-A-HV&IR		✓		
12-I-ESWPA		✓		
12-I-ESWPB		✓		

Table 4-8: Screening Status for SHNPP Fire Areas / Compartments				
Fire Area	Screened Out Qualitatively (Note 1)	Screened Out Quantitatively (Note 2)	Screened Out Using COMPBRN Arguments (Note 3)	CDF Calculated
TG			✓	
1-A-4-CHF B	✓			
1-A-4-CHF A		✓		
1-A-4-COM I		✓		
1-A-4-CHF C	✓			
1-A-3-COR			✓	
1-A-3-MP			✓	
1-A-34-RHXA			✓	
HP STORAGE RM A-467C	✓			
CHG PUMP 1A-SA		✓		
CHG PUMP 1C-SAB		✓		
CHG PUMP 1B-SB		✓		
SPARE ROOM A-467	✓			
1-A-34-RHXB		✓		
1-A-3-PB			✓	
BORIC ACID TRF PUMP	✓			
1-A-3-COMB			✓	
LETDOWN HX AREA	✓			
1-A-3-COM E			✓	
1-A-3-COM I			✓	
HV-AREA	✓			
MECH PEN AREA			✓	
1-A-2-MP			✓	
1-A-2-PT	✓			
1-A-1-PA		✓		
1-A-1-FD		✓		
1-A-1-ED		✓		
1-A-1-PB		✓		

Table 4-8: Screening Status for SHNPP Fire Areas / Compartments				
Fire Area	Screened Out Qualitatively (Note 1)	Screened Out Quantitatively (Note 2)	Screened Out Using COMPBRN Arguments (Note 3)	CDF Calculated
1-A-3-TA		✓		
1-A-5-HVA			✓	
1-A-5-HV3		✓		
1-A-5-CEH	✓			
1-A-5-BATN	✓			
1-A-4-CHLR			✓	
1-A-4-COR		✓		
1-A-4-TA	✓			
1-A-46-ST		✓		
VCT	✓			
1-A-4-COMB			✓	
BORIC ACID TANK AREA	✓			
VALVE GALLERY-A		✓		
VALVE GALLERY-B	✓			
1-A-4-COM-E-E			✓	
1-A-4-COM-E-W			✓	

Note 1: No safe shutdown equipment and no plant trip initiator in the area/compartment

Note 2: Conservative calculation shows that core damage frequency is less than 1E-6 per year

Note 3: COMPBRN results show that damage to components is limited and bounding CDF is less than 1E-6 per year

SECTION 5

OTHER EXTERNAL EVENTS

5.0 INTRODUCTION

The individual plant examination of external events (IPEEE) requires an evaluation of the impact on the plant of hazards that are external to it. The hazards are classified into seismic, fire, and other. In NUREG-1407, (NRC, 1991) the conclusion was reached that, of the other external events, only the following need be considered on a plant specific basis; high winds, external floods, and transportation and nearby facility accidents. However, there is also a requirement that there be a review performed to confirm that there are no external hazards unique to the site, that would invalidate the conclusions of NUREG-1407. This section of the report documents the analysis of other external hazards for the SHNPP.

The approach used follows the method described in NUREG/CR-4839 (NRC, 1992) by performing an initial screening analysis, followed by bounding or detailed analyses as necessary.

Section 5.1 gives a brief description of SHNPP, extracted from the FSAR (CP&L, FSAR). Section 5.2 describes the initial screening analysis approach, and presents the conclusions. Sections 5.3, 5.4, and 5.5 discuss high winds, floods, and transportation and nearby facility accidents respectively. Conclusions are given in section 5.6, and references in section 5.7.

5.1 GENERIC PLANT DESCRIPTION

5.1.1 Site Description

The site is in central North Carolina, located in the extreme southwest corner of Wake County and southeast corner of Chatham County. The City of Raleigh is approximately 16 miles NE, and the City of Sanford is about 15 miles SW. It is located also 69 miles ESE of Greensboro and 117 miles ENE of Charlotte. Coordinates of the site are latitude 35° 38.0'N and longitude 78° 57.4'W. The principal water source for the plant is the main reservoir which is formed by an impoundment of Buckhorn Creek just below its confluence with Whiteoak Creek. The power block structures are located on the northwest shore of the main reservoir about 4.5 miles N of the main dam. There is also an adjoining and independent auxiliary reservoir for emergency cooling purposes. The site occupies approximately 10,723 acres of land. The environment is rural and primarily devoted to farming and dairying. Local industrial activity is centered in an area WSW from the plant. Another major center of industrial and research activity is located to the north-northwest. The shortest distance to the exclusion boundary is 6,640 ft. in the northwest direction; the longest distance is 7,200 ft. in the south direction. The low population distance is three miles. The region surrounding the site is generally characterized by a gently rolling topography resulting from extensive weathering and erosion of the underlying bedrock.

The foundations have been placed on sound rock. The inland location of the plant site (115 miles from the Atlantic Ocean) modifies the effects of coastal storms, both tropical and extratropical, so that they are reduced in intensities to levels which are generally no greater than those produced by regional thunderstorms. The severity of continental air mass systems approaching from the northwest is modified by the Appalachian mountain range which acts as a protective barrier. The area is not on a usual path of either continental or coastal cyclonic storm centers, although frontal passages are frequent. The major weather influence in the region is the predominance of the subtropical belt of high pressure. The thermal effects of the ocean coupled with the barrier formed by the mountain range, result in a high frequency of occurrence of northwesterly winds in the fall and of southwesterly winds in the spring.

The major structures of the plant are the Containment Building, Auxiliary Building, Turbine Building, Waste Processing Building, Diesel Generator Building, Service Building, Fuel Handling Building, Tank Building, and Cooling Tower. A general plan of the building arrangements is shown in Figure 1.2.2–2 of the FSAR.

5.1.2 Identification of Structures, Systems and Components Susceptible to External Events

A principal concern in a study of external events is the identification of structures, systems or components which are susceptible to damage, and which, if damaged, could lead to a loss of capability to safely shut down the reactor. The equipment necessary to achieve safe shutdown to hot standby is addressed in the Individual Plant Examination (CP&L, 1993). The majority of that equipment is safety related and, as such, is protected by the major structures, namely the Containment Building, the Auxiliary Building, Diesel Generator Building, ESW Structures, the Condensate Storage Tank Building, and the Diesel Fuel Oil Storage Tank Building. These are seismic class I structures, designed to withstand tornado impact. However, there are important components which are not protected by these structures and are consequently vulnerable. These include:

the switchyard,
the main transformers,
the power conversion system which is housed in the turbine building,
the refueling water storage tank,
the fire pumps located beside the ESW intake structure

In addition to potential damage to this equipment, there is a concern as to whether there exists the possibility for damage to the class I structures sufficient to damage the equipment they contain. This damage may be as a result of a direct impulsive force, or by ingress of harmful agents through penetrations in the structures. The most obvious of the latter are water, due to flooding, or toxic gases leading to control room habitability problems.

5.2 SCREENING OF EXTERNAL HAZARDS

5.2.1 Description of Approach

The objective of this screening analysis is to provide confirmation of the NUREG-1407 conclusion that there are no hazards unique to the site that require evaluation, other than those posed by high winds, external floods, and transportation and nearby facility accidents.

The PRA Procedures Guide (NRC, 1983a) provides an exhaustive list of potential external hazards which provides the starting point for the analysis. An extensive review of information on the site region and plant design is made to identify external events that are applicable using the screening criteria below. The data in the safety analysis report on the geologic, seismologic, hydrologic, and meteorological characteristics of the site region as well as present and projected industrial activities (i.e., the building of a reservoir, increases in the number of flights at an airport, construction of a road that carries explosive materials, etc.) in the vicinity of the plant are reviewed for this purpose. The set of screening criteria has been formulated to minimize the possibility of omitting significant risk contributors while reducing the amount of detailed analyses to manageable proportions. The following screening criteria have been adopted from those given in the PRA Procedures Guide.

An external event is excluded if:

1. The event is of equal or lesser damage potential than the events for which the plant has been designed. This requires an evaluation of plant design bases in order to estimate the resistance of plant structures and systems to a particular external event. For example, it is shown by Kennedy, Blejwas, and Bennett (NRC, 1983b) that safety-related structures designed for earthquake and tornado loadings in Uniform Building Code Zone 1 can safety withstand a 3.0 psi static pressure from explosions. Hence, if the PRA analyst demonstrates that the overpressure resulting from explosions at a source (e.g., railroad, highway or industrial facility) cannot exceed 3 psi, these postulated explosions need not be considered.

2. The event has a significantly lower mean frequency of occurrence than other events with similar uncertainties and could not result in worse consequences than those events. For example, the PRA analyst may exclude an event whose mean frequency of occurrence is less than some small fraction of those for other events. In this case, the uncertainty in the frequency estimate for the excluded event is judged by the PRA analyst as not significantly influencing the total risk.

3. The event cannot occur close enough to the plant to affect it. This is also a function of the magnitude of the event. Examples of such events are landslides, volcanic eruptions and earthquake fault ruptures.

4. The event is included in the definition of another event. For example, storm surges and seiches are included in external flooding; the release of toxic gases from sources external to the plant is included in the effects of either pipeline accidents, industrial or military facility accidents, or transportation accidents.

In addition to these, another criterion is added.

5. The event is slow in developing and there is sufficient time to eliminate the source of the threat, or to take precautionary measures to minimize the consequences.

Each of the potential other external hazards listed in the PRA Procedures Guide was reviewed with respect to the above criteria and determined to meet one or more of these screening criteria as summarized in Table 5-2.

In accordance with the recommendation of NUREG-1407, a structured plant walkdown was performed to confirm the conclusions of the paper study. The walkdown documentation is included in the analysis file. The plant site is generally very clean with no accumulation of objects that could become airborne during a tornado strike. There are large open areas with no possibility for ponding during heavy downpours. Plant structures containing safety related structures have relatively few openings and penetrations that would be susceptible to external hazards.

5.2.2 Results of Screening Analysis

Each of the external hazards listed in the PRA Procedures Guide was reviewed. Based on information in the FSAR, and on the basis of the walkdown, it was determined that the conclusions of NUREG-1407 were valid for SHNPP, namely that there are no known plant-unique other external events that pose a significant threat of severe accidents within the context of the NUREG-1407 screening approach. The next three sections discuss the potential for significant impact of the three hazards identified by NUREG-1407 for plant-specific evaluation, namely, high winds, external floods, and transportation and nearby facility accidents.

Table 5-2
Screening of External Events for SHNPP

Event	Applicable Screening Criteria
Avalanche	3
Biological Events	5
Coastal Erosion	3
Drought	2,5
Fire	3
Fog	4
Forest Fire	3
Frost	1
Hail	1,4
High Tide, High Lake	3
High Summer Temperature	1,5
Ice Cover	3, 4, 5
Landslide	3
Lightning	4
Low Lake or River Water Level	4
Low Winter Temperature	1,5
Meteorite	2
Pipeline Accident	1
Intense Precipitation	treated under external flooding
River Diversion	3
Sandstorm	3

Table 5-2
Screening of External Events for SHNPP
(Continued)

Event	Applicable Screening Criteria
Seiche	3
Snow	1
Soil Shrink-Swell Consolidation	1
Storm Surge	1
Tsunami	3
Toxic Gas	2
Turbine Generated Missiles	2
Volcanic Activity	3
Waves	3

5.3 HIGH WINDS

5.3.1 Straight Winds and Tornados

The 100-year recurrence extreme-mile wind speed at the plant site was determined to be 90 mph. The extreme-mile wind is defined as the one-mile passage of wind with the highest speed and includes all meteorological phenomena except tornadoes, which are dealt with separately. It does not include gustiness occurring during a short-time interval. Adjustment for gustiness (a factor of 1.3) yielded an instantaneous gust of 117 mph at the 30 ft level once in a 100-year period. This speed (117 mph) is conservative compared to the observed one-minute fastest mile wind speeds recorded at Raleigh-Durham (73 mph from WNW, in October 1954), at Greensboro (63 mph from N, in July 1932), and at Charlotte (59 mph from SW, in July 1962), (Sec. 2.3.1.2.7).*

Wind loading was based on ANSI A58.1-1972 "Building Code Requirements for Minimum Design Loads in Buildings and Other Structures", the recommendations of ASCE Paper No. 3269, "Wind Forces on Structures" for cases not covered by A58.1, and ASCE Paper No. 4933, "Wind Loads on Dome-Cylinder and Dome-Cone Shapes" for detailed containment dome pressure coefficients. (Sec. 3.3.1) The plant seismic category I structures are designed to withstand the effects of the design wind, a maximum wind of 179 mph at 30 ft above plant grade. The design wind is based on a 1,000-yr return period is much more conservative than the 100-yr return wind speed of 117 mph. Standard Review Plan 3.3.1 requires that the design wind speed be based on a 100-yr return period "fastest mile of wind". Therefore, the SHNPP design is conservative. (Sec. 3.3.1.1)

The plant site lies within region I for determining design basis tornadoes according to Regulatory Guide 1.76. Region I has the following tornado characteristics:

Maximum wind speed	360 mph
Rotational wind speed	290 mph
Translational speed	70 mph max., 5 mph min.
Radius of maximum rotational speed	150 ft
Pressure drop	3.0 psi
Rate of pressure drop	2.0 psi/sec

The tornado strike probability was calculated to be 0.00106 per year. (Sec. 2.3.1.2.1) Structures, systems, and components whose failure, due to design wind loading, tornado wind

* Section nos. refer to the FSAR (NRC, 1993a).

loading, or associated missiles, could prevent safe shutdown of the reactor are protected from such failure by one of the following methods:

(a) the structure or the component is designed to withstand design wind, tornado wind and tornado generated missiles, or
(b) the system or components are housed within a structure which is designed to withstand the design wind, tornado wind and tornado generated missiles. (Sec.3.3)

The plant design conforms with the standard review plan criteria and hence tornadoes are not considered a significant hazard. The most likely damage by a tornado would be a loss of offsite power with a long recovery time. This is already included in the IPE model.

5.3.2 Hurricanes

Sustained hurricane force winds (winds above 74 mph) have never been reported by the Raleigh-Durham Weather Service (19 miles NNE). Hurricanes usually deteriorate rapidly as they move on shore. Since the SHNPP site is 115 miles from the nearest coastline, the major effect on the plant area due to hurricanes is usually heavy precipitation. The maximum 24-hour precipitation of 5.20 in. at the Raleigh-Durham Weather Service was the result of Hurricane Diane in August 1955.

The fastest one-minute wind observed at Raleigh-Durham was 73 mph associated with Hurricane Hazel in October 1954. The intensities of wind and precipitation produced by hurricanes at the plant site are generally no greater than those produced by severe thunderstorms in the area.

Since hurricane winds are far less damaging than tornados, and the plant is designed against floods, hurricanes are considered to be bounded. Hurricanes and tornados may cause debris to build up in the service water reservoirs. However, in the case of SHNPP, there are two separate reservoirs, the main reservoir and the auxiliary reservoir. In addition, the cooling tower basins provide another reservoir for an ultimate heat sink, albeit for a limited time. Thus a loss of ultimate heat sink is extremely unlikely. (This diversity also protects the plant from the impact of biological impacts, which would appear gradually with enough lead time for a deterioration in performance to be noticed, and preventive measures taken.)

The walkdown confirmed that the potential concerns raised in IEN 93-53, Supplement 1 (NRC, 1993) about the potential for failures of non-safety equipment leading to failures of safety-related equipment, were not an issue at SHNPP.

5.4 EXTERNAL FLOODS

The general area of the site is subject to local intense precipitation. The plant island faces the Main Reservoir and its grade, 260 ft, is 40 ft above the nominal water level of the main reservoir (220 ft) and 8 ft above the nominal water level of the auxiliary reservoir (252 ft). Most of the site is drained to the main reservoir, while a small portion of the run-off is drained

to the auxiliary reservoir via the ESW intake and discharge channels. Thus, the site drainage does not pose any potential problems. (Sec 2.4.2.3) The PMF (probable maximum flood) in the Cape Fear River is not considered because of the large difference in elevation between the river bank (approximate elevation of 160 ft) and the top of the main dam (elevation of 260 ft). (Sec. 2.4.2.2)

Most of the runoff from the plant grade is drained by means of a graded ground surface with inlet structures and associated underground reinforced concrete pipe. Along the peripheral areas of the plant island, the drainage system consists of open ditches and underground reinforced concrete pipe. The plant drainage system is designed for a 5 in./hr rainfall intensity. Storm runoff will flow into the main reservoir through the underground reinforced concrete pipe and into the auxiliary reservoir via the ESW intake and discharge channels. Should the flow through the drainage system become blocked during a period of such rainfall intensity, the plant island is capable of being drained by overland flow on the open roads and ground surface directly to the main reservoir or the ESW intake and discharge channels. Sediment buildup is monitored in accordance with the requirements in Regulatory Guide 1.127, Rev. 1. (Sec. 2.4.1.1)

Both the main dam and auxiliary dam have uncontrolled spillways to release floods. The top of the main dam, the top of the auxiliary dam, and nominal plant grades are all at 260 ft, while the maximum water level at the corresponding locations resulting from the PMF coincident with the corresponding designed wind velocity and wave runup are 243.1 ft, 258 ft, and 257.7 ft, respectively. (Sec. 2.4.1.1, 2.4.2.2. and 2.4.3.6.2) Thus, the facilities located on the plant island will not be subject to any flooding caused by probable maximum events such as the PMF and the probable maximum hurricane (PMH), coincident with the wave runup and wind setup. Moreover, seismic category I structures, systems, and components requiring flood protection for safe shutdown are protected against floods in the main and auxiliary reservoirs. (Sec. 3.4.1.1.)

The accumulated water depth during the probable maximum precipitation (PMP) considered was approximately 14.8 in. This depth was calculated based on the PMP estimates given in the Hydrometeorological Reports No. 51 and 52 (dated June 1978 and August 1982, respectively), the plant site drainage for runoff of 4 in. per hour, and the assumption of a complete blockage of the entire drainage system. NUREG-1407 requires the use of these two PMP reports for onsite flooding and roof ponding. Thus, the maximum elevation to which water will pond on the plant site during a PMP event is 261.23 ft. All structures on the plant site are protected to at least elevation 261 ft, and no structure has any access openings below 261 ft. However, ponding to elevation 261.23 ft will not impact the plant ability for safe shutdown, if it were necessary, because safety-related structures which have entrances at elevation 261 ft. are protected against any ponding during a PMP event by artificial barriers such as water tight or air tight doors, or low structural barriers such as curbs with the minimum elevation of 262 ft, with the exception of the two entrances of the Waste Processing Building which are not protected against any ponding above elevation 261.06 ft. These doors, however, do not provide access to areas that house any safety-related equipment. Electrical manholes and duct runs for auxiliary and emergency power system cables are capable of normal function while completely or partially

flooded. None of the structures housing safety-related equipment have personnel access openings below elevation 261 ft.

While water ponding on the flat roofs of safety related structures is possible as a result of there being a surrounding parapet, roof drains are supplied that are adequate to prevent ponding. In addition, the required load capacity of the roof would support water to the level of the parapet even if the drains were to be blocked.

No safety-related structures will be jeopardized as a result of the maximum still water level or wave run-up resulting from a PMF, or storm water accumulated at the plant site due to a PMP, and therefore, it will not be necessary to bring the reactor to a cold shutdown for flood conditions (Sec. 3.4.1.1).

The plant as designed therefore meets the 1975 Standard Review Plan criteria, and external floods are not a significant hazard.

5.5 TRANSPORTATION AND NEARBY FACILITY ACCIDENTS

5.5.1 Aircraft Impact

There are three small aviation airports within a ten-mile radius of the plant: Raleigh Executive Airport (six miles E), Deck Airport (eight miles N), and Cox Airport (10 miles NNE). Traffic consists entirely of light aircraft and none of these airports has a commercial service. Since no records of the traffic were maintained by these airports, estimates of the traffic were obtained from the Federal Aviation Agency at Raleigh-Durham Airport. The nearest major commercial airport is the Raleigh-Durham Airport (19 miles NNE). Three of the ten major airways from this airport pass within ten miles of the site. The closest military aviation is located at Pope Air Force Base, 35 miles S. A National Guard Air Facility is located at Raleigh-Durham Airport. (Sec. 2.2.2.5) The FSAR concludes that the aircraft hazards analysis is not required because:

(a) no federal airways or airport approaches pass within two miles of SHNPP,
(b) no airports are located within five miles of SHNPP,
(c) the movements per year from the three general aviation airports and the major commercial airport are below the aircraft analysis limits per year (18000, 32000, 50000,and 361000, respectively), and
(d) the closest military airport is 35 miles from SHNPP. (Sec. 3.5.1.6)

These criteria were still met in 1993. Data obtained from the FAA for the number of movements through November 1993 at the RDU airport showed an annual number of movements less than 300,000.

However, there is a military flight path that is used by helicopters that passes relatively close to the plant. It is considered that this presents a low hazard to the plant, because of the low momentum of the aircraft and the design of the structures.

5.5.2 Road and Rail Accidents

The issues of concern are road and rail accidents leading to explosions or releases of flammable or toxic chemicals.

The Cities of Raleigh and Durham, both located 16 miles NE from the plant serve as railroad and highway transportation centers for the area. The highways in and around these cities carry large amounts of traffic. Approximately 8,000 vehicles daily use U.S. Highway 1, which passes approximately 6,600 ft NNW from the plant site. Rail transportation is principally for freight to and through the major cities. (Sec. 2.2.1) Three railroad segments come within five miles of the plant site, which carry scheduled railroad traffic. The three segments are:

(a) the Bonsal-Durham segment, 2.5 miles NW
(b) the Fuquay-Varina-Brickhaven segment, 4.3 miles S
(c) the Raleigh-Moncure segment, 1.9 miles NW

Only the Raleigh-Moncure segment carries hazardous materials on a regular basis. (Sec. 2.2.3.3.1)

Review of combustible materials transported within five miles of SHNPP identified rail and/or truck transportation of high explosives as the sources for a potential hazard. (Sec. 2.2.3.1) The complete and instantaneous detonation of one train car load of TNT (200,000 lb) at the closest point to the plant was evaluated to determine the blast loadings on critical plant structures. The maximum loads were determined to be 0.4 psi or less within 0.062 seconds. This loading, as well as any missiles generated by the explosion, will be satisfactorily resisted by seismic category I structures and critical storage tanks. In addition, other safety-related equipment which is not capable of withstanding this pressure pulse is protected against the pressure pulse by location inside an enclosure. The complete and instantaneous detonation of one truck load of TNT (approximately 50,000 lb) would be comparatively less severe to the critical plant structures. (Sec. 2.2.3.1.1)

The release of toxic chemicals causing a control room habitability concern due to a railroad accident in the vicinity of the site has been calculated to be an event with a probability of occurrence of less than 1.0E-7 per year. A national average probability value of 2.2E-8 per mile of travel per year was used in the calculation. This is reasonable as CSX, which runs the railroad, has an average accident rate close to that of the national average. No known railcar accident have ever occurred on the segment of the railroad considered in the analysis. Although two chemicals (anhydrous ammonia and vinyl chloride) were considered in the evaluation, the results of the consequence (dose) analysis were not presented because of the low probability of accident occurrence. (Sec. 2.2.3.3.1) The area close to the plant has no industrial development, and thus the volume of hazardous materials transported on the 2-lane section of US Route 1 should be low. Furthermore, the road is further away from the plant than the Department of Transportation impact radius for any of its classes of hazardous materials. In addition, an

analysis of a chlorine spill done for the FSAR, revealed no control room habitability concern for SHNPP.

5.5.3 Fixed Facility Accidents

5.5.3.1 Industrial Facilities

In the area surrounding the plant within a 50-mile radius, tobacco manufacturing and processing is the principal industry in Durham County,furniture manufacturing in Range, Alamance, and Guilford Counties, and textile manufacturing in Guilford and Alamance Counties. The Research Triangle Park, approximately 20 miles NNE, has some light industry such as electronic component manufacturing, electronic research, fiber chemistry research, pharmaceutical research, health statistics studies, and air pollution control studies. There is a local concentration of industry including wood products, adhesive resins, and synthetic fibers in the vicinity of Moncure, about seven miles W. There is no industrial development within a five-mile radius of the plant site. (Sec. 2.2.2.1) There are two mining operations (clay and shale, and crushed stone) and five inactive quarries within a ten-mile radius of the plant site. (Sec. 2.2.2.2)

5.5.3.2 Military Facilities

There are no significant military facilities within a 25 mile radius of the plant site. The nearest active military facility is Fort Bragg (35 miles S), a support base for Army training operations, and the adjoining Pope Air Force Base. A National Guard facility is located at Raleigh-Durham Airport (19 miles NNE). (Sec. 2.2.1 and 2.2.2.5)

The FSAR does not present analyses related to industrial or military facility accidents. The industrial facilities and their products are located such distances from the plant site that they will pose no safety hazard to the plant site. Significant military facilities (support base for Army training operations) are located beyond 30 miles from the plant site, and therefore they will not pose any safety hazard to the plant site. (Sec. 2.2.1 and 2.2.2.1)

5.5.3.3 Pipeline Accidents

An 8-in. liquefied petroleum gas (LPG) pipeline, operated by the Dixie Pipeline Company, and buried three feet underground, passes in excess of 8,500 ft. (W) of the closest plant critical structures. It carries approximately 1,600 barrels per hour at peak flow at a maximum pressure of 1,440 psi. (Sec. 2.2.3.2) The line terminates at Apex, North Carolina, where the fuel is stored and distributed for local use. The pipeline is not used for storage of gas at higher than normal pressures. There are no plans to carry any product other than liquified propane in the pipeline. There are no other petroleum operations within a ten-mile radius of the plant site. (Sec. 2.2.2.3) The effects on the plant safety-related structures resulting from a break in the LPG line have been evaluated on the assumption of double-ended rupture or slot rupture with the slot size equal to twice the flow area of the pipeline and instantaneous rupture at the closest

location to the plant. It was further assumed that propane dispersed toward the plant at 1m/sec as an airborne cloud, or alternatively, drifted by gravity toward the plant. It would take approximately 5 to 10 min. to detect and isolate a major line leak or rupture during the day, or 30 min. at night. It was estimated that the detonation strength would be somewhere between the 8.9 and 100 tons of TNT, but closer to the 8.9 tons. The resulting peak overpressures were 0.10 psi at 8.9 tons and 0.5 psi at 100 tons, and the peak accelerations at 0.002 g and 0.023 g, respectively. Critical plant structures are designed so that they are able to withstand these overpressures and ground motions, and hence it was concluded that a detonation of propane that had escaped from a break in the 8-in. LPG line would not result in unacceptable consequences.

For a non-explosive release, the cloud containing escaped LPG would have to travel a minimum of 500 ft to reach the auxiliary reservoir, and after reaching the reservoir, the cloud would continue to disperse so that at the point of closest approach the fringe of the flammable cloud would be more than 2,200 ft from safety-related structures. However, fires from such clouds would pose no hazard to the plant because none of the flammable cloud would reach any part of the plant site. But average concentration of propane in a cloud that continues slumping toward the plant should fall below the lower flammable limit. (Sec. 2.2.3.2)

5.6 CONCLUSIONS

This review of the impact on SHNPP of other external events leads to the conclusion that there are no significant events of concern. A comprehensive screening analysis of those other external hazards identified in the PRA Procedures Guide resulted in supporting the NUREG-1407 conclusion that only high winds, external floods, and transportation and nearby facility accidents required to be reviewed in detail. The plant as designed meets the intent of the criteria of the Standard Review Plan of 1975 and thus it is not surprising that these events also do not pose a significant threat to the plant.

5.7 REFERENCES

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(CP&L, 1993), Carolina Power and Light Company, "Shearon Harris Nuclear Power Plant Unit No.1, Individual Plant Examination Submittal," August 1993.

(NRC, 1983a), NUREG/CR-2300, "PRA Procedures Guide," January 1983.

(NRC, 1983b), Kennedy, R.P., Blejwas, T.E., Bennett, D.E., "Capacity of Nuclear Power Plant Structures to Resist Blast Loadings," NUREG/CR-2462, September 1983.

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

(NRC, 1992), Ravindra M.K., and Bannon, H., "Methods for External Event Screening Quantification: Risk Methods Integration and Evaluation Program (RMIEP) Methods Development," NUREG/CR-4839, July 1992.

(NRC, 1993), USNRC, Information Notice 93-53, Supplement 1: Effect of Hurricane Andrew on Turkey Point Nuclear Generating Station and Lessons Learned, April 29, 1993.

SECTION 6

LICENSEE PARTICIPATION AND INTERNAL REVIEW TEAM

6.1 IPEEE PROGRAM ORGANIZATION

Management of the overall IPEEE project at CP&L was provided by Mr. R. E. Oliver, Manager-PWR Safety Analysis, who is responsible for all PRA related work performed for the two PWR plants owned and operated by CP&L.

Responsibility for the technical aspects of the project was divided by technical area. Mr. R. L. Knott was responsible for the seismic analysis, and Mr. A. J. Howe was responsible for the fire analysis and the analysis of Other External Events.

6.1.1 Seismic Analysis

The seismic review was performed through the efforts of a CP&L project engineer and a site project manager. The project engineer facilitated the completion of engineering activities while the project manager provided for effective plant interface. The project engineer and project manager worked closely to coordinate site walkdowns, implement repairs and plan for modifications. CP&L's consultants for engineering activities were as follows:

- EQE International, Inc. (EQE)
- System and Reliability Optimization Services, Inc. (SAROS)
- Vectra Technologies, Inc.

The seismic analysis required various organization structures depending on the task being performed. A summary of the various responsibilities by task is addressed below.

Safe Shutdown Equipment List (SSEL) Development:

The SSEL development was facilitated by a preliminary walkthrough by SAROS, CP&L and EQE personnel to search for potential low seismic capacity components. The success path logic and supporting information for SSEL development was completed by Ricky Summit (formerly SAROS) and reviewed by CP&L.

Seismic Walkdowns and Reviews:

A seismic review team (SRT) was assembled following the guidance provided in EPRI NP-6041 drawing on the experience and expertise of EQE and CP&L personnel.

Each walkdown team included a minimum of two SRT members who had completed the Seismic Qualification Utility Group (SQUG) Walkdown Screening and Seismic Evaluation training course, as well as EPRI's add-on training for IPEEE. Joint walkdown teams generally consisted of at least one EQE Engineer and at least one CP&L Engineer. Component screening and HCLPF analysis candidate selection was performed jointly between CP&L and EQE. HCLPF calculations were performed by EQE and reviewed by CP&L.

Relay Evaluation:

The relay evaluations were primarily performed by SAROS. However, early involvement was provided by operations personnel.

Peer Review:

The seismic peer review was performed by Vectra Technologies, Inc. CP&L and EQE supported the peer reviews by participating in the site walkdown review and providing responses for reviewer questions.

6.1.2 Fires and Other External Events

The analysis was, for the most part, performed by NUS at their Gaithersburg office. In order to ensure that CP&L personnel are fully conversant with the IPEEE methods and are in a position to fully integrate the knowledge gained from performing the work into operating procedures, training programs and appropriate hardware changes, a cognizant CP&L engineer was appointed to be the point of contact throughout the study, and CP&L engineers performed an in-depth review of each of the separate analyses that make up the study, and outlined below.

- Qualitative fire area screening analyses
- Fire frequency analyses
- Deterministic fire modeling assumptions
- Fire induced accident sequence analyses
- Human reliability/recovery action analyses
- Other external events analyses

In addition, CP&L engineers performed the quantification of the conditional core damage probabilities for the various plant damage states that were identified during the course of performing the fire analysis.

6.2 COMPOSITION OF THE INDEPENDENT REVIEW TEAM

An independent review team considered the final results of the IPEEE analysis in order to assess potential vulnerabilities, evaluate alternatives to address them and recommend actions to resolve severe accident issues using the NUMARC closure guidelines. The composition of the team is

shown below. The depth of experience of the plant operations, training, fire protection, licensing and nuclear engineering personnel assigned to this team ensured appropriate disposition of the issues identified in the IPEEE.

Corporate Support

Fred A. Emerson, Director - NEI Regulatory and INPO Affairs
Andrew J. Howe, Project Engineer - Risk Assessment
Rudy E. Oliver, Manager - PWR Safety Analysis

SHNPP Staff

David L. Markle, Senior Specialist - Fire Protection
James F. Nevill, Manager - Design Engineering
A. Wayne Powell, Manager - Operations Training
Robert L. Prunty, Manager - Licensing
Lewis S. Rowell, Project Engineer - Licensing
Vann Stephenson, Manager - Civil Engineering
Anthony Williams, Manager - Operations

The SHNPP and corporate support staff groups were convened to review the technical assumptions, bases, results, and conclusions of the analyses, and either provide confirmation that the results appeared valid or provide recommendations for revising the analyses based on adjusted assumptions. The results were then reviewed by a group of cognizant managers from corporate and SHNPP management. The group then decided (using the NUMARC 91-04 criteria for IPE closure and a qualitative cost-effectiveness criterion) how best to resolve the issues. Possible resolution pathways for each sequence with a core damage frequency above 1E-6/year ranged from modifications to procedure changes or consideration for inclusion in Severe Accident Management Guidance to be developed at a later date. All sequences with core damage frequencies below 1E-6 were not evaluated further, in accordance with the NUMARC 91-04 guidelines. Finally, the results and conclusions were reviewed and accepted by plant senior management.

SECTION 7

PLANT IMPROVEMENTS AND UNIQUE SAFETY FEATURES

As this IPEEE has confirmed, SHNPP has been designed to cope with the occurrence of energetic external events and internal fires. The plant is located in such an area that there are few significant external hazards, and for those that are possible, such as tornadoes, the plant is well designed by protecting equipment required for safe shutdown.

In terms of fire hazard, the risk is minimized by a combination of features including a minimization of potential fire sources, and mitgation of the impact of fires by a combination of measures, which include detection, suppression, and separation of potential targets from the fire sources.

Because of these design features, the IPEEE has been able to demonstrate that there are no significant issues that need to be resolved. The fire analysis identified three fire scenarios that, on application of NUMARC evaluation criteria, require Severe Accident Management Guidelines (SAMG) be in place with emphasis on prevention/mitigation of core damage or vessel failure, and containment failure.

The scenarios are the following:

Switchgear Room B (Fire Area 1-A-SWGRB)

This fire area is located at 286' elevation of the Auxiliary Building. It houses equipment and cabling associated with the safety train B and other non-safety equipment. Significant fire ignition sources for this area include electrical cabinets, transformers, and battery chargers. Cable insulation is the primary source of combustible material for this area. The transient combustible loading for this area is negligible.

The dominant scenario for this area results from fires originating in any bus that is not suppressed within the cabinet, and therefore has the potential for impacting cables from several cabinets. Such fires were, conservatively, assumed to be able to ignite substantial quantity of combustibles before they could be suppressed. The contribution of these fires to CDF was estimated to be 4.0E-6 per year.

Switchgear Room A (Fire Area 1-A-SWGRA)

This fire area is similar to Switchgear Room B, but houses equipment and cabling associated with the safety train A and other non-safety equipment. The contribution of fires in this area to CDF was estimated to be 3.1E-6 per year.

The independent review team identified in section 6.4 reviewed the fire scenarios for the two switchgear rooms. No cost effective modifications were identified which could substantially reduce the likelihood of these fire scenarios. The current plant fire response procedures and operating procedures for plant shutdown after a fire adequately address these scenarios, and no enhancements to the procedures were required.

Control Room Scenarios 1D1 and 6B

The SHNPP Control Room Area is located at elevation 305' of the Auxiliary Building. The area contains control panels, computer consoles, radiation monitoring panels, alarms, incore instrumentation, desk relay panels, exhaust fans, a component cooling water surge tank and associated controls, wiring in conduit, a kitchen, and an office area.

The two scenarios that are not screened out are assumed to require control room evacuation with control of safe shutdown components from the ACP. Operator action at the ACP includes the closing of the appropriate PORV block valve if it is necessary to mitigate a LOCA resulting from a spurious opening of a PORV.

- Scenario 1D1—This scenario results in loss of control for the AFW and ESW systems from the main control room. In addition, control functions for many train A components (including those for feed and bleed) are unavailable in the control room. Shutdown from the ACP is assumed to be necessary. A potential LOCA can be mitigated by the closing of the appropriate PORV Block valve from the ACP. It was conservatively assumed that 10% of all fires in this scenario will result in hot shorts causing a PORV to spuriously open. Thus, the scenario results in a transient with a frequency of 5.01E-5 per year, and a small LOCA with a frequency of 5.57E-6 per year. Even though it is not explicitly identified as an entry condition into AOP-004, it was assumed that the inability to control AFW and ESW from the control room will lead the operators to the remote shutdown procedure. It was further assumed that, using the values for conditional core damage probabilities given in section 4.6.3.4, the human error probability for failing to take control is dominant. The total core damage frequency is estimated as 1.25E-6 per year.

- Scenario 6B—This scenario involves a fire in any cabinet that is not suppressed within 15 minutes. The assumption here is that the effects of smoke produced will necessitate control room evacuation. Plant shutdown is assumed from the ACP. This scenario does not involve damage to any equipment, but requires an orderly shutdown from the ACP. The frequency of core damage is estimated to be 3.0E-6 per year.

The frequency of core damage for each scenario is comprised of a frequency of the fire scenario combined with a human error probability for failure to successfully shut down the plant at the ACP. The independent review team identified in section 6.4 reviewed the fire scenarios for this area. No cost effective modifications were identified which could substantially reduce the likelihood of these fire scenarios. The team identified an enhancement to the procedure for

remote shutdown (outside of the main control room) which would improve the response to these fire scenarios. The procedure will be revised to specifically check the status of the pressurizer PORVs after transfer to the ACP to require closure of a block valve if necessary to isolate a failed open relief valve. The current results reported in this document do not credit this procedural enhancement. This procedure change will be implemented prior to startup after refueling outage 6, which is currently scheduled for fall 1995.

SECTION 8

SUMMARY AND CONCLUSIONS

8.1 SUMMARY

8.1.1 Overview of IPEEE

Carolina Power and Light (CP&L) has completed an examination of the potential for events external to the plant to cause core damage accidents at its Shearon Harris Nuclear Power Plant, Unit No. 1 (SHNPP). This report describes the results of the examination and illustrates the acomplishment of one of the principal goals of the study, namely compliance with the Nuclear Regulatory Commission's Generic Letter 88-20, Supplement 4 (NRC, 1991), requesting that every licensee conduct an Individual Plant Examination of External Events (IPEEE). This analysis complements the analysis presented in the Individual Plant Examination (IPE) (CP&L, 1993), which addressed internal initiating events. By the performance of this project, CP&L has achieved for the most part the four primary objectives of the IPEEE, which were, for initiating events resulting from events external to the plant systems:

- to develop an appreciation of severe accident behavior,
- to understand the most likely severe accident sequences that could occur at the plant under full power conditions,
- to gain a qualitative understanding of the overall likelihood of core damage and fission product releases, and
- if necessary, to reduce the overall likelihood of core damage and fission product release by modifying, where appropriate, hardware and procedures that would help prevent or mitigate severe accidents.

The results of this study are not however directly comparable with those of the IPE. The methodology used to perform the IPE is based on a systems analysis approach that has a achieved an accepted degree of maturity. The analysis of external initiating events, by contrast, has not reached the same degree of maturity. For example, some of the potentially damaging external initiating events have very low frequencies that cannot be estimated using actuarial data without considerable extrapolation, so that the frequency estimates are subject to a large uncertainty. Many of the events can occur with a range of severity with the damage potential being a function of that severity. Analyzing the impact of such events can be very complex and time consuming. Because of this, the methods that have been developed to analyze the impact of external initiating events are essentially screening analyses, designed either to identify the

most significant contributors, while minimizing the need for detailed analyses, or to identify specific weaknesses without explicitly estimating risk.

The method chosen to analyze the impact of seismic events, the seismic margin method, is the latter type of analysis. There is no estimation of core damage frequency. Instead, the analysis is an assessment of whether the plant has sufficient margin over and above the design basis to withstand what is known as the review level earthquake. The analysis of the other external events for SHNPP is essentially a confirmation that the plant meets the Standard Review Plan (NRC, 1975) criteria, and again does not require that core damage frequency be evaluated.

The fire analysis does, on the other hand, result in the evaluation of the core damage frequencies from a set of fire initiated scenarios. However, even in this case, the core damage frequency is not evaluated in the same way as was done for the internal initiating events. The analysis is based on a successive screening approach, at each stage of which, fire scenarios are screened from further consideration on the basis that a conservative analysis shows that the frequency of core damage is less than 1E-6 per year. However, since for scenarios that are screened, the analysis is not further refined, the degree of conservatism is not estimated, and therefore it would be inaccurate to sum the screening core damage frequencies to obtain the overall core damage frequency. Instead, the analysis has been used to identify the scenarios that have the highest likelihood of leading to core damage.

There is an additional difference in that, for the purposes of screening, and for comparison with the Severe Accident Issue Closure Guidelines (NUMARC, 1992), the sequences in the IPE were grouped by functional type. In the fire analysis they were grouped by fire location. The reason for this is that it is the vulnerable locations that are of interest.

8.1.2 Results

The only items resulting fron the seismic margin assessment that are outstanding are minor repairs or modifications which will be completed prior to startup from refueling outage 7, currently scheduled for Spring 1997. No vulnerabilities were identified during the analysis of the other external events.

Only four fire scenarios, one in each switchgear room and two in the control room, were identified as having a contribution to core damage frequency greater than 1E-6 per year. These are described below:

Area 1-A-SWGRB

This fire area is located at 286' elevation of the Auxiliary Building. It houses equipment and cabling associated with the safety train B and other non-safety equipment. Significant fire ignition sources for this area include electrical cabinets, transformers, and battery chargers. Cable insulation is the primary source of combustible material for this area. The transient combustible loading for this area is negligible.

Fire protection consists of early warning ionization detection located throughout the fire area. Hose stations, fire extinguishers and manual alarm stations are located in and adjacent to the area. Safety train A, powered by equipment located in the Switchgear Room A fire area, will be relied upon for plant shutdown in case of a fire in this fire area.

The dominant scenario for this area (scenario 2) results from fires originating in any bus that is not suppressed within the cabinet, and therefore has the potential for impacting cables from several cabinets. Such fires were, conservatively, assumed to be able to ignite a substantial quantity of combustibles before they could be suppressed. The impact of such fires was assumed to be loss of the entire division B safe shutdown path (i.e. loss of 1B-SB and 1E buses and all equipment that are powered from these buses). In addition, bus 1D was assumed to be initially de-energized due to either loss of control power to or spurious opening of its supply breaker. Operator action to locally close the breaker and restore offsite AC power to bus 1D (and therefore to bus 1A-SA), as directed by emergency procedures, was credited.

The frequency of this fire was estimated as:

$$F_{S2} = F_{sf} * P_{fs}$$

where F_{sf} = frequency of significant electrical cabinet induced fires = 3.5E-3
P_{fs} = probability of failure to suppress = 0.1 (EPRI, 1992b)

Therefore, F_{S2} = 3.5E-3 * 0.1 = 3.5E-4 per year.

For cases where operator recovery of offsite power to bus 1D (and hence to 1A-SA) is successful, the consequence of the fire is limited to the loss of the 1B-SB and 1E buses. The CCDP for this case is 7.1E-3 and the resultant CDF was estimated as:

$$CDF_{S2,1} = F_{S2} * CCDP_{S2,1} = 3.5E\text{-}4 * 7.1E\text{-}3 = 2.5E\text{-}6 \text{ per year.}$$

For cases where operator recovery of offsite power is not successful (from the IPE, this HEP is 1E-2), the CCDP is 7.5E-2, and the resultant CDF was estimated as:

$$CDF_{S2,2} = F_{S2} * HEP_{S2} * CCDP_{S2,2} = 3.5E\text{-}4 * 1E\text{-}2 * 7.5E\text{-}2 = 2.6E\text{-}7 \text{ per year.}$$

Thus the total contribution from this scenario to CDF is:

$$CDF_{S2} = 2.5E\text{-}6 + 2.6E\text{-}7 = 2.8E\text{-}6 \text{ per year.}$$

The second most significant scenario is that which results in loss of the 1B-SB bus from fires contained within the cabinets in which they originate. These contributions are estimated to add 1.1E-6 per year to the CDF. The total contribution to CDF for Switchgear Room B is therefore estimated to be 4.0E-6 per year (including a small contribution from welding/cutting fires).

Area 1-A-SWGRA

This area is similar to Switchgear Room B, except that there is no potential for the loss of the turbine-driven AFW pump, and no potential for loss of offsite power to division B. The contribution to CDF from the dominant scenarios is 2.6E-6 per year.

Control Room Scenarios 1D1 and 6B

The SHNPP control room is located at 305' elevation of the Auxiliary Building and contains control panels, computer consoles, radiation monitoring panels, alarms, incore instrumentation, desk relay panels, exhaust fans, a component cooling water surge tank and associated controls, wiring in conduit, a kitchen, and an office area.

The fire postulated for this area assumes ignition and subsequent development into the most severe single fire expected in the area of localized concentrations of combustibles permanently present in the area. Propagation of the postulated fire will be reduced by early detection using ionization-type smoke detectors installed at the ceiling and in the panels of the main control board. The automatic detection system senses products of combustion generated by the incipient fire and alerts employees both at the location of the local fire detection control panel and in the control room via the communications room. As such, manual fire response can be initiated promptly; this fire area is permanently occupied. In addition, ready access is provided to the area from adjacent plant areas facilitating initial use of area fire extinguishers on incipient fires and supplemental use of standpipe hose lines on developing fires by employees responding to the fire. The postulated fire is not considered to have sufficient potential for spread to cause failure of redundant safety-related plant equipment and associated cabling and controls.

The two scenarios that are not screened out are described below. The scenarios are assumed to require control room evacuation with control of safe shutdown components from the auxiliary control panel (ACP). Operator action at the ACP includes the closing of the appropriate power-operated relief valve (PORV) block valve if it is necessary to mitigate a LOCA resulting from a spurious opening of a PORV.

- Scenario 1D1—This scenario results in loss of control for the auxiliary feedwater (AFW) and emergency service water (ESW) systems from the main control room. In addition, control functions for many train A components (including those for feed and bleed) are unavailable in the control room. Shutdown from the ACP is assumed to be necessary. A potential LOCA can be mitigated by the closing of the appropriate PORV block valve from the ACP. It was conservatively assumed that 10% of all fires in this scenario will result in hot shorts causing a PORV to spuriously open. Thus, the scenario results in a transient with a frequency of approximately 5.01E-5 per year, and a small LOCA with a frequency of 5.57E-6 per year. Even though it is not explicitly identified as an entry condition, it was assumed that the inability to control AFW and ESW from the control room will lead the operators to the remote shutdown procedure. It was further assumed that, using the

values for CCDPs given in section 4.6.3.4, the human error probability for failing to take control is dominant. The total core damage frequency is estimated as 1.25E-6 per year.

- Scenario 6B - This scenario involves a fire in any cabinet that is not suppressed within 15 minutes. The assumption here is that the effects of smoke produced will necessitate control room evacuation. Plant shutdown is assumed from the ACP. This scenario does not involve damage to any equipment, but requires an orderly shutdown from the ACP. The frequency of core damage is estimated to be 3.0E-6 per year.

CP&L has reviewed these three fire scenarios and has determined that no plant modifications or administrative changes need to be made. However, the procedure for remote shutdown (outside of the main control room) will be enhanced to check the status of the pressurizer PORVs after transfer to the ACP and require closure of a block valve if necessary to isolate a failed open relief valve. The current results reported in this document do not credit this procedural enhancement. This procedure change will be implemented prior to startup after refueling outage 6, which is currently scheduled for fall 1995.

8.2 CONCLUSIONS

The IPEEE has demonstrated that the SHNPP has no significant vulnerabilities to external events. By performing this IPEEE, CP&L has not only addressed the requirements of the Generic Letter 88-20, Supplement 4 (NRC, 1991), but has also addressed other regulatory requirements.

Three programs, i.e., (1) the external event portion of USI A-45, (2) GI-131, and (3) the Eastern U.S. Seismicity issue, are subsumed in the IPEEE.

Any vulnerabilities associated with decay heat removal (USI-A-45) would have been revealed and resolved during this process. By virtue of the fact that no seismic vulnerabilities were uncovered in the seismic margin study, and that the safe shutdown paths analyzed in that study included equipment for decay heat removal, there are no seismic vulnerabilities specific to decay heat removal. Three of the scenarios identified during the fire analysis involve loss of control or power to the AFW system, and therefore are relevant to the USI-A-45 resolution. In the case of switchgear room fire scenarios, the loss of power to the complete division is a conservative assumption. In the case of the control room fire scenario, the frequency has been assessed to be 1.25E-6 per year, and when compared with the overall CDF, is not a significant contributor.

The Eastern U.S. Seismicity Issue is resolved by the seismic part of the IPEEE. Since CP&L exercised the seismic margins option, the resolution was achieved by an appropriate choice of review level earthquake. GI-131 deals with the seismically induced failure of the flux mapping transfer cart that would lead directly to the rupture of instrumentation tubes at the seal table. Since this is applicable to Westinghouse plants, it is applicable to SHNPP. It has been addressed

in the IPEEE. USI-A-46 has subsumed USI-A-17, "Seismic Interactions in Nuclear Power Plants". Although SHNPP is not an A-46 plant, USI-A-17 was addressed through the seismic walkdown that was performed to meet the requirements of the IPEEE.

The FRSS issues, NUREG/CR-5088, were examined through comparison to standardized checklist questions and through specifically tailored plant walkdowns according to the FIVE Methodology. The FRSS issues are discussed in section 4.8. The issue of seismic-fire interactions has been addressed and is discussed in section 3.1.6.

The revised "Design Probable Maximum Precipitation (PMP)" criteria were assessed with the other external events as requested in Generic Letter 89-22, Supplement 4. The conclusions are presented in section 5.4.

IEN 93-53, Supplement 1 requested that the IPEEE address the lessons learned from the effects of Hurricane Andrew on the Turkey Point Nuclear Generating Station (NRC, 1993). This was addressed during the performance of a walkdown that was conducted to confirm the conclusions of the review of the plant design with respect to Other External Events, as discussed in section 5.

8.3 REFERENCES

(CP&L, 1993), Carolina Power and Light Co., "Shearon Harris Nuclear Power Plant, Unit No. 1, Individual Plant Examination Submittal", August 1993.

(NRC, 1975), USNRC, "Standard Review Plan for Review of Safety Analysis Report for Nuclear Power Plants", NUREG-75/187, December 1975.

(NRC, 1991), USNRC, Generic Letter 88-20, Supplement 4, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities—10 CFR 50.54(f)", April, 1991.

(NUMARC, 1991), NUMARC, "Severe Accident Issue Closure Guidelines", 91-044, 1991.

SEISMIC IPEEE
SHEARON HARRIS NUCLEAR POWER PLANT

March 1995
Revision 0

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0	3/95	Original Issue

1. INTRODUCTION AND METHODOLOGY SELECTION

In the Commission policy statement on severe accidents in nuclear power plants issued in 1985, the Commission concluded, based on available information, that existing plants pose no undue risk to the public health and safety and that there is no present basis for immediate action on any regulatory requirements for these plants. However, the Commission recognized that systematic examinations are beneficial in identifying plant-specific vulnerabilities to severe accidents that could be fixed with low-cost improvements. In 1988 the Commission requested that each licensee conduct an individual plant examination (IPE) for internally initiated events including internal flooding. Many PRAs indicated that, in some instances, the risk from external events could contribute significantly to core damage.

In July 1990, following public comments and a workshop, the Commission issued Supplement 4 to Generic Letter 88-20 (Reference 1) requesting that each licensee conduct an individual plant examination of external events (IPEEE). The general objectives of the IPEEE are similar to that of the IPE - that is, for each 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 fission product releases, and (4) if necessary, to reduce the overall likelihood of core damage and fission product releases by modifying, where appropriate, hardware and procedures that would help prevent or mitigate severe accidents.

The staff has concluded that five external events need to be included specifically in the IPEEE: seismic events, internal fires, high winds, floods, and transportation and nearby facility accidents. This report addresses seismic events.

Acceptable methodologies for performing the seismic IPEEE are summarized in NUREG-1407 (Reference 2). This evaluation may be conducted by performing a

seismic PRA or a Seismic Margins Assessment (SMA). The SMA methodology was designed to demonstrate sufficient margin over the Safe Shutdown Earthquake (SSE) to ensure plant safety and to find any "weak links" that might limit the plant shutdown capacity to safely withstand a seismic event larger than the SSE or lead to seismically induced core damage. The SMA may in turn be performed using the methodology developed by Lawrence Livermore National Laboratories (LLNL), or by Electric Power Research Institute (EPRI). CP&L has opted to perform a SMA using the EPRI methodology (Reference 3).

Harris was placed in the focused-scope category for margin assessment. The basic information used was the 1989 Lawrence Livermore National Laboratory seismic hazard estimates for nuclear power plant locations in the eastern United States (Reference 4) and the EPRI hazard study (Reference 6).

New seismic hazard data were published in October, 1993 that demonstrates that the seismic hazard at existing eastern United States nuclear power plants is much less than what the NRC staff originally believed (Reference 5). The data demonstrate a much lower annual probability of Harris exceeding the 0.15g design basis earthquake based on the 1993 LLNL mean hazard curves than the annual probability of exceeding the 0.3g review level earthquake (RLE) based on the revised hazard curves. Furthermore, the LLNL results confirm that the mean seismic hazard for Harris is lower than the 1989 seismic hazard estimates for the group of plants that were originally designated as reduced-scope.

CP&L elected to complete the Harris SMA following NUREG 1407 and EPRI NP-6041 as a focused-scope plant without schedule delays or major scope changes. The new information and extensive seismic evaluation performed for the recent vintage plant were, however, considered when determining the quantity of components selected for high-confidence-of-low-probability of failure (HCLPF) evaluation and the level of evaluation for issues such as soils, structures and NSSS components.

Detailed plant walkdowns are considered the most cost-effective and beneficial aspect of the SMA program. Harris walkdowns were performed by teams of CP&L and consultant Seismic Review Teams (SRTs) in accordance with EPRI NP-6041. Pre-walkdown activities included prescreening of success path components with available data entered into EHOST, a microcomputer database developed by EQE International. Walkdowns were performed using pen-based computers and the program EWALK. EQE proprietary software EWALK is compatible with EHOST to facilitate efficient data collection and subsequent data management.

These walkdowns identified several housekeeping, maintenance and systems interaction issues that lead to cost effective improvements as a result of the SMA program. Analyses to determine to high confidence of low probability of failure (HCLPF) capacity of selected success path elements confirmed that the plant HCLPF meets or exceeds the 0.3g Review Level Earthquake (RLE).

2. REVIEW OF PLANT INFORMATION

A brief description of the general plant, ground response spectra, structures, equipment, distribution systems is presented below. All the information presented in this section is contained in existing plant licensing documents including the Final Safety Analysis Report (FSAR). The purpose is to provide a review of the plant design.

2.1 GENERAL PLANT DESCRIPTION

The Nuclear Steam Supply System (NSSS) for the Unit is a pressurized water reactor (PWR) consisting of three closed reactor coolant loops connected in parallel to the reactor vessel, each containing a reactor coolant pump and a steam generator. An electrically heated pressurizer is connected to the "hot" leg of one of the loops. The NSSS, along with the design and fabrication of the initial fuel core, is supplied by Westinghouse Electric Corporation.

The Containment is a steel lined reinforced concrete structure in the form of a vertical right cylinder with a hemispherical dome and a flat base with a recess beneath the reactor vessel. The Containment is designed by Ebasco Services Incorporated, architect/engineer for Harris.

The Unit is designed for an initial licensed power output of 2785 megawatts thermal (Mwt), which includes 10 Mwt from the reactor coolant pumps. This output corresponds to approximately 900 megawatts electric (Mwe). The NSSS is capable of producing approximately 2910 Mwt (approximately 940 Mwe), which includes 10 Mwt from the reactor coolant pumps. Although the license application is for 2785 Mwt, all safety systems, including Containment and engineered safety features, are designed and evaluated for operation at the higher power level of 2910 Mwt.

2.1.1 Site Location and Area

The Harris site is located in the extreme southwest corner of Wake County, North Carolina, and the southeast corner of Chatham County, North Carolina. The city of Raleigh, North Carolina, is approximately 16 miles northeast, and the city of Sanford is about 15 miles southwest.

Maps of the site area are included as Figures 2-1 and 2-2. Indicated on these maps are the site boundary line (which is the same as the station property boundary), the principal plant structures, the exclusion area, and the principal transportation routes. The station requires approximately 10,800 acres. Carolina Power & Light Company owns all land within the site boundary lines. There are no private, residential, industrial, recreational, institutional, or commercial structures (other than those related to plant operation) within this area.

The environment is rural and primarily devoted to farming and dairying. Local industrial activity is centered in an area west-southwest from the plant. Another major center of industrial and research activity is located to the north-northwest.

2.1.2 Hydrology

The plant site is located at the confluence of Buckhorn and Whiteoak Creeks, just north of the Cape Fear River. The power block area is located between Tom Jack and Thomas Creeks. These two creeks are tributaries of Whiteoak Creek; Whiteoak Creek is a tributary of Buckhorn Creek. Figure 2-1 shows a plan of the site development.

The principal water source for the plant is the Main Reservoir which is formed by an impoundment of Buckhorn Creek just below its confluence with Whiteoak Creek. The project design also includes an adjoining and independent Auxiliary Reservoir for emergency cooling purposes. See FSAR Section 2.4 for a more detailed discussion of hydrology.

2.1.3 Geology and Seismology

The region surrounding the site is generally characterized by a gently rolling topography resulting from extensive weathering and erosion of the underlying bedrock. Elevations of the hill tops and ridge crests are mostly between 250 feet and 275 feet (msl) and local relief is generally less than 60 feet. The finished grade elevation is approximately 260 feet.

The site is located in the southeastern part of the Durham Basin, which is in the northern part of the Deep River Triassic Basin. Sediments that underlie much of the southeastern portion of the Durham Basin were placed as alluvial fans and stream channels and flood plain deposits. Below an occasional thin layer of alluvial sand and/or clay, there are from 0 to 15 ft. of residual soil. The depth of weathering below this to sound rock generally varies from about 0 to 15 ft. depending on the type of underlying rock. The foundations have been placed on sound rock.

A small fault was discovered during excavation for the Waste Processing Building. The studies performed showed that this fault is not a capable fault, as documented in the Shearon Harris Fault Investigation Report submitted to the NRC in 1975.

The nearest known fault outside the site is one lying just west of Merry Oaks about three miles to the southwest of the site. Test borings showed nothing that would indicate the development of faults, joints, slickensides or other structural weakness since the late Triassic and early Jurassic time.

Based on historical seismicity, the maximum potential earthquake which might affect the site would be a recurrence of the Charleston, South Carolina earthquake of 1886 which was probably felt as an intensity VI at the site. The largest earthquakes in the site region which are not attributable to any particular geologic structure or seismic zone have been of intensity V. However, it is considered possible that some intensity VII earthquakes in the eastern Piedmont and the Coastal Plain may have been related to exposed or buried Triassic Basins.

Therefore, a shock of intensity VII occurring in the Deep River Basin is considered to be the maximum potential earthquake.

The safe shutdown earthquake is designated as an intensity VII earthquake occurring close to the site. The resulting maximum horizontal ground acceleration at foundation level within the competent bedrock at the site is estimated to be less than 12 percent of gravity. In order to provide an additional margin of conservatism, a value of 15 percent of gravity is assigned as the maximum horizontal ground acceleration. All safety related structures and systems are designed to assure safe plant shutdown for two horizontal excitations and one vertical excitation simultaneously. Seismic Category I systems and components are designed for a minimum of 10 loading cycles under safe shutdown earthquake conditions.

The operating basis earthquake is designated as one with half the accelerations of the safe shutdown earthquake and equivalent to an Intensity VI earthquake near the site. The corresponding horizontal acceleration at foundation level in the bedrock would be less than 7.5 percent of gravity.

The site maximum horizontal ground accelerations for the Safe Shutdown Earthquake (SSE) and Operating Basis Earthquake (OBE) are 0.150g and 0.075g, respectively. See FSAR Section 2.5 for a more detailed discussion of geology and seismology.

2.2 GROUND RESPONSE SPECTRA

Two earthquake motions were considered in the dynamic analyses of all Seismic Category I structures, systems, subsystems, and equipment: the operating basis earthquake (OBE) and safe shutdown earthquake (SSE). The design value of the maximum horizontal ground acceleration is 0.150g for the safe shutdown earthquake and .075g for the operating basis earthquake.

The design response spectra used for all Seismic Category I structures, systems, and components, except dams and dikes, were developed in accordance with Regulatory Guide 1.60. The horizontal and vertical design response spectra, normalized to 0.150g for the SSE and 0.075g for the OBE, are presented on Figures 2-3 through 2-6 and were applied at the foundation level.

The design response spectra used for the Seismic Category I dams and dikes were based on a modified form of a smoothed response spectra developed from the strong motion record of the 1935 Helena, Montana earthquake, normalized to the maximum horizontal ground accelerations of the safe shutdown earthquake and the operating basis earthquake. This record was obtained from a seismograph that was established on competent bedrock and is, therefore, considered appropriate for the proposed plant site.

The horizontal design response spectra for the dams and dikes, normalized to 0.150g for the SSE and 0.075g for the OBE, are presented on Figures 2-7 and 2-8, respectively. The vertical design response spectra for the dams and dikes, normalized to 0.10g for the SSE and 0.05g for the OBE, are presented on Figures 2-9 and 2-10, respectively. The seismic analysis of the dams and dikes, based on the design response spectra presented on Figures 2-7 through 2-10, is discussed in the FSAR, Section 2.5.6. An evaluation of the behavior of the dams and dikes during an earthquake whose response spectra were developed using the Regulatory Guide 1.60 methodology, is also presented in Section 2.5.6 of the FSAR.

2.3 STRUCTURES

Seismic Category I structures are cast-in-place reinforced concrete structures. The floors are supported on beams and girders which are in turn supported on interior columns and/or exterior walls. Where interior shear walls are installed, the beams and girders are supported on the shear walls. All interior shielding walls and partitions, other than shear walls, are either reinforced concrete or concrete block,

and are not load bearing. The buildings are supported on separate foundation mats 10 feet thick which are founded on suitable rock.

The seismic analyses of the Seismic Category I structures were performed by using the normal mode time-history technique. The structures, considered as seismic systems and analyzed in this manner, are Containment, Reactor Auxiliary Building, Fuel Handling Building, Waste Processing Building, Tank Building, Diesel Generator Building, Diesel Fuel Oil Storage Building, ESWS Intake Structure, ESWS Discharge Structure and ESWS Screening Structure.

These structures are founded on sound rock which has a shear wave velocity of 5600 ft/sec. The lumped mass-spring approach was used to develop the mathematical model for the dynamic analyses of the structures. The mathematical model assumes a single cantilever or multi-cantilever lumped mass system. The lumped masses are connected by weightless elastic bars which represent the stiffness of structural walls and/or columns. Each mathematical model is supported by a mass which represents the foundation mat; the interaction of the foundation mat with the supporting rock medium is represented by linear elastic springs.

The lumped masses are located at floor levels and at any other points where the dynamic responses are important. The dead weights of the structural floor system, steel framing, grating, miscellaneous steel, equipment, piping, and electrical cables and trays (considered as a uniform load distributed over the floor) are included in the lumped mass at the corresponding level. The dead weights of columns and structural walls are evenly distributed between the levels over which they span. The dead weights of block walls are lumped at the levels at which they are supported.

Ebasco's in-house computer program DYNAMIC 2037 was used to generate floor response spectra. The damping values used were 4 percent for structures and 2 percent for rock for OBE and 7 percent and 5 percent, respectively for SSE. The floor response spectra calculations were based on the exact analytical solutions of

the governing differential equations for the successive linear segments of the excitation, specified at equal time intervals. The method is described in detail in Reference 35. The floor response spectra were generated separately for three directions of earthquake motion.

The peaks of the floor response spectra are broadened plus or minus fifteen percent in frequency according to the example shown on Figure 1 of Regulatory Guide 1.122. The broadening on the frequency axis is to account for variations in parameters, such as the material properties of the structures and soil, damping values, soil-structure interaction techniques and approximations in the modeling techniques.

The seismic analysis of all Seismic Category I structures takes into consideration three orthogonal directions of seismic motions; two horizontal and one vertical. The maximum responses to each of the three components of motion are determined separately and combined by the square root of the sum of the squares (SRSS) method to obtain the total seismic responses in accordance with Regulatory Guide 1.92.

The Seismic Category I structures listed above conform with the applicable requirements of the following codes, standards, regulatory guides and specifications listed below:

General Codes and Standards

OSHA - Occupational Safety and Health Administration, Federal Safety Regulations (1975 listing)

NCSBC - North Carolina State Building Code, 1969 Edition

ACI - American Concrete Institute Standards

211.1-1974 Recommended Practices for Selecting Proportions for Normal and Heavy Weight Concrete

301-1975 Specifications for Structural Concrete for Buildings

304-1973 Recommended Practice for Measuring, Mixing, Transporting, and Placing Concrete

305-1972 Recommended Practice for Hot Weather Concreting (Use this edition except Paragraph 4.4.3. Comply with ACI 305-1974 Paragraph 4.4.3 only)

306-1966 Recommended Practice for Cold Weather Concreting

309-1974 Recommended Practice for Consolidation of Concrete

315-1974 Manual of Standard Practice for Detailing Reinforced Concrete Structures

318-1971 Building Code Requirements for Reinforced Concrete

347-1968 Recommended Practice for Concrete Formwork

SP-2-1975 Manual of Concrete Inspection

AISC - American Institute of Steel Construction

Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings (AISC Specification) (2/12/69, with Supplements 1- 11/1/70, 2- 12/8/71, and 3- 6/12/74)

ASME - American Society of Mechanical Engineers

"Boiler and Pressure Vessel Code," 1975 Edition

Section II - Material Specifications

Section III, Division 1 - Nuclear Power Plant Components

Subsection ND "Class 3 Components"

Subsection NE "Class MC Components"

Section III, Division 2 - Code for Concrete Reactor Vessels and Containments (as required by ASME Section III, Division 2/ACI 359 Code, exceptions to the ASME Section III, Division 2/ACI 359-74 Code are listed in Appendix 3.8A of the FSAR

AWS - American Welding Society

D 1.1-75 Structural Welding Code, with Revisions 1 (1976) and 2 (1977) for services performed after 4/29/77

NRC Regulatory Guides

1.10 Mechanical (Cadweld) Splices in Reinforcing Bars of Category I Concrete Structures

1.15 Testing of Reinforcing Bars for Category I Concrete Structures

1.18 Structural Acceptance Test for Concrete Primary Containment

1.19 Nondestructive Examination of Primary Containment Liner Welds

1.54 Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

1.55 Concrete Placement in Category I Structures

1.57 Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components

1.60 Design Response Spectra for Seismic Design of Nuclear Power Plants

1.61 Damping Values for Seismic Design of Nuclear Power Plants

1.63 Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants

1.76 Design Basis Tornado for Nuclear Power Plants

1.92 Combination of Modes and Spatial Components in Seismic Response Analysis

1.94 Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel during the Construction Phase of Nuclear Power Plants

1.122 Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components

The following specifications specify the requirements for materials, design criteria, fabrication, erection, inspection, and quality assurance. These specifications, in general, reflect and expand on the requirements set forth in ASME Section III, Division 2/ACI 359 Code.

a) Ebasco Specification CAR-SH-AS-1 "Containment Liner, Air Locks, and Hatch"

b) Ebasco Specification CAR-SH-AS-7 "Structural Steel"

c) Ebasco Specification CAR-SH-M-54 "Mechanical Penetrations"

d) Ebasco Specification CAR-SH-E-30 "Electrical Penetrations"

e) Ebasco Specification CAR-SH-CH-6 "Concrete"

f) Ebasco Specification CAR-SH-CH-7A "Concrete Reinforcing Steel"

g) Ebasco Specification CAR-SH-CH-7 "Weldable Concrete Reinforcing Steel"

h) Ebasco Specification CAR-SH-CH-12 "Waterstops"

i) Ebasco Specification CAR-SH-CH-13 "Waterproofing"

j) Ebasco Specification CAR-SH-CH-15 "Mechanical Splicing of Concrete Reinforcing Steel"

k) Ebasco Specification CAR-SH-CH-16 "Dome Hub Plates and Reinforcing Steel Splice Assembly"

l) Ebasco Specification CAR-SH-CH-22 "Structural Integrity Test of Concrete Containment Building"

2.4 EQUIPMENT SUPPLIED BY THE NSSS VENDOR

Seismic qualification of safety related electrical equipment is demonstrated by either type testing, analysis or a combination of these methods. The choice of qualification method employed by Westinghouse for a particular item of equipment is based upon many factors including; practicability, complexity of equipment, economics, availability of previous seismic qualification to earlier standards, etc. The qualification method employed for a particular item of equipment is identified in the individual equipment qualification document.

The qualification and documentation procedures used for equipment and supports which were purchased prior to March 1, 1977, are in compliance with IEEE 344-1971 and Standard Review Plan 3.10 (Revision 1), Section II.1.a or the Supplemental Qualification Program, Reference NS-CE-692, Letter dated July 10, 1975 from C. Eicheldinger (Westinghouse) to D. B. Vassllo (NRC). The qualification and documentation procedures for equipment and supports purchased on or after March 1, 1977, are in compliance with IEEE 344-1975.

The methods and procedures for equipment qualified in compliance with IEEE 344-1971 and Standard Review Plan 3.10 (Revision 1), Section II.1.a is as follows:

A. Type Test - From 1969 to mid-1974 Westinghouse seismic test procedures employed single axis sine beat inputs in accordance with IEEE 344-1971 to seismically qualify equipment. Much of this early testing was reported in WCAP-7817 and WCAP-7821 as referenced in the FSAR, Table 3.10.1-1. The input form selected by Westinghouse was chosen following an investigation of building responses to seismic events as reported in WCAP-7558, "Seismic Vibration Testing With Sine Beats." Further, this input has been justified with respect to the methods of IEEE 344-1975 and documented in WCAP-8373 "Qualification of Westinghouse Seismic Testing Procedure for Electrical Equipment Tested Prior to May 1974." In addition, Westinghouse has conducted seismic retesting of certain items of equipment as part of the Supplemental Qualification Program. This retesting was performed at the request of the NRC staff on agreed selected items of equipment employing multi-frequency, multi-axis test inputs, Reference WCAP-8624 and WCAP-8373, to demonstrate the conservatism of the original sine-beat test method with respect to the modified methods of testing for complex equipment recommended by IEEE 344-1975.

B. Analysis - The structural integrity of safety related motors is demonstrated by a static seismic analysis in accordance with IEEE 344-1971, with justification. Should analysis fail to show the resonant frequency to be significantly greater than 33 Hz, a test is performed to establish the motor resonant frequency. Motor operability during a seismic event is demonstrated by calculating critical deflections, loads and stresses under various combinations of seismic, gravitational and operational loads. The worst case (maximum) values calculated are tabulated against the allowable values. On combining these stresses, the most unfavorable possibilities are considered in the following areas; 1) maximum rotor deflection, 2) maximum shaft stresses, 3) maximum bearing load and shaft slop at the bearings, 4) maximum stresses in the stator core welds, 5) maximum stresses in the

stator core to frame welds, 6) maximum stresses in the motor mounting bolts and, 7) maximum stresses in the motor feet.

The analytical models employed and the results of the analysis are described in the individual equipment qualification document.

The methods and procedures for equipment qualified in compliance with IEEE 344-1975 is as follows:

A. **Type Test** - The original single-axis sine beat testing and the additional retesting completed under the Supplemental Test Program have been the subject of generic review by the NRC staff. Both test programs are described later in this section. For equipment which has been previously qualified by the single axis sine beat method and included in the NRC seismic audit and, where required by the NRC staff, the Supplemental Qualification Program (Reference 3.10.2-2), no additional qualification testing is required to demonstrate acceptability to IEEE 344-1975, provided that:

1) The Westinghouse aging evaluation program for aging effects on complex electronic equipment located outside Containment demonstrates there are not deleterious aging phenomena. In the event that the aging evaluation program identifies materials that are marginal, either the materials will be replaced or the projected qualified life will be adjusted.

2) Any changes made to the equipment due to 1) above or due to design modifications do not significantly affect the seismic characteristics of the equipment.

3) The previously employed test inputs can be shown to be conservative with respect to applicable plant specific response spectra. The equipment that requires no additional testing is identified in WCAP-8587, Table 7.1 and the test results in the

applicable Equipment Qualification Data Packages (EQDP's) of Supplement 1 to WCAP-8587.

For equipment tests after July, 1974 (i.e., new designs, equipment not previously qualified, or previously qualified equipment that does not meet 1), 2), and 3), above, seismic qualification by test is performed in accordance with IEEE 344-1975. Where testing is utilized, multi-frequency multi-axis inputs are developed by the general procedures outlined in WCAP-8624 and WCAP-8695. The test results contained in the individual EQDP's of Supplement 1 to WCAP-8587 demonstrate that the measured test response spectrum envelopes the applicable required response spectrum (RRS) defined for generic testing as specified in Section 1 of the EQDP. Qualification for plant specific use is established by verification that the generic RRS specified by Westinghouse envelopes the applicable plant specific response spectrum. Alternative test methods, such as single frequency, single axis inputs, are used in selected cases as permitted by IEEE 344-1975 and Regulatory Guide 1.100.

B. Analysis - The structural integrity of safety related motors (Supplement 1 to WCAP-8587, Table 3.10.1-1 EQDP-AE-2 and 3) is demonstrated by a static seismic analysis in accordance with IEEE 344-1975, with justification. Should analysis fail to show the resonant frequency to be significantly greater than 33 Hz, a test is performed to establish the motor resonant frequency. Motor operability during a seismic event is demonstrated by calculating critical deflections, loads and stresses under various combinations of seismic, gravitational and operational loads. The worst case (maximum) values calculated are tabulated against the allowable values. On combining these stresses, the most unfavorable possibilities are considered in the following areas; 1) maximum rotor deflection, 2) maximum shaft stresses, 3) maximum bearing load and shaft slope at the bearings, 4) maximums tresses in the stator core welds, 5) maximum stresses in the

stator core to frame welds, 6) maximum stresses in the motor mounting bolts, and 7) maximum stresses in the motor feet.

The analytical models employed and the results of the analysis are described in Section 4 of the applicable EQDP's, Supplement 1 to WCAP-8587.

2.5 EQUIPMENT SUPPLIED BY OTHER THAN NSSS VENDOR

The safety related electrical (includes instrumentation and control) and mechanical equipment and their supports which are within Ebasco's scope, have been qualified by testing and/or analysis to Seismic Category I requirements to verify their ability to withstand the effects of earthquakes and other applicable accident-related loadings (i.e., dynamic loadings).

In addition, the qualification and documentation procedures for Seismic Category I electrical equipment and their supports have been prepared utilizing the guidance of IEEE 344-1975 and Regulatory Guide 1.100. Such equipment and supports which are Class 1E are qualified in accordance with IEEE 323. IEEE 344 is considered ancillary to IEEE 323 and any exceptions taken to age testing requirements have been evaluated and accepted with applicable justification for the exception.

The purchase specifications for safety related equipment contain seismic input data for the safe shutdown earthquake (SSE) and operating basis earthquake (OBE). This input data consist of floor response spectra (for the appropriate damping values) and/or appropriate "G" values for the various levels of the building (taking into consideration the location of the equipment on the floor) or other mounting locations such as pipes, ducts, etc. Each set of curves consists of two horizontal and one vertical design response spectra curves at the floor elevation of the equipment mounting location.

The equipment supplier's seismic qualification program demonstrates the ability of the equipment to perform its required function during and after the time it is subjected to the forces resulting from the application of five consecutive OBE's

followed by one SSE, with a proper combination of other applicable concurrent loads.

Depending upon the practicability of the method for the type, size, shape, and complexity of the equipment and the reliability of the conclusion, the equipment supplier uses testing, analysis, or a combination of testing and analysis as a method of qualification, as follows:

A. **Testing** - Testing has been the preferred method of qualification. It is performed by subjecting the equipment to vibratory motions, which conservatively simulate the OBE and SSE responses at the equipment mounting locations. The SSE test is preceded by five events of the OBE. The test input motions are such that the resulting response spectra envelope the design floor response spectra.

   Thermal and radiation aging is performed prior to seismic testing for equipment qualified in accordance with IEEE 323-1974 unless it could be justified that the equipment would not approach the end-of-life condition during the installed life, when subjected to the specified service conditions.

   Instrumentation and electrical equipment are tested in the operational mode and their operability is verified before, during, and after the testing. Test methods described in Section 6.6, "Test Methods," of IEEE 344-1975 are utilized to perform the required qualification testing. The test input motion has generally been of the random type.

B. **Analysis** - Analysis without testing is accepted when the equipment functional operability can be assured by its structural integrity alone. The procedures described in Sections 5.2 through 5.4 of IEEE 344-1975 are utilized. Component fatigue is checked for the effect of five OBE's and one SSE when the analysis method of qualification is used.

C. **Combination of Testing and Analysis** - When the equipment cannot be qualified by testing or analysis alone because of its size and complexity, a combined testing and analysis method is utilized. Methods described in Section 7 of IEEE 344-1975 are used for qualification.

2.6 PIPING

The stress analysis of Seismic Category I, ASME, Section III, Safety Class 2 and 3 piping is in accordance with ASME B & PV Code, Section III, subarticles NC/ND, and is described below. The design criteria is in accordance with formulations given in subarticle NC/ND-3600.

The seismic analytical procedure using the computer methods, described in Section 3.7.3.8.1.1 of the FSAR, involves an analysis of the piping systems using characteristic spring rates of various rigid constraints and snubbers. Restraint loads based on this analysis were used to design particular controls (i.e., rigid restraints or snubbers). The final design analysis is based on characteristic spring rates.

Equipment having frequencies 33 Hz or higher was assumed rigid for the purpose of analyzing the connected piping. Where the frequency search of equipment indicated a frequency less than 33 Hz, the equipment was considered nonrigid. In such a case, a dynamic model of the equipment having the same response in two orthogonal horizontal directions and the vertical direction was prepared. This dynamic model of the equipment was included in the stress analysis of the piping.

Welded attachments were avoided to the degree practicable. However, where integral attachments could not be avoided, local stress generated in the pipe due to their presence were considered.

Design criteria was based on formulations and allowable stress limits given in ASME Section III, subarticle NC/ND-3600, with load combinations which consider OBE and SSE effects along with other coincident loading conditions as delineated in design specifications.

For the seismic design of piping, the two orthogonal horizontal and vertical loadings were obtained from the floor response spectra that were generated for the appropriate structures and elevations. Relative displacements within buildings and between buildings due to seismic response were also considered in the design of the piping.

An alternative method for broadening of the structure peaks can be based on a probabilistic approach. In the particular case where there is more than one piping frequency located within the frequency range of a widened spectrum peak that is associated with a structural frequency, the floor spectrum curve may be more realistically applied in accordance with the following criterion. Based on the fact that the actual natural frequency of the structure can possibly assume only one single value within the frequency range defined by $fj \pm \Delta fj$, but not a range of values, only one of these piping modes can respond with a magnitude indicated by the peak spectral value.

Therefore seismic analysis of piping systems using the broadened floor design response spectra may be accomplished by applying the method of peak shifting as described in the Summer 1984 Addendum of ASME Section III, Appendix N, paragraph N-1226.3(d).

All Seismic Category I, Safety Class 2 and 3 piping systems were seismically analyzed utilizing the methods described in the FSAR, Sections 3.7.3.8.1.1 or 3.7.3.8.1.2. Piping 2-1/2 in. nominal size or larger with design temperature above 275° F, were analyzed by the computer method described in Section 3.7.3.8.1.1. All other piping subsystems were analyzed by either the computer method described in Section 3.7.3.8.1.1 or by the simplified method described in Section 3.7.3.8.1.2.

2.7 BURIED PIPING

Ebasco's design procedure for seismic analysis of Seismic Category I buried piping was based upon Newmark's method, Reference 36 and Hetenyi's theory in beams

on elastic foundations, Reference 37. The analysis procedure included calculation of stresses in the buried portion of the piping due to loads acting on the non-buried portion of the piping inside the building (interaction effect), superimposed on the stresses due to various loads acting on the buried portion of the piping. The resultant stresses were within allowable stress criteria based on the applicable ASME Section III Code.

The buried piping in the yard was analyzed using the above procedure. It was assumed that the piping would be distorted in the same fashion as the earth and, therefore, would assume a sinusoidal wave shape. The wave length and maximum displacement were calculated and the bending moment and stress effects on the piping were obtained. Settlement in the fill along the piping due to differential depth of backfill did not cause any significant stresses in the piping and the resultant stresses were still within allowable stress limits.

At points where piping leaves the ground and is attached to structures, the maximum possible differential movement between the ground and the structure was determined. The differential movement was absorbed either by providing sufficient flexibility in the piping from the ground to the structure or by the use of flexible joints in the piping such as ball joints.

In certain instances, piping which enters structures is supported or anchored within the structure and not at the wall penetration. Wall penetrations were sized to provide sufficient room for differential pipe movement. Flexible membranes provided a moisture seal between the pipe and the structure wall.

The excavated area under the 30 in. diameter and 8 in. diameter service water pipe lines between the Tank Building and Turbine Building walls and the rock or natural ground was backfilled with concrete which will have insignificant differential settlement.

Seismic Category I electrical conduits in the yard were also analyzed by Newmark's method. The electrical conduits and electrical manholes were both buried in fill or

backfill. Both of them would move with the fill with no local differential settlement to cause shear in the conduit. Moreover, the ends of conduits are not anchored in the wall of manholes and pass through sleeves with elastic boots which permit free movement of the conduits in any direction. Settlement in the fill or backfill along the conduit due to differential depth of fill did not cause any significant stresses in the conduit and the resultant stresses were well within the allowable stress limits.

The sleeves at the electrical manhole will permit rotation of the conduit end due to differential settlement of the manhole and the adjacent soils, if any.

The fill in the yard area supporting Seismic Category I piping and conduits is not subject to liquefaction during a seismic event.

2.8 DISTRIBUTION SYSTEMS

Seismic Category I cable trays, conduits, HVAC duct systems and equipment supports were analyzed by the method of modal response spectra. This accounted for the effects of multiple spans and multiple modes on seismic response.

A three dimensional mathematical model was constructed with a sufficient number of dynamic degrees of freedom to closely simulate the dynamic behavior of the subsystems. All of the significant modes of the subsystems were selected for the determination of the seismic response. When the supports for a subsystem were all mounted at the same floor, the relative displacement among supports was not considered. This relative displacement was considered where the supports of the same subsystem were located at different floors.

For the case where the supports of the same subsystem were located in different buildings, the maximum relative displacements among the different supports were considered in the seismic dynamic analysis of the subsystem.

2.9 SEISMIC SPATIAL SYSTEM INTERACTIONS

The following sections describe the minimum clearance requirements between components and the Seismic II/I criteria for Harris.

2.9.1. Interdiscipline Clearances

Various structure systems and components for Harris have been designed with consideration for minimum clearance requirements to prevent detrimental effects to safety related components due to seismic interactions with non-seismically designed components. Nuclear Engineering Department (NED) Design Guide Number DG-II.17, Reference 30 was written to address minimum clearance requirements. This design guide describes the walkdown that took place at the end of construction to identify any clearance violations that may have occurred during installation due to physical constraints.

The design guide provides Tables with minimum clearances between components, eg. 1" diameter conduit to 1" diameter conduit requires 1.187" clearance, 2" diameter pipe to a 2" diameter conduit requires 1.653" clearance, 2" diameter pipe to tube track requires 0.396" clearance, top of cable tray to duct requires 0.528" clearance and etc. Any violations noted during the walkdown were documented and resolved in accordance with the design guide.

The design guide is a current document and is used for continuing compliance to the clearance requirements.

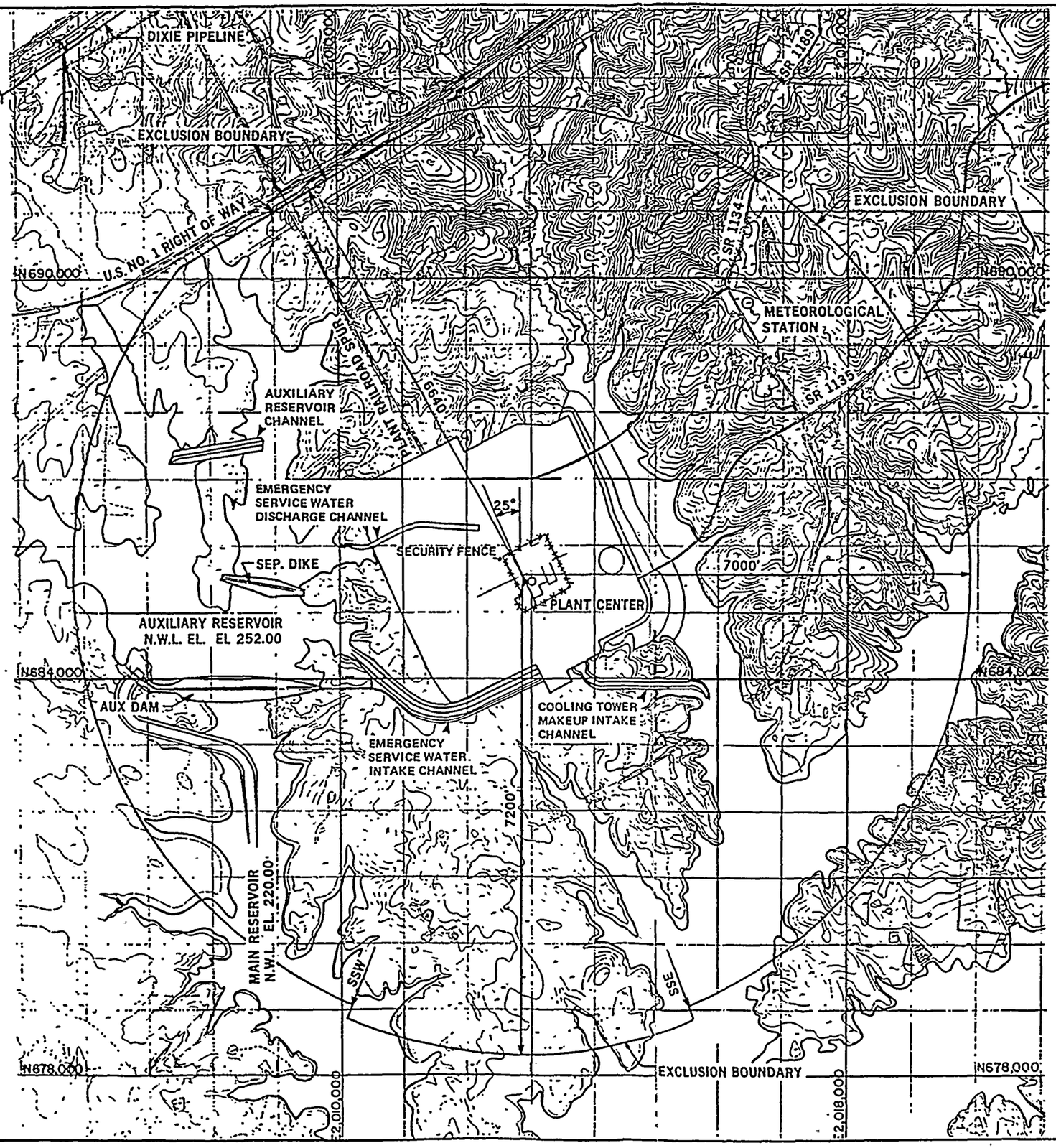
2.9.2 Seismic II/I Criteria

Various structures, systems and components for Harris have been designed in accordance with Regulatory Guide 1.29 to ensure that all safety related components remain functional following the postulated failure of non-seismically designed components. The provisions of this Regulatory Guide have been fully considered in the original design and in design changes. During the design process,

interdiscipline drawings were reviewed to identify interaction between safety related and non-safety related components. These include system piping drawings, HVAC duct layout drawings, conduit and cable tray drawings general arrangements and civil/structural design drawings. Close coordination between design disciplines was maintained to assure that interpretation of the design drawings was accurate and that all spatial considerations were incorporated in the design. During field design and modification work, any potential seismic interactions that were identified were reviewed and dispositioned by design engineering.

Nuclear Engineering Department (NED) Design Guide Number DG-II.19, Reference 31 was written to address seismic II/I criteria. This design guide describes the walkdown that took place at the end of construction. The intent of the walkdown was to confirm that existing design and quality controls required by Regulatory Guide 1.29, Sections C.2 and C.4 were implemented correctly during erection of both design and field-located components. These walkdowns were systematically performed in accordance with established zone areas. All cases identified during the walkdown were documented and resolved in accordance with the design guide.

The design guide is a current document and is used for continuing compliance to Regulatory Guide 1.29.



AREA = 3535 ACRES

ANSTEC APERTURE CARD

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1000 0 1000 2000 3000

SCALE IN FEET

AMENDMENT NO. 15

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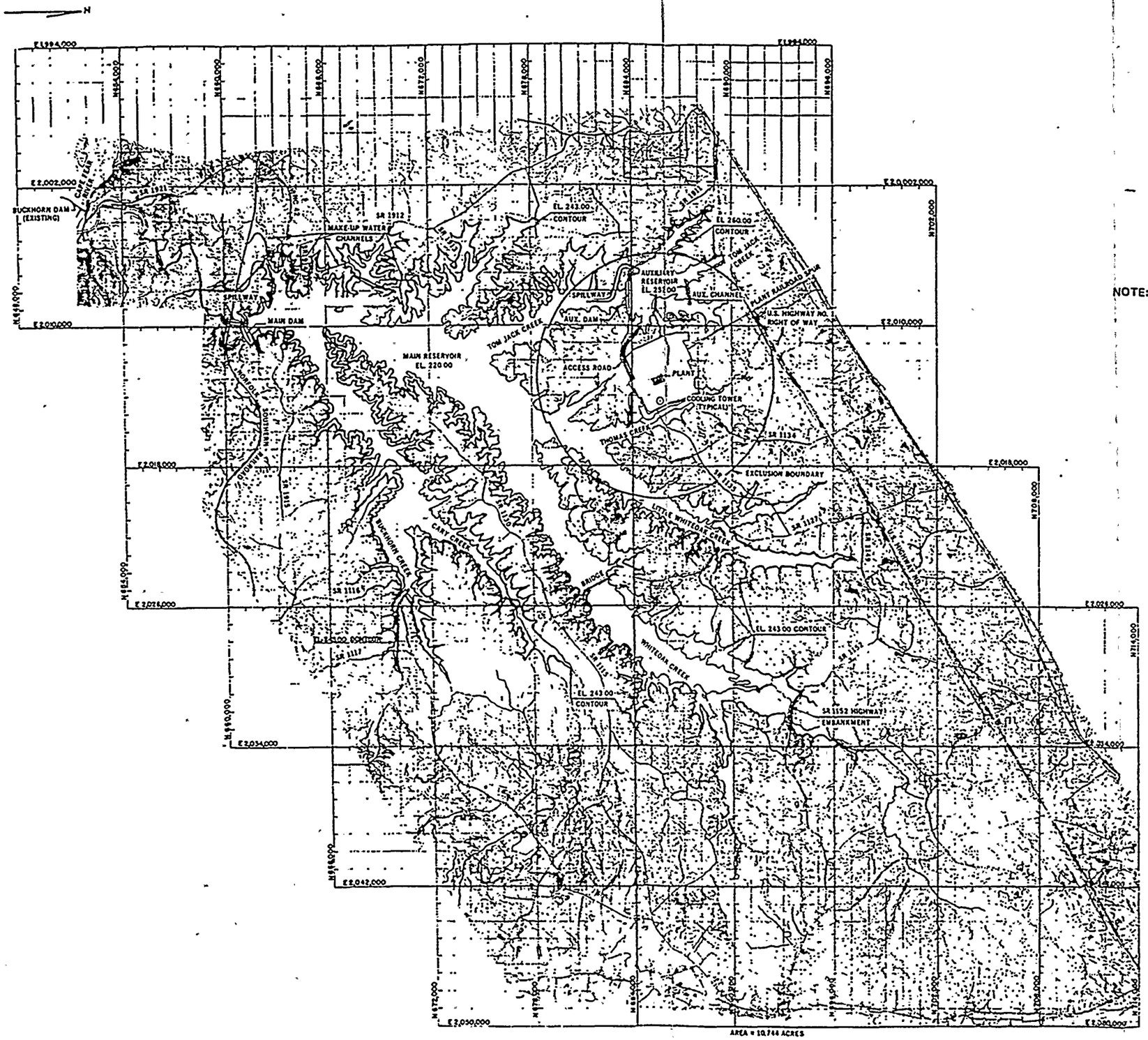
SHNPP EXCLUSION BOUNDARY PLAN

Figure 2-1:



NOTE: SITE BOUNDARY IS ENCLOSED BY THE EXCLUSION BOUNDARY, THE EL 243 CONTOUR OF THE MAIN RESERVOIR, AND THE EL 260 CONTOUR OF THE AUXILIARY RESERVOIR.

9507060080-02

SCALE IN FEET

AMENDMENT NO. 21

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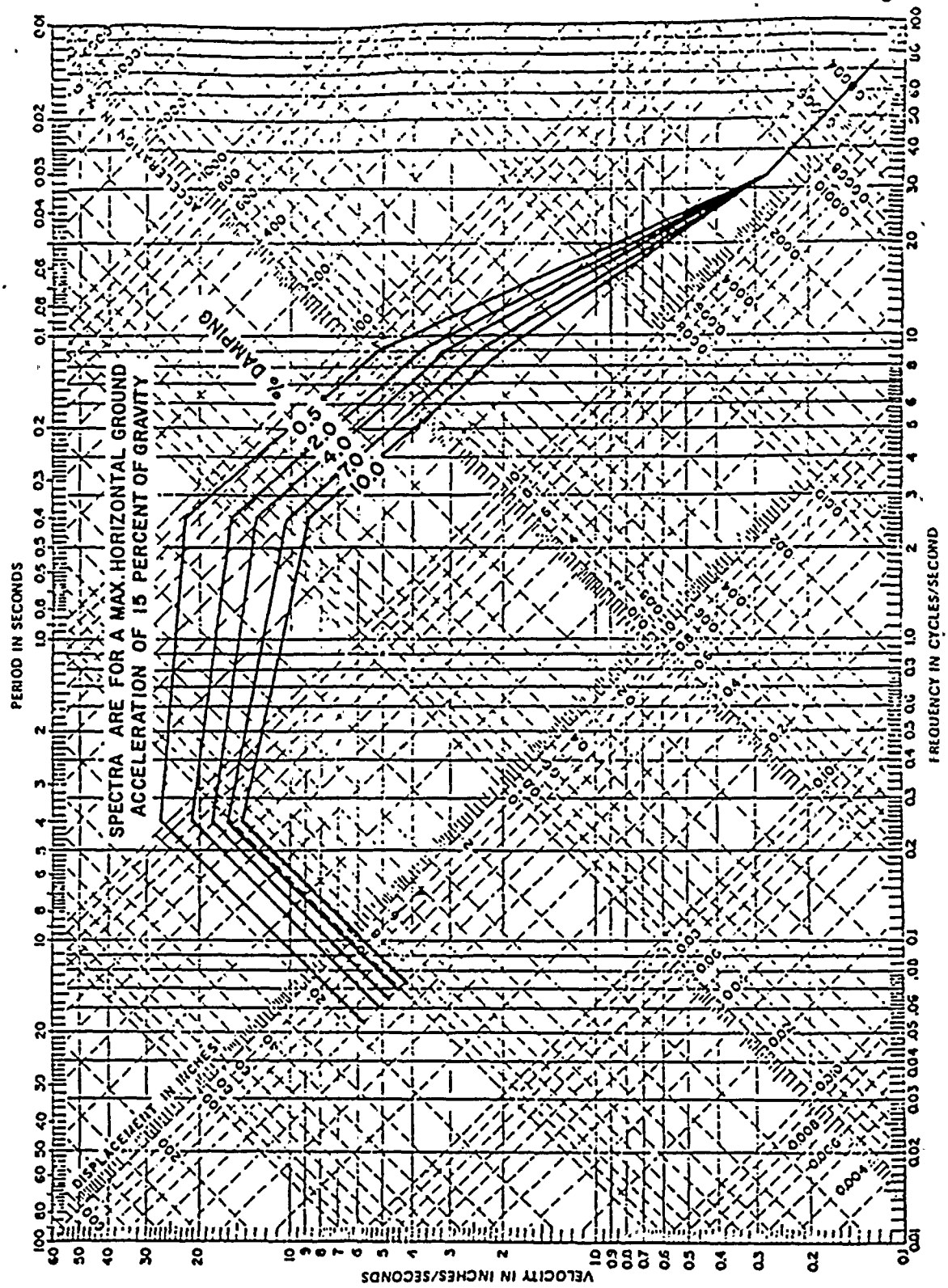
MAP OF SITE EXCLUSION BOUNDARY AND SITE BOUNDARY

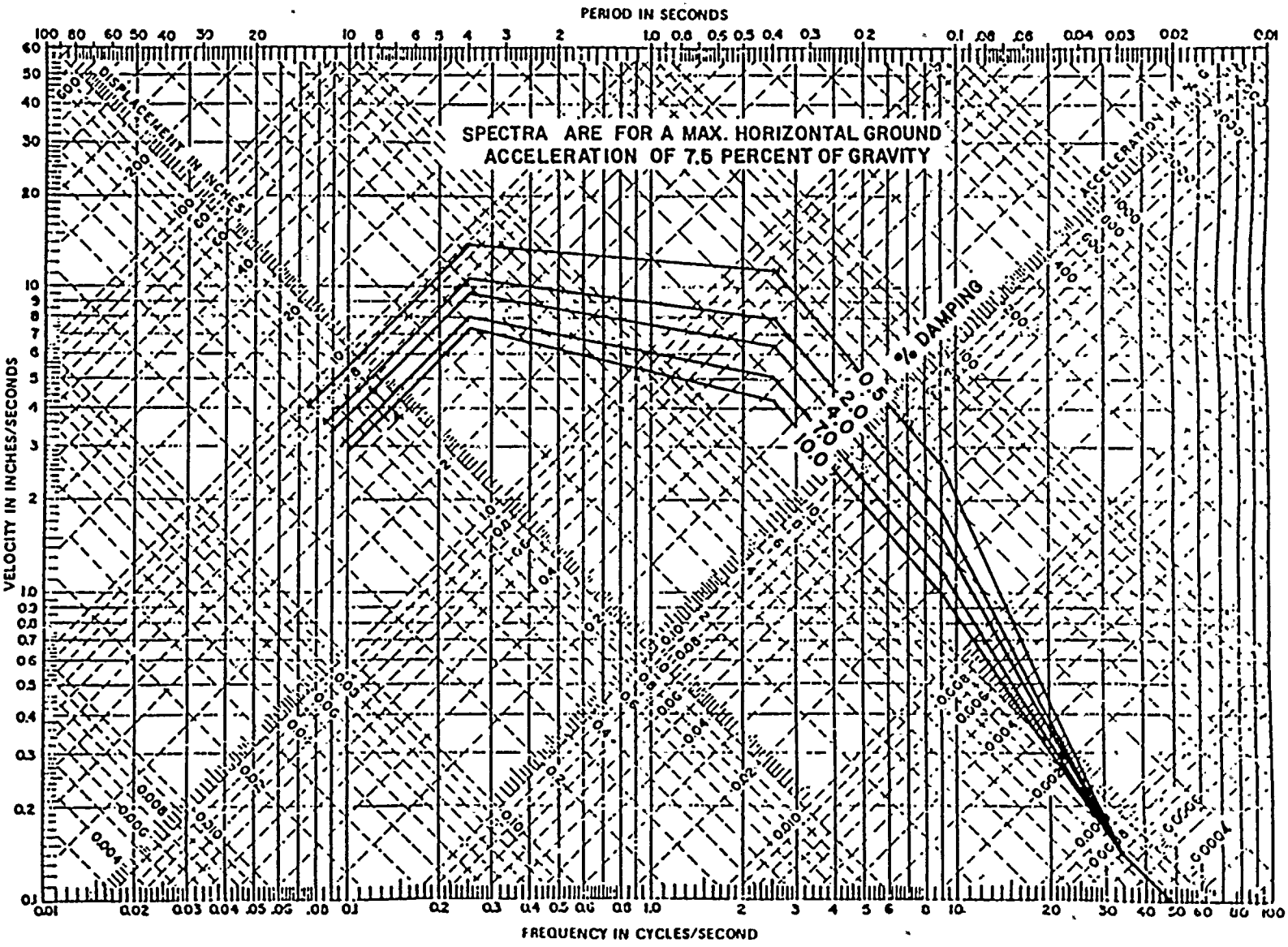
Figure 2-2:



HORIZONTAL RESPONSE SPECTRA

DESIGN BASIS EARTHQUAKE

SHEARON HARRIS NUCLEAR POWER PLANT Carolina Power & Light Company FINAL SAFETY ANALYSIS REPORT	HORIZONTAL DESIGN RESPONSE SPECTRA SAFE SHUTDOWN EARTHQUAKE	FIGURE 2-3:



HORIZONTAL RESPONSE SPECTRA
OPERATING BASIS EARTHQUAKE

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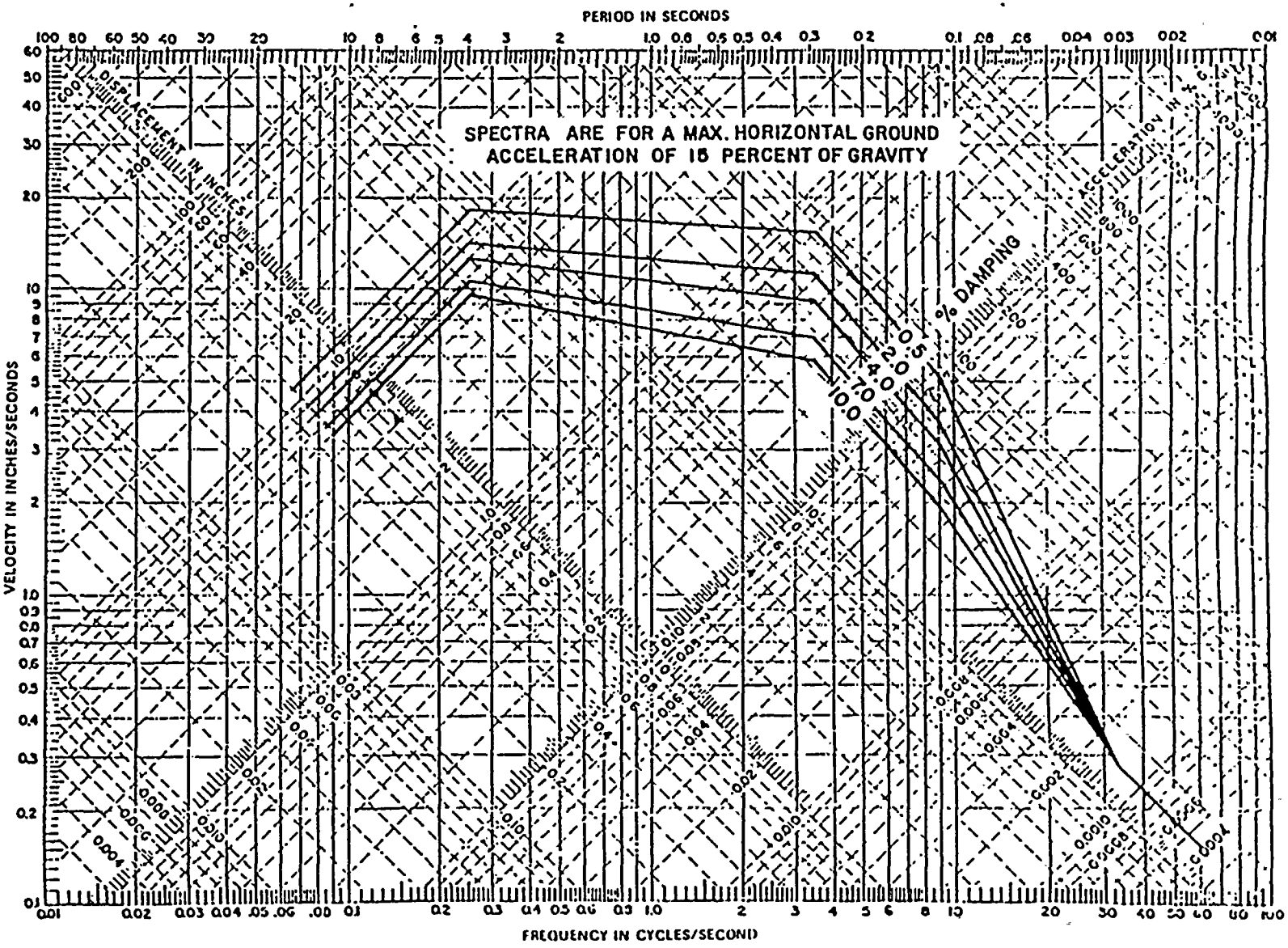
HORIZONTAL DESIGN RESPONSE SPECTRA
OPERATING BASIS EARTHQUAKE

FIGURE
2-4:



VERTICLE RESPONSE SPECTRA
DESIGN BASIS EARTHQUAKE

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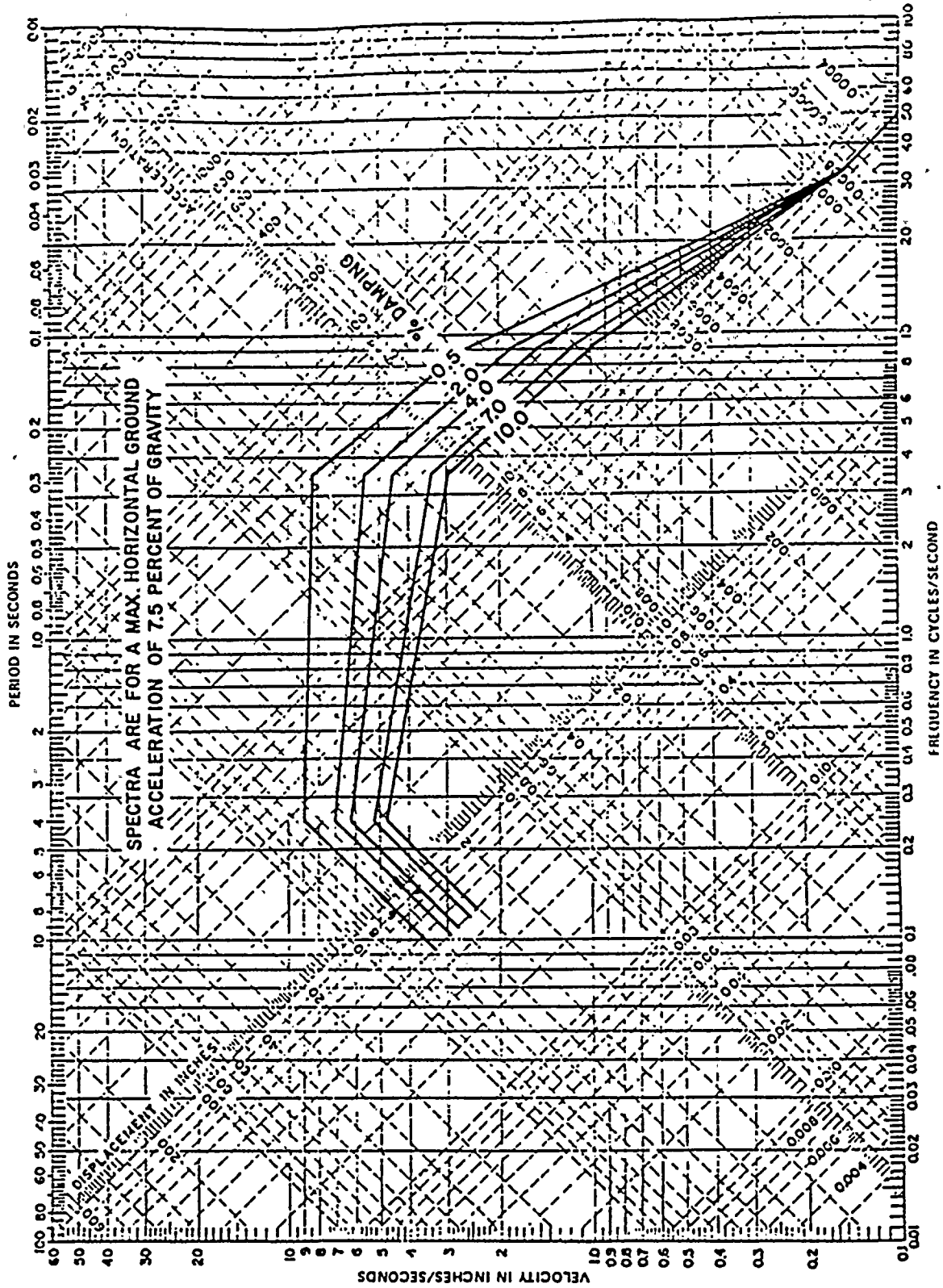
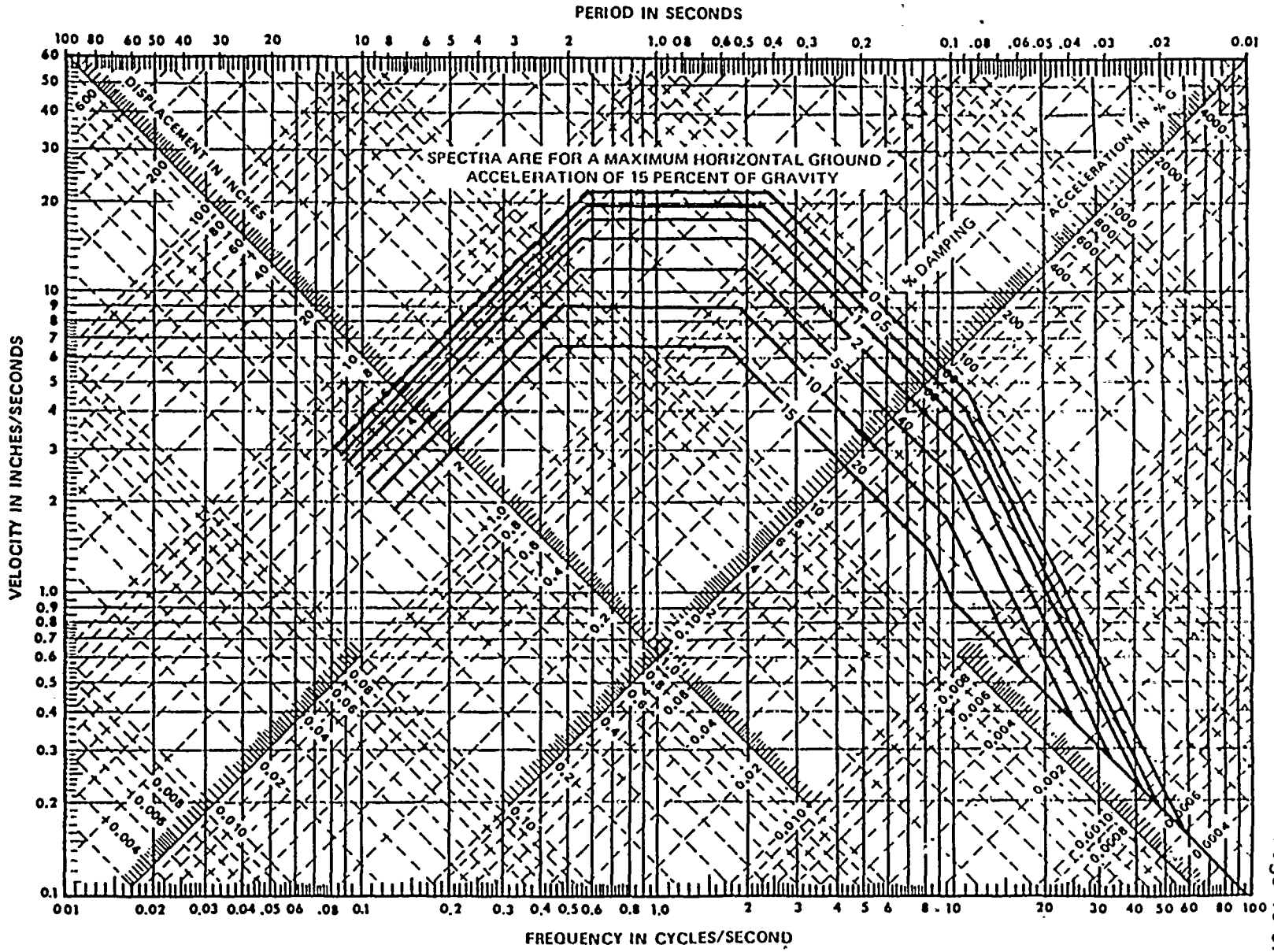
VERTICAL DESIGN RESPONSE SPECTRA
SAFE SHUTDOWN EARTHQUAKE

FIGURE
2-5:



VERTICLE RESPONSE SPECTRA
OPERATING BASIS EARTHQUAKE

SHEARON HARRIS NUCLEAR POWER PLANT Carolina Power & Light Company FINAL SAFETY ANALYSIS REPORT	VERTICAL DESIGN RESPONSE SPECTRA OPERATING BASIS EARTHQUAKE	FIGURE 2-6:



RESPONSE SPECTRA

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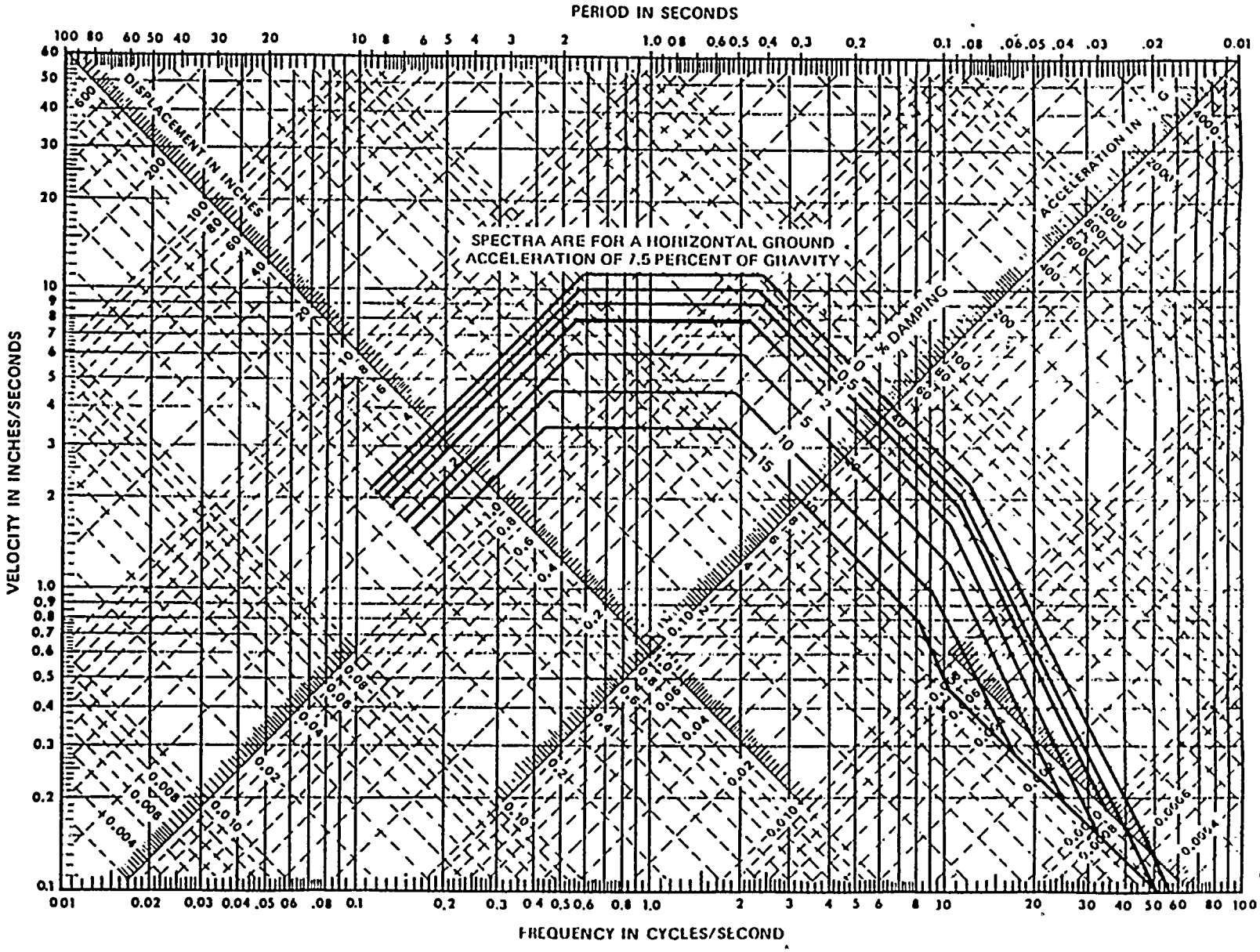
HORIZONTAL DESIGN RESPONSE SPECTRA
SAFE SHUTDOWN EARTHQUAKE
DAMS AND DIKES

FIGURE
2-7:



RESPONSE SPECTRA

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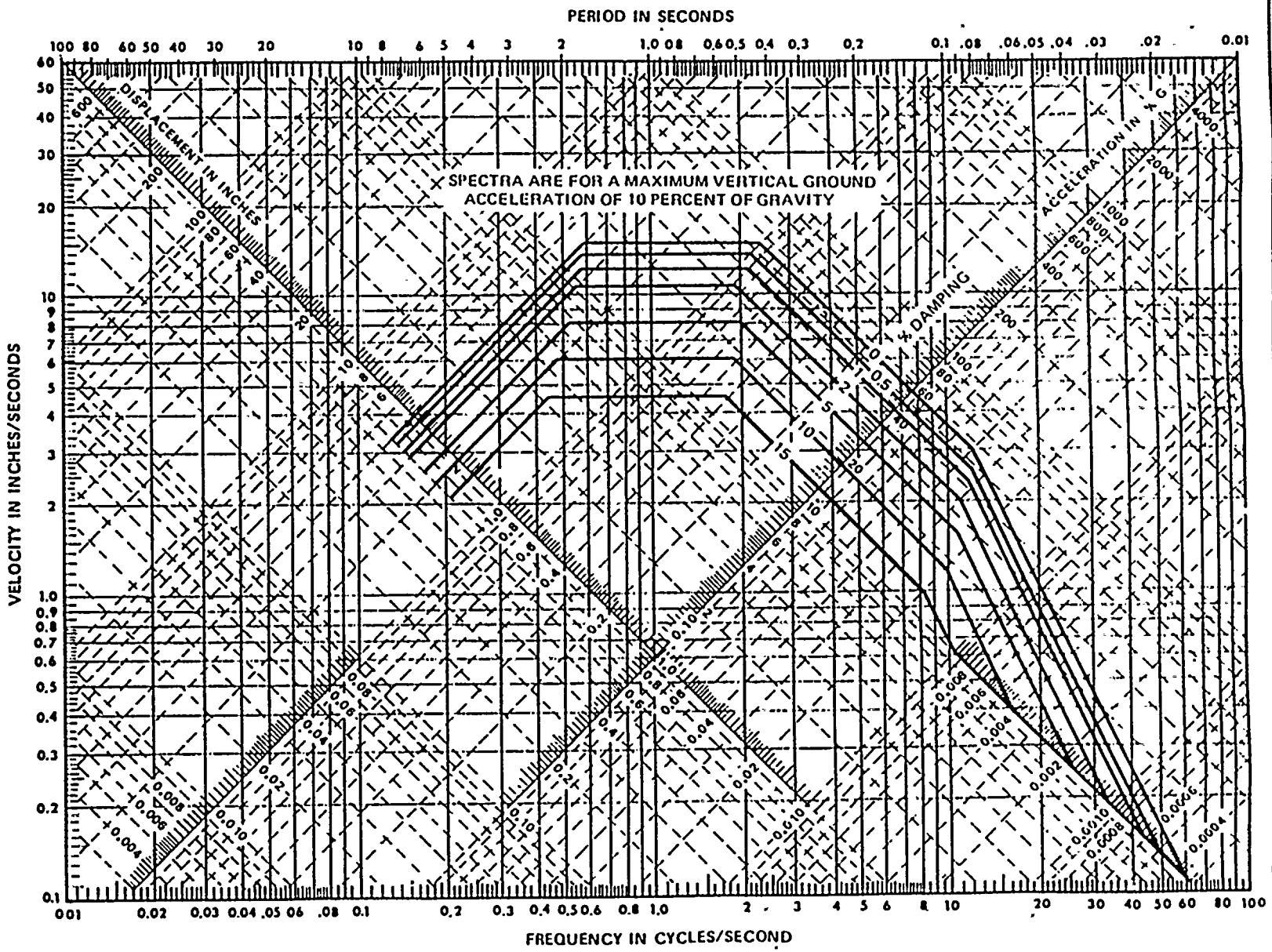
HORIZONTAL DESIGN RESPONSE SPECTRA
OPERATING BASIS EARTHQUAKE
DAMS AND DIKES

FIGURE
2-8: -



RESPONSE SPECTRA

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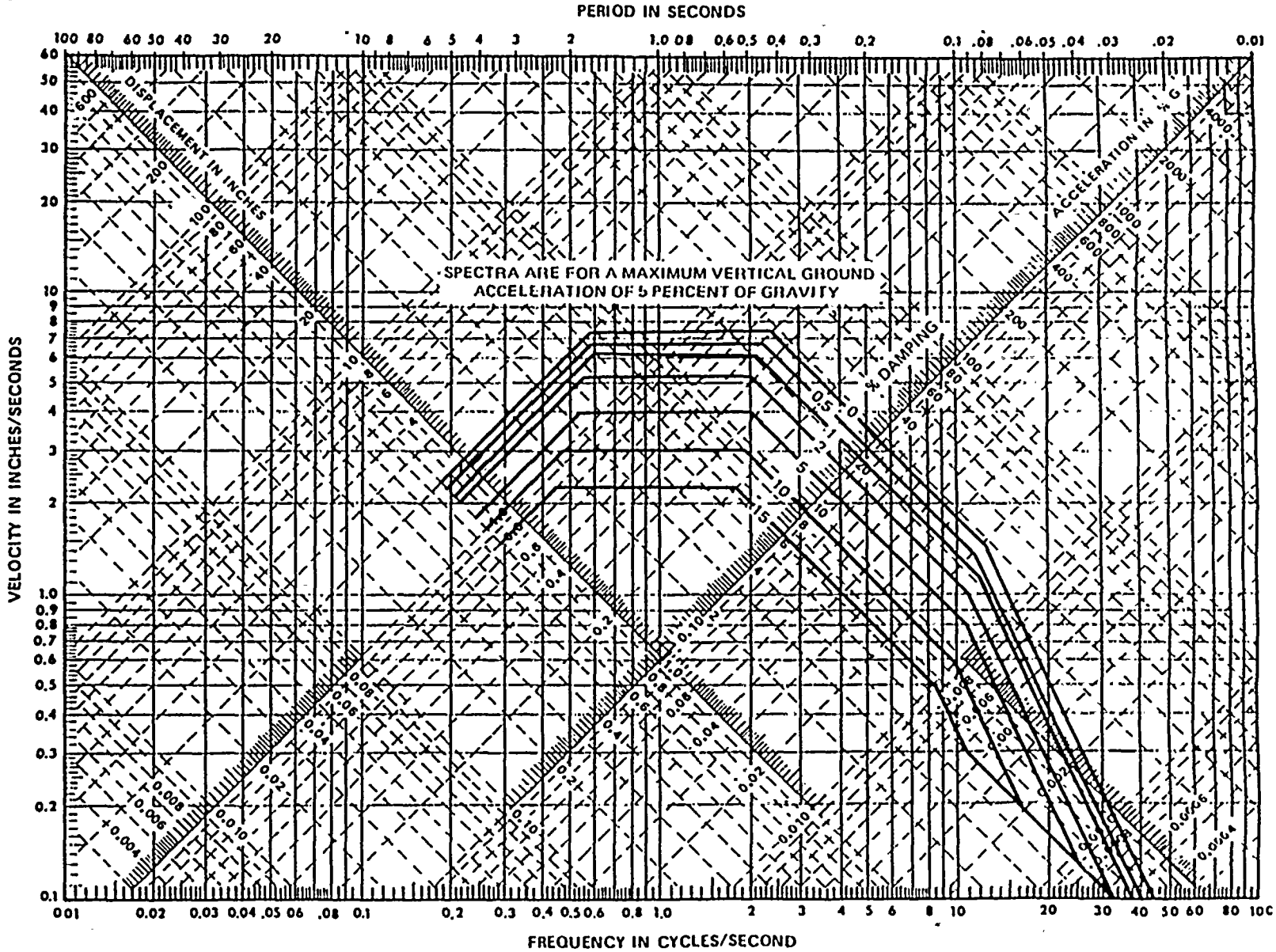
VERTICAL DESIGN RESPONSE SPECTRA
SAFE SHUTDOWN EARTHQUAKE
DAMS AND DIKES

FIGURE
2-9:



RESPONSE SPECTRA

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VERTICAL DESIGN RESPONSE SPECTRA
OPERATING BASIS EARTHQUAKE
DAMS AND DIKES

FIGURE
2-10:

3. SYSTEM DESCRIPTION AND SUCCESS PATH SELECTION

This task involves the identification of components and structures for in-plant review. A preliminary walkthrough was performed by Safety and Reliability Optimization Services, Inc. (SAROS), CP&L, and EQE personnel to search for potential low seismic capacity components. Reference 3 was utilized in choosing the items and identifying boundary conditions and assumptions.

The functions involved in the plant response to the RLE are reactivity control, reactor coolant system inventory control, reactor coolant system pressure control, and decay heat removal. In addition, the following were identified as support systems for ensuring critical plant functions:

- Safety and some Non-Safety Related AC Power
- Safety Related DC Power
- HVAC for Charging and Safety Injection Pumps, Diesel Generators, and Control Room
- Emergency Service Water
- Chilled Water System

The structures housing the components included in the above systems are:

- Reactor Auxiliary Building (including main steam tunnel)
- Containment Building
- Emergency Service Water Intake Structure
- Diesel Generator Building
- Tank Building

The resulting success path logic diagram (SPLD) evolved from studying available plant equipment function as well as the plant's normal and emergency operating

procedures. Two or more success paths are required for each of the four major system functions. The SPLD considers two conditions, one being a 1 inch loss of coolant accident (LOCA) and the other being a transient without Reactor Coolant System (RCS) leakage.

The SPLD was reviewed and agreed upon by Harris operations personnel. Equipment selected for inclusion on the (SSEL) was evaluated in a manner similar to that described in the SQUG Generic Implementation Procedure (GIP), Reference 7. Guidance from EPRI NP-6041 (Reference 3) was also used in preparing the format for the list of components. The SSEL (Reference 38) used for the IPEEE walkdown is presented in Appendix B.

4. SEISMIC MARGIN EARTHQUAKE DEMAND

The Harris plant is a relatively modern plant with all Seismic Category I structures, except for Seismic Category I Electrical Manholes, Seismic Category I Underground Electrical Conduits, and some Seismic Category I piping, founded on sound rock (shear velocity of 5600 fps). A shallow layer of soil varying from 15′ to 25′ feet in depth, with average shear wave velocity of roughly 610 fps exists over the rock base. Using the simple relationship,

$f_{soil} = V_s/4H$ where:

f_{soil} = fundamental soil column frequency

V_s = Shear wave velocity of soil column

H = Height of soil column

the fundamental frequency of the soil column is estimated to be in the 6 - 10 Hz range. The Design Basis Earthquake (DBE) for Harris is the Regulatory Guide 1.60 (Reference 8) spectra anchored to 0.15g. In the design analysis, this motion was introduced at the foundation level of the structure and is therefore directly transmitted into the building basemat. For other structures founded above the rock, a SHAKE analysis was performed to propagate the rock motion through the soil column. The design analysis also used soil springs to represent soil-structure interaction effects. However, these springs actually represent stiff rock and should not result in any inertial interaction effects. A uniform damping of 7% was assumed for the rock/structure system.

For the seismic IPEEE program, the Review Level Earthquake (RLE) is defined as the NUREG/CR-0098 median amplification response spectrum anchored to 0.30g. NUREG/1407 made the general statement that the ground motion should be considered at the surface in the freefield. It also states that if secondary conditions such as shallow soil conditions are considered, appropriate procedures should be used to determine the freefield motion in the vicinity of those affected structures and components. To follow the NUREG/1407 recommendation, a CR-0098 median

soil spectrum geared to 0.30g need to be defined on the soil surface, and a deconvolution study performed to determine the motion on the rock interface at foundation level. Such a deconvolution analysis would show the motion at depth on top of the rock to be deamplified in the 6 - 10 Hz range, when compared to the ground surface motion. Therefore, for structures such as the RAB-Common, RAB-Unit 1, and Containment with structural frequencies within this range, some relief may be obtained. The DGB with fundamental structural frequency of 12.4 Hz falls outside of the deamplified range, and hence is not expected to derive much benefit from deconvolution. The deconvolution effect is difficult to quantify without performing the actual analysis. Hence, it was decided to conservatively ignore deconvolution by specifying the NUREG/CR-0098 median rock spectrum at foundation level. This approach is in line with the original design basis in which the DBE was also applied at foundation level. Given that Reference 3 considers the CR-0098 median spectrum and the Regulatory Guide 1.60 ground response spectrum to be similar in shape, scaling of the design basis floor spectra to the RLE is readily accomplished. Scale factors were conservatively determined in Calculation 5224-C-001 (Reference 9) based on the methodology described in detail in Reference 3. The values indicate both the scaled peak and zero period acceleration (ZPA) in-structure acceleration values for the appropriate elevation in the Reactor Auxiliary Building, Containment Building and Diesel Generator Building. It should be noted that in the scaling process, the available design basis floor response spectra with either N-411 or 4% damping, were treated as 5% damped spectra, thereby introducing some added conservatisms. Scale factors range from 1.60 to 1.67 for the North-South direction, 1.56 to 1.67 for the East-West direction, and 1.11 to 1.33 for the vertical direction. An exception is the diesel generator pedestal, Node 5, which is rigid. The diesel generator scale factors are 2.00 for horizontal, and 1.33 for vertical.

Calculation 52214-C-001 (Reference 9) is provided in Appendix A, "In-Structure Response Spectra".

5. SEISMIC MARGIN ASSESSMENT SCREENING AND WALKDOWN

Section 2 summarizes activities that were performed in preparation of the Seismic Review Team (SRT) walkdowns. The activities include selection of the SRT, systems description and success path selection, development of seismic margin earthquake demand, walkdown preparation and pre-screening, and establishment of screening criteria.

5.1 SEISMIC REVIEW TEAM

The SRT was assembled following guidance provided in Reference 3, drawing on the experience and expertise of EQE International, Inc. (EQE) and Carolina Power & Light Company (CP&L) personnel.

Each walkdown team included a minimum of two SRT members who had completed the Seismic Qualification Utility Group (SQUG) Walkdown Screening and Seismic Evaluation training course, as well as EPRI's add-on training for IPEEE. Joint walkdown teams generally consisted of at least one EQE Engineer and at least one CP&L Engineer. The following persons participated in the SRT walkdowns:

- Jeffrey H. Bond (CP&L)
- Steven R. Bostian (CP&L)
- Martha C. Cook (CP&L)
- Daryl W. Hughes (CP&L)
- Ronald L. Knott (CP&L)
- Robert N. Panella (CP&L)
- Kevin N. Poythress (CP&L)
- Ronald W. Cushing (EQE)
- Gregory S. Hardy (EQE)
- Timothy Mason (EQE)
- Thomas R. Roche (EQE)

Among all the team members there is strong experience in each of the areas listed below:

- Knowledge of the failure modes and performance of structures, tanks, piping, process and control equipment, and active electrical and mechanical components 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.

- Knowledge of the plant system functions and normal and emergency operating procedures.

The qualifications of each of the CP&L and EQE seismic walkdown team members are presented in Appendix A.

5.2 WALKDOWN PREPARATION AND PRE-SCREENING

The purpose of pre-screening was to ensure efficiency in the walkdowns and evaluations with a goal of completing the maximum amount of data entry in advance of the walkdown. This was accomplished by incorporating existing data onto the seismic IPEEE documentation forms prior to the walkdowns. Data that was reviewed consisted of the Final Safety Analysis Report (FSAR), design criteria, stress reports, equipment qualification reports (testing and analysis), structures and equipment support drawings, equipment location drawings, anchorage calculations. and records from other related programs previously performed at Harris. An initial

walkdown was performed by CP&L and EQE personnel as part of the pre-screening task to review the SSEL and to group items according to the "Rule of the Box."

Pre-screening was performed with three purposes in mind:

- To identify critical failure modes to be specifically reviewed on the walkdown.
- Assemble qualification and installation data for use as a basis for screening in the margins review.
- To provide data to be utilized in HCLPF calculations.

A considerable amount of information was extracted from the existing documentation and was subsequently recorded on the Screening and Evaluation Work Sheets (SEWS) prior to commencing the detailed walkdowns. Information entered into SEWS during prescreening was intended to provide available data to the SRT to assist in equipment screening. An example of data is comparison of MCC Test Response Spectrum (TRS) Zero Period Acceleration (ZPA) to the RLE ZPA based on equipment qualification summary data. The information is not intended as the sole basis for screening, but assists the SRT in their review.

Pre-screening was enhanced by the use of the software program EHOST. EHOST is a data base program which has been adapted specifically for use in performing Unresolved Safety Issue (USI) A-46 and IPEEE evaluations. The program is set up so that the data is incorporated onto SEWS forms which are consistent with those recommended in EPRI NP-6041. In this manner the walkdown teams, using portable computers with the companion program EWALK were then able to work more efficiently by having access to SEWS that had already been partially completed.

5.3 SCREENING CRITERIA

The Harris seismic IPEEE was completed following the EPRI seismic margins methodology recommended by NUREG-1407 (Reference 2) for a focused scope plant.

Civil structures, equipment and subsystems were screened following the methodology provided in EPRI NP-6041 (Reference 3) for a focused-scope plant. Screening criteria are provided in Tables 2-3 and 2-4 of Reference 3 for civil structures and equipment and subsystems, respectively. The criteria corresponding to 5 percent-damped peak spectral acceleration less than 0.8g were used for Harris based on the RLE. The guidelines are supplemented by Appendix A of the EPRI seismic margins methodology which provides the basis for the seismic capacity screening guidelines. Walkdown data sheets provided by EPRI NP-6041 (Reference 3) were used during the SRT walkdowns.

SEWS were loaded into EQE's computer program EWALK for field screening and data collection using portable pen-based computers. Prescreening information was downloaded from the database program EHOST. The effectiveness of in-plant reviews was improved by access to SEWS forms enhanced with plant specific data. This also allowed the walkdown teams to be alerted to specific concerns that may have been identified during pre-screening.

The SRT had liberal access to plant design drawings, analyses and test reports to use in conjunction with the screening criteria. Much of this information was reviewed and summarized in the SEWS prior to the field walkdowns. This provided the SRT with information such as:

- Seismic coefficients used in motor operated valve weak-link analyses to verify that the intent of valve mass and eccentricity guidelines were satisfied.

- Valve yoke material from vendor drawings to rule out cast iron material.

- Test report for battery chargers used to verify capacity of the base channels.

- Anchorage calculation for CCW heat exchanger indicated that the closely spaced cast-in-place anchors were considered as a single group (shear cone) and not as individual anchors.

- Test report for 6.9 KV switchgear used to verify margin between TRS and SSE level and then compared to RLE level.

- Chiller qualified by using finite element analysis, and separate qualification by test for control panel was reviewed during pre-screening.

- Anchorage data from design drawings were reviewed for anchor bolt type and embedment for various components.

5.4 SEISMIC MARGIN WALKDOWN RESULTS

The Harris seismic margin walkdown was completed during the winter and spring of 1994 in two phases, balance of plant (BOP) and outage walkdowns.

BOP walkdowns were completed in January 1994 prior to refueling outage RFO-5 in order to capture elements that could be reviewed during plant operation. Outage walkdowns were performed in March during RFO-5, capturing items located inside of containment as well as electrical and control equipment that needed to be de-energized for access or was critical to plant operation.

Completed SEWS are included in Reference 32 with copies of photographs included in Reference 33.

The procedure for performing walkdowns is described in the Harris Project Plan, Reference 10. Some equipment was found to be inaccessible during the walkdowns for various reasons, such as high radiation, sealed confined spaces, etc. The following equipment was inaccessible during the walkdown: regenerative heat exchanger 1X-SN; motor operated valves 1SI-300 and 1SI-301; and temperature elements 1TE-410, 1TE-420 and 1TE-430. In these cases, thorough drawing reviews were performed as well as reviews of equipment known to be similar in design and configuration. In addition, photographs of the regenerative heat exchanger were available for review from the radiation control group. These inaccessible equipment were screened out based on these reviews.

The walkdown concentrated on the strength and load path of the equipment to the structure as well as function and integrity. The review of equipment anchorage was a prime objective for the walkdown teams. The anchorage evaluation addressed both physical attributes of the anchorage installation and the capacity relative to other success path items as well as the postulated demand at the RLE. Anchorage capacities were addressed in the pre-screening, as most of the components already had been evaluated for seismic capacities. The anchorage calculation for the Transfer Panels was the only calculation that was not found during the reviews/walkdown. The Transfer Panels were included as a component for HCLPF evaluation based on the anchorage configuration and the fact that the calculation was not reviewed. The walkdown teams also verified that the anchorage was generally in accordance with the design configuration. The anchorage of the components was screened based on the high capacity anchorage and the SRT walkdown.

Interaction reviews were performed to identify falling, impact, spray and flood issues that could affect success path items. Housekeeping issues were also identified, e.g. compressed gas cylinder not sufficiently secured, fuel board not restrained, storage cabinets that were unrestrained, etc. Thirteen items were identified that had minor interaction, housekeeping or maintenance issues. No spray or flood issues were noted during the SRT walkdown.

Tools, test equipment and other maintenance items used during the outage were not noted as housekeeping issues during the outage walkdown. Housekeeping walkdowns were conducted subsequent to the outage to verify that non-plant equipment is in compliance with the Harris housekeeping procedures, Reference 27 and 28. These procedures were revised to enhance the storage and restraint provisions for non-plant equipment.

Suspended systems, such as conduit, cable trays and ductwork were evaluated on a sampling basis in the plant. A general survey was performed to obtain an overview of the suspended system construction throughout the plant. This included a review of the variety of system layouts, support configurations, and construction details. The inspection also included known concerns for suspended systems, such as taut cables, sharp edges, or overloading of cable trays and supports, and potential anchor point displacements. The ceiling above the control room was also reviewed to verify if the light fixtures and ceiling grid were adequately supported, and to evaluate the potential for ceiling panels to fall.

Containment penetrations were reviewed on an area basis to identify anomalies that might affect containment performance. Concerns such as falling and differential building displacement were considered. Also reviewed were displacement concerns between the containment shell and internal structure. Containment isolation valves were also reviewed on a walk-by basis based on the caveats listed on the valve SEWS.

Seismic margin walkdown results are summarized for structures and equipment and subsystems in Tables 5-1 and 5-2, respectively.

Table 5-1 lists civil structures following the format of EPRI NP-6041, Table 2-3, along with screening results for the Harris plant. All Harris civil structures were screened from further review based on EPRI NP-6041, Table 2-3, screening criteria and Section 3.8 of the Harris FSAR.

Table 5-2 lists equipment and subsystems following the format of EPRI NP-6041, Table 2-4, along with screening results for the Harris plant. Equipment and subsystems that were not screened were grouped into 5 categories:

- Thirteen items had minor interaction, housekeeping or maintenance issues that will be resolved through routine maintenance activities via work requests (WR/JO). These items are listed in Table 5-3 along with the corresponding work request number. Work was completed by December 31, 1994 with the exception with WR/JO 95ACLTL which will be completed by the end of RFO-7.

- Six items were identified as requiring repairs or modifications. These items are listed in Table 5-4 along with the description of the repair or modification required for the item. This work is scheduled to be completed by the end of RFO-7.

- One potential interaction issue was identified due to relative building displacement. This issue is addressed in Section 9.

- Two components were identified due to interaction issues with HVAC ducts. These items are addressed in Section 5.8.2.

- Several other items were identified as candidates for HCLPF evaluation.

At the conclusion of plant walkdowns SRT members, including senior level participants from CP&L and EQE, convened to complete the ranking and screening task. SRT members reviewed SEWS and categorized components into the following resolution categories:

- Screened out by the SRT
- Housekeeping or maintenance issue

- Repairs or modification required
- Specific issues require clarification
- Candidate for HCLPF evaluation

Next, SRT members re-walked items not screened out and re-visited existing design and qualification documentation. SRT members that performed the initial walkdowns presented and discussed issues with remaining SRT members. Categorization was refined by group consensus.

The first pass through SSEL items categorized about 45 items representing about 15 specific issues for HCLPF evaluation. Following these group walkdowns and follow-up discussion, 16 items were selected for HCLPF evaluation to address 5 issues. Several of the unscreened components were unique issues such as no top supports on RHR Heat Exchangers while others, such as low voltage switchgear located relatively high in the structure, were selected to represent a group of equipment. These 5 issues are considered to represent the most vulnerable issues observed by the SRT. Other items may have comparable seismic capacity but are considered representative of the selected items.

- Sixteen components were selected for HCLPF evaluation (See Table 5-5). The 16 components were further grouped into five issues:

  Group 1: Six Panels Having Anchorage with 45° Nelson Studs

  Group 2: Four Low Voltage Switchgear

  Group 3: Two Residual Heat Removal (RHR) Heat Exchangers

  Group 4: Two Flat Bottom Storage Tanks

  Group 5: Two Emergency Service Water Pumps

  HCLPF evaluations are summarized in Section 6.

The following sections summarize the review of each major equipment class.

5.4.1 Motor Control Centers

The SSEL contains sixteen motor control centers (MCC's) that are located in the Diesel Generator Building (DGB), Reactor Auxiliary Building (RAB) and the Emergency Service Water Intake Structure (ESWIS) at various elevations. The MCC's are typical Gould Inc. 5600 series, 480 volts, consisting of 20" wide by 20" deep by 90" high sections. Each section weighs approximately 500 lbs. The MCC has a solid load path down to the shipping channels. The anchorage consists of the MCC being bolted to shipping channels and the shipping channels are welded to embedded channels. The MCC's are screened by SRT based on the walkdown, anchorage calculations and the seismic testing performed on the MCC.

Three MCC's were noted to have missing latches on the breaker panel doors. Work requests have been issued to replace the latches, see Table 5-3. Refer to the individual MCC SEWS for specific screening and walkdown results.

5.4.2 Low Voltage Switchgear

The SSEL contains four low voltage switchgear. The switchgear are located in the RAB at elevation 286'. The switchgear are Gould Inc. indoor single ended substation, 480V, type LK, with a 2000kVA transformer. The switchgear were evaluated to be of good seismic design. The switchgear are constructed of structural steel framing and sheet metal panels with an integral structural steel base which provides adequate stiffness and a good load path. The anchorage of the switchgear uses a variation of structural shapes, embedded plates and expansion anchors. No interaction issues or maintenance issues were noted during the walkdown regarding the switchgear. The transformer was noted as not having any top bracing. The low voltage switchgear were selected for HCLPF evaluation based on the anchorage design margin and the transformer anomalies during the seismic testing (without top bracing), see section 6. Refer to the individual SEWS for specific screening and walkdown results.

5.4.3 Medium Voltage Switchgear

The SSEL contains two medium voltage switchgear. The switchgear are located in the RAB (Unit 1) at elevation 286'. The switchgear are Seimens-Allis Inc. 6.9kVA, model FB 500 consisting of thirteen cubicles. Each cubicle is 36" wide by 94" deep by 90" high and weighs approximately 3200 lbs. The switchgear were evaluated to be of good seismic design. The switchgear are mounted on three sill channels. The sill channels are welded to a plate. The plate is anchored via 5/8 inch diameter cast-in-place J-bolt anchors. The anchors are spaced on 36" centers. Each switchgear cubicle has six plug welds, two to each sill channel. No interaction issues or maintenance issues were noted during the walkdown regarding the medium voltage switchgear. The medium voltage switchgear are screened by SRT based on the walkdown, anchorage calculations and the seismic testing performed on the switchgear. Refer to the individual SEWS for specific screening and walkdown results.

5.4.4 Transformers

The SSEL contains eight transformers. Four transformers are mounted in MCC's and the other four transformers are mounted in the low voltage switchgear. These MCC's and switchgear are located in the RAB at elevation 286'. The transformers have been treated as rule-of-box in which the transformers are evaluated as part of the MCC or switchgear.

5.4.5 Horizontal Pumps

The SSEL contains eighteen horizontal pumps. The pumps are located in the RAB (Unit 1) at elevation 236' with the exception of two fuel oil transfer pumps, two chill water pumps and three relief valve oil pumps (rule-of-box). The fuel oil transfer pumps are located in the Fuel Oil Building at elevation 246' and the chill water pumps are located in the RAB (Unit 1) at elevation 261'. The pumps have been evaluated to be of good seismic design. No interaction issues or maintenance

issues were noted during the walkdown regarding the pumps. The horizontal pumps are screened based on the walkdown, anchorage calculations and the review of the seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.6 Vertical Pumps

The SSEL contains four vertical pumps. Two of the pumps are RHR motor driven pumps located in the RAB (Unit 1) at elevation 190' and the other two pumps are the ESW suction pumps located in the ESWIS at elevation 261'. The RHR pumps have been evaluated to be of good seismic design. No interaction issues or maintenance issues were noted during the walkdown regarding the RHR pumps. The RHR pumps are screened based on the walkdown, anchorage calculations and the review of the seismic qualification documentation. Refer to the SEWS for specific screening and walkdown results.

The ESW suction pumps were selected for HCLPF evaluation, see section 6. No interaction issues or maintenance issues were noted during the walkdown regarding the ESW suction pumps. Refer to the SEWS for specific screening and walkdown results.

5.4.7 Pneumatic Operated Valves

The SSEL contains twenty-three pneumatic operated valves including one safety relief valve. These valves are located in the RAB and Containment Building (CB) at various elevations. These valves have been evaluated to be of good seismic design. No cast iron components were noted for these valves during pre-screening and the walkdown. The operator height and weight were evaluated/judged to meet the intent of the caveat. No interaction or maintenance issues were noted during the walkdown. The pneumatic operated valves are screened based on the walkdown and the review of the seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.8 Motor Operated Valves

The SSEL contains fifty-seven motor operated valves. These valves are located in the RAB and CB and Main Steam Tunnel at various elevations. These valves have been evaluated to be of good seismic design. No cast iron components were noted for these valves during pre-screening and the walkdown. The operator height and weight were evaluated/judged to meet the intent of the caveat. No interaction or maintenance issues were noted during the walkdown except for valve 1AF-55, see Table 5.3. The motor operated valves are screened based on the walkdown and the review of the seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.9 Fans

The SSEL contains four fans. The fans are associated with the emergency diesel exhaust system and are located in the DGB. The fans are Joy Manufacturing Company, model S-1000, 54-26½-1170. The weight of the fans is approximately 2161 lbs. The fans are mounted horizontally in-line to structural steel supports with six 1/2" diameter, SAE grade 2 bolts. There are no vibration isolators. No interaction or maintenance issues were noted during the walkdown. The fans are screened by SRT based on the walkdown and the seismic analysis of the fans. Refer to the individual SEWS for specific screening and walkdown results.

5.4.10 Air Handling Units

The SSEL contains four air handling units (AHU's). The AHU's are located in the RAB (Unit 1) with two units at elevation 236' and two units at 305'. The AHU's are associated with cooling the charging/safety injection pump rooms, electrical cabinet rooms and the control room. The AHU's are manufactured by Bahnson. The units at elevation 236' weigh 6,000 lbs and the units at elevation 305' weigh 8200 lbs. The base of the AHU's is constructed of C8 x 13.75 structural steel. The bases are secured to the structure with a minimum of sixteen 5/8 inch

diameter cast-in place anchors. There are no vibration isolators. No interaction or maintenance issues were noted during the walkdown. The AHU's are screened by SRT based on the walkdown. Refer to the individual SEWS for specific screening and walkdown results.

5.4.11 Chillers

The SSEL contains two chillers. The chillers are located in the RAB (Unit 1) at elevation 261'. The chillers provided chilled water to the AHU's. The chillers are manufactured by York (division of Borg Warner Corp.), model OTS4G1-IMBS, 752 tons per unit. The weight of the entire assembly is approximately 60,000 lbs. The fundamental frequency of the unit is greater than 33 Hertz based on the seismic analysis. Each chiller is anchored with (28) 1-3/4 inch diameter A307 cast-in place anchors of length 2'-5". There are no vibration isolators. No interaction or maintenance issues were noted during the walkdown. The chillers are screened by SRT based on the walkdown, anchorage calculations and the seismic analysis. Refer to the individual SEWS for specific screening and walkdown results.

5.4.12 Air Compressors

The SSEL contains four air compressors. The compressors are located in the DGB at elevation 261'. The compressors are associated with the air start system of the emergency diesel generator. The compressors are manufactured by Ingersoll-Rand, model H251BKMX2, Type 40. The weight of the entire assembly is approximately at 2860 lbs. The base of the assembly is constructed of structural steel channels. The base is anchored with six 3/4 inch diameter by 33" long cast-in place anchors . There are no vibration isolators. No interaction or maintenance issues were noted during the walkdown. The air compressors are screened by SRT based on the walkdown. Refer to the individual SEWS for specific screening and walkdown results.

5.4.13 Motor Generators

The SSEL does not contain any motor generators.

5.4.14 Distribution Panels

The SSEL contains fourteen distribution panels. Six of the distribution panels are an integral part of MCC's. The MCC's are located in the RAB at elevation 286'. These distribution panels have been included as rule-of-box components and are evaluated with the associated MCC.

Four of the distribution panels are located in the RAB at elevation 305'. The equipment tag numbers are IDP-1A-SI, IDP-1A-SIII, IDP-1B-SII and IDP-1A-SIV. These distribution panels are manufactured by Gould Inc., and are constructed in a similar manner to the Gould 5600 series MCC. The anchorage is the same as an MCC being bolted to shipping channels and the shipping channels are welded to embedded channels. These distribution panels are screened by SRT based on the walkdown and the seismic testing performed on MCC's with the exception of the maintenance issues listed in Table 5.3. Refer to the individual SEWS for specific screening and walkdown results.

The remaining four distribution panels are located in the DGB at elevation 261' and the RAB at elevation 286'. The distribution panels are manufactured by Gould Inc. The weight of the distribution panels are estimated at 800 lbs (DGB distribution panels) and 1550 lbs (RAB distribution panels). The base of the DGB distribution panels are welded to channels that are welded to embedded plates. No interaction or maintenance issues were noted during the walkdown. The DGB distribution panels are screened by SRT based on the walkdown and seismic testing of the distribution panels. The two distribution panels in the RAB, 1A-SA and 1B-SB were selected for HCLPF evaluation due to the embedded channel with nelson studs at 45 degree angle, see section 6. These two distribution panels were also included in Table 5.4 for repair of the access doors with stripped screws. Refer to the individual SEWS for specific screening and walkdown results.

5.4.15 Battery Racks

The SSEL contains two battery racks. The battery racks are located in the RAB (Unit 1) at elevation 286'. The two step, four bay battery racks were supplied by C&D Batteries. The weight of one rack and 30 cells is approximately 8,550 lbs. The racks are constructed of a welded structural steel frame with cross bracing. Each rack is anchored with (40) 1/2" diameter by 2'-6" long, A193 Grade B8 cast-in-place J-bolt. No interaction or maintenance issues were noted during the walkdown. The battery racks are screened by SRT based on the walkdown, anchorage calculations and the seismic testing performed on the racks. Refer to the individual SEWS for specific screening and walkdown results.

5.4.16 Battery Chargers and Inverters

The SSEL contains two battery chargers and four inverters. The battery chargers are located in the RAB (Unit 1) at elevation 286'. The battery chargers were manufactured by C&D Batteries, model ARR130K150F. The weight of one battery charger is approximately 800 lbs. The battery charger base is constructed of structural steel channels and is anchored with (4) 3/8" diameter by 2'-6" long, A193 Grade B8 cast-in-place J-bolt. No interaction or maintenance issues were noted during the walkdown. The battery chargers are screened by SRT based on the walkdown, anchorage calculations and the seismic testing performed on the battery chargers. Refer to the individual SEWS for specific screening and walkdown results.

The inverters are located in the RAB (Unit 1) at elevation 305'. The inverters were manufactured by Westinghouse. The weight of one inverter is approximately 1150 lbs. The inverters are welded with 1/4" fillet welds by 4" long spaced at 9" centers. The internal frame is bolted to the bottom skid with 5/8 inch diameter bolts in each corner. No interaction or maintenance issues were noted during the walkdown. The inverters are screened by SRT based on the walkdown. Refer to the individual SEWS for specific screening and walkdown results.

5.4.17 Engine Generators

The SSEL contains two engine generators, the emergency diesel generators (EDG). The EDG are located in the DGB at elevation 261'. The EDG were supplied by DeLaval Turbine Inc. model DSRV, 16-4. The engine weighs 235,000 lbs and the generator weighs 63,500 lbs. The engine is anchored with (22) 2" diameter by 65" long (45" embedment) cast-in-place anchors. The generator is anchored with (12) 1-1/4" diameter by 40" long (33-5/8" embedment) cast-in-place anchors. No interaction or maintenance issues were noted during the walkdown. The EDG are screened by SRT based on the walkdown, anchorage calculations and the seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.18 Automatic Transfer Switches

This category covers flow switches, flow transmitters, level switches, level transmitters, pressure switches and pressure transmitters. The SSEL contains sixty-two switches and transmitters. These instruments are located through out the plant and are mounted directly to the concrete structures, instrument racks or cabinets. These instruments were generally of rugged construction. No interaction or maintenance issues were noted during the walkdown. The switches and transmitters are screened by SRT based on the walkdown and the seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.19 Instrument Racks

The SSEL contains twenty instrument racks. The racks are located in the CB at elevation 236', the Tank Building at elevation 236' and the RAB at elevations 236' and 261'. The instrument racks are generally rigid and construction of structural steel tubing, channel and angle. The racks are either secured to the structure by welds or expansion anchors. No interaction or maintenance issues were noted

during the walkdown except for a fluorescent light interaction with rack A21-R15, see Table 5.3. The instrument racks are screened by SRT based on the walkdown and the seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.20 Temperature Sensors

The SSEL contains thirteen temperature indicators, elements, controllers or sensors. These instruments are located through out the plant and are mounted directly to the concrete structures, instrument racks or piping. These instruments were generally of rugged construction. No interaction or maintenance issues were noted during the walkdown except for a misaligned U-bolt attaching 1TIS-658A to a pipe, see Table 5.3. The temperature components are screened by SRT based on the walkdown and the seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.21 Control and Instrumentation Cabinets

The SSEL contains thirty control and instrumentation cabinets. The cabinets are located in the DGB at elevation 261' and the RAB at elevations 236', 286' and 305'. The cabinets have all been evaluated to be of good seismic design. In general, the cabinets are constructed of structural steel framing and sheet metal panels with an integral structural steel base which provides adequate stiffness and a good load path. The cabinets are secured to the structure by expansion anchors, cast-in-place anchors, embedded plates or embedded channels. The anchorage of the cabinets were all screened with the exception of four cabinets in the RAB at elevation 286'. The four cabinets are the transfer panels 1A and 1B and the sequencer panels 1A-SA and 1B-SB. These cabinets were selected for HCLPF evaluation due to the embedded channel with nelson studs at 45 degree angle, see section 6. Also, nine cabinets were noted as having interaction or maintenance issues, see Tables 5.3 and 5.4. Refer to the individual SEWS for specific screening and walkdown results.

5.4.22 Buried Tanks

The SSEL contains two buried tanks, main fuel oil storage tanks. The tanks are located in the Fuel Oil Building at elevation 242'. The tanks are associated with the fuel oil system of the emergency diesel generator. The fuel oil storage tanks consists of a concrete structure that has an internal steel liner. The tank is partially buried in the ground. The tank has a concrete cover that is exposed. the cover has a large concrete cap that can be removed by a crane which is used to service the tank. The piping routed to the transfer pumps is well supported. No interaction or maintenance issues were noted during the walkdown. The fuel oil storage tanks are screened by SRT based on the walkdown. Refer to the individual SEWS for specific screening and walkdown results.

5.4.23 Vertical Tanks and Heat Exchangers

The SSEL contains twenty vertical tanks and two vertical heat exchangers. Twelve tanks are associated with the air start system of the emergency diesel generator, four air dryers, four air separators and four air tanks (compressor receiver). These tanks are located in the DGB at elevation 261' and were evaluated to be of good seismic design. No interaction or maintenance issues were noted during the walkdown. The tanks associated with the air start system are screened by SRT based on the walkdown. Refer to the individual SEWS for specific screening and walkdown results.

The eight remaining vertical tanks are the diesel generator fuel oil day tanks (two), boron injection tank, boric acid tank, volume control tank, boric acid filter, condensate storage tank (CST) and refueling water storage tank (RWST). The two largest tanks, CST and RWST were selected for HCLPF evaluation since these tanks are important and high profile elements of the shutdown paths, see section 6. The CST anchorage consists of (80) 3" diameter cast-in-place bolts and the RWST consists of (76) 3" diameter cast-in-place bolts. The HCLPF capacity is estimated to be over 1g based on methodology provided in Reference 3, see Section 6. No

interaction or maintenance issues were noted during the walkdown. These vertical tanks are screened by SRT based on the walkdown, anchorage calculations, HCLPF evaluation, and seismic analysis of the tanks. Refer to the individual SEWS for specific screening and walkdown results.

The two vertical heat exchangers are for the RHR system.. The RHR heat exchangers are located in the RAB at elevation 236'. The heat exchangers are manufactured by Joseph Oat & Sons, Inc., and are 40" diameter and 26'-9½" high. The heat exchangers weigh 38,000 lbs. The baseplate is 1½" thick steel plate and is stiffened by a 3/4" thick steel skirt of the heat exchanger. The baseplate is attached to the structure with eight 1½" diameter by 42½" long cast-in-place anchors. Upper lateral restraints were included in the original design but were not installed based on analyses that justifies this configuration for DBE levels. The heat exchangers were selected for HCLPF evaluation based on the upper lateral supports not being installed, see section 6. Refer to the individual SEWS for specific screening and walkdown results.

5.4.24 Horizontal Tanks and Heat Exchangers

The SSEL contains fifteen horizontal tanks and heat exchangers. The horizontal tanks and heat exchangers are located throughout the plant. These tanks and heat exchangers were evaluated to be of good seismic design and to have adequate anchorage. No interaction or maintenance issues were noted during the walkdown. The horizontal tanks and heat exchangers are screened by SRT based on the walkdown, anchorage calculations, and seismic qualification documentation. Refer to the individual SEWS for specific screening and walkdown results.

5.4.25 Solenoid Operated Valves

The SSEL contains sixteen solenoid operated valves. Six of the solenoid valves are associated with the power operated relief valves (PORV's). The PORV's are located in the CB at elevation 315'. These solenoid valves have been included as rule-of-

box components and are screened with the PORV's. Eight of the solenoid valves are associated with the air start system of the emergency diesel generator. The emergency diesel generator air start system is located in the DGB at elevation 261'. These solenoid valves have been included as rule-of-box components and are screened with the emergency diesel generator air start system..

The remaining two solenoid operated valves are the fill valves to the diesel fuel oil day tanks. These valves are located in the DGB at an approximate elevation of 263'. The valves are Target Rock, model 79Q-007 and are of good seismic design. No interaction issues or maintenance issues were noted during the walkdown regarding these solenoid valves. These two solenoid operated valves are screened by SRT based on the walkdown and the seismic qualification documentation. Refer to the SEWS for specific screening and walkdown results.

5.5 STRUCTURES

All Harris Seismic Category I buildings are founded upon reinforced concrete mats resting on suitable rock or on concrete fill founded on suitable rock. The structural dynamic analysis of the Seismic Category I buildings is based on use of the response spectra developed for 0.075g for the operating basis earthquake and 0.15g for the safe shutdown earthquake.

Harris Category I structures are all screened from further review based on Reference 3, Table 2.3 and Section 3.8 of the FSAR. A brief description of each of the buildings within seismic IPEEE success paths is provided in the following subsections.

5.5.1 Concrete Containment

The concrete containment is a steel lined reinforced concrete structure in the form of a vertical right cylinder with a hemispherical dome. The 4 ft. 6 in. thick cylindrical wall measures 160 ft. in height from the liner on the base to the springline of the dome and has an inside diameter of 130 ft. The inside radius of

the 2 ft. 6 in. thick dome is equal to that of the cylinder so that the discontinuity at the spring line due to the change in thickness is on the outer surface. The base mat consists of a 12 ft. thick structural concrete slab and a metal liner. The liner is welded to inserts embedded in the concrete slab. The base liner is covered with concrete, the top of which forms the floor of the containment. The base mat is supported by sound rock.

The basic structural elements considered in the design of the containment structure are the basemat, cylinder wall, and dome. These act essentially as one structure under all loading conditions. The liner plate is 3/8 in. thick in the cylinder, ¼ in. thick on the bottom, and ½ in. thick in the dome. The liner is anchored to the concrete shell by means of anchor studs fusion welded to the liner plate so that it forms an integral part of the containment structure. The liner functions primarily as a leaktight membrane.

The containment design loads and loading combinations included earthquake loads using the safe shutdown earthquake horizontal ground acceleration is 0.15g. To account for the simultaneous action of the three spatial components of the earthquake, the representative maximum value of a particular response is obtained by taking the square root of the sum of the squares of the corresponding maximum values of the response to each of the three spatial components calculated independently.

The analysis of the containment shell is based on the classical theory of thin elastic shells of revolution in accordance with Section CC-3300 of the ASME Code, Section III, Division 2. The shell is assumed to be ideally elastic, homogeneous, and isotropic. Reinforcement and the steel liner are neglected in calculating the member stiffness. The design of the Containment demonstrates that, for factored load conditions, the following requirements are met:

a) The summation of external and internal forces and moments satisfies the laws of equilibrium and does not bring any structural section to a general yielding state.

b) Tensile yielding in the reinforcement is acceptable when thermal gradient temperature effects are combined with other applicable loads, provided that the temperature induced forces and moments are reduced as yielding in the reinforcement occurs, and the increased concrete cracking does not cause deterioration of the Containment.

The liner plate is not used as a strength element. Interaction of the liner with the Containment is considered in determining liner behavior.

The containment wall is independent of adjacent interior and exterior structures; sufficient space is provided between the containment wall and adjacent structures to prevent contact under any combination of loading. The interior grating platforms and concrete slabs are supported on steel beams which span between the secondary shield wall and the containment wall. These beams are independently supported, near the containment wall, by steel columns resting on the concrete mat.

5.5.2 Internal Structures

The reinforced Concrete Containment Structure encloses the concrete structures and structural steel components which comprise the Containment Internal Structures. The Containment Internal Structures provide support for the NSSS equipment during all operational phases and, in the unlikely event of an accident, act to mitigate the consequences of the accident by protecting safety-related equipment and other engineered safety features from the effects induced by the accident.

The concrete internal structures, which consist of the primary and secondary shield walls and other concrete enclosures, form compartments within which the entire RCS is located. The main components are the concrete primary shield wall, which encloses the reactor cavity, the semicircular concrete secondary shield walls, which forms the steam generator compartments, the reinforced concrete walls and floors, the fuel storage area, refueling pool and reactor internals laydown areas, the concrete enclosure wall around the pressurizer, the containment steel floors, stairs, and platforms, reactor vessel supports, steam generator supports, and reactor coolant pump supports. The concrete and steel internal structures are supported on a concrete foundation mat 5 ft. thick, resting on the 12-ft. thick concrete containment structure foundation mat. The internal foundation mat is placed on top of the bottom liner plate; no anchorages of the internal structures and internal mat penetrate through the containment liner plate into the external mat. The walls of the internal structures are anchored into the internal foundation mat.

The structural acceptance criteria for the Containment Internal Concrete Structures and the internal and other Seismic Category I structural steel structures consists of compliance with the following requirements:

a) Concrete Structures - To assure that the structural integrity of Category I concrete structures is maintained for the service and factored load conditions, the limits of the stress and strain intensity of concrete generally follow the strength design method requirements of American Concrete Institute (ACI) 318-71.

Using the factored loads, the various components have the required load capacity if the stresses in them do not exceed the yield strengths of the materials used. To provide for the possibility that small, adverse variations in dimensions and control, while individually within required tolerances and the limits of good practice, occasionally may combine to result in a net under capacity of the component, the

load capacities of the individual structural members are reduced by a reduction factor "ϕ" for the design cases.

The factors were established for the design on the basis of the function of the component and the effect on its net capacity of the variations enumerated above. These factors are generally in accordance with the ACI 318-71 Code and are tabulated in Table 3.8.3-1 of the FSAR.

a) Steel Internal Structures - Structural steel framing is designed for the loading combinations, given in Section 3.8.3.3.3 of the FSAR, to exhibit either elastic or plastic behavior in all load carrying elements. To assure that the structural integrity of Seismic Category I steel structures is maintained, limits on the resulting stresses and the reduced strength capacities are observed.

5.5.3 Reactor Auxiliary Building

The Reactor Auxiliary Building (RAB) houses engineered safeguards and supporting systems, switchgear, sampling rooms, and the Control Room. The Seismic Category I building consists of two independent structures. One section is designated as RAB-1. The adjacent section is designated as RAB-Common.

The RAB-1 is a reinforced concrete structure, 207 ft. long by 187 ft. wide, varying in height from 69 ft. to 134 ft. from the top of foundation mat to the top of roof. The top of the foundation mat varies from 24 ft. to 70 ft. below finished grade, Elevation 260 ft.

The RAB-Common is a reinforced concrete structure, 120 ft. long by 187 ft. wide by 88 ft. high from the top of mat to the top of roof. The top of the foundation mat is at Elevation 236 ft. except for the pipe tunnel area, which is at Elevation 216 ft.

These buildings are cast-in-place reinforced concrete structures. The floors are supported on beams and girders which are in turn supported on interior columns and/or exterior walls. Where interior shear walls are installed, the beams and girders are supported on the shear walls. All interior shielded walls and partitions, other than shear walls, are either reinforced concrete or concrete block, and are not load bearing. Provisions are made for installation of these walls after the framing, floor systems, and equipment have been installed.

The buildings are supported on separate foundation mats 10 ft. thick which are founded on suitable rock.

5.5.4 Diesel Generator Building

Diesel-Generator Building (DGB) houses the stand-by diesel generators, day tanks, silencers, and associated equipment. The building is a Seismic Category I, missile-proofed, reinforced concrete structure, approximately 153 ft. long and 114 ft. wide.

The building is constructed on concrete fill, which is founded on suitable rock. The top of the foundation mat is 3.5 ft. below the grade floor Elevation 261.0 ft.; there is a space (gap) between the foundation mat and the grade floor (within the building walls) that is filled with sand for the electrical main leads and pipe lines. The foundation mat is 6 ft. thick.

The building is cast-in-place concrete with reinforced concrete exterior and interior shear walls, and reinforced concrete floors. The floors are supported on wall beams. Interior walls, other than shear walls, are reinforced concrete walls or concrete masonry (block) walls and are not load bearing walls. All reinforced concrete floor slabs are designed to act as horizontal diaphragms to transfer horizontal forces to shear walls and to carry vertical loads simultaneously.

5.5.5 Tank Building

The Tank Building houses the refueling water storage tank, reactor make-up water storage tank, condensate storage tank, and other associated equipment. The Tank Building also houses the waste monitoring tanks, secondary waste sampling tank, their associated pumps, and other facilities.

The Tank Building is a reinforced concrete structure, approximately 142 ft. long by 63 ft. wide, and 83 ft. high. The top of the foundation mat is at Elevation 236 ft. and the top of the roof, which provides for missile protection, is at approximately Elevation 319 ft. The foundation mat is 8 ft. thick and is founded on suitable rock.

The top of the foundation mat is 24 ft. below the finished grade elevation of 260 ft. The Tank Building has cast-in-place reinforced concrete exterior walls, interior shear walls, and reinforced concrete floors, supported on shear walls, beams, and columns. All interior shielding or partition walls, other than shear walls, are either reinforced concrete or concrete block walls and are not load bearing walls.

The overall tank building analysis was run using a time history seismic input forcing function. Response spectra were developed from that analysis for Elevation 261 ft., the elevation of the bottom of the tank. These response spectra were broadened by plus or minus 15 percent as required by Regulatory Guide 1.122. These broadened response spectra resulted in higher accelerations for essentially the entire range of frequencies of the spectra curves, thus increasing the seismic input which in turn increased the accelerations and moments at the common points in detailed tank analysis as compared to overall tank building analysis.

The seismic input for the detailed tank analysis for the fundamental frequency of the tank of 15.67 cycles/sec is 0.61g is compared to 0.39g of the actual unbroadened spectra curve indicating a margin of approximately 56 percent.

5.5.6 Diesel Fuel Oil Storage Tank Building

The Diesel Fuel Oil Storage Tank Building consists of a below grade reinforced concrete structure which provides for two reinforced concrete diesel oil tanks and two pumps. The structure is 94 ft. long, 86 ft. wide, and 24 ft. high (including the foundation mat); the top slab is at Elevation 263 ft. The building is supported on a reinforced concrete foundation mat which is founded on sound rock. The top of the foundation mat is at Elevation 242.25 ft; the mat is 3 ft. 3 in. thick.

The tanks have a capacity of 175,000 gallons each. Each compartment is 66 ft. long, 21 ft. wide, and 18 ft. 6 in. high; the free board is at least 12 in. The inside surfaces of the concrete compartments are lined with carbon steel to prevent leakage.

The pumps are housed in below grade cubicles separated by reinforced concrete walls.

5.5.7 Structures for the Emergency Service Water System

The Seismic Category I structures of the ESWS consist of the Emergency Service Water Intake Channel, Emergency Service Water Screening Structure, Emergency Service Water and Cooling Tower Makeup Intake Structure, Emergency Service Water Discharge Structure, and the Emergency Service Water Discharge Channel. Retaining walls are provided at the Emergency Service Water Screening Structure. All Concrete structures are reinforced and founded on sound rock.

Cooling water is drawn from either the Auxiliary Reservoir or the Main Reservoir. Water drawn from the Auxiliary Reservoir is carried by a series of steel pipes from the Emergency Service Water (ESW) Screening Structure to the Emergency Service Water and Cooling Tower Makeup Intake Structure. Cooling water is discharged into the Auxiliary Reservoir through the Emergency Service Water Discharge Channel.

a) Emergency Service Water Intake Channel - The Emergency Service Water Intake Channel extends from the Auxiliary Reservoir to the Emergency Service Water Screening Structure. The bottom of the channel is at Elevation 238 ft., except at the intake screening structure where it slopes down to Elevation 231 ft. Channel side slopes in rock are approximately four vertical to one horizontal; a 15 ft. wide beam is cut at the interface of soil and rock. Side slopes in soil are one vertical to two horizontal. The channel bottom is 50 ft. wide at all sections except at the intake structure. The lowest water level in the channel is Elevation 246.5 ft. and the maximum velocity in the channel is less than one ft. per sec. at this level.

b) Emergency Service Water Screening Structure - The ESW Screening is located at the eastern end of the ESW Intake Channel. It contains eight bays separated by reinforced concrete walls. Only two bays are used for the ESW system. Each ESW bay, 8 ft. 2 in. wide, is sized for seven ft. wide traveling screens. A reinforced concrete enclosure covers the deck to protect the traveling screens and valve pit from tornado missiles. A reinforced concrete skimmer wall, at the front of the intake structure, extends to Elevation 247.5 ft. and prevents ice and floating trash from entering the intake structure.

c) Emergency Service Water and Cooling Tower Makeup Intake Structure - The ESW and Cooling Tower Makeup Intake Structure is located at the northern end of the Cooling Tower Makeup Water Intake Channel. The intake structure has fourteen bays. Two bays are used for cooling tower make up pumps and two bays are used for ESW system. The screen

bays, containing ESW pumps, have a concrete dividing wall with an eight by ten ft. butterfly valve. The dividing wall-butterfly valve arrangement permits operation of the ESW pumps from either the Main or Auxiliary Reservoir. A reinforced concrete enclosure covers the deck to protect all ESWS equipment from tornado missiles.

d) Emergency Service Water Discharge Channel - The ESW Discharge Channel extends from the ESW Discharge Structure to the Auxiliary Reservoir. The bottom of the channel is at Elevation 240 ft. and it is 50 ft. wide. Channel side slopes in rock are approximately four vertical to one horizontal and in soil they are one vertical to two horizontal. A berm 15 ft. wide is cut at the interface of the soil and rock.

e) Emergency Service Water Discharge Structure - The ESW Discharge Structure, is located at the eastern end of the ESW Discharge Channel. It is a reinforced concrete structure which serves as the termination point for the service water discharge piping. The discharge structure has eight bays whereas only two bays are used.

f) Retaining Wall - Reinforced concrete retaining walls, where required, are located at the end of the Cooling Tower Makeup Water Intake Channel and at the ESW Screening structure. The walls are utilized to contain the earth adjacent to the concrete structures.

Harris Category I structures are all screened from further review based on Reference 3, Table 2.3 and Section 3.8 of the FSAR. No further action is required.

5.6 SOILS EVALUATION

Soil failure is deemed not a significant issue based on a review of the FSAR. Brief discussion on soil failure modes, embankments and dams is provided below.

In the spirit of the IPEEE program, CP&L does not believe that a detailed assessment of soils, embankments and dams is warranted. Key objectives of the IPEEE program are to gain useful insights in identifying plant specific vulnerabilities to severe accidents that could be fixed with low-cost improvements. CP&L does not believe that either of these objectives are furthered by a detailed margins assessment of soils, embankments and dams given that no design concerns exist.

5.6.1 Soil Failure Modes

The plant is founded on gently dipping, well-consolidated Triassic siltstones and sandstones. All Seismic Category I structures within the plant area, except for Seismic Category I Electrical Manholes, Seismic Category I Underground Electrical Conduits, and some Seismic Category I pipes, are founded on sound rock. The foundation of the plant has no potential for liquefaction because it consists of hard sound rock.

The Seismic Category I underground piping systems, underground electrical conduits and electrical manholes, founded on soil, compacted fill, of weathered rock, are the only Seismic Category I structures that are not founded on sound rock. The fill in the yard area supporting Seismic Category I piping and conduits is not subject to liquefaction during a seismic event (FSAR 3.7.3.12).

Programs of subsurface exploration based primarily on trenching and borehole sampling and drilling were conducted for both the preliminary site investigation and the site fault investigation. In addition, the floors and walls of excavations for plant foundations were mapped geologically. No areas of actual or potential surface or subsurface subsidence, uplift, or collapse were found.

5.6.2 Embankments and Dams

Two dams were constructed in the Buckhorn Creek watershed to impound cooling water for the Harris Nuclear Plant. The Main Dam impounds a reservoir used primarily for cooling tower makeup water which has a normal water level elevation of 220 ft. and a water surface area of approximately 4,000 acres. The Main Reservoir also serves as a backup source of emergency service water. The Auxiliary Dam impounds a reservoir for emergency service water which has a minimum pond elevation of 250 ft. and a surface area of 317 acres. An Auxiliary Separating Dike and Auxiliary Reservoir Channel control the flow of discharged emergency service water through the east and west arms of the Auxiliary Reservoir.

The dike, constructed across the east arm of the reservoir, prevents discharged emergency service water from flowing directly back to the emergency service water intake area. The Auxiliary Reservoir Channel connects the east and west arms of the Auxiliary Reservoir, allowing emergency service water discharge to enter the west arm of the reservoir for maximum cooling before circulating back to the intake area.

The Main Dam, Auxiliary Dam, Auxiliary Separating Dike, Auxiliary Reservoir Channel, and Emergency Service Water Intake and Discharge Channels are designed and constructed to Seismic Category I criteria and to withstand the effects of natural phenomena. The slope of the dams, dike, and channels are designed to a factor of safety of 1.5 under static conditions, 1.2 for simultaneous OBE and 100-year return period flood level, and 1.1 for simultaneous SSE and 25-year return period flood level.

The Main Dam is a rockfill dam with a maximum height of 108 ft. and a length of approximately 1550 ft. at the beam elevation of 260 ft. Its outside slopes are 2.0 horizontal to one vertical. The main dam's spillway, with a crest elevation of 220

ft., is uncontrolled. The spillway crest has a net length of 50 ft. with a pier at its mid-length.

The Main Dam has a core of compacted silty clay and clayey silt material protected on each side by two 8-ft. thick transitional filter zones and a rockfill shell. The core is founded on suitable rock and the rockfill shell is founded on weathered rock.

The Auxiliary Dam is an earth dam approximately 4060 ft. long with a maximum height of approximately 73 ft. and a beam elevation of 260 ft. Its outside slopes are 2.5 horizontal to one vertical. The basis for its hydraulic design is the probable maximum flood (PMF).

The Auxiliary Dam area is in the Deep River Basin and is underlain by sedimentary rocks which, like those underlying the plant site, belong to the lower part of the Triassic Sanford Formation. The bedrock consists of four major lithologic units: medium-to coarse-grained sandstone, fine-to medium-grained sandstone, siltstone, and shaky siltstone.

The Auxiliary Dam has a compacted core of silty clay and clayey silt material protected by a transition filter zone and a random rockfill shell on each []side. The downstream shell is provided with two horizontal drainage blankets, each three ft. thick, which are connected with the transition filter zone adjacent to the core of the dam. In addition, a 200 ft. wide drainage layer is provided under the shell in each of two areas where pre-existing creeks had been located. The foundation of the dam was excavated into weathered rock and the cutoff trench was excavated to suitable rock.

The Auxiliary Reservoir Separating Dike is located across the east arm of the Auxiliary Reservoir about 1700 ft. north of the Auxiliary Dam. It is approximately 1200 ft. long with a maximum height of approximately 55 ft. Its outside slopes are 2.5 horizontal to one vertical.

The bedrock underlying the Auxiliary Reservoir Separating Dike consists of clastic sedimentary rocks of the Triassic Sanford Formation and is similar in most respects to the strata underlying the Auxiliary Dam.

The Auxiliary Reservoir Separating Dike has a core of compacted silty clay and clayey silt material protected by a random-rockfill shell which is size graded near the core, with the finer material placed adjacent to the core. The core and rockfill shell are founded either on weathered rock or on a thin layer of stiff residual soil overlying weathered rock.. Slope protection is provided by riprap placed on random rockfill.

The Emergency Service Water Intake and Discharge Channels are conservatively designed to carry the service flow required for normal and emergency shutdown of Harris. The intake channel is approximately 3580 ft. long and 50 ft. wide at its invert elevation of 238 ft. The discharge channel is approximately 2170 ft. long. The walls of both channels have a slope of two horizontal to one vertical in soil and one horizontal to four vertical in rock. Portions of the slopes were shaped to grade by backfilling with an impervious material. Diabase dikes were capped with concrete where they crossed channels.

The Auxiliary Reservoir Channel is approximately 1570 ft. long and 140 ft. wide at its invert elevation of 235 ft. Its walls have a slope of two horizontal to one vertical in soil and one horizontal to four vertical in rock. The Auxiliary Reservoir Channel is sized to carry the maximum ultimate discharge of the Service Water System coincident with a PMF flow for the upstream drainage basin.

All three channels are underlain by gently dipping strata of the Triassic Sanford Formation. Bedrock is lithologically and structurally similar to that at the Auxiliary Dam. Foundation conditions were explored by means of borehole drilling, sampling, and testing.

Embankments and dams are designed to a factor of safety of 1.1 for simultaneous SSE and 25 year flood. Further evaluation is not expected to identify any

significant vulnerabilities considering the revised hazard curves which support grouping Harris in the reduced-scope category (References 5 and 6). No further action is required.

5.7 NSSS REVIEW

A review of the Harris NSSS system was performed based on available information in accordance with Reference 3. The system is a modern 3 loop pressurized water reactor supplied by Westinghouse. In the spirit of the IPEEE program, CP&L does not believe that a detailed assessment of soils, embankments and dams is warranted. Key objectives of the IPEEE program are to gain useful insights in identifying plant specific vulnerabilities to severe accident that could be fixed with low-cost improvements. CP&L does not believe that either of these objectives are furthered by a detailed margins assessment of NSSS system and components given that no design concerns exist. The NSSS system and components are screened from further review.

5.7.1 NSSS Primary Coolant Systems and Supports

The primary coolant system and supports are screened from further review based on Appendix A of Reference 3.

5.7.2 Reactor Internals

The fuel assembly component stresses induced by horizontal seismic disturbances were analyzed through the use of finite element computer modeling. The fuel assembly safety analysis was performed for combined seismic and loss of coolant accidents (LOCA). The recent vintage reactor internals, such as Harris are screened from further review since they were designed for combined SSE and LOCA.

5.7.3 Control Rod Drive Mechanisms

The Control Rod Drive Mechanisms (CRDMs) were seismically analyzed to confirm that system stresses under combined loading conditions do not exceed allowable levels as defined by the ASME Code, Section III. The CRDM was modeled as a system of lumped and distributed masses and analyzed under appropriate seismic excitation and the resultant seismic bending moments along the length of the CRDM were calculated. The corresponding stresses were combined with the stresses from the other loadings required and the combination was shown to meet ASME Code, Section III requirements.

Additionally, the SRT verified that the CRDMs have seismic support tie rods to resist seismic loads (References 25 and 26). Therefore, CRDMs are screened from further review.

5.8 DISTRIBUTION SYSTEMS

The following sections address the distribution systems; cable tray and conduit, HVAC duct and piping.

5.8.1 Cable Tray and Conduit

Cable tray and conduit were reviewed on an area basis during SRT equipment and subsystem walkdowns to identify any anomalies that could lead to failure. No such anomalies were observed. Cable and conduit are screened from further review based on Appendix A of Reference 3, and SRT walkdowns.

5.8.2 HVAC Duct

HVAC duct was reviewed on an area basis during SRT equipment and subsystem walkdowns to identify any anomalies that could lead to failure. Two specific cases were noted during these walkdowns which are described below:

1. A large span of duct above the auxiliary feedwater (AFW) motor driven pump, 1A-SA require further review. The duct is 30 inches by 30 inches with a 24 ft. span between supports. This span has a vertical branch duct with a register attached to the bottom. The original design calculations were reviewed and was judged acceptable for RLE. Refer to the SEWS for AFW motor driven pump, 1A-SA for the basis of acceptance.

2. A non-safety non-seismic duct was noted as a potential interaction above motor operated valve, 1SW-40. The duct is 10 inches by 10 inches with duct span of approximately 14 ft. The duct and supports were judged to be acceptable for RLE. Refer to the SEWS for motor operated valve 1SW-40.

HVAC duct are screened from further review based on Appendix A of Reference 3, and SRT walkdowns.

5.8.3 Piping

Harris Seismic Category I, ASME, Section III, Safety Class 2 and 3 piping is analyzed in accordance with ASME B & PV code, Section III, subarticles NC/ND. The design criteria was based on formulations and allowable stress limits given by in ASME, Section III, subarticle NC/ND-3600, with load combinations which consider operating basis earthquake (OBE) and SSE effects along with other coincident loading conditions. The two orthogonal horizontal and vertical loadings were obtained from the appropriate floor response spectra.

Piping system were reviewed on an area basis during SRT equipment and subsystem walkdowns. The SRT looked for any anomalies related to potential displacement induced failure modes. No such anomalies were observed.

Additionally, the SRT looked for potential failure modes of piping system appurtenances such as instrument tubing and associated instruments, vent valves

and drain valves. Seismic interaction and seismic anchor motion were considered potential failure modes for small bore lines attached to larger piping systems. No anomalies noted that could lead to the loss of a pressure boundary of a success path list system were observed.

Containment penetrations were also reviewed on an area basis to identify any anomalies that may affect containment performance. Anomalies such as seismic interaction (falling) and differential building displacement were considered. A walk-by of containment isolation valves for the intent of the caveats identified on the valve SEWS was also performed. No anomalies that could effect containment performance were observed.

Harris piping was screened from further review based on Appendix A of Reference 3, and SRT walkdowns.

5.9 OTHER COMPONENTS

The following sections discuss the in-core flux mapping system and masonry walls.

5.9.1 In-core Flux Mapping System

In 1984, CP&L discovered that the In-Core Flux Mapping System was not seismically designed. Seismic induced failure of the In-Core Flux Mapping System components above the seal table could cause failures of the flux mapping tubing or fittings which would produce a small break LOCA. CP&L notified Westinghouse of the potential failure of the In-Core Flux Mapping System and informed the Nuclear Regulatory Commission (NRC) of a potentially reportable item under both 10CFR50.55(e) and 10CFR21. Information Notice 85-45, (Reference 22) was issued as a result of this information provided by CP&L. CP&L notified the NRC that this item was reportable under 10CFR50.55(e) and 10CFR21 on January 16, 1985.

CP&L designed and installed wheel stops on the Flux Mapping Control System Trolley to prevent seismic interaction between the trolley and the In-Core instrumentation tubing or fittings. The wheel stops are of substantial size and are fabricated from 1/2" and 3/4" thick structural steel plate. The design details for the wheel stops are provided on Drawing CPL-2168-S-9479. The installation of the wheel stops was visually verified by using the Harris Surrogate Tour system. The tour program uses the combined technology of laser videodiscs and the personal computer to effectively simulate travel through the plant and provide detailed visual information about plant areas. The surrogate tour shows the wheel stops installed. The wheel stops have sufficient design margin to be screened out for the RLE.

5.9.2 Masonry Walls

The guidelines for assessment of nuclear power plant seismic margin (Reference 3) recommends a review of masonry walls, in particular unreinforced or lightly reinforced walls. There are no unreinforced masonry walls located in safety related areas at Harris.

The masonry (block) walls in the Containment Building and Diesel Generator Building are all seismically designed. All masonry walls in the Reactor Auxiliary Building are seismic except in the hot shop area on Elevation 236 ft., between 'B' and 'H' lines and '43' and '45' line where seismic and non-seismic walls are utilized. Both seismic and non-seismic walls are used in the Fuel Handling Building and Waste Processing Building. These walls are utilized for shielding and equipment removal purposes or support of non-safety equipment.

The following codes are used for the analysis and design of masonry block walls and any associated steel framing:

- ACI 531-79, American Concrete Institute, "Building Code Requirements for Concrete Masonry Structures"

- UBC-79, Uniform Building Code, by International Conference of Building Officials

- AISC, American Institute of Steel Construction, "Specification for Seventh the Design, Fabrication and Erection of Structural Steel for Edition Buildings"

- ACI 318-71, American Concrete Institute, "Building Code Requirements for Reinforced Concrete"

Also, the design criteria utilized in the design of masonry walls located in Seismic Category I structures complies with the NRC Structural Engineering Branch Criteria for Safety Related Masonry Wall Evaluation, dated July 1981.

Four masonry walls were chosen for further evaluation to demonstrate the high design margin that exists. These four specific cases were noted being adjacent to SSEL components during the SRT walkdown. The wall location, description, allowable stress level, calculated stress level and interaction coefficient for the four walls are given in Table 5-6.

The maximum interaction coefficient of the four masonry walls is 0.53. The RLE to DBE scaling factor is approximately 1.6. Therefore, these masonry walls are screened out for RLE. These walls are typical of other safety related masonry walls within the plant which are also screened out for RLE based on the above evaluations. No further action is required.

Table 5-1

SUMMARY OF CIVIL STRUCTURES SEISMIC MARGIN EVALUATION

(Format Follows EPRI NP-6041, Table 2-3)

TYPE OF STRUCTURE	DISPOSITION
Concrete containment	Screened based on EPRI NP-6041, Table 2-3
Containment internal Structure	Screened based on EPRI NP-6041, Table 2-3. The structure was designed for greater than 0.1g.
Shear walls, footing and containment shield walls	Screened based on EPRI NP-6041, Table 2-3. The walls were designed for greater than 0.1g.
Diaphragms	Screened based on EPRI NP-6041, Table 2-3. Diaphragms were designed for greater than 0.1g.
Category I concrete frame structures	Screened based on EPRI NP-6041, Table 2-3. Concrete frame structures were designed for greater than 0.1g. See Section 5.5 for a summary of the evaluation.
Masonry walls	Screened based on existing analyses. See Section 5.9.2 for a summary.
Control room ceilings	Screened. The control room ceiling was judged adequate by the SRT.
Impact between structures	Screened based on EPRI NP-6041, Table 2-3
Category II structures with safety-related equipment or with potential to fail Category I structures	Screened based on EPRI NP-6041, Table 2-3 and SRT walkdowns.
Dams, levees, dikes	Designed to a factor of safety of 1.1 for simultaneous SSE and 25 year flood. Further evaluation is not expected to identify any significant vulnerabilities. See Section 5.6.
Soil failure modes	Screened based on the FSAR. See Section 5.6 for a summary.

Table 5-2

SUMMARY OF EQUIPMENT AND SUBSYSTEMS SEISMIC MARGIN EVALUATION

(Format Follows EPRI NP-6041, Table 2-4)

EQUIPMENT TYPE	DISPOSITION
NSSS primary coolant system	Screened based on EPRI NP-6041, Table 2-4. See Section 5.7 for a summary of the evaluation.
NSSS supports	Screened. See Section 5.7 for a summary of the evaluation.
Reactor internals	Screened. See Section 5.7 for a summary of the evaluation.
CRDM mechanisms	Screened. See Section 5.7 for a summary of the evaluation.
Category I piping	Screened by the SRT. See Section 5.8.3.
Active valves	Screened based on EPRI NP-6041, Table 2-4 and SRT walkdowns. See Section 5.4.7, 5.4.8, and 5.4.25.
Passive valves	Screened based on EPRI NP-6041, Table 2-4.
Heat Exchangers	The RHR Heat Exchanger HCLPF is estimated to be 0.29g (see Section 6). All other heat exchangers were screened by the SRT, see Sections 5.4.23 and 5.4.24.
Atmospheric storage tanks	RWST and CST HCLPF capacities are much greater than the RLE (see Section 6 for evaluation results). All other tanks were screened by the SRT, see Sections 5.4.23 and 5.4.24.
Pressure vessels	Screened by the SRT. See SEWS for each success path pressure vessel.
Buried tanks	The diesel fuel oil storage tanks were considered to be buried tanks. These tanks consisted of a Seismic Category I concrete structure that has an internal steel liner. See Sections 5.4.22 and 5.5.6.
Batteries and racks	Screened by the SRT. See SEWS for battery racks. See Section 5.4.15.

Table 5-2 (Continued)

SUMMARY OF EQUIPMENT AND SUBSYSTEMS SEISMIC MARGIN EVALUATION

EQUIPMENT TYPE	DISPOSITION
Diesel generators	Screened by the SRT. See diesel generator SEWS. See Section 5.4.17.
Horizontal pumps	Screened by the SRT. See horizontal pump SEWS. See Section 5.4.5.
Vertical pumps	Service Water Pump HCLPF is greater than the RLE (see Section 6). All other vertical pumps were screened by the SRT. See Section 5.4.6.
Fans	Screened by the SRT. No fans are supported on vibration isolators. See individual SEWS. See Section 5.4.9.
Air handlers	Screened by the SRT. No air handlers are supported on vibration isolators. See individual SEWS. See Section 5.4.10.
Chillers	Screened by the SRT. No chillers are supported on vibration isolators. See individual SEWS. See Section 5.4.11.
Air Compressors	Screened by the SRT. No air compressors are supported on vibration isolators. See diesel air start SEWS. See Section 5.4.12.
HVAC ducting and dampers	Screened by the SRT. See Section 5.8.2.
Cable trays	Screened by the SRT. See Section 5.8.1.
Electrical conduit	Screened by the SRT. See Section 5.8.1.
Electrical power distribution panels, cabinets, switchgear, motor control centers	HCLPF capacities were estimated to be greater than the RLE for low voltage switchgear and miscellaneous electrical panels. See Section 6 for a summary of the evaluations. All other electrical gear were screened by the SRT. See Sections 5.4.1, 5.4.2, 5.4.3 & 5.4.14.

Table 5-2 (Continued)

SUMMARY OF EQUIPMENT AND SUBSYSTEMS SEISMIC MARGIN EVALUATION

EQUIPMENT TYPE	DISPOSITION
Transformers	Included in the low voltage switchgear and MCC's, see above item.
Battery chargers	Screened by the SRT. See battery charger SEWS. See Section 5.4.16.
Inverters	Screened by the SRT. See inverter SEWS. See Section 5.4.16.
Instrumentation and control panels and racks	Screened by the SRT. See panel and rack SEWS. See Sections 5.4.19 and 5.4.21.
Temperature sensors	Screened by the SRT. See temperature sensor SEWS. See Section 5.4.20.
Pressure and level sensors	Screened by the SRT. See instrument SEWS. See Section 5.4.18.

Table 5-3

COMPONENTS REQUIRING MAINTENANCE REPAIRS

EQUIP ID NO.	EQUIPMENT DESCRIPTION	LOCATION	COMMENT	WR/JO NO.
1A-SA	1DG-E036 Diesel generator control panel	DGB 261'	Close both ends of the "S" hooks on the hanging fluorescent lights in the DG control panel room	94-ANQC1
1B-SB	1DG-E037 Diesel generator control panel	DGB 261'	Close both ends of the "S" hooks on the hanging fluorescent lights in the DG control panel room	94-ANQE1
1A1,1A2 2A1 & 2A2	1EE-E064, 65, 68 and 69 Isolation cabinets	RAB 305'	The row of fluorescent lights needs to be relocated on the existing Unistrut three inches to the west (away from the cabinets)	95-ACLT1
AUX-RLY-PNL-19A	Train A Aux. relay panel 19A	RAB 305'	Install missing mounting screw for relay CR-1-1273	94-AAPQ1
AUX-RLY-PNL-19B	Train B Aux. relay panel 19B	RAB 305'	Install three missing mounting screws relay CR-1191	94-AAPP1
1B31-SB	MCC 1B31-SB (Includes panel and transformer PP-1B311-SB)	RAB 286'	Replace missing latch on breaker panel door missing latch	90-AEMY1
1A32-SA	Motor control center 1A32-SA	ESWS 261'	Replace missing latch on breaker panel door	92-AFHI1
1B32-SB	Motor control center 1B32-SB	ESWS 261'	Replace missing latch on breaker panel door	89-AISZ1
IDP-1A-SI	120 Vac instrument panel (Includes IDP-1A-SIII)	RAB 305'	Replace three missing access panel screws, and replace two missing latches for breaker panel doors	94-ANKZ1 and 94-ANXK1

Table 5-3 (Continued)

COMPONENTS REQUIRING MAINTENANCE REPAIRS

EQUIP ID NO.	EQUIPMENT DESCRIPTION	LOCATION	COMMENT	WR/JO NO.
IDP-1B-SII	120 Vac instrument panel (Includes IDP-1B-SIV)	RAB 305'	Replace three missing access panel screws	94-ANXJ1
1TIS-658A	RHR heat exchanger 1A-SA temp. switch	RAB 236'	U-Bolt has slipped off top of pipe and needs to be reworked	94-ANXL1
A21-R15	Instrument rack, LT-9010B	TANK 236'	Close both ends of the "S" hooks on the hanging fluorescent light above rack	94-APBY1
1AF-55	Electric motor operated valve	MST 261'	Compressed gas cylinder adjacent to valve needs to be removed or restrained in accordance with AP-003	Compressed gas cylinder has been removed

Table 5-4

ITEMS REQUIRING REPAIR OR MODIFICATION

ENGINEERING SERVICE REQUEST (ESR) 94-152

EQUIP ID NO.	EQUIPMENT DESCRIPTION	LOCATION	COMMENT
1B-SB	1DG-E037 Diesel generator control panel	DGB 261'	Four of the hanging fluorescent fixtures in the DG control panel room "B" are not the spring loaded fluorescent tube design. These fixtures require fluorescent tube clamps/clips to prevent the tube from coming loose due to vibration.
AUX-RLY-PNL-4A	Train A Aux. relay panel 4A	RAB 305'	Auxiliary relay panel 4A needs to be physically attached w/ cabinet main termination cabinet 11A-SA . Potential impact/interaction between cabinets is not acceptable since 4A contains essential relays.
AUX-RLY-PNL-1B, 2B, 3B, AND 4B	Train B Aux. relay panels: 1B, 2B, 3B, and 4B	RAB 305'	The fuel status board (which is on wheels) needs to be restrained, possibly with cables to the wall. Potential impact/interaction with cabinets is not acceptable since cabinet contains essential relays.
AUX-RLY-PNL-19B	Train B Aux. relay panel 19B	RAB 305'	
MAIN-CTRL-BOARD	Main control board -1AA, 1A1, 1A2, 1BB, 1B1, 1B2, 1C, 1D1 and 1D2	RAB 305'	Cabinets, carts, and etc. that are to the south of the main control board need to be restrained. Potential impact/interaction with Main Control Board (MCB) is not acceptable.
DP-1A-SA	Distribution panel for vital DC 1A-SA	RAB 286'	Relay access door not properly secured - stripped screws. The door/fastening mechanism needs to be repaired.
DP-1B-SB	Distribution panel for vital DC 1B-SB	RAB 286'	Relay access door not properly secured - stripped screws. The door/fastening mechanism needs to be repaired.

Table 5-5

COMPONENTS REQUIRING HCLPF CALCULATIONS

GROUP	EQUIP ID NO.	EQUIPMENT DESCRIPTION
1	1A	Transfer panel 1A
1	1B	Transfer panel 1B
1	1A-SA	1DG-E038 ESS panel
1	1B-SB	1DG-E039 ESS panel
1	DP-1A-SA	Distribution panel for vital 1A-SA
1	DP-1B-SB	Distribution panel for vital 1B-SB
2	1A2-SA	Low voltage switchgear 1A2-SA
2	1A3-SA	Low voltage switchgear 1A3-SA
2	1B2-SB	Low voltage switchgear 1B2-SB
2	1B3-SB	Low voltage switchgear 1B3-SB
3	1A-SA	RHR heat exchanger 1A-SA
3	1B-SB	RHR heat exchanger 1B-SB
4	1X-SAB	Condensate storage tank
4	1X-SN	Refueling water storage tank
5	1A-SA	ESW suction pump A
5	1B-SB	ESW suction pump B

Table 5-6

REVIEW OF MASONRY WALLS ADJACENT TO SSEL COMPONENTS

WALL	DESCRIPTION	COMPRESSION		INTERACTION fa/Fa + fm/Fm	SHEAR
		AXIAL	FLEX		
DGB EL. 261'	Type IV	fa = 21 psi Fa = 633 psi	fm = 125 psi Fm = 955 psi	0.16	fv = 2 psi Fv = 48 psi
RAB EL. 236' STAIR NO. A4	North Wall Type II	fa = 32 psi Fa = 513 psi	fm = 153 psi Fm = 950 psi	0.22	fv = 10 psi Fv = 48 psi
	South Wall Type II	fa = 37 psi Fa = 547 psi	fm = 382 psi Fm = 950 psi	0.46	fv = 26 psi Fv = 48 psi
	West Wall Type II	fa = 29 psi Fa = 535 psi	fm = 287 psi Fm = 950 psi	0.36	fv = 15 psi Fv = 48 psi
RAB EL. 261' STAIR NO. A3	North Wall Type II	fa = 29 psi Fa = 535 psi	fm = 225 psi Fm = 950 psi	0.25	fv = 12 psi Fv = 48 psi
	East & West Walls Type II	fa = 4 psi Fa = 585 psi	fm = 160 psi Fm = 950 psi	0.18	fv = 23 psi Fv = 48 psi
RAB EL. 305'	West Wall Type II	fa = 39 psi Fa = 553 psi	fm = 433 psi Fm = 955 psi	0.53	fv = 31 psi Fv = 48 psi
	North, South & East Walls Type II	fa = 31 psi Fa = 535 psi	fm = 301 psi Fm = 955 psi	0.38	fv = 26 psi Fv = 48 psi

6. ASSESSMENT OF ELEMENTS NOT SCREENED OUT

Sixteen items were selected for HCLPF evaluation by the SRT. The items were grouped into 5 HCLPF calculations based on similar characteristics. Results of the HCLPF evaluations are summarized below.

1. Panel Anchorage with 45° Nelson Studs

The SRT observed several panels that met all screening guidelines during the field visual review, however, a suspect load path to structural concrete was noted during a drawing review. Embedded 6 x 8.2 structural channels are anchored to a raised pad via Nelson studs welded to the inside corners of the channel. The detail was considered suspect because the studs are relatively small and short (3/8" diameter, 2-9/16" long, and spaced at 30").

Initial analyses indicated HCLPF capacities of less than 0.3g. Upon further refinement of the model, assuming shear loads are transferred directly to the concrete by the channel legs rather than through the studs, a HCLPF capacity of 0.59g was calculated. The governing failure mode was determined to be concrete cone failure. The evaluation is documented in Reference 11.

2. Low Voltage Switchgear

Low voltage switchgear were selected for HCLPF evaluation due to a test response spectrum (TRS) that did not exceed the scaled required response spectrum for RLE by an appreciable margin. Additionally, transformer anchorage anomalies were observed during the test and the anchorage calculation for the switchgear indicated a small margin using SSE loads.

Initial analyses indicated a HCLPF capacity significantly less than 0.3g due to the low margin between the TRS and RRS. Seismic floor response spectra at the location contain a sharp peak between about 6 and 8 Hz,

within the frequency range of interest. The spectra were peak clipped in accordance with Reference 3 to significantly reduce the RLE seismic demand. The resulting HCLPF is 0.35g.

Transformer anchorage details observed were substantially more robust than the details that experienced anomalies during the test, leading to an anchorage HCLPF of 0.70g. The evaluation is documented in Reference 12.

3. RHR Heat Exchangers

Harris RHR heat exchangers were selected for HCLPF evaluation since upper lateral restraints for the vertical heat exchangers were not installed. Top supports were included in the original design but were not installed based on analyses that justifies the configuration for DBE levels.

The CCW inlet piping attached near the top of the RHR heat exchangers is supported differently for Train A and B. The piping for the Train B heat exchanger has more supports than the Train A piping. The stress analysis of the piping gives higher nozzle loads on the Train B heat exchanger than on the Train A heat exchanger even though Train B has more supports on the inlet piping. This was noted as an observation during the peer review walkdown.

Upon review of the two stress calculations, the response spectra and damping levels used in the two analysis were not the same. The Train B stress analysis conservatively used one percent and two percent damping for OBE and DBE, respectively and enveloped the Reactor Auxiliary Building and Containment Building spectra for elevation 261' and below. The Train A stress analysis used code case N411 (PVRC) damping for Reactor Auxiliary Building, elevation 261' and below. Both methods are acceptable with Train B being more conservative. The piping configuration and supports are correctly reflected in each stress analysis. The higher loads on the Train B

heat exchanger are attributed to the difference in the response spectra used in the stress analysis.

Anchor bolts holding the based of the RHR heat Exchangers to the foundation were identified as the critical item. The HCLPF was estimated by scaling existing analyses and eliminating some of the conservatism. Conservatism in the combination of heat exchanger nozzle loads was eliminated by combining seismic loads by square-root-sum-of-squares and actual concrete strength was used rather than design strength. This led to a HCLPF of 0.29g. It should be noted that additional margin may be extracted from piping dynamic analyses for nozzle loads. The evaluation is documented in Reference 13.

4. CST and RWST Flat Bottom Storage Tanks

The HCLPF capacity of the Condensate Storage Tank (CST) and the Refueling Water Storage Tank (RWST) were estimated since these tanks are important and high profile elements of the shutdown paths.

The HCLPF capacity is calculated to be over 1g based on the methodology provided in Reference 3. The evaluation is documented in Reference 14.

5. Emergency Service Water Pumps

The emergency service water pumps were selected for HCLPF evaluation because the seismic qualification indicated low margin to allowable stress levels in the long vertical column.

The HCLPF capacity was estimated by scaling existing analyses, considering the pump column and sole plate as potential failure modes. The seismic contribution to pump column stresses was low due to the numerous bearing supports. The governing failure mode was determined to be the sole plate with a sufficiently high HCLPF of 0.67g. The evaluation is documented in Reference 15.

Four of the 5 groups of equipment have a HCLPF capacity of greater than the RLE. The RHR Heat Exchanger HCLPF capacity is calculated to be 0.29g. Further refinement of the associated piping analyses to eliminate any unnecessary conservatism in the nozzle loads may raise the HCLPF capacity above the RLE. Conservatism also exists in the RLE spectra as discussed in Section 4. This refinement is not considered necessary since the HCLPF capacity is essentially equal to the RLE.

7. RELAY EVALUATION

As described in NUREG-1407, for the focused-scope plants (including Harris), the evaluation of relay chatter emphasizes consideration of relays with known low seismic ruggedness. These relays are to be evaluated for potential plant impact. The seismic margins analysis (SMA) process developed by EPRI is being used to satisfy the generic letter for Harris. For the SMA methodology, the effect on the plant safety is determined by examining the potential impact of chattering of low-ruggedness relays on the operation of the equipment in the safe shutdown paths. If it can be shown that there are no low-ruggedness relays, or that they would have insignificant effect if they chattered during an earthquake, the evaluation is complete.

The relay study was performed by Safety and Reliability Optimization Services, Inc. (SAROS) and documented in SAROS Report No. 93-9, Reference 20. The relay study focused on identifying low-ruggedness relays. Fifty-one relays were evaluated because they were identified to be potentially low-ruggedness models. These identifications were made based on a comparison of the makes, models, and configurations (energized vs. de-energized, normally open vs. normally closed contact pairs) to the list of low-ruggedness relays provided in Appendix E of EPRI NP-7148-SL, Reference 18.

Further review of these 51 relays were performed with the following results, Reference 20, Section 4:

- Twelve of the 51 relays were determined not to be low-ruggedness relays because they were not in a configuration that had been determined to be subject to chatter for the relevant model.

- Twenty-nine of the 51 relays were determined to be non-essential relays in which chatter is not a concern.

- Four of the 51 relays were determined to be essential. However, chatter of these four relays would not produce any unacceptable consequences.

- The remaining six relays, of the 51, were determined to be essential relays. These are the differential relays (one for each phase) that would actuate the lockout relays on the two 6.9kv emergency buses (switchgear units). These relays are all General Electric model 12PVD21B1A relays. The equipment tag no. for these six relays are 87SA-A-1738, 87SA-B-1738, 87SA-C-738, 87SB-A-1739, 87SB-B-1739 and 87SB-C-1739. The relays are mounted in the doors of cubicle 10 and 6 on the emergency buses 1A-SA and IB-SB, respectively. The relays are mounted within 18 inches of the floor. Further discussion on these relays is given below:

This make and model relay, GE 12PVD21B1A, is on the low-ruggedness relay list as a result of Licensee Event Report (LER) No, 84-020, Docket No. 352, Reference 23. The event involved an inadvertent trip of the D14 bus 'A' phase differential relay which caused the D14 bus to de-energize. The cause of the event was described as follows: "Maintenance personnel were working on a door stop inside breaker cubicle number 6 of bus D14. The D14 bus 'A' phase differential relay is mounted on the door of this cubicle. While work was being performed on the door stop the 'A' phase differential relay was bumped causing the relay to trip and isolate the bus." This is defined as a high frequency vibration issue.

The configuration of these relays provide an inherent seismic margin. The following description of the differential relay function is presented in Reference 24, Section 4: "These differential relays are normally de-energized; when two of three on a particular bus are operated, they cause the lockout relay for that bus to operate. Each of the differential relays has three coils, each with a set of auxiliary contacts. Simultaneous chatter of these contact pairs on two or more of the relays for a

particular bus would cause that bus to be locked out. Operation of the lockout relay would cause the associated emergency diesel generator to trip, and would trip open the supply breakers to the bus and the feeds to the 6.9kv safety equipment and to the 6.9kv/480v transformers. If this were to occur on both buses, a station blackout would result. These breakers could not be re-closed or the diesel generators started until the lockout relays were manually reset. This could only be done locally (i.e., at the respective 6.9kv emergency bus). Although there are seal-in circuits for the differential relays, these relays would be de-energized after the lockout relays had operated. After the initial chatter, the contact pairs should be in their normal (open) positions. They should not impede subsequent attempts to reset the lockout relays."

Sufficient margin exists in the seismic qualification of the relay that inadvertent trip of the relay is not a concern. The 6.9kv emergency buses, including the differential relays and the lockout relays are seismically qualified per the Seimens-Allis Qualification Report No. 90365-1, Reference 24. As described above, chatter on two of three differential relays is needed for the lockout relay to operate. When the lockout relay is operated the associated bus would be de-energized. During the seismic test, the differential relays were not monitored for contact chatter. However, they were energized and configured consistent with design requirements. The lockout relay was monitored for contact chatter greater than 2 milliseconds. This monitoring would detect any unacceptable chatter of the differential relays. No contact chatter greater than 2 milliseconds was recorded for the lockout relay during the seismic testing.

The SSE test response spectra (TRS) envelops the review level earthquake (RLE) for the Reactor Auxiliary Building, Unit 1, at elevation 286'. The SSE TRS horizontal ZPA for the front-to-back and side-to-side directions were recorded as 1.87g (test run 11) and 1.90g (test run 20), respectively, Reference 24, Table I. The RLE ZPA for the Reactor Auxiliary Building, Unit 1, at elevation 286' is 0.773g, N-S and 0.613g, E-W. This results in a margin of 2.4 above the RLE and a margin of 3.9 above the Design Basis Earthquake for Harris.

In addition to the review of the seismic qualification, the emergency busses were reviewed for interaction issues during the SRT walkdown. No interaction issues were noted that would cause high frequency vibration to the emergency buses. The floor in front of cubicle 6 and 10 for emergency buses 1B-SB and 1A-SA, respectively are painted yellow the full width of the door and approximately 18 inches out from the door. This yellow area has black lettering stating "STAY CLEAR." Cautionary labels are also attached to the cubicle doors. These labels state the follow "Vibration Sensitive Relays. Jarring Switches or Cabinet Will Cause a Reactor Trip." These labels are precautionary measures that identify the sensitivity of these components. Therefore, inadvertent relay trip is not a concern for the differential relays located on the emergency buses based on the system configuration, seismic qualification review, no interaction issues, and the cautionary labels on and in front of the cubicles with the relays.

The relay study also noted some relays with unidentified make and models, see Tables 5 and 6 of SAROS Report No. 93-9. Make and models were subsequently identified through further reviews. None of the relays listed in Tables 5 and 6 were identified to be low-ruggedness relays and the Equipment Database System (EDBS) has been updated to reflect the results of the further reviews.

The results of the relay evaluation meets the intent of generic letter 88-20 and no further action is required.

8. SEISMIC INDUCED FIRE AND FLOOD EVALUATION

Seismic/fire interactions, effects of suppressants on safety equipment, and control system interaction should be addressed in the IPEEE per NUREG-1407, Reference 2. The majority of seismic/fire issues are identified in the NUREG/CR-5088 "Fire Risk Scoping Study," Reference 16 and NRC Information Notice 94-12, "Insights Gained from Resolving Generic Issue 57," Reference 17. A description of the fire suppression systems is given below. Specific fire issues are addressed later in this section.

The following four types of automatic fire suppression systems are used at Harris:

1. Water spray system
2. Wet pipe sprinkler system
3. Pre-action sprinkler system
4. Multi-cycle sprinkler system

The water spray system consist of dry pipe with a one-step release. The water flow is controlled by a deluge valve which is activated by a signal from a thermal detector. The water is discharged through open sprinkler heads. This type of sprinkler system is used in the Turbine Building. There is no success path equipment located in this area.

The wet pipe sprinkler system are supplied through hydraulically designed piping systems charged with water up to the sprinkler heads. Water is discharged through the sprinkler heads upon the melting of fusible links. This type of sprinkler system is provided in areas where inadvertent operation will not have a negative effect, such as the Warehouse and Administration Building. There is no success path equipment located in these areas.

The pre-action sprinkler system is a two-step water release system. The system is supplied through hydraulically designed piping, which downstream of the deluge valve controlling the water flow contains air under supervisory air pressure. The

deluge valve is automatically actuated by a thermal fire detection system installed in the same area as the sprinklers, and are manually shut off after the fire is extinguished. Pre-action systems are provided in safety related or non-safety related areas where inadvertent sprinkler operation is not acceptable. Pre-action systems limit discharge because water will not flow unless the pre-action valve is opened by a signal from the fire detection system and the sprinkler heads near the fire are fused open by heat from the fire.

The multi-cycle sprinkler system is a pre-action system modified to provide the capability for on and off cycling. Because of their ability to limit water discharge, multi-cycle sprinklers are used in areas where radioactivity may be a problem and the drainage from these areas must be treated or areas where drainage is pumped out of the area, and water discharge should be limited.

Piping for all four types of automatic fire suppression systems is seismically supported to assure system pressure integrity after a safe shutdown earthquake (SSE). Piping and valves are designed to comply with ANSI B31.1.

Standpipe and hose stations are located throughout the plant at approximately 100 ft intervals so that all portions of the plant can be reached by two effective hose streams. This system is basically passive and is not susceptible to inadvertent actuation. The Post SSE Standpipe system piping is analyzed for SSE loading and seismically supported to assure system pressure integrity after a SSE.

The following seismic/fire issues are identified in the NUREG/CR-5088 "Fire Risk Scoping Study," Reference 16:

- **Identify unanchored CO_2, halon, oxygen or hydrogen tanks.**

  Gas bottles are stored in the following locations:

  1. RAB, elev. 236' outside the Reactor Containment Building (RCB) personnel hatch - These bottles are stored in seismically designed storage rack.

2. RAB, elev. 236', hot machine shop located in the Unit 2 side of the RAB common area - The hot machine shop does not contain permanent plant equipment.

3. RAB, elev. 261' between column lines Gz/43 and H/43 in the Unit 2 side of the RAB common area - This area does not contain any permanent plant equipment.

4. RAB, elev. 286' at column line E/13 - A halon bottle/cart is located away from permanent plant equipment and is chained to the wall.

5. RAB, elev. 286' stairwell near column line D/35 - A halon bottle/cart is located under the stairs. The stairwell does not contain permanent plant equipment.

   A first aid storage cabinet and other non-plant equipment is stored in the stairwell. The first aid cabinet potentially could impact the halon bottle during a seismic event. This does not affect any safe shutdown equipment. A potential personnel safety issue is a concern if personnel need to use the stairwell. An adverse condition and feedback report (ACFR) number 95-0128 was initiated to document this condition. As a result of this ACFR, the halon bottle has been relocated to the turbine building.

   The gas bottles are adequately stored/restrained within the power block to preclude any damage to SSEL equipment and permanent plant equipment.

- **Identify actuation systems that are sensitive to vibration, relay chatter, and/or locking circuits:**

Typical relays contained within the fire protection system are listed in Table 8-1.

These are small relays that plug-in to printed circuit board cards within the fire detection panels. These are not low-rugged relays with respect to the list of low rugged relays provide in Appendix E of EPRI NP-7148-SL, Reference 18. Therefore, no further action is required.

- **Identify fire detection systems with only ionization detectors where dust may cause a spurious alarm:**
  Table 8-2 lists areas within buildings that contain success path items that have ionization detectors only. This may result in an alarm but will not cause an inadvertent actuation of the fire suppression system.

- **Identify fire pumps that may have weak mounts or vibration mounts:**
  There are three non-safety related fire pumps located at the Emergency Service Water Screening Structure. The pumps are anchored to the concrete without vibration isolation mounts. In addition, if a seismic event affects the operation/ functionality of these pumps, the backup water supply can be provided by the Emergency Service Water pumps to the Post SSE Standpipe System, per the Design Basis Document (DBD) No. 306, "Fire Protection and Detection System," Reference 19. Therefore, the mounting of the non-safety related fire pumps is not a concern.

- **Identify fire mains that are of cast iron material:**
  The material for the outside underground piping is ductile iron per DBD No. 306, Reference 19. The standpipe, hose system

and automatic suppression system piping material is carbon steel. No cast iron material was identified within the fire piping system.

- **Verify that all electrical cabinets are properly anchored and have sufficient slack in the cables entering the cabinet:**
  The SRT walkdown included an interaction review between SSEL electrical cabinets and adjacent non-SSEL electrical cabinets. The SRT walkdown also verify that there is sufficient slack existing in the cables entering the electrical cabinets. The results from the SRT walkdown did not identify any vulnerabilities in this area.

- **Identify credible interactions between sprinkler systems and adjacent piping:**
  The automatic fire suppression system piping is seismically supported to assure system pressure integrity after a SSE. No interaction issues between the sprinkler system and adjacent piping were noted during the SRT walkdown.

The following seismic/fire issues are identified in NRC Information Notice 94-12, "Insights Gained from Resolving Generic Issue 57," Reference 17:

- **Mercury Relays:**
  No mercury relays have been located in the fire protection circuits.

- **Seismic Dust/Smoke Detectors:**
  Several fire zones within the power block have ionization detectors only which sends an alarm to the control room. Actuation of the fire suppression system (pre-action sprinklers)

is only by thermal detection and, is independent of the detection. Therefore, inadvertent actuation will not occur.

- **Water Deluge Systems:**
  The SRT walkdown included an interaction review for potential sources that could flood or spill onto the electrical cabinets. This is specifically addressed on the SEWS form. No interaction issues, with respect to flooding or fire protection systems flooding electrical cabinets, were noted during the SRT walkdown. No further action is needed.

- **Fire Suppressant Availability During a Seismic Event:**
  There are three non-safety related fire pumps located at the Emergency Service Water Screening Structure. If a seismic event affects the operation/functionality of these pumps, the backup water supply can be provided by the Emergency Service Water pumps to the post SSE standpipe system, per the Design Basis Document (DBD) No. 306, "Fire Protection and Detection System," Reference 19. The post SSE standpipe system piping is analyzed for SSE loading and seismically supported to assure pressure integrity after a SSE. Therefore, the operation/functionality of the non-safety related fire pumps is not a concern.

- **Switchgear Fires:**
  The SRT walkdown included screening/evaluation of switchgear. The SRT walkdown verified adequate switchgear anchorage, sufficient slack in cables entering the switchgear and sufficient separation to other electrical cabinets. The Train "A" and Train "B" switchgear are also physically separated by a reinforced concrete wall. The results from the

SRT walkdown did not identify any seismic/fire interaction concerns with regards to the switchgear.

- **Electro-Mechanical Components in Cable Spreading Room:** The cable spreading rooms only contains two electrical cabinets, Auxiliary Transfer Panel SA and SB. The SSEL includes both of these electrical cabinets and were screened out from further review during the SRT walkdown. These electrical cabinets are seismically anchored which addresses this issue. No interaction issues were noted in the cable spreading rooms.

In addition to the seismic/fire interactions addressed above, fire sources are to be identified and evaluated. The following fire sources were identified:

1. **Hydrogen Hazard** - Hydrogen is supplied to the Turbine Building from the Hydrogen storage tank for the main generator and from the Turbine Building into the Reactor Auxiliary Building to the Volume Control Tank. The hydrogen lines within the Turbine Building are not a concern since this area does not contain any SSEL equipment. The hydrogen line in the Reactor Auxiliary Building is non-safety, non-seismic from the Turbine Building to the air operated valve 1-CS-322 and is Class 2 from valve 1-CS-322 to the Volume Control Tank. Two exceedances of the recommended ANSI B31.1 spans were observed. Both exceedances are approximately 15 foot spans. The 15 foot spans are not considered a significant seismic hazard based on the inherent ruggedness of small bore socket welded pipe as demonstrated by earthquake experience, test and analytical data.

2. **Liquid Fire Hazard** - There are two liquid fire hazards that were identified in areas where safety related equipment are present; the diesel generator fuel oil day tanks located in the Diesel Generator Building, and the reactor coolant pump (RCP) oil collection system in the Containment Building. The seismic walkdown list included the diesel generator fuel oil day tanks and were screened out from further review during the SRT walkdown. The RCP oil collection system was evaluated by reviewing the oil collection system drawings, CP&L drawing no. 1364-53480, Reference 29 and viewing the RCP's using the Harris Surrogate Tour system. The tour program uses the combined technology of laser videodiscs and the personal computer to effectively simulate travel through the plant and provide detailed visual information about plant areas. The oil collection system is well supported and is screened out based on these reviews.

Other sources of liquid fire hazards are the lube oil systems of various pumps (excluding the RCP's). These sources are insignificant in terms of risk and can be ignored in the seismic/fire walkdown. Even though these may be insignificant, the lube oil systems of the pumps included on the SSEL were considered rule-of-box and evaluated/screened with the pump during the SRT walkdown. The results from the SRT walkdown did not identify any vulnerabilities in this area.

No further action is required as a result of the seismic/fire evaluations reviews and walkdown.

Table 8-1

TYPICAL FIRE PROTECTION SYSTEM RELAYS

Description	Make	Model
Relay, Signal, 24VDC	Potter & Brumfield	R10-E6210-1 & R10-E1x4-V700
Relay, Transfer, Power	Potter & Brumfield	R10-E1-M2
Relay, Trouble (Alarm Only)	Telemecanique	TF154-2C-2C

Table 8-2

FIRE ZONES WITH ONLY IONIZATION DETECTORS

BUILDING	ZONE	LOCATION	BUILDING	ZONE	LOCATION
RCB	1-7A	ELEVATOR	RAB	1-43	1-A-ACP
RAB	1-10	1-A-1-FD	RAB	1-44	12-A-5-DIH
RAB	1-11	1-A-1-ED	RAB	1-185	1-A-5-COMA
RAB	1-15	5-W-1-C1	RAB	1-46	12-A-6-RT1
RAB	1-23	1-A-4-COR	RAB	1-47	12-A-6-RCC1
RAB	1-33	1-A-5-HVA	RAB	1-48	12-A-6-CR1
RAB	1-34	1-A-5-HVB	RAB	1-49	12-A-6-ARP1
RAB	1-35	1-A-5-SWGR A	RAB	1-50	12-A-6-CR
RAB	1-36	1-A-5-SWGR B	RAB	1-51	12-A-6-1RR
RAB	1-37	1-A-5-BAT A	RAB	1-52	12-A-6-PICR1
RAB	1-38	1-A-5-BAT N	RAB	1-55	12-A-7-HV
RAB	1-39	1-A-BAT N	RAB	1-56	ELEVATOR
RAB	1-41A	1-A-PICA	RAB	1-122	CONTROL BOARD
RAB	1-42A	1-A-5-PIC-B	RAB	1-123	HVAC ROOM

Duct Detector Zones 1-150 through 1-177 are also only ionization detectors.

9. CONTAINMENT INTEGRITY

The main objective of the containment analysis is to identify vulnerabilities that involve early failure of containment functions. This includes consideration of containment integrity, containment isolation, and other containment functions.

The guidance provided in NUREG-1407, Reference 2 states that "generally containment penetrations are seismically rugged; a rigorous fragility analysis is needed only at review levels greater than 0.3g, but a walkdown to evaluate for unusual conditions (e.g., spatial interactions, unique penetration configurations) is recommended." With regard to containment systems, the guidance provided is that "seismic failures of actuation and control systems are more likely to cause isolation system failures and should be included in the examination." The major concern deals with relay chatter which is addressed in Section 7 of this report.

A review of seismic capacities for containment's of similar design to Harris indicates that the containment structure is expected to have a seismic capacity far above the review level earthquake, Reference 21. In addition to the containment structure, NUREG-1407, Reference 2 suggests that certain considerations could require some additional study. Hatches that employ inflated seals is one potential area for concern. The Harris design does not employ this type of seal. Another concern is the post-operation of penetration cooling that is present in some designs. Harris, however, does not employ this design feature. Finally, air-closed valves used for isolation are also listed as a possible concern. Harris does not utilize air-operated valves for containment isolation that require a supply of air to function. Thus, failures in containment isolation would not be expected due to containment system failures.

Containment heat removal is an important aspect in evaluating containment performance. If heat is not adequately removed from the containment the containment pressure may increase to the containment failure pressure. Two mechanisms can lead to energy being transmitted to the containment. The first is

due to the small LOCA. As RCS inventory is lost through the break it carries stored energy which is then release to the containment and pressurization occurs. Feed-and-bleed cooling also results in energy being transferred to the containment. Containment fan coolers can reduce the pressurization due to these mechanisms.

Based on Modular Accident Analysis Program MAAP analyses performed for the individual plant evaluation (IPE) the containment pressure is not expected to increase to the design limit as long as the RHR heat exchangers are available to remove heat. Thus, the fan coolers represent an additional heat removal mechanism but are not required for successful containment cooling as long as the RHR heat exchangers are present. Failure of this heat removal function will result in containment heatup and pressurization.

The pressurization, however, is predicted to occur over many hours and would not result in an early, rapid containment over pressurization. It is concluded that containment fan coolers are not needed to ensure early containment integrity. As a result, the only containment issues to be addressed are the seismic relay review and walkdown. The relay review is addressed in Section 7.

The containment walkdown consisted of looking/evaluating unusual conditions/configurations (e.g., spatial interactions, unique penetrations, piping hard spots, items/components bridging the seismic gap between the containment liner and interior structure, and etc.). The containment walkdown was performed by the SRT (see section 3).

No unusual conditions/configurations where noted except for the platform in the equipment hatch at elevation 286 ft. The platform is supported/welded to the liner at the equipment hatch barrel and is anchored to the floor of the interior structure at elevation 286 ft. Therefore, the platform bridges between the interior and exterior containment structures. This interaction issue is evaluated in calculation HNP-C/PLAT-1023 and is determined not to be detrimental to the containment integrity.

As stated previously, the main objective of the containment analysis is to identify vulnerabilities that involve early failure of containment functions. The SRT reviews and walkdown performed of the containment did not reveal any significant vulnerabilities. Therefore, the HCLPF for the containment is greater than 0.3g, based on SRT reviews, walkdowns and Appendix A of Reference 3.

10. PEER REVIEW

The Harris IPEEE peer review was performed by Mr. Charbel M. Abou-Jaoude and Mr. Steve Reichle of Vectra Technologies, Inc. during December, 1994. Peer reviewer resumes are included in Appendix A.

Peer review comments on the draft IPEEE report, SSEL report and relay evaluation report were submitted to CP&L (Reference 34). The comments were constructive and incorporated into their respective reports to improve the clarity and presentation of the seismic IPEEE program. Excerpts from the peer review summary are included in Sections 10.1 and 10.2 for the walkdown and systems peer review, respectively.

10.1 WALKDOWN PEER REVIEW

The following documents were reviewed by Charbel M. Abou-Jaoude:

- EQE Document No. 52214-P-001, "Project Plan, CP&L Harris IPEEE", dated January 10, 1994.
- EQE Calculation No. 52214-C-001, Revision 0, "CP&L Shearon Harris: Scaling of In-Structure Spectra for Seismic IPEEE", dated August 6, 1993.
- EQE High Confidence of Low Probability of Failure (HCLPF) calculations:

  52214-C-002, Rev. 0
  52214-C-005, Rev. 0
  52214-C-006, Rev. 0
  52214-C-007, Rev. 0
  52214-C-008, Rev. 0

- EQE Document No. 52214-R-001, "Seismic IPEEE, Shearon Harris Nuclear Power Plant", Draft, dated December 5, 1994.

In addition, a plant visit of all accessible areas, excluding Containment, high radiation areas, and the Emergency Service Water, was conducted. Representative

SEWS and data packages were also sampled. A comparison of the reviewer's field walkdown notes and the corresponding SEWS shows that all plant conditions that required further actions had been captured by the SRT. One minor housekeeping concern near the Diesel Control Panels was noted during the Peer Walkdowns: this condition was apparently introduced after the original Plant-Wide Walkdowns by the SRT.

Based on the above, the Peer Reviewer finds that the IPEEE program is being conducted in a very thorough and competent manner. The seismic examinations follow the guidance of EPRI NP-6041 for seismic margin reviews, and meet the objectives stated in NUREG-1407. The Peer Reviewer concurs with the overall results documented in the draft summary and has validated the judgment that has been exercised by the SRT during the walkdowns; also, the selection of equipment that require further reviews or detailed HCLPF calculations was found to be satisfactory given the vintage of the plant and the conservatisms associated with the original seismic designs. In view of some of the conservatism in the estimation of the in-structure demand for a 0.3g RLE, the Peer Reviewer judges that the plant structures, equipment, and systems are very rugged and are capable of withstanding a Review Level Earthquake greater than 0.3g.

The observations that follow primarily deal with areas that the reviewer believes could use some additional clarifications in order to capture some of the SRT's thought process. Also, one technical issue relative to the In-Structure RLE demand is being identified as requiring further discussions in order to better support some of the screening decisions and the limited scope of the HCLPF calculations.

10.2 SSEL AND RELAY PEER REVIEW

The following CP&L documents were reviewed by Mr. Steve Reichle:

- "Success Path Logic Diagram and Supporting Information Development", RSC 94-01, Revision 1, dated August 1994.

- "Relay Study for the Shearon Harris IPEEE", SAROS 93-9, Volume 1, dated December 1993.

- CP&L Drawings (flow diagrams):

2165-2-0542, Rev. 20	2165-S-1330, Rev. 17	2165-S-1308, Rev. 9
2165-2-0544, Rev. 25	2165-S-1301, Rev. 6	2165-S-1309, Rev. 15
2165-2-0545, Rev. 41	2165-S-1303, Rev. 9	2165-S-1310, Rev. 10
2165-2-0547, Rev. 26	2165-S-1305, Rev. 15	2165-S-1324, Rev. 9
2165-2-0550, Rev. 12	2165-S-1307, Rev. 6	2165-S-1344, Rev. 4

The peer review of the safe shutdown equipment selection and relay review work completed for the HNPP was performed against the guidance provided in EPRI NP-6041 and NUREG-1407. The methodology utilized to select and document the safe shutdown paths and equipment selection, as documented in RSC 94-01, fully meets the intent of EPRI NP-6041.

In addition to reviewing the above reports against the referenced guidance documents, a detailed check of the AFW and CVCS SSELs was performed with their respective flow diagrams. This review was made to determine if all applicable components were identified, and whether the correct review types (i.e. seismic and/or relay) were specified.

As a result of these reviews the following observations and comments were made and provided to Ricky Summitt Consulting. The "Response" to each comment was provided by Ricky Summitt Consulting. Based on a follow-up conversation with Messrs Ricky Summitt and Daryl Hughes of CP&L, action items have been identified under the "Recommended Follow-up" section for Items 3, 18 and 21.

The comments made by the Peer Reviewer are mostly questions presented to the preparer of the documents, and do not necessarily indicate that an error or omission had been made. Following the completion of the recommendations made in this attachment, the Peer Reviewer finds that the SSEL and Relay Review work followed the guidance of both EPRI NP-6041 and NUREG-1407, and are complete and acceptable.

11. SUMMARY AND CONCLUSIONS

The Harris seismic IPEEE was completed in accordance with NUREG 1407 guidelines using the EPRI seismic margins methodology provided in EPRI NP-6041.

The most important aspect of the program was plant walkdowns. Detailed SRT walkdowns were performed using the methodology, criteria and SEWS provided in EPRI NP-6041. Several components were identified for subsequent HCLPF evaluation.

The Harris plant is a modern late vintage pressurized water reactor which underwent thorough engineering review with extensive documentation. Nevertheless, the SRT identified 13 issues related to maintenance, housekeeping and seismic interaction that required work orders to satisfy SRT field issues. Six items were noted as requiring repairs or modifications. The SRT also identified design issues that required aggressive evaluation to establish HCLPF capacities that met or exceeded the RLE. The lowest calculated HCLPF capacity is for the RHR heat exchangers. A HCLPF of 0.29g based on conservative RLE spectra compares favorably to the RLE.

A minor potential plant seismic vulnerability surfaced while preparing for the walkdowns. The systems analyst identified five instruments that are powered from sources that may not be available after a seismic event, off-site power and the non-safety uninterruptible power supply (UPS). Alternate instruments or actions have been identified and have been determined to meet the intent of Generic Letter 88-20. The site Abnormal Operating Procedures (AOP's) are being updated to address the alternate instruments or actions that were identified by the system analyst.

A personnel safety issue was noted during the walkdown with regards to the potential for a first aid storage cabinet to fall on a halon bottle located in the stairwell of the RAB 286 ft. This does not affect safe shutdown equipment and

was documented in ACFR number 95-0128. As a result of this ACFR, the halon bottle was relocated to the Turbine Building.

The relay evaluation identified 51 potentially low-ruggedness relays within the Harris Plant. Six of the relays did not pass systems review screens. These relays are components of the 6.9K switchgear. A detailed review of the seismic qualification documentation for the 6.9K switchgear, including the relay qualification was performed. As a result of this review, it was determined that sufficient margin exists in the seismic qualification in which the intent of Generic Letter 88-20 is satisfied.

All issues identified by the SRT were satisfactory resolved. The evaluation concluded that the Harris plant HCLPF capacity meets the 0.3g RLE.

12. REFERENCES FOR SEISMIC ANALYSIS

1. USNRC, Generic Letter 88-20, Supplement No. 4, "Individual Plant Examination of External Events (IPEEE) for severe accident vulnerabilities," Final, April 1991.

2. USNRC, NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," final report, June 1991.

3. EPRI NP-6041, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin", Revision 1, August 1991.

4. USNRC, NUREG/CR-5250, "Seismic Hazard Characterization of 69 Nuclear Power Plant Sites East of the Rocky Mountains," January 1989.

5. USNRC, NUREG-1488, "Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains," October 1993.

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

7. Seismic Qualification Utility Group (SQUG), "Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment," Revision 2.

8. US Atomic Energy Commission, "Design Response Spectra for Seismic Design of Nuclear Power Plants," Regulatory Guide 1.60, Rev. 1, 1973.

9. EQE Calculation 52214-C-001, "CP&L Shearon Harris: Scaling of In-Structure Spectra for Seismic IPEEE," Revision 0.

10. EQE International, "Project Plan CP&L Harris IPEEE," EQE Document Number 52214-P-001, Revision 0.

11. EQE Calculation 52214-C-002, "CP&L Shearon Harris IPEEE: HCLPF Capacity Calculation for Panel Anchorage With 45° Nelson Studs," Revision 0.

12. EQE Calculation 52214-C-005, "CP&L Shearon Harris IPEEE: HCLPF Capacity Calculation for Low Voltage Switchgears 1A2- & 1A3-SA and 1B2- & 1B3-SB," Revision 0.

13. EQE Calculation 52214-C-006, "CP&L Shearon Harris IPEEE: HCLPF Capacity Calculation for RHR Heat Exchangers 1A-SA & 1B-SB," Revision 0.

14. EQE Calculation 52214-C-007, "CP&L Shearon Harris IPEEE: HCLPF Capacity Calculation for 1X-SAB CST Tank and 1X-SN RWST Tank," Revision 0.

15. EQE Calculation 52214-C-008, "CP&L Shearon Harris IPEEE: HCLPF Capacity Calculation for Emergency Service Water Suction Pumps A & B," Revision 0.

16. NUREG/CR-5088 "Fire Risk Scoping Study,"

17. NRC Information Notice 94-12, "Insights Gained from Resolving Generic Issue 57,"

18. EPRI NP-7148-SL

19. Design Basis Document (DBD) No. 306, "Fire Protection and Detection System."

20. Safety and Reliability Optimization Services, Inc. Report No. 93-9, "Relay Study for the Shearon Harris Individual Plant Examination of External Events," Volumes 1 and 2, Dated December, 1993, Including Addendum I, Dated February, 1995.

21. Summitt, R. L., Assessment of Containment Capacity for the ALWR Based on Prior PRA Assessments, USDOE Advanced Reactor Severe Accident Program, April 1990

22. IE Information Notice No. 85-45, "Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System used in Westinghouse Designed Plants," Dated June 6, 1985

23. Licensee Event Report (LER) No, 84-020, Docket No. 352

24. Seimens-Allis Qualification Report No. 90365-1

25. Westinghouse Electric Corporation, "Shearon Harris Units 1,2,3 &4 C.R.D.M. Seismic support Tie Rod Assembly," CP&L Drawing No.: 1364-41579, Revision 1.

26. Westinghouse Electric Corporation, "Reactor Integrated Head Package," CP&L Manual ID: MED, Revision 08.

27. CP&L Administrative Procedure AP-003, "General Plant Personnel Safety and Housekeeping"

28. CP&L Plant Programs Procedure PLP-401, "Ladder, Scaffold, and Equipment Use and Storage"

29. CP&L Drawing 1364-53480, Sheets 1 through 7 of 7, Revision 1, "Oil Spill Protection System for RCP Motors."

30. Nuclear Engineering Department Design Guide Number DG-II.17, "Interdiscipline Clearance Verification Walkdown"

31. Nuclear Engineering Department Design Guide Number DG-II.19, "Verification Walkdown in Accordance with Regulatory Guide 1.29"

32. EQE International, "Screening and Evaluation Walkdown Sheets for Shearon Harris Seismic IPEEE," EQE Document Number 52214-R-002, Revision 0.

33. EQE International, "Photographs From Shearon Harris Seismic IPEEE Walkdown," EQE Document Number 52214-R-003, Rev. 0.

34. Letter from Charbel M. Abou-Jaoude of Vectra Technologies, Inc. to Ronald L. Knott of CP&L dated December 30, 1994, "Carolina Power & Light Company Harris Nuclear Plant - IPEEE Peer Review." Letter No.: 0132-00161.000-001.

35. Nigam, Navin C. And Jennings, Paul C., "Digital Calculation of Response Spectrum for Strong-Motion Earthquake Records," National Science Foundation, June, 1968.

36. Newmark N.M., "Earthquake Response of Reactor Structures," Nuclear Engineering and Design, Vol. 20, Pages 303 to 322, 1972.

37. Hetenyi, M., "Beams on Elastic Foundations," University of Michigan Press, Ann Arbor, Michigan, 1967.

38. Summitt, R.C., Report No. RSC 95-01, Revision 1, "Shearon Harris Nuclear Power Plant Success Path Logic Diagram and Supporting Information Development," August, 1994, Including Addendum 1 Dated February, 1995.

APPENDIX A

SEISMIC REVIEW TEAM QUALIFICATIONS

JEFFREY H. BOND

Jeffrey H. Bond has over seventeen years of experience in the design, analysis, testing, and qualification of industrial and nuclear systems, structures, and components. His responsibilities have included finite element modeling and analysis; vibration testing and analysis; and load, shock, vibration, and environmental testing for hardware qualification. His experience includes fourteen years with an engineering consulting organization with primary responsibilities in the area of equipment qualification for both manufacturers and utilities. His three years of experience at CP&L have included design responsibilities, NRC audit preparations, forced-outage plant material condition resolution programs, and responsibility for SQUG/IPEEE implementation at CP&L's Brunswick Plant. He completed the SQUG and IPE Seismic Add-On courses in preparation for participation in USI A-46/IPEEE resolution at all CP&L's nuclear power plants. He holds both BS and MS degrees in mechanical engineering, and is a registered professional engineer in the state of North Carolina.

STEVEN R. BOSTIAN

Steven R. Bostian has over thirteen years of experience in nuclear plant construction and design. This experience includes two years of on-site field engineering during the construction phase of the Comanche Peak Nuclear Plant, three years of on-site field engineering during the construction phase of the Shearon Harris Nuclear Plant, six years of civil/structural design engineering for the three nuclear plants operated by Carolina Power and Light Company, and two years in the USI A-46/Seismic IPEEE project. Primary engineering responsibilities have been in seismic support design and justification of mechanical and electrical components including electrical raceway, small and large bore piping systems, instrumentation, HVAC equipment, cabinets, and panels. He was selected for CP&L's USI A-46/Seismic IPEEE project in late 1992. He completed the SQUG and IPE Seismic Add-On courses in preparation for participation in the USI A-46/Seismic IPEEE

resolution at all CP&L's nuclear facilities in early 1993. He is currently the responsible engineer for the A-46/Seismic IPEEE project for the Robinson Nuclear Plant in Hartsville, SC. He has also participated in the efforts for the Harris and Brunswick plants. He is a graduate of North Carolina State University with a Bachelor of Science Degree in Civil Engineering. He is currently registered as a professional engineer in both North and South Carolina.

MARTHA C. COOK

Martha C. Cook graduated from North Carolina State University in December, 1992 with a BS in Civil Engineering. She accepted an associate engineering position with CP&L in March, 1993. She was responsible for maintaining the SSEL databases and coordinating walkdown preparations for all three CP&L nuclear power plants including review of equipment qualification reports (testing and analysis), structures and equipment support drawings, equipment location drawings and anchorage calculations. She attended the SQUG Walkdown Screening and Seismic Evaluation Video Training Course in preparation for the USI A-46 and Seismic IPEEE walkdowns at CP&L's Harris, Brunswick and Robinson nuclear power plants.

RONALD W. CUSHING

At EQE, Mr. Cushing is a principal engineer for EQE Engineering Consultants involved in the application of earthquake experience data for component seismic verification at nuclear power plants. Mr. Cushing has investigated sites which have experienced major seismic activity for the SQUG earthquake experience database. He has extensive experience in performing nuclear power plant walkdowns for seismic adequacy in association with A-46 and IPEEE programs. Mr. Cushing is responsible for maintaining a database of replacement parts and components for equipment in nuclear power facilities. He is an author of the industry guidelines for the seismic technical evaluation for replacement items (STERI).

Mr. Cushing has over 17 years experience in nuclear plant walkdowns and startup testing, including valve testing, pump performance and vibration testing, system functional and preoperational testing on such systems as plant cooling water, condensate, main and auxiliary steam, turbine control and lube oil, main and auxiliary feedwater, chemical injection, service gas, and demineralizer systems.

Mr. Cushing is an instructor for the SQUG walkdown screening and seismic evaluation training course. He has also completed the SQUG equipment selection and relay evaluation training course and the EPRI add-on and seismic IPE training course. He is a registered Mechanical Engineer in the State of California.

GREGORY S. HARDY

Mr. Hardy has over 18 years experience in the design, analysis and testing of chemical, nuclear and aerospace structures and components. His responsibilities have included probabilistic risk assessments, earthquake experience data-based studies, stress analysis, finite element analysis, seismic margin studies, mass property studies, and shock and vibration environmental testing for hardware qualification.

Mr. Hardy has served as project manager on many projects including multi-million dollar efforts for Comanche Peak Nuclear Power Plant and for the Department of Energy K, L and P reactors at the Savannah River site. He also managed a seismic probabilistic risk assessment for the Chinshan Nuclear Power Plant in Taiwan, a seismic margin study for the Idaho National Engineering Laboratory ICPP facility, seismic research efforts for Mitsubishi Atomic Power in Japan and numerous seismic related projects for the commercial nuclear industry, the Department of Energy and the oil/gas industry. Mr. Hardy participated in the seismic safety margins research project SSMRP (the original margin research effort for LLNL) and was instrumental in the original development of the equipment fragility methods. He has also been a consultant to the Seismic Qualification Utilities Group(SQUG) for

9 years. He has directed and/or participated in the capacity evaluations of mechanical and electrical components on over 25 Probabilistic Risk Assessments (PRAs) for nuclear power plants. He has played a major role in both the development of the methodology and in the completion of the equipment fragility studies.

DARYL W. HUGHES

Daryl W. Hughes has over fourteen years of experience associated with structural design, analysis, testing and construction of nuclear power plant systems, equipment and components. He responsibilities have included seismic qualification of mechanical and electrical equipment and their supporting structures, review and approval of vendor seismic qualification reports, providing seismic requirements for equipment specifications, and evaluating equipment modifications. He has coordinated and directed reverification efforts of HVAC air handling units, plenums and equipment supports including supervision of personnel, design of hardware modifications, evaluation and resolution of design changes. He has four years of on-site design and construction experience of two nuclear plants. He completed the SQUG Walkdown Screening and Seismic Evaluation Training Course and the Add-On Seismic IPE Training Course in preparation for participation in USI A-46 and Seismic IPEEE resolution at CP&L's Harris, Brunswick and Robinson nuclear power plants. He holds a BS in Mechanical Engineering from the University of Illinois. He is a registered professional engineer in the state of North Carolina.

RONALD L. KNOTT

Ronald L. Knott has over eleven years of experience associated with the design and construction of nuclear power plants. For the majority of that time he has been involved with the seismic qualification of equipment. He has reviewed vendor reports and prepared calculations and reports documenting the dynamic analysis and qualification of distribution systems, structures, tanks, valves, and mechanical

and electrical equipment for seismic loads. He served as equipment seismic qualification supervisor for the nuclear engineering department at CP&L. He was assigned to the probabilistic risk assessment section and later assigned to the Brunswick Plant for restart following a dual unit shutdown associated with structural deficiencies. In this capacity, he was responsible for the reanalysis of 250 masonry walls under the IEB 80-11 criteria, plant walkdowns and evaluations for material condition deficiencies, electrical equipment anchorage assessments, HVAC ducting upgrade and instrument rack replacements. He has completed the SQUG and the IPEEE Seismic Add-on courses. He has participated development of a resolution approach for CP&L, performed walkdowns and documentation reviews. He holds a BS in Civil Engineering. He is a registered Professional Engineer in North Carolina.

TIMOTHY MASON

At EQE International Dr. Mason has been involved in structural assessment, ranging from the use of hand calculations to complex numerical modeling. He has gained experience in seismic analysis using the finite element program ANSYS. He has experience in nuclear plant walkdowns and seismic qualification, including structural and pipework assessments, equipment inspection for seismic adequacy and the investigation of thermal and seismic interactions. He has also carried out a comprehensive study on nuclear plant equipment identifying similarities between equipment at UK power stations and that found in the US SQUG seismic experience database. This project involved site walkdowns and data collection in the UK, equipment assessment and comparison with equipment documented in the database.

Dr. Mason's experience of analytical techniques for the seismic qualification of nuclear plant has been extensive. This work has included soil structure interaction to generate building responses from pre-defined ground motion and the use of this secondary response to assess the integrity of both the buildings and other major

structures. These analyses have been performed using time histories and, in the frequency domain, using response spectra.

Dr. Mason has completed the SQUG walkdown screening and seismic evaluation training course. He has a B.Sc. and a Ph.D. in Mechanical Engineering.

ROBERT N. PANELLA

Robert N. Panella has over twelve years of experience associated with design and construction of nuclear power plants. He has experience in seismic response spectra development, masonry wall analysis, pipe stress analysis, pipe and conduit support design, and seismic qualification of equipment. He has served as department expert in computer-assisted design of steel frames and re-analysis of existing structures. He has also provided training to engineering personnel on structural design issues to ensure consistency of approach among designers. He completed the SQUG Walkdown Screening and Seismic Evaluation Training Course and the Add-On Seismic IPE Training Course in preparation for participation in USI A-46 and Seismic IPEEE resolution at CP&L's Harris, Brunswick and Robinson nuclear power plants. He was the project manager for the USI A-46 and Seismic IPEEE programs of all three plants from 1992 through 1993. He holds a BS in Civil Engineering.

KEVIN N. POYTHRESS

Kevin N. Poythress has over four years of experience in structural design and analysis. He has been working for CP&L in the HESS civil stress subunit for 1 1/2 years performing pipe stress analyses, and has completed Harris Basic Systems Training. He was the lead pipe stress analyst for the replacement of the Brunswick Emergency Diesel Generator Service Water Piping. This MOD replaced a significant amount of piping and therefore required careful attention to schedule, budget and technical issues. He has also performed pipe stress operability and long term evaluation for the RESS Piping Improvement Program. He completed the SQUG

Walkdown Screening and Seismic Evaluation Training Course and the Add-On Seismic IPE Training Course in preparation for participation in USI A-46 and Seismic IPEEE resolution at CP&L's Harris, Brunswick and Robinson nuclear power plants. He has a BS and MS in civil engineering, and is a licensed engineer in the State of Tennessee.

THOMAS R. ROCHE

Mr. Roche has over eleven years of experience in the design, engineering, startup and analysis of systems and equipment at power, industrial and nuclear facilities. His responsibilities have included evaluation and analysis of systems and equipment for seismic events, preoperational testing of nuclear power plant systems, system engineer for nuclear and non-nuclear power plant systems, equipment qualification and post earthquake investigations. Mr. Roche is a Technical Manager with EQE International. He is responsible for various seismic evaluation efforts for nuclear facility systems and equipment. Mr. Roche is the Electric Power Research Institute (EPRI) Principal Investigator for investigating the 1989 Loma Prieta, 1994 Northridge and 1995 Great Hanchin earthquakes. He completed the SQUG walkdown and relay evaluation courses as well as the EPRI seismic individual plant evaluation of external events add-on course. He is a registered Mechanical Engineer in the State of California.

Mr. Roche has contributed to the development of the earthquake experience data base generated for the Seismic Qualification Utilities Group (SQUG). He concentrates on the response of systems to earthquakes at power and industrial facilities. Systems are investigated for the effects of power interruption, relay actuations due to vibration, relay actuations due to system transients, spurious electrical and pneumatic signals, and control room alarms. This seismic experience data is being utilized by the nuclear industry to resolve the seismic issues associated with the NRC's Unresolved Safety Issue A-46.

PEER REVIEWER RESUMES

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Mr. Abou-Jaoude is a Project/Service Area Manager in VECTRA's Boston Office, with a broad technical and managerial experience in the power industry. His areas of technical expertise are Structural Mechanics and Seismic Design; he has an in-depth knowledge of various industry codes/standards such as Sections III & XI of the ASME Code, ANSI B31.1, IEEE-344 and 382, various USNRC Reg. Guides and NUREG Reports, WRC Bulletins, AISC, and ACI-349. He is well versed in the Generic Implementation Procedure developed by the Seismic Qualification Utility Group for the resolution of USI-A-46, and the methodologies developed by the industry for the response to Generic Letter 88-20 as outlined in NUREG-1407; he has completed the SQUG/EPRI sponsored A-46 and Seismic IPEEE training courses and has participated in several A-46/IPEEE walkdowns as an SRT member. While at VECTRA, he has lead the engineering efforts of various work scopes; his responsibilities have included: Criteria development, training and personnel development, project execution, interface with regulators and outside organizations, and overall project management.

STEPHEN P. REICHLE

Mr. Reichle has over 20 years of power plant engineering, design, maintenance, and operations experience. As Technical Services Consultant for Mechanical Systems in VECTRA's Boston office he is currently assigned as the Project Manager for the Fire Hazards Analysis (FHA) project for the New York Power Authority. This project consists of updating the FHAs for both the James A. FitzPatrick and Indian Point 3 nuclear plants. The project also includes the preparation of an analysis that assesses the effects of pipe rupture, inadvertent actuation and manual use of fire protection systems on safety-related equipment at JAF and IP3.

Mr. Reichle is also currently serving as the Systems Project Engineer on the NRC's Unresolved Safety Issue (USI) A-46 projects for: Northeast Utilities (Millstone 1, 2 and Connecticut Yankee), Philadelphia Electric (Peach Bottom and Limerick) and Public Service Electric & Gas (Salem). In this role, he is responsible for the identification of safe shutdown paths and the development of a Success Path Component List for each unit. These NRC programs deal with the seismic adequacy, or margin of equipment in operating plants.

APPENDIX B

SHEARON HARRIS NUCLEAR POWER PLANT
SUCCESS PATH LOGIC DIAGRAM AND
SUPPORTING INFORMATION DEVELOPMENT
RSC 94-01
REVISION 1 AND ADDENDUM 1

RSC 94-01

Shearon Harris Nuclear Power Plant Success Path Logic Diagram and Supporting Information Development

Revision 1

August 1994

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1.0 Success Path Logic Diagram

As a part of the individual plant examination of external events (IPEEE)[1] , an evaluation of plant response to a seismic event that exceeds the design basis earthquake is required. A successful response is defined by the ability to maintain plant frontline systems that provide critical plant functions. The functions involved are: reactivity control, reactor coolant system inventory control, reactor coolant system pressure control, and decay heat removal. In addition the systems that support frontline system operation, for example, ac power, service water, etc., must be available. The Electric Power Research Institute (EPRI) has developed a process for seismic margins assessment (SMA) and it is documented in EPRI report NP-6041[2]. This document outlines the steps required to perform the assessment and identifies the boundary conditions and assumptions that are required for this assessment. The major assumptions are summarized below.

- Offsite power is assumed to be lost following the seismic event. The analyst should, however, consider the potential for adverse effects should ac power not be lost or if it should be restored.

- The success paths must be capable of maintaining the plant in either hot or cold shutdown for a period of 72 hours.

- The SMA should address two conditions. The first is a transient without RCS leakage and the second is a 1" LOCA condition. For the LOCA case, one reactor coolant system inventory control path must be capable of mitigating a 1 inch LOCA.

- Success is measured at the system level for success path logic diagram elements that represent multiple train systems. In other words, if one train is sufficiently rugged the other trains should provide similar seismic capacity.

- Non-seismic component failures should not be explicitly addressed within the EPRI process. The analyst should provide a check to ensure that the reliability of components will be adequate to exclude random failures. This is especially important for single train systems.

- The potential for relay chatter should be addressed. Note: Relay identification is provided in a separate analysis.

- Only core damage prevention systems should be addressed. Containment mitigation systems are not in the scope of the seismic margins evaluation.

The NRC, in their generic letter (Reference 1), indicated that the EPRI methodology is acceptable given two proposed supplements are adopted. Non-seismic failures and human actions should be considered in accordance to the guidance provided in NUREG-1407[3] and containment isolation and required mitigation systems should be examined as appropriate.

NUREG-1407 (Reference 3) indicates that non-seismic failures and human errors should be considered during the selection of systems needed to respond to a seismic event. It further suggests that a method similar to the method provided in NUREG/CR-4826[4] (Maine Yankee evaluation) is considered acceptable. In this evaluation quantitative guidance is provided for determining if non-seismic or human error events should be included.

The EPRI approach adopts a more qualitative criterion that serves as a guide for choosing systems and equipment for the success path logic diagram. In choosing the systems required for the SHNPP success paths, the equipment train reliability is qualitatively considered and only the most reliable alternative is chosen.

With regard to the analysis of the containment, NUREG-1407 (Reference 3) states that "the primary purpose of the evaluation for a seismic event is to identify vulnerabilities that involve early failure of containment functions. These include containment integrity, containment isolation, prevention of bypass functions, and some specific systems depending on a containment design (e.g., ignitors, suppression pools, ice baskets)." The major concern presented is for early containment failure modes.

The guidance further states that "generally containment penetrations are seismically rugged; a rigorous fragility analysis is needed only at review levels greater than 0.3g, but a walkdown to evaluate for unusual conditions (for example, spatial interactions, unique penetration configurations) is recommended." With regard to containment systems, the guidance provided is that "seismic failures of actuation and control systems are more likely to cause isolation system failures and should be included in the examination." The major concern deals with relay chatter that is out of scope for this evaluation. Isolation valves are expected to be seismically rugged and the walkdown should confirm this belief. The containment walkdown should also examine containment systems, for example, containment spray and fan coolers.

In considering this guidance, there appears to be only a marginal benefit to be gained by preparing a listing for containment functions (which is not required by either the EPRI or NRC guidance) and only a brief discussion is provided in Section 5.0 of this report to assist in performing the walkdown.

The information provided in the EPRI report outlines each step in the seismic margins evaluation process. This report documents the performance of step 3 of the EPRI process which involves the development of the success plant logic diagram (SPLD) for Shearon Harris, the development of equipment walkdown lists for systems of interest, and the execution of a pre-walkdown to provide early identification of any components with potentially low seismic ruggedness.

The SPLD is in the format of a reliability block diagram which identifies the systems required for success. The methodology requires that two or more success paths be provided for each of the major functions that must be accomplished to meet the success criteria. It is read in a similar fashion to an electrical diagram. Single entries indicate that

the system must function to ensure success. Parallel entries indicate two or more options for success. The following discussion outlines the development of success paths for Shearon Harris and serve as the basis for the SPLD.

1.1 Required Support Systems

Along with the frontline systems that are assigned to the success paths, the status of support systems necessary to maintain required frontline functions must be identified. To define these systems a review of the draft Shearon Harris IPE system notebooks was performed to identify interfaces between frontline and support systems. The information contained in the IPE system notebooks provides a concise source for identifying support system requirements. In addition to frontline systems, some support systems require cooling or power. Table 1-1 summarizes the links between the frontline and support systems addressed in the SPLD.

Using the information presented in Table 1-1, the support systems which must be addressed in the assessment are chosen. As the table demonstrates, ac power is required by most equipment following a seismic event. Some systems, however, are only needed for selected equipment. For example, HVAC is only required for operation of the charging pumps and the diesel generators. Other components do not require HVAC cooling over the period of interest. The pressurizer power-operated relief valves (PORVs) are equipped with air accumulators which provide sufficient air for PORV operation. The compressed nitrogen and instrument air systems, therefore, are not required or addressed by this evaluation. Based on this assessment six support systems are identified as important and are examined by this report. These support systems are:

- Safety-related ac power (including diesel generators)
- Safety-related dc power (including 120 Vac)
- HVAC cooling for CSIPs and diesel generators
- Emergency service water
- Component cooling water
- Essential chilled water (ECW)

Each of these systems provides an important support function which must be assured following a seismic event. As such, the important components in each support system success path must be included in the development of the safe-shutdown equipment list (SSEL) and evaluated.

Table 1-1
Support System Dependency Matrix

Frontline/Support System	Ac Power	Dc Power[a]	Emergency Service Water	Component Cooling Water	HVAC	Compressed Nitrogen
Auxiliary Feedwater System	X[b]	X				
Charging/Safety Injection System	X	X	X		X	
Residual Heat Removal/ Low Pressure Injection System	X	X		X[c]		
Pressurizer PORVs		X				X[e]
Steam Generator PORVs	X					
HVAC/ESCW	X	X	X[d]			
Component Cooling Water System	X	X	X			
Emergency Service Water	X	X				
Control Room					X[f]	
Ac Power (diesel generators)		X	X		X	

a - Many systems require dc power to start equipment.
b - Ac power is not directly required for steam-driven pump operation.
c - CCW required for recirculation and RHR cooling.
d - ESCW is also required for some HVAC.
e - The PORV accumulators have sufficient nitrogen for PORV operation.
f - Control room cooling required over the 72 hour period.

1.2 Reactivity Control

Following the convention established by the EPRI document (Reference 2), the next block involves the ability of the plant to establish and to maintain adequate shutdown margin following the seismic event. Two paths are identified for this function. The primary path is the insertion of the control rods. This is the normal method for reactor shutdown and occurs automatically when a reactor trip signal is generated. As a backup action the operators can execute a reactor trip from the main control board. Another possibility is that the loss of offsite ac power will result in a loss of power to the control rod motor control centers. This will result in rod insertion by gravity as the motor control rod drives unlatch and release the control rods. Since the EPRI guidance suggests that the analyst should consider averse effects due to power not being lost, this path is not considered a success and a trip signal must be received to ensure rod insertion. The control rods provide adequate shutdown margin to allow for the control rod of the highest worth to fail to insert.

As the RCS temperature decreases, additional boration may be required to maintain adequate shutdown. This function can be accomplished using the normal charging system. If normal charging is not present the RCS may begin to heatup which will increase the temperature component of negative reactivity and trend the reactor to shutdown. RCS inventory control addresses the need to monitor and maintain long-term shutdown.

Should an inadequate number of control rods be inserted, a backup action can be initiated by the operators to introduce makeup water with a high boron concentration using either of two paths. Inadequate control rod insertion could be the result of control rod binding caused by a shift in reactor internals due to the seismic event. The operators can align the charging system to the boration system and provide highly borated water to the RCS to increase shutdown margin using the emergency boration steps of the Shearon Harris plant ATWS procedure (EOP-FRP-S.1). The operators can also use the RWST source as a means of increasing boron concentration and negative reactivity. The use of the RWST is somewhat slower due to the lower concentration of boron but is adequate to ensure shutdown.

The component review identified that instrumentation called for in the emergency boration procedure may not be available following the seismic event. Flow meter FT-110 is used to monitor flow from the boric acid storage tank to the charging pump suction. This instrument is powered from a non-safety power bus that may not be available is offsite power is disrupted. An acceptable alternative is the level instruments mounted on the boric acid storage tank (LT-106, LT-161). These instruments are powered by vital power supplies and can be used to confirm flow from the tank to the charging pumps. Level indication is provided in the control room and the operators could substitute this information in the absence of the specified flow meter.

The high reliability of the control rod drives and the need for operator supports the use of the control rod drives as the primary path and emergency boration is chosen as a secondary option. The block diagram for reactivity control is shown below in Figure 1-1.

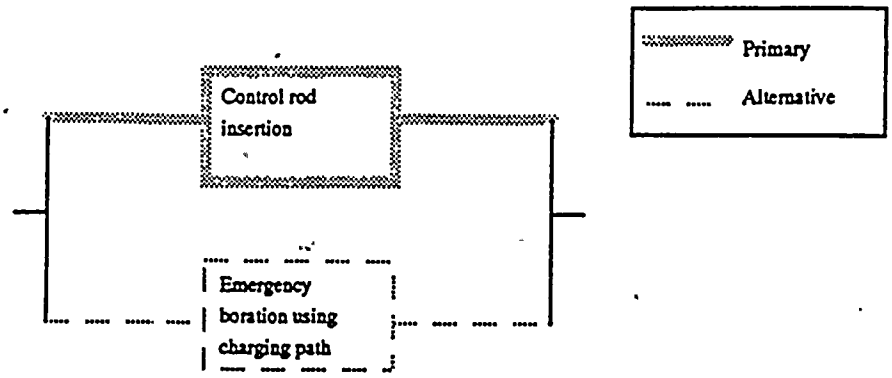

Figure 1-1. Success Path Logic Diagram: Reactivity Control Block

1.3 Reactor Coolant System Inventory Control

RCS inventory control requires that the operators be able to maintain core coverage and decay heat removal. Inventory may be lost from the RCS due to normal letdown. The normal letdown lines can be isolated to preclude this path but would preclude other normal activities such as chemistry control or the addition of additional boron for long-term shutdown. The RCP seals also provide a path for small inventory losses (~8 gpm/pump). For these smaller leakage paths the normal charging process is adequate.

At Shearon Harris, the RCS high pressure makeup capability is provided by the combined charging and safety injection pumps (CSIPs). The normal makeup function is provided by taking suction from the volume control tank (VCT) to the CSIPs and then discharging through the normal charging paths to the RCS. As an alternative, the RWST can be employed as a suction path when the VCT is unavailable with the CSIPs discharging through the safety injection cold and hot leg injection points. This path is also available for responding to the 1" LOCA required to be evaluated by the EPRI guidance.

Evaluation of the VCT level instrumentation identified that level transmitters LT-115 and LT-112 are powered from non-vital power supplies. This may result in a loss of these instruments which will reduce the operator's ability to maintain adequate inventory control. The loss of the level instrumentation, however, will most likely result in one of two outcomes. If both instruments are lost, an automatic signal will swap the charging pump suction from the VCT to the RWST and this will eliminate the need for level monitoring. If only one instrument is lost, the operators may elect to swap to the RWST. In either case, the loss of instrumentation would not greatly impact the potential for success.

The use of the CSIPs to support RCS makeup is governed by procedure EOP-EPP-004 which deals with the response to a reactor trip and operating procedure OP-107 which addresses chemical and volume control. Because of the potential for a loss of the VCT and since both the normal charging and safety injection paths require the same pumps a secondary alternative path is considered.

Based on procedural guidance (EOP-EPP-009, Post-LOCA Cooldown and Depressurization) the operators are directed to cooldown and depressurize the RCS if safety injection is not available and use the RCS accumulators and residual heat removal system to provide makeup. Analysis performed for the IPE using the MAAP code indicate that the accumulators are not required for a 1" LOCA and their operation does not preclude successful injection using LPI. This requires the availability of secondary-side heat removal and some operator action. The use of this path does provide a means independent of the other paths with the exception of the common injection lines. For cases involving a LOCA, the need for additional makeup will also require the use of the RWST in a similar manner as used in the CSIP path.

In considering the success paths for this function several factors influence the final choice. First, isolation of normal letdown would significantly reduce the need for RCS makeup such that normal charging may not be required. Over 72 hours, however, RCS shrinkage and small leaks within the range of technical specification allowances may result in unacceptable RCS inventory loses and a need for additional makeup. Additional boron may be required to maintain adequate shutdown margin after many hours of decay heat removal. To increase boron concentration the letdown path is, although not required, desirable. These considerations lead to the conclusion that the isolation of letdown is overly restrictive and not necessary to ensure RCS inventory control.

For cases without a LOCA the use of normal charging seems the most logical choice since it is the normal method of control and provides reactor coolant pump seal injection. The combination of makeup and letdown provides the operators with a flexible means to control RCS inventory and is a method familiar to the operators. The normal charging path, therefore, is chosen as the primary path for RCS inventory control. Although letdown is not required, its presence would improve the operators ability to respond to any challenges.

The normal charging flow is not capable of mitigating a 1" LOCA. The use of the CSIPs in their safety injection mode provides an adequate response to a 1" LOCA and is a secondary means of RCS inventory control. It does require the use of the same pumps as the charging function but utilizes different suction sources and discharge paths. Based on seismic evaluations for other plants[5], the pumps are not expected to be a potentially limiting component for the either path. Past studies have indicated median capacities for pumps on the order of 1.5 mpga (β_c = 0.45). This converts to a HCLPF value of about 0.34g which exceeds the Shearon Harris review level earthquake.

The use of the RHR system does provide additional independence but requires that additional systems function. Further, the use of this success path requires additional operator actions and monitoring. Thus, the use of the CSIPs in their safety injection path is considered the alternative with the RHR path being a secondary alternative. Figure 1-2 summarizes the success paths for this function.

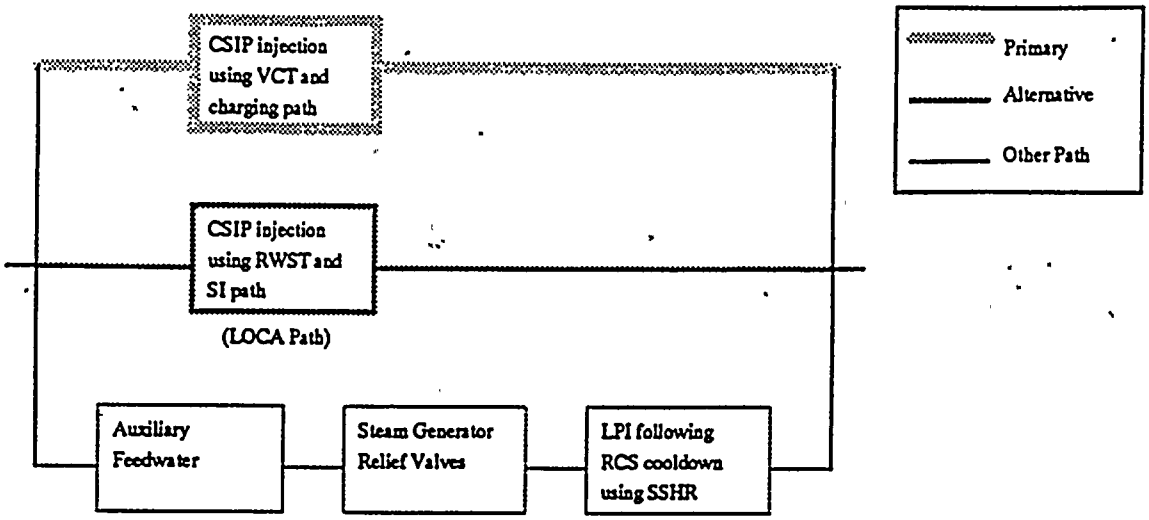

Figure 1-2. Success Path Logic Diagram: RCS Inventory Control

1.4 Reactor Coolant System Pressure Control

The potential exists for a seismically-induced loss of offsite power and for an RCS pressure challenge due to the sudden loss of condenser cooling and an isolation of the power conversion system due to the closure of the main steam isolation valves. This, in turn, temporarily increases RCS temperature and pressure and may require RCS pressure relief and control.

Several potential paths exist for pressure control. Under normal situations the pressurizer sprays can be used to reduce RCS pressure. The spray driving force is provided by the reactor coolant pumps. The assumption that ac power is lost results in a loss of the reactor coolant pumps and normal sprays as a means of pressure control. It is possible to provide auxiliary spray from the normal charging system. RCS pressure reduction would not occur sufficiently to preclude a relief valve challenge. This option is covered by procedure AOP-019 "Malfunction of RCS Pressure Control" which is consulted immediately after trip and referenced in EPP-004 and EPP-005.

Two sets of diverse pressure relief valves also provide pressure control. These pressurizer relief valves provide adequate capacity to mitigate any pressure transient as a result of a loss of offsite power. The pressurizer PORVs are considered the primary means of pressure control with the secondary path involving the pressurizer safety relief valves. Three PORVs are provided with each having sufficient capacity to mitigate the pressure rise associated with a loss of offsite power. The PORVs require dc power control power and either compressed nitrogen or air to function. Two sources of compressed gas are available, instrument air and nitrogen. Following a loss of power the instrument air system is lost and the containment air supply line is isolated. Accumulators present on the PORV supply lines maintain adequate pressure to allow PORV operation (98 psi). This provides a more than adequate supply of compressed gas for RCS pressure challenges following

reactor trip. Three spring-loaded safety relief valves are present. The safety relief valves are designed to function at a preset pressure and do not require any support system in order to function.

The PORVs have the benefit of an ac-powered block valve which may be closed if a PORV fails to close. The block valves, however, are not needed for pressure control. By code requirements, the safety relief valves do not have an associated block valve.

Due to the presence of block valves and the fact that the PORVs will be utilized for other functions, the PORVs are chosen as the preferred path for RCS pressure control with the safety relief valves being considered as the alternative path. The two success paths for this function are identified in Figure 1-3.

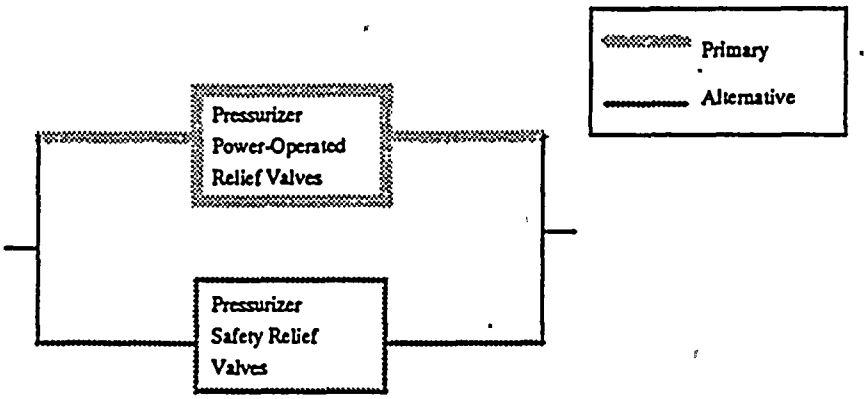

Figure 1-3. Success Path Logic Diagram: RCS Pressure Control

1.5 Decay Heat Removal

The final function addressed is decay heat removal. Generally, decay heat removal following a reactor trip is provided using the steam generators (Reference EPP-005). The auxiliary feedwater system provides steam generator makeup. In addition to a supply source the steam generators must be able to dump steam. Given that the condenser is isolated following the event, steam can be relieved by either the steam generator safety relief valves or the steam generator PORVs. The safety relief valves cannot be used to perform an RCS cooldown to allow the use of RHR cooling. In order to simplify the analysis, only the steam generator PORVs are included for steam removal. The use of the steam generator PORVs allows both normal steam generator cooling and provides an alternative long-term cooling mechanism.

An RCS cooldown may be initiated if either the condenser or steam generator PORVs are available and the residual heat removal (RHR) system initiated when RCS conditions are within the operating limits of the RHR system. The mission time is 72 hours. Based on the inventory present in the condensate storage tank (CST) the tank will empty prior to meeting 72 hours of decay heat removal.

Two options are available to extend cooling for 72 hours. The operators can maintain hot shutdown conditions by aligning the emergency service water header to the suction of the AFW pumps (Reference procedures OP-137 and EPP-005). This will provide a source of water which will exceed that required for 72 hours of core cooling but requires manual action.

As an option, the operators can perform RCS cooldown and establish cold shutdown using RHR cooling (using the RHR pumps and heat exchangers) prior to CST depletion. The RHR system circulates RCS inventory through the RHR heat exchanger and transfers RCS decay heat to the component cooling water system. One consideration in establishing RHR cooling is the presence of adequate instrumentation. The normal RCS temperature instruments do not provide an adequate representation of the temperatures within the reactor vessel if the reactor coolant pumps are stopped, as is the case during shutdown cooling. For this situation, the instruments provided in the RHR system are required. On the basis of an instrumentation review associated with the SSEL development, the normal temperature indication (TE-606A, TE-606B) may not be available to the operators. These instruments are powered by non-vital power supplies an may be lost following the seismic event. As a result, the operators will need to use alternative temperature indicators to ensure that adequate margins are met.

The use of RHR is not an immediate action and there is considerable time between the seismic event and the time that operators achieve RHR entry conditions. This provides time for operator mitigative actions and the investigation of other alternatives. Two local instruments (TI-5551A, TI-5551B) are mounted near the RHR heat exchangers and are available to provide temperature indication if required. These instruments are located in a radiation area and personnel exposure is a concern. The expected dose, however, would not exceed acceptable dose limits.

In the absence of secondary-side heat removal, an alternative cooling method is possible. The CSIPs and pressurizer PORVs may be used to establish feed-and-bleed cooling. The CSIPs inject cool water into the RCS and the PORVs relieve heated water to the containment which transfers the decay heat from the RCS to the containment. This option is addressed in EOP-CSFST "Critical Safety Function Status Tree" and EOP-FRP-H.1.

For the PORVs to function, dc power and a compressed gas supply must be present. Two sources of compressed gas are available, instrument air and nitrogen from accumulators. Following a loss of power the instrument air system is lost and the containment air supply line is isolated. Accumulators present on the PORV supply lines maintain adequate pressure to allow PORV operation (98 psi). The leakage rate through the lines is estimated to be on the order of two pounds per hour. The operational range for the PORVs is from about 80 to 60 psi. Given the leakage rate, the PORVs will remain open for approximately 19 hours. At this point the PORVs would fully close and the CSIPs would increase RCS pressure to the SRV setpoint. The CSIPs can continue to inject at the SRV opening setpoint. This mode of feed-and-bleed cooling provides adequate heat removal given the reduced decay heat load at 19 hours. This conclusion is supported by plant-specific MAAP analysis. The PORVs and the pressurizer SRVs, therefore, must be

available for successful feed-and-bleed cooling or the RCS pressure must be lowered to allow for shutdown cooling.

The inventory used during feed-and-bleed comes from the RWST. Once this inventory is depleted, the operators establish high pressure recirculation. This involves the automatic alignment of the RHR pumps to the containment sump, manually establishing CCW flow to the RHR heat exchangers, and swapping the CSIP suction from the RWST to the discharge of the RHR pumps. The RHR heat exchangers provide necessary cooling to maintain RCS conditions within limits. Required operator actions are identified in procedure EPP-EOP-010.

The primary method for decay heat removal utilizes the steam generators. This involves the use of AFW, steam generator PORVs, and a source of water. The CST provides the water source initially. After this source is depleted, the emergency service water system is used. The alternative method for decay heat removal is the use of feed-and-bleed cooling as described by EOP FRP-H.1. This requires the operation of the CSIPs in safety injection mode, the operation of the pressurizer PORVs, and the pressurizer SRVs. The use of RHR cooling is included as a long-term alternative to aligning AFW to essential service water. Figure 1-4 presents the success logic associated with decay heat removal.

1.6 Overall Success Path Logic Diagram

The individual functions are combined to develop an overall success path logic diagram. Two diagrams (Figures 1-5 and 1-6) are used to address the two different cases. The first case addresses the transient and assumes that no leakage is present. The second logic diagram is provided for the LOCA case. For both cases, the first consideration is the status of the support systems. Success indicates that all support systems are functioning. The next block addresses the ability to control reactivity. This block is equivalent for both cases.

The RCS inventory control block is somewhat different for the two cases. In the transient case success requires that makeup using charging flow rates be provided. The LOCA case requires that additional RCS makeup be provided using either safety injection or low pressure injection. In the case of the transient event, a need for RCS pressure control exists and the RCS pressure control block is included. Following a 1" LOCA, the RCS pressure will decrease and no pressure challenge sufficient to lift the RCS relief valves is expected. The pressure control block is, therefore, not included. Finally, the decay heat removal function required for both cases is the same.

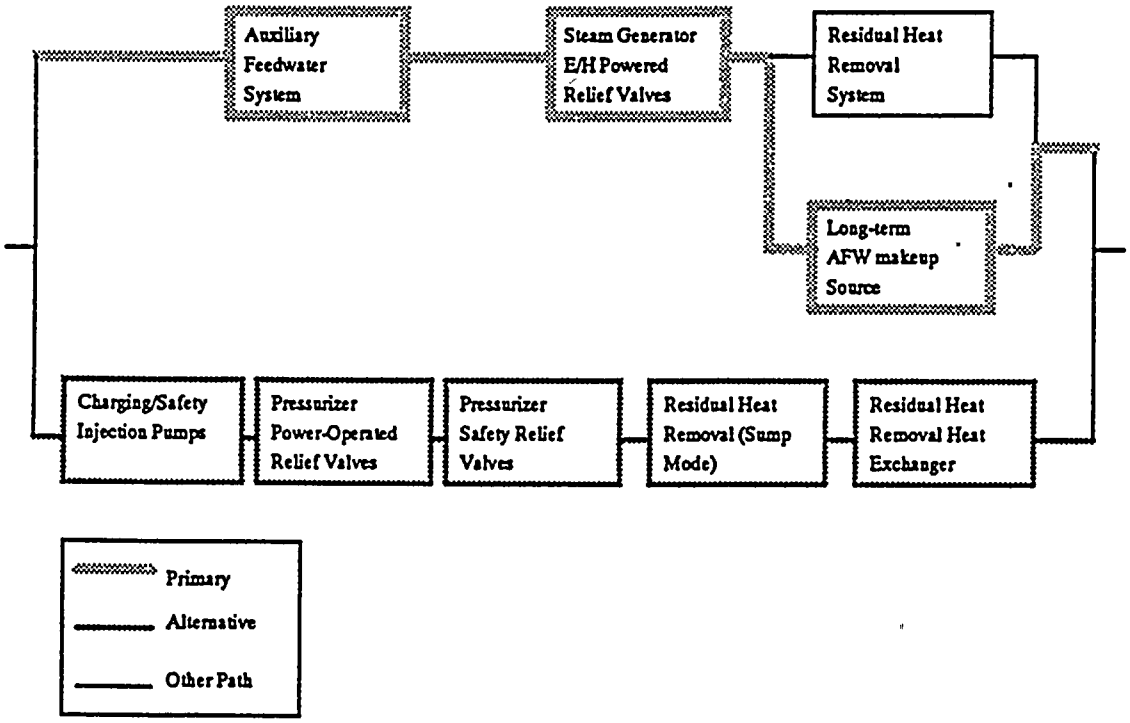

Figure 1-4. Success Path Logic Diagram: Decay Heat Removal

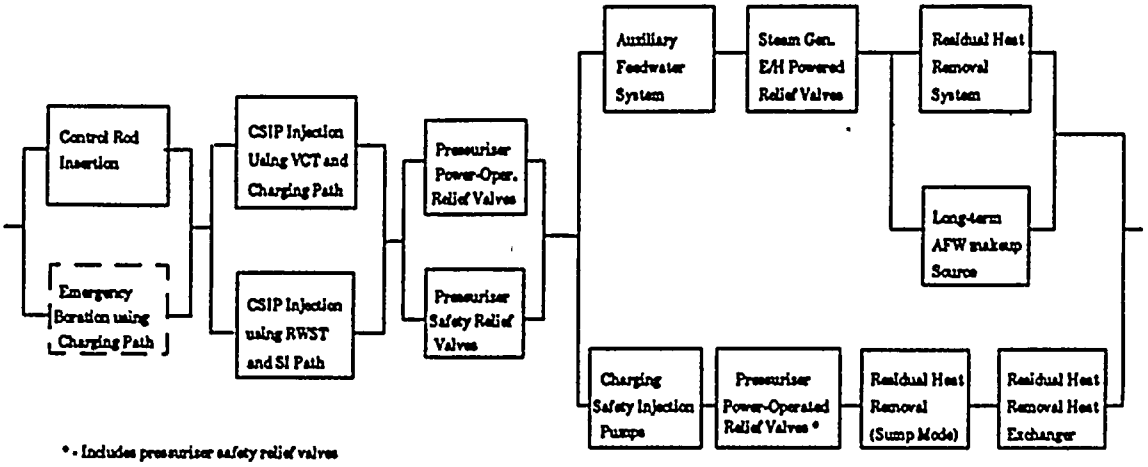

Figure 1-5. Success Path Logic Diagram: Transient Case

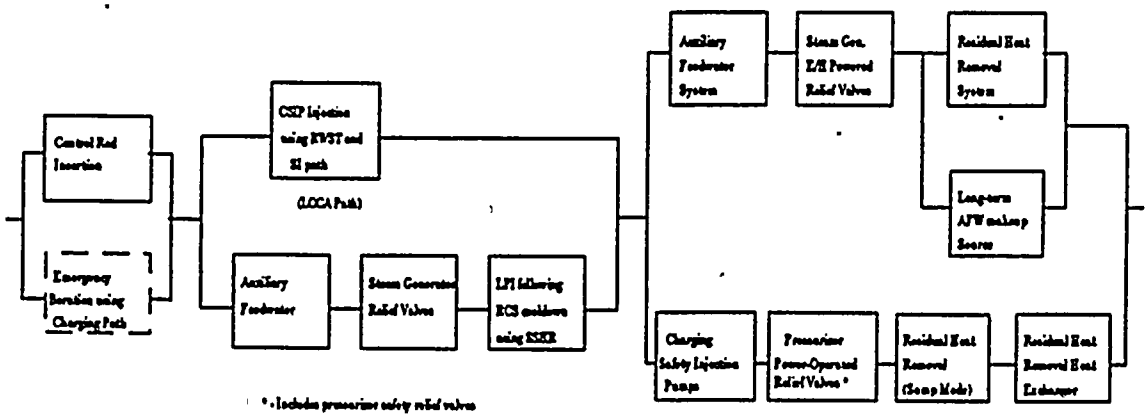

Figure 1-6. Success Path Logic Diagram: LOCA Case

In examining the SPLD it is important to realize that the earlier failure of some paths may preclude success of other functions. As an example, if the CSIPs fail the RCS inventory control path the path for feed-and-bleed cooling will also be lost. In other words, the loss of particular paths within functions due to a system failure may result in other paths also being failed for other functions. The converse of this is also true in that the failure of a particular path may not preclude any paths for other functions. As an illustration, if the CSIPs succeed in maintaining RCS inventory following a LOCA, the operators may have successful heat removal by either the AFW system or bleed-and-feed cooling. The success of CSIP injection for the RCS inventory function does not require that only bleed-and-feed cooling be used for secondary-side heat removal.

2.0 Early Component Seismic Walkthrough

As part of the process of identifying the components necessary for ensuring safe shutdown following a seismic event, an early walkthrough was performed. This walkthrough identified, at an early stage, any components which have the potential for low seismic capacity and are identified in the shutdown paths. The walkthrough did not involve a detailed evaluation of all components but concentrated on some of the more critical components for each system. The walkthrough did not examine components in the containment or areas requiring significant radiation protection. Detailed screening and evaluations will occur during the required walkdown that is performed by the seismic review team (SRT).

Prior to the walkthrough a component listing was generated which identified equipment to be examined. This listing is based on the SPLD paths and engineering judgment. For most cases the components chosen represent active components which are required to function following a seismic event (pumps, motor-operated valves, diesel generator). Components with the potential for low seismic capacities, as found in other seismic assessments, are also included (batteries, tanks). The list developed for Shearon Harris is provided as Table 2-1.

Table 2-1
Walkthrough Equipment List for SHNPP Seismic IPEEE

SPLD Function	System	Equipment
Reactivity Control	Control Rod Drives	Control cabinets and MCCs
RCS Inventory Control	Charging/Safety Injection	CSIPs 1A-SA, 1B-SB
		RWST and suction valves 1CS-291, 1CS-292
		VCT and suction valves 1CS-165, 1CS-166
		CSIP safety injection discharge valves 1SI-1, 1SI-2, 1SI-3, 1SI-4
	Residual Heat Removal (low pressure injection mode)	RHR pumps 1A-SA, 1B-SB
		RHR heat exchangers 1A-SA, 1B-SB

Table 2-1 (continued)
Walkthrough Equipment List for SHNPP Seismic IPEEE

SPLD Function	System	Equipment
RCS Inventory Control		RWST suction valves 1SI-322, 1SI-323
		RHR to CSIP suction valves 1RH-25, 1RH-63
RCS Pressure Control	Nitrogen System	Storage Tanks
Decay Heat Removal	Auxiliary Feedwater	Pumps 1A-SA, 1B-SB, and, 1X-SAB
		SD pump steam inlet valves 1MS-70, 1MS-72 and, 1MS-G
Decay Heat Removal	Auxiliary Feedwater	Control valves 1AF-131, 1AF-130, 1AF-129, 1AF-51, 1AF-50, 1AF-49
		Condensate storage tank
		SWS to AFW suction valves 1SW-121, 1SW-123, 1SW-124, 1SW-126, 1SW-129, 1SW-127, 1SW-130, and 1SW-132
	Steam Dumps	Steam generator power operated steam dump valves 1MS-58, 1MS-60, 1MS-62
Support Systems	Ac Power	Diesel generators and support equipment (day tank, jacket cooler, etc.)
		Fuel oil transfer pumps 1A-SA, 1B-SB
		Buses 1A-SA, 1B-SB
	Dc Power	Batteries and racks

Table 2-1 (continued)
Walkthrough Equipment List for SHNPP Seismic IPEEE

SPLD Function	System	Equipment
	Dc Power	Chargers and buses 1A-SA and 1B-SB
Support Systems (cont.)	Service Water System	ESW pumps 1A-SA, 1B-SB
		Expansion joints 2A, 2B
		Normal service water isolation valves 1SW-39, 1SW-40
		SWS return valves 1SW-275, 1SW-276 and 1SW-274
		CCW to SWS heat exchangers 1A-SA, 1B-SB
	Component Cooling Water System	CCW surge tank
		CCW pumps 1A-SA, 1B-SB
		RHR to CCW heat exchangers 1A-SA and 1B-SB discharge isolation valves 1CC-147 and 1CC-167
	HVAC	Air handling units AH-9 (1A-SA) and AH-9 (1B-SB) cooling for CSIPs
	ESCW system	Pumps P4 (1A-SA) and P4 (1B-SB)
		Chiller/condenser WC-2 for 1A-SA and 1B-SB

A standard form was developed which documented the findings of the walkthrough. The form provided guidance to the walkthrough team in investigating the potential for low seismic capacity components. In addition to identifying the component the form addressed anchorage, elevation, orientation, interaction, and structural issues. An example form is provided as Figure 2-1.

The walkthrough was performed using four individuals. Three of the team members were from CP&L's Nuclear Engineering Department. Two had been to the EPRI course on seismic walkdown. The fourth member was a consultant who was familiar with the Shearon Harris IPE and had considerable experience in the performance of seismic risk analyses. The walkthrough was performed on January 14-15, 1993 and included as many components as possible. To expedite the process, like components were not examined if they were of similar function, kind, and location. For example, only one CSIP pump was examined since they are from the same manufacturer and are located at the same elevation and have the same orientation. Some listed components were not examined due to radiation control concerns. The volume control tank was an example of an item not examined due to this consideration. The team examined approximately 50 components. The findings are documented in Appendix A.

The general purpose of the walkthrough is to search for any potential low seismic capacity components which could result in low system seismic capacity. Additionally, the information can streamline the detailed walkdown and capacity evaluation. The insights obtained from the walkthrough are provided below.

- The examination of pumps and drivers did not uncover any significant factor which would lead to the potential for low seismic capacity. The components examined are mounted on common skids with what appears to be adequate anchorage. It is reasonable to assume that average component capacities will be present and that pumps will not be a "weak link".

- The anchorage for the motor-operated valves, where present, did not involve the potential for operator and valve differential displacement due to using two different anchorage surfaces.

- The examined heat exchangers are well anchored on common pads and should provide adequate seismic capacity. The RHR heat exchanger anchorage design, however, should be examined since it was not visible during the walkthrough.

- The battery racks appear rugged and should provide adequate seismic capability. The inclusion of crush resistant spacers also supports this conclusion. The eyewash stations located in each room, however, are of some concern. It is unclear if they are seismically rugged. Given their proximity to the batteries, their similar design, location, and orientation, they should be examined further.

Figure 2-1
Seismic Walkthrough Checklist

Component Identification:		Component Type:
Anchorages: Concrete pad Bolted. Welded	Elevation from floor:	Orientation: (for valve orientation of operator)
Seismic II/I:	Adjoining structures:	Nearby walls or piping:
Support Equipment Mounting/Flexibility:		
Comments/Insights:		

- The mounting flange for the vital chargers may be a potential weak point for the long-term availability of dc power. The mounting flange was thin and could tear which would allow the charger to topple. The strength of the material should be examined along with the weight distribution in the charger.

- A diesel generator control panel found near the diesel generator is welded to a support plate only on one side at the four corners. This may be a concern if the panel is needed. Other more important panels could not be explicitly examined due to base plates. These panels should be more closely examined due to their proximity.

- Examination of the steam generator PORVs found that they may be capable of meeting the required seismic capacity. Their proximity to walkways and light fixtures may be somewhat important but should not be a significant concern.

- The essential service water system equipment provides a key support system link through the need for diesel generator cooling and a long-term AFW source. The service water intake structure and equipment were not examined during the walkthrough. The pumps should be examined to ensure that they are adequately supported. This is especially true for the long shaft associated with vertical suction pumps. Given the observations from the plant walkthrough and the vintage of the plant design this is not expected to be a concern but should be verified.

As previously noted, the above observations are based on the initial walkthrough. The final results and conclusions are derived from the detailed screening and evaluation performed by the SRT.

3.0 Operational Review of Success Path Logic Diagram

The draft SPLD was provided to SHNPP operations personnel to provide a plant review of the success paths and the required equipment. The reviewer examined the paths and components for correctness, applicability to plant procedures, and to identify any other alternatives that are not addressed. A meeting was held between the plant reviewer and the team responsible for the development of the SPLD with two main purposes. The first was to resolve any comments generated during the plant review and the second purpose was to refine the required instrumentation listing. The plant reviewer concluded that the SPLD and required systems are appropriate and did reflect the various success paths that would be available and utilized by the plant operators following a seismic event. The important comments and resolutions are summarized below.

- Control room HVAC may be important over a 72 hour period and should be considered. *Resolution:* Control room air handlers (AHU-15 and AHU-16) were added to the HVAC listing.

- The steam-driven pump supply line could be used as a means for dumping steam if the steam generator PORVs are unavailable and that plant operations are familiar with this option. *Resolution:* The group resolved that this option would only be included if the steam generator PORVs could not meet the required seismic capacity.

- The procedures direct the operators to use both accumulators and low pressure injection following a loss of the CSIPs which is not reflected by the present text. *Resolution:* The text was changed to include the accumulators. Based on MAAP analysis, however, the accumulators are not included in the SPLD required equipment.

- The operators are directed to open the reactor head vents if the PORVs are unavailable. This may provide a bleed path for feed-and-bleed cooling. *Resolution:* The reactor head vents are considered too small to provide adequate feed-and-bleed cooling and are not included in the SPLD listing.

Other comments were more editorial in nature and were resolved accordingly.

A review of the instrumentation listing was performed for each system. The process used involved a discussion of the function required of the system, a listing of available instrumentation, and the identification of the minimal set of instruments required to maintain the system. In some cases the components performed multiple functions. For these systems each function was reviewed individually. A final instrumentation list was developed based on this review.

4.0 Modifications to Equipment Listing Based on Seismic Walkdown

Several modifications were made to the SSEL following the completion of the seismic walkdown. Changes were made to address the addition or deletion of some components to the SSEL listing and corrections due to input errors. The largest addition to the listing is instrumentation racks and cabinets housing essential relays. Using the "rule of the box" definition several instruments were grouped according to their common instrumentation rack and the rack was added to the SSEL listing. In addition, a complete review of the SSEL component list was performed to ensure that component information (i.e, tag numbers, reference drawings, etc.) was correct. Examples of changes to the SSEL are presented below with an associated rationale.

Action: Removed switchgears 1A1, 1B1, transformers 1A1, 1B1, and motor control centers 1A22, 1B22, 1A24, and 1B24 from the ac power system listing.

Rationale: These components are not required to support SSEL components.

Action: Remove items 23 and 24 from the essential chilled water system listing.

Rationale: The purpose of these temperature switches, TS-6522A1-SA(B1-SB), is to provide control for air handling units which supply cooling to CSIP A & B. This control is only applicable for cases without a safety injection signal. For the SSEL the CSIPs are used to respond to two situations, a small LOCA and feed-and-bleed cooling. For the small LOCA, the loss of RCS coolant will result in a safety injection signal and, therefore, the temperature switch will be overridden. In a similar manner the implementation of feed-and-bleed cooling will result in a loss of RCS inventory and a subsequent safety injection signal. Thus, for the cases covered by the SSEL the control function of the devices will be overridden and they can be removed from the list. From information obtained during the 3/25/93 SSEL review meeting, no important instrumentation function is provided by these components.

Action: Components PS-2250A, PS-2250B, and PS-2270 should be listed as pressure switches and not pressure sensors. The SSEL review will include both the switches and the signal transmitted to the control room.

Rationale: From the 3/25/93 meeting, SHNPP operations indicated that suction pressure, along with a table provided in AOP-004, would be used to determine CST level if level indication were lost. It is important, therefore, that suction pressure indication be provided in the control room.

Action: Added components associated with the diesel generator starting air system.

Rationale: These components were inadvertently omitted from the report. Adding these components to the SSEL corrects this omission.

Action: Added nitrogen/air accumulator tanks for PORVs to SSEL.

Rationale: The accumulators provide air to the pressurizer PORVs and serve as an alternative to instrument air. These accumulators are added to allow the removal of the dependence on instrument air.

Action: Added PORV control solenoid valves to listing. Action: The valve tag numbers were changed from 1SI-411, 1SI-412, 1SI-415, and 1SI-416 to 1RC-114:002, 1RC-114:003, 1RC-118:002, and 1RC-118:003 respectively to reflect current valve tags.

Rationale: These valves are separate from valve control and should be listed separately.

Action: Deleted valve 1CS-282 from the SSEL listing.

Rationale: This valve is associated with an alternative boration path that is not utilized in the SSEL.

Action: Deleted duplicate listings for components associated with more than one function.

Rationale: The initial report listed several components, such as the steam generators, under different systems. Duplicate listings have been deleted to avoid future confusion.

Action: Deleted ECS instruments PS-9426A and PS-9426B from the SSEL listing.

Rationale: These instruments are not required for operation of ECW.

Action: Added rugged valves associated with the starting air system to the SSEL.

Rationale: Including the rugged valves is consistent with other system listings in the SSEL and provides a clear indication of the success path.

Action: Added boric acid tank level transmitters LT-106 and LT-161, and RHR temperature instruments TI-5551A and TI-5551B to the SSEL.

Rationale: As discussed earlier in this report, additional instrumentation was found to be necessary and has been added to the listing.

5.0 Safe Shutdown Equipment Listing

Based on the requirements for maintaining a safe stable state following a seismic event the required frontline and support systems are identified. The equipment required for the system to function is evaluated to ensure a high degree of confidence of a seismic capacity which exceeds the review level earthquake. Although not required, a form similar to that specified by the Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment[6] is utilized for recording the equipment necessary for system function.

For Shearon Harris a total of 11 systems are included in the search to identify required equipment. Components included in the listing are chosen based on one-line flow diagrams and guidance contained in EPRI report NP-6041 (Reference 2). NP-6041 suggests that the components be specified by system and that the following information be made available:

- General description (e.g., 6 inch MOV)
- Component identification (tag identifier)
- General building location (e.g., reactor auxiliary building)
- Additional comments

This information is contained on the forms. In addition to the required information, the drawing number, normal state, desired state, and power requirements are included. For components requiring support systems, the support system interface is identified (e.g., 1A-SA, CCW, DP-1A, ...). The expected type of evaluation is also included. Acronyms are used in some cases. Each column is briefly described below.

Column 1 - Line Number

This column provides each component a unique number for each system.

Column 2 - Train

A numeric value is provided for frontline systems that represents the associated system train. For example, AFW train 1 includes the components associated with auxiliary feedwater motor-driven pump 1A-SA.

Column 3 - Equipment Class

This column provides the equipment classification according to a standard listing provided in the GIP (Reference 6, Table 3-1). In addition to the standard listing, two other characters are used. Components which are considered seismically rugged and do not require evaluation are specified by an "R". Some components identified for the IPEEE are not required to be evaluated by the GIP. For these components an "*" is used to show that no equivalent GIP class is provided.

Column 4 - Equipment ID Number

This column lists the equipment tag number, or equivalent, which can be used to identify the specific component on P&IDs and during the walkdown.

Column 5 - System/Equipment Description

This column provides a brief description of the component being addressed.

Column 6 - Drawing No.

This column lists the drawing which was used to locate the component and serves as a documentation reference.

Columns 7, 8, & 9 - Building, Floor Elevation, and Room or Row/Column

The location of the component is given in terms of building and the plant elevation. The following building codes are used for location information:

- SW Emergency Service Water Intake
- RAB Reactor Auxiliary Building
- CB Containment Building
- DG Diesel Generator Building
- MST Main Steam Tunnel
- TANK Tank Area
- YARD Yard Area
- FO Fuel Oil Storage Area

The elevations reflect the floor elevation and may or may not represent the actual component elevation. The specification of room or row/column information is beyond the scope of this effort and is not input into the table.

Column 10 - Evaluation Type

This column specifies the type of evaluation which may be required for the component. Three different responses are provided. An "S" indicates that a seismic loading evaluation is needed. The addition of an "R" indicates that if relay chatter were to occur the component could react in a way which may impact the successful operation of the system or subsystem. For these cases, and if low ruggedness relays are identified, a relay evaluation may be necessary. The final classification is "None". This classification is used for any component which is listed for completeness but does not require evaluation.

Column 11 - Notes

This column provides reference numbers for important assumptions and other information which is provided below the component listing.

Columns 12 & 13 - Normal State and Desired State

These columns specify the normal state of the component and the desired state after the seismic event. The following abbreviations are used:

- OP - Open
- CL - Closed
- CL/OP - Component cycles over mission time
- OFF - Equipment stopped
- ON - Equipment functioning
- N/A - State not applicable

Column 14 - Power Required

This column indicates if ac or dc power is required in order for the component to perform its function or maintain its desired state.

Column 15 - Required Supporting Systems or Components

This column lists the support system interfaces with the component being addressed. For example, in order for AFW MDP 1A-SA to start and function the following support system interfaces must function:

- AC switchgear 1A-SA
- DC distribution center DP-1A
- Engineered safeguards actuation relay K640A

These three interfaces are identified in an abbreviated format. The required support systems are listed in a specific order to aid the reader. The order is presented below:

Ac power bus; Dc power bus; Cooling source; Control signal

Only those support systems which are necessary, as defined by the Shearon Harris IPE system notebooks, are listed. The system equipment lists are based on information from the IPE system notebooks and other plant sources, including the plant walkthrough and walkdown. The system equipment listings are provided in Appendix B.

In addition to the equipment listings, other important issues must be addressed in the development of the SPLD and to complete the information needed for the SMA. The following discussion provides the resolution of these issues for the Shearon Harris evaluation within the context of this report.

Nuclear Steam Supply System (NSSS) Components

In addition to the system equipment lists provided in Appendix B, NP-6041 requires that other components be evaluated. This includes an evaluation of major NSSS components, or more specifically the component supports, to ensure that component failure will not occur following the seismic margin earthquake. Thus, the following components should be examined and screened if possible

- Reactor vessel and supports
- Steam generators and supports
- Pressurizer and supports
- Reactor coolant pumps and supports
- Reactor coolant piping

In addition to these components, the reactor vessel internal package and the control rod drive packages must be examined. A comparison of prior plants has been compiled and is documented in Reference 5. This information indicates that an average expected median component capacity would be greater than 1.2g and that the HCLPF value should exceed the SME acceleration level. Based on the plant vintage and design considerations it is unlikely that these components will provide plausible "weak-links". A screening evaluation to ensure this, however, is necessary.

System Piping

A general rule was applied when piping was considered. Safety-related piping which is adequately anchored has been shown to be very rugged and would not be challenged by an earthquake level postulated for the SME. A high seismic capacity is anticipated and the piping is expected to be screened from assessment. A verification walkdown will be required to ensure this conclusion which will include examination of instrumentation and other connections to the piping path for potential vulnerabilities. Since a verification walkdown will be necessary, it was deemed more appropriate and efficient to examine piping concerns during the walkdown and not to include each connection in the component listing. Further, a specific listing is not required by the procedure and this approach does not represent a deviation from the methodology. The walkdown will ensure that the preliminary conclusion about the piping strength will be verified.

Containment Isolation and Mitigation Systems

The main objective of the containment analysis is to identify vulnerabilities that involve early failure of containment functions. This includes consideration of containment integrity, containment isolation, and other containment functions

The guidance provided in Reference 3 states that "generally containment penetrations are seismically rugged; a rigorous fragility analysis is needed only at review levels greater than 0.3g, but a walkdown to evaluate for unusual conditions (e.g., spatial interactions, unique penetration configurations) is recommended." With regard to containment systems, the guidance provided is that "seismic failures of actuation and control systems are more likely to cause isolation system failures and should be included in the examination." The major concern deals with relay chatter which is addressed in Reference 8.

The containment isolation function is expected to be rugged with respect to seismic events. A walkdown that examines representative containment penetrations to ensure that the Shearon Harris design does not have any unique configurations that would lead to conclusions which are contrary to those found in prior studies will be accomplished.

A review of seismic capacities for containments of similar design to Shearon Harris indicates that the containment structure is expected to have a seismic capacity far above the review level earthquake[7]. In addition to the containment structure, NUREG-1407 (Reference 3) suggests that certain considerations could require some additional study. Hatches that employ inflated seals is one potential are for concern.. The Shearon Harris design does not employ this time of seal. Another concern is the post-operation of penetration cooling that is present in some designs. Shearon Harris, however, does not employ this design feature. Finally, air-closed valves used for isolation are also listed as a possible concern. Shearon Harris does not utilize air-operated valves for containment isolation that require a supply of air to function. Thus, failures in containment isolation would not be expected due to containment system failures.

Containment heat removal is an important aspect in evaluating containment performance. If heat is not adequately removed from the containment the containment pressure may increase to the containment failure pressure. Two mechanisms can lead to energy being transmitted to the containment. The first is due to the small LOCA. As RCS inventory is lost through the break it carries stored energy which is then release to the containment and pressurization occurs. Feed-and-bleed cooling also results in energy being transferred to the containment. Containment fan coolers can reduce the pressurization due to these mechanisms.

Based on MAAP analyses performed for the IPE the containment pressure is not expected to increase to the design limit as long as the RHR heat exchangers are available to remove heat. Thus, the fan coolers represent an additional heat removal mechanism but are not required for successful containment cooling as long as the RHR heat exchangers are present. Failure of this heat removal function will result in containment heatup and pressurization.

The pressurization, however, is predicted to occur over many hours and would not result in an early, rapid containment overpressurization. It is concluded that containment fan coolers are not needed to ensure early containment integrity. As a result, containment issues are not addressed in this report and are expected to be addressed through a mixture of the seismic relay review and walkdown.

Random Component Failures and Human Errors

Reference 3 indicates that non-seismic failures and human errors should be considered during the selection of systems needed to respond to a seismic event. It further suggests that a method similar to the method provided in NUREG/CR-4826[4] (Maine Yankee evaluation) is considered acceptable. In this evaluation quantitative guidance is provided for determining if non-seismic or human error events should be included.

The EPRI approach (Reference 2) adopts a more qualitative criteria which serves as a guide for choosing systems and equipment for the success path logic diagram. Specifically, the analyst should consider equipment train reliability and required operator actions when choosing the systems required for the SHNPP success paths. The analyst is directed to only consider the most reliable paths.

The reliability of components identified in the success paths were considered to ensure that only the more reliable systems and components were included. Where more than one system was available to meet a particular function, the most reliable components were chosen. In addition, system alignments which required considerable operator action or were not well documented in procedures were avoided.

The primary paths chosen for the SPLD require limited operator action. These actions are long-term in nature and require the operators to perform actions many hours after the event occurs and provides considerable time for the operators to prepare. For alternative paths some operator action is required within a shorter time frame. The major operator actions are identified in Table 4-1 along with procedures which direct the action.

The first operator action is associated with the alternative reactivity shutdown path. Emergency boration requires the operators to align the chemical volume and control system suction to the boron transfer tanks. The required actions can be performed from the control room and adequate indication is provided to the operators to monitor the success of the operation.

Feed-and-bleed cooling is an alternative to the normal decay heat removal path. To start feed-and-bleed cooling the operators must manually open the pressurizer PORVs and initiate safety injection. The actions to open the valves and to start the pumps are performed from the control room and the operators are well trained on these actions.

Table 4-1
Major Operator Actions Required in the SPLD

Operator Action	Procedure
Emergency boration	EOP-FRP-S.1/AOP-002[1]
Feed-and-bleed cooling	EOP-FRP-H.1
RCS cooldown (non-LOCA)	EOP-EPP-005
RCS cooldown (LOCA)	EOP-EPP-009
Swapover of AFW source	EOP-EPP-005
Recirculation swapover	EOP-EPP-010

Notes:
1. EOP-FRP-S.1 addresses ATWS and requires the implementation of AOP-002 (emergency boration)

RCS cooldown requires the operators to utilize the steam generators to reduce RCS pressure to establish shutdown cooling using the residual heat removal system. Two different situations are addressed in the SPLD. The actions required by the operators is similar in both cases. As with the prior operator actions, the operator actions can be performed from the control room.

The AFW swapover is performed many hours after the postulated seismic event has occurred and allows considerable time for remedial actions. The operators must open paths between the AFW and service water systems by opening several motor-operated valves. This action can be accomplished from the control room. Recirculation swapover is similar to AFW swapover and involves operator action many hours after the seismic event. Most of the recirculation swapover is automatic with the operators only performing a few actions from the control room.

Instrumentation and Control

The identification of component control is limited to identifying only those signals which are needed to operate equipment and does not include actuation circuits and relays which are beyond the scope of this effort and require special consideration. Since Shearon Harris is not an A-46 plant, NUREG-1407 (Reference 3) requires that only low ruggedness relays be evaluated. A limited number of relays were identified based on a search of relay information. This evaluation is documented in Reference 8. The impact of these low ruggedness relays on operating equipment is examined in this report.

Instrumentation identification is limited to that which is required to maintain system function and does not include local indicators which are not required. Two conditions are considered and reflect assumptions used in the Shearon Harris IPE. Instrumentation is only addressed if it (1) controls active components or (2) if it is required by the operators in order to maintain system operation.

It is believed that this level of investigation meets the intent of the IPEEE for a focused scope plant and provides the necessary information required for the walkdown associated with EPRI report NP-6041. Although limited in this evaluation, other tasks will be used to provide assurance that any potentially important control malfunction or instrumentation failure will be addressed. The piping walkdown will be used to insure that unlisted instrumentation does not effect system performance or piping integrity.

The detailed screening process for potential low ruggedness relays (Reference 8) identified any relays for which relay chatter is a concern. This work also examined if identified relays could impact system operation and what operator actions might be necessary.

6.0 References

1. Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - 10CFR 50.54(f), Generic Letter No. 88-20, Supplement 4, USNRC, June 28, 1991.

2. Reed, J. W., et al, A Methodology for Assessment of Nuclear Power Plant Seismic Margin (Revision 1), Electric Power Research Institute, NP-6041, August 1991.

3. Chen, J. T., et al, Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, USNRC, NUREG-1407, June 1991.

4. Prassinos, P. G., et al, Seismic Margin Review of the Maine Yankee Atomic Power Station, Vols 1-3, Lawrence Livermore National Laboratory, NUREG/CR-4826, March 1987.

5. Campbell, R. D., et al, Compilation of Fragility Information from Available Probabilistic Risk Assessments, Lawrence Livermore National Laboratory, UCID-20571, September 1985.

6. Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment, Seismic Qualification Utility Group (SQUG) and the Electric Power Research Institute, February 1992.

7. Summitt, R. L., Assessment of Containment Capacity for the ALWR Based on Prior PRA Assessments, USDOE Advanced Reactor Severe Accident Program, April 1990.

8. Boyd, G. J., et al, Relay Study for the Shearon Harris Individual Plant Examination of External Events, SAROS 93-9, Safety and Reliability Optimization Services, Inc., December 1993.

Referenced Drawings

2165-S-0542, Rev. 19
2165-S-0544, Rev. 20
2165-S-0545, Rev. 31
2165-S-0547, Rev. 22
2165-S-0550, Rev. 12
2165-S-0563, Rev. 6
2165-S-1300, Rev. 17
2165-S-1301, Rev. 6
2165-S-1303, Rev. 9
2165-S-1305, Rev. 12
2165-S-1307, Rev. 5
2165-S-1308, Rev. 8

Referenced Drawings (continued)

2165-S-1309, Rev. 15
2165-S-1310, Rev. 10
2165-S-1319, Rev. 13
2165-S-1320, Rev. 3
2165-S-1324, Rev. 9
2165-S-1344, Rev. 4
2165-S-633S02, Rev. 8
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2165-S-633S04, Rev. 13
2165-S-998S02, Rev. 12
2165-S-998S03, Rev. 7
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2166-B-401-S1470
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2168-G-548, Rev. 9
2166-B-401/sh 1995
2166-B-401/sh 2008

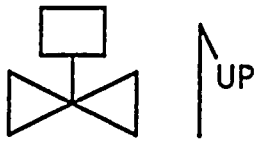
Appendix A

Walkthrough Documentation

Seismic Walkthrough Checklist

Component Identification: CSIP 1A-SA		Component Type: Motor-driven pump
Anchorages: Mounted on common skid which is anchored to concrete pad ~4" high by 16 -1" bolts.	Elevation from floor: 1 ft	Orientation: 90 degrees from CCW pumps but parallel to other CSI pumps at same elevation
Seismic II/I: A fire header is located above the pump and motor	Adjoining structures: Inside reinforced concrete room	Nearby walls or piping: Not a concern
Support Equipment Mounting/Flexibility: The pump is well mounted and the piping appears rugged. A non Q-list switch is located on separate wall and the potential exists for short.		
Comments/Insights: The control cabling does not have as much slack as was found at some other pumps.		

Seismic Walkthrough Checklist

Component Identification: CS-291		Component Type: Electric motor operated valve
Anchorages: Piping is anchored but operator is not	Elevation from floor: 1 ft from floor about elevation 246 above CSIP rooms	Orientation: 
Seismic II/I: HVAC duct sections above which are bolted together	Adjoining structures: none	Nearby walls or piping: none
Support Equipment Mounting/Flexibility: Anchorage for piping includes pipe being welded to anchor		
Comments/Insights: A unrelated piping restraint device is about 2" from valve operator		

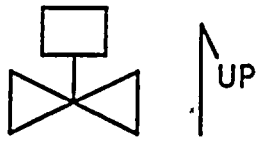
Seismic Walkthrough Checklist

Component Identification: RHR pump 1A-SA		Component Type: Vertical suction pump
Anchorages: Pump anchored to stand which is, in turn, anchored to concrete pad about 8 inches tall. The stand had three legs for which 2" bolts were used for anchorage. The motor did not have apparent anchorage except for that from the pump connection.	Elevation from floor: 5 ft from floor mounted to metal stand.	Orientation: The pump was located near the containment wall and was elevated from the floor.
Seismic II/I: HVAC duct sections above which are bolted together	Adjoining structures: none	Nearby walls or piping: Containment wall
Support Equipment Mounting/Flexibility: It is unclear how the pump was anchored to the motor. Could not examine closely due to contamination.		
Comments/Insights: Near the pump valve SI-322 was found.		

Seismic Walkthrough Checklist

Component Identification:		Component Type:
RHR heat exchanger 1A-SA		Vertical heat exchanger
Anchorages: Due to skirt around base could not examine the actual anchorage	Elevation from floor: Mounting approximately 1 ft from floor	Orientation: The heat exchanger was vertically mounted with what appeared to be a skirt arrangement.
Seismic II/I: None identified	Adjoining structures: Permanent scaffolding surrounded the heat exchanger about 8 ft from floor	Nearby walls or piping: Inside reinforced wall structure. No block walls
Support Equipment Mounting/Flexibility:		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification: RH-25		Component Type: Electric motor operated valve
Anchorages: Valve is not anchored but piping is	Elevation from floor: Located approximately 4 ft from floor	Orientation: 
Seismic II/I: One light fixture directly above the operator	Adjoining structures: none	Nearby walls or piping: Reinforced wall structure. No block walls
Support Equipment Mounting/Flexibility: Cables a flexible		
Comments/Insights: The valve hand wheel release is very close to a mounted ladder and could strike it if movement occurred.		

Seismic Walkthrough Checklist

Component Identification: Nitrogen storage tank		Component Type: Vertical and horizontal tanks
Anchorages: vertical tank mounted on pad using 4 one inch bolts	Elevation from floor: Located approximately 4 ft from ground level	Orientation: Three tanks horizontal, one large tank vertical. The vertical tank is approximately 20 ft tall
Seismic II/I:	Adjoining structures:	Nearby walls or piping:
Support Equipment Mounting/Flexibility:		
Comments/Insights: Located in yard. If needed would be difficult to provide acceptable due to long distances of piping and tank supports.		

Seismic Walkthrough Checklist

Component Identification: AFW MDP 1A-SA		Component Type: Motor driven pump
Anchorages: Pump and motor bolted to common skid. The skid is bolted to 4" pad using eight 1" bolts	Elevation from floor: Located about 3 ft from floor	Orientation: Located in parallel to other AFW pumps
Seismic II/I:	Adjoining structures: Missile shield wall is reinforced and not block	Nearby walls or piping:
Support Equipment Mounting/Flexibility:		
Comments/Insights:		

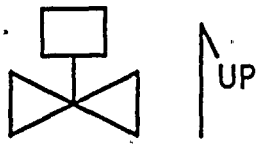
Seismic Walkthrough Checklist

Component Identification: AFW MDP 1B-SB		Component Type: Motor driven pump
Anchorages: Pump and motor bolted to common skid. The skid is bolted to 4" pad using eight 1" bolts	Elevation from floor: Located about 3 ft from floor	Orientation: Located in parallel to other AFW pumps
Seismic II/I:	Adjoining structures: Missile shield wall is reinforced and not block	Nearby walls or piping:
Support Equipment Mounting/Flexibility:		
Comments/Insights:		

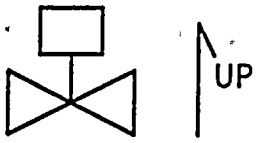
Seismic Walkthrough Checklist

Component Identification: AFW SDP XAB		Component Type: Steam driven pump
Anchorages: Pump and turbine bolted to common skid. The skid is bolted to 6" pad using 10 1" bolts	Elevation from floor: Located about 3 ft from floor	Orientation: Located in parallel to other AFW pumps
Seismic II/I:	Adjoining structures: Missile shield wall is reinforced and not block	Nearby walls or piping:
Support Equipment Mounting/Flexibility:		
Comments/Insights: Local control panel is located off skid and mounted to wall by angle iron		

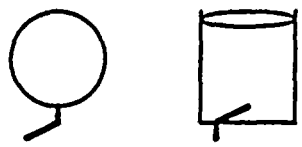
Seismic Walkthrough Checklist

Component Identification: AFW valves AF-51, AF-50, AF-49	Component Type: Air operated control valve	
Anchorages: Valves are not anchored although piping is. Operators are not anchored	Elevation from floor: Located about 3 ft from floor	Orientation: Valves located in parallel with each other 
Seismic II/I:	Adjoining structures:	Nearby walls or piping: Block wall located next to AF-49
Support Equipment Mounting/Flexibility: Piping strongly anchored. The operators are tall ~3.5 ft and are not anchored.		
Comments/Insights:		

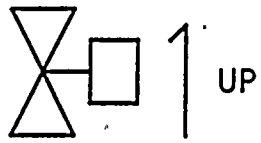
Seismic Walkthrough Checklist

Component Identification:		Component Type:
AFW valves AF-131, AF-130, AF-129		Hydraulic motor valves
Anchorages:	**Elevation from floor:**	**Orientation:**
Valves are mounted with x-y anchorage on operator. Valve body and operator are mounted to common anchorage	Located about 3 ft from floor	Located in parallel to each other 
Seismic II/I:	**Adjoining structures:**	**Nearby walls or piping:**
Support Equipment Mounting/Flexibility:		
Comments/Insights:		

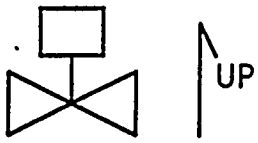
Seismic Walkthrough Checklist

Component Identification: Condensate Tank		Component Type: Vertical tank
Anchorages: Mounted to concrete pad using 3" bolts spaced about 1' apart	Elevation from floor:	Orientation:
Seismic II/I:	Adjoining structures: Located in tank room	Nearby walls or piping:
Support Equipment Mounting/Flexibility: AFW discharge piping is fixed to the tank and the concrete basemat without any support.		
Comments/Insights:  Simple schematic of CST tank AFW suction line (top and side view)		

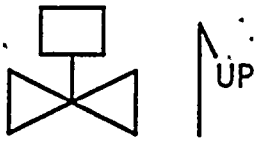
Seismic Walkthrough Checklist

Component Identification: SW valves SW-124, SW-126, SW-127, SW-129; AFW supply		Component Type: Electric motor operated
Anchorages: Piping anchored but valves are not. In particular the operators are not anchored.	Elevation from floor: Located about 3.5 ft from floor near post 28/C	Orientation: Located in parallel to each other 
Seismic II/I:	Adjoining structures:	Nearby walls or piping:
Support Equipment Mounting/Flexibility: The control and power cables for SW-127 seem somewhat tight		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification: SW valves SW-121, SW-123		Component Type: Electric motor operated valve
Anchorages: Valves and operators are not anchored. An xyz anchorage is present on the piping near the valves	Elevation from floor: Located about 1 ft from floor	Orientation: Located in parallel to each other 
Seismic II/I:	Adjoining structures:	Nearby walls or piping: concrete walls nearby
Support Equipment Mounting/Flexibility: Control cabling seemed tight		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification: SG PORVs, SM-58, SM-60, SM-62	Component Type: Electric-hydraulic valves	
Anchorages: PORVs are not anchored	Elevation from floor: Located about 6 ft from floor	Orientation: Located in parallel to each other 
Seismic II/I: Light fixture is mounted over valve SM-60	Adjoining structures:	Nearby walls or piping:
Support Equipment Mounting/Flexibility: Valves are close to walkway railing and steam lines could have interaction potential		
Comments/Insights:		

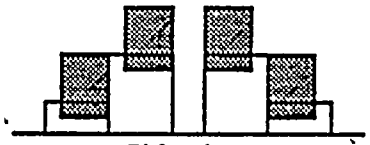
Seismic Walkthrough Checklist

Component Identification: DG-1B (1A similar)		Component Type: Diesel Generator
Anchorages: Diesel generator is mounted to common pad - 8 " pad. Two skids are used, however, between the diesel and some support systems. Lubrication oil cooler and jacket water cooler are saddle mounted with 3 brackets which are 1/2 up heat exchanger and bolted to pad	Elevation from floor: Diesel is located about 3 ft from floor	Orientation: Located in parallel to each other
Seismic II/I:	Adjoining structures: in diesel generator building	Nearby walls or piping:
Support Equipment Mounting/Flexibility: Control panel 1E-23 has four fillet welds on only one side of panel anchorage. Anchorage for other control panels needs to be examined.		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification:		Component Type:
Fuel oil transfer pump 1A-SA		Electric motor pump
Anchorages: Small motor mounted on 4" pad by four 0.5" bolts	Elevation from floor: 4" from floor on pad	Orientation: Pumps are located at fuel building about 20" underground in separate rooms.
Seismic II/I:	Adjoining structures:	Nearby walls or piping:
Support Equipment Mounting/Flexibility: Piping for fuel oil in building is supported at the top of the run in the room but there exists several 90-degree elbows which do not have support		
Comments/Insights: 1B-SB is similar in design		

Seismic Walkthrough Checklist

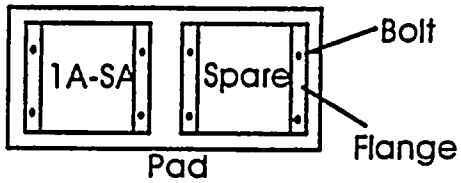
Component Identification:		Component Type:
Vital batteries 1A-SA (1B-SB similar)		DC batteries
Anchorages: Batteries are located on two racks which are mounted to the floor through five "feet" which are bolted to floor using 0.5" bolts with four bolts for each "foot". Batteries are braced and have crush resistant spacers.	**Elevation from floor:** Batteries located on rack from <6" to 2.5 ft from floor	**Orientation:**  Side view One bank (1B-SB) orientation
Seismic II/I: Light fixtures are located in room above batteries	**Adjoining structures:** Inside reinforced structure	**Nearby walls or piping:** Eyewash station located in room with shower head near position to spray batteries
Support Equipment Mounting/Flexibility: Batteries are well mounted and anchored within each rack but are not anchored between racks.		
Comments/Insights: The eyewash stations in both rooms are of some concern if both were to fail (similar location, orientation, and elevation).		

Seismic Walkthrough Checklist

Component Identification:		Component Type:
Charger 1A-SA (1B-SB similar)		DC Charger
Anchorages:	**Elevation from floor:**	**Orientation:**
Mounted to concrete pad about 6" from floor by 4 3/8" bolts. The mounting flange for the charger cabinet is very thin and about 1" long. No welds present	6" from floor on pad	All chargers are located in similar orientation at the same elevation
Seismic II/I:	**Adjoining structures:**	**Nearby walls or piping:**
None	none	Battery room wall

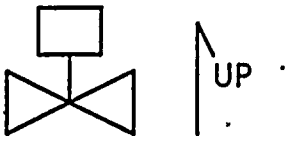
Support Equipment Mounting/Flexibility:
The flange for mounting the charger unit needs to be examined to ensure structural capability.

Comments/Insights:



Orientation of 1A-SA and installed spare

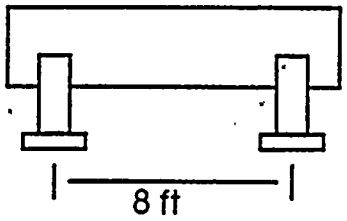
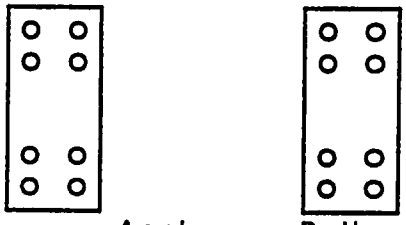
Seismic Walkthrough Checklist

Component Identification:		Component Type:
SW discharge valves SW-274, SW-276		Electric motor operated valve
Anchorages:	**Elevation from floor:**	**Orientation:**
No anchorage for valve but pipe is anchored	5' from floor	
Seismic II/I:	**Adjoining structures:**	**Nearby walls or piping:**
None	none	Reinforced wall

Support Equipment Mounting/Flexibility:
Adequate cable flexibility. Valve motor operator for valve SW-276 is ~4" from adjacent piping. The bottom of valve SW-274 is about 1" from piping anchorage.

Comments/Insights:

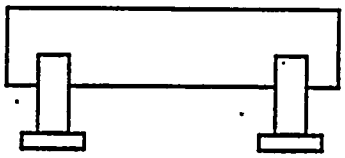
Seismic Walkthrough Checklist

Component Identification:		Component Type:
CCW surge tank		Horizontal tank
Anchorages: Located on concrete pad with 1" bolts for anchorage. Eight bolts for each saddle.	**Elevation from floor:** 5' from floor	**Orientation:** 
Seismic II/I: None	**Adjoining structures:** Inside wall of tank room is block	**Nearby walls or piping:** Block wall
Support Equipment Mounting/Flexibility: Tank appears to be well supported.		
Comments/Insights:  Anchorage Pattern		

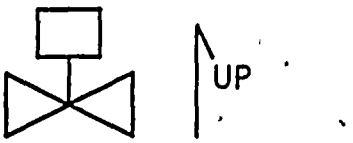
Seismic Walkthrough Checklist

Component Identification:		Component Type:
CCW pump 1A-SA (1B-SB similar)		Electric motor pump
Anchorages:	**Elevation from floor:**	**Orientation:**
Mounted on common skid which is anchored to 4" pad using 12 1" bolts. Five on each side and two at each end.	5' from floor	Located at same elevation and orientation as other CCW pumps
Seismic II/I:	**Adjoining structures:**	**Nearby walls or piping:**
HVAC ducting above 1A-SA but not major issue. For 1B-SB, lighting is located above pump	none	4" ESW line located above pump
Support Equipment Mounting/Flexibility:		
Electrical connections flexible. Local control and instrumentation is separate from skid on nearby wall. For pump 1A-SA, the motor is located ~1" from piping support.		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification:		Component Type:
CCW heat exchanger		Heat exchanger
Anchorages: Located on concrete pad with two saddle supports welded to heat exchanger. Saddle supports are anchored to pad by eight 3" bolts	Elevation from floor: 2' from floor at base of heat exchanger. 4' to horizontal centerline	Orientation: 
Seismic II/I: None	Adjoining structures: none	Nearby walls or piping:
Support Equipment Mounting/Flexibility: Tank appears to be well supported.		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification:		Component Type:
RHR HX isolation valve CC-142		Electric motor operated valve
Anchorages:	**Elevation from floor:**	**Orientation:**
Valve is not anchored. The pipe is welded to supports in both lateral and vertical directions	1 ft from floor	
Seismic II/I:	**Adjoining structures:**	**Nearby walls or piping:**
Some non-safety equipment (speaker) located above operator	none	Reinforced wall, RHR line above (well supported)
Support Equipment Mounting/Flexibility:		
The operator for the valve is not supported and is located about 4' above floor		
Comments/Insights:		

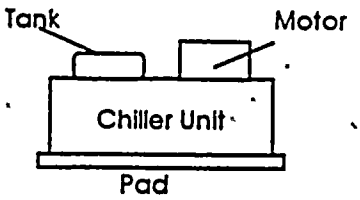
Seismic Walkthrough Checklist

Component Identification: CSIP AHU AH-9-1A (AH-9-1B similar)		Component Type: Air handling unit
Anchorages: Mounted on common skid which is bolted to 6" concrete pad using sixteen 0.5" bolts. Six on each side and two at either end.	Elevation from floor: 6"	Orientation: Located above CSIP room with all oriented in same direction
Seismic II/I: Ductwork shielded by other anchorage supports	Adjoining structures: none	Nearby walls or piping: Reinforced wall, RHR line above (well supported)
Support Equipment Mounting/Flexibility:		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification: Essential chilled service water pump 1A-SA		Component Type: Electric motor pump
Anchorages: Mounted on skid which is bolted to 6" concrete pad using 10 1" bolts. Five on each side.	Elevation from floor: Pump about 2' from floor	Orientation: Located near chiller
Seismic II/I: None	Adjoining structures: none	Nearby walls or piping: Reinforced wall
Support Equipment Mounting/Flexibility: Control cables are not supported over four foot span and then anchored to wall. Could have some displacement		
Comments/Insights:		

Seismic Walkthrough Checklist

Component Identification: Essential chiller unit WC-2		Component Type: Chiller package
Anchorages: Unit on common skid with tank and motor above. It is setting on concrete pad supported at the four end points. No mounting apparent although unable to confirm due to coverings	Elevation from floor: Unit about 1' from floor	Orientation: 
Seismic II/I: None	Adjoining structures: none	Nearby walls or piping: Reinforced wall
Support Equipment Mounting/Flexibility:		
Comments/Insights: Unit does not appear to be mounted to concrete pad. Additional information should be obtained about anchorage. [Later found to be well anchored.]		

Appendix B

Safe Shutdown Equipment Listing

Auxiliary Feedwater System

21 Aug 94

System List Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	5	1A-SA	AFW motor-driven pump 1A-SA	2165-S-0544, Rev. 20	RAB	236	S,R		OFF	ON	Yes	1A-SA;DP-1A; K640A
2	1	R	1AF-16	Check valve	2165-S-0544, Rev. 20	RAB	236	None		CL	CL/OP	No	
3	1	7	1AF-19	Electric-hydraulic valve	2165-S-0544, Rev. 20	RAB	236	S,R	1	OP	OP	No	
4	1	R	1AF-40	Manual valve	2165-S-0544, Rev. 20	RAB	261	None		OP	OP	No	
5	1	7	1AF-49	Electric-hydraulic valve	2165-S-0544, Rev. 20	RAB	261	S,R	1	OP	OP	No	
6	1	R	1AF-201	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
7	1	R	1AF-54	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
8	1	8a	1AF-55	Electric motor operated valve	2165-S-0544, Rev. 20	RAB	236	S,R		OP	OP	No	
9	2	5	1B-SB	AFW motor-driven pump 1B-SB	2165-S-0544, Rev. 20	RAB	236	S,R		OFF	ON	Yes	1B-SB; DP-1B; K640B
10	2	R	1AF-31	Check valve	2165-S-0544, Rev. 20	RAB	236	None		CL	CL/OP	No	
11	2	7	1AF-34	Electric-hydraulic valve	2165-S-0544, Rev. 20	RAB	236	S,R	1	OP	OP	No	
12	2	R	1AF-42	Manual valve	2165-S-0544, Rev. 20	RAB	261	None		OP	OP	No	
13	2	7	1AF-51	Electric-hydraulic valve	2165-S-0544, Rev. 20	RAB	261	S,R	1	OP	OP	No	
14	2	R	1AF-202	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
15	2	R	1AF-92	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
16	2	8a	1AF-93	Electric motor operated valve	2165-S-0544, Rev. 20	RAB	261	S,R		OP	OP	No	
17	3	5	1X-SAB	AFW steam-driven pump 1X-SAB	2165-S-0544, Rev. 20	RAB	236	S,R		OFF	ON	Yes	DP-1B; K641A/B
18	3	R	1AF-117	Check valve	2165-S-0544, Rev. 20	RAB	236	None		CL	CL/OP	No	
19	3	R	1AF-120	Manual valve	2165-S-0544, Rev. 20	RAB	261	None		OP	OP	No	
20	3	R	1AF-121	Manual valve	2165-S-0544, Rev. 20	RAB	261	None		OP	OP	No	
21	3	R	1AF-122	Manual valve	2165-S-0544, Rev. 20	RAB	261	None		OP	OP	No	
22	3	7	1AF-129	Electric-hydraulic valve	2165-S-0544, Rev. 20	RAB	261	S,R	1	OP	OP	No	
23	3	7	1AF-130	Electric-hydraulic valve	2165-S-0544, Rev. 20	RAB	261	S,R	1	OP	OP	No	
24	3	7	1AF-131	Electric-hydraulic valve	2165-S-0544, Rev. 20	RAB	261	S,R	1	OP	OP	No	
25	3	R	1AF-204	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
26	3	R	1AF-205	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
27	3	R	1AF-206	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
28	3	R	1AF-136	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
29	3	R	1AF-148	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
30	3	R	1AF-142	Check valve	2165-S-0544, Rev. 20	RAB	261	None		CL	CL/OP	No	
31	3	8a	1AF-137	Electric motor operated valve (D.C.)	2165-S-0544, Rev. 20	RAB	261	S,R		OP	OP	No	
32	3	8a	1AF-149	Electric motor operated valve (D.C.)	2165-S-0544, Rev. 20	RAB	261	S,R		OP	OP	No	
33	3	8a	1AF-143	Electric motor operated valve (D.C.)	2165-S-0544, Rev. 20	RAB	261	S,R		OP	OP	No	

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
34	1,2,3	R	1AF-68	Check valve	2165-S-0544, Rev. 20	RAB	286	None		CL	CL/OP	No	
35	1,2,3	R	1AF-106	Check valve	2165-S-0544, Rev. 20	CB	286	None		CL	CL/OP	No	
36	1,2,3	R	1AF-87	Check valve	2165-S-0544, Rev. 20	CB	286	None		CL	CL/OP	No	
37	1,2,3	21	1X-SAB	Condensate storage tank	2165-S-0545, Rev. 31	TANK	261	S		N/A	N/A	No	
38	1,2,3	R	1CE-34	Manual valve	2165-S-0545, Rev. 31	TANK	261	None		OP	OP	No	
39	1	R	1CE-35	Manual valve	2165-S-0545, Rev. 31	RAB	236	None		OP	OP	No	
40	1	R	1CE-36	Check valve	2165-S-0545, Rev. 31	RAB	236	None		CL	CL/OP	No	
41	2	R	1CE-45	Manual valve	2165-S-0545, Rev. 31	RAB	236	None		OP	OP	No	
42	2	R	1CE-46	Check valve	2165-S-0545, Rev. 31	RAB	236	None		CL	CL/OP	No	
43	3	R	1CE-55	Manual valve	2165-S-0545, Rev. 31	RAB	236	None		OP	OP	No	
44	3	R	1CE-56	Check valve	2165-S-0545, Rev. 31	RAB	236	None		CL	CL/OP	No	
45	1,2,3	18	FT2050A	AFW flow transmitter FT 2050A	2165-S-0544, Rev. 20	RAB	261	None	24	N/A	N/A	Yes	1DP-1A-S3
46	1,2,3	18	FT2050B	AFW flow transmitter FT 2050B	2165-S-0544, Rev. 20	RAB	261	None	24	N/A	N/A	Yes	1DP-1B-S2
47	1,2,3	18	FT2050C	AFW flow transmitter FT 2050C	2165-S-0544, Rev. 20	RAB	261	None	24	N/A	N/A	Yes	1DP-1B-S2
48	1	18	PT2150A	AFW pressure transmitter PT 2150A	2165-S-0544, Rev. 20	RAB	236	None	24	N/A	N/A	Yes	1DP-1A-S3
49	2	18	PT2150B	AFW pressure transmitter PT 2150B	2165-S-0544, Rev. 20	RAB	236	None	24	N/A	N/A	Yes	1DP-1B-S2
50	3	18	PT2170	AFW pressure transmitter PT 2170	2165-S-0544, Rev. 20	RAB	236	None	24	N/A	N/A	Yes	1DP-1B-S2
51	1	8a	1SW-121	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1A-35-SA
52	1	8a	1SW-123	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1A-35-SA
53	3	8a	1SW-124	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1A-35-SA
54	3	8a	1SW-126	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1A-35-SA
55	3	8a	1SW-127	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1B-35-SB
56	3	8a	1SW-129	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1B-35-SB
57	2	8a	1SW-130	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1B-35-SB
58	2	8a	1SW-132	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	2	CL	OP	Yes	1B-35-SB
59	3	8a	1MS-70	Electric motor operated valve (D.C.)	2165-S-0542, Rev. 19	MST	261	S,R		CL	OP	Yes	1DP-1A2-SA
60	3	8a	1MS-72	Electric motor operated valve (D.C.)	2165-S-0542, Rev. 19	MST	261	S,R		CL	OP	Yes	1DP-1B2-SB
61	3	R	1MS-71	Check valve	2165-S-0542, Rev. 19	RAB	261	None		CL	CL/OP	No	
62	3	R	1MS-73	Check valve	2165-S-0542, Rev. 19	RAB	261	None		CL	CL/OP	No	
63	3	R	1MS-74	Manual valve	2165-S-0542, Rev. 19	RAB	236	None		OP	OP	No	
64	3	8a	1MS-T	Electric motor operated valve (D.C.)	2165-S-0542, Rev. 19	RAB	236	S,R		OP	OP	No	
65	3	7	1MS-G	Electric hydraulic valve	2165-S-0542, Rev. 19	RAB	236	S,R		CL	OP	Yes	1DP-1B-SB
66	1,2,3	18	LT-9010A	Level instrument (CST level)	2165-S-0545, Rev. 31	TANK	236	None	24	N/A	N/A	Yes	1DP-1A-S3
67	1,2,3	18	LT-9010B	Level instrument (CST level)	2165-S-0545, Rev. 31	TANK	236	None	24	N/A	N/A	Yes	1DP-1B-S2
68	1	18	PS-2250A	Pressure switch	2165-S-0545, Rev. 31	RAB	305	S,R	3	N/A	N/A	Yes	1DP-1A-S3

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
69	2	18	PS-2250B	Pressure switch	2165-S-0545, Rev. 31	RAB	305	S,R	3	N/A	N/A	Yes	1DP-1B-S2
70	3	18	PS-2270	Pressure switch	2165-S-0545, Rev. 31	RAB	305	None	3	N/A	N/A	Yes	1DP-1B-S2
71	3	18	PS-431	Pressure switch	2165-S-0542, Rev. 19	RAB	236	None	3	N/A	N/A	Yes	1DP-1B-S2
72	1	18	PT-2250A	Pressure transmitter for PS-2250A	2165-S-0545, Rev. 31	RAB	236	S,R		N/A	N/A	Yes	PIC-C9
73	2	18	PT-2250B	Pressure transmitter for PS-2250B	2165-S-0545, Rev. 31	RAB	236	S,R		N/A	N/A	Yes	PIC-C10
74	3	18	PT-2270	Pressure transmitter for PS-2270	2165-S-0545, Rev. 31	RAB	236	S,R		N/A	N/A	Yes	PIC-C10
75	1	18	PS-2150A	Pressure switch for PT-2150A	2165-S-0544, Rev. 20	RAB	305	S,R		N/A	N/A	Yes	PIC-C9
76	2	18	PS-2150B	Pressure switch for PT-2150B	2165-S-0544, Rev. 20	RAB	305	S,R		N/A	N/A	Yes	PIC-C10
77	1	18	PS-2170	Pressure switch for PT-2170	2165-S-0544, Rev. 20	RAB	305	S,R		N/A	N/A	Yes	PIC-C10
78	2	18	A1-R13	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	
79	1	18	A1-R14	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	
80	2	18	A21-R15	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	
81	1	18	A21-R17	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	
82	1	18	A1-R28	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	261	S		N/A	N/A	No	
83	2	18	A1-R29	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	
84	1	18	A1-R27	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	261	S		N/A	N/A	No	
85	1	18	A1-R33	Instrument rack fror safe shutdown instrumen	Equipment Rack	RAB	261	S		N/A	N/A	No	

System Analyst

Residual Heat Removal System

21-Aug-94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	5	1A-SA	RHR motor driven pump 1A-SA	2165-S-1324, Rev. 9	RAB	190	S,R		OFF	ON	Yes	1A2-SA;DP-1A-SA; CC
2	1	R	1RH-19	Manual valve	2165-S-1324, Rev. 9	RAB	190	None		OP	OP	No	
3	1	21	1A-SA	RHR heat exchanger 1A-SA	2165-S-1324, Rev. 9	RAB	236	S		N/A	N/A	No	
4	1	8b	1RH-30	Air operated valve	2165-S-1324, Rev. 9	RAB	236	S,R		OP	OP	No	
5	1	R	1RH-34	Check valve	2165-S-1324, Rev. 9	RAB	236	None		CL	CL/OP	No	
6	1	18	1FT-605A	Flow transmitter 1FT-605A	2165-S-1324, Rev. 9	RAB	236	None	24	N/A	N/A	Yes	PIC-C7
7	2	5	1B-SB	RHR motor driven pump 1B-SB	2165-S-1324, Rev. 9	RAB	190	S,R		OFF	ON	Yes	1B2-SB;DP-1B-SB; CC
8	2	R	1RH-57	Manual valve	2165-S-1324, Rev. 9	CB	216	None		OP	OP	No	
9	2	21	1B-SB	RHR heat exchanger 1B-SB	2165-S-1324, Rev. 9	RAB	236	S		N/A	N/A	No	
10	2	8b	1RH-66	Air operated valve	2165-S-1324, Rev. 9	CB	216	S,R		OP	OP	No	
11	2	R	1RH-70	Check valve	2165-S-1324, Rev. 9	CB	216	None		CL	CL/OP	No	
12	2	18	1FT-605B	Flow transmitter 1FT-605B	2165-S-1324, Rev. 9	RAB	236	None	24	N/A	N/A	Yes	PIC-19
13	2	8a	1SI-323	Electric motor operated valve	2165-S-1310, Rev. 10	RAB	236	S,R		OP	OP	No	
14	2	R	1SI-321	Check valve	2165-S-1310, Rev. 10	RAB	190	None		CL	CL/OP	No	
15	1	8a	1SI-322	Electric motor operated valve	2165-S-1310, Rev. 10	RAB	236	S,R		OP	OP	No	
16	1	R	1SI-320	Check valve	2165-S-1310, Rev. 10	RAB	190	None		CL	CL/OP	No	
17	2	8a	1SI-311	Electric motor operated valve	2165-S-1310, Rev. 10	RAB	190	S,R	7	CL	OP	Yes	1B21-SB; K740B&K739
18	2	8a	1SI-301	Electric motor operated valve	2165-S-1310, Rev. 10	RAB	190	S,R	7	CL	OP	Yes	1B21-SB; K740B&K741
19	1	8a	1SI-310	Electric motor operated valve	2165-S-1310, Rev. 10	RAB	190	S,R	7	CL	OP	Yes	1A21-SA; K740A&K739
20	1	8a	1SI-300	Electric motor operated valve	2165-S-1310, Rev. 10	RAB	190	S,R	7	CL	OP	Yes	1A21-SA; K740A&K741
21	1,2	18	1TE-606A	Temperature elements TE-606A	2165-S-1324, Rev. 9	RAB	236	S,R	8	N/A	N/A	Yes	PIC-C7
22	1	18	1TE-604A	Temperature elements TE-604A	2165-S-1324, Rev. 9	RAB	236	S,R	8	N/A	N/A	Yes	PIC-C7
23	2	18	1TE-604B	Temperature elements TE-604B	2165-S-1324, Rev. 9	RAB	236	S,R	8	N/A	N/A	Yes	PIC-C8
24	1,2	18	1TE-606B	Temperature elements TE-606B	2165-S-1324, Rev. 9	RAB	236	S,R	8	N/A	N/A	Yes	PIC-C8
25	1	18	TI-5551A	Local temperature instrument TI-5551A	2165-S-1324, Rev. 9	RAB	236	S	23	N/A	N/A	No	
26	2	18	TI-5551B	Local temperature instrument TI-5551B	2165-S-1324, Rev. 9	RAB	236	S	23	N/A	N/A	No	
27	1	18	A1-R6	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	

System Analyst: [illegible]

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Appendix B
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Chemical Volume and Control System/SI

21-Aug-94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1,2	5	1A-SA	CSIP motor-driven pump 1A-SA	2165-S-1305, Rev. 12	RAB	236	S,R		OFF	ON	Yes	1A-SA:DP-1A-SA:AHU-
2	1,2	R	1CS-178	Check valve	2165-S-1305, Rev. 12	RAB	236	None		CL	CL/OP	No	
3	1,2	R	1CS-183	Manual valve	2165-S-1305, Rev. 12	RAB	236	None		OP	OP	No	
4	1,2	R	1CS-173	Manual valve	2165-S-1305, Rev. 12	RAB	236	None		OP	OP	No	
5	1,2	R	1CS-187	Manual valve	2165-S-1305, Rev. 12	RAB	236	None		OP	OP	No	
6	1,2	5	1B-SB	CSIP motor-driven pump 1B-SB	2165-S-1305, Rev. 12	RAB	236	S,R		OFF	ON	Yes	1B-SA:DP-1B-SB:AHU-
7	1,2	R	1CS-192	Check valve	2165-S-1305, Rev. 12	RAB	236	None		CL	CL/OP	No	
8	1,2	R	1CS-197	Manual valve	2165-S-1305, Rev. 12	RAB	236	None		OP	OP	No	
9	1	R	1CS-167	Check valve	2165-S-1305, Rev. 12	RAB	261	None		CL	CL/OP	No	
10	1	8a	1CS-166	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	261	S,R		OP	OP	No	
11	1	8a	1CS-165	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	261	S,R		OP	OP	No	
12	1	21	1X-SN	Volume control tank	2165-S-1305, Rev. 12	RAB	236	S		N/A	N/A	No	
13	2	8a	1CS-291	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		CL	OP	Yes	1A35-SA:K602A
14	2	8a	1CS-292	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		CL	OP	Yes	1B35-SB:K602B
15	2	R	1CS-294	Check valve	2165-S-1305, Rev. 12	RAB	236	None		CL	CL/OP	No	
16	1	8a	1CS-171	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
17	1	8a	1CS-169	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
18	1	8a	1CS-168	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
19	1	8a	1CS-170	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
20	1	8a	1CS-235	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
21	1	R	1CS-234	Manual valve	2165-S-1305, Rev. 12	RAB	236	None		OP	OP	No	
22	1	7	1CS-231	Electric-hydraulic valve	2165-S-1305, Rev. 12	RAB	261	S,R		OP	OP	No	
23	1	R	1CS-228	Manual valve	2165-S-1305, Rev. 12	RAB	236	None		OP	OP	No	
24	1	18	1FT-122	Flow transmitter 1FT-122	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
25	1,2	8a	1CS-217	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
26	1,2	8a	1CS-219	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
27	1,2	8a	1CS-218	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
28	1,2	8a	1CS-220	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		OP	OP	No	
29	1	8a	1CS-238	Electric motor operated valve	2165-S-1303, Rev. 9	RAB	236	S,R		OP	OP	No	
30	1	R	1CS-477	Check valve	2165-S-1303, Rev. 9	CB	236	None		CL	CL/OP	No	
31	1	21	1X-SN	Regenerative heat exchanger	2165-S-1303, Rev. 9	CB	236	S		N/A	N/A	No	
32	1	7	1CS-492	Air operated valve	2165-S-1303, Rev. 9	CB	236	S,R		AIR	OP	No	
33	1	R	1CS-497	Check valve	2165-S-1303, Rev. 9	CB	257	None		CL	CI/OP	No	

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
34	1	R	1CS-500	Check valve	2165-S-1303, Rev. 9	CB	258	None		CL	CL/OP	No	
35	2	21	1X-SN	Refueling water storage tank	2165-S-0550, Rev. 12	TANK	261	S		N/A	N/A	No	
36	1,2	18	1FT-943	Flow transmitter 1FT-943	2165-S-1308, Rev. 8	RAB	236	None	24	N/A	N/A	Yes	DC-1A-SA
37	1,2	8a	1SI-1	Electric motor operated valve	2165-S-1308, Rev. 8	RAB	216	S,R		CL	OP	Yes	1A31-SA;K601A
38	1,2	8a	1SI-2	Electric motor operated valve	2165-S-1308, Rev. 8	RAB	216	S,R		CL	OP	Yes	1B-31-SB;K601B
39	1,2	21	1X-SAB	Boron injection tank	2165-S-1308, Rev. 8	RAB	216	S		OP	OP	No	
40	1,2	8a	1SI-3	Electric motor operated valve	2165-S-1308, Rev. 8	RAB	216	S,R		CL	OP	Yes	1A31-SA;K603A
41	1,2	8a	1SI-4	Electric motor operated valve	2165-S-1308, Rev. 8	RAB	216	S,R		CL	OP	Yes	1B31-SB;K603B
42	1,2	R	1SI-5	Manual valve	2165-S-1308, Rev. 8	CB	216	None		CL	CL/OP	No	
43	1,2	R	1SI-6	Manual valve	2165-S-1308, Rev. 8	CB	216	None		OP	OP	No	
44	1,2	R	1SI-7	Manual valve	2165-S-1308, Rev. 8	CB	216	None		OP	OP	No	
45	1,2	R	1SI-8	Check valve	2165-S-1308, Rev. 8	CB	216	None		CL	CL/OP	No	
46	1,2	R	1SI-9	Check valve	2165-S-1308, Rev. 8	CB	216	None		OP	OP	No	
47	1,2	R	1SI-10	Check valve	2165-S-1308, Rev. 8	CB	216	None		OP	OP	No	
48	1,2	R	1SI-81	Check valve	2165-S-1308, Rev. 8	CB	236	None		OP	OP	No	
49	1,2	R	1SI-82	Check valve	2165-S-1308, Rev. 8	CB	236	None		CL	CL/OP	No	
50	1,2	R	1SI-83	Check valve	2165-S-1308, Rev. 8	CB	236	None		CL	CL/OP	No	
51	1,2	18	1FT-940	Flow transmitter 1FT-940	2165-S-1308, Rev. 8	RAB	236	None		N/A	N/A	Yes	DC-1B-SB
52	1,2	18	1LT-990	Level transmitter 1LT-990	2165-S-0550, Rev. 12	TANK	261	S,R	4	N/A	N/A	Yes	PIC-C1
53	1,2	18	1LT-991	Level transmitter 1LT-991	2165-S-0550, Rev. 12	TANK	261	S,R	4	N/A	N/A	Yes	PIC-C2
54	1,2	18	1LT-992	Level transmitter 1LT-992	2165-S-0550, Rev. 12	TANK	261	S,R	4	N/A	N/A	Yes	PIC-C3
55	1,2	18	1LT-993	Level transmitter 1LT-993	2165-S-0550, Rev. 12	TANK	261	S,R	4	N/A	N/A	Yes	PIC-C4
56	1	8a	RH-25	Electric motor operated valve	2165-S-1324, Rev. 9	RAB	236	S,R	5	CL	OP	Yes	1A35-SA
57	2	8a	RH-63	Electric motor operated valve	2165-S-1324, Rev. 9	RAB	236	S,R	5	CL	OP	Yes	1B35-SB
58	1,2	18	LT-115	Level transmitter LT-115	2165-S-1305, Rev. 12	RAB	236	S,R	6	N/A	N/A	Yes	PIC-C5
59	1,2	18	LT-112	Level transmitter LT-112	2165-S-1305, Rev. 12	RAB	236	S,R	6	N/A	N/A	Yes	PIC-C8
60	1,2	18	A1-R7	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	
61	1	18	PIC-CAB-1	Protection cabinet I	1364-46574S01	RAB	305	S,R		N/A	N/A	Yes	IDP-1A-SI
62	2	18	PIC-CAB-2	Protection cabinet II	1364-46575S01	RAB	305	S,R		N/A	N/A	Yes	IDP-1B-SII
63	1	18	PIC-CAB-3	Protection cabinet III	1364-46576S01	RAB	305	S,R		N/A	N/A	Yes	IDP-1A-SIII
64	2	18	PIC-CAB-4	Protection cabinet IV	1364-46577S01	RAB	305	S,R		N/A	N/A	Yes	IDP-1B-SIV

System Analyst

Reactor Coolant System

21 Aug 94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	8a	1RC-113	Electric motor operated valve	2165-S-1301, Rev. 6	CB	286	S,R		OP	OP	Yes	1A-24
2	1	8b	1RC-114	Solenoid operated valve	2165-S-1301, Rev. 6	CB	286	S,R	9	CL	OP	Yes	DP-1A-SA
3	2	8a	1RC-115	Electric motor operated valve	2165-S-1301, Rev. 6	CB	286	S,R		OP	OP	Yes	1B-24
4	2	8b	1RC-116	Solenoid operated valve	2165-S-1301, Rev. 6	CB	286	S,R	9	CL	OP	Yes	DP-1A-1
5	3	8a	1RC-117	Electric motor operated valve	2165-S-1301, Rev. 6	CB	286	S,R		OP	OP	Yes	1B24
6	3	8b	1RC-118	Solenoid operated valve	2165-S-1301, Rev. 6	CB	286	S,R	9	CL	OP	Yes	DP-1B-SB
7	1	R	1RC-123	Safety relief valve	2165-S-1301, Rev. 6	CB	307	S		CL	CL/OP	No	
8	2	R	1RC-125	Safety relief valve	2165-S-1301, Rev. 6	CB	307	S		CL	CL/OP	No	
9	3	R	1RC-127	Safety relief valve	2165-S-1301, Rev. 6	CB	307	S		CL	CL/OP	No	
10	1	18	1PT-444	Pressure transmitter PT-444	2165-S-1301, Rev. 6	CB	236	S,R		N/A	N/A	Yes	DP-1A-S1
11	1	18	1PT-445	Pressure transmitter PT-445	2165-S-1301, Rev. 6	CB	236	S,R		N/A	N/A	Yes	DP-1A-S1
12	1	18	1PT-455	Pressure transmitter PT-455	2165-S-1301, Rev. 6	CB	236	S,R		N/A	N/A	Yes	DP-1A-S1
13	2	18	1PT-456	Pressure transmitter PT-456	2165-S-1301, Rev. 6	CB	236	S,R		N/A	N/A	Yes	DP-1B-S2
14	3	18	1PT-457	Pressure transmitter PT-457	2165-S-1301, Rev. 6	CB	236	S,R		N/A	N/A	Yes	DP-1A-S3
15	1	18	1PT-402	Pressure transmitter PT-402	2165-S-1344, Rev. 4	RAB	236	S,R		N/A	N/A	Yes	DP-1A-S1
16	2	18	1PT-403	Pressure transmitter PT-403	2165-S-1344, Rev. 4	RAB	236	S,R		N/A	N/A	Yes	DP-1A-S1
17	1	18	1TE-410	Cold level temperature element TE-410	2165-S-1300, Rev. 17	CB	255	S,R	10	N/A	N/A	Yes	DP-1B-S2
18	2	18	1TE-420	Cold level temperature element TE-420	2165-S-1300, Rev. 17	CB	255	S,R	10	N/A	N/A	Yes	DP-1B-S2
19	3	18	1TE-430	Cold level temperature element TE-430	2165-S-1300, Rev. 17	CB	255	S,R	10	N/A	N/A	Yes	DP-1B-S2
20	1	18	1PT-474	Steam generator pressure transmitter PT-474	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1B-S2
21	1	18	1PT-475	Steam generator pressure transmitter PT-475	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1A-S3
22	1	18	1PT-476	Steam generator pressure transmitter PT-476	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1A-S3
23	2	18	1PT-484	Steam generator pressure transmitter PT-484	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1B-S2
24	2	18	1PT-485	Steam generator pressure transmitter PT-485	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1A-S3
25	2	18	1PT-486	Steam generator pressure transmitter PT-486	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1A-S3
26	3	18	1PT-494	Steam generator pressure transmitter PT-494	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1B-S2
27	3	18	1PT-495	Steam generator pressure transmitter PT-495	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1A-S3
28	3	18	1PT-496	Steam generator pressure transmitter PT-496	2165-S-0542, Rev. 19	RAB	261	S,R		N/A	N/A	Yes	DP-1A-S3
29	1	21	1A-SA	Nitrogen/Air accum. tank 1A-SA for PORV	2165-S-1309, Rev. 15	CB	286	S		N/A	N/A	No	
30	2	21	1B-NNS	Nitrogen/Air accum. tank 1B-NNS for PORV	2165-S-1309, Rev. 15	CB	286	S		N/A	N/A	No	
31	3	21	1C-SB	Nitrogen/Air accum. tank 1C-SB for PORV	2165-S-1309, Rev. 15	CB	286	S		N/A	N/A	No	
32	1	8b	1RC-114:002	Solenoid valve for PORV	2165-S-1309, Rev. 15	CB	315	S,R		CL	CL/OP	Yes	Transfer panel 1B
33	1	8b	1RC-114:003	Solenoid valve for PORV	2165-S-1309, Rev. 15	CB	315	S,R		CL	CL/OP	Yes	Transfer panel 1B

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
34	2	8b	1SI-413	Solenoid valve for PORV	2165-S-1309, Rev. 15	CB	315	S,R		CL	CL/OP	Yes	Transfer panel 1A
35	2	8b	1SI-414	Solenoid valve for PORV	2165-S-1309, Rev. 15	CB	315	S,R		CL	CL/OP	Yes	Transfer panel 1A
36	3	8b	1RC-118:002	Solenoid valve for PORV	2165-S-1309, Rev. 15	CB	315	S,R		CL	CL/OP	Yes	Transfer panel 1A
37	3	8b	1RC-118:003	Solenoid valve for PORV	2165-S-1309, Rev. 15	CB	315	S,R		CL	CL/OP	Yes	Transfer panel 1A
38	1	18	A1-R22	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	261	S		N/A	N/A	No	
39	1	18	A1-R23	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	261	S		N/A	N/A	No	
40	1	18	A1-R24	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	261	S		N/A	N/A	No	
41	1	18	A1-R45A	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	261	S		N/A	N/A	No	
42	2	18	A1-R45B	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	261	S		N/A	N/A	No	
43	1	18	C1-R6	Containment instrument rack for safe shut. In	Equipment Rack	CB	236	S		N/A	N/A	No	
44	1	18	C1-R8	Containment instrument rack for safe shut. In	Equipment Rack	CB	236	S		N/A	N/A	No	
45	1	18	C1-R17	Containment instrument rack for safe shut. In	Equipment Rack	CB	236	S		N/A	N/A	No	
46	1	18	C1-R9	Containment instrument rack for safe shut. In	Equipment Rack	CB	236	S		N/A	N/A	No	
47	3	R	1RC-182	Manual valve	2165-S-1309, Rev. 15	CB	286	None		OP	OP	No	
48	2	R	1RC-181	Manual valve	2165-S-1309, Rev. 15	CB	286	None		OP	OP	No	
49	1	R	1RC-180	Manual valve	2165-S-1309, Rev. 15	CB	286	None		OP	OP	No	

System Analyst

Emergency Boration System

21-Aug-94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	21	1X-SN	Boric acid tank	2165-S-1307, Rev. 5	RAB	261	S		N/A	N/A	No	
2	1	R	1CS-513	Manual valve	2165-S-1307, Rev. 5	RAB	261	None		OP	OP	No	
3	1	R	1CS-530	Manual valve	2165-S-1307, Rev. 5	RAB	236	None		OP	OP	No	
4	1	5	1A-SA	Boric acid transfer pump 1A-SA	2165-S-1307, Rev. 5	RAB	236	S,R		OFF	ON	Yes	1A35-SA
5	1	R	1CS-536	Check valve	2165-S-1307, Rev. 5	RAB	236	None		CL	CL/OP	No	
6	1	R	1CS-535	Manual valve	2165-S-1307, Rev. 5	RAB	236	None		OP	OP	No	
7	1	R	1CS-540	Manual valve	2165-S-1307, Rev. 5	RAB	236	None		OP	OP	No	
8	1	5	1B-SB	Boric acid transfer pump 1B-SB	2165-S-1307, Rev. 5	RAB	236	S,R		OFF	ON	Yes	1B35-SB
9	1	R	1CS-546	Check valve	2165-S-1307, Rev. 5	RAB	236	None		CL	CL/OP	No	
10	1	R	1CS-549	Manual valve	2165-S-1307, Rev. 5	RAB	236	None		OP	OP	No	
11	1	7	1CS-559	Pneumatic valve	2165-S-1307, Rev. 5	RAB	261	S,R		OP	OP	No	
12	1	7	1CS-563	Pneumatic valve	2165-S-1307, Rev. 5	RAB	261	S,R		OP	OP	No	
13	1	*	1X-SN	Boric acid filter	2165-S-1307, Rev. 5	RAB	261	S		N/A	N/A	No	
14	1	8a	1CS-278	Electric motor operated valve	2165-S-1305, Rev. 12	RAB	236	S,R		CL	OP	Yes	1B35-SB
15	1	R	1CS-279	Check valve	2165-S-1305, Rev. 12	RAB	236	None		CL	CL/OP	No	
16	1	18	1FT-110	Flow transmitter	2165-S-1305, Rev. 12	RAB	236	S,R		N/A	N/A	Yes	PIC-C6
17	1	20	LT-106	Boric acid tank level transmitter	2165-S-1307, Rev. 5	RAB	261	S,R		N/A	N/A	Yes	IDP-1A-SI
18	2	20	LT-161	Boric acid tank level transmitter	2165-S-1307, Rev. 5	RAB	261	S,R		N/A	N/A	Yes	IDP-1B-SII

System Analyst

Main Steam System

21 Aug 94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	8a	1MS-58	Electric-hydraulic valve	2165-S-0542, Rev. 19	MST	261	S,R		CL	CL/OP	Yes	PP-1A312SA
2	2	8a	1MS-60	Electric-hydraulic valve	2165-S-0542, Rev. 19	MST	261	S,R		CL	CL/OP	Yes	PP-1B312SB
3	3	8a	1MS-62	Electric-hydraulic valve	2165-S-0542, Rev. 19	MST	261	S,R		CL	CL/OP	Yes	IDP-1A-S III
4	1	R	1MS-59	Manual valve	2165-S-0542, Rev. 19	MST	261	None		OP	OP	No	
5	2	R	1MS-61	Manual valve	2165-S-0542, Rev. 19	MST	261	None		OP	OP	No	
6	3	R	1MS-63	Manual valve	2165-S-0542, Rev. 19	MST	261	None		OP	OP	No	
7	1	*	1A-SN	Steam Generator	2165-S-0542, Rev. 19	CB	236	S		N/A	N/A	No	
8	2	*	1B-SN	Steam Generator	2165-S-0542, Rev. 19	CB	236	S		N/A	N/A	No	
9	3	*	1C-SN	Steam Generator	2165-S-0542, Rev. 19	CB	236	S		N/A	N/A	No	
10	1	5	2MS-P18SA-1	Relief valve oil pump A	2166-B-401/sh 1252, Re	MST	261	S,R		OFF	ON	Yes	1A31-SA
11	2	5	2MS-P19SB-1	Relief valve oil pump B	2166-B-401/sh 1253, Re	MST	261	S,R		OFF	ON	Yes	1B31-SB
12	3	5	2MS-P20SA-1	Relief valve oil pump C	2166-B-401/sh 1257, Re	MST	261	S,R		OFF	ON	Yes	1A31-SA

System Analysts R. Dunnett

Component Cooling Water System

21 Aug 94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	5	1A-SA	Component cooling water pump 1A-SA	2165-S-1319, Rev. 13	RAB	236	S,R	11	ON	ON	Yes	1A-SA; DP-1A-SA; 2-8/
2	1	R	1CC-33	Check valve	2165-S-1319, Rev. 13	RAB	236	None		OP	CL/OP	No	
3	1	R	1CC-36	Manual valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
4	1	R	1CC-88	Manual valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
5	1	21	1A-SA	Component cooling water heat exchanger	2165-S-1319, Rev. 13	RAB	236	S		N/A	N/A	No	
6	1	R	1CC-95	Manual valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
7	1	18	1FT-652	Flow transmitter FT-652	2165-S-1319, Rev. 13	RAB	236	None	24	N/A	N/A	Yes	PIC-C7
8	1	R	1CC-27	Manual valve	2165-S-1319, Rev. 13	RAB	236	S,R		OFF	ON	Yes	1B-SB; DP-1B-SB; 2-8/
9	2	5	1B-SB	Component cooling water pump 1B-SB	2165-S-1319, Rev. 13	RAB	236	None		OP	CL/OP	No	
10	2	R	1CC-50	Check valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
11	2	R	1CC-53	Manual valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
12	2	R	1CC-102	Manual valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
13	2	21	1B-SB	Component cooling water heat exchanger	2165-S-1319, Rev. 13	RAB	236	S		N/A	N/A	No	
14	2	R	1CC-109	Manual valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
15	2	18	1FT-653	Flow transmitter FT-653	2165-S-1319, Rev. 13	RAB	236	None	24	N/A	N/A	Yes	PIC-C8
16	2	R	1CC-44	Manual valve	2165-S-1319, Rev. 13	RAB	236	None		OP	OP	No	
17	2	R	1CC-152	Manual valve	2165-S-1320, Rev. 3	RAB	190	None		OP	OP	No	
18	2	21	1B-SB	RHR pump 1B-SB cooler	2165-S-1320, Rev. 3	RAB	236	S		N/A	N/A	No	
19	2	R	1CC-155	Manual valve	2165-S-1320, Rev. 3	RAB	190	None		OP	OP	No	
20	2	R	1CC-156	Manual valve	2165-S-1320, Rev. 3	RAB	236	None		OP	OP	No	
21	2	21	1B-SB	RHR heat exchanger 1B-SB	2165-S-1320, Rev. 3	RAB	236	S		N/A	N/A	No	
22	2	R	1CC-166	Manual valve	2165-S-1320, Rev. 3	RAB	236	None		OP	OP	No	
23	2	8a	1CC-167	Electric motor operated valve	2165-S-1320, Rev. 3	RAB	236	S,R		CL	OP	Yes	1B35-SB
24	2	18	1TIS-658B	RHR heat exchanger 1B-SB temp. switch	2165-S-1320, Rev. 3	RAB	236	None	24	N/A	N/A	Yes	PP-1E121
25	2	18	1FT-689	RHR heat exchanger 1B-SB flow transmitter	2165-S-1320, Rev. 3	RAB	236	None	24	N/A	N/A	Yes	PIC-C8
26	1	R	1CC-132	Manual valve	2165-S-1320, Rev. 3	RAB	190	None		OP	OP	No	
27	1	21	1A-SA	RHR pump 1A-SA cooler	2165-S-1320, Rev. 3	RAB	236	S		N/A	N/A	No	
28	1	R	1CC-135	Manual valve	2165-S-1320, Rev. 3	RAB	190	None		OP	OP	No	
29	1	R	1CC-136	Manual valve	2165-S-1320, Rev. 3	RAB	236	None		OP	OP	No	
30	1	21	1A-SA	RHR heat exchanger 1A-SA	2165-S-1320, Rev. 3	RAB	236	S		N/A	N/A	No	
31	1	R	1CC-146	Manual valve	2165-S-1320, Rev. 3	RAB	236	None		OP	OP	No	
32	1	8a	1CC-147	Electric motor operated valve	2165-S-1320, Rev. 3	RAB	236	S,R		CL	OP	Yes	1A35-SA
33	1	18	1TIS-658A	RHR heat exchanger 1A-SA temp. switch	2165-S-1320, Rev. 3	RAB	236	None	24	N/A	N/A	Yes	PP-1D121

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
34	1	18	1FT-688	RHR heat exchanger 1A-SA flow transmitter	2165-S-1320, Rev. 3	RAB	236	None	24	N/A	N/A	Yes	PIC-C7
35	1	21	1X-SAB	Component cooling water surge tank	2165-S-1319, Rev. 13	RAB	305	S		N/A	N/A	No	
36	1	R	1CC-13	Manual valve	2165-S-1319, Rev. 13	RAB	305	None		OP	OP	No	
37	1	R	1CC-12	Manual valve	2165-S-1319, Rev. 13	RAB	305	None		OP	OP	No	
38	1	18	A1-R30	Instrument rack for safe shutdown instrument	Equipment Rack	RAB	236	S		N/A	N/A	No	

System Analyst

Service Water System

11 Aug 94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	*	BAY	Emergency service water intake structure	2165-S-0547, Rev. 22	SW	262	S		N/A	N/A	No	
2	1	R	1SW-1	Manual valve	2165-S-0547, Rev. 22	SW	235	None		OP	OP	No	
3	1	R	1SW-3	Manual valve	2165-S-0547, Rev. 22	SW	242	None		OP	OP	No	
4	1	6	1A-SA	ESW vertical suction pump 1A-SA	2165-S-0547, Rev. 22	SW	262	S,R		OFF	ON	Yes	1A-SA; DP-1A; 2-6/SA
5	1	*	1A	Expansion joint 1A	2165-S-0547, Rev. 22	SW	262	S		N/A	N/A	No	
6	1	R	1SW-9	Check valve	2165-S-0547, Rev. 22	SW	249	None		N/A	N/A	No	
7	1	*	1A-SA	ESW Strainer 1A-SA	2165-S-0547, Rev. 22	SW	262	S	17	N/A	N/A	No	
8	1	R	1SW-25	Manual valve	2165-S-0547, Rev. 22	SW	242	None		OP	OP	No	
9	1	*	2A	Expansion joint 2A	2165-S-0547, Rev. 22	SW	262	S		N/A	N/A	No	
10	1	R	1SW-33	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
11	1	8a	1SW-39	Electric motor operated valve	2165-S-0547, Rev. 22	TANK	236	S,R	18	OP	CL	Yes	1A35-SA; K609A
12	1	R	1SW-2	Manual valve	2165-S-0547, Rev. 22	YARD	250	None		OP	OP	No	
13	1	R	1SW-4	Manual valve	2165-S-0547, Rev. 22	SW	242	None		OP	OP	No	
14	1	6	1B-SB	ESW vertical suction pump 1B-SB	2165-S-0547, Rev. 22	SW	262	S,R		OFF	ON	Yes	1A-SA; DP-1A; 2-6/SB
15	1	*	1B	Expansion joint 1B	2165-S-0547, Rev. 22	SW	262	S		N/A	N/A	No	
16	1	R	1SW-10	Check valve	2165-S-0547, Rev. 22	YARD	250	None		N/A	N/A	No	
17	1	*	1B-SB	ESW Strainer 1B-SB	2165-S-0547, Rev. 22	SW	262	S	17	N/A	N/A	No	
18	1	R	1SW-26	Manual valve	2165-S-0547, Rev. 22	SW	242	None		OP	OP	No	
19	1	*	2B	Expansion joint 2B	2165-S-0547, Rev. 22	SW	262	S		N/A	N/A	No	
20	1	R	1SW-34	Manual valve	2165-S-0547, Rev. 22	TANK	236	None		OP	OP	No	
21	1	8a	1SW-40	Electric motor operated valve	2165-S-0547, Rev. 22	TANK	236	S,R	18	OP	CL	Yes	1B35-SB; K609B
22	1	8a	1SW-270	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	19	CL	OP	Yes	1A35-SA; K608A
23	1	8a	1SW-271	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	19	CL	OP	Yes	1B35-SB;K608B
24	1	8a	1SW-275	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	19	OP	CL	Yes	1A35-SA;K608A
25	1	8a	1SW-276	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	19	OP	CL	Yes	1B35-SB; K608B
26	1	8a	1SW-274	Electric motor operated valve	2165-S-0547, Rev. 22	RAB	236	S,R	19	OP	CL	Yes	1A35-SA; K608A
27	1	R	1SW-50	Check valve	2165-S-0547, Rev. 22	TANK	236	None		OP	CL	No	
28	1	R	1SW-140	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
29	1	R	1SW-142	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
30	1	R	1SW-148	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
31	1	R	1SW-149	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
32	1	R	1SW-141	Check valve	2165-S-0547, Rev. 22	RAB	236	None		CL	CL/OP	No	
33	1	R	1SW-143	Check valve	2165-S-0547, Rev. 22	RAB	236	None		CL	CL/OP	No	

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems, or Components
34	1	21	1A-SA	Charging pump oil cooler	2165-S-0547, Rev. 22	RAB	236	None	20	N/A	N/A	No	
35	2	R	1SW-164	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
36	2	R	1SW-162	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
37	2	R	1SW-170	Manual valve	2165-S-0547, Rev. 22	TANK	236	None		OP	OP	No	
38	2	R	1SW-172	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
39	2	R	1SW-165	Check valve	2165-S-0547, Rev. 22	RAB	236	None		CL	CL/OP	No	
40	2	R	1SW-163	Check valve	2165-S-0547, Rev. 22	RAB	236	None		CL	CL/OP	No	
41	2	21	1B-SB	Charging pump oil cooler	2165-S-0547, Rev. 22	RAB	236	None	20	N/A	N/A	No	
42	1	R	1SW-57	Manual valve	2165-S-0547, Rev. 22	RAB	261	None		OP	OP	No	
43	1	8a	1SW-1055	Electric motor operated valve	2165-S-998S02, Rev. 12	RAB	261	S,R	21	OP	OP	No	
44	1	R	1SW-73	Manual valve	2165-S-0547, Rev. 22	RAB	261	None		OP	OP	No	
45	2	R	1SW-135	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
46	2	8a	1SW-1208	Electric motor operated valve	2168-G-499S02, Rev. 19	RAB	261	S,R	21	OP	OP	No	
47	2	R	1SW-136	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
48	1	R	1SW-58	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
49	1	R	1SW-70	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
50	2	R	1SW-256	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
51	2	R	1SW-266	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
52	1	R	1SW-175	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
53	1	R	1SW-754	Manual valve	2165-S-633S02, Rev. 8	DG	261	None		OP	OP	No	
54	1	R	1SW-770	Manual valve	2165-S-633S02, Rev. 8	DG	261	None		OP	OP	No	
55	1	R	1SW-207	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
56	2	R	1SW-176	Manual valve	2165-S-0547, Rev. 22	RAB	236	None		OP	OP	No	
57	2	R	1SW-773	Manual valve	2165-S-633S02, Rev. 8	DG	261	None		OP	OP	No	
58	2	R	1SW-789	Manual valve	2165-S-633S02, Rev. 8	DG	261	None		OP	OP	No	
59	2	R	1SW-208	Manual valve	2165-S-0547, Rev. 22	TANK	236	None		OP	OP	No	

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Essential Chilled Water System

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System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power, Required to Function	Required Support Systems or Components
1	1	11	1A-SA	Water chiller unit (WC-2)	2165-S-998S02, Rev. 12	RAB	261	S	11	ON	ON	Yes	1A-SA; DP-1A-SA; SW;
2	1	R	1CH-35	Manual valve	2165-S-998S02, Rev. 12	RAB	261	None		OP	OP	No	
3	1	R	1CH-23	Manual valve	2165-S-998S02, Rev. 12	RAB	261	None		OP	OP	No	
4	1	5	1A-SA-P4	Chiller water pump P4 1A-SA	2165-S-998S02, Rev. 12	RAB	261	S,R	11	ON	ON	Yes	1A2-SA; DP-1A-SA; 2-1
5	1	R	1CH-12	Manual valve	2165-S-998S02, Rev. 12	RAB	261	None		OP	OP	No	
6	1	R	1CH-252	Manual valve	2165-S-998S03, Rev. 7	RAB	236	None		OP	OP	No	
7	1	R	1CH-254	Manual valve	2165-S-998S03, Rev. 7	RAB	236	None		OP	OP	No	
8	1	8b	1CH-251	Air operated valve	2165-S-998S03, Rev. 7	RAB	236	S	12	OP	OP	No	
9	1	10	1A-SA-9	Air handling unit 9 1A-SA	2165-S-998S03, Rev. 7	RAB	236	S	11	ON	ON	Yes	1A35-SA; 94-6/SA
10	1	R	1CH-255	Manual valve	2165-S-998S03, Rev. 7	RAB	236	None		OP	OP	No	
11	1	R	1CH-256	Manual valve	2165-S-998S03, Rev. 7	RAB	236	None		OP	OP	No	
12	1	R	1CH-253	Manual valve	2165-S-998S03, Rev. 7	RAB	236	None		OP	OP	No	
13	1	R	1CH-613	Manual valve	2165-S-999S03, Rev. 6	RAB	236	None		OP	OP	No	
14	1	8b	1CH-616	Air operated valve	2165-S-999S03, Rev. 6	RAB	236	S	12	OP	OP	No	
15	1	10	1B-SB-9	Air handling unit 9 1B-SB	2165-S-999S03, Rev. 6	RAB	236	S		OFF	ON	Yes	1B31-SB; 94-6/SB
16	1	R	1CH-624	Manual valve	2165-S-999S03, Rev. 6	RAB	236	None		OP	OP	No	
17	1	R	1CH-620	Manual valve	2165-S-999S03, Rev. 6	RAB	236	None		OP	OP	No	
18	1	11	1B-SB	Water chiller unit (WC-2)	2168-G-499S02, Rev. 19	RAB	261	S		OFF	ON	Yes	1B-SB, DP-1B-SB; SW;
19	1	R	1CH-79	Manual valve	2168-G-499S02, Rev. 19	RAB	261	None		OP	OP	No	
20	1	R	1CH-67	Manual valve	2168-G-499S02, Rev. 19	RAB	261	None		OP	OP	No	
21	1	5	1B-SB-P4	Chiller water pump P4 1B-SB	2168-G-499S02, Rev. 19	RAB	261	S,R		OFF	ON	Yes	1B2-SB; DP-1B-SB; 2-1
22	1	R	1CH-56	Manual valve	2168-G-499S02, Rev. 19	RAB	261	None		OP	OP	No	
23	1	R	1CH-612	Manual valve	2165-S-999S03, Rev. 6	RAB	236	None		OP	OP	No	
24	1	18	1FS-9429A1	Chiller flow switch FS-9429A1	2165-S-998S02, Rev. 12	RAB	305	S,R		N/A	N/A	Yes	PIC-C13
25	2	18	1FS-9429B1	Chiller flow switch FS-9429B1	2168-G-499S02, Rev. 19	RAB	286	S,R		N/A	N/A	Yes	PIC-C14
26	2	10	1B-SB-15	Air handling unit 15 1B-SB	2165-S-999S03, Rev. 6	RAB	305	S		OFF	ON	Yes	1B31-SB; 94-6/SB
27	2	8b	1CH-703	Air operated valve	2165-S-999S03, Rev. 6	RAB	305	S,R	12	OP	OP	No	
28	1	10	1A-SA-16	Air handling unit 16 1A-SA	2165-S-998S03, Rev. 7	RAB	305	S	11	ON	ON	Yes	1A35-SA; 94-6/SA
29	1	8b	1CH-343	Air operated valve	2165-S-998S03, Rev. 7	RAB	305	S,R	12	OP	OP	No	
30	1	18	FT-9429A	Chiller low flow transmitter FT-9429A	2165-S-998S02, Rev. 12	RAB	305	S,R		N/A	N/A	Yes	PIC-C13
31	1	18	FT-9429B	Chiller low flow transmitter FT-9429B	2168-G-499S02, Rev. 19	RAB	305	S,R		N/A	N/A	Yes	PIC-C14
32	1	18	PIC-CAB-9	Panel for safe-shutdown instrumentation	1364-47236S01	RAB	305	S		N/A	N/A	Yes	IDP-1A-SII
33	1	18	PIC-CAB-10	Panel for safe-shutdown instrumentation	1364-47241S01	RAB	305	S		N/A	N/A	Yes	IDP-1B-SII

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
34	2	18	PIC-CAB-13	Panel for safe-shutdown instrumentation	1364-47243S01	RAB	305	S		N/A	N/A	Yes	IDP-1A-SIII
35	2	18	PIC-CAB-14	Panel for safe-shutdown instrumentation	1364-47238S01	RAB	305	S		N/A	N/A	Yes	IDP-1B-SIV
36	2	18	PIC-CAB-18	Panel for safe-shutdown instrumentation	1364-92080S01	RAB	286	S,R		N/A	N/A	Yes	IDP-1B-SII
37	2	R	1CII-619	Manual valve	2165-S-999S03, Rev. 6	RAB	236	None		OP	OP	No	
38	1	R	1CII-345	Manual valve	2165-S-998S03, Rev. 7	RAB	305	None		OP	OP	No	
39	1	R	1CII-350	Manual valve	2165-S-998S03, Rev. 7	RAB	305	None		OP	OP	No	
40	1	R	1CII-347	Manual valve	2165-S-998S03, Rev. 7	RAB	305	None		OP	OP	No	
41	1	R	1CII-349	Manual valve	2165-S-998S03, Rev. 7	RAB	305	None		OP	OP	No	
42	1	R	1CII-346	Manual valve	2165-S-998S03, Rev. 7	RAB	305	None		OP	OP	No	
43	1	R	1CII-348	Manual valve	2165-S-998S03, Rev. 7	RAB	305	None		OP	OP	No	
44	1	R	1CII-344	Manual valve	2165-S-998S03, Rev. 7	RAB	305	None		OP	OP	No	
45	2	R	1CII-711	Manual valve	2165-S-999S03, Rev. 6	RAB	305	None		OP	OP	No	
46	2	R	1CII-715	Manual valve	2165-S-999S03, Rev. 6	RAB	305	None		OP	OP	No	
47	2	R	1CII-717	Manual valve	2165-S-999S03, Rev. 6	RAB	305	None		OP	OP	No	
48	2	R	1CII-706	Manual valve	2165-S-999S03, Rev. 6	RAB	305	None		OP	OP	No	
49	2	R	1CII-708	Manual valve	2165-S-999S03, Rev. 6	RAB	305	None		OP	OP	No	
50	2	R	1CII-700	Manual valve	2165-S-999S03, Rev. 6	RAB	305	None		OP	OP	No	
51	2	R	1CII-699	Manual valve	2165-S-999S03, Rev. 6	RAB	305	None		OP	OP	No	

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DC Power System/120 Vital AC

21 Aug 94

System Line Number	System Train	Equipment Class	Equipment IDTag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	15	1A-SA	Vital batteries in rack (1A-SA)	2166-G-042S01, Rev. 14	RAB	286	S		N/A	N/A	No	
2	1	16	1A-SA	Solid state battery charger (1A-SA)	2166-G-042S01, Rev. 14	RAB	286	S,R		N/A	N/A	Yes	1A21-SA
3	1	14	DP1A-SA	Distribution panel for vital DC 1A-SA	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
4	1	14	DP1A1-SA	Distribution panel for vital DC 1A1-SA	2166-G-042S01, Rev. 14	DG	261	S,R	13	N/A	N/A	No	
5	1	14	DP1A2-SA	Distribution panel for vital DC 1A2-SA	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
6	2	15	1B-SB	Vital batteries in rack (1B-SB)	2166-G-042S01, Rev. 14	RAB	286	S		N/A	N/A	No	
7	2	16	1B-SB	Solid state battery charger (1B-SB)	2166-G-042S01, Rev. 14	RAB	286	S,R		N/A	N/A	Yes	1B21-SB
8	2	14	DP1B-SB	Distribution panel for vital DC 1B-SB	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
9	2	14	DP1B1-SB	Distribution panel for vital DC 1B1-SB	2166-G-042S01, Rev. 14	DG	261	S,R	13	N/A	N/A	No	
10	2	14	DP1B2-SB	Distribution panel for vital DC 1B2-SB	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
11	1	16	CI I	7.5 kVA inverter channel I	2166-G-042S01, Rev. 14	RAB	305	S,R		N/A	N/A	Yes	1A21-A; DP1A-A
12	2	16	CI II	7.5 kVA inverter channel II	2166-G-042S01, Rev. 14	RAB	305	S,R		N/A	N/A	Yes	1A31-A; DP1A-B
13	1	16	CI III	7.5 kVA inverter channel III	2166-G-042S01, Rev. 14	RAB	305	S,R		N/A	N/A	Yes	1B21-A; DP1B-A
14	2	16	CI IV	7.5 kVA inverter channel IV	2166-G-042S01, Rev. 14	RAB	305	S,R		N/A	N/A	Yes	1B31-A; DP1B-B
15	1	14	IDP-1A-SI	120 Vac instrument panel channel I	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
16	2	14	IDP-1B-SII	120 Vac instrument panel channel II	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
17	1	14	IDP-1A-SIII	120 Vac instrument panel channel III	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
18	2	14	IDP-1B-SIV	120 Vac instrument panel channel IV	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	

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AC Power System

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System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	3	1A-SA	6.9KV switchgear 1A-SA	2166-G-030, Rev. 12	RAB	286	S,R		N/A	N/A	Yes	EDG 1A-SA
2	1	4	1A3-SA	Stepdown transformer 6.9KV to 480V	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
3	1	4	1A2-SA	Stepdown transformer 6.9KV to 480V	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
4	1	2	1A2-SA	Low voltage switchgear 1A2-SA	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
5	1	2	1A3-SA	Low voltage switchgear 1A3-SA	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
6	1	1	1A32-SA	Motor control center 1A32-SA	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
7	1	1	1A23-SA	Motor control center 1A23-SA	2166-G-030, Rev. 12	DG	261	S,R	13	N/A	N/A	No	
8	1	1	1A21-SA	Motor control center 1A21-SA	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
9	1	1	1A34-SA	Motor control center 1A34-SA	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
10	1	1	1A35-SA	Motor control center 1A35-SA	2166-G-030, Rev. 12	RAB	261	S,R	13	N/A	N/A	No	
11	1	1	1A36-SA	Motor control center 1A36-SA	2166-G-030, Rev. 12	RAB	305	S,R	13	N/A	N/A	No	
12	1	1	1A31-SA	Motor control center 1A31-SA	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
13	1	14	PP-1A211-SA	208/120 distribution panel	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
14	1	14	PP-1A311-SA	208/120 distribution panel	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
15	1	4	PP-1A211-SA	Stepdown transformer	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
16	1	4	PP-1A311-SA	Stepdown transformer	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
17	1	3	1B-SB	6.9KV switchgear 1B-SB	2166-G-030, Rev. 12	RAB	286	S,R		N/A	N/A	Yes	EDG 1B-SB
18	1	4	1B3-SB	Stepdown transformer 6.9KV to 480V	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
19	1	4	1B2-SB	Stepdown transformer 6.9KV to 480V	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
20	1	2	1B2-SB	Low voltage switchgear 1B2-SB	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
21	1	2	1B3-SB	Low voltage switchgear 1B3-SB	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
22	1	1	1B32-SB	Motor control center 1B32-SB	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
23	1	1	1B23-SB	Motor control center 1B23-SB	2166-G-030, Rev. 12	DG	261	S,R	13	N/A	N/A	No	
24	1	1	1B21-SB	Motor control center 1B21-SB	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
25	1	1	1B34-SB	Motor control center 1B34-SB	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
26	1	1	1B35-SB	Motor control center 1B35-SB	2166-G-030, Rev. 12	RAB	261	S,R	13	N/A	N/A	No	
27	1	1	1B36-SB	Motor control center 1B36-SB	2166-G-030, Rev. 12	RAB	305	S,R	13	N/A	N/A	No	
28	1	17	1A-SA	Diesel Generator 1A-SA	2166-G-030, Rev. 12	DG	263	S,R		OFF	ON	Yes	DP-1A1-SA
29	1	1	1B31-SB	Motor control center 1B31-SB	2166-G-030, Rev. 12	RAB	286	S,R	13	N/A	N/A	No	
30	1	14	PP-1B211-SB	208/120 distribution panel	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
31	1	14	PP-1B311-SB	208/120 distribution panel	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
32	1	4	PP-1B211-SB	Stepdown transformer	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	
33	1	4	PP-1B311-SB	Stepdown transformer	2166-G-042S01, Rev. 14	RAB	286	S,R	13	N/A	N/A	No	

System Line Number	System Train	Equipment Class	Equipment IDTag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems, or Components
34	1	17	1B-SB	Diesel Generator 1B-SB	2166-G-030, Rev. 8	DG	263	S,R		OFF	ON	Yes	DP-1B1-SB
35	1	9	1A-SA	Diesel Generator Fan E-86 (1A-SA)	2168-G-548, Rev. 9	DG	263	S,R		OFF	ON	Yes	1A23-SA; DP-1A-SA
36	1	9	1B-SA	Diesel Generator Fan E-86 (1B-SA)	2168-G-548, Rev. 9	DG	263	S,R		OFF	ON	Yes	1A23-SA; DP-1A-SA
37	1	9	1C-SB	Diesel Generator Fan E-86 (1C-SB)	2168-G-548, Rev. 9	DG	263	S,R		OFF	ON	Yes	1B23-SB; DP-1B-SB
38	1	9	1D-SB	Diesel Generator Fan E-86 (1D-SB)	2168-G-548, Rev. 9	DG	263	S,R		OFF	ON	Yes	1B23-SB; DP-1B-SB
39	1	18	TE 6903A	Temperature controller	2166-B-401 sh 3261, Re	DG	263	S,R		N/A	N/A	Yes	PIC-C13
40	1	18	TE 6903B	Temperature controller	2166-B-401 sh 3272, Re	DG	263	S,R		N/A	N/A	Yes	PIC-C14
41	1	21	1A	Main fuel oil storage tank 1A	2165-S-0563, Rev. 6	FO	242	S		N/A	N/A	No	
42	1	21	1B	Main fuel oil storage tank 1B	2165-S-0563, Rev. 6	FO	242	S		N/A	N/A	No	
43	1	R	1DFO-162	Manual valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
44	1	R	1DFO-164	Manual valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
45	1	5	1A-SA	Fuel oil transfer pump	2165-S-0563, Rev. 6	FO	242	S,R		OFF	ON	Yes	1A35-SA
46	1	R	1DFO-168	Check valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
47	1	R	1DFO-169	Manual valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
48	1	8b	1DFO-173	Solenoid operated valve	2165-S-633S03, Rev. 5	DG	263	S,R	14	N/A	N/A	No	
49	1	21	1A-SA	Diesel generator fuel oil day tank	2165-S-633S03, Rev. 5	DG	263	S		N/A	N/A	No	
50	1	R	1DFO-175	Manual valve	2165-S-633S03, Rev. 5	DG	263	None		N/A	N/A	No	
51	1	18	LS-2463A-SA	Day tank level switch L/H	2165-S-633S03, Rev. 5	DG	263	S,R	15	N/A	N/A	No	
52	1	18	LS-2464A-SA	Day tank level switch HH	2165-S-633S03, Rev. 5	DG	263	S,R	15	N/A	N/A	No	
53	1	21	1A-SA	Diesel generator 1A-SA jacket water cooler	2165-S-633S02, Rev. 8	DG	263	S		N/A	N/A	No	SW
54	1	21	1A-SA	Diesel generator 1A-SA lube oil cooler	2165-S-633S02, Rev. 8	DG	263	S		N/A	N/A	No	SW
55	1	R	1DFO-180	Manual valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
56	1	R	1DFO-182	Manual valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
57	1	5	1B-SB	Fuel oil transfer pump	2165-S-0563, Rev. 6	FO	242	S,R		OFF	ON	Yes	1B35-SB
58	1	R	1DFO-186	Check valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
59	1	R	1DFO-187	Manual valve	2165-S-0563, Rev. 6	FO	242	None		N/A	N/A	No	
60	1	21	1B-SB	Diesel generator 1B-SB lube oil cooler	2165-S-633S02, Rev. 8	DG	263	S		N/A	N/A	No	SW
61	1	8b	1DFO-191	Solenoid operated valve	2165-S-633S03, Rev. 5	DG	263	S,R	16	N/A	N/A	No	
62	1	21	1B-SB	Diesel generator fuel oil day tank	2165-S-633S03, Rev. 5	DG	263	S		N/A	N/A	No	
63	1	R	1DFO-193	Manual valve	2165-S-633S03, Rev. 5	DG	263	None		N/A	N/A	No	
64	1	18	LS-2463B-SB	Day tank level switch L/H	2165-S-633S03, Rev. 5	DG	263	S,R	15	N/A	N/A	No	
65	1	18	LS-2464B-SB	Day tank level switch HH	2165-S-633S03, Rev. 5	DG	263	S,R	15	N/A	N/A	No	
66	1	21	1B-SB	Diesel generator 1B-SB jacket water cooler	2165-S-633S02, Rev. 8	DG	263	S		N/A	N/A	No	SW
67	1	21	1A-SA	Diesel starting air tank 1A-SA	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
68	1	21	1B-SA	Diesel starting air tank 1B-SA	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
69	2	21	1C-SB	Diesel starting air tank 1C-SB	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
70	2	21	1D-SB	Diesel starting air tank 1D-SB	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
71	1	12	1A-NNS	Diesel starting air compressor 1A-NNS	2165-S-633S04, Rev. 13	DG	261	S,R		OFF	ON	Yes	1A23-SA
72	1	12	1B-NNS	Diesel starting air compressor 1B-NNS	2165-S-633S04, Rev. 13	DG	261	S,R		OFF	ON	Yes	1A23-SA
73	2	12	1C-NNS	Diesel starting air compressor 1C-NNS	2165-S-633S04, Rev. 13	DG	261	S,R		OFF	ON	Yes	1B23-SB
74	2	12	1D-NNS	Diesel starting air compressor 1D-NNS	2165-S-633S04, Rev. 13	DG	261	S,R		OFF	ON	Yes	1B23-SB
75	1	21	1A-NNS	Diesel starting air separator 1A-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
76	1	21	1B-NNS	Diesel starting air separator 1B-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
77	2	21	1C-NNS	Diesel starting air separator 1C-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
78	1	21	1D-NNS	Diesel starting air separator 1D-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
79	1	14	1A-SA	1DG-E036 DG A control panel	2166-B-401/sh 1995	DG	261	S,R	13	N/A	N/A	Yes	
80	1	14	1B-SB	1DG-E037 DG B control panel	2166-B-401/sh 2008	DG	261	S,R	13	N/A	N/A	Yes	
81	1	14	1A-SA	1DG-E034 DG A engine control panel	2166-B-401/sh 1998, Re	DG	261	S,R	13	N/A	N/A	Yes	
82	1	14	1B-SB	1DG-E035 DG B engine control panel	2166-B-401/sh 2009, Re	DG	261	S,R	13	N/A	N/A	Yes	
83	1	R	1EA-4	Check valve	2165-S-633S04, Rev. 13	DG	261	None		CL	OP	No	
84	1	R	1EA-5	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
85	1	R	1EA-12	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
86	1	8b	1EA-14	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
87	1	8b	1EA-15	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
88	1	R	1EA-19	Check valve	2165-S-633S04, Rev. 13	DG	261	None		CL	OP	No	
89	1	R	1EA-20	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
90	1	R	1EA-27	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
91	1	8b	1EA-29	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
92	1	8b	1EA-30	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
93	2	R	1EA-35	Check valve	2165-S-633S04, Rev. 13	DG	261	None		CL	OP	No	
94	2	R	1EA-36	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
95	2	R	1EA-43	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
96	2	8b	1EA-45	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
97	2	8b	1EA-46	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
98	2	R	1EA-50	Check valve	2165-S-633S04, Rev. 13	DG	261	None		CL	OP	No	
99	2	R	1EA-51	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
100	2	R	1EA-58	Manual valve	2165-S-633S04, Rev. 13	DG	261	None		OP	OP	No	
101	2	8b	1EA-60	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
102	2	8b	1EA-61	Solenoid valve	2165-S-633S04, Rev. 13	DG	261	None	23	CL	OP	No	
103	1	21	1A-NNS	Diesel starting air dryer 1A-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
104	1	21	1B-NNS	Diesel starting air dryer 1B-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
105	2	21	1C-NNS	Diesel starting air dryer 1C-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	
106	2	21	1D-NNS	Diesel starting air dryer 1D-NNS	2165-S-633S04, Rev. 13	DG	261	S		N/A	N/A	No	

System Analysts

Relay Panel

21 Aug 94

System Line Number	System Train	Equipment Class	Equipment ID/Tag	Equipment Description	Reference Drawing, Revision	Building Location	Floor Elevation	Evaluation Type	Notes	Normal Equipment State	Desired Equipment State	Power Required to Function	Required Support Systems or Components
1	1	14	1B2	Isolation cabinet 1B2	2166-B-401-S1470	RAB	305	S,R	22	N/A	N/A	No	
2	1	14	1B1	Isolation cabinet 1B1	2166-B-401-S1470	RAB	305	S,R	22	N/A	N/A	No	
3	1	14	1A2	Isolation cabinet 1A2	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
4	1	14	1A1	Isolation cabinet 1A1	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
5	2	18	SSPST CAB B	Solid state protection test cabinet B	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
6	1	18	SSPS-CAB B	Solid state protection cabinet B	2166-B-401S0037	RAB	305	S,R	22	N/A	N/A	No	
7	1	18	SSPST CAB A	Solid state protection test cabinet A	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
8	2	14	2A1	Isolation cabinet 2A1	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
9	1	18	ARP-1A	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
10	1	18	ARP-19A	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
11	1	18	ARP-2A	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
12	1	18	ARP-3A	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
13	1	18	SSPS-CAB A	Solid state protection cabinet A	2165-S-0553S03	RAB	305	S,R	22	N/A	N/A	No	
14	1	18	ARP-4A	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
15	1	14	3A1	Isolation cabinet 3A1	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
16	2	18	ARP-19B	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
17	2	18	ARP-4B	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
18	2	18	ARP-3B	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
19	2	18	ARP-2B	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
20	2	18	ARP-1B	Auxiliary relay panel	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
21	1,2	18	MCB	Main control board	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
22	2	14	2B2	Isolation cabinet 2B2	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
23	1	14	3A2	Isolation cabinet 3A2	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
24	2	14	2B1	Isolation cabinet 2B1	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	
25	2	14	2A2	Isolation cabinet 2A2	2166-G-0324	RAB	305	S,R	22	N/A	N/A	No	

System Analyst

Notes on SSEL Tables

1. Power not required since valves are designed to fail as is on a loss of power
2. Service water source required for long term AFW water source
3. Loss of function or power will result in pump trip
4. Level transmitters provide operators with RWST level information
5. Valves are manually operated for high head recirculation
6. Non-vital power supply. Loss of instrument results in swap to RWST.
7. Spurious opening of these valves could dump the RWST inventory into containment
8. Non-vital power supply. Local instrumentation available.
9. The solenoid control valves associated with the PORVs are included. Air supply is supplied by accumulators and no additional air supply is required.
10. Selected based on plant operations review
11. Train A is assumed to be operating but will need to restart following loss of offsite power.
12. Air-operated valves fail open to allow flow to cooler. Spurious operation of valve controller could close valve.
13. Power is required but is addressed by other components
14. Valve fails open on a loss of power and is normally open
15. Level switch power supply is addressed by other equipment
16. Valve fails open on a loss of power and is normally open
17. Strainer is assumed not to require power over 72 hours to maintain function
18. Although not required if both pumps start, isolation is assumed to be required
19. Although swapover to the auxiliary source is not strictly required, it is assumed to be necessary
20. Charging pump cooler is considered a part of the charging pump (rule of the box)
21. Spurious operation of valve could isolate air handling unit coolers
22. Panels contain essential relays
23. Considered a part of the diesel generator
24. Instrumentation for information only

RSC 95-01

Shearon Harris Nuclear Power Plant Success Path Logic Diagram and Supporting Information Development

Addendum 1 to Report RSC 94-01

Revision 0

February 1995

Principle Analyst

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AD.1 Background

The success path logic diagram and safe shutdown equipment list developed for Shearon Harris was reviewed. This addendum documents the resolution of peer review comments provided by VECTRA Technologies on revision 1 of the SSEL report[2]. The peer review generated 19 comments on the report with two of these requiring follow-up actions. The two comments are presented in this addendum along with their resolution.

AD.2 Resolution to Peer Review Comment #3

Peer review comment #3 states:

> "Table 1-1. The dependencies between HVAC systems and the systems they support is not clear (i.e., is HVAC required for any system or plant area other than the Control Room?). The table indicates that HVAC is required for the Control Room [CR] and Charging/Safety Injection (CSI). However, on page 3 of the document, no mention of CR or CSI HVAC is made under support systems evaluated by this report. This discrepancy should be cleaned up".

A review of the document (Reference 1) identified that the information on page 3 had omitted the need for control room HVAC. The requirement for CSI pump room cooling was included in the referenced material. The support system success path logic requires that HVAC be available to both the control room and to the Charging/Safety Injection pump rooms. In addition, HVAC cooling for the emergency diesel generators is also required. The support systems required in the SSEL are:

- Safety-related ac power (including the diesel generators
- Safety-related dc power (including 120 Vac)
- HVAC cooling for CSIPs, control room, and diesel generators
- Emergency service water
- Component cooling water
- Essential chilled water

AD.3 Resolution to Peer Review Comment #18

Peer review comment #18 states:

> A path for feeding the "C" steam generator from either of the motor driven auxiliary feedwater pumps appears to have been excluded from the shutdown path. Is there any reason for this?

An examination of the safe shutdown equipment listing (Appendix B, page B-1 through B-3, Reference 1), identified that this path was inadvertently omitted. The path, shown in Figure AD-1, provides auxiliary feedwater to the steam generators from either auxiliary feedwater motor-driven pump.

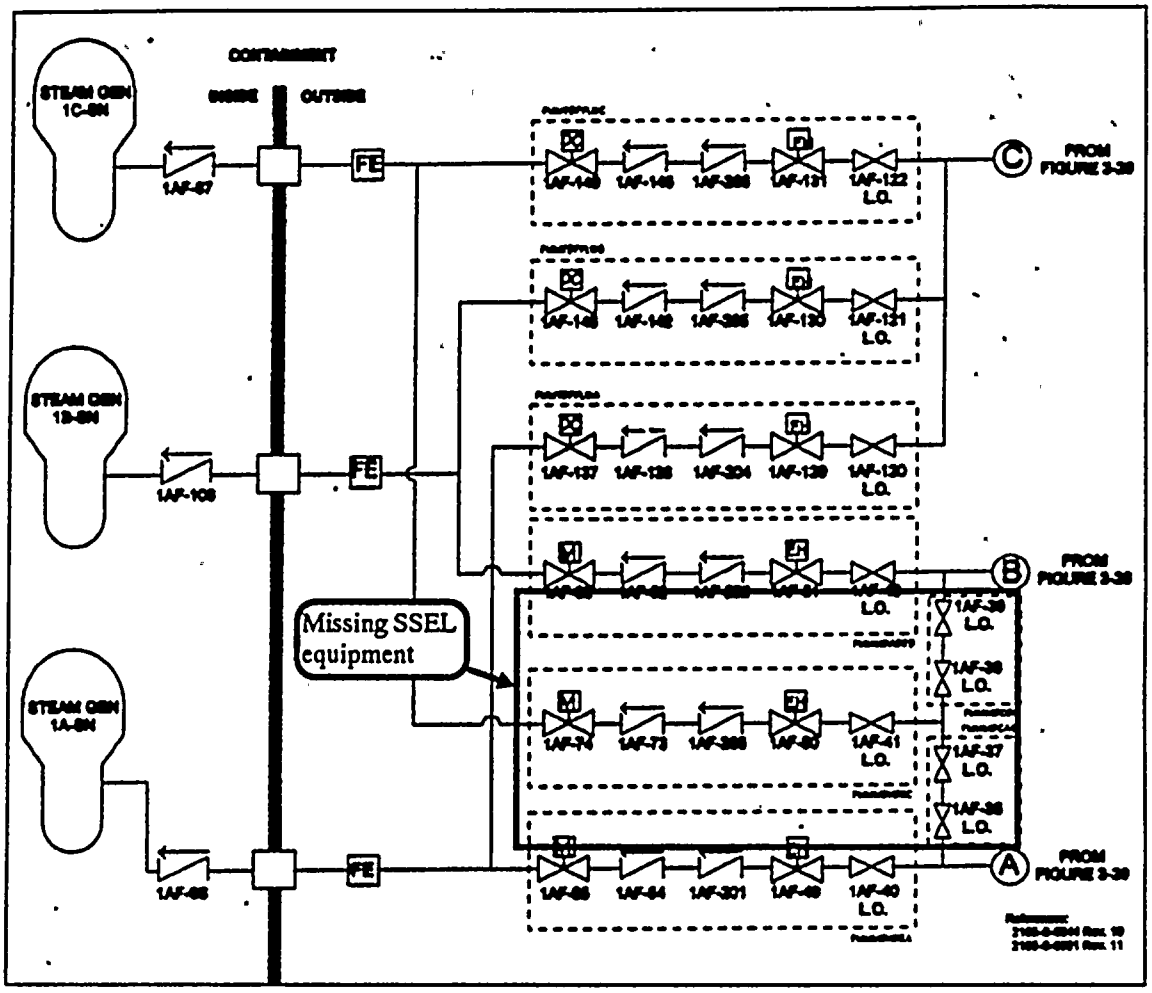


Figure AD-1. Simplified Illustration of the Auxiliary Feedwater System Discharge Piping (Reproduced from Reference 3)

The inclusion of this path requires the addition of the following components to the equipment list that will require examination:

- Motor-operated valve 1AF-74
- Electric-hydraulic valve 1AF-50

Additionally, other rugged valves are added to the equipment listing for completeness and do not require examination. These valves are:

- Check valves 1AF-73, 1AF-203
- Locked-open manual valves 1AF-41, 1AF-36, 1AF-37, 1AF-38, 1AF-39

The required information for the valves is provided in Table AD-1. This additional information is included in a revision to the SSEL database.

Table AD-1
SSEL Parameters for Identified Valves

Parameter	1AF-74	1AF-50	1AF-41[1]	1AF-73	1AF-203
System Line Number	86	87	88, 89, 90, 91, 92	93	94
System Train	1,2	1,2	1,2	1,2	1,2
Equipment Class	8a	7	R	R	R
Equipment Description	Electric motor operated valve	Electric hydraulic valve	Manual valve	Check valve	Check valve
Reference Drawing, Revision	2165-S-0544, Rev. 20	2165-S-0544, Rev. 20	2165-S-0544, Rev. 20	2165-S-0544, Rev. 20	2165-S-0544, Rev. 20
Building Location	RAB	RAB	RAB	RAB	RAB
Floor Elevation	261	261	261	261	261
Evaluation Type	S,R	S,R	None	None	None
Notes	1	1			
Normal Equipment State	OP	OP	OP	CL	CL
Desired Equipment State	OP	OP	OP	CL/OP	CL/OP
Power Required to Function	No	No	No	No	No
Required Support Systems or Components					

1. The entry for 1AF-41 is representative of all locked-open manual valves added to the SSEL in response to the peer review.

AD.4 References

1. Correspondence from Charbel M. Abou-Jaoude, VETRA Technologies to Mr. Ronald L. Knott, Carolina Power and Light Company dated December 30, 1994.

2. Summitt, Ricky, Shearon Harris Nuclear Power Plant Success Path Logic Diagram and Supporting Information Development, Revision 1, Ricky Summitt Consulting, RSC 94-01, August 1994.

3. Oliver, Rudy, et. al, Shearon Harris Nuclear Power Plant Individual Plant Examination, Carolina Power and Light Company, August 1993.

APPENDIX C

IN-STRUCTURE RESPONSE SPECTRA

EQE CALCULATION 52214-C-001, REVISION 0

EQE ENGINEERING CONSULTANTS

CALCULATION COVER SHEET

Calculation No: 52214-C-001

Project: CP & L SHEARON HARRIS - SPECTRA

Calculation Title: CP & L SHEARON HARRIS : SCALING OF IN-STRUCTURE SPECTRA FOR SEISMIC IPEEE

References: SEE SECTION 4

Attachments: NONE

Total Number of Pages (Including Cover Sheet): 17

Revision Number	Approval Date	Description of Revision	Originator	Checker	Approver
0	8/6/93	ORIGINAL ISSUES	SL	LWT	JMR

12312-01/Coversht (7/91)

SHEET NO. 2/1

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/28.
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LVJT DATE 7/28

TABLE OF CONTENTS

SECTION 1. INTRODUCTION

To support the seismic IPEEE program at the Shearon Harris Nuclear Power Plant (SHNPP) of Carolina Power & Light Company (CPL), the licensing basis in-structure response spectra for structures housing the success path equipment are scaled to yield the median-centered spectra. The following structures are included in this study:

Reactor Auxiliary Building (RAB) - Common,
Reactor Auxiliary Building - Unit 1,
Containment Inner Structure (CIS), and
Diesel Generator Building (DG).

For the seismic IPEEE program, the Review Level Earthquake (RLE) is defined as the NUREG/CR-0098 [2] median spectral shape anchored to *0.30g*. The median structural damping is recommended to be *7%* for median-centered response analyses [3]. For the evaluation of components and subsystems, higher in-structure seismic demands (response spectra) are required to account for the increase of the RLE ground response spectrum over the Design Basis Earthquake (DBE) ground spectrum.

SHNPP is a relatively modern plant with all Seismic Category I structures founded on rock (shear wave velocity V_S=*5600 fps*) [4]. The major structures were modeled as sticks with lumped masses and stiffnesses in both the horizontal and vertical directions. For the above listed structures, torsional effects were considered insignificant, so the horizontal models did not include any torsional coupling [4]. In the vertical stick models, the slab flexibility was accounted for. In summary, structural modeling is in accordance with the current analysis practice. Soil springs were included in the original structure models. Damping value of *7%* was assumed for the structures and soil springs at the DBE excitation level.

For design analysis, the DBE ground spectra were the R.G.1.60 [1] spectra anchored to *0.15g* except for dams and dikes. The seismic motions were applied at foundation level. The floor response spectra were developed in accordance with R.G. 1.122 [7] with the peaks broadened *±15%*. Therefore, the original analysis models [4] used to generate the existing in-structure response spectra are qualitatively considered adequate, so are the response spectra [5].

SHEET NO. 4

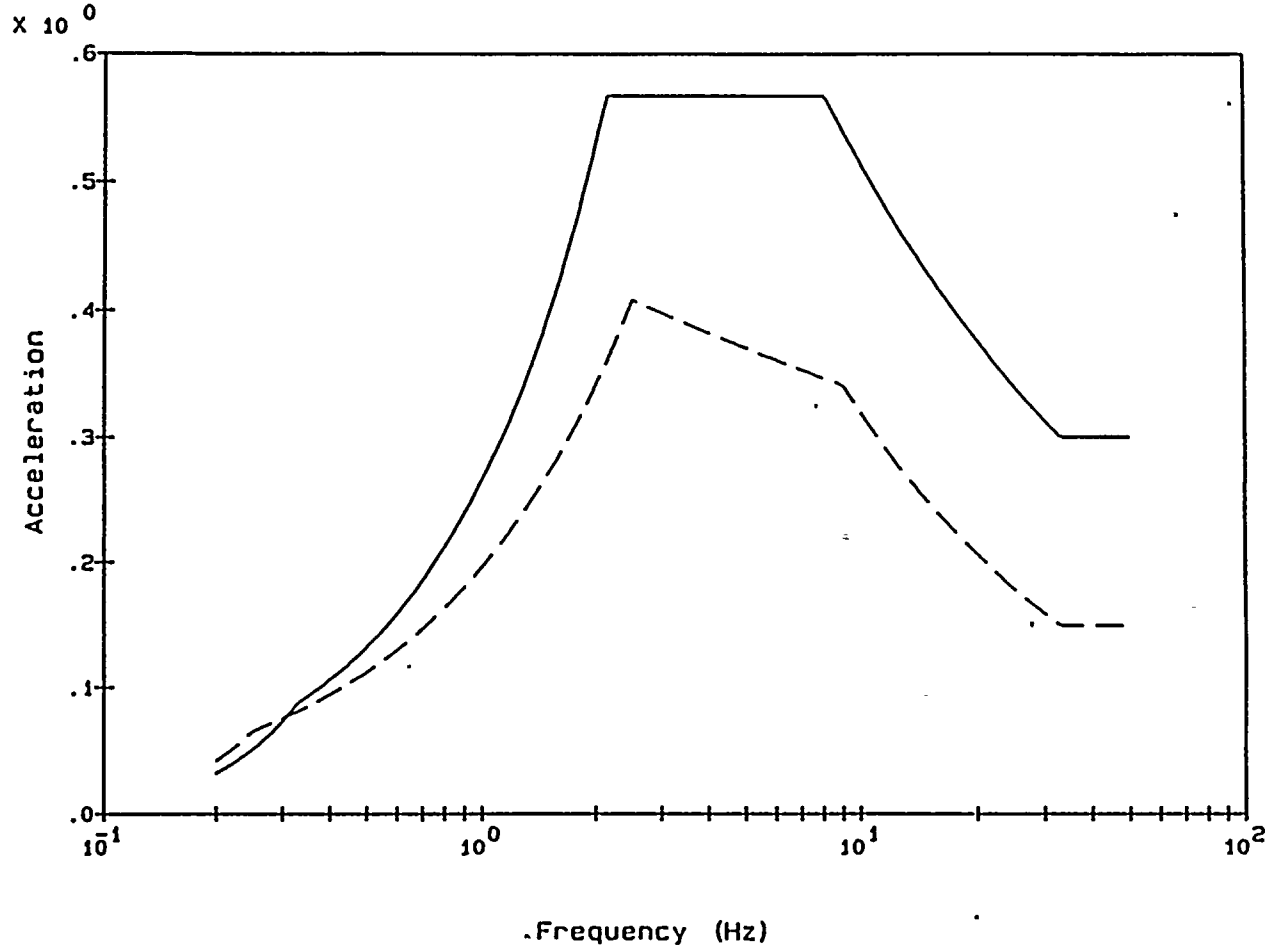
JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/25
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LWT DATE 7/25

For comparison, the RLE and DBE ground spectrum, both at 7% damping, are overploted in Figures 1-1 and 1-2 for the horizontal and vertical directions, respectively. The RLE and DBE ground spectra are digitized in Tables 3-4 and 3-5.

The original analysis conforms to the Standand Review Plan (SRP), and the in-structure response spectra may be designated as "conservative design spectra" per GIP terminology [6]. The direct scaling approach recommended in NP-6041 [3] is considered appropriate for the rock founded structures. Therefore, the licensing basis floor response spectra are scaled to develop the realistic median-centered spectra for seismic margin purposes.

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/23/83

CALC NO. C-001 SUBJECT SPECTRA SCALING CHK LWT DATE 7/28/83



Legend:

Median CR0098, Rock ———————

R.G.- 1.60 (DBE) — — — — -

Notes:

Acceleration in g's

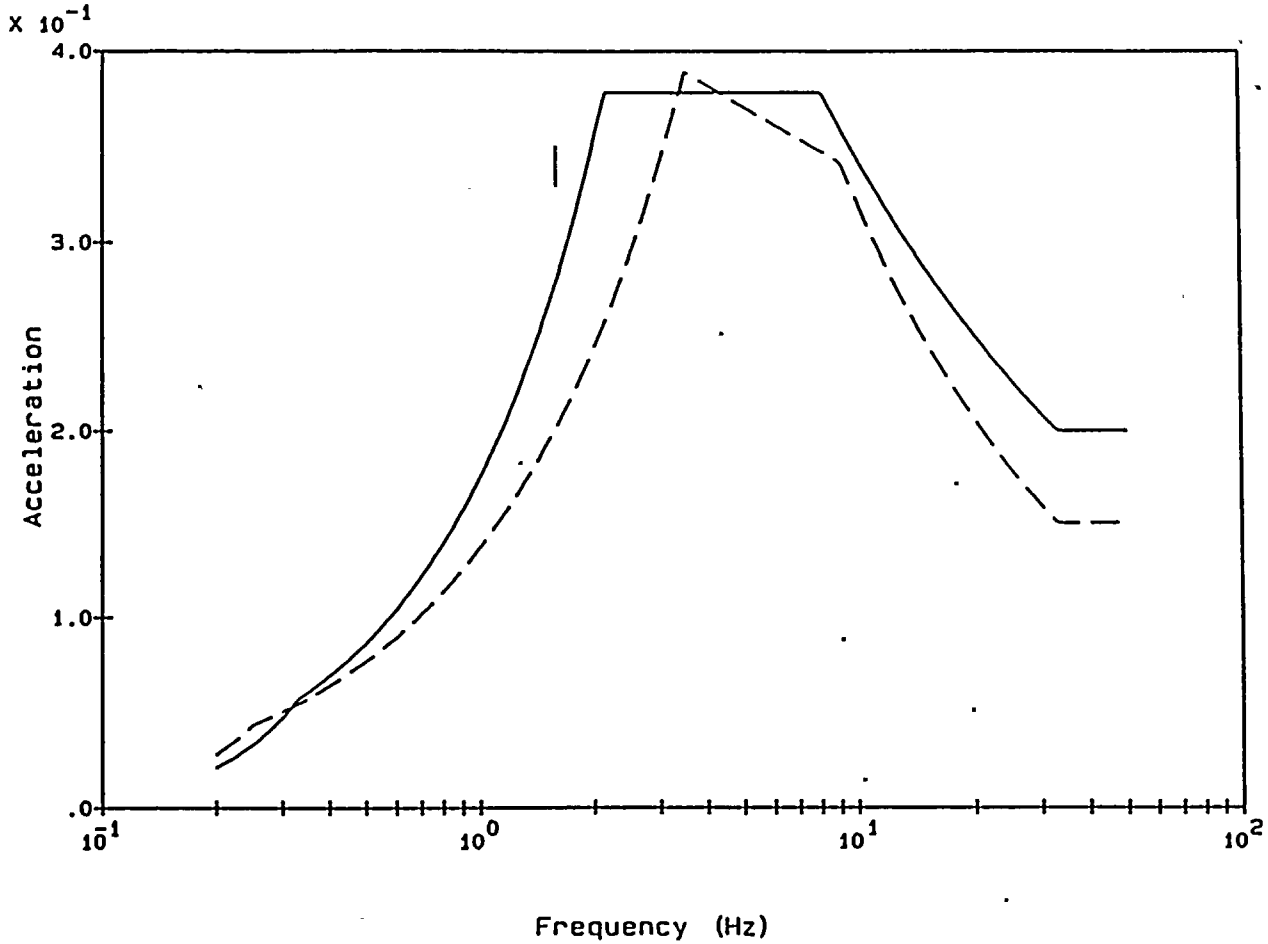
Spectral acceleration at D=0.07

Fig. 1-1 Comparison of SHNPP Horizontal Ground Spectra
DBE vs Review Level Earthquake Ground Spectrum

horiz.plt

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/25/95

CALC NO. C-001 SUBJECT SPECTRA SCALING CHK LWT DATE 7/28/95



Legend:

Median CR0098, Rock ————————

R.G.- 1.60 (DBE) — — — — -

Notes:

Acceleration in g's

Spectral acceleration at D=0.07

Fig. 1-2 Comparison of SHNPP Vertical Ground Spectra
DBE vs Review Level Earthquake Ground Spectrum

vert.plt

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/28/
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LWT DATE 3/28/

SECTION 2. METHODOLOGY

This effort focuses on estimating realistic median-centered *5%* damped ZPA and spectral peaks, rather than the complete spectral shape. The median-centered in-structure spectral peaks and ZPA's applicable to a seismic margin assessment are developed by scaling the existing spectra to account for the increased seismic demand of the RLE over the DBE.

The rationale and details of this approach are discussed in the EPRI NP-6041 report [3]. The NP-6041 report considers the CR-0098 median spectral shape and the R.G.1.60 ground response spectra to be similar in shape. Therefore, an acceptable method to scale the existing in-structure spectra for this rock site is to retain the original floor spectral shape, but scale the floor ZPA up for the RLE. For SHNPP the scale factor is obtained by comparing the *7%* damped RLE ground spectrum to the *7%* damped DBE ground spectrum. It is observed from the modal participation data and response spectra plots [4 & 5] that the in-structure responses for SHNPP structures have a dominant mode. Therefore the scale factor for a single mode structure can be estimated by direct comparison of the RLE ground spectrum to the DBE ground spectrum at the fundamental frequency of the structure.

The information available to EQE is the CPL SHNPP FSAR [4] containing the dynamic characteristics of three of the four structures of interest, and SHNPP *4%* and *7%* damped response spectrum plots [5]. Also available are the ASME Code Case N-411 spectra. These N-411 spectra have 5% damping below *10 Hz*, a linear reduction from *5%* to *2%* damping between *10 Hz* and *20 Hz*, and *2%* above *20 Hz*. The available N-411 spectra cover only the frequency range between *6 Hz* to *44 Hz*.

To estimate median-centered peak floor spectral acceleration with the preferred *5%* damping, the N-411 spectra were used for structures with fundamental frequencies above *6 Hz*, which include the RAB-Common, RAB-Unit 1, and CIS. For structures with dominant frequencies below *6 Hz* (i.e., the RAB-Unit 1 in the E-W direction), the information on spectral peaks were lost. Also N-411 spectra were not available for the Diesel Generator Building and for Elevations 226' and 206' in the N-S direction in the Reactor Auxiliary Building - Unit 1. In such cases, the more conservative *4%* damped response spectra were used to estimate the spectral peaks.

SHEET NO. 3/1

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/28
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LWT DATE 7/28

SECTION 3. RESULT PRESENTATION

The fundamental frequencies of the structures of interest are extracted from SHNPP FSAR [4], and they are listed in Table 3-1. Also shown in the tables are the corresponding digitized *7%* damped RLE and DBE ground spectral accelerations (see Tables 3-4 and 3-5). The scale factors for the structures in each direction are obtained from the ratios of the RLE and DBE accelerations. The in-structure spectral peaks and ZPA's for DBE are tabulated in Table 3-2. The scaled median-centered in-structure spectral accelerations corresponding to an RLE ground input are provided in Table 3-3.

The major sources of conservatism in this study include the following:

1) The estimated spectral peaks shown in Table 3-3 were effectively scaled from *5%* damped DBE floor spectra with some exceptions. Due to the unavailability of *5%* damped floor spectra, the spectral peaks for the following locations and directions were scaled from the *4%* damped floor spectra:

   - RAB-Unit 1 Elevations 226' and 206' in the N-S direction and all elevations in the E-W direction, and

   - All elevations of the DG building in the horizontal and vertical directions.

2) In the vertical direction, the RAB-Common, RAB-Unit 1, and CIS have fundamental frequencies in the *10* to *20 Hz* range. Since the peak vertical response shown in Table 3-3 for these structures were scaled from the N-411 floor spectra, the effective equipment damping is less than *5%* (i.e., the N-411 spectra have equipment damping varying linearly from *5%* to *2%* between *10* to *20 Hz*).

SHEET NO. 2/1

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/23/
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LWT DATE 7/26

TABLE 3-1 (a) SCALE FACTORS FOR REACTOR AUXILIARY BUILDING - COMMON AT SHNPP REVIEW LEVEL EARTHQUAKE OVER DBE

Direction	Fundmtl Frequency (Hz)	Partcptn Factor (%)	RLE Accel (g)	DBE Accel (g)	Scale Factor
N-S	8.029	59.206	0.567	0.346	1.64
E-W	7.605	56.798	0.567	0.348	1.63
Vert.	14.355	87.915	0.293	0.253	1.16

TABLE 3-1 (b) SCALE FACTORS FOR REACTOR AUXILIARY BUILDING - UNIT 1 AT SHNPP REVIEW LEVEL EARTHQUAKE OVER DBE

Direction	Fundmtl Frequency (Hz)	Partcptn Factor (%)	RLE Accel (g)	DBE Accel (g)	Scale Factor
N-S	7.577	50.755	0.567	0.349	1.62
E-W	5.800	46.595	0.567	0.362	1.56
Vert.	11.839	90.242	0.317	0.287	1.11

TABLE 3-1 (c) SCALE FACTORS FOR CONTAINMENT INTERIOR STRUCTURE AT SHNPP REVIEW LEVEL EARTHQUAKE OVER DBE

Direction	Fundmtl Frequency (Hz)	Partcptn Factor (%)	RLE Accel (g)	DBE Accel (g)	Scale Factor
N-S	8.781	29.121	0.547	0.342	1.60
E-W	9.853	35.861	0.520	0.321	1.62
Vert.	19.738	30.135	0.252	0.205	1.23

TABLE 3-1 (d) SCALE FACTORS FOR DIESEL GENERATOR BUILDING AT SHNPP REVIEW LEVEL EARTHQUAKE OVER DBE

Direction	Fundmtl Frequency (Hz)	Partcptn Factor (%)	RLE Accel (g)	DBE Accel (g)	Scale Factor
N-S	12.370 *	N/A	0.466	0.279	1.67
E-W	12.370 *	N/A	0.466	0.279	1.67
Vert. (Floor)	6.74 to 14.32 *	N/A	0.290	0.253	1.15
Vert.	23.070 *	N/A	0.235	0.186	1.27
Node 5 (Horiz)	Rigid *	N/A	0.300	0.150	2.00
Node 5 (Vert)	Rigid *	N/A	0.200	0.150	1.33

NOTE: * The Frequeny is estimated from In-Structure response spectra. Participation Factor not available.

SHEET NO. 101

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/28

CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LWT DATE 7/28

TABLE 3-2 (a) DBE RESPONSE SPECTRA FOR RAB-COMMON AT SHNPP

Elevation (ft)	N-S Peak (*) (g)	N-S ZPA (*) (g)	E-W Peak (*) (g)	E-W ZPA (*) (g)	Vert. (BD) (#) Peak (*) (g)	Vert. (BD) (#) ZPA (*) (g)	Vert. (D) (##) Peak (*) (g)	Vert. (D) (##) ZPA (*) (g)
324.00	3.167	0.654	2.785	0.560	2.840	0.713	1.889	0.475
305.00	2.766	0.562	2.515	0.478	3.119	0.657	1.791	0.441
286.00	2.231	0.451	2.108	0.404	2.744	0.607	1.612	0.389
261.00	1.403	0.343	1.462	0.335	2.537	0.544	1.287	0.325

TABLE 3-2 (b) DBE RESPONSE SPECTRA FOR RAB-UNIT 1 AT SHNPP

Elevation (ft)	N-S Peak (*) (g)	N-S ZPA (*) (g)	E-W Peak (*) (g)	E-W ZPA (*) (g)	Vert. (BD) (#) Peak (*) (g)	Vert. (BD) (#) ZPA (*) (g)	Vert. (D) (##) Peak (*) (g)	Vert. (D) (##) ZPA (*) (g)
324.00	2.959	0.587	3.218	0.553	2.579	0.710	1.905	0.484
305.00	2.645	0.565	2.889	0.486	3.078	0.891	1.875	0.474
286.00	2.143	0.476	2.317	0.392	2.935	0.832	1.757	0.438
261.00	1.477	0.343	1.573	0.313	2.486	0.689	1.576	0.389
236.00	0.812	0.231	0.951	0.232	3.290	0.720	1.355	0.345
226.00	0.724 **	0.199 **	0.688	0.190				
216.00	0.618	0.191	0.611	0.201	1.342	0.441	1.172	0.308
206.00	0.629 **	0.177 **	0.628	0.178				

TABLE 3-2 (c) DBE RESPONSE SPECTRA FOR CONTM/INT. AT SHNPP

Elevation (ft)	N-S Peak (*) (g)	N-S ZPA (*) (g)	E-W Peak (*) (g)	E-W ZPA (*) (g)	Vert. (BD) (#) Peak (*) (g)	Vert. (BD) (#) ZPA (*) (g)	Vert. (D) (##) Peak (*) (g)	Vert. (D) (##) ZPA (*) (g)
302.65	2.925	0.620	2.290	0.571			1.373	0.422
286.00	2.527	0.534	2.000	0.498	2.490	0.574	1.336	0.403
261.00	1.743	0.372	1.466	0.383	2.650	0.587	1.194	0.336
249.00	1.275	0.296	1.154	0.320			1.071	0.288
236.00	0.854	0.245	0.833	0.253	1.762	0.482	0.919	0.255

TABLE 3-2 (d) DBE RESPONSE SPECTRA FOR DG BLDG AT SHNPP

Elevation (ft)	N-S Peak (**) (g)	N-S ZPA (**) (g)	E-W Peak (**) (g)	E-W ZPA (**) (g)	Vert. (Floor) Peak (**) (g)	Vert. (Floor) ZPA (**) (g)	Vert. Peak (**) (g)	Vert. ZPA (**) (g)
323.875	2.303	0.427	2.448	0.514	2.890	0.497	0.696	0.299
310.875	2.172	0.408	2.150	0.434	1.890	0.554	0.682	0.294
291.000	1.714	0.348	1.651	0.378	2.340	0.512	0.635	0.275
280.000	1.368	0.291	1.270	0.335	2.788	0.510	0.619	0.261
264.000	0.710	0.231	0.698	0.216			0.600	0.228

NOTES:
* Spectral values are obtained from SHNPP N-411 spectra
** Spectral values are obtained from CP&L SHNPP spectra with 4% damping
\# Vert. (BD) shows the Responses between Column Lines B & D
\#\# Vert. (D) shows the Responses on Column Line D

SHEET NO. 11/1

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/28
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LWT DATE 7/28

TABLE 3-3 (a) SCALED RESPONSE SPECTRA TO REVIEW LEVEL EARTHQUAKE FOR REACTOR AUXILIARY BUILDING - COMMON AT SHNPP

	N-S (N-411)			E-W (N-411)			Vertical (BD) - N-411			Vertical (D) - N-411		
Elevation (ft)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)
324.00	1.64	5.190	1.072	1.63	4.536	0.912	1.16	3.288	0.826	1.16	2.187	0.550
305.00	1.64	4.533	0.921	1.63	4.096	0.779	1.16	3.611	0.761	1.16	2.074	0.511
286.00	1.64	3.656	0.739	1.63	3.433	0.658	1.16	3.177	0.703	1.16	1.866	0.450
261.00	1.64	2.299	0.562	1.63	2.381	0.546	1.16	2.937	0.630	1.16	1.490	0.376

TABLE 3-3 (b) SCALED RESPONSE SPECTRA TO REVIEW LEVEL EARTHQUAKE FOR REACTOR AUXILIARY BUILDING - UNIT 1 AT SHNPP

	N-S (N-411)			E-W (4%)			Vertical (BD) - N-411			Vertical (D) - N-411		
Elevation (ft)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)
324.00	1.62	4.804	0.953	1.56	5.034	0.865	1.11	2.851	0.785	1.11	2.106	0.535
305.00	1.62	4.294	0.917	1.56	4.519	0.760	1.11	3.402	0.985	1.11	2.072	0.524
286.00	1.62	3.479	0.773	1.56	3.624	0.613	1.11	3.244	0.920	1.11	1.942	0.484
261.00	1.62	2.398	0.557	1.56	2.461	0.490	1.11	2.748	0.762	1.11	1.742	0.430
236.00	1.62	1.318	0.375	1.56	1.488	0.363	1.11	3.636	0.796	1.11	1.498	0.381
226.00	1.62	1.175	0.323	1.56	1.076	0.297						
216.00	1.62	1.003	0.310	1.56	0.956	0.314	1.11	1.483	0.487	1.11	1.295	0.340
206.00	1.62	1.021	0.287	1.56	0.982	0.278						

TABLE 3-3 (c) SCALED RESPONSE SPECTRA TO REVIEW LEVEL EARTHQUAKE FOR CONTAINMENT INTERIOR STRUCTURE AT SHNPP

	N-S (N-411)			E-W (N-411)			Vertical (BD) - N-411			Vertical (D) - N-411		
Elevation (ft)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)
302.65	1.60	4.680	0.992	1.62	3.712	0.926				1.23	1.689	0.519
286.00	1.60	4.044	0.854	1.62	3.242	0.807	1.23	3.064	0.706	1.23	1.644	0.496
261.00	1.60	2.789	0.595	1.62	2.376	0.621	1.23	3.261	0.722	1.23	1.469	0.413
249.00	1.60	2.040	0.474	1.62	1.871	0.519				1.23	1.318	0.354
236.00	1.60	1.367	0.392	1.62	1.350	0.410	1.23	2.168	0.593	1.23	1.131	0.314

TABLE 3-3 (d) SCALED RESPONSE SPECTRA TO REVIEW LEVEL EARTHQUAKE FOR DIESEL GENERATOR BUILDING AT SHNPP

	N-S (4%)			E-W (4%)			Vertical (Floor) - 4%			Vertical - 4%		
Elevation (ft)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)	Scale Factor	Peak (g)	ZPA (g)
323.875	1.67	3.849	0.714	1.67	4.092	0.859	1.15	3.313	0.570	1.27	0.881	0.378
310.875	1.67	3.630	0.682	1.67	3.594	0.725	1.15	2.167	0.635	1.27	0.863	0.372
291.000	1.67	2.865	0.582	1.67	2.760	0.632	1.15	2.683	0.587	1.27	0.804	0.348
280.000	1.67	2.287	0.486	1.67	2.123	0.560	1.15	3.196	0.585	1.27	0.784	0.330
Node 5	2.00	1.420	0.462	2.00	1.396	0.432				1.33	0.800	0.304

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/23/0
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LVJT DATE 7/28/

Table 3-4 RLE: NUREG/CR-0098 Median Spectral Shape anchored to 0.3g

0098	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl Accel (g)
1	0.20000	0.03219	0.03219	0.02103
2	0.20448	0.03365	0.03365	0.02197
3	0.20907	0.03519	0.03519	0.02296
4	0.21376	0.03679	0.03679	0.02400
5	0.21855	0.03846	0.03846	0.02508
6	0.22345	0.04022	0.04022	0.02621
7	0.22846	0.04205	0.04205	0.02739
8	0.23358	0.04396	0.04396	0.02863
9	0.23882	0.04596	0.04596	0.02992
10	0.24418	0.04806	0.04806	0.03126
11	0.24965	0.05025	0.05025	0.03267
12	0.25525	0.05253	0.05253	0.03415
13	0.26097	0.05493	0.05493	0.03569
14	0.26682	0.05743	0.05743	0.03729
15	0.27281	0.06004	0.06004	0.03897
16	0.27892	0.06278	0.06278	0.04073
17	0.28518	0.06564	0.06564	0.04257
18	0.29157	0.06863	0.06863	0.04449
19	0.29811	0.07175	0.07175	0.04649
20	0.30479	0.07502	0.07502	0.04859
21	0.31163	0.07844	0.07844	0.05078
22	0.31861	0.08201	0.08201	0.05306
23	0.32576	0.08574	0.08574	0.05546
24	0.33306	0.08881	0.08881	0.05743
25	0.34053	0.09080	0.09080	0.05874
26	0.34817	0.09283	0.09283	0.06007
27	0.35597	0.09490	0.09490	0.06144
28	0.36395	0.09702	0.09702	0.06283
29	0.37212	0.09919	0.09919	0.06426
30	0.38046	0.10141	0.10141	0.06572
31	0.38899	0.10367	0.10367	0.06721
32	0.39771	0.10599	0.10599	0.06874
33	0.40663	0.10836	0.10836	0.07030
34	0.41575	0.11078	0.11078	0.07190
35	0.42507	0.11325	0.11325	0.07353
36	0.43460	0.11578	0.11578	0.07520
37	0.44434	0.11837	0.11837	0.07691
38	0.45431	0.12102	0.12102	0.07866
39	0.46449	0.12372	0.12372	0.08044
40	0.47491	0.12648	0.12648	0.08227
41	0.48556	0.12931	0.12931	0.08414
42	0.49645	0.13220	0.13220	0.08605
43	0.50758	0.13515	0.13515	0.08801
44	0.51896	0.13817	0.13817	0.09001
45	0.53059	0.14126	0.14126	0.09205
46	0.54249	0.14442	0.14442	0.09414
47	0.55465	0.14764	0.14764	0.09628
48	0.56709	0.15094	0.15094	0.09847
49	0.57981	0.15431	0.15431	0.10070
50	0.59281	0.15776	0.15776	0.10299
51	0.60610	0.16129	0.16129	0.10533
52	0.61969	0.16489	0.16489	0.10772
53	0.63358	0.16858	0.16858	0.11017

Table 3-5 DBE: Reg. Guide 1.60 anchored to 0.15g

RG 160	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl Accel (g)
1	0.20000	0.04160	0.04160	0.02764
2	0.20448	0.04349	0.04349	0.02889
3	0.20907	0.04546	0.04546	0.03020
4	0.21376	0.04752	0.04752	0.03157
5	0.21855	0.04967	0.04967	0.03301
6	0.22345	0.05193	0.05193	0.03450
7	0.22846	0.05428	0.05428	0.03607
8	0.23358	0.05674	0.05674	0.03771
9	0.23882	0.05932	0.05932	0.03942
10	0.24418	0.06201	0.06201	0.04121
11	0.24965	0.06482	0.06482	0.04308
12	0.25525	0.06609	0.06609	0.04395
13	0.26097	0.06727	0.06727	0.04477
14	0.26682	0.06847	0.06847	0.04561
15	0.27281	0.06969	0.06969	0.04646
16	0.27892	0.07093	0.07093	0.04732
17	0.28518	0.07220	0.07220	0.04821
18	0.29157	0.07349	0.07349	0.04910
19	0.29811	0.07480	0.07480	0.05002
20	0.30479	0.07613	0.07613	0.05095
21	0.31163	0.07749	0.07749	0.05190
22	0.31861	0.07887	0.07887	0.05287
23	0.32576	0.08028	0.08028	0.05385
24	0.33306	0.08171	0.08171	0.05486
25	0.34053	0.08317	0.08317	0.05588
26	0.34817	0.08466	0.08466	0.05692
27	0.35597	0.08617	0.08617	0.05798
28	0.36395	0.08771	0.08771	0.05906
29	0.37212	0.08927	0.08927	0.06016
30	0.38046	0.09087	0.09087	0.06129
31	0.38899	0.09249	0.09249	0.06243
32	0.39771	0.09414	0.09414	0.06359
33	0.40663	0.09582	0.09582	0.06478
34	0.41575	0.09753	0.09753	0.06598
35	0.42507	0.09927	0.09927	0.06721
36	0.43460	0.10104	0.10104	0.06847
37	0.44434	0.10284	0.10284	0.06974
38	0.45431	0.10468	0.10468	0.07104
39	0.46449	0.10655	0.10655	0.07237
40	0.47491	0.10845	0.10845	0.07371
41	0.48556	0.11038	0.11038	0.07509
42	0.49645	0.11235	0.11235	0.07649
43	0.50758	0.11436	0.11436	0.07791
44	0.51896	0.11640	0.11640	0.07937
45	0.53059	0.11848	0.11848	0.08084
46	0.54249	0.12059	0.12059	0.08235
47	0.55465	0.12274	0.12274	0.08389
48	0.56709	0.12493	0.12493	0.08545
49	0.57981	0.12716	0.12716	0.08704
50	0.59281	0.12943	0.12943	0.08866
51	0.60610	0.13174	0.13174	0.09032
52	0.61969	0.13409	0.13409	0.09200
53	0.63358	0.13649	0.13649	0.09372

Table 3-4 RLE: NUREG/CR-0098 Median Spectral Shape anchored to 0.3g

0098	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl. Accel (g)
54	0.64779	0.17234	0.17234	0.11267
55	0.66232	0.17619	0.17619	0.11523
56	0.67717	0.18013	0.18013	0.11785
57	0.69235	0.18416	0.18416	0.12053
58	0.70787	0.18827	0.18827	0.12326
59	0.72375	0.19248	0.19248	0.12606
60	0.73997	0.19678	0.19678	0.12893
61	0.75657	0.20117	0.20117	0.13185
62	0.77353	0.20567	0.20567	0.13485
63	0.79087	0.21027	0.21027	0.13791
64	0.80861	0.21496	0.21496	0.14105
65	0.82674	0.21977	0.21977	0.14425
66	0.84528	0.22468	0.22468	0.14753
67	0.86423	0.22970	0.22970	0.15088
68	0.88361	0.23483	0.23483	0.15430
69	0.90342	0.24008	0.24008	0.15781
70	0.92368	0.24544	0.24544	0.16139
71	0.94439	0.25092	0.25092	0.16506
72	0.96556	0.25653	0.25653	0.16881
73	0.98721	0.26226	0.26226	0.17264
74	1.00935	0.26812	0.26812	0.17657
75	1.03198	0.27411	0.27411	0.18058
76	1.05512	0.28024	0.28024	0.18468
77	1.07878	0.28650	0.28650	0.18887
78	1.10296	0.29290	0.29290	0.19316
79	1.12770	0.29945	0.29945	0.19755
80	1.15298	0.30614	0.30614	0.20204
81	1.17883	0.31298	0.31298	0.20663
82	1.20527	0.31997	0.31997	0.21132
83	1.23229	0.32712	0.32712	0.21612
84	1.25992	0.33443	0.33443	0.22103
85	1.28817	0.34190	0.34190	0.22605
86	1.31705	0.34954	0.34954	0.23119
87	1.34659	0.35735	0.35735	0.23644
88	1.37678	0.36534	0.36534	0.24181
89	1.40765	0.37350	0.37350	0.24730
90	1.43921	0.38185	0.38185	0.25292
91	1.47148	0.39038	0.39038	0.25866
92	1.50448	0.39910	0.39910	0.26454
93	1.53821	0.40802	0.40802	0.27055
94	1.57270	0.41713	0.41713	0.27669
95	1.60796	0.42646	0.42646	0.28298
96	1.64402	0.43598	0.43598	0.28941
97	1.68088	0.44573	0.44573	0.29598
98	1.71857	0.45568	0.45568	0.30270
99	1.75710	0.46587	0.46587	0.30958
100	1.79650	0.47628	0.47628	0.31661
101	1.83678	0.48692	0.48692	0.32380
102	1.87797	0.49780	0.49780	0.33116
103	1.92008	0.50892	0.50892	0.33868
104	1.96313	0.52029	0.52029	0.34637
105	2.00715	0.53192	0.53192	0.35424
106	2.05215	0.54380	0.54380	0.36229

Table 3-5 DBE: Reg. Guide 1.60 anchored to 0.15g

RG 160	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl Accel (g)
54	0.64779	0.13892	0.13892	0.09546
55	0.66232	0.14140	0.14140	0.09724
56	0.67717	0.14393	0.14393	0.09905
57	0.69235	0.14650	0.14650	0.10090
58	0.70787	0.14911	0.14911	0.10278
59	0.72375	0.15177	0.15177	0.10470
60	0.73997	0.15448	0.15448	0.10665
61	0.75657	0.15724	0.15724	0.10864
62	0.77353	0.16004	0.16004	0.11066
63	0.79087	0.16290	0.16290	0.11272
64	0.80861	0.16581	0.16581	0.11482
65	0.82674	0.16877	0.16877	0.11696
66	0.84528	0.17178	0.17178	0.11914
67	0.86423	0.17484	0.17484	0.12136
68	0.88361	0.17796	0.17796	0.12363
69	0.90342	0.18114	0.18114	0.12593
70	0.92368	0.18437	0.18437	0.12828
71	0.94439	0.18766	0.18766	0.13067
72	0.96556	0.19101	0.19101	0.13310
73	0.98721	0.19442	0.19442	0.13558
74	1.00935	0.19789	0.19789	0.13811
75	1.03198	0.20142	0.20142	0.14069
76	1.05512	0.20502	0.20502	0.14331
77	1.07878	0.20868	0.20868	0.14598
78	1.10296	0.21240	0.21240	0.14870
79	1.12770	0.21619	0.21619	0.15147
80	1.15298	0.22005	0.22005	0.15429
81	1.17883	0.22398	0.22398	0.15717
82	1.20527	0.22798	0.22798	0.16010
83	1.23229	0.23204	0.23204	0.16308
84	1.25992	0.23619	0.23619	0.16612
85	1.28817	0.24040	0.24040	0.16922
86	1.31705	0.24469	0.24469	0.17237
87	1.34659	0.24906	0.24906	0.17558
88	1.37678	0.25350	0.25350	0.17886
89	1.40765	0.25803	0.25803	0.18219
90	1.43921	0.26263	0.26263	0.18559
91	1.47148	0.26732	0.26732	0.18905
92	1.50448	0.27209	0.27209	0.19257
93	1.53821	0.27695	0.27695	0.19616
94	1.57270	0.28189	0.28189	0.19981
95	1.60796	0.28692	0.28692	0.20354
96	1.64402	0.29204	0.29204	0.20733
97	1.68088	0.29725	0.29725	0.21120
98	1.71857	0.30256	0.30256	0.21513
99	1.75710	0.30796	0.30796	0.21914
100	1.79650	0.31345	0.31345	0.22323
101	1.83678	0.31905	0.31905	0.22739
102	1.87797	0.32474	0.32474	0.23162
103	1.92008	0.33054	0.33054	0.23594
104	1.96313	0.33644	0.33644	0.24034
105	2.00715	0.34244	0.34244	0.24482
106	2.05215	0.34855	0.34855	0.24938

SHEET NO. 14/1

JOB NO. 52214 JOB CP&L SHEARON HARRIS - SPECTRA BY SL DATE 7/28/
CALC. NO. C-001 SUBJECT SPECTRA SCALING CHK'D LWT DATE 7/28

Table 3-4 RLE: NUREG/CR-0098 Median Spectral Shape anchored to 0.3g

0098	Freq (Hz)	Horiz Accel (g)	Horiz. Accel. (g)	Vertl Accel (g)
107	2.09817	0.55595	0.55595	0.37052
108	2.14521	0.56700	0.56700	0.37800
109	2.19331	0.56700	0.56700	0.37800
110	2.24249	0.56700	0.56700	0.37800
111	2.29277	0.56700	0.56700	0.37800
112	2.34418	0.56700	0.56700	0.37800
113	2.39674	0.56700	0.56700	0.37800
114	2.45048	0.56700	0.56700	0.37800
115	2.50543	0.56700	0.56700	0.37800
116	2.56161	0.56700	0.56700	0.37800
117	2.61904	0.56700	0.56700	0.37800
118	2.67777	0.56700	0.56700	0.37800
119	2.73781	0.56700	0.56700	0.37800
120	2.79920	0.56700	0.56700	0.37800
121	2.86196	0.56700	0.56700	0.37800
122	2.92613	0.56700	0.56700	0.37800
123	2.99174	0.56700	0.56700	0.37800
124	3.05883	0.56700	0.56700	0.37800
125	3.12741	0.56700	0.56700	0.37800
126	3.19753	0.56700	0.56700	0.37800
127	3.26923	0.56700	0.56700	0.37800
128	3.34253	0.56700	0.56700	0.37800
129	3.41748	0.56700	0.56700	0.37800
130	3.49411	0.56700	0.56700	0.37800
131	3.57245	0.56700	0.56700	0.37800
132	3.65256	0.56700	0.56700	0.37800
133	3.73445	0.56700	0.56700	0.37800
134	3.81819	0.56700	0.56700	0.37800
135	3.90380	0.56700	0.56700	0.37800
136	3.99133	0.56700	0.56700	0.37800
137	4.08083	0.56700	0.56700	0.37800
138	4.17233	0.56700	0.56700	0.37800
139	4.26588	0.56700	0.56700	0.37800
140	4.36153	0.56700	0.56700	0.37800
141	4.45933	0.56700	0.56700	0.37800
142	4.55931	0.56700	0.56700	0.37800
143	4.66154	0.56700	0.56700	0.37800
144	4.76607	0.56700	0.56700	0.37800
145	4.87293	0.56700	0.56700	0.37800
146	4.98219	0.56700	0.56700	0.37800
147	5.09390	0.56700	0.56700	0.37800
148	5.20812	0.56700	0.56700	0.37800
149	5.32490	0.56700	0.56700	0.37800
150	5.44429	0.56700	0.56700	0.37800
151	5.56637	0.56700	0.56700	0.37800
152	5.69118	0.56700	0.56700	0.37800
153	5.81879	0.56700	0.56700	0.37800
154	5.94925	0.56700	0.56700	0.37800
155	6.08265	0.56700	0.56700	0.37800
156	6.21904	0.56700	0.56700	0.37800
157	6.35848	0.56700	0.56700	0.37800
158	6.50105	0.56700	0.56700	0.37800
159	6.64682	0.56700	0.56700	0.37800

Table 3-5 DBE: Reg. Guide 1.60 anchored to 0.15g

RG 160	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl Accel (g)
107	2.09817	0.35477	0.35477	0.25403
108	2.14521	0.36111	0.36111	0.25876
109	2.19331	0.36755	0.36755	0.26359
110	2.24249	0.37411	0.37411	0.26850
111	2.29277	0.38079	0.38079	0.27350
112	2.34418	0.38758	0.38758	0.27860
113	2.39674	0.39450	0.39450	0.28379
114	2.45048	0.40154	0.40154	0.28908
115	2.50543	0.40788	0.40788	0.29447
116	2.56161	0.40661	0.40661	0.29996
117	2.61904	0.40535	0.40535	0.30555
118	2.67777	0.40409	0.40409	0.31124
119	2.73781	0.40284	0.40284	0.31705
120	2.79920	0.40159	0.40159	0.32295
121	2.86196	0.40035	0.40035	0.32897
122	2.92613	0.39911	0.39911	0.33511
123	2.99174	0.39787	0.39787	0.34135
124	3.05883	0.39663	0.39663	0.34771
125	3.12741	0.39540	0.39540	0.35419
126	3.19753	0.39418	0.39418	0.36080
127	3.26923	0.39296	0.39296	0.36752
128	3.34253	0.39174	0.39174	0.37437
129	3.41748	0.39052	0.39052	0.38135
130	3.49411	0.38931	0.38931	0.38845
131	3.57245	0.38811	0.38811	0.38789
132	3.65256	0.38690	0.38690	0.38669
133	3.73445	0.38570	0.38570	0.38550
134	3.81819	0.38451	0.38451	0.38431
135	3.90380	0.38331	0.38331	0.38312
136	3.99133	0.38213	0.38213	0.38194
137	4.08083	0.38094	0.38094	0.38076
138	4.17233	0.37976	0.37976	0.37958
139	4.26588	0.37858	0.37858	0.37841
140	4.36153	0.37741	0.37741	0.37724
141	4.45933	0.37624	0.37624	0.37608
142	4.55931	0.37507	0.37507	0.37492
143	4.66154	0.37391	0.37391	0.37376
144	4.76607	0.37275	0.37275	0.37261
145	4.87293	0.37159	0.37159	0.37146
146	4.98219	0.37044	0.37044	0.37031
147	5.09390	0.36929	0.36929	0.36917
148	5.20812	0.36815	0.36815	0.36803
149	5.32490	0.36701	0.36701	0.36689
150	5.44429	0.36587	0.36587	0.36576
151	5.56637	0.36473	0.36473	0.36463
152	5.69118	0.36360	0.36360	0.36350
153	5.81879	0.36248	0.36248	0.36238
154	5.94925	0.36135	0.36135	0.36126
155	6.08265	0.36023	0.36023	0.36015
156	6.21904	0.35912	0.35912	0.35904
157	6.35848	0.35800	0.35800	0.35793
158	6.50105	0.35689	0.35689	0.35682
159	6.64682	0.35579	0.35579	0.35572

Table 3-4 RLE: NUREG/CR-0098 Median Spectral Shape anchored to 0.3g

0098	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl Accel (g)
160	6.79586	0.56700	0.56700	0.37800
161	6.94823	0.56700	0.56700	0.37800
162	7.10403	0.56700	0.56700	0.37800
163	7.26332	0.56700	0.56700	0.37800
164	7.42618	0.56700	0.56700	0.37800
165	7.59269	0.56700	0.56700	0.37800
166	7.76293	0.56700	0.56700	0.37800
167	7.93699	0.56700	0.56700	0.37800
168	8.11496	0.56338	0.56338	0.37559
169	8.29691	0.55779	0.55779	0.37186
170	8.48295	0.55226	0.55226	0.36818
171	8.67315	0.54679	0.54679	0.36453
172	8.86763	0.54137	0.54137	0.36091
173	9.06646	0.53601	0.53601	0.35734
174	9.26975	0.53069	0.53069	0.35379
175	9.47759	0.52543	0.52543	0.35029
176	9.69010	0.52022	0.52022	0.34682
177	9.90738	0.51507	0.51507	0.34338
178	10.12952	0.50996	0.50996	0.33998
179	10.35665	0.50491	0.50491	0.33661
180	10.58887	0.49990	0.49990	0.33327
181	10.82629	0.49495	0.49495	0.32997
182	11.06905	0.49004	0.49004	0.32669
183	11.31724	0.48519	0.48519	0.32346
184	11.57100	0.48038	0.48038	0.32025
185	11.83045	0.47561	0.47561	0.31708
186	12.09571	0.47090	0.47090	0.31393
187	12.36693	0.46623	0.46623	0.31082
188	12.64422	0.46161	0.46161	0.30774
189	12.92774	0.45704	0.45704	0.30469
190	13.21760	0.45251	0.45251	0.30167
191	13.51397	0.44802	0.44802	0.29868
192	13.81699	0.44358	0.44358	0.29572
193	14.12680	0.43918	0.43918	0.29279
194	14.44355	0.43483	0.43483	0.28989
195	14.76741	0.43052	0.43052	0.28701
196	15.09853	0.42625	0.42625	0.28417
197	15.43707	0.42203	0.42203	0.28135
198	15.78321	0.41785	0.41785	0.27856
199	16.13711	0.41370	0.41370	0.27580
200	16.49894	0.40960	0.40960	0.27307
201	16.86888	0.40554	0.40554	0.27036
202	17.24712	0.40152	0.40152	0.26768
203	17.63384	0.39754	0.39754	0.26503
204	18.02923	0.39360	0.39360	0.26240
205	18.43349	0.38970	0.38970	0.25980
206	18.84681	0.38584	0.38584	0.25723
207	19.26940	0.38201	0.38201	0.25468
208	19.70147	0.37823	0.37823	0.25215
209	20.14322	0.37448	0.37448	0.24965
210	20.59488	0.37077	0.37077	0.24718
211	21.05666	0.36709	0.36709	0.24473
212	21.52880	0.36345	0.36345	0.24230

Table 3-5 DBE: Reg. Guide 1.60 anchored to 0.15g

RG 160	Freq (Hz)	Horiz Accel (g)	Horiz. Accel (g)	Vertl Accel (g)
160	6.79586	0.35468	0.35468	0.35462
161	6.94823	0.35358	0.35358	0.35353
162	7.10403	0.35249	0.35249	0.35244
163	7.26332	0.35139	0.35139	0.35135
164	7.42618	0.35030	0.35030	0.35026
165	7.59269	0.34922	0.34922	0.34918
166	7.76293	0.34813	0.34813	0.34810
167	7.93699	0.34706	0.34706	0.34703
168	8.11496	0.34598	0.34598	0.34596
169	8.29691	0.34491	0.34491	0.34489
170	8.48295	0.34384	0.34384	0.34382
171	8.67315	0.34277	0.34277	0.34276
172	8.86763	0.34171	0.34171	0.34171
173	9.06646	0.33942	0.33942	0.33942
174	9.26975	0.33469	0.33469	0.33469
175	9.47759	0.33004	0.33004	0.33004
176	9.69010	0.32544	0.32544	0.32544
177	9.90738	0.32091	0.32091	0.32091
178	10.12952	0.31645	0.31645	0.31645
179	10.35665	0.31204	0.31204	0.31204
180	10.58887	0.30770	0.30770	0.30770
181	10.82629	0.30342	0.30342	0.30342
182	11.06905	0.29919	0.29919	0.29919
183	11.31724	0.29503	0.29503	0.29503
184	11.57100	0.29092	0.29092	0.29092
185	11.83045	0.28687	0.28687	0.28687
186	12.09571	0.28288	0.28288	0.28288
187	12.36693	0.27894	0.27894	0.27894
188	12.64422	0.27506	0.27506	0.27506
189	12.92774	0.27123	0.27123	0.27123
190	13.21760	0.26746	0.26746	0.26746
191	13.51397	0.26373	0.26373	0.26373
192	13.81699	0.26006	0.26006	0.26006
193	14.12680	0.25644	0.25644	0.25644
194	14.44355	0.25287	0.25287	0.25287
195	14.76741	0.24936	0.24936	0.24936
196	15.09853	0.24588	0.24588	0.24588
197	15.43707	0.24246	0.24246	0.24246
198	15.78321	0.23909	0.23909	0.23909
199	16.13711	0.23576	0.23576	0.23576
200	16.49894	0.23248	0.23248	0.23248
201	16.86888	0.22924	0.22924	0.22924
202	17.24712	0.22605	0.22605	0.22605
203	17.63384	0.22291	0.22291	0.22291
204	18.02923	0.21980	0.21980	0.21980
205	18.43349	0.21674	0.21674	0.21674
206	18.84681	0.21373	0.21373	0.21373
207	19.26940	0.21075	0.21075	0.21075
208	19.70147	0.20782	0.20782	0.20782
209	20.14322	0.20493	0.20493	0.20493
210	20.59488	0.20207	0.20207	0.20207
211	21.05666	0.19926	0.19926	0.19926
212	21.52880	0.19649	0.19649	0.19649

Table 3-4 RLE: NUREG/CR-0098 Median Spectral Shape anchored to 0.3g

0098	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl Accel (g)
213	22.01153	0.35985	0.35985	0.23990
214	22.50508	0.35628	0.35628	0.23752
215	23.00969	0.35275	0.35275	0.23517
216	23.52562	0.34926	0.34926	0.23284
217	24.05312	0.34579	0.34579	0.23053
218	24.59245	0.34237	0.34237	0.22824
219	25.14387	0.33897	0.33897	0.22598
220	25.70765	0.33561	0.33561	0.22374
221	26.28408	0.33229	0.33229	0.22152
222	26.87343	0.32899	0.32899	0.21933
223	27.47599	0.32573	0.32573	0.21716
224	28.09207	0.32250	0.32250	0.21500
225	28.72196	0.31931	0.31931	0.21287
226	29.36597	0.31614	0.31614	0.21076
227	30.02442	0.31301	0.31301	0.20867
228	30.69764	0.30991	0.30991	0.20660
229	31.38595	0.30683	0.30683	0.20456
230	32.08970	0.30379	0.30379	0.20253
231	32.80923	0.30078	0.30078	0.20052
232	33.54488	0.30000	0.30000	0.20000
233	34.29704	0.30000	0.30000	0.20000
234	35.06606	0.30000	0.30000	0.20000
235	35.85232	0.30000	0.30000	0.20000
236	36.65621	0.30000	0.30000	0.20000
237	37.47813	0.30000	0.30000	0.20000
238	38.31848	0.30000	0.30000	0.20000
239	39.17767	0.30000	0.30000	0.20000
240	40.05612	0.30000	0.30000	0.20000
241	40.95427	0.30000	0.30000	0.20000
242	41.87256	0.30000	0.30000	0.20000
243	42.81144	0.30000	0.30000	0.20000
244	43.77137	0.30000	0.30000	0.20000
245	44.75283	0.30000	0.30000	0.20000
246	45.75629	0.30000	0.30000	0.20000
247	46.78225	0.30000	0.30000	0.20000
248	47.83122	0.30000	0.30000	0.20000
249	48.90371	0.30000	0.30000	0.20000
250	50.00024	0.30000	0.30000	0.20000

Table 3-5 DBE: Reg. Guide 1.60 anchored to 0.15g

RG 160	Freq (Hz)	Horiz Accel (g)	Horiz Accel (g)	Vertl Accel (g)
213	22.01153	0.19375	0.19375	0.19375
214	22.50508	0.19106	0.19106	0.19106
215	23.00969	0.18840	0.18840	0.18840
216	23.52562	0.18578	0.18578	0.18578
217	24.05312	0.18319	0.18319	0.18319
218	24.59245	0.18064	0.18064	0.18064
219	25.14387	0.17813	0.17813	0.17813
220	25.70765	0.17565	0.17565	0.17565
221	26.28408	0.17320	0.17320	0.17320
222	26.87343	0.17079	0.17079	0.17079
223	27.47599	0.16841	0.16841	0.16841
224	28.09207	0.16607	0.16607	0.16607
225	28.72196	0.16376	0.16376	0.16376
226	29.36597	0.16148	0.16148	0.16148
227	30.02442	0.15923	0.15923	0.15923
228	30.69764	0.15702	0.15702	0.15702
229	31.38595	0.15483	0.15483	0.15483
230	32.08970	0.15268	0.15268	0.15268
231	32.80923	0.15055	0.15055	0.15055
232	33.54488	0.15000	0.15000	0.15000
233	34.29704	0.15000	0.15000	0.15000
234	35.06606	0.15000	0.15000	0.15000
235	35.85232	0.15000	0.15000	0.15000
236	36.65621	0.15000	0.15000	0.15000
237	37.47813	0.15000	0.15000	0.15000
238	38.31848	0.15000	0.15000	0.15000
239	39.17767	0.15000	0.15000	0.15000
240	40.05612	0.15000	0.15000	0.15000
241	40.95427	0.15000	0.15000	0.15000
242	41.87256	0.15000	0.15000	0.15000
243	42.81144	0.15000	0.15000	0.15000
244	43.77137	0.15000	0.15000	0.15000
245	44.75283	0.15000	0.15000	0.15000
246	45.75629	0.15000	0.15000	0.15000
247	46.78225	0.15000	0.15000	0.15000
248	47.83122	0.15000	0.15000	0.15000
249	48.90371	0.15000	0.15000	0.15000
250	50.00024	0.15000	0.15000	0.15000

SECTION 4. REFERENCES

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