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b. Important insights gained from the PRA review are documented throughout the PRA report in the sections which are the most applicable for that particular insight.

PALO VERDE
NUCLEAR GENERATING STATION

Individual Plant Examination

IPE Submittal Cross Reference

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b. Important insights gained from the PRA review are documented throughout the PRA report in the sections which are the most applicable for that particular insight.

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List of Tables and Matrix

List of Acronyms

A

ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACU	Air Cooling Unit
AD	Atmospheric Dump
ADV	Atmospheric Dump Valve
AF	Auxiliary Feedwater
AFAS	Auxiliary Feedwater Actuation Signal
AHU	Air-Handling Unit
AISC	American Institute of Steel Construction, Inc.
AltFW	Alternate Feedwater
AMI	Automatic Motion Inhibit
ANS	American Nuclear Society
ANSYS	ANSYS Engineering Analysis Systems
AO	Auxiliary Operator
AOO	Anticipated Operational Occurrence
AOV	Air-Operated Valves
APS	Arizona Public Service
APSS	Auxiliary Pressurizer Spray System
AR	Condenser Air Removal system
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without SCRAM
AWP	Automatic Withdrawal Prohibit

B

BAC	Boric Acid Concentrator
BAM	Boric Acid Make-up
BD	Steam Generator Blowdown
BHEP	Basic Human Error Probability
BJ	Byron-Jackson
BMT	Basemat Melt-Through
BOP	Balance of Plant
BOP/ESFAS	Balance of Plant/Engineered Safety Features Actuation Signal
BTP	Branch Technical Position
BTU	British Thermal Unit

BWR	Boiling Water Reactor

C

CAFTA	Computer-Aided Fault Tree Analysis
CC	Common Cause
CCF	Common-Cause Failure
CD	Condensate system
CDF	Core Damage Frequency
C-E	Combustion-Engineering
CEA	Control Element Assembly
CEAC	Control Element Assembly Calculator
CEDM	Control Element Drive Mechanism
CE-KSB	CE-KSB Pump Co.
CEOG	Combustion Engineering Owners Group
CEPAC	C-E Plant Analysis Code
CESSAR	Combustion Engineering Standard Safety Analysis Report
CET	Containment Event Tree
CH	Chemical and Volume Control system
CHEP	Critical Human Error Probability
CHR	Containment Heat Removal
CIAS	Containment Isolation Actuation Signal
CMC	Core Monitoring Computer
CPC	Core Protection Calculator
CR	Control Room
CREFAS	Control Room Essential Filtration Actuation Signal
CRS	Control Room Supervisor
CRVIAS	Control Room Ventilation Isolation Actuation Signal
CS	Containment Spray system
CSAS	Containment Spray Actuation Signal
CST	Condensate Storage Tank
CT	Condensate Storage and Transfer system
CVCS	Chemical and Volume Control System
CW	Circulating Water

D

DC	Direct Current
DCCC	DC Control Center

DCH	Direct Containment Heating
DET	Decomposition Event Tree
DF	Diesel Fuel Oil system
DG	Diesel Generator
DGSS	Diesel Generator Start Signal
DH	Decay-Heat
DHR	Decay-Heat Removal
DNBR	Departure from Nucleate Boiling Ratio
DPs	Departmental Procedures
DRC	Document Review Control
DS	Domestic Water system
DW	Demineralized Water system

E

EC	Emergency Coordinator
EC	Essential Chilled Water system
ECCS	Emergency Core Cooling Systems
EDG	Emergency Diesel Generator
EER	Engineering Evaluation Request
EF	Error Factor
EHC	Electro-Hydraulic Control Oil system
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation Signal
EW	Essential Cooling Water system

F

FAI	Fauske and Associates, Inc.
FBEVAS	Fuel Building Essential Ventilation Actuation Signal
FBT	Fast Bus Transfer
FLB	Feedwater Line Break
FP	Fire Protection
FSAR	Final Safety Analysis Report
FT	Fault Tree
FW	Main Feedwater system
FWCS	Feedwater Control System

	FWCV	Feedwater Control Valve
	FWIV	Feedwater Isolation Valve
G		
	GA	Service Gas
	GE	General Electric
	GL	Generic Letter
	gpm	gallons per minute
	GSI	Generic Safety Issue
H		
	HEP	Human Error Probability
	HJ	Control Building HVAC system
	HLI	Hot-Leg Injection
	hp	horse power
	HPME	High-Pressure Melt Ejection
	HPSC	High-Pressure Seal Cooler
	HPSI	High-Pressure Safety Injection
	HPSR	High-Pressure Safety Recirculation
	HRA	Human Reliability Analysis
	HVAC	Heating, Ventilation, and Air-Conditioning
I		
	IA	Instrument Air
	I&C	Instrument and Control
	ICI	In-Core Instrumentation
	IE	Initiating Event
	IEEE	Institute of Electrical and Electronics Engineers
	IEF	Initiating Event Frequencies
	IIR	Incident Investigation Report
	INEL	Idaho National Engineering Laboratory
	IPE	Independent Plant Examination
	IREP	Interim Reliability Evaluation Program
	IRS	Iodine Removal System
	ISLOCA	Interfacing System Loss Of Coolant Accident
	IST	Independent Subtree
K		
	kV	kilovolt

	kW	kilowatt
L		
	LAN	Local Area Network
	LCO	Limiting Condition for Operation
	LDHX	Letdown Heat Exchanger
	LER	Licensee Event Report
	LHS	Latin Hypercube Sampling
	LOCA	Loss of Coolant Accident
	LOOP	Loss Of Off-site Power
	LOP	Loss Of Power
	LPD	Local Power Density
	LPSI	Low-Pressure Safety Injection
	LPSR	Low-Pressure Safety Recirculation
	LS	Load Shed
	LSS	Lower Support Structure
	LTOP	Low-Temperature Over-Pressure Protection
M		
	MAAP	Modular Accident Analysis Program
	MCC	Motor Control Center
	MOV	Motor Operated Valve
	MSIS	Main Steam Isolation Signal
	MSIV	Main Steam Isolation Valve
	MSLB	Main Steam Line Break
	MSSS	Main Steam Support Structure
	MSSV	Main Steam Safety Valve
	MTC	Moderator Temperature Coefficient
N		
	NA	Non-class 13.8kV Power system
	NB	Non-class 4.16kV Power Distribution system.
	NC	Nuclear Cooling Water system
	NG	Non-class 1E 480V Load Center
	NH	Non-class 1E 480V Motor Control Center
	NI	Nuclear Instrumentation
	NK	Non-class 1E 125V DC system
	NN	Non-class 1E 120V AC Instrument Power system

	NPRDS	Nuclear Power Reliability Data System
	NPSH	Net Positive Suction Head
	NRC	Nuclear Regulatory Commission
	NRP	Non-Recovery Probability
	NSAC	Nuclear Safety Analysis Center
	NSSS	Nuclear Steam Supply System
	NUS	Nuclear Utilities Service
O		
	OA	Operator Action
	ORNL	Oak Ridge National Laboratory
P		
	P&ID	Piping and Instrumentation Diagram
	PB	Class 1E 4.16kV AC Power System
	PC	Spent Fuel Pool Cleaning and Cleanup System
	P/C	Planner/Coordinator
	PCN	Plant Change Request
	PCO	Permissive Controller Output
	PDS	Plant Damage State
	PE	Class 1E Standby Generation system
	PG	Class 1E 480V Power Switchgear system
	PH	Class 1E 480V AC Power system
	PK	Class 1E 125V DC Power system
	PLCS	Pressurizer Level Control System
	PMS	Plant Monitoring System
	PN	Class 1E 120V AC Instrument Power system
	PORV	Power Operated Relief Valve
	PPCS	Pressurizer Pressure Control System
	PPS	Plant Protection System
	PRA	Probabilistic Risk Assessment
	PSF	Performance Shaping Factor
	PSRV	Primary Safety Relief Valve
	PSV	Pressurizer Safety Valve
	PTRR	Post Trip Review Report
	PTS	Pressurized Thermal Shock
	PV	Pressurizer Vent

PVNGS	Palo Verde Nuclear Generating Station
PW	Plant Cooling Water system
PWR	Pressurized Water Reactor
PZR	Pressurizer

Q

QO	Quick Open demand

R

RAS	Recirculation Actuation Signal
RC	Reactor Coolant system
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RDT	Reactor Drain Tank
RMWT	Reactor Makeup Water Tank
RO	Reactor Operator
RPCB	Reactor Power Cutback
RPCS	Reactor Power Cutback System
RPS	Reactor Protection System
RRS	Reactor Regulating System
RS	Responsible Supervisor
RSP	Remote Shutdown Panel
RSS	Reactor Safety Study
RTB	Reactor Trip Breaker
RV	Reactor Vessel
RWT	Refueling Water Tank

S

SA	Standard Addendum
SBCS	Steam Bypass Control System
SBO	Station Blackout
SC	Secondary Chemical Control system
SCN	Specification Change Notice
SCR	Silicon-Controlled Rectifier
SDC	Shutdown Cooling
SDCHX	Shutdown Cooling Heat Exchanger
SEAS	Safety Equipment Actuation System
SER	Safety Evaluation Report

SESS	Safety Equipment Status System
SETS	Set Equation Transformation System
SG	Main Steam system
SG	Steam Generator
SGBD	Steam Generator Blowdown
SGC	Steam Generator Cooling
SGTR	Steam Generator Tube Rupture
SHARP	Systematic Human Action Reliability Procedure
SI	Safety Injection system
SIAS	Safety Injection Actuation Signal
SIMS	Station Information Management System
SIT	Safety Injection Tank
SLB	Steam Line Break
SORV	Solenoid Operated Relief Valve
SOV	Solenoid Operated Valve
SP	Essential Spray Pond system
SPS	Supplementary Protection System
SRO	Senior Reactor Operator
SRP	Standard Review Plan
SS	Shift Supervisor
SSE	Safe Shutdown Earthquake
STA	Shift Technical Advisor
STC	Source Term Category
STCP	Source Term Code Package

T

TBV	Turbine Bypass Valve
TC	Turbine Cooling Water
TEMAC	Top Event Matrix Analysis Code
TDS	Total Dissolved Solids
TLI	Turbine Load Index
TMI	Three Mile Island
T/S	Technical Specification
TSCCR	Technical Specification Component Condition Record

U

UCB	Upper Confidence Bound

UCHB	Unconditional Hydrogen Burn
UDE	Undeveloped Event
UFSAR	Updated Final Safety Analysis Report
UGS	Upper Guide Structure
USNRC	U.S. Nuclear Regulatory Commission
USI	Unresolved Safety Issue

V

VCT	Volume Control Tank
VOPT	Variable Over-Power Trip

W

WC	Normal Chilled Water
WO	Work Order
WR	Wide Range

SECTION 1 Introduction

This document reports the results of the Probabilistic Risk Assessment (PRA) study performed by Arizona Public Service (APS) for the Palo Verde Nuclear Generating Station (PVNGS). The purpose of the PRA was threefold: (1) to develop a team of APS engineers who can use the PRA expertise to support continued safe operation of PVNGS, (2) to provide a living plant model for use by APS engineers to evaluate issues related to plant safety, configuration and compliance, and (3) to meet the U. S. Nuclear Regulatory Commission (NRC) requirements for an Individual Plant Examination (IPE) as outlined in Generic Letter (GL) 88-20 (NRC, 1988) and Supplement No. 1.

The study was performed by a project team consisting of personnel from APS, Halliburton NUS Corporation, and Bechtel Power Company at the APS offices. APS personnel performed over seventy percent of the tasks.

The PVNGS PRA is a full scope Level 2 PRA without the evaluation of external events. Internal Flooding was evaluated as a part of this study to fulfill the requirements of GL 88-20. NUREG-2300, "PRA Procedures Guide" was used as guidance in developing the PRA. While the detailed scope can be appreciated only from the detailed discussion included in later Sections; the scope of this study can be summarized as follows:

1. Analysis of a full complement of internal initiating events, including support system failures and internal flooding. Both Generic and plant-specific initiators have been considered. Fault tree models were developed and quantified for certain support systems initiators. IDCOR IPEM screening process was used for the internal flooding evaluation.

2. Plant-specific event tree and fault tree models of the mitigating systems needed to maintain Critical Safety Functions were developed.

3. A plant-specific Containment Event Tree (CET) was developed and quantified. Input to the CET was based on the plant-specific Modular Accident Analysis Program (MAAP), computer simulation results and NUREG-1150. Ultimate containment failure pressure, failure mode, and location were determined using two-dimensional ANSIS program simulation.

4. Plant-specific failure data was used for critical components such as Auxiliary Feedwater pumps and Emergency Diesel Generators. Bayesian updates were performed for these components. Generic failure data were used for the other components.

5. Plant-specific maintenance unavailabilities were used for safety-related pumps, motor-operated valves and 4160V breakers. Operational data between 1988 and 1989 were used for this purpose. Generic maintenance unavailabilities were used for the other components.

6. Core damage accident sequences and Plant Damage States were quantified using SETS program. The dominant cutsets were processed and analyzed using the CAFTA code. Containment Event Tree was quantified using NUCAP+ computer program to produce source term frequencies. The MAAP code was used to determine source term characteristics for the dominant source term bins.

7. Realistic assessments were made of the recovery actions that might be taken to prevent loss of Critical Safety Functions which leads to severe core damage.

8. Assessment of sensitivity and uncertainty. Sensitivity evaluation included equipment failures, human errors, and on-line maintenance effects. Uncertainties were propagated for dominant cutsets using TEMAC computer program.

Two significant scenarios identified were determined by APS to be of major significance and immediate actions were taken to minimize the likelihood of these accident initiators and the consequences. The scenarios deal with loss of Class 1E DC power and were significant because of resulting multiple dependent failures. Compensatory measures were developed and implemented prior to installation of permanent design changes. The design changes are discussed in Sections 2 and 9 of this report. Once the expedited design changes were finalized, the Level 1 Core Damage model was revised and re-quantified. A factor of 10 reduction in Core Damage Frequency (CDF) was achieved with these modifications (from 1.0E-3 to 9.0E-5 per reactor year). Total modification cost per unit is about $333,000.

This report presents the post-modification analysis.

Submittal of this report fulfills the reporting requirements of GL 88-20. Development and application of PRA for PVNGS to date have demonstrated that PRA is an effective tool to support management decision making. Continued usage in the future is expected.

SECTION 2

Summary of Results and Conclusions

Generic Letter 88-20, issued November 23, 1988, requested nuclear utilities to perform an Individual Plant Examination to identify severe accident vulnerabilities to satisfy the following objectives:

a) Develop an appreciation of severe accident behavior

b) Understand the most likely severe accident sequences that could occur

c) Gain a more quantitative understanding of the overall probabilities of core damage and fission product releases

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

Satisfying these objectives is expected to help achieve the goals of the Nuclear Regulatory Commission (NRC) Safety Goal Policy Statement.

It is the NRC's expectation that utility staff would participate to the maximum extent possible in the examination, as well as an independent in-house review of the PRA process and the results, in order to gain the greatest benefit from the analysis.

Arizona Public Service Company (APS) engineering and operations staff have been involved in all phases of the Probabilistic Risk Assessment (PRA) process. The PRA Model was developed and quantified principally by utility staff with minimal contractor support. Contractor support was utilized to provide guidance in applying the PRA methodology, plant damage state determination, and Containment performance analysis. Technology transfer to the utility Reliability and Risk Assessment Group staff has occurred wherever contractor support was used.

APS started the PRA Model for the Palo Verde Nuclear Generating Station (PVNGS) in 1986, well before any requirement was issued by the NRC, for use as a tool in assessing risk-related issues. The Reliability and Risk Assessment Group has grown from three engineers to nine, including two who have held Senior Operator licenses from the NRC. Over the last six years, PRA has been used at Palo Verde for a number of applications, including:

a) Evaluating and prioritizing design changes

b) Evaluating compliance issues, including Justifications for Continued Operation and Technical Specification waivers of compliance

c) Identifying important safety systems to enhance their reliability through risk-based preventive maintenance and setting safety system performance goals

d) Supporting upgrade of Emergency Operating Procedures

e) Supporting Emergency Planning in scenario development and emergency response

f) Performing qualitative shutdown risk evaluations.

Several future applications of risk analysis are planned:

a) Expand the scope of shutdown risk evaluations from the current qualitative approach to one more comprehensive, incorporating lessons learned from part outages and expected NRC-developed insights

b) Support Quality Assurance risk-focused inspection program development

c) Provide risk insights to licensed operator training

d) Fulfill requirements of Generic Letter 88-20, Supplement 4, IPE for External Events.

The PRA Model has been fully integrated into day-to-day operation of PVNGS and will continue to be an important factor in decision-making.

A preliminary result from the PRA Model analysis was obtained in mid-1990. It showed an annual Core Damage Frequency (CDF) of approximately 1.0E-3 per reactor-year. Two transient initiators were responsible for over 70% of the total CDF, namely Loss of HVAC (space cooling) to the Train A DC equipment rooms, which contain Class 1E battery chargers, DC power distribution equipment, vital AC inverters, and distribution panels; and Loss of Class 1E Channel A DC Power. No other single initiator contributed more that 6% to total CDF. Through an iteration process with design engineering, four cost-effective plant modifications were conceived, which would not only greatly reduce the importance of those initiating events, but also enhance the plant's ability to supply feedwater to the steam generators. Section 9.3 discuses the plant modifications in detail. Briefly, the changes are:

1. Change the source of power for the Main Steam and Feedwater Isolation Valve Logic Cabinets
2. Change the loss of power failure mode of the Train A Steam Generator Downcomer Containment Isolation Valves to fail-open
3. Provide a backup source of control power for the Train N auxiliary feedwater pump circuit breaker
4. Install temperature detectors in the DC Equipment Rooms, with an alarm in the Control Room.

Change 4 has been installed on all three Palo Verde units. All four changes will have been installed in Unit 1 by the end of its Spring 1992 refueling outage. The three remaining changes will be installed in Unit 3 by the end of its third refueling outage (Fall 1992). Unit 2 has received three of the four changes. Change 3 will be installed during the next refueling outage (Spring 1993).

The PRA Model has been updated to include the four plant changes. Other model refinements were also made at the same time. Re-quantification was completed in February 1992. Total CDF for internal events is now 9.0E-5 per reactor year, a 91% reduction.

Relative contribution to total CDF from the various initiating events is now much more evenly distributed (See Figure 9.1-1). No single initiator accounts for more than 21% of total CDF. Station Blackout is the single largest contributor at 21%, followed by Loss of Off-Site Power and Miscellaneous Reactor Trips at 18% each, Loss of Turbine or Plant Cooling Water (non-class component and service water) at 8%, and Loss of Instrument Air at 6%. Other initiators were less than 5% each, including Small Loss of Coolant Accidents, Anticipated Transients Without Scram, and Steam Generator Tube Rupture. Station Blackout, although very unlikely, is an important risk contributor due to its severe impact on the plant's ability to remove decay heat and to maintain seal injection and/or cooling to the reactor coolant pump (RCP) shaft seals to prevent loss of coolant. Loss of Off-site Power is considerably more likely than Station Blackout, but has a lesser impact on options available for decay heat removal and for maintaining RCP seal injection/cooling. These two important risk contributors will be reduced substantially by the installation of two gas-turbine generators on-site. This Alternate AC Power supply is to be installed to satisfy the NRC's Station Blackout coping rules. Although the alternate AC power source has not been incorporated into the PRA model, it was credited in the sensitivity analysis for Unresolved Safety Issue A-45, Decay Heat Removal.

Miscellaneous Reactor Trip, by definition, has no impact on the plant's ability to mitigate the resulting transient. However, it is still an important risk contributor because of its high frequency. PVNGS has an aggressive trip reduction program. Its purpose is to identify components whose failure could lead to reactor trip, as well as personnel practices that might result in a reactor trip, and to implement appropriate changes to procedures or the physical plant. This same program should also reduce the likelihood of a trip due to several other initiators, such as Turbine Trip, Loss of Turbine or Plant Cooling Water, Loss of Instrument Air and Loss of Nuclear Cooling Water. Loss of these non-safety related systems impacts the plant's ability to mitigate the resulting transient by making unavailable certain normally operating equipment, thereby placing higher dependence on the standby safety systems. For example, loss of Nuclear Cooling Water or Instrument Air causes loss of normal heating, ventilating and air conditioning (HVAC), which would otherwise continue to provide cooling to the Control Room and ESF switchgear and DC equipment rooms.

Internal flooding at PVNGS was evaluated using a screening approach described in Appendix D of the IDCOR Technical Report (Reference 9.4.1). No vulnerabilities due to internal flooding were identified.

Two Unresolved Safety Issues (USI) are addressed in this report: A-17, System Interactions, and A-45, Decay Heat Removal.

USI A-17 was resolved in Generic Letter 89-18 by referring the internal flooding issue to IPE. This issue has been addressed in Section 13.2. It was concluded that no vulnerabilities exist in that area.

USI A-45 is addressed in Section 13.1. It was concluded that no vulnerabilities exist at PVNGS. The addition of Pressurizer Power Operated Relief Valves (PORVs) to PVNGS cannot be justified from a risk reduction perspective given installation of the gas turbine generators.

The Palo Verde Containment Building and associated equipment are robust with respect to the challenge presented by severe accidents. An independent Containment structural calculation was performed and reveals that the median failure pressure of the Palo Verde Containment is 169 psig. Because of the high assessed strength of the Palo Verde Containment and the reliability of the ESFs, Level 2 results show that radioactive source terms for 72% of core melt sequences are retained in Containment. Early Containment failure (10%), late Containment failure (8%), Containment basemat melt-through (6%), and Containment bypass (4%) result from the remaining accident sequences (see Figure 11.7-2). The dominant contributor to early Containment failure is slow over-pressurization due to a LOCA with loss of Containment heat removal capability during Containment sump recirculation.

The major contributor to large radionuclide release at PVNGS results from Containment bypass sequences, particularly SGTRs. For non-bypass sequences, early release source term is smaller. This can be attributed to reactor cavity configuration, and availability of sprays for scrubbing.

APS will continue to evaluate Accident Management Strategies to further reduce the probability of the most likely Containment failures.

The IPE at PVNGS identified several design improvements, which significantly improve the calculated core damage risk. This was primarily due to unexpected intersystem dependencies, which were not precluded during the design and construction of the facility. With the improvements implemented, good train separation, highly compartmentalized spaces, a highly reliable electrical transmission system in the Southwestern United States, and having dedicated, standby ESF systems all contribute to the overall level of safety at PVNGS.

In conclusion, no vulnerabilities to core damage, nor to Containment effectiveness now exist at Palo Verde. Consistent with NUMARC's severe accident closure guidelines for accident sequences whose CDF is greater than 1E-4 per reactor year, cost-effective plant changes were developed, which accomplished an order of magnitude reduction in the calculated CDF. Additional planned improvements, continued vigilance in trip reduction efforts, and use of the PRA model to support decision making will contribute to an even greater level of safety in the future.

2.1 References

2.1.1 USNRC, Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities - 10 CFR 50.54(f)", November 23, 1988

2.1.2 USNRC, Generic Letter 88-20, Supplement No. 1, "Individual Plant Examination for Severe Accident Vulnerabilities - 10 CFR 50.54(f)", August 29, 1989

2.1.3 USNRC, NUREG-1335, "Individual Plant Examination: Submittal Guidance", August, 1989

2.1.4 APS to USNRC, Letter ID No. 161-02550-WFC/RAB/GAM, Palo Verde Nuclear Generating Station Units 1, 2, and 3 Proposed Program for Completion of IPE", October 30, 1989.

SECTION 3

Plant and Site Description

3.1 Introduction

The Palo Verde Nuclear Generating Station (PVNGS) is comprised of three virtually identical nuclear units, each a Combustion Engineering System 80™ (C-E System 80™) Pressurized Water Reactor (PWR) Nuclear Steam Supply System (NSSS) design. Palo Verde 1 (typical of the three units), as shown in Figure 3.1-1, includes Reactor Containment, Turbine, Auxiliary, Fuel, Radwaste, Control/Corridor, Diesel Generator and Operations Support buildings (a Radioactive Waste Laundry facility is included only in Unit 1). PVNGS plant systems and components are primarily remotely operated from the Main Control Room, located at the 140-foot elevation of the Control Building. In the event of Control Room uninhabitability, plant shutdown may be accomplished/monitored from the Remote Shutdown Panels (RSPs), located at the 100-foot elevation of the Control Building.

Operating at full power, each unit produces 3817 MWt, for a nominal net output of 1270 MWe. The NSSS was designed and manufactured by Combustion Engineering, while the turbine-generator was manufactured by General Electric Company. The engineering and construction of PVNGS was contracted to Bechtel Power Corporation in 1973. PVNGS Units 1, 2, and 3 were declared commercial on January 28, 1986, September 19, 1986, and January 8, 1988, respectively.

3.2 General Plant Site Description

PVNGS is located in Maricopa County in mid-southwestern Arizona. The site is approximately 34 miles west of the nearest boundary of the City of Phoenix. PVNGS is located in a very sparsely populated area; the closest population center of more than 25,000 is Sun City, Arizona, which is located approximately 34 miles east/northeast of the PVNGS site.

Buckeye Salome Road is located to the north of the site and runs northwest to southeast. Wintersburg Road, a paved county road, runs north to south along the west site boundary. A Southern Pacific Railroad line runs southeast to northwest, five miles south of the power plant complex.

3.2.1 Plant Surroundings

Topographical and meteorological characteristics of the site play an important role in determining consequential release of radioactive materials. Atmospheric and topographical conditions affect dispersion, transport, and diffusion of radioactive particulates. These factors ultimately affect human exposure rates.

PVNGS is located six miles west of the Gila River and Salt River base. The general site surrounding area consists of a broad desert basin, surrounded by a series of intermittent hills (buttes). Relief of the Palo Verde Hills is relatively low (250-foot maximum). The basin area elevation averages about 950-foot, and adjacent hills rise to about 1200-foot elevation. The hills located about five miles northwest of the site area are the most rugged in the vicinity, and the highest ridges reach approximately the 2100-foot elevation. The basin floor slopes very gently (28-feet per mile) to the south. The basin floor is intersected by a number of ephemeral stream channels that converge and flow toward the Gila River, located about ten miles to the south.

3.3 General Plant Description

3.3.1 Reactor and Reactor Coolant System

The C-E System 80™ NSSS design is shown, in simplified form, in Figure 3.3-1. The C-E design contains two independent primary coolant loops. Each Reactor Coolant System (RCS) loop consists of a 42-inch ID reactor vessel outlet (hot-leg) pipe, a U-tube Steam Generator (SG), two Reactor Coolant Pumps (RCPs), and two 30-inch ID reactor vessel inlet (cold-leg) pipes. The RCS contains no loop isolation valves. An electrically-heated pressurizer, provided with four code safety valves, is connected to primary loop one hot-leg. The Shutdown Cooling System (SDC) takes suction from each of the two RCS hot-legs, and injects water into the four RCS cold-legs. Per RCS Design Criteria, the arrangement of the RCS must provide sufficient natural circulation (approximately 2% of normal full-power flow) to permit residual heat removal following a complete loss of flow (from maximum power) as a result of a Station Blackout (SBO) event. This criteria precludes the possibility of exceeding fuel design limits, system design pressures, and system design temperatures.

The NSSS primary system is enclosed within a single Containment system (large, dry PWR type), consisting of a steel-lined, post-tensioned concrete cylindrical structure with a hemispherical dome. Secondary system lines penetrate the Containment building at the Main Steam Support Structure (MSSS) building wall. SDC, Safety Injection (SI) System, and primary Chemical and Volume Control System (CVCS) lines penetrate the Containment building at the Auxiliary Building wall. A detailed description of the Containment structure (including reactor cavity characteristics) is contained in Section 11.1.

The reactor core is fueled with sintered uranium dioxide (UO_2) pellets, enclosed within zircaloy tubes. The tubes (fuel pins) are fabricated into 16 x 16 array fuel assemblies. Stainless steel fuel assembly end-fittings limit axial motion of the fuel pins, and internal fuel spacer grids limit lateral motion of the tubes.

The Control Element Assemblies (CEAs) consist of NiCrFe alloy clad boron-carbide (B_4C) absorber rods. The CEAs are guided by tubes located within the fuel assemblies. The reactor core contains 89 CEAs. The two shutdown control CEA groups and five regulating control CEA groups are composed of 48 full-length, 12-fingered assemblies, and 28 full-length, four-fingered assemblies. The two power shaping CEA groups are composed of 13 part-length, four-fingered assemblies.

The reactor core provides a thermal output of 3800 MWt, resulting in an NSSS total thermal output of 3817 MWt (approximately 17 MWt is attributed to RCP operation).

The principal design bases for the reactor internals are to provide reactor vertical support and horizontal restraint during all normal operating, upset, and faulted conditions. The reactor vessel is a carbon-molybdenum pressure vessel, lined with 1/8-inch stainless steel. Reactor Vessel Internal Structures (shown in Figure 3.3-2) include the core support barrel, the core shroud, the Upper Guide Structure (UGS) assembly, the Lower Support Structure (LSS), and the In-Core Instrumentation (ICI) nozzle assembly. The core support barrel is a right circular cylinder supported from above by a ring flange which is suspended from a ledge on the reactor vessel wall. The ring flange transfers the entire weight of the core to the core support barrel. The core shroud surrounds the sides of the core, minimizing the amount of coolant bypass flow (limited to 3% core total flow). The UGS consists of two sub-assemblies, the UGS Support Barrel sub-assembly and the CEA Shroud sub-assembly, which are joined together by tie-rods. The UGS assembly provides a flow shroud for the CEAs, and limits upward motion of the fuel assemblies during pressure transients. The LSS consists of a welded grid structure, which is suspended from the bottom of the core support barrel. This assembly directs coolant flow through the reactor core, provides for fuel assembly alignment, and provides a guide-path for the ICIs.

Four electric, motor-driven, single-stage, centrifugal pumps circulate coolant through the primary system. Reactor coolant (at approximately 564.5° F and 2250 psia) enters near the mid-plane of the reactor vessel, above the active core region. It then flows downward between the reactor vessel and the core support barrel. Coolant flows upward through the core (average core exit coolant temperature is 624° F), and exits the reactor vessel (at approximately 621° F). The discharged coolant then proceeds to the SGs.

The two SGs receive heat, which is generated by the reactor core, and carried by the primary coolant. The SGs transfer heat from the primary to the secondary side, producing steam, which drives the turbine-generator. Each SG is a vertical, inverted, U-tube heat exchanger with an integral economizer. The SGs operate with primary coolant on the tube side, and secondary coolant on the shell side. Each SG is provided with feedwater from the Main Feedwater (FW) system. Upon loss of FW (the PRA conservatively assumes that this occurs at a maximum of 30 minutes post-trip), SG makeup is provided by the Auxiliary Feedwater (AF) system.

Each SG is designed to transfer heat from the RCS to the secondary system to produce saturated steam. Hot reactor coolant from the reactor vessel enters the SG through the inlet nozzle in the primary head. From here, it flows through the U-tubes, where it transfers heat to the secondary coolant, and then flows to the outlet side of the primary head. The flow then discharges through two primary head outlet nozzles.

After passing through the turbine, condensate is collected in the Main Condenser. The Circulating Water (CW) system transfers heat from the condensate to atmosphere via the cooling towers.

3.3.2 Plant Systems

The following sections provide a brief description of PVNGS systems modeled in the PRA. A summary of plant safety systems and related safety functions is provided in Table 3.3-1. A complete system dependency matrix is provided in Section 5. Complete system descriptions, including associated assumptions and system modeling methodology for each one shown, are included in Section 5.2.

3.3.2.1 Safety Systems

Engineered Safety Features (ESF) function in the event of a transient or accident to prevent a fission product release. These safeguards localize, mitigate, and terminate such accidents to maintain exposure levels below 10CFR100 criteria.

The SI system includes two 100% capacity trains each of High Pressure Safety Injection (HPSI), Low Pressure Safety Injection (LPSI), and SDC heat exchangers (SDCHX), as well as associated valves and instrumentation. This system also includes four Safety Injection Tanks (SITs), one on each RCS cold-leg.

In the event of a LOCA and certain other transient events, self-cooled SI pumps inject borated water into the RCS. As the HPSI system shut-off head (1800 psig) is lower than normal RCS operating pressure (2250 psia), HPSI injection will only occur after primary system pressure is reduced below HPSI shut-off head.

The SI system provides cooling to limit core damage and fission product release while maintaining adequate shutdown margin. The SI system also provides continuous, long-term, post-accident core cooling by recirculating borated water from the containment sump. The HPSI and LPSI pumps are contained in separate cubicles located at the 40-foot elevation of the Auxiliary Building. The HPSI, and LPSI systems share suction headers from the Refueling Water Tank (RWT) in the CVCS, suction lines from the containment sump, and RCS injection lines.

The Containment Spray System (CSS) includes two 100% capacity trains, which use the RWT, the containment sump, two self-cooled pumps (located at the 40-foot elevation of the Auxiliary Building), two heat exchangers (located at the 70-foot elevation of the Auxiliary Building), and two independent containment spray headers. The spray nozzles disperse coolant into the containment atmosphere. When the coolant spray reaches the containment floor, it drains to the containment sump where it remains until the recirculation mode begins.

The containment hydrogen control system, although not designed for severe accident hydrogen control, is used to prevent the concentration of hydrogen in the containment from reaching 4% (by volume) following a Design Basis LOCA. The system is comprised of two 100% capacity, independent, parallel loops. Each loop contains a hydrogen recombiner capable of maintaining the containment hydrogen concentration below 3.5% (by volume), assuming design basis cladding oxidation. The hydrogen purge sub-system serves as backup to the hydrogen recombiners.

The AF system maintains water in the SGs during emergency operations when the FW system is unavailable. The self-cooled AF pumps also provide feedwater during plant start-up, normal shutdown, and hot standby modes. The major AF components include one class-powered, Seismic Category I, motor-driven pump, one class-powered, Seismic Category I, turbine-driven pump, and one non-class-powered, non-Seismic Category I, motor-driven pump. Steam supply to the turbine-driven pump is provided from two main steam connections upstream of the Main Steam Isolation Valves (MSIVs). The two class pumps are located in separate compartments at the 70-foot elevation of the MSSS, while the non-class pump is located at the 100-foot elevation of the Turbine Building.

The steam relief systems, associated with the four main steam lines (two per SG), include eight Turbine Bypass Valves (TBVs), two Atmospheric Dump Valves (ADVs) per SG (a total of four ADVs), and ten Main Steam Safety Valves (MSSVs) per SG (a total of 20 MSSVs). The TBVs, located downstream of the MSIVs, provide the preferred means of removing secondary steam. These valves are operated automatically by the Steam Bypass Control System (SBCS) to prevent lifting of the secondary safety valves following a turbine trip. The TBVs may also be manually-operated from the control room. Six of the TBVs discharge to the Main Condenser, and will not open to inadequate condenser vacuum. The two remaining TBVs relieve directly to atmosphere outside the Turbine Building. If the TBVs or the Main Condenser are unavailable, secondary steam may be removed via remote-manual operation of the ADVs from the Control Room (although the ADVs are provided with block isolation valves, no credit was taken for isolation on ADV failure-to-close). The MSSVs will relieve secondary steam pressure in the unlikely event that the TBVs and the ADVs are simultaneously unavailable. The MSSVs open automatically when secondary system pressure reaches the MSSV setpoint; however, with both the TBVs and the ADVs unavailable, it is not possible to bring the plant to SDC entry conditions.

3.3.2.2 Support Systems

The Essential Chilled Water (EC) system consists of two redundant, independent, 100% capacity, closed-loop systems. The EC system supplies chilled water to essential HVAC units, which cool certain areas within the Control, Auxiliary, and

MSSS buildings. Each EC system includes a chilled water refrigeration unit (chiller), a chilled water circulating pump, and associated valves, instrumentation, and piping.

The Essential Cooling Water (EW) system consists of two redundant, Seismic Category I trains. This system acts as a "buffer" between potentially contaminated components and the Essential Spray Pond (SP). The EW system supplies corrosion-inhibited cooling water to certain plant components required for normal plant operation, and for emergency shutdown. Following a Safety Injection Actuation Signal (SIAS), the EW system supplies cooling water to the SDCHXs and EC system chillers.

The SP system provides the plant "ultimate heat sink." The SP system is a Seismic Category I system, which includes two separate, independent, and redundant trains. Each SP train supplies cooling water to the associated EW heat exchanger, and to Diesel Generator jacket water, lube oil, fuel oil, and air intercoolers. The SP system is actuated each time an Emergency Diesel Generator (EDG) is started, and/or whenever EW operation is required. The SP system (both ponds operating together) can provide adequate cooling for 27 days, without requiring makeup water.

The charging system is a sub-system of the CVCS. Charging system flow is provided by three redundant, positive-displacement charging pumps. The pumps take suction from the Volume Control Tank (VCT) during normal operations or the RWT, via the Boric Acid Makeup (BAM) Pumps, on Lo-Lo VCT level. Charging suction flow may also be established via gravity-feed from the RWT upon subsequent loss of BAM pumps. This system supplies water to the RCP seal injection system, and controls RCP seal bleed-off. In addition, the charging pumps also supply water to the auxiliary pressurizer spray system, and supply borated water to the RCS during an Anticipated Transient Without SCRAM (ATWS) event.

The Instrument Air (IA) system consists of three, identical, parallel trains. Major components in each train include an intake filter, air compressor, aftercooler, and an air receiver. The IA system provides a continuous supply of filtered, dry, oil-free, compressed air for pneumatic instrument operation, and control of pneumatic valve/damper actuators. The Service Gas (GA) system provides short-term, low-pressure nitrogen backup to the IA system.

The Control Building HVAC (HJ) system provides room cooling to the 100-foot elevation of the Control Building, including the ESF switchgear, DC equipment, and battery rooms, to maintain operability of equipment contained in these rooms during normal and emergency conditions. The Control Building "normal" HVAC systems serve both ESF switchgear room divisions, while separate "essential" HVAC systems are provided for each of the divisions. In addition, the Class DC equipment room divisions are provided with separate "essential" HVAC units.

The Control Room HVAC system provides cooling to the 140-foot elevation of the Auxiliary Building, to maintain personnel occupancy conditions, and equipment operating conditions in the Control Room and habitability area during normal and emergency conditions. The Control Room HVAC system consists of a "normal"

Air Handling Unit (AHU), and two trains of 100%-capacity "essential" AHU. All Control Room AHUs are located at the 74-foot elevation of the Control Building. During certain plant emergencies, this system isolates the Control Room to prevent entry of smoke, gas, or contamination.

The ESF system AC electrical loads belong to one of two independent and redundant load groups. Each Class 1E power system consists of one 4.16kV AC bus, three 480V AC load centers, and four 480V AC Motor Control Centers (MCCs). Power to the Class 1E 4.16kV AC switchgear (PBA-S03 and PBB-S04) is normally provided directly from the preferred (off-site) power system. Thus, no dependency on Fast Bus Transfer (FBT) exists following a turbine-generator trip. Standby AC power is provided by two EDGs, each dedicated to a single load group.

Class 1E DC power is provided by four independent Class 1E 125V DC channels. Each channel consists of a battery charger, battery, and DC control center. The four Class battery channels are located in separate cubicles on the 100-foot elevation of the Control Building, while the Class DC equipment for each channel is located in a separate cubicle adjacent to its associated class battery room. Each DC channel also provides power to one channel of 120V AC vital instrument power via an inverter (also located in the associated Class 1E DC equipment room). Together, the Class 1E 125V DC, and the 120V AC power systems provide power to the Engineered Safety Features Actuation System (ESFAS) and the Reactor Protection System (RPS), along with vital instrument and control power, and selected DC motor loads. Non-vital DC is supplied by two non-class 1E 125V DC systems located in the non-class switchgear building adjacent to the 100-foot elevation of the Turbine Building. Non-vital AC instrument and control power is supplied by voltage regulators powered from non-class 1E MCCs.

3.3.2.3 Instrumentation and Control

Automatic protection and control systems are provided to assure safe plant operation. PVNGS consists of two systems:

1. the Plant Protection System (PPS) which contains the RPS and ESFAS
2. the Supplementary Protection System (SPS)

The RPS sub-system initiates a reactor trip (when the two out of four logic for trip setpoints is exceeded) when the reactor approaches prescribed safety limits. These include maximum Local Power Density (LPD) at 21 kW/ft, low Departure from Nucleate Boiling Ratio (DNBR) at 1.24, and pressurizer pressure at 2750 psia. Reactor trips include Variable Overpower Trip (VOPT), High Logarithmic Power Level Trip, High LPD, Low DNBR, High/Low Pressurizer Pressure, High/Low SG Level, Low SG Pressure, High Containment Pressure, and SG Low Flow (primary-side). When an RPS actuation setpoint is exceeded, power to the Control Element Drive Mechanisms (CEDMs) is interrupted, releasing the CEAs, which drop into the core to accomplish reactor shutdown. Sufficient redundancy is installed to permit removal of any one protection system channel from service without precluding protective action when required.

The Core Protection Calculators (CPCs) are designed to initiate a reactor trip signal to the RPS on low DNBR and high LPD to assure that the specified acceptable fuel design limits are not exceeded during Anticipated Operational Occurrences (AOOs). In addition, the CPCs initiate automatic reactor protective action during certain accident conditions to aid the ESFAS in limiting the consequences of the accident.

The SPS sub-system augments the RPS system by initiating independent reactor trip signals. The SPS provides a diverse method of tripping the reactor on high pressurizer pressure if the RPS fails to function. The SPS uses selective logic (two of four) to interrupt the CEDM power supply, causing the CEAs to drop into the core. The SPS provides a separate, diverse reactor trip system for ATWS pressure transient mitigation. Although SPS and RPS act on the same reactor trip breakers, the SPS uses separate contacts to de-energize the trip breaker undervoltage coils, and to energize the trip coils.

The ESFAS system operates to automatically actuate ESF systems. The ESFAS system is completely independent of plant control systems and, like RPS/SPS, uses two of four actuation logic. An ESFAS actuation occurs when an RCS, SG, RWT level, or containment parameter reaches a prescribed limit (actuation signals are discussed in greater detail in Section 5.2.2.20). Sufficient redundancy is installed to permit removing any one protection system channel from service without precluding protective action when required.

The reactor control systems are used for start-up and shutdown of the reactor, as well as for reactor power level adjustment in response to changes in turbine load demand. The reactor is controlled by a combination of CEA motion, and soluble boric acid contained in the RCS. Boric acid is used for reactivity control associated with large, gradual, changes in water temperature, xenon concentration, and fuel burn-up. Addition of boric acid also provides increased shutdown margin during refueling. CEA movement provides changes in reactivity for plant shutdown, or power changes. The CEAs are moved by the CEDMs, which are designed to permit rapid gravity-insertion of the CEAs into the core. The part-length CEAs allow core axial power distribution control, but are not credited in providing additional shutdown margin.

The pressure in the RCS is controlled by regulating coolant temperature within the pressurizer. The pressurizer steam bubble is controlled to minimize RCS volume variations caused by expansion and contraction of the reactor coolant due to system temperature fluctuations. The pressurizer steam bubble is regulated through controlled operation of pressurizer heaters, and pressurizer sprays. Overpressure protection for the pressurizer is provided by four Primary Safety Valves (PSVs), which relieve to the Reactor Drain Tank (RDT). Overpressure protection for the RDT is provided by a rupture disc, which relieves directly to the containment atmosphere.

The Steam Bypass Control System (SBCS) operates in conjunction with the Reactor Power Cutback System (RPCS) to permit continued low-power reactor operation (as opposed to reactor trip) when certain secondary-side events occur, i.e., main turbine load-rejection. In the event of a large and rapid decrease in steam flow from the SGs (symptomatic of a large turbine load-rejection event), the SBCS relieves steam pressure by dropping selected CEA groups into the core to rapidly reduce reactor power to approximately 35%.

The Plant Monitoring System (PMS) performs general monitoring of the NSSS, and Balance of Plant (BOP) conditions, including parameter logging, trending, and alarming. System temperatures, pressures, and flows are monitored to keep operating personnel aware of current operating conditions.

3.3.2.4 Power Conversion Systems

The rated NSSS power level is 3800 MWt (net reactor heat output) plus 17 MWt (net heat from non-reactive sources) for a total of 3817 MWt. The corresponding turbine-generator gross output is 1335 MWe (at 3.5-inches Hga back-pressure). The nominal net output of PVNGS is 1270 MWe per unit.

The main steam supply system delivers steam from the SGs to the high-pressure turbine and steam re-heaters. High pressure turbine exhaust is dried and reheated to supply approximately 200° F superheated steam to the three low-pressure turbines. Steam is extracted at various points for the feedwater heaters, main feedwater pump turbines, main steam re-heaters, and auxiliary steam header supply.

Steam from the low-pressure turbine exhausts to the Main Condenser where it is condensed and drops to the condenser hotwells. The Main Condenser also serves as a heat sink for the turbine bypass system.

Three condensate pumps take the deaerated condensate from the hotwells, and deliver it through the low-pressure feedwater heaters to the feedwater pumps. The heater drain pumps also discharge to the suction of the feedwater pumps. The feedwater pumps discharge the total feedwater flow through the high-pressure feedwater heaters, and back to the SGs.

The Condensate Storage and Transfer (CT) system maintains the required capacity for the AF system, as well as providing backup makeup water for the Diesel Generator jacket cooling, EW, and EC systems. The CT system consists of a Condensate Storage Tank (CST), two condensate transfer pumps, and the necessary controls and instrumentation. The CST is also used as a surge tank for the Condensate system.

3.3.2.5 Auxiliary Systems

The Shutdown Cooling (SDC) system is used to reduce reactor coolant temperature (at a controlled rate) from 350° F to a refueling temperature of approximately 135° F. During refueling, the SDC system maintains proper RCS temperature. This system uses the LPSI pumps or containment spray pumps, taking suction from the two RCS hot-legs. The SDC system circulates the reactor coolant through two Shutdown Cooling Heat Exchangers (SDCHXs). The coolant then discharges to the RCS cold-legs via the four low-pressure injection headers.

The CVCS system controls the purity, volume, and boric acid concentration of the RCS. Coolant is extracted from the RCS via the letdown line connection to RCS loop-2B. The letdown fluid is cooled on the tube-side of the Regenerative Heat Exchanger. The fluid then flows to the Letdown Heat Exchanger (LDHX), and then proceeds through a filter and ion-exchanger network. Corrosion and fission products are removed, and the coolant is sprayed into the VCT. It is then returned, via the Charging Pumps, to the shell-side of the Regenerative Heat Exchanger, and discharges to RCS loop-2A. In response to Pressurizer Level Control System

(PLCS) demand, the CVCS automatically adjusts letdown and charging flow to maintain a pre-set liquid level in the pressurizer.

The CVCS controls the primary coolant boric acid concentration via feed and bleed. During normal operation, water from the RWT is automatically blended with pure water to provide the desired boron concentration. If required, highly borated water (2.5 weight-percent Boric Acid) may be aligned directly from the RWT to the charging pump suction to allow negative reactivity insertion.

The Secondary Chemical Control (SC) system continuously monitors and injects chemicals into the feedwater to minimize corrosion in the SGs and in the condensate and feedwater systems.

The Steam Generator Blowdown (SGBD) system is a sub-system of the SC system. The SGBD system consists of one hot-leg and one cold-leg blowdown nozzle provided for each SG, and a Blowdown Flash Tank (at the 140-foot elevation of the Turbine Building), and associated processing equipment. The SGBD system compensates for the concentrating effect of the SGs through continuous normal-rate blowdown, processing, and re-use of a portion of the secondary fluid from each SG. The SGBD system can also be used during a Steam Generator Tube Rupture (SGTR) to aid in removing contaminated secondary water.

The Nuclear Sampling system is designed to collect RCS and auxiliary system samples for analysis. System configuration permits sampling during reactor operation without requiring containment access.

The Plant Cooling Water (PW) system removes heat from the Nuclear Cooling Water (NC), Turbine Cooling Water (TC), and Condenser Air Removal (AR) systems. PW system heat is rejected to atmosphere via the cooling towers.

The TC system provides treated, demineralized cooling water to components in the steam plant. It also acts as an intermediate system between secondary system components and the PW system.

The NC system is another closed-loop heat transport system. It includes two 100% capacity pumps and heat exchangers. The NC system provides an adequate supply of cooling water to the non-safety-related primary plant components. These include the LDHX, the RCPs, the fuel pool cooling heat exchangers, the CEDM air coolers, and the nuclear sample coolers. In addition, the NC system supplies the WC system chillers, the Radwaste Evaporator, the Boric Acid Concentrator (BAC), and the waste gas compressors.

The Spent Fuel Pool Cooling and Cleanup (PC) system maintains forced cooling of the pool water as required under normal and emergency operating conditions by circulating fuel pool water through one of two PC system heat exchangers. The PC heat exchangers are normally cooled by the NC system. Backup cooling to the PC heat exchanger is provided by the EW system via a NC to EW system cross-tie. This cross-tie provides cooling for the PC heat exchanger when the NC system is unavailable. A purification loop is used to maintain the purity and clarity of water in the fuel transfer canal, spent fuel pool, and refueling pool.

The non-class 1E electrical distribution system is divided into two load groups. During power operation, station auxiliary power is supplied from the auxiliary transformer at 13.8kV, stepped down from the 24kV turbine-generator output voltage. When the generator is not on-line, station auxiliary power is supplied from two of three start-up transformers near the main switchyard. The start-up transformers receive power from the 525kV switchyard, and are also the source of off-site power to the Class 1E electrical distribution system. Within the plant, power is distributed to loads from 13.8kV switchgear, 4.16kV switchgear, several 480V load centers, and MCCs.

The Fire Protection (FP) system is a site-wide system consisting of two fire protection/well water storage tanks, one electric-driven pump, two diesel engine-driven pumps, one jockey pump (to maintain system pressure), a yard-loop distribution header system, associated valves, and hose stations. The FP system includes automatic CO_2 flooding capability for the ESF switchgear rooms, the class battery rooms, and the class DC equipment rooms. CO_2 hose-reel stations are provided for non-class switchgear building fire protection. An automatic Halon flooding system provides fire protection for the Control Building computer, communications, and inverter rooms.

The Demineralized Water (DW) system (also site-wide) furnishes demineralized water to each nuclear unit. Water from the reverse-osmosis subsystem of the Domestic Water (DS) system is used to supply makeup to the DW system. The DW demineralizer consists of three mixed-bed units. The CST, DW Storage Tank, and Reactor Makeup Water Tank (RMWT) for each unit maintain the required demineralized water inventory.

The site-wide DS system supplies necessary potable water to each unit for consumptive use by plant personnel and other general plant usage.

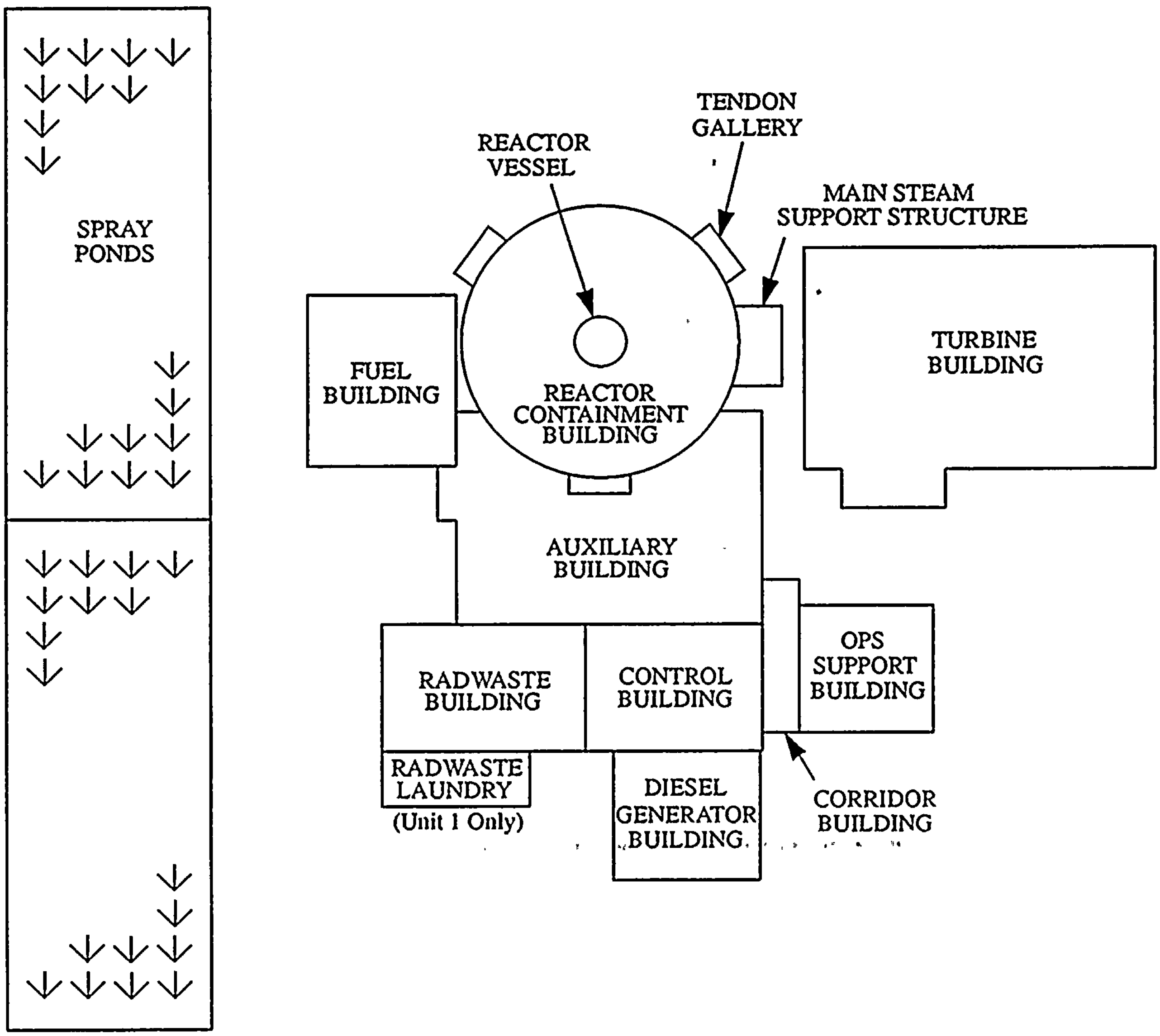

Figure 3.1-1

Palo Verde Unit 1 - Plant Layout

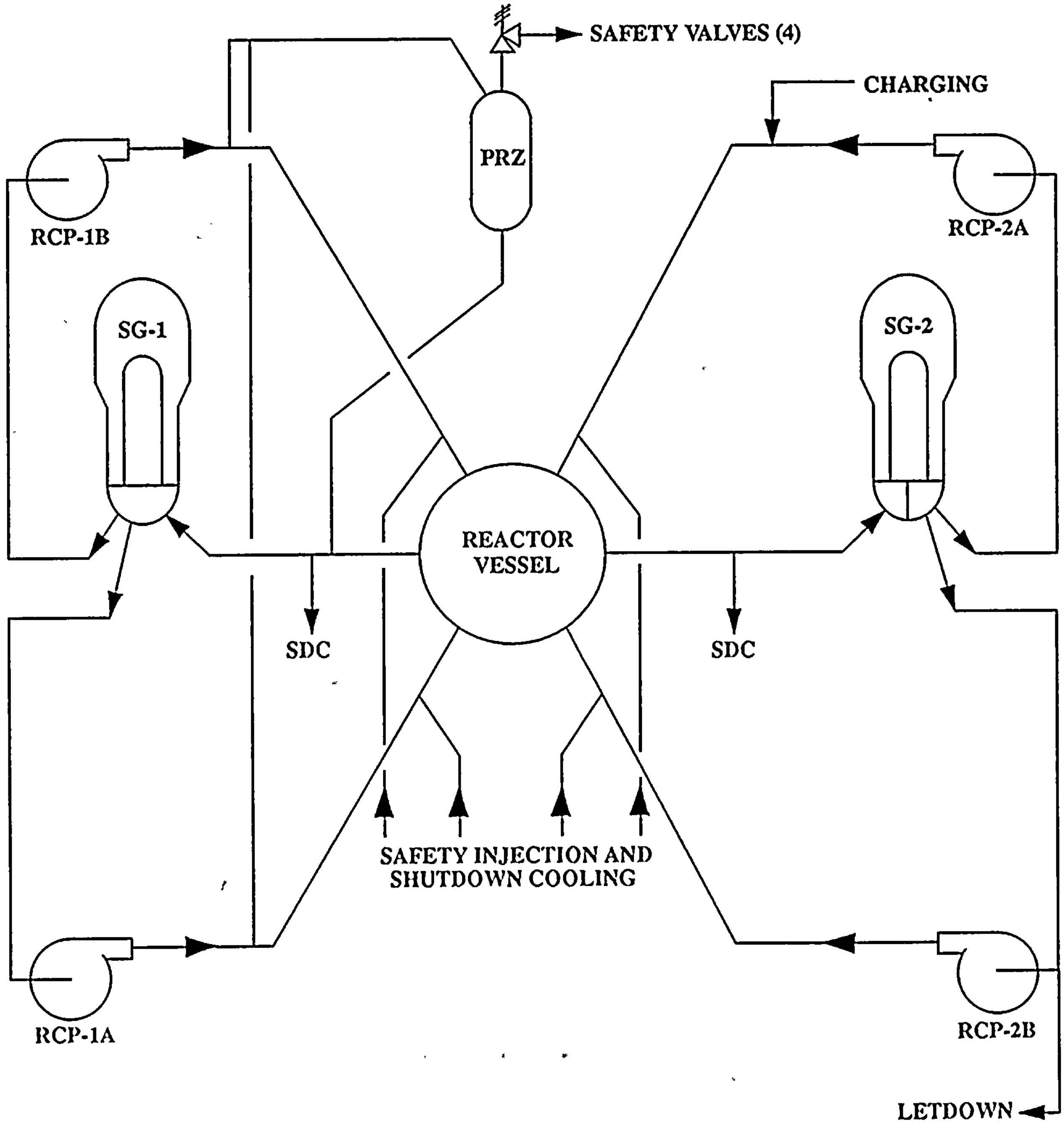

Figure 3.3-1

C-E System 80™ NSSS

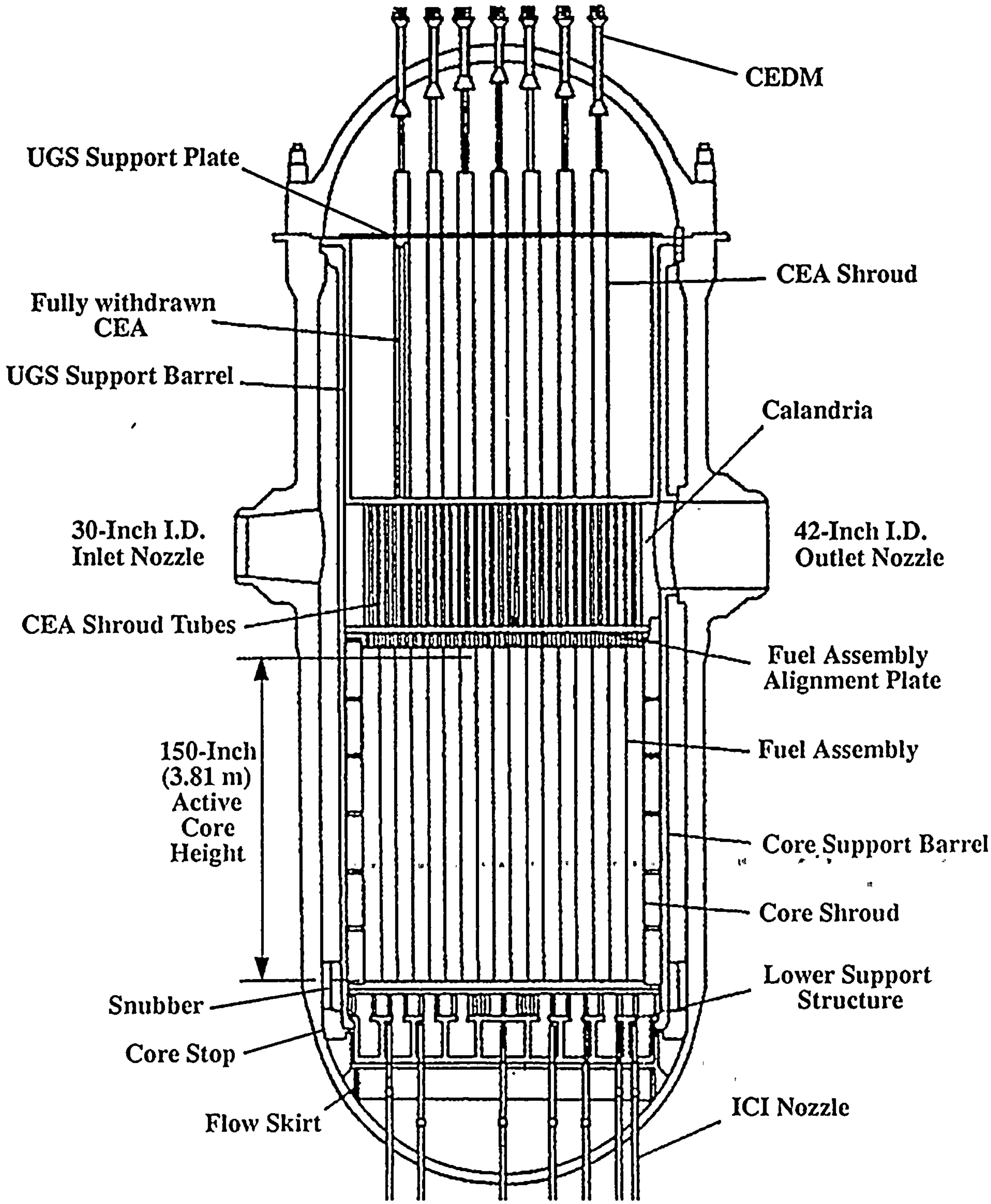

Figure 3.3-2

C-E System 80™ Reactor Vessel Internal Structures

Table 3.3-1 Front-line Systems Vs. Critical Safety Functions

Critical Safety Function	RC	HPSI	LPSI	CSS	RPS/ SPS	AF	AltFW	ADV/ TBV	CVCS	SIT	SDC
Reactivity Control		X	X		X				X	X	
RCS Over-pressure Control	X				X			X			
RCS Inventory Control		X	X						X	X	
Decay Heat Removal	X	X	X	X		X	X	X			X
Containment Temp Control				X							
Containment Pressure Control				X							

SECTION 4

Event-Tree Development

Accident sequences are developed using an event-tree procedure that considers both initiating events and the success or failure of the relevant systems in succession. Each accident sequence contains an initiating event and the subsequent failure of one or more safety systems.

The PVNGS Probabilistic Risk Assessment (PRA) approach to detailing the accident sequences is to have different tiers of fault trees. These fault trees are linked to each other, thus creating a complete model of the plant. Fault trees can be identified as one of three types: a support system fault tree, a front-line system fault tree, or a top logic fault tree. The linked model would be configured as such: at the top of the model would be found the top logic trees linked to front-line system fault trees, which are in turn linked to support system fault trees. Top logic trees represent the logic needed to answer the event-tree elements and model the failure of a safety function (see Section 4.3 for more details and diagrams). Modeling could include failure states of front-line systems, operator errors relating to safety function actions such as depressurization of the Reactor Coolant System (RCS) or event conditions, e.g., isolation of a ruptured Steam Generator (SG). Front-line systems model the systems used to mitigate the accident such as High Pressure Safety Injection (HPSI), Low Pressure Safety Injection (LPSI), or Auxiliary Feedwater (AF). Modeling includes equipment failures and operator errors relating to the system's operation. Support system fault trees provide modeling for systems which are considered to be required by the front-line system for the front-line system to successfully operate. These trees contain equipment failures, operator errors relating to the operation of the system, and the logic structure for setting conditions for each initiator.

The fault trees for the event-tree elements are solved and a Boolean equation is produced. The equation is then quantified to find the minimal cutsets for the sequence (see Section 8, Quantification of Accident Sequences, for a detailed discussion on quantification). Thus, any dependencies in the way of shared components or support systems are automatically accounted for in the Boolean reduction process.

The accident sequence equation can be modified, based upon the initiating event (IE) being analyzed by setting IEs and IE flags within the equation to true or false.

IEs and IE flags are included in the front-line and support system fault trees. IE flags represent multiple IEs and are used where several IEs produce the same effect in the logic. The IEs and IE flags can be set to logical true or false, depending on the system responses to the initiator being analyzed. For example, if the initiating event is loss of Class 125V DC, Channel A, the flag, IEPKAM41, is set to true, which fails all equipment that requires Channel A, DC power.

In support of the Level II analysis, the methodology described here also applies to the quantification method used to determine the plant damage states (see Section 11.3).

4.1 Initiating Event Identification and Grouping

4.1.1 Basic Approach

An initiating event is considered to be a failure or action that results in either a manual or automatic plant trip, thus requiring a mitigating action or system response. The identification of initiating events was performed in two steps. First, a list of possible transients was identified from generic sources. (Reference 4.4.17 and 4.4.21). The list was then reduced to only those transients that were applicable to PVNGS. Second, plant-specific initiators were identified through an evaluation of plant emergency procedures, abnormal operating procedures, drawings, design documents, PVNGS Licensee Event Reports (LERs), system descriptions, and other plant support documentation. This group included loss of specific systems or electrical buses that might directly or indirectly lead to a plant trip and would impact the availability of the mitigating system.

The two lists were consolidated, creating an initiating event list. The events were then separated into groups whose members had plant response and system requirements that were similar to each other. An event tree for all events in a group was then developed based on this criteria. For example, a loss of condenser vacuum automatically trips the main feedwater pumps as does a loss of all condensate pumps. These two events created a similar plant response, required similar mitigation equipment, and were therefore treated using one event tree, the loss of main feedwater/condensate pumps. This information, along with the identified initiators, are listed in the following section.

4.1.2 Identification of Initiating Events

The initiating events identified for potential inclusion in the PVNGS PRA is shown in Table 4.1-1. This is a list of generic and plant-specific initiators. The generic listing of initiators, Part A, was taken from EPRI report NP-2230, "ATWS: A Reappraisal, Part 3: Frequency of Anticipated Transients" (Reference 4.4.17). The plant-specific initiators listed in Part B of Table 4.1-1 were identified during the plant document review process for the PRA. This review was supplemented by a review of LERs, Post Trip Review Report (PTRR), and Incident Investigation Reports (IIRs). The review process identifies potential plant-specific initiating events as well as enhances the PRA model accuracy for plant specific response to these initiators. Initiating events, such as the loss of control room and DC equipment room HVAC, were directly identified during analysis in response to an LER.

Upon review of the potential initiators, a final list was generated (Table 4.1-2). These initiators were then grouped according to the type of systems affected by the initiator or unique mitigating requirements. This grouping process resulted in the development of the PRA event trees, which are discussed in Section 4.3. Table 4.1-2 also provides the results of the grouping process. The table lists the initiator name used in the PRA models and what event tree was used for the treatment of each initiator.

4.1.3 Discussion of Initiators

The following sections describe each of the internal initiators analyzed for the PVNGS PRA and systems affected by the IE at the onset of the event.

4.1.3.1 Loss of Coolant Accidents - IELLOCA, IEMLOCA, IESMLOCA

The LOCA initiating event is divided into three categories: Large, Medium, and Small LOCAs. Each LOCA size is treated separately due to differences in plant effects and mitigating system requirements. Based on these constraints, equivalent break sizes for each of the LOCAs can be defined as follows. For the Small LOCA, the equivalent break size range is between 0.38 in. to less than 3.0 in. For Medium LOCA, the range is 3.0 in. to 6.0 in., and for Large LOCA, the range is greater than 6.0 in. The rationale for selecting these break size ranges is provided in Section 4.3. Failures that contribute to each of the LOCAs are defined in detail in Section 6.

4.1.3.2 Steam Generator Tube Rupture - IESGTR

The SG tube rupture initiating event applies to the rupture of one or more tubes in one SG causing primary coolant to leak to the secondary system. Credible tube failures range in severity from leak rates of a few gallons per minute (gpm) to several hundred gpm for the guillotine rupture of several tubes. The event analyzed in the PVNGS PRA is the complete severance of a single tube, resulting in a leakage rate of about 400 gpm at normal RCS and secondary-system conditions. This choice was made on the basis that less-than-complete failure will result in much smaller leak rates, generally within the capacity of the normal makeup system and a fairly normal shutdown can take place. Multiple-tube failures, on the other hand, were not explicitly addressed, because they are less likely to happen and because the success criteria for systems called upon to respond are substantially the same as those for the failure of a single tube. The impact is the loss of one SG for cooling.

4.1.3.3 Large Secondary-line Break - IESLB

A large secondary-line break includes all large downcomer feedwater line breaks downstream of the Feedwater Isolation Valves (FWIVs) and all large steamline breaks. Multiple spurious openings of Main Steam Safety Valves (MSSVs), Atmospheric Dump Valves (ADVs) and Turbine Bypass Valves (TBVs) are also considered. The break causes over cooling of the RCS. This could also cause a possible return to power once the reactor has tripped. Once the event has occurred, the main steam isolation valves are closed. No credit was taken for the isolation of the ruptured SG. The model assumes only one SG will be available for decay heat removal.

4.1.3.4 Feedwater Line Break - IEFLB

Economizer feedwater line breaks downstream of the last check valve prior to the steam generator fall into this category, along with breaks in the blowdown piping up to the inside-containment isolation valve. Feedwater line breaks upstream of the last check valves are isolable and the event is the same as a loss of feedwater; i.e., a steam generator does not blow down and both steam generators are subsequently available for heat removal. Although the peak RCS pressure achieved is a function of break size, it was conservatively assumed that any event in this category causes pressurizer safety valves to lift.

4.1.3.5 Loss of 125V Class 1E DC Power - IEPKAM41, IEPKBM42, IEPKCM43, IEPKDM44

Loss of 125V Class 1E DC power is defined as four separate initiators (see Table 4.1-2) in the PRA model. Each of the four events affect the plant differently with Channels A and B being the most severe. Each initiating event is actually the combination of two events -- the loss of the distribution panel and the loss of the control center. All of the equipment failures that could fail either panel are included in the initiating event. This is conservative, since control center equipment that would not fail on a loss of the distribution panel are assumed to fail for this initiator. However, since most equipment required in this analysis are supplied from the distribution panel, this is only slightly conservative. A discussion of each initiator and its consequences follows. Only consequences applicable to this analysis are included.

The initiator, IEPKAM41, Loss of Channel A DC control center, or distribution panel affect the plant in the following ways:

a) One ADV on each steam generator fails closed

b) All of the Train A Engineered Safety Feature (ESF) pumps, AF, SI, Containment Spray (CS), Essential Chilled Water (EC), Essential Cooling Water (EW), Essential Spray Pond (SP) system, fail to start due to loss of DC control power

c) DG A will not start or run

d) The normal pressurizer spray valves fail closed (instrument air is isolated to containment)

e) The non-essential (start-up) AF N pump loses primary DC control power
f) Normal and Train A essential control room HVAC unavailable
g) Normal and Train A essential DC equipment room HVAC unavailable.

The initiator, IEPKBM42, Loss of Channel B DC control center, or distribution panel affect the plant in the following ways:

a) One ADV on each steam generator fails closed
b) All of the Train B ESF pumps fail to start due to the loss of DC control power
c) DG B will not start or run
d) Normal and Train B essential control room HVAC unavailable
e) Normal and Train B essential ESF switchgear room HVAC unavailable.

The initiator, IEPKCM43, Loss of Channel C DC control center, or distribution panel affect the plant in the following ways:

a) One ADV on each steam generator fails closed
b) AF pump A fails to supply water to either SG due to failure to open two Channel C-powered AF isolation valves
c) Loop 1 (Train A) shutdown cooling valve fails to operate
d) Train A HPSI hot-leg recirculation unavailable [Motor Operated Valve (MOV) fails to open].

The initiator IEPKDM44, Loss of Channel D DC control center, or distribution panel affect the plant in the following ways:

a) One ADV on each steam generator fails closed
b) Loop 2 (Train B) shutdown cooling valve fails to operate
c) Train B HPSI hot-leg recirculation unavailable (MOV fail to open).

The first two initiators have a greater consequence than do the others due to the large number of equipment failures involved. The last two events, in fact, do not necessarily trip the reactor automatically, since it is assumed that the operator will trip the reactor on an extended loss of these buses. This assumption does not greatly affect the final overall results.

4.1.3.6 Loss of 120V Class 1E AC Instrument Power - IEPNAD25, IEPNBD26

The loss of class instrument power includes two events: IEPNAD25, Loss of Channel A Vital 120V AC and IEPNBD26, Loss of Channel B Vital 120V AC. Each initiator includes all of the equipment failures that could fail the distribution panel. Loss of either of the two initiators will eventually trip the plant because of the loss of cooling to the respective Balance of Plant (BOP) Engineered Safety Features Actuation System (EFAS) cabinets. Loss of cooling to the cabinets can lead to the failure of the load sequencer, resulting in a continuous load shed to vital equipment. Other system impacts are to essential chillers and SG ADVs (one on each SG).

4.1.3.7 Loss of Instrument Air - IEIAS

The Instrument Air system contains three air compressors; two normally running. On the loss of all three, nitrogen backup allows the operators to shut down the plant with minimal effect. In this analysis, no credit is given for the low-pressure nitrogen backup, since it will only provide instrument air backup for approximately four hours. Backup nitrogen is credited for allowing continued operation of the N pump (see Section 7.4). A loss of Instrument Air initiating event causes the following equipment failures:

a) The TBVs fail to operate

b) Letdown isolation valves close

c) Normal plant ventilation isolates due to dampers failing closed

d) The condenser hotwell automatic makeup fails

e) Instrument air to the ADVs fails (each ADV has a nitrogen accumulator backup)

f) The operator will (some time later) manually trip the reactor per procedure

g) The condensate pump shaft seal water isolation valves fail closed, failing the pumps

h) Instrument air to the Feedwater Regulating Valves fail (valves each have high pressure nitrogen backup).

4.1.3.8 Loss of Plant Cooling Water, Loss of Nuclear Cooling Water, Loss of Turbine Cooling Water - IEPCW, IENCW, IETCW

The effects of an extended loss of plant cooling water (PW) are the same as the combined effects of an extended loss of nuclear cooling water (NC) and turbine cooling water (TC), since PW cools both NC and TC. NC provides cooling to the RCP shaft seals, containment air, normal chillers, and the spent fuel pool. Containment loads can be backed up with essential cooling water. TC provides cooling water to the Main Turbine lube oil, Main Generator stator and hydrogen coolers, FW pump lube oil, instrument air compressors, and circulating water pumps. An extended loss of PW causes the following:

a) Loss of cooling to TC, NC, and condenser air removal pumps

b) Manual turbine trip (per procedure)

c) Possible RCP trip due to loss of NC heat sink (also possible RCP seal leak)

d) Manual FW pump trip

e) Manual circulating water pump trip

f) Manual condensate pump trip

g) Manual instrument air compressor trip

h) Eventual loss of condenser vacuum

i) Eventual loss of normal HVAC.

4.1.3.9 Closure of All Main Steam Isolation Valves - IEMSIV

Simultaneous closure of all of the MSIVs will lead to a trip on high pressurizer pressure and a primary safety relief valve lift. Main feedwater is lost and the TBVs cannot be used to provide steam relief unless the Main Steam Isolation Valves (MSIVs) are unisolated.

4.1.3.10 Loss of DC Equipment Room HVAC - IEDCRHVAC-1, IEDCRHVAC-2

Loss of DC equipment room HVAC consists of two individual initiators: the loss of Division 1 HVAC and the loss of Division 2 HVAC. Division 1 HVAC supplies cooling to Channels A and C DC equipment rooms. Division 2 HVAC supplies cooling to Channels B and C DC equipment rooms. The rooms contain class inverters, battery chargers, and voltage regulators for the class 1E 125V DC system and the class 1E 120V AC instrument control system. The most temperature sensitive solid state equipment in the rooms can operate in room temperatures of 104° F. The solid state equipment begins to fail at approximately 122° F.

The DC equipment room HVAC initiator is highly complex. The HVAC system has a non-class normally operating portion which is backed up by a class (essential) portion during LOCA or Loss Of Off-site Power (LOOP) conditions. The systems that support HVAC are also the systems which are supported by HVAC. To increase the complexity, these same support systems are also support systems for all the front-line systems. As a result, the DC equipment room HVAC initiator tends to become important. Its importance is based upon how much time there is between loss of HVAC and failure of the equipment that the HVAC is cooling. The following briefly describes the most likely and the most limiting scenarios evaluated in the PRA model. This evaluation is based upon results from room heat-up modeling conducted for PVNGS.

- A spurious actuation of the Fire Protection (FP) system occurs. This also includes spurious CO_2 spray. The room or rooms become isolated from any air source. This could happen to one or both of the divisions of HVAC. The control room will receive an alarm indicating actuation of the FP system. If no CO_2 is released in the rooms, the operators have approximately 12 hours to restore cooling to the room. If CO_2 is present, then a longer time is available unless immediate failure due to subcooling of the equipment occurs. Opening closed dampers requires long periods of time due to their location. Operators would have to supply cooled air by opening doors and placing blowers in appropriate places. These actions are proceduralized.
- Accidental dropping of the dampers either by testing the FP system or by failure of the damper(s) to remain open. Flow to the room becomes blocked. Dropped dampers are not alarmed. Indication would come from an increase in the affected room temperature. Temperature indication for the rooms is in the control room. The operators have approximately 12 hours after the dampers have dropped to restore cooling to the room. Opening closed dampers requires long periods of time due to their location. Operators would have to supply cooled air by opening a door and placing blowers in appropriate places. These actions are proceduralized.
- The loss of the Air Handling Unit (AHU) fans due to random failure faults thus causing failure to circulate air through the rooms. Heat-up will occur in approximately 12 hours in this scenario also. The operators have control room alarms on the AHUs and room temperature.

- The loss of the source of chilled water due to random failure faults thus causing failure to cool the return air from the rooms. By only providing air circulation, the rooms could be kept cool long enough so that the failure temperature would not be reached in 24 hours. There are various alarms in the control room which indicate availability of chilled water. For conservatism this sequence was also included in the model.

4.1.3.11 Turbine Trip - IETT

Loss of the turbine does not in and of itself always trip the reactor; however, if the Reactor Power Cutback System (RPCS) and the Turbine Bypass Valves (TBVs) fail, a transient would occur. The RPCS monitors the power balance between the turbine load and the reactor. When a mismatch occurs, the RPCS drops in groups five and four of the control rods and sheds the steam load through the TBVs. Should RPCS and TBVs fail, the reactor will trip as a result of the turbine tripping before the reactor. The RCS will experience a pressure spike, thus creating the possibility of a stuck-open safety valve on the primary side. This is considered to be a Small LOCA.

4.1.3.12 Miscellaneous Trips - IEMISC

Miscellaneous trips comprise those events that were identified in NUREG 3862 and EPRI NP-2230 initiator lists as either causing or possibly causing an uncomplicated trip at PVNGS. Events in this category do not, in themselves, significantly impact the plant systems called on to respond to the transient. See Section 6.1 for the final list of contributors to the initiating event frequency.

4.1.3.13 Loss Of Off-Site Power - IELOOP

The Loss Of Off-site Power event includes all events initiated by a loss of grid power from the high voltage transmission lines supplying the station. Output to the switchyard from either of the other Palo Verde units is assumed unavailable. Following a loss of off-site power, much of the plant non-safety equipment will not function and the safety equipment will depend on the Diesel Generators (DGs) for power. Lost equipment includes the Nuclear Cooling Water System (NC) pumps, the TBVs, Turbine Cooling Water (TC) pumps, instrument air, the condensate pumps, the main feedwater pumps, the reactor coolant pumps, and normal HVAC. The loss of the condensate pumps assures that alternate feedwater will not function until off-site power is restored. Additionally, loss of NC could lead to an eventual Reactor Coolant Pump (RCP) seal Loss of Coolant Accident (LOCA) should operators fail to back up NC with Essential Chilled Water (ECW) and seal injection via charging pumps.

4.1.3.14 Loss of Main Feedwater/Condensate Pumps or Loss of Condenser Vacuum - IEFWP, IECPST, IECONDVAC

A loss of main feedwater is defined as a loss of both Main Feedwater (FW) pumps. The turbine driven FW pumps receive steam from the SGs and cannot be relied on for long-term decay heat removal, but they provide operators with a longer time window in which to align other sources of feedwater, if necessary. A loss of the FW pumps does not cause failure of alternate feedwater because of a bypass line. A loss of all condensate pumps or a loss of condenser vacuum also leads to a loss of both FW pumps. The reactor will trip following any of these events on a low SG level signal. The SG inventory at the beginning of the transient is, therefore, much less in both SGs than for a normal reactor trip. For the loss of the FW pumps or for the loss of condenser vacuum, the effect on other systems is minimal. The loss of the condensate pumps fails the Alternate Feedwater system (AltFW) (See Section 5 for system description).

4.1.3.15 Station Blackout - IEBLACK

Station Blackout is a loss of off-site power coupled with failure of both standby emergency diesel generators and their related circuitry to supply power. The only station power not assumed to be unavailable is DC control power and DC-backed vital AC instrument power. The effect on the plant is the loss of all accident mitigating equipment except the turbine-driven auxiliary feedwater pump and the ADVs.

4.1.3.16 Anticipated Transient without SCRAM - All Initiators

Anticipated Transient without SCRAM (ATWS) occurs after a PVNGS initiator has transpired. Ideally, the effects of ATWS are calculated for each initiator; however, it is possible to simplify the calculation by grouping together the initiators that have similar effects during the ATWS. Grouping or binning the initiators is based on the response of the reactor core after the initiator has occurred. As a result, the initiators can be categorized into two groups:

- Turbine trip
- No turbine trip

A third category was created for the loss of off-site power and station blackout initiators because of the larger effect on the systems needed to mitigate the ATWS. Section 6 identifies each category and the initiators that were included in the category.

4.1.3.17 RCS Interfacing System LOCA

Interfacing System LOCA (ISL) is a term used to identify the LOCAs that can occur through systems that interface with the RCS. Typically, this type of LOCA is due to the rupture of one or more valves or heat exchanger tubes followed by the rupture of low-pressure piping in the interfacing system. LOCAs of this sort are of special concern because they can adversely affect a system that is required to mitigate the event. RCS inventory is lost outside containment and the mitigating effect of containment on radiological releases is lost. There are several systems such as Safety Injection (SI) system, NC, Chemical and Volume Control System (CVCS), and shutdown cooling that interface with the RCS. Systems such as the CVCS are designed to withstand RCS pressure and temperature during full-power operations and therefore are not considered for ISL analysis.

Two distinct types of ISLs can occur: those which discharge reactor coolant outside of containment and those which discharge inside containment. The first is of much greater concern, since primary coolant is not returning to the sump for eventual recirculation and radiological releases will be significantly higher than for inside-containment ISLs. Non-isolable outside-containment ISLs, therefore, are assumed to lead directly to core melt if they are not terminated. ISLs inside-containment have the same effect on Emergency Core Cooling Systems (ECCS) success as primary piping LOCAs. This is because it is assumed that ISL flow is the same as flow lost from one SI line to the RCS leg. The inside-containment ISLs are accounted for by increasing the appropriate LOCA initiator frequencies by the calculated ISL frequencies (see Section 6).

4.1.3.18 Loss of Control Room HVAC - IECRHVAC

The Control Room HVAC initiator is defined as the loss of the normal operating portion of control room HVAC followed by a failure to initiate backup cooling either by calling upon the essential HVAC or by operator intervention. The control room HVAC consists of a non-class normally operating portion and a two-train class, essential portion which is operated during LOCA or LOOP conditions.

The Control Room contains various temperature sensitive, solid state equipment. A loss of most of this equipment does not impact the operability of systems which would be called upon to mitigate the transient. However there are, two cabinets that contain equipment, which upon equipment failure, would have a large impact on the plant's ability to respond to an accident. These cabinets house the ESF load sequencers for both safety trains. The load sequencers, upon receiving a LOCA or a LOOP signal, shed the loads on the class 4160V AC buses and allow the DG to close onto the bus. The sequencer then sequences back on all of the essential loads (AF, SI, etc.). One of the possible failure modes of the sequencer is to generate a continuous load shed signal. This strips the bus of all loads, but does not allow reloading of the safety loads. The occurrence of a continuous load shed signal after the reactor has tripped can lead to core melt if recovery of the safety loads is not performed.

The load sequencer fails when room temperatures become greater than 120° F. The following information briefly describes the most likely and limiting scenarios evaluated in the PRA model for loss of cooling to the control room. These scenarios are based upon results from room heat-up modeling conducted for PVNGS.

- Accidental dropping of the dampers due to random failure faults. There is no automatic actuation via the Fire Protection (FP) system for the control room. Flow to the room becomes blocked. Dropped dampers are not alarmed. Indication would come from an increase in the room temperature. Once cooling has been lost, the operator has 12 hrs. to provide cooling to the room. Opening closed dampers requires long periods of time due to their location. Operators would have to supply cooled air by opening the doors. Since the operator is within the room of concern, there is continual feedback to him and the success of his actions is highly likely.
- The loss of the AHU fans due to random failure faults thus causing failure to circulate air through the rooms. Heat-up will occur in approximately 15 hrs. in this scenario. Recovery for this sequence of events is the same as for dropped dampers.

4.2 Mitigating System Requirements

General requirements for the front-line mitigating systems are discussed in this section.

Most systems needed for mitigating each of the initiating events described in Section 4.1 have the same requirement throughout the analysis. For some systems however, the requirements change from one initiator to another. Safety Injection system requirements, for example, vary with the size and location of a LOCA. The modeling and analysis of each system is discussed in Section 5 and includes the details of each systems success criteria. Section 4.3 lists the system requirements specific to each event tree. Support systems required for front-line system function are discussed in Section 5.2.2.

4.2.1 High Pressure Safety Injection (HPSI)

The primary function of the High Pressure Safety Injection (HPSI) system is to inject borated water from the Refueling Water Tank (RWT) into the RCS following a LOCA or Steam Generator Tube Rupture (SGTR). There are two HPSI pumps with at least one HPSI pump required to inject water into the cold-legs of the primary piping. The HPSI system gets actuation signals from the ESF bus load sequencers and the Engineered Safety Features Actuation System (ESFAS). The Safety Injection Actuation Signal (SIAS) setpoint is 1837 psia.

Following actuation, the HPSI system injects water from the RWT into the RCS when RCS pressure is below the HPSI pump shutoff head (approximately 1900 psig). Recirculation of water from the containment sump is achieved using the HPSI pumps and is treated as a separate function.

HPSI is also required on a large secondary line break, where it functions to inject sufficient boron to prevent a return to power given a stuck control rod, as well as to provide RCS makeup.

HPSI is successful if the RWT supplies the required volume of borated water and at least one HPSI pump functions to deliver water to at least three of the four RCS cold-legs.

4.2.2 High Pressure Safety Recirculation (HPSR)

HPSI recirculation is required on all RCS LOCAs where water/steam from the break remains in containment. Recirculation of the RWT water in the containment sump using the HPSI pumps provides long-term core cooling and RCS makeup. Following injection of the RWT water into the Reactor Coolant System, a Recirculation Actuation Signal (RAS) is generated on RWT low level (7.4%). The RAS secures the LPSI pumps and opens the sump isolation valves so that the HPSI and CS pumps can take suction from the sump. The requirement for cold-leg recirculation is that one HPSI pump provides flow from the sump to the RCS.

4.2.3 Hot-Leg Injection (HLI)

Following a Large or Medium LOCA, borated water is injected via HPSI and Low Pressure Safety Injection (LPSI) through the cold-leg injection lines. For cold-leg breaks, part of the flow is lost to the break and part of the flow is injected into the core. Since the system cannot remain pressurized, the reactor vessel upper head, outlet plenum, and steam generator tubes void. Steam will be formed in the core and be transferred through the SG tubes and to the break location. Boron is left behind in the reactor vessel. If this continues over several hours, the boric acid concentration in the reactor will increase to its solubility limit. Boric acid will then precipitate and may interfere with coolant circulation and heat removal. This problem does not occur for a hot-leg break, since liquid flows through the core prior to flowing out of the break.

The problem of boric acid precipitation can be avoided by providing SI flow to both the hot and cold-legs. The flow into the hot-leg injection lines (50% of HPSI flow) limits the boron concentration in the core region.

Since the operator has no knowledge of where the break occurred, the LOCA emergency procedure requires hot-leg injection to be initiated from the Control Room between 2 and 3 hrs. following a LOCA. The requirements for hot-leg injection are that one of the two hot-leg injection lines be opened to the RCS and provide flow from an operating HPSI pump.

4.2.4 Safety Injection Tank (SIT) Injection

The Safety Injection Tanks (SITs) provide the initial injection of borated water needed to cool the core following a Large or Medium LOCA. There are four SITs, one per Reactor Coolant System (RCS) cold-leg. Each SIT contains a minimum of 1802 cubic ft. of borated water. It is assumed that one SIT is lost through the RCS break. The success criterion for SIT injection is that two of the remaining three SITs inject coolant into the intact RCS cold-legs. The SITs are pressurized and start to inject their water when the RCS pressure decreases below approximately 615 psia.

In the event of a Small LOCA, the RCS pressure remains elevated above 615 psia and the SITs are only required if a rapid de-pressurization is necessary in order to initiate LPSI on failure of HPSI. The same SIT requirement is conservatively used in this circumstance, even though only a portion of one SIT would be lost through the break.

4.2.5 Low Pressure Safety Injection (LPSI)

Low Pressure Safety Injection (LPSI) provides high volume coolant injection to the core for Large and Medium LOCAs. There are two LPSI pumps, each supplying flow to two cold-leg injection lines. LPSI and CS pumps can be used to back up the other given its failure; this is not credited in the analysis. LPSI will inject water when RCS pressure decreases to less than about 200 psig.

4.2.6 Low Pressure Safety Recirculation (LPSR)

If HPSI Recirculation fails for reasons other than failure of the containment sump valves, the LPSI pumps can be used to perform the same function once RCS pressure is sufficiently low. Since RAS shuts down the LPSI pumps, operator action is required to restart at least one pump. For the Small LOCA initiating event, operator action to rapidly cooldown and de-pressurize the RCS is also necessary for utilization of LPSR. The only other event in which LPSR is credited is Large LOCA, where its use is of limited value since LPSI cannot provide hot-leg injection.

4.2.7 Reactor Protection System (RPS)

The Reactor Protection System (RPS) trips the reactor to reduce thermal energy production following a transient or accident. Power is removed from control element drive mechanism (CEDM) cabinets by opening the Reactor Trip Breakers (RTBs), which allows the control element assemblies (CEAs) to drop into the reactor core under the influence of gravity. A reactor trip also generates a turbine trip. The RPS is required to do two things: generate a trip signal and de-energize the CEDMs releasing the CEAs into the reactor core. Failure of either is considered a failure of the RPS.

The RPS generates a trip signal on any of the following conditions using any two of four channel logic:

a) Low Departure from Nucleate Boiling Ratio (DNBR) (1.24)*
b) High Linear Power Density (21 kw/ft.)*
c) High Pressurizer Pressure (2383 psia)
d) Low Pressurizer Pressure (1837 psia)
e) RCS Low Flow (11.9 psid)+
f) High SG #1 or SG #2 Level (91.0% Narrow Range)
g) Low SG #1 or SG #2 Level (44.2% Wide Range)
h) Variable Overpower (neutron flux) (110%)+
i) Low SG #1 or SG #2 pressure (919 psia)
j) High Containment Pressure (3.0 psig)

* Generated by Core Protection Calculators (CPCs). CPCs will generate both trip signals for several conditions other than actual Departure from Nucleate Boiling Ratio (DNBR) or Local Power Density (LPD) exceeding setpoint; such as input parameter out of range and loss of subcooling.

+ These trip functions also have rate of change and band limits.

4.2.8 Auxiliary Feedwater (AF)

Steam Generator cooling is required following all transients and accidents except Large and Medium LOCAs. For most initiation events, Main Feedwater (FW) will continue to be available following the trip; however, it is not credited for long-term decay heat removal. Auxiliary Feedwater (AF) is used as the primary source for

SG cooling. The AF system consists of two Seismic Category I, Class 1E Essential pumps (Train A is turbine-driven, Train B is motor-driven) and one non-qualified, non-essential pump referred to as Train N. Normally following a trip, the Train N AF pump is used. Use of this pump requires operator action for startup and alignment. The essential portion of AF is automatically actuated by an Auxiliary Feedwater Actuation Signal (AFAS) from ESFAS. It can also be manually actuated from the Control Room. The success criterion for AF is that feedwater flow must be delivered from one of two essential AF pumps or the non-essential AF pump to one steam generator before SG dry-out.

In addition, AF is used during rapid RCS de-pressurization to a pressure less than the shut-off head of the LPSI pumps on failure of HPSI. In this case, AF is required to supply flow to both SGs from at least one AF pump.

4.2.9 Turbine Bypass Valves (TBVs)

The operationally preferred means of removing secondary steam following a trip is via the Turbine Bypass Valves. These valves are automatically opened by the Steam Bypass Control System (SBCS) to prevent lifting of the Main Steam Safety Valves (MSSVs) following a trip. These valves can also be manually controlled from the Control Room. Six of the eight valves dump to the condenser and the other two discharge to atmosphere. The turbine bypass valves to the condenser will not open if condenser vacuum is insufficient. In this analysis, because of the high reliability of Main Steam Safety Valves, TBVs are only credited in sequences where either the RCS or the SGs alone must be de-pressurized. These initiators are Small LOCA, Steam Generator Tube Rupture, and AF failure.

The TBVs are isolated by the Main Steam Isolation Valves (MSIVs) on a Main Steam Isolation Signal (MSIS), and are also not available on a Loss Of Off-site Power, loss of control power, or loss of instrument air.

4.2.10 Atmospheric Dump Valves (ADVs)

The analysis principally credits the ADVs for controlled secondary steam removal. There are four ADVs: two per steam generator. The ADVs are air operated valves and are remotely operated from the Control Room. They are not automatically actuated. Local operation of the ADVs is also possible but is not credited. The requirement for the ADVs is that one of the two atmospheric dump valves opens to remove secondary steam on a SG being supplied with feedwater. ADVs are credited for maintaining Hot Standby, along with MSSVs, and for cooldown and de-pressurization sequences along with TBVs.

4.2.11 Main Steam Safety Valves (MSSVs)

There are ten MSSVs per Steam Generator. On a failure of the ADVs, the steam generator pressure will increase until the Main Steam Safety Valve (MSSV) setpoint is reached. Two MSSVs (per SG) have a setpoint of 1250 psig, two are at 1290 psig and six at 1315 psig. The MSSVs will then begin to cycle to maintain the SG pressure in a narrow band around the MSSV setpoint pressure. The RCS temperature and pressure will then increase until an equilibrium point is reached where the heat transfer from the RCS to the steam generators is balanced by the heat removed through the MSSVs. As long as SG cooling is available, the plant will remain stable. However, it is not possible to cooldown and de-pressurize the RCS to bring the plant to shutdown cooling entry conditions unless an atmospheric dump valve or a turbine bypass valve is restored, since MSSVs cannot be used for SG pressure reduction. The success criterion for the MSSVs is that one of the main steam safety valves opens on a SG being supplied with feedwater.

4.2.12 Alternate Feedwater (AltFW)

The Alternate Feedwater system uses the low pressure condensate pumps to provide an alternate method to supply SG cooling when main feedwater is no longer available and AF has failed. Per the Functional Recovery Procedure, the Control Room operator would have to reduce the pressure in one SG to less than approximately 500 psia using the TBVs or ADVs. The condensate pumps are then aligned through the three low pressure heater trains, one of two FW pump bypass valves, and the high pressure heater bypass valve to the SG.

This task requires operator actions that take place outside of the Control Room. The condensate pumps take suction from the hotwell; over the long term, hotwell makeup must occur from the Condensate Storage Tank (CST).

The success criterion for AltFW is that at least one condensate pump is aligned and supplies flow to one SG prior to core uncovery.

4.2.13 RCS Pressure Control

Following a steam generator tube rupture, in order to reduce the leakage from the primary to the secondary, RCS pressure must be reduced to shutdown cooling entry conditions. To perform this function, RCS pressure control must be maintained. Main Spray, which requires Reactor Coolant Pump operation, is not credited in the analysis. It is conservatively assumed that subcooling will not be adequate to operate RCPs. Therefore, either auxiliary pressurizer sprays or pressurizer vents can be used to reduce pressure. Auxiliary spray is supplied by the charging pumps and is manually controlled. Pressure can also be reduced by opening the pressurizer vents. There are two pressurizer vent flow paths on the top of the pressurizer. Flow through either line can be established by opening two or three (depending on the path) solenoid valves from the Control Room. Using auxiliary spray or opening the pressurizer vents performs two functions: (1) reduces RCS pressure and thus the leak rate and (2) allows the level in the pressurizer to rise (increase makeup from HPSI) so that HPSI can be throttled to control RCS inventory. Until HPSI is throttled, RCS de-pressurization is not possible.

4.2.14 Shutdown Cooling (SDC)

Shutdown Cooling can be used to remove decay heat from the RCS, once the plant has been cooled to 350° F and de-pressurized to 400 psia. It is only credited for Steam Generator Tube Rupture, since there is a significant likelihood that complete RCS de-pressurization would be required to terminate the loss of RCS inventory.

Each LPSI pump is aligned to take suction from a hot-leg through the three SDC suction isolation valves. Injection into the RCS is then accomplished via the SDC heat exchangers through the normal LPSI injection lines. SDC requires at least one LPSI pump to recirculate RCS water through at least one injection line.

A Containment Spray pump can be used in place of a LPSI pump. However, it was found to be not necessary to credit this in the analysis.

4.2.15 Steam Generator Blowdown (BD)

Blowdown is normally operating prior to the reactor trip, but the blowdown containment isolation valves are isolated on a SIAS, AFAS or MSIS. On a Steam Generator Tube Rupture event, the operator is directed to isolate the ruptured SG and to use blowdown to prevent overfilling it. Either abnormal or high rate blowdown can be used to reduce the level. If blowdown functions correctly, an almost normal shutdown can be maintained. If the blowdown system cannot be used, the operator must steam the ruptured SG using ADVs or TBVs to reduce SG level, which can lead to an unisolable SG leak from the ruptured generator if an ADV fails to close.

4.2.16 Containment Spray System (Containment Heat Removal)

On a Medium or Large LOCA, the Containment Spray (CS) system is automatically started by a Containment Spray Actuation Signal (CSAS) from ESFAS. The CSAS actuates at 8.5 psig in the containment and opens both spray isolation valves. (The Containment Spray pumps should have started on a SIAS.) Water is then supplied from the RWT to the spray rings in the containment dome. On a RAS, the CS pumps continue to run with their suction source switching to the containment sump. In the recirculation mode, cooling is required from the SDC heat exchangers, which are cooled by the Essential Cooling Water systems. This is the decay heat removal mechanism. The CS system is considered successful when at least one CS pump supplies cooled containment sump water to the spray rings during the recirculation mode. A LPSI pump can be used in place of a Containment Spray pump. However, it was found to be not necessary to credit this in the analysis.

Containment Spray as required for maintaining containment integrity is discussed in Section 11.

4.3 Event Tree Sequence Determination

This section describes each core damage sequence for each event tree utilized in the PVNGS PRA. Some event trees are unique to particular initiators, while some are more generic and are utilized for two or more initiators, such as the Grouped Transients event tree.

First, the initiator is described, along with the systems required to mitigate it. Then each accident sequence is described, followed by an explanation of each top event in the event tree and the success criteria for each of those top events.

One or more top events in each event tree may be combinations of functions and systems required to perform those functions. For example, Secondary Cooling includes two means of providing feedwater to the steam generators and up to three means of relieving steam. Both means of feeding or all three means of steaming must fail to fail the top event. Combinations of successes and failures are handled by means of top logic fault trees, which in turn call the appropriate system fault trees, and in some cases, contain logic "switches" to activate or deactivate particular sections of the fault tree, as appropriate to the event under consideration. The Top Logic fault trees are shown as Figures 4.3-11 through 4.3-18.

Finally, major assumptions that went into the accident sequence quantification and major dynamic human actions within the event and fault trees are delineated.

Plant Damage States and Containment Response are discussed in Section 11.

4.3.1 Small LOCA Event Tree

The Small LOCA event tree (Figure 4.3-1) applies to all reactor coolant system (RCS) ruptures inside containment, which have an equivalent break diameter of 0.38 to 3.0 in. Breaks up to 3.0 in. in diameter do not pass enough water to remove core decay heat. Secondary cooling is therefore required. RCS pressure is not expected to drop to the Safety Injection Tank pressure; early core uncovery is not expected.

The preferred systems required to mitigate a Small LOCA are the RPS for reactor trip, High Pressure Safety Injection, Auxiliary Feedwater, and some means of secondary steam removal. Once the RWT inventory is depleted, the coolant must be recirculated from the containment sump. Hot-leg injection during long-term cooling is not required. (Boron precipitation is not expected, since prolonged loss of subcooling and boil-off does not occur.) If HPSI fails or is not available, a rapid RCS depressurization can allow the LPSI system to be used to provide injection into the RCS. This dynamic human action is in the Functional Recovery Emergency Operating Procedure.

4.3.1.1 Sequence Description

Refer to Figure 4.3-1, for a logic diagram of the Small LOCA Event Tree.

Following the initiating event, the reactor would be expected to trip on low pressurizer pressure or Low Departure from Nucleate Boiling Ratio (DNBR). Failure of reactor trip with HPSI success is covered in detail in the ATWS event tree. However, if the reactor fails to trip, HPSI is required immediately for Small LOCA and Steam Generator Tube Rupture initiators, as opposed to within 1 hr. following a transient-induced LOCA as modelled in the ATWS event tree. This leads to early core damage.

Following successful reactor trip, the makeup of RCS inventory via HPSI is required. If HPSI were to fail, it is possible to de-pressurize the RCS through a rapid cooldown from the secondary side to a pressure low enough to allow Safety Injection Tank injection and ultimately Low Pressure Safety Injection. Long-term secondary heat removal is required, and is also included under the De-pressurize top event.

If HPSI is successful, secondary cooling is necessary for heat removal. All means of steaming and feeding the steam generators are covered under the Secondary Heat Removal top event.

Once the contents of the Refueling Water Tank (RWT) are injected into the RCS via HPSI, High Pressure Recirculation (HPSR) is necessary for continued inventory makeup. If HPSR fails, Low Pressure Recirculation (LPSR) may be used if the RCS can be rapidly de-pressurized as discussed above. Failure to de-pressurize or to achieve recirculation leads to core damage, since inventory makeup cannot occur.

Had HPSI initially failed and de-pressurization and LPSI were successful, Low Pressure Safety Recirculation (LPSR) from the containment sump would be necessary to continue inventory makeup. If LPSR fails, the core will not remain covered.

The five core damage sequences then are as follows:

a) Reactor Trip failure, HPSI failure

b) HPSI failure, de-pressurization or LPSI failure

c) HPSI failure, de-pressurization and LPSI success, LPSR failure

d) HPSI success, secondary cooling failure

e) HPSI success, secondary cooling success, HPSR failure, de-pressurization, LPSR failure.

4.3.1.2 Small LOCA Sequence Elements

4.3.1.2.1 Small LOCA Initiators

Section 6.1.3 shows the calculations used in determining the Small LOCA initiating event frequency. Small LOCAs outside of containment are treated under the Interfacing LOCA - Event V-Sequence (Section 6.1.3.3). Transient-induced LOCAs are treated separately in the event tree for that initiator. These initiators include Grouped Transients, Loss of Main Feedwater, and Station Blackout.

4.3.1.2.2 Reactor Trip

On a Small LOCA, the RPS will generate a reactor trip signal on low pressurizer pressure, Low DNBR (a CPC trip). Success criteria is that all but one CEA fully inserts into the reactor core in response to a trip condition.

4.3.1.2.3 High Pressure Safety Injection (HPSI)

There are two HPSI trains, and success is defined as injection of RWT water by at least one pump via at least three of the six HPSI lines that feed the three RCS cold-legs unaffected by the LOCA. (It is assumed the LOCA occurs in a cold-leg.) This is the design basis of HPSI for a Large LOCA. It is a conservative requirement for a Small LOCA, because HPSI is only performing an inventory makeup function, not a heat removal function. The HPSI system injects water into the RCS when RCS pressure is below the HPSI pump shut-off head (approximately 1900 psig).

4.3.1.2.4 Secondary Heat Removal

Refer to the Steam Generator Heat Removal Top Logic fault tree, (Figure 4.3-11).

Following a Small LOCA event, feedwater must be supplied to the steam generators in order to remove decay heat from the RCS in conjunction with the break flow. Also, steam must be vented from the steam generators in order to remove heat from the RCS and to prevent steam generator overfill. Several means to accomplish these functions exist. Each is described below. The time available for initiating auxiliary or alternate feedwater is dependent upon whether main feedwater is available after the trip. If FW is available following the trip, it is assumed to be available for at least 30 min.

Palo Verde experience shows that if FW is available immediately post-trip, it will remain available for a considerable length of time. The FW pumps are not shutdown until a source of auxiliary feedwater is operating satisfactorily. See Section 7.4 for a discussion of FW availability and dynamic operator actions involved with Auxiliary and Alternate Feedwater.

Auxiliary Feedwater (AF)

The Auxiliary Feedwater (AF) system may be actuated automatically by the Engineered Safety Features Actuation System (ESFAS) or started manually by the Control Room operators in accordance with the safety function flow chart in the Emergency Operating Procedure. The operator's first choice will be the Train N AF pump if no MSIS has occurred and it functions properly. The operator's next choice is the Train B electric pump followed by the Train A turbine-driven pump. Only Train A and B pumps actuate automatically. Core uncovery does not occur for 60 min. without FW, and not for 100 min. if it is available for 30 min. However, in order to ensure negligible likelihood of a stuck open pressurizer safety valve (PSV), operator action to align Train N AF pump is limited to 35 min. without FW and 70 min. with FW. The success criterion is that AF flow must be delivered to one steam generator from one of the three AF pumps.

Alternate Feedwater (AltFW)

If AF fails, it is still possible to deliver water to the steam generators from the low pressure condensate pumps. The operator must reduce the secondary pressure to below the shut-off head of the pumps using the Turbine Bypass or Atmospheric Dump Valves. This dynamic human action is in the Functional Recovery Emergency Operating Procedure, 41RO-1ZZ10.

For Alternate Feedwater, feeding may begin as late as the initiation of core uncovery; however, the analysis accounts for the possibility that a stuck open PSV leads to an induced Small LOCA. This implies that credit has been taken for feeding a dried out steam generator. Feeding a dry SG has been analyzed by Combustion Engineering (C-E) and found to be acceptable for a limited number of times.

The success criterion for Alternate Feedwater is that flow be delivered from one of three condensate pumps to one steam generator within 60 min. if FW is not initially available, or 100 min. following the loss of feedwater.

<u>Turbine Bypass Valves (TBVs)</u>

The preferred means of removing secondary steam is via the TBVs. These valves have automatic control and their use conserves water inventory and minimizes unmonitored radioactive releases due to SG tube leakage. Six of the eight TBVs discharge to the condenser while two vent to atmosphere. The success criterion for this element with successful HPSI is that at least one of the eight TBVs is opened as needed to vent secondary steam. If a rapid de-pressurization upon HPSI failure is necessary, two valves are required.

<u>Atmospheric Dump Valves (ADVs)</u>

The ADVs are the means of SG steam relief credited in the Safety Analysis. The success criterion for this element is that one of the two atmospheric dump valves is opened as needed to vent steam from a SG receiving AF flow with successful HPSI.

<u>Main Steam Safety Valves (MSSVs)</u>

If the ADVs and TBVs fail, the steam generator pressure will increase until the Main Steam Safety Valve setpoint of 1250 psig is reached. The MSSVs will then begin to cycle to maintain the steam generator pressure in a narrow band around the setpoint pressure. The success criterion is that one of the ten MSSVs opens from a SG receiving AF flow. Alternate feedwater cannot be used if the MSSVs are the only means of steam relief.

4.3.1.2.5 High Pressure Safety Recirculation (HPSR)

Following injection of the RWT water into the RCS, a RAS is generated to switch the suction of the HPSI pumps from the RWT to the containment sump. RAS occurs several hours after a Small LOCA, depending on break size. The success criterion for HPSR is that at least one HPSI pump provides flow from the sump to the RCS through at least three cold-leg injection lines.

4.3.1.2.6 De-pressurize RCS, Inject with SITs and LPSI

Refer to the Low Pressure Injection Top Logic fault tree, Figure 4.3-12.

If the HPSI system does not function following a Small LOCA, the LPSI system can be used to provide injection if the RCS is first rapidly de-pressurized. This de-pressurization can be achieved by feeding and steaming both steam generators using AF and the ADVs, or TBVs at a rapid rate.

The success criteria are:

a) Operator action to start an aggressive cooldown must be initiated within 15 min. following the Small LOCA break.

b) AF is supplied to both steam generators.

c) Steam is removed from both steam generators using one of two ADVs on each generator or, if a Main Steam Isolation Signal (MSIS) has not occurred, at least two TBVs.

d) At least two of the four SITs supply water to the RCS during the cooldown in order to keep the core covered. This is conservative, since this amount of inventory is the design basis for the SITs for Large LOCAs.

e) LPSI flow is delivered from the RWT using one of two LPSI pumps through at least one LPSI injection line.

4.3.1.2.7 Low Pressure Safety Recirculation (LPSR)

If HPSR cannot be established and the RCS has been de-pressurized to use LPSI, the LPSI system can be used in the recirculation mode. The success criteria for this element are successful switchover of at least one LPSI pump suction to the containment sump, manual restart of the LPSI pump (RAS shuts down LPSI), and the successful recirculation through at least one injection line.

4.3.1.3 Major Assumptions

The following assumptions were made in developing the Small LOCA Event Tree:

a) If HPSI or HPSR fails, both steam generators must be used for secondary heat removal in order to depressurize the primary system below the LPSI discharge head before core uncovery occurs.

b) All HPSI flow from one injection line goes out of the break.

c) Operator failure to close the RWT suction isolation valves, once the RAS has opened the sump suction valves, does not impact any of the SI pumps, since the pressure of water from the containment exceeds that from the RWT.

d) The Containment Spray system is not required for core heat removal. All necessary core heat removal is accomplished via the steam generators.

e) No credit was taken for the use of the Main Feedwater (FW) pumps to provide long-term secondary side heat removal.

f) Hot-leg injection is not required for Small LOCAs, since RCS steaming, which could precipitate boric acid, does not occur for breaks within the Small LOCA range (subcooling is restored).

4.3.1.4 Major Dynamic Human Actions

Two major dynamic human actions are credited for Small LOCA:

a) Rapid de-pressurization of the RCS upon HPSI or HPSR failure so that LPSI and/or LPSR may be used.

b) Alignment of Alternate Feedwater for secondary cooling should AF fail.

Other important operator actions are assumed to be successful, such as throttling HPSI flow when conditions so warrant and properly controlling SG steaming and feeding rates to maintain steady and stable heat removal. The latter is routine, and is done following any transient-induced reactor trip. Throttling HPSI applies to Small LOCA, SGTR, and various over-cooling transients. Although not as routine as controlling steaming and feeding, it is a well rehearsed procedure.

4.3.2 Medium LOCA Event Tree

The Medium LOCA event tree (Figure 4.3-2) applies to all reactor coolant system ruptures inside containment that have an effective equivalent break diameter between 3.0 and 6.0 in.

A Medium LOCA encompasses a range of break size large enough to provide core decay heat removal via the break, but for which RCS pressure does not decrease to the shut-off head of the LPSI pumps until several hundred seconds into the accident. The core is quenched primarily by the SITs and the HPSI pumps. Reactor trip is required for reactivity control.

The systems required for response to a Medium LOCA include the SITs, the High Pressure Safety Injection system (HPSI), and the Reactor Protection system (RPS). The HPSI pumps are also required for HPSR and hot-leg injection (HLI) during the long-term cooling phase. After the initial injection, long-term cooling is initiated. For Medium LOCAs, Shutdown Cooling (SDC) conditions cannot be established. Therefore, Large Break LOCA procedures are followed and simultaneous hot and cold-leg injection is used to cool the core and prevent excessive boron concentration. Long-term recirculation cooling is provided by the containment spray pumps aligned to the SDC heat exchanger. Containment Response is covered in Section 11.

4.3.2.1 Sequence Description

Following the initiating event, the first action called for is Reactor Trip, so that heat from fission is terminated quickly. Failure of reactor trip is covered in detail in the ATWS event tree, Section 4.3.11.

Due to the rapid de-pressurization of the RCS, the Safety Injection Tanks (SITs) are called upon to keep the core covered until High Pressure Safety Injection (HPSI) can commence. SIT failure is assumed to lead to core damage.

HPSI is required to supply inventory makeup as well as core cooling. HPSI failure leads to core damage.

Once the contents of the Refueling Water Tank (RWT) are injected into the RCS, suction for the HPSI pumps must switch to the containment sumps to establish High Pressure Safety Recirculation (HPSR) for long-term core cooling. Containment Spray (CS) is also required to provide the actual heat rejection path through the Shutdown Cooling Heat Exchangers following establishment of sump recirculation. This is called Containment Spray Recirculation (CSR). Failure of either HPSR or of CSR leads to core damage.

Because the RCS could remain in a saturated condition for an extended period of time, boric acid would concentrate and precipitate out of solution, which would have a detrimental effect on heat transfer. Therefore, HPSI hot-leg injection (HLI) is required. Failure of HLI is assumed to lead to core damage.

The accident sequences then are:

a) Failure of SITs

b) SIT success, HPSI failure

c) SIT success, HPSI success, HPSR or CS failure

d) SIT success, HPSI success, HPSI and CS success, HLI failure

4.3.2.2 Medium LOCA Event Tree Elements

4.3.2.2.1 Medium LOCA Initiators

Section 6.1.3 shows the calculations used in determining the Medium LOCA initiating event frequency. The Medium LOCA initiator is a random RCS pipe break.

4.3.2.2.2 Reactor Trip

Following a Medium LOCA, the RPS should generate a reactor trip signal on low pressurizer pressure.

4.3.2.2.3 Safety Injection Tank (SIT) Injection

The Safety Injection Tanks provide the initial injection of borated water needed to cool the core following a Medium LOCA. It is assumed that the contents of one SIT are lost through the RCS break. The success criterion for SIT injection is that two of the remaining three SITs inject coolant into the two intact RCS cold-legs.

4.3.2.2.4 High Pressure Safety Injection (HPSI)

HPSI success is defined as at least one HPSI pump injects water via at least three of the six unaffected HPSI injection lines.

4.3.2.2.5 Core and Containment Heat Removal

Refer to the High Pressure Recirculation Heat Removal Top Logic fault tree, (Figure 4.3-13)

Following injection of the RWT water into the RCS, a RAS is generated to switch the suction of the HPSI and CS pumps from the RWT to the containment sump. RAS also turns off the LPSI pumps. Recirculation of the RWT water in the containment sump using the HPSI pumps provides long-term core cooling. The success criterion for HPSR is that at least one HPSI pump provides flow from the sump to the RCS through at least three of the six unaffected injection lines. (Two injection points, one from each pump, are assumed unavailable due to the pipe break location.) Containment cooling via the Containment Spray (CS) pumps is required in order to reduce the containment pressure and to cool the sump water injected into the RCS. The success criterion is the recirculation of containment sump water by at least one containment spray pump via the train-related SDC heat exchanger.

4.3.2.2.6 Hot-Leg Injection

Following a period of cold-leg injection after a Medium LOCA, hot-leg injection is needed to provide circulation through the core so that boron precipitation is prevented. Between 2 and 3 hrs. post-LOCA, the operators are directed by the LOCA procedure to open the hot-leg injection valves from the Control Room. The success criteria are: the operator properly aligns the system and one of two hot-leg injection lines provides flow from an operating HPSI pump.

4.3.2.3 Major Assumptions

The following assumptions were made in developing the Medium LOCA Event Tree:

a) A cold-leg break is assumed, with all of the related SIT and HPSI flow lost out the break

b) LOCAs within this break range remove enough decay heat via the break (once through cooling) so that secondary heat removal is not required

c) If HPSI fails, HPSR is assumed to fail

d) Failure of HPSI or HPSR (except injection valves) results in failure of hot-leg injection because HLI relies on the HPSI system

e) No credit is given for RCS de-pressurization for LPSI following a HPSI failure because of the short period of time available for operator action due to rapid voiding in the core.

4.3.2.4 Major Dynamic Human Actions

The only major dynamic human action modeled is the operator action to align hot-leg injection.

4.3.3 Large LOCA Event Tree

The Large LOCA event tree (Figure 4.3-3) applies to all RCS ruptures inside containment that have an effective break diameter greater than 6.0 in. This includes the design basis accident, double-ended guillotine break in a reactor coolant cold-leg pipe.

The Large LOCA is a severe event in which blowdown of the reactor coolant system occurs within seconds to a few minutes. The SITs refill the reactor vessel downcomer and the LPSI pumps maintain water in the reactor vessel. Because of rapid de-pressurization, the nuclear reaction is quickly shut down due to voiding in the core region. A reactor trip is not required for this event.

Continued subcriticality is assured by the boron concentration in the injected water of the SITs and LPSI system. The injection phase lasts approximately 20 min. Following initial cooling of the core via injection, long-term cooling is required. For Large LOCAs, RCS pressure remains below 538 psi and shutdown cooling conditions cannot be established. Therefore, simultaneous hot and cold-leg injection with HPSI recirculation (HPSR) is used to cool the core and flush boron from the system, with long-term sump inventory cooling performed via containment spray recirculation through the Shutdown Cooling Heat Exchangers.

4.3.3.1 Sequence Description

Following the initiating event, the SITs are immediately called upon to quench the rapidly voiding core region. Failure of SITs leads to early core damage.

If SITs are successful, Low Pressure Safety Injection (LPSI) is required to provide sufficient makeup water to keep the core covered in the injection phase. HPSI does not have adequate capacity to provide injection for Large LOCAs.

When the contents of the RWT have been injected, a RAS occurs switching HPSI and CS pump suction to the containment sumps. LPSI pumps are automatically shut down. HPSR is required to recirculate water to the RCS, while CS is necessary to protect containment integrity and provide the heat rejection path through the Shutdown Cooling Heat Exchangers.

If HPSR fails, the LPSI pumps may be available to carry out the same function. If LPSR also fails, the core cannot be cooled.

If HPSR and Containment Spray are successful, Hot-Leg Injection (HLI) must be established to prevent boron precipitation. Procedures direct the operators to initiate HLI between 2 and 3 hrs. after the LOCA occurs. Failure to establish HLI is assumed to lead to core damage.

The five core damage sequences then are:

a) SIT failure
b) SIT success, LPSI failure
c) SIT success, LPSI success, HPSR or CS failure, LPSR or CS failure
d) SIT success, LPSI success, HPSR failure, LPSR success, HLI failure
e) SIT success, LPSI success, HPSR and CS success, HLI failure

4.3.3.2 Large LOCA Event Tree Elements

4.3.3.2.1 Large LOCA Initiators

Section 6.1.3 shows the calculations used to determine the Large LOCA initiating event frequency. Large LOCA is initiated by random RCS pipe breaks of at least 6-in. equivalent diameter. Reactor vessel breaks of a size and location that are within the capabilities of the ECCS are included in this initiator. Containment Response is discussed in Section 11.

4.3.3.2.2 Safety Injection Tank (SIT) Injection

The Safety Injection Tanks provide the initial injection of borated water needed to cool the core following a Large LOCA. Since break location is unknown, but could be in a cold-leg, it is conservatively assumed that one SIT is lost out the break. The success criterion for SIT injection is that two of the remaining three SITs inject borated water into two intact RCS cold-legs.

4.3.3.2.3 Low Pressure Safety Injection (LPSI)

LPSI keeps the core covered and provides core cooling following a Large LOCA and SIT injection until inventory losses out the break and RCS boil-off can be matched by the HPSI recirculation cooling. The success criterion for Low Pressure

Safety Injection is one of two LPSI pumps must deliver flow to the RCS through at least one of the unaffected cold-legs, which is consistent with the design basis for the ECCS. For Large LOCAs, HPSI does not provide sufficient inventory makeup to prevent core uncovery and provides negligible cooling early in the event.

4.3.3.2.4 Core and Containment Heat Removal using HPSR and CSR

Reference High Pressure Recirculation Heat Removal Top Logic fault tree, (Figure 4.3-13).

Following injection of the RWT water into the RCS, a RAS is generated to switch the suction of the HPSI and CS pumps from the RWT to the containment sump. RAS occurs approximately 20 min. after a Large LOCA. The RAS secures the LPSI pumps and opens the sump isolation valves so that the HPSI and CS pumps can take suction from the sump.

The success criterion for core cooling is that at least one HPSI pump provides flow from the sump to at least three unaffected HPSI cold-leg injection lines.

Containment cooling via the CS pumps is required in order to reduce the containment pressure and to cool the sump water injected into the RCS. The success criterion is the recirculation of containment sump water by at least one CS pump via the train-related SDC Heat Exchanger. This is the design basis for the CS system. Failure of containment cooling is assumed to lead to core damage.

4.3.3.2.5 Core and Containment Heat Removal using LPSR and CSR

Reference the LPSR and Heat Removal-Large LOCA Top Logic fault tree, (Figure 4.3-14).

If HPSR is unsuccessful, it may be possible to align LPSR. LPSI pumps can be restarted by the operator to provide Low Pressure Safety Recirculation (LPSR). The success criterion for LPSR requires that the operator restarts at least one LPSI pump, which takes suction from the containment sump and injects into the RCS through one cold-leg. This is directed by the Functional Recovery Emergency Operating Procedure.

Containment cooling via the CS pumps is required in order to reduce the containment pressure and to cool the sump water injected into the RCS. The success criterion is the recirculation of containment sump water by at least one CS pump via the train-related SDC Heat Exchanger.

4.3.3.2.6 Hot-Leg Injection

Between 2 and 3 hrs. post-LOCA, hot-leg injection is initiated from the Control Room. The success criteria are the operator properly aligns the system and at least one of two hot-leg injection lines provides flow to the RCS from an operating HPSI pump.

4.3.3.3 Major Assumptions and Dependencies

The following important assumptions were made in the development of the Large LOCA Event Tree:

a) Due to rapid de-pressurization, the nuclear reaction is quickly shutdown due to voiding in the core region followed by quenching with borated water. Reactor Trip is therefore not required for Large LOCAs

b) LOCAs within this break range remove enough decay heat via the break so that secondary heat removal is not required

c) Failure of HPSR due to failure of the HPSI pumps to provide flow results in failure of hot-leg injection because both rely on the HPSI pumps.

4.3.3.4 Major Dynamic Human Actions

The only major dynamic human actions modeled are:

a) Align hot-leg injection

b) Utilize Low Pressure Safety Recirculation should HPSR fail.

4.3.4 Steam Generator Tube Rupture Event Tree

The Steam Generator Tube Rupture (SGTR) event tree (Figure 4.3-4) applies to the rupture of one or more tubes in one steam generator causing primary coolant to leak to the secondary side. Credible tube failures range in severity from leak rates of a few to several hundred gallons per minute for the guillotine rupture of several tubes. The event chosen as representative of this range is the complete severance of a single tube, resulting in a leak rate of about 400 gpm at normal RCS and secondary-system conditions. This choice was made on the basis that less than complete failure will result in much smaller leak rates, generally within the capacity of the normal makeup system, and a fairly normal shutdown can take place. Multiple-tube failures, on the other hand, were not explicitly addressed, because they are much less likely, and because the success criteria for systems called upon to respond are substantially the same as those for the failure of a single tube. In fact, multiple-tube failures may aid in de-pressurizing the RCS, a necessary action in recovering from a tube failure.

A steam generator tube rupture event begins as a breach of the primary coolant barrier between the RCS and the secondary side of the steam generator. Primary system pressure (nominally 2250 psia) is initially much greater than the steam generator pressure (nominally 1070 psia), so RCS water flows from the primary into the secondary side of the affected steam generator at approximately 400 gpm. If leakage exceeds the capacity of the Charging system, 132 gpm (CVCS), RCS inventory will continue to decrease and eventually an automatic reactor trip signal on low pressurizer or loss of subcooling will occur.

Following the reactor trip, core power rapidly decreases to decay heat levels, steam flow to the turbine is terminated, and the Turbine Bypass Valves (TBVs) actuate to dump steam to the condenser to establish no-load coolant temperatures in the primary system. If the Turbine Bypass system is unavailable, MSSVs would lift to relieve steam pressure. The Feedwater Control system throttles FW flow in response to the reduced steam flow. If FW flow is interrupted, the AF system would be automatically actuated on low steam generator level or it could be manually actuated. Eventually, manual action is required to adjust AF flow to maintain proper level in the steam generators. If, at this point, the TBVs were unavailable, the operators would open one ADV on each steam generator to initiate plant cooldown.

A SIAS occurs on low pressurizer pressure shortly after the reactor trip. On SIAS, two of the four RCPs (one in each loop) would be manually tripped. If RCP operating limits were not met or if subcooling were lost, the remaining two RCPs would also be tripped. (Two of the RCPs would be restarted if and when restart criteria were met.)

Following reactor trip, initiation of plant cooldown, and safety injection, the operators would identify and isolate the steam generator with the tube rupture. Indications used to identify the ruptured generator are blowdown process radiation monitor alarms and main steam line area radiation alarms. Chemical analyses for radionuclides and boron in the secondary water are used for confirmation. The actions involved in isolation include closing the appropriate MSIVs, ADVs and MFIVs. Steam generator blowdown and steam drains are verified to be isolated by SIAS. (SG blowdown is later used to reduce/control SG level.)

Operators must also act to stabilize the RCS and cooldown, and de-pressurize it to a pressure slightly above the pressure in the ruptured steam generator to minimize or terminate the flow of reactor coolant to the ruptured SG. RCS pressure is kept slightly above that in the ruptured generator to prevent reverse flow and potential dilution of boric acid in the RCS and to maintain subcooling. The RCS is cooled down by secondary heat removal via the intact steam generator. The pressurizer main spray (if the RCPs are running), auxiliary spray, or pressurizer vents can be used for RCS pressure control and de-pressurization. When pressurizer level and subcooling requirements are met, the operator would throttle the HPSI flow to prevent repressurizing the RCS and increasing the leak rate to the secondary system.

After the ruptured SG is isolated, its level will continue to increase as long as there is a non-zero leak rate. To prevent overfilling the affected SG, it will be necessary to occasionally drain the steam generator via the blowdown system or, if the blowdown system is unavailable, dump steam to the condenser, if the TBVs are available, or to the atmosphere using the ADVs.

With the RCS stabilized and the ruptured generator isolated, the RCS will be cooled down and de-pressurized to shutdown cooling entry conditions (350° F and 400 psia). The Shutdown Cooling system would be aligned and started, and the plant would be taken to cold shutdown. During the cooldown to shutdown cooling entry conditions, the RWT and Condensate Storage Tank (CST), levels must be monitored to ensure adequate inventory for the cooldown. If during the transient RCS, pressure cannot be reduced within approximately 20 hrs., RWT water would be depleted.

4.3.4.1 Sequence Description

Reactor trip is demanded first following a SGTR. Breaks up to 3.0 in. in diameter do not pass enough water to remove core decay heat. Secondary cooling is therefore required. RCS pressure is not expected to drop to the Safety Injection Tank pressure; early core uncovery is not expected. If reactor trip is successful, HPSI is required for RCS inventory makeup. If HPSI fails, operator action to cooldown and de-pressurize the RCS through a rapid secondary cooldown by steaming and feeding both steam generators is necessary. (See the Low Pressure Injection Top Logic fault tree, Figure 4.3-12). Failure to de-pressurize results in core uncovery. If de-pressurization is successful, shutdown cooling is called for to allow complete RCS de-pressurization (by bringing the plant to cold shutdown), thus terminating the loss of coolant to the secondary side. If shutdown cooling fails, low pressure injection can continue indefinitely, provided the RWT is refilled. Failure to refill the RWT leads to core damage.

If HPSI is successful, cooling the intact steam generator is necessary for decay heat removal. If the intact SG cannot be cooled, core damage results, since insufficient heat is removed through the ruptured tube, and cooling via the ruptured SG is not credited.

With successful heat removal from the intact SG, the ruptured SG must be isolated and stabilized at a pressure less than the MSSV setpoint (1250 psig) to stop the loss of RCS inventory. If this is not successful, the RCS must be de-pressurized to shutdown cooling entry conditions in order to terminate the leak. If SDC cannot be successfully achieved, core damage can still be averted by refilling the RWT to maintain long-term inventory control.

The six core damage sequences then are:

a) Failure of Reactor Trip, HPSI failure

b) HPSI failure, RCS de-pressurization failure

c) HPSI failure, successful RCS de-pressurization with LPSI injection, failure of shutdown cooling, failure to refill the RWT

d) HPSI success, failure to cool the intact SG

e) HPSI success, successful cooling of intact SG, failure to isolate ruptured SG, failure to de-pressurize for SDC, failure to refill RWT

f) HPSI success, successful cooling of the intact SG, failure to isolate the ruptured SG, successful de-pressurization, failure of SDC, failure to refill the RWT.

4.3.4.2 SGTR Event Tree Elements

4.3.4.2.1 Steam Generator Tube Rupture Initiators

Steam generator tube ruptures include the failure of one or more steam generator tubes in one steam generator, such that the total leak flowrate exceeds the capacity of the charging system (132 gpm). See Section 6.1.3 for a discussion on determination of SGTR frequency.

4.3.4.2.2 Reactor Trip

On a SGTR, the RPS will generate a reactor trip signal on hot-leg saturation (CPC trip), low DNBR, or low pressurizer pressure. Failure to trip with HPSI success is treated under the ATWS event tree. Failure to trip with HPSI failure is an early core damage sequence.

4.3.4.2.3 High Pressure Safety Injection (HPSI)

There are two HPSI trains. Success is defined as injection of RWT water via one of eight HPSI lines. The HPSI starts to inject water into the system when the RCS pressure falls below the HPSI pump shut-off head (approximately 1900 psig).

4.3.4.2.4 Secondary Cooling to Intact SG

See the Steam Generator Heat Removal Top Logic fault tree, Figure 4.3-11

Following the reactor trip, the operators will respond by establishing flow to both SGs using AF and vent steam via the TBVs, if available, or the ADVs until the ruptured steam generator is identified and isolated. From that point, feeding and steaming will only be done with the intact SG. Use of the ruptured SG could result in a release of radioactive material to the environment even without core damage. The Emergency Procedures do not address using the ruptured steam generator for plant cooldown. Each of the possible means of feeding and steaming the intact SG is described below:

Auxiliary Feedwater (AF)

The success criterion for AF is defined as flow established to the intact SG from at least one of the three AF pumps within 35 min. (See Section 4.3.1.2.4 for a more complete discussion.)

Alternate Feedwater System (AltFW)

If Auxiliary Feedwater is not available, it may be possible to deliver water to the intact steam generator from the low pressure condensate pumps. The operator will have to reduce the secondary pressure to below 500 psig using the TBVs or ADVs. The actions required to align Alternate Feedwater are described further in Section 7.4. The success criterion for Alternate Feedwater is defined as the delivery of flow from one of the low pressure condensate pumps to the intact SG within 60 min. (See Section 4.3.1.2.4 for a more complete discussion.)

Turbine Bypass Valves (TBVs)

The preferred path for venting steam is through the TBVs to the condenser in order to minimize radioactive releases to the environment and conserve secondary coolant. The TBVs are not credited if a Main Steam Isolation occurs, although procedurally, the operators would attempt to restore this means of cooling. The success criterion for the TBVs is that at least one of eight TBVs operates. (Use of one of the six valves to the condenser is preferred.)

Atmospheric Dump Valves (ADVs)

If the TBVs fail or are unavailable, steam can be vented using the ADVs. These valves are remotely controlled from the Control Room. The success criterion for this element is that one of two ADVs on the intact steam generator opens to vent steam.

4.3.4.2.5 De-pressurize RCS, Inject With SITs and LPSI

If, following an SGTR event, the HPSI system does not function, the LPSI system can be used to provide injection if the primary system can be rapidly de-pressurized. To achieve this, both steam generators must be used. This will result in higher atmospheric radioactive releases, but will prevent core uncovery. Refer to Figure 4.3-12, Low Pressure Injection Top Logic Fault Tree.

The success criteria for this element are:

a) Operator action to start an aggressive cooldown is initiated within 15 min. of the SGTR
b) AF is supplied to both SGs
c) Steam is removed from both SGs using one of two Atmospheric Dump Valves on each SG or two of eight TBVs
d) LPSI flow is delivered from the RWT using one of two LPSI pumps through at least one LPSI injection line
e) At least two of four SITs supply water to the RCS during the cooldown in order to keep the core covered during de-pressurization.

4.3.4.2.6 Ruptured Steam Generator Isolated

This event is unique to the SGTR event tree. It includes all sequences where, following a SGTR, the operator fails to control and eventually stop the leak of the RCS inventory into the ruptured SG. It is also includes secondary leaks, such that a continuous blowdown of the ruptured steam generator results. In the latter case, it will not be possible to minimize the pressure differential between the RCS and SGs. If the operator is able to stop the RCS leak, then no further actions or system responses are required to prevent core damage. If the operator is unable to stop the RCS leak, then the operator would eventually run out of RWT inventory. Once HPSI has no RWT water to inject, core uncovery will eventually follow. In order to prevent this, the operator will be forced to reduce the RCS pressure and go on Shutdown Cooling or refill the RWT to continue HPSI.

The following paragraphs list the success criteria for proper response to a SG tube rupture. Refer to Figure 4.3-15 for the Unisolated Leak During SGTR Top Logic fault tree.

<u>RCS De-pressurization</u>

The success criteria for reducing RCS pressure are:

a) The operator properly throttles HPSI based on maintaining satisfactory subcooling and controlling pressurizer level, and utilizes both RCS and SG pressure control systems to reduce SG pressure to less than the MSSV setpoint of 1250 psig
b) SG pressure control systems function properly, i.e., one of two ADVs or one of eight TBVs opens on demand
c) RCS pressure control systems function properly, i.e., one of two Class 1E Pressurizer Auxiliary Spray valves, and at least one Charging Pump or the Class 1E Pressurizer Vent valves.

<u>Ruptured SG Isolated</u>

A ruptured SG is isolated by closing the MSIVs and by ensuring that the ADVs and the MSSVs remain closed. The credible failure modes that result in an isolated ruptured SG are: a failure to close the MSIVs due either to mechanical faults or human error, or failure of either an ADV or a MSSV to reclose after opening. Spurious open failures of the ADVs and MSSVs are not modeled because of the small probability of such an event occurring during the SGTR. Situations where the ruptured SGs ADVs, or MSSVs are demanded and fail to reclose are more likely and therefore were considered, such as when TBVs fail or a spurious MSIS occurs prior to RCS cooldown to a point where secondary pressure is less than the MSSV setpoint.

The success criteria for isolating the ruptured SG are:

a) If TBVs are unavailable, both ADVs and any MSSVs, which opened on a pressure transient, re-close
b) Both MSIVs close on demand
c) Operator properly isolates SG per procedure, specifically closing the MSIVs.

Ruptured SG Level Controlled After Isolation

The Control Room operators are instructed, per the Steam Generator Tube Rupture recovery procedure, to isolate the ruptured SG and then use blowdown to keep the SG level below 90% wide range. In the event that blowdown fails, the operator would probably not open the MSIV and would thus only have the option of using the ADVs to prevent overfilling the SG. If the operator fails to use the ADVs, it is assumed that the SG eventually will overfill.

On a SG overfill, two events could occur that would unisolate the SG. First, the steam lines, which are not designed to carry water, could break under the dynamic forces of the water in the lines. (However, this was determined to have a low conditional probability of 1E-3/event in NUREG-0844 Section 3.4.1.) Second, if the steam line does not rupture, then water would relieve through the MSSVs. Since the MSSVs are designed for steam relief, one of the MSSVs could eventually fail open due to the water relief. It was therefore conservatively assumed that the ruptured SG becomes unisolated with a probability of 1.0 on a SG overfill.

The success criteria for preventing SG overfill are:

a) The operator initiates blowdown prior to overfill and
b) The blowdown system is available and operates properly;

or

a) The operator utilizes ADVs to steam the ruptured steam generator and
b) One of the two ADVs on the ruptured SG operates on demand.

4.3.4.2.7 De-pressurization to SDC Entry Conditions

If the RCS leak to the ruptured SG continues, the Control Room operator will attempt to go onto shutdown cooling. In order to perform this action, it is necessary to de-pressurize and cool the RCS to 350° F and 400 psia. Without the required RCS pressure control, this cannot be performed. To provide successful RCS de-pressurization, either the ADVs or TBVs on the intact SG must be used and pressurizer pressure control must be available to meet the HPSI throttle conditions.

On natural circulation, with the Auxiliary Sprays operating and AF to the intact SG, the RCS can be brought down to SDC entry conditions within about 8 hrs. Even using pressurizer vents for primary pressure control, the RCS could be cooled to SDC within 8 hrs. An additional 8 hrs. would be required on SDC to complete the cooldown to 212° F and completely de-pressurize.

On a failure to establish RCS pressure control, the operator would be required to refill the RWT with borated water in order to continue RCS makeup via HPSI.

4.3.4.2.8 Shutdown Cooling

Shutdown Cooling is required following sequences involving HPSI failure and on failure to terminate the RCS leak. The SDC system utilizes LPSI pumps with a shutdown cooling heat exchanger (SDCHX). To align one LPSI pump, the operator must open three SDC isolation valves and align the LPSI discharge through the train-related SDCHX.

The success criterion for SDC is successful alignment of at least one LPSI pump through the train-related SDCHX to at least one injection header.

4.3.4.2.9 Refill the RWT

If there is an unisolable path from the ruptured SG and SDC is not successfully achieved, there will be continuous leakage from primary to secondary. This leakage will eventually deplete the RWT inventory. Depletion of the RWT inventory will lead to core uncovery and core melt, since coolant lost via the tube rupture does not find its way to the containment sumps. To prevent this, the RWT inventory must be replenished. However, the RWT contains at least 600,000 gallons; its depletion is unlikely before any necessary equipment repairs could be done.

Additional inventory can be supplied to the RWT from the Spent Fuel Pool via the Boric Acid Makeup Pumps, from the Hold-up Tank via the Hold-up Tank Pumps, from the Reactor and Equipment Drain Tanks using the Reactor Drain Pumps, or it can be batched using the boric acid batch tank with the Reactor Makeup Water Pumps supplying water from the Reactor Makeup Water Tank. Since the fastest and easiest method of replenishing the RWT is to take inventory from the Spent Fuel Pool, this is the only makeup means credited. The Spent Fuel Pool has 33,500 gallons of borated water, which can be delivered to the RWT at 165 or 330 gpm (1 or 2 pumps).

4.3.4.3 Major Assumptions and Dependencies

The following important assumptions were made in the development of the SGTR event tree:

a) The operators will not establish secondary heat removal using the faulted steam generator even if the intact SG cannot be used

b) If the ruptured SG is not isolated and RCS and SG pressure control is not established, then shutdown cooling entry conditions cannot be established; therefore, long-term cooling must be maintained via secondary heat removal and the RWT must eventually be refilled in order to continue HPSI

c) If Auxiliary Feedwater is unavailable, the intact SG must be de-pressurized to less than 500 psia to use the condensate pumps to supply feedwater

d) If HPSI and AF are not available, there is insufficient time to establish condensate feedwater flow before core uncovery

e) No credit is taken for the FW pumps to provide secondary side heat removal

f) If the RCS is rapidly de-pressurized for LPSI due to the unavailability of the HPSI system, pressurizer spray or vents are not needed for RCS pressure control, because RCS pressure and temperature will be within the limits of shutdown cooling entry conditions

g) If the ruptured SG is allowed to overfill, it is conservatively assumed that it becomes unisolated.

4.3.4.4 Major Dynamic Human Actions

The following major dynamic human actions are explicitly modeled within the event tree and fault trees:

a) Alignment of Alternate Feedwater upon failure of Auxiliary Feedwater

b) Rapid de-pressurization of the RCS to use LPSI upon failure of HPSI

c) Refilling the RWT if injection must be continued long-term due to RCS de-pressurization failure or SDC system failure.

4.3.5 Large Steam (Secondary) Line Break Event Tree

The Large Steam Line Break Event Tree is shown in Figure 4.3-5.

Large secondary side breaks are characterized as rapid cooldown events due to increased steam flowrate, which causes excessive heat removal from the steam generators (SG) and the reactor coolant system (RCS). This results in a decrease in reactor coolant temperature and pressure. The cooldown causes an increase in core reactivity due to the negative moderator and Doppler reactivity coefficients. Only unisolable breaks in the main steam lines and downcomer feedwater lines are included in this event. (Large breaks in the economizer lines and blowdown lines are not included in this event, since plant response is fundamentally different. These are covered in Section 4.3.6 Feedwater Line Breaks.)

A large steam line break will be indicated by pressurizer and SG low pressure alarms, high reactor power alarm, and by the low SG water level alarm. A reactor trip following a steam line break is caused by any one of these reactor trip signals.

The de-pressurization of the steam generators results in the actuation of a Main Steam Isolation Signal (MSIS). This closes the MSIVs, isolating the affected and the unaffected steam generators from each other and closes the main feedwater isolation valves (MFIVs), terminating main feedwater flow to both steam generators. After the reduction of steam flow that occurs with a MSIV closure, the level in the intact steam generator falls below the Auxiliary Feedwater Actuation Signal (AFAS) setpoint. The resulting AFAS causes AF flow to be initiated to the intact steam generator. The AFAS logic prevents feeding the affected steam generator due to its lower pressure. Meanwhile, pressurizer pressure decreases to the point where a Safety Injection Actuation Signal (SIAS) is initiated to start HPSI. The isolation of the unaffected steam generator and subsequent emptying of the affected steam generator terminate the cooldown. The introduction of borated RWT water via HPSI causes core reactivity to decrease, thus ensuring that a return to criticality is not experienced should a stuck control rod (CEA) occur. The Control Room operators will initiate plant cooldown by manual control of the ADVs or, if off-site power is available, by opening the MSIV bypass valves associated with the unaffected steam generator and using the turbine bypass valves to relieve steam any time after the affected steam generator empties.

For this analysis, the location of the break, inside containment, or outside containment, is not considered important because plant and operator responses with respect to core melt prevention will be similar. The primary differences relate to containment effects, availability of containment safeguards systems, and potential release paths. Containment Response is discussed in Section 11.

4.3.5.1 Sequence Description

Following the initiating event, the first action called for is Reactor Trip so that heat from fission is terminated quickly. Failure of reactor trip is covered in detail in the ATWS event tree. Success criteria for the reactor trip include a trip signal is properly generated and all but one CEA fully inserts into the core.

Return to criticality is possible late in the fuel cycle if the most reactive CEA fails to insert. The next event in the tree asks whether a CEA sticks out, which determines whether boration via HPSI is required. Following the initial rapid cooldown, long-term decay heat removal is required. This event includes only Auxiliary Feedwater and Main Steam Safety Valves or Atmospheric Dump Valves for steaming. If secondary cooling fails, HPSI is called upon for added inventory to act as a temporary heat sink until a backup means of heat removal is established. Failure of HPSI is assumed to lead to core damage for a stuck CEA.

If HPSI is successful following failed secondary cooling, a backup means of secondary cooling utilizes Alternate Feedwater.

If secondary cooling is initially successful following a stuck CEA, HPSI is called upon for reactivity control. Failure of HPSI is assumed to lead to core damage.

If a stuck CEA did not occur, but secondary cooling fails, time can be gained for aligning Alternate Feedwater by injecting cool water into the RCS via HPSI. If HPSI is unsuccessful, it is assumed insufficient time is available for implementing Alternate Feedwater and core damage results.

The core damage sequences then are:

a) Stuck Rod, Secondary Cooling failure, HPSI failure

b) Stuck Rod, Secondary Cooling failure, HPSI success, Alternate Feedwater failure

c) Stuck Rod, Secondary cooling success, HPSI failure

d) No stuck rod, Secondary cooling failure, HPSI failure

e) No stuck rod, Secondary cooling failure, HPSI success, Alternate feedwater failure

4.3.5.2 Large Secondary Line Break Sequence Elements

4.3.5.2.1 Large Secondary Line Break Initiators

Large secondary side breaks include large main steam line piping breaks up to and including double-ended guillotine breaks, feedwater downcomer line breaks, and spurious openings of multiple MSSVs, ADVs, or TBVs. Piping breaks inside or outside of containment are included in this category. The spurious opening of a single MSSV, ADV, or TBV and small steam line breaks are not covered in this event tree, but are included in the Grouped Transients Event Tree analysis. Feedwater economizer line and steam generator blowdown line ruptures are covered under the Feedwater Line Break Event Tree, Section 4.3.6.

4.3.5.2.2 Reactor Trip

On a secondary line break, the RPS will generate a reactor trip signal on any of a number of trip signals. Failure of reactor trip is treated under the ATWS event tree. Reactor trip is considered to be successful if no more than one CEA sticks out. This is adequate negative reactivity for all analyzed events except Large Secondary Line Breaks, thus the following event is necessary.

4.3.5.2.3 No Stuck CEA

Following a large secondary line break, an overcooling transient causes a positive reactivity feedback. At the end of core life, there is a chance that if the CEA with the most reactivity worth does not insert into the core, the reactor could return to power unless boron injection into the RCS succeeds. This element in the event tree is actually a single probability, and as such does not appear in the fault tree logic. This event probability is derived in Section 6.2.5.

4.3.5.2.4 Secondary Cooling (flow from Auxiliary Feedwater)

Refer to the Steam Generator Heat Removal Top Logic fault tree, Figure 4.3-11.

Following a secondary side break event, Auxiliary Feedwater must be supplied to the intact steam generator in order to remove decay heat from the RCS. The success criterion for this element requires that Auxiliary Feedwater flow be delivered from at least one of the three auxiliary feedwater pumps to the intact SG.

Steam must be vented from the intact steam generator in conjunction with the supply of AF flow. The following sections describe the two methods of secondary steam removal. No credit for TBVs is given, since an MSIS occurs early in the sequence on low SG pressure.

Atmospheric Dump Valves (ADVs)

Following a secondary side break, the preferred means of removing steam from the intact steam generator is via the ADVs to avoid cycling the MSSVs. The success criterion for ADVs on the intact SG is that one of the two ADVs operates on demand.

Main Steam Safety Valves (MSSVs)

If steam is not vented through an ADV, steam relief will be through one of the ten SG's MSSVs. The success criterion for this element is that one of ten MSSVs on the intact steam generator opens.

4.3.5.2.5 High Pressure Safety Injection (HPSI)

Due to the cooldown, the RCS volume shrinks substantially. HPSI is automatically initiated on low pressurizer pressure and injects sufficient borated water to prevent a return to power. The success criterion for boration is delivery of RWT water from at least one of two HPSI pumps through at least one of eight HPSI injection lines to the RCS.

If the AF system fails with or without a stuck CEA, the HPSI system will provide sufficient inventory to the RCS during the initial cooldown so that 1 hr. is available to align the condensate pumps to deliver Alternate Feedwater to the intact steam generator. The success criterion for makeup is the same as for boration.

4.3.5.2.6 Secondary Cooling (flow from Alternate Feedwater)

As stated earlier, if secondary cooling via AF fails, the Condensate Pumps can be aligned to supply feedwater. TBVs are not credited for steaming due to the Main Steam Isolation.

4.3.5.3 Major Assumptions and Dependencies

a) It is conservatively assumed that HPSI is required for any stuck CEA at any time during a fuel cycle

b) Certain routine or well proceduralized and practiced human actions, such as throttling AF or HPSI flow and control of steaming rate, are assumed to be successful

c) If Auxiliary Feedwater is unavailable, the secondary system must be de-pressurized to less than 500 psig to use the condensate pumps to supply feedwater. The MSSVs cannot de-pressurize the system, and the ADVs must be available.

d) HPSI flow through any path reaches the RCS, i.e., no assumed flow through a break as in LOCA

e) Only the intact SG is credited for long-term decay heat removal.

4.3.5.4 Major Dynamic Human Actions

Two recoveries are modeled:

a) Override MSIS to use the Train N AF pump to feed the intact SG

b) Align Alternate Feedwater upon failure of AF.

4.3.6 Large Feedwater Line Break

The Large Feedwater Line Break event tree (Figure 4.3-6) shows the sequence of events following a rupture of an economizer line or blowdown line that is unisolable from the steam generators. These events are very similar to loss of feedwater transients. Indications would include rising RCS temperature, a steam flow/feed flow mismatch, possibly low pressure in the feedwater system and decreasing steam generator water level in both SGs, because feedwater will preferentially flow out the break (path of least resistance). A reactor trip could result from a number of conditions depending on break size, including high RCS temperature (CPC-initiated), high pressurizer pressure, high containment pressure, or low steam generator water level. A Main Steam Isolation Signal (MSIS) will be generated when either the affected steam generator de-pressurizes at the end of blowdown or when the high containment pressure setpoint is reached. High containment pressure will also bring in Containment Isolation/Safety Injection. The MSIS will isolate the steam generators. Auxiliary Feedwater Actuation will occur for both steam generators, but the AFAS logic will not allow flow to the ruptured steam generator after a 150 psi pressure differential develops between the two SGs. From this point on, only the intact steam generator is available for heat removal. Containment Response is treated in Section 11.

4.3.6.1 Sequence Description

Following the initiating event, a reactor trip is necessary to terminate heat generation from fission as soon as possible, as this is a heatup event. After successful reactor trip, secondary cooling is called for both to remove the excess stored energy resulting from the heatup and to remove subsequent decay heat. Only AF is credited for a water source, and MSSVs and ADVs are credited for steaming the intact steam generator. Failure of secondary cooling leads to core damage.

If secondary cooling is successful, RCS integrity is questioned, since pressurizer safety valves lift to mitigate the pressure transient in the RCS. If one or more does not reseat, an induced Small LOCA results, and HPSI will be required for inventory makeup. No credit is taken for RCS de-pressurization for low pressure safety injection, so HPSI failure is assumed to lead to core damage.

If HPSI is successful, the RWT contents will all eventually be injected into the RCS, and a RAS will be generated. Unsuccessful transition to HPSR leads to core damage.

The three core damage sequences then are:

a) AF failure

b) AF success, RCS integrity failure, HPSI failure

c) AF success, RCS integrity failure, HPSI success, HPSR failure.

4.3.6.2 Large Feedwater Line Break Sequence Elements

4.3.6.2.1 Large Feedwater Line Break Initiators

Economizer feedwater line breaks downstream of the last check valve prior to the steam generator fall into this category, along with breaks in the blowdown piping up to the inside-containment isolation valve. Feedwater line breaks upstream of the last check valves are isolable and the event is the same as a loss of feedwater; i.e., a steam generator does not blow down and both steam generators are subsequently available for heat removal. Although the peak RCS pressure achieved is a function of break size, it was conservatively assumed that any event in this category causes pressurizer safety valves to lift.

4.3.6.2.2 Reactor Trip

In the event of a feedwater line or blowdown line break, RPS will generate a reactor trip signal on any one of several parameters. Failure of reactor trip is treated under the ATWS Event Tree, Section 4.3.11.

4.3.6.2.3 Secondary Cooling (Auxiliary Feedwater)

Auxiliary Feedwater is required to remove decay heat, whether or not a Small LOCA results due to a pressurizer safety valve failing to reseat. The success criterion for AF is that one of three Auxiliary Feedwater pumps delivers flow to the intact steam generator.

Following a large secondary line break, steam must be removed from the unaffected steam generator in conjunction with the supply of AF. The following sections describe the two methods of steam removal modeled.

Atmospheric Dump Valves (ADVs)

Following a secondary side break, the preferred means of removing steam from the unaffected steam generator is via the ADVs to avoid cycling the MSSVs. The success criterion for ADVs on the intact SG is that one of the two ADVs operates for steaming.

Main Steam Safety Valves (MSSVs)

If the ADVs on the intact SG fail, steam relief will be through one of the ten SG's MSSVs. The success criterion for this element is that one of ten MSSVs opens on the intact steam generator.

4.3.6.2.4 RCS Integrity

The heatup associated with this event leads to lifting of the pressurizer safeties early in the transient. If one or more does not reseat properly, an induced Small LOCA results.

4.3.6.2.5 High Pressure Safety Injection (HPSI)

If an induced Small LOCA occurs, HPSI is required for RCS inventory makeup. The success criterion is that one of two HPSI pumps delivers flow through at least three injection lines to the RCS.

4.3.6.2.6 High Pressure Safety Recirculation (HPSR)

For long-term RCS inventory control, high pressure recirculation is necessary once the Refueling Water Tank (RWT) inventory is depleted and a Recirculation Actuation Signal occurs. The success criterion for HPSR is that one HPSI pump successfully transfers its suction source to the containment sump and provides recirculation through at least three HPSI lines.

4.3.6.3 Major Assumptions

The following important assumptions were made in development of the Large Feedwater Line Break event tree:

a) Unlike most other initiating events, no credit is taken for aligning Alternate Feedwater if AF fails. Feedwater line break is a heatup event, which also leads to some loss of RCS inventory through pressurizer safety valves. A large fraction of the SG inventory is blowdown followed by a MSIS, which isolates Main Feedwater and one AF pump. All this leads to a much shorter time available to initiate feedwater to avoid core damage than allowed by the modeling used for the Alternate Feedwater alignment

b) TBVs are not credited for steaming due to the MSIS, although operators could override MSIS and steam the intact SG

c) All events of this type lead to pressurizer safety valves lifting, although the peak pressure is a function of break size

d) No credit is taken for operator action to de-pressurize the RCS for Low Pressure Safety Injection if HPSI fails, because feeding and steaming both SGs is required.

4.3.6.4 Major Dynamic Human Actions

No major dynamic human actions are modeled for Feedwater Line Break.

4.3.7 Grouped Transients Event Tree

The Grouped Transients event tree, shown in Figure 4.3-7, is used for a diverse group of initiators that initially require only SG cooling and steam relief to mitigate the transient. The event tree also models the possibility that an initiating event could cause a Small LOCA through failure of the RCP shaft seals or failure to close a Pressurizer Safety Valve following a demand.

The initiators for which this event tree pertains cause a reactor trip, at which time Auxiliary Feedwater is demanded. Main Feedwater may be available initially and can provide time for operators to establish long-term feedwater supply. For most of the initiators, the event is terminated once a long-term source of feedwater is established to the SGs and steam relief is successful.

For those events which could induce a Small LOCA via the means mentioned earlier, the HPSI and HPSR systems are required to avoid core damage. The use of LPSI and LPSR on a loss of HPSI are not credited in the present model.

4.3.7.1 Sequence Description

After any one of the transient initiating events, a reactor trip is called for. After reactor trip, secondary cooling is required. Failure of secondary cooling leads to core damage.

Upon successful secondary cooling, RCS integrity is questioned. Certain events may lead to lifting of pressurizer safety valves, which may not reseat. Other events may cause loss of RCP seal cooling and seal injection, which may in turn lead to RCP seal LOCA. If RCS integrity is lost, HPSI is required for inventory makeup to the RCS. No credit is taken for depressurizing the RCS for Low Pressure Safety Injection if HPSI fails. Failure of HPSI, therefore, leads to core damage.

If HPSI is successful, recirculation from the containment sump must eventually be established. Failure of High Pressure Safety Recirculation (HPSR) leads to core damage.

The three core damage sequences for all transient events are:

a) Failure of Secondary Cooling (AF and AltFW)

b) Secondary Cooling success, RCS integrity failure, HPSI failure

c) Secondary Cooling success, RCS integrity failure, HPSI success, HPSR failure.

4.3.7.2 Grouped Transients Sequence Elements

4.3.7.2.1 Grouped Transient Initiators

Grouped Transient initiators include all initiators for which the basic plant response is a reactor trip with RCS heat removal satisfied by delivery of auxiliary or alternate feedwater and steam removal via the ADVs, MSSVs, or the TBVs. These initiators include turbine or generator protective trips, spurious MSIV closures, CEA drops, spurious manual or automatic reactor trips, RCS flow reductions, partial losses of power events, RCS parameter perturbations leading to a trip, loss of room cooling events (HVAC), loss of instrument air, and loss of cooling water systems. Section 4.1 further describes these events. Loss Of Off-site Power, although it uses this tree, is treated separately in Section 4.3.9.

4.3.7.2.2 Reactor Trip

On a transient initiating event, the RPS will generate a reactor trip signal. Failure of the reactor to trip is treated under the ATWS Event Tree, Section 4.3.11.

4.3.7.2.3 Secondary Cooling

Following the transient and reactor trip, secondary cooling must be supplied to the steam generators in order to remove decay heat from the RCS. Systems for supplying feedwater and venting steam are discussed below. However, not every system is available for each transient covered by this tree. For example, AltFW is not available if off-site power is lost. Those options available for each transient are determined in the fault tree logic when the initiating event sequences are quantified. Refer to the Steam Generator Heat Removal Top Logic fault tree, Figure 4.3-11.

Auxiliary Feedwater (AF)

The success criterion for AF is that flow must be delivered from one of the three auxiliary feedwater pumps to at least one steam generator within 35 min., if FW is not available after the trip or within 70 min. if it is available. See Section 7.4 for a discussion of FW and time available to establish AF or AltFW flow.

The Control Room operators will most likely attempt to start the non-essential (Train N) AF pump prior to stopping FW and receiving AFAS on those events where FW is not lost because of the initiator.

Alternate Feedwater (AltFW)

If AF fails, it may be possible to deliver water to the steam generators from the low pressure condensate pumps. The operator would have to reduce the secondary pressure to less than 500 psia using the turbine bypass or atmospheric dump valves. The success criterion for Alternate Feedwater is that flow is supplied from one of the three condensate pumps to at least one SG within the required time following the reactor trip. No credit is taken for local manual operation of the ADVs and TBVs, so if they fail, AltFW cannot be used.

Turbine Bypass Valve (TBVs)

In addition to supplying feedwater to a SG, steam must be vented in order to remove RCS decay heat. The preferred means of venting steam is via the TBVs. There is an automatic system that controls these valves. Their use prevents loss of secondary coolant inventory and possibly unmonitored radioactive releases due to leaking SG tubes.

Atmospheric Dump Valves (ADVs)

Operators can vent steam using the atmospheric dump valves (ADVs). The success criterion for ADVs is that one of the two ADVs on a SG being fed must open to vent steam.

Main Steam Safety Valves (MSSVs)

If the TBVs and ADVs are unavailable or fail, steam relief will be through the MSSVs. The success criterion for MSSVs is that one of ten main steam safety valves opens on a SG being fed.

4.3.7.2.4 RCS Integrity (No RCP Seal LOCA or Stuck Open PSV)

The RCS Integrity Loss Top Logic fault tree (Figure 4.3-16) models the causes for a loss of RCS integrity following a transient event, Loss Of Off-site Power (Section 4.3.8), or Loss of Feedwater (Section 4.3.9).

It represents a transient-induced Small LOCA from either a stuck-open Pressurizer Safety Value (PSV) or a failed RCP shaft seal package. (See Sections 4.3.10 and 6.1.3.2.5 for a discussion of RCP seal failures.)

The PSVs can be expected to actuate following all trips initiated by or leading to closure of all four MSIVs prior to a reactor trip. The PSVs may also lift on a turbine trip (load rejection) followed by failure of the Reactor Power Cutback System (RPCS) and the TBV quick-open function. (The RPCS acts to rapidly reduce reactor power by dropping selected control group CEAs upon loss of load or loss of one main feedwater pump.) In addition to lifting to relieve the initial pressure transient, the PSVs would be demanded multiple times following dry out of the steam generators (if feedwater were not supplied within about 35 min.) as reactor coolant boils away. After RCS temperature reaches saturation, a steam bubble will form in the reactor vessel head forcing water through the PSVs. Since the PSVs were designed to relieve steam, they are assumed to have a higher probability of failure to close for water relief. This higher failure probability was accommodated in the cutset analysis; the failure probability for steam relief appears in the RCS Integrity Loss fault tree.

The RCP shaft seals could fail under certain combinations of loss of seal cooling, loss of seal injection, and operator failure to secure the pumps. The initiating events more likely to lead to seal failure are those that directly cause a loss of seal cooling: Loss of Nuclear Cooling Water, Loss of Plant Cooling Water, Loss Of Off-site Power, and Station Blackout. Except for Station Blackout, the operator can backup loss of normal seal cooling by Nuclear Cooling Water (NC) using Essential Cooling Water (EW).

4.3.7.2.5 High Pressure Safety Injection (HPSI)

In the case of a transient-induced LOCA, HPSI is required to maintain RCS inventory. The success criterion for HPSI is defined as flow to the RCS from at least one HPSI pump through at least three HPSI lines.

4.3.7.2.6 High Pressure Recirculation (HPSR)

Following HPSI, the containment sump valves are automatically opened on RAS and HPSR from the sump to the RCS injection lines continues. The success criterion is a successful switchover and recirculation of at least one HPSI pump from the sump through at least three of the eight RCS injection lines.

4.3.7.3 Major Assumptions and Dependencies

The following assumptions were made in developing the Grouped Transients event tree:

a) It is conservatively assumed that if RCP shaft seal failure occurs, all three seals in the seal package fail

b) No credit is taken for restarting a FW pump nor for long-term decay heat removal using a FW pump.

4.3.7.4 Major Dynamic Human Actions

The only major dynamic human actions incorporated into the event tree and its top logic are:

a) Override MSIS to establish flowpath for the Train N AF pump or AltFW

b) Align Alternate Feedwater if AF fails.

LPSI and LPSR following failure of HPSI could have been applied as a top event as it was in Small LOCA. However, the CDF for HPSI or HPSR failure sequences is generally very small, so it was deemed not necessary to include it.

4.3.8 Loss Of Off-site Power

The Loss Of Off-site Power initiator utilizes the Grouped Transients Event Tree, Figure 4.3-7.

A Loss Of Off-site Power (LOOP) will result in a loss of forced reactor coolant flow due to simultaneous loss of electrical power to all four reactor coolant pumps (RCPs). A LOOP also produces a loss of condenser vacuum and loss of main feedwater (due to the loss of power to the condenser cooling water pumps), and a start signal to the emergency diesel generators due to low voltage on the 4.16kV ESF buses. Due to the loss of condenser vacuum, the Turbine Bypass Valves (TBVs) are unavailable. (No credit is taken for just the two TBVs that discharge to atmosphere.) The condensate pumps are also without power, so Alternate Feedwater is not available.

The loss of forced coolant flow following loss of power to the RCPs leads to a reactor trip on low DNBR (CPC auxiliary trip) and reactor power begins to decrease, accompanied by a decrease in pressurizer level due to decreased RCS average temperature. The loss of secondary heat sink then results in a loss of RCS heat removal. Both primary and secondary pressure will increase. The main steam safety valves will lift to control secondary pressure. The primary safety valves are not expected to lift during the transient. Concurrently, steam generator level will be decreasing and auxiliary feedwater will be actuated or initiated manually. When secondary heat removal (and therefore RCS heat removal) via the auxiliary feedwater and the main steam safety valves or ADVs is re-established, primary pressure and temperature will begin to decrease.

When off-site power is lost, the diesel generators will receive a start signal. Once the diesel generators are up to rated speed and voltage, the load sequencer will load the Engineered Safety Features (ESF) buses. The ESF buses provide power to the HPSI if needed, motor-driven Auxiliary Feedwater, Essential Cooling Water, and Spray Pond pumps and motor operated valves associated with each system. The charging pumps are manually re-loaded.

4.3.8.1 Sequence Description

The sequence descriptions are virtually identical to those given for Grouped Transients, since the same event tree is used. However, the loss of AC power to most non-safety-related equipment, such as normal HVAC, Instrument Air, and Nuclear Cooling Water, precludes its use in mitigating this transient.

Auxiliary Feedwater must be available for secondary heat removal, along with either MSSVs or ADVs. Failure of AF or both MSSVs and ADVs leads to core damage.

If heat removal is successful, RCS integrity is questioned. Without off-site power, the possibility of a RCP seal LOCA exists, since normal seal cooling and seal injection are lost. The operator must either restart a charging pump to regain seal injection or back up NC with EW for cooling if a seal LOCA develops. HPSI will be required to supply inventory makeup. Failure of HPSI is assumed to lead to core damage. (No credit is taken for operator action to de-pressurize the RCS for Low Pressure Safety Injection.)

If HPSI is successful, sump recirculation will be necessary when the contents of the RWT have been used. Failure of HPSR leads to core damage, since no credit is taken for refilling the RWT.

The three core damage sequences are:

a) Failure of Secondary Cooling

b) Secondary Cooling success, RCS integrity failure, HPSI failure

c) Secondary Cooling success, RCS integrity failure, HPSI success, HPSR failure.

4.3.8.2 Loss Of Off-site Power Sequence Elements

4.3.8.2.1 Loss Of Off-site Power Initiators

Loss Of Off-site Power events include all events initiated by a loss of grid power of any duration from the high voltage distribution lines serving the station concurrent with a unit trip and all events involving loss of normal off-site power to both Essential Safety Features buses. The loss of grid power may be caused by external events such as storms, fires, floods or earthquakes, equipment failures within the grid system or site, or switchyard or human error. Subsequent failures leading to loss of all AC power to both Essential Safety Features buses are analyzed as Station Blackout and covered in Section 4.3.10.

The Loss Of Off-site Power event tree presumes the success of at least one emergency diesel generator.

4.3.8.2.2 Reactor Trip

On a LOOP, the RPS will generate trip signals on low DNBR, low RCS flow, low steam generator level, and high pressurizer pressure. If the RPS does not generate a trip signal, the Supplementary Protection System (SPS) will generate a trip signal on high pressurizer pressure. In addition, on LOOP, power will be lost to the motor generator sets, which provide holding power to the Control Element Drive Mechanisms (CEA holding coils). Thus, even if a trip signal is not generated, the CEA holding coils will be de-energized within approximately 5 secs. Failure to insert the CEAs is treated under the ATWS Event Tree, Section 4.3.11.

4.3.8.2.3 Secondary Cooling (Auxiliary Feedwater)

Each of the means available to steam and feed the steam generators is discussed below.

Auxiliary Feedwater (AF)

Following a LOOP, auxiliary feedwater must be supplied to the steam generators in order to remove decay heat from the RCS. The success criterion for AF is that auxiliary feedwater must be delivered from at least one of the three auxiliary feedwater pumps to one steam generator.

Atmospheric Dump Valves (ADVs)

Following a LOOP, the preferred means of venting steam is via the atmospheric dump valves to avoid cycling the MSSVs. However, each valve has a backup Nitrogen supply bottle, which will maintain valve operation for a limited number of cycles.

The success criteria for ADVs are that one of two ADVs must be opened to vent steam from the SG to which AF flow is supplied.

Main Steam Safety Valves (MSSVs)

If, following a LOOP, the ADVs fail, the main steam safety valves can be used for steam removal. The main steam safety valves will cycle to maintain the steam generator pressure in a narrow band around the main steam safety valve setpoint pressure.

The success criterion for MSSVs is that one of ten main steam safety valves opens on the SG to which AF is being delivered.

4.3.8.2.4 RCS Integrity (No RCP Seal LOCA or Stuck Open PSV)

The loss of RCS integrity event represents a transient-induced Small LOCA from an RCP seal leak. Since a LOOP causes all RCPs to trip, conditions that could induce a seal LOCA will only occur on an extended loss of seal cooling and seal injection. Seal cooling is normally supplied by Nuclear Cooling Water, which is lost on a LOOP, but the operator is directed to back it up with Essential Cooling Water. Seal injection is supplied from normal charging. In order for the seals to degrade sufficiently such that a LOCA could occur, both systems must fail. See Section 6.1.3.2.5 for a discussion of RCP seal LOCA.

A Pressurizer Safety Valve LOCA is not a significant concern for LOOP. The initial pressure transient is not expected to lift the PSVs. In order to avoid core damage, off-site power is required to be restored by the time the steam generators dry out.

4.3.8.2.5 High Pressure Safety Injection (HPSI)

In the case of a transient-induced LOCA, HPSI is required to maintain RCS inventory. The success criterion for HPSI is defined as flow to the RCS from at least one HPSI pump through at least three HPSI lines.

4.3.8.2.6 High Pressure Safety Recirculation (HPSR)

Following HPSI, the containment sump valves are automatically opened on RAS, and HPSI recirculation from the sump to the RCS injection lines continues. The success criterion is a successful switchover and recirculation of at least one HPSI pump from the sump through at least three RCS injection lines. This is conservative, since with only one HPSI pump operating, each cold-leg injection line delivers at least 270 gpm (Technical Specification average minimum value).

4.3.8.3 Major Assumptions

The following important assumptions were made in developing the LOOP event:

a) On a loss of both seal cooling and seal injection to the RCPs, a seal LOCA could possibly occur. The probability derived for seal failure is discussed in Section 6.1.3.2.5

b) At least one Diesel Generator is available and providing power

c) No credit is taken for operator action to de-pressurize the RCS for Low Pressure Safety Injection if HPSI fails.

4.3.8.4 Major Dynamic Human Actions

The following dynamic human actions are modeled:

a) Alignment at Train N AF Pump

b) Restoration of charging flow for RCP seal injection.

The restoration of off-site power will be addressed in the recovery analysis for the LOOP sequences.

4.3.9 Loss of Main Feedwater Event Tree

The Loss of Main Feedwater/Condensate Pumps (MFW) Event Tree (Figure 4.3-8) includes all events initiated by a loss of all FW. This group includes loss of all FW pumps, all condensate pumps, and condenser vacuum. A loss of condensate pumps, which supply flow to the suction of the FW pumps, will automatically trip the FW pumps on low suction pressure. A loss of condenser vacuum automatically sends a trip signal to the FW pumps.

The Loss of MFW events are treated separately from the grouped transients due to the RCS response following the transient. On the loss of MFW, the SG levels will rapidly decrease until a reactor trip occurs on low SG level. Prior to reactor trip, at least one third of the SG inventory has been depleted. If AF functions properly, the transient continues as a normal reactor trip. However, if AF is unavailable, then prior to aligning AltFW, the Pressurizer Safety Valves will have lifted due to high RCS pressure. This could lead to a stuck open PSV and a LOCA. The resulting LOCA is then treated as a transient-induced Small LOCA in the event tree and requires HPSI and HPSR to avoid core damage.

4.3.9.1 Sequence Description

Following the initiating event, reactor trip is called for to reduce the heat generated from fission. Assuming successful reactor trip, AF is called for to remove heat from the steam generators. Alternate feedwater is called for in a separate top event, because SG dryout and lifting of pressurizer safety relief valves may occur before AltFW can be aligned to backup AF.

If AF fails, Alternate Feedwater is called for. If AltFW fails, core damage results; if AltFW succeeds, heat removal is established, but the pressurizer safeties may not have reseated leading to an induced Small LOCA. Therefore, HPSI is required for inventory makeup. Core damage results if HPSI fails.

With HPSI successful, HPSR from the sumps will be required when the RWT has been injected into the RCS. Recirculation failure results in core damage.

The three core damage sequences then are:

a) AF failure, AltFW failure

b) AF failure, AltFW success, RCS integrity failure, HPSI failure

c) AF failure, AltFW success, RCS integrity failure, HPSI success, HPSR failure.

4.3.9.2 Loss of Main Feedwater Sequence Elements

4.3.9.2.1 Loss of Main Feedwater Initiators

Three initiating events fall into the loss of main feedwater category: condensate pump spurious trips, main feedwater pump spurious trips, and loss of condenser vacuum. All three are heatup events. There are other initiating events that result in loss of feedwater, but they are not included in this group, because of unique impacts they have on other plant systems.

The initiating event frequencies for the above events are discussed in Section 6.1.

4.3.9.2.2 Reactor Trip

On a loss of MFW, the RPS will generate a trip signal on low SG level. Failure of reactor trip is treated under the ATWS Event Tree.

4.3.9.2.3 Secondary Cooling (Auxiliary Feedwater)

Auxiliary Feedwater (AF)

Refer to the Steam Generator Heat Removal Top Logic fault tree, Figure 4.3-11.

Following the loss of MFW and reactor trip, AF (Trains A and B) will automatically start on AFAS due to low SG level. Success criterion for AF is that flow is supplied from at least one AF pump to at least one SG. If Train N AF Pump is to be used, it must be aligned within 30 min. to ensure that lifting the pressurizer safety valves will not be a concern. The following sections describe the methods for venting steam in conjunction with AF.

Atmospheric Dump Valves (ADVs)

If TBVs are unavailable or fail, steam can be vented by manual operator control of the ADVs, although the MSSVs will be challenged by the initial transient. The success criterion for ADVs is that one of the two ADVs on a SG being used for heat removal opens.

Main Steam Safety Valves (MSSVs)

If the TBVs and ADVs are unavailable or fail, SG pressure will rise until the MSSVs open to relieve steam. The success criterion for the MSSVs is that one of ten MSSVs open on a SG being used for heat removal.

4.3.9.2.4 Secondary Cooling (Alternate Feedwater)

Given AF is unavailable, procedure calls for the operators to attempt to align the low pressure condensate pumps to provide feedwater to the SGs. For sequences where the initiator was a loss of condensate pumps, no credit is given for aligning AltFW. On a loss of FW pumps, AltFW can be aligned. Operators have approximately 1 hr. to perform the alignment to avoid core damage. The success criterion for this element is that alternate feedwater is aligned from at least one of the condensate pumps to one SG within 1 hr. following a reactor trip. Alternate Feedwater is not credited for the Condensate Pump Spurious Trip initiator i.e., no credit is taken for operator action to restart a condensate pump. For steam removal, ADVs (described above) and TBVs are credited in conjunction with Alternate Feedwater. The preferred means of venting steam is via the turbine bypass valves to avoid challenging the steam generator safety valves and conserve secondary inventory. TBVs are not credited for Loss of Condenser Vacuum. The success criterion for TBVs is that one of eight TBVs opens to relieve steam.

4.3.9.2.5 RCS Integrity (No Stuck Open PSV)

Upon a loss of MFW, if AF is unavailable, then the PSVs may lift before Alternate Feedwater can be aligned. If operator action takes longer than about 30 min., water relief out of the PSVs will occur. The PSVs were originally designed for steam relief and are more likely to fail open following water relief than following steam relief (see Section 6.1.3.2.3 for PSV fail to reclose probabilities for steam and water relief). For this analysis, it is conservatively assumed that if AF is unavailable, water relief will occur prior to aligning AltFW.

4.3.9.2.6 High Pressure Safety Injection (HPSI)

Refer to the RCS Integrity Loss Top Logic fault tree, Figure 4.3-16.

In the event of a Loss of MFW induced LOCA, HPSI is required to maintain RCS inventory. The success criterion for HPSI is defined as flow from at least one HPSI pump through at least three HPSI lines.

4.3.9.2.7 High Pressure Safety Recirculation (HPSR)

Following HPSI, the containment sump valves are automatically opened on RAS and HPSR from the sump to the RCS injection lines continues. The success criterion is a successful switchover and recirculation via at least one HPSI pump through at least three HPSI lines.

4.3.9.3 Major Assumptions

The following assumptions were made in the development of the Loss of MFW Event Tree:

a) If AF fails and AltFW is successful, it is assumed that pressurizer safety valves lift venting water

b) Alternate feedwater is not available following a loss of all condensate pumps (no credit is taken for restarting a condensate pump)

c) No credit is taken for operator action to de-pressurize the RCS for LPSI if HPSI fails.

4.3.9.4 Major Dynamic Human Actions

The following major dynamic human actions are included in the top events:

a) Alignment of Train N AF pump

b) Alignment of Alternate Feedwater if AF fails.

If ADV use is necessary, it is assumed the operator will attempt to do so.

4.3.10 Station Blackout Event Tree

The Station Blackout (SBO) event tree (Figure 4.3-9) covers the concurrent LOOP and loss of all AC power on both 4.16kV Engineered Safety Features buses due to diesel generator or power distribution equipment failures. If the diesel generators cannot supply AC power to the ESF buses following the LOOP, the resulting transient must be mitigated, at least initially, by AC-independent equipment. With no AC power, Trains B and N AF Pumps, HPSI, LPSI, Containment Spray and Essential HVAC systems are unavailable, and the Essential Cooling Water and Essential Spray Pond systems are not available for cooling the RCP seals or for decay heat removal via the SDCHXs.

The turbine-driven (Train A) AF pump is required to supply auxiliary feedwater to the steam generators, and secondary steam must be removed via the Main Steam Safety Valves and the Atmospheric Dump Valves.

The initial progression of the transient would be similar to the standard LOOP, with FW unavailable, AF being delivered to the steam generators to restore RCS heat removal and the ADVs being opened for secondary steam removal. The ADVs receive control power from the vital AC and DC buses (powered from batteries) and use nitrogen for opening (instrument air is unavailable). The batteries can supply rated load for a minimum of 2 hrs. (Reference 4.4.7), and the nitrogen supply reservoirs are good for a limited number of cycles. Thus, in lieu of other problems, initial plant cooldown can proceed for at least 2 hrs. without restoration of AC power. When the batteries are depleted, the ADVs would fail closed, and primary side temperature and pressure would increase until the heat transfer from the RCS to the steam generators was in equilibrium with the heat removed from the steam generators via the Main Steam Safety Valves. Additionally, the AF pump turbine controller would lose DC power and the pump would likely trip. Steam generators would boil dry in about 30 min. The RCS would then heat up and the Pressurizer Safety Valves (PSVs) would lift. Core uncovery would occur after about another 30 min. For this sequence, restoration of power within 3 hrs. could prevent core damage. There are several conservatisms in this analysis. First, station batteries would be expected to last considerably longer than 2 hrs., since the performance exceeds the minimum required and loading is not as great under blackout conditions as was assumed in the Safety Analysis. Secondly, recent MAAP analyses indicate that with feedwater available for 2 hrs. post trip, SG dryout occurs 80 min. later and core uncovery 36 min. after that.

With a loss of all station AC power (Station Blackout), the RCPs trip and RCP seal injection and cooling water will be lost. The Nuclear Regulatory Commission (NRC) has postulated in their evaluation of Station Blackout that under these conditions, the seals will begin to degrade and gross seal leakage on the order of several hundred gpm may occur. The Combustion Engineering Owners Group (CEOG) contends that this is not credible for Byron-Jackson (BJ) Pumps (Reference 4.4.13) nor for the PVNGS CE-KSB RCP seals (Reference 4.4.19). However, if gross seal leakage does occur, a source of AC power must be restored and the HPSI system started to provide RCS inventory makeup before the core uncovers. The time available to accomplish this is dependent on the seal leak rate. The need for HPSI and HPSR is based on the conservative assumption that gross seal leakage can occur.

If the turbine-driven AF pump fails to start and deliver feedwater to the steam generators following the initial transient, secondary steam removal through the MSSVs or ADVs will continue until the steam generators boil dry at approximately 30 min. Primary pressure will rapidly rise and the primary safety valves will open. Core uncovery will occur within 30 min. of generator dry-out. Thus, with initial loss of auxiliary feedwater, AC power must be restored and AF flow established within 1 hr. to prevent core damage. Again, these times are conservative. MAAP analysis indicates SG dry out at 56 min. and core uncovery at 77 min.

4.3.10.1 Sequence Description

Following a turbine-generator trip, LOOP and failure to power both ESF buses, a reactor trip is called upon to terminate the heat generation from fission. After successful reactor trip, FW is unavailable and only the steam-driven auxiliary feedwater pump is available to provide secondary cooling. Should it fail, off-site power must be restored within 1 hr. in order to start a motor-driven auxiliary feedwater pump and re-establish secondary heat removal to avoid uncovering the core. Failure to restore off-site power within 1 hr. is assumed to lead to core damage.

If off-site power is not restored in time to avoid lifting PSVs, an induced LOCA may result if one or more PSVs do not reseat. This is not addressed in the event tree, but rather in the system analysis.

In addition, if off-site power is restored within 2 hrs., there is the possibility that the RCP seals may have degraded sufficiently to result in a LOCA, since both seal injection and cooling are unavailable without AC power. If a seal LOCA develops during the period without off-site power, HPSI and HPSR are required to make up RCS inventory when AC power is restored. Recirculation of containment sump water will be necessary once the contents of the RWT are injected. Failure of HPSI or HPSR leads to core damage.

Whether or not a RCP seal LOCA results, long-term secondary cooling is necessary using AF. Failure of long-term secondary cooling results in core damage.

If early auxiliary feedwater from the turbine-driven pump is available at the beginning of the transient, then power need not be restored for 3 hrs. to avoid core damage, since there is enough DC power available to operate this pump for at least 2 hrs., with an additional 1 hr. before core uncovery occurs. Failure to restore off-site power within 3 hrs. is assumed to lead to core damage.

There are eight core damage sequences as follows:

a) Early AF failure, failure to restore off-site power within 1 hr.

b) Early AF failure, successful power restoration within 1 hr., RCS integrity failure, HPSI or HPSR failure

c) Early AF failure, successful power restoration within 1 hr., RCS integrity failure, HPSI and HPSR success, long-term secondary cooling failure (AF)

d) Early AF failure, successful power restoration within 1 hr., RCS integrity maintained, long-term secondary cooling failure (AF)

e) Early AF success, failure to restore power within 3 hrs.

f) Early AF success, successful power restoration within 3 hrs., RCS integrity failure, HPSI or HPSR failure

g) Early AF success, successful power restoration within 3 hrs., RCS integrity failure, HPSI and HPSR success, long-term secondary cooling failure (AF)

h) Early AF success, successful power restoration within 3 hrs., RCS integrity maintained, long-term secondary cooling failure (AF).

4.3.10.2 Station Blackout Sequence Elements

The SBO event tree is shown in Figure 4.3-9. The event tree consists of the initiator and seven function-oriented top events which are described in detail below:

4.3.10.2.1 Station Blackout Initiators

The initiating event frequency was derived from multiplying the LOOP frequency by the probability of losing all power to both 4.16kV ESF buses. The plant-based equation method for quantifying this initiator, as described in Section 6.1, ensures that dependencies between this complex initiator and the plant systems that must respond to it, are explicitly accounted for.

4.3.10.2.2 Reactor Trip

On the LOOP the RPS will generate trip signals on low DNBR (CPC Auxiliary Trip), low SG level, and high pressurizer pressure. Reactor Trip failure is addressed within the ATWS event tree, Section 4.3.11.

4.3.10.2.3 Secondary Cooling Early

This top event addresses the need to deliver flow to at least one SG using the AF turbine pump for a period of no less than 2 hrs., along with steam removal.

Steam Generator water inventory control must be provided by the turbine-driven AF pump. The success criteria is that this pump delivers flow to at least one SG.

Two means of steam removal are available. The preferred means is use of the ADVs. The success criterion is that one of two ADVs on a SG being fed auxiliary feedwater operates under operator control. If ADVs fail, the MSSVs will relieve steam pressure. The success criterion for MSSVs is that one of ten MSSVs opens on a SG being fed auxiliary feedwater.

4.3.10.2.4 Restore Power within One Hour

In the absence of early phase AF system flow, power must be restored within 1 hr. to avoid lifting Pressurizer Safety Valves (PSVs). The probability of non-restoration of off-site power within 1 hr. was calculated from the correlation developed from statistical analysis of NSAC-111 data (Reference 4.4.3); details of this statistical analysis are described in Section 6.2. The success criteria are restoration of power to the switchyard and re-energization of at least one ESF bus from off-site power.

4.3.10.2.5 Restore Power within Three Hours

The AF system requires 125V DC to control the turbine pump throttle valve and other system valves. During a SBO event, this power is provided exclusively by the Channel A station battery. Based on a review of 125V DC bus loads typical to a SBO event and the 18 and 60-month tests of the DC batteries (References 4.4.6 and 4.4.7), it is assumed that the DC batteries will last for at least 2 hrs. into an SBO event. However, it is conservatively assumed that the AF pump fails at 2 hrs. into the event. As described earlier, the probability of restoration of off-site power by a specific time into the SBO event may be calculated from the correlation developed from NSAC-111 report data. Success is defined as restoration of power to the switchyard and re-energization of at least one ESF bus from off-site power (See Section 6.2).

4.3.10.2.6 RCS Integrity (No RCP Seal LOCA)

Reactor coolant pump (RCP) seals are designed to limit the leakage of reactor coolant along the pump shaft. With SBO, the RCP seal cooling and seal injection from charging pumps are lost, initiating a process of potential seal degradation that may lead to excessive RCP seal leakage.

This study has adopted the CEOG findings in Reference 4.4.12 and the quantitative assessment of seal failure probability of 0.08. The functional dependency displayed in the SBO event tree reflects the assumption that primary coolant losses due to excessive pump seal leakage do not lead to core uncovery prior to 3 hrs. (in the absence of HPSI), an assumption which is consistent with the C-E System 80™ PRA. Excessive seal leakage is defined as leakage leading to loss of primary coolant inventory in excess of charging pump ability to replenish it once power is restored. This translates into an average leakage rate in excess of 30 gpm per pump, starting no earlier than 2 hrs. after the SBO event.

The possibility of PSV LOCA is not considered in the event tree, but was assessed in the analysis for scenarios in which feedwater is lost for more than 1 hr. Considering the conservatisms in assumed battery life and time required to restore off-site power, the likelihood that a PSV will pass water is small.

4.3.10.2.7 High Pressure Safety Injection/High Pressure Safety Recirculation (HPSI/HPSR)

In the event of a SBO-induced LOCA, HPSI is required to maintain RCS inventory once off-site power is restored. The success criterion for HPSI is defined as flow from at least one HPSI pump via at least three HPSI lines. Following HPSI, the containment sump valves automatically open on RAS, and HPSI recirculation from the sump to the RCS injection lines continues. The success criterion is a successful switch-over of at least one HPSI pump providing recirculation through at least three HPSI lines. The HPSI, HPSR and Containment Heat Removal Top Logic fault tree shown in Figure 4.3-17 combines these two functions.

4.3.10.2.8 Secondary Cooling Long-Term (AF)

The success criterion for AF is to deliver flow to at least one SG with one of three AF pumps for a period of up to 24 hrs. after off-site power recovery has been obtained.

Two means of steam removal are available. The preferred means is use of the ADVs. The success criterion is that one of two ADVs on a SG being fed auxiliary feedwater operates under operator control. If ADVs fail, the MSSVs will relieve steam pressure. The success criterion for MSSVs is that one of ten MSSVs opens on a SG being fed auxiliary feedwater.

4.3.10.3 Major Assumptions and Dependencies

The following assumptions were made in developing the Station Blackout event tree:

a) If the turbine-driven AF pump is unavailable, off-site power has to be restored within 1 hr. in order to prevent core damage. This requirement is based on the assumptions that the SGs will boil dry within about 30 min. and the core will be uncovered due to coolant loss through the primary safety valves about 30 min. later

b) If the turbine-driven AF pump is initially available, off-site power to the ESF buses must be restored within 3 hrs. in order to avert core damage. This requirement is based on the dependence of turbine control on DC power and the conservative 2 hrs. assumed useful life of the Channel A Class 1E battery. The core uncovery assumption is based on a conservative estimate of time to core uncovery

c) No credit is taken for operator action to shed DC loads to extend battery life for AF pump operation

d) RCS integrity will not be lost due to a stuck open primary safety relief valve(s). (This possibility is accounted for in the cutset analysis.)

e) The DC batteries are assumed to discharge during an SBO event. This means that after power is recovered, 125V DC power is only available from battery chargers. This is a conservative assumption, especially for those sequences where power is restored within 1 hr.

f) It is assumed that excessive RCP seal leakage prior to 2 hrs. after an SBO is not a credible event. This assumption is based on the CEOG conclusions after review of operating experience with CE-BJ RCPs. A comparison of CE-BJ and CE-KSB RCPs found both pump designs operationally equivalent. The CEOG conclusions have been extended to the CE-KSB RCP design

g) Recovery of off-site power is defined as restoration of power to the switchyard and re-energization of at least one ESF bus from off-site power

h) No credit is taken for recovery of an emergency diesel generator

i) No credit is taken for operator action to de-pressurize the RCS for LPSI if HPSI fails.

4.3.10.4 Major Dynamic Human Actions

Only the recovery of off-site power is modeled.

4.3.11 Anticipated Transients without SCRAM (ATWS) Event Tree

4.3.11.1 Sequence Description

ATWS events are modeled to be an imbalance between steam generator heat removal and core heat generation with the subsequent failure to SCRAM when the appropriate reactor trip parameters are reached. As the coolant temperature increases, two important features of ATWS events occur: RCS pressure will increase because of coolant expansion in a controlled volume and temperature increase of the coolant will decrease the neutron moderation, thus reducing reactivity. As RCS temperature increases, reactivity decreases such that a quasi-stable state is reached at a reactivity level where total core power is matched by whatever heat removal is available from the steam generator. The reactor must remain at an elevated temperature in order to maintain this state. The negative effect of coolant temperature increase is the accompanying increase in pressure.

Depending on the value of moderator temperature coefficient in the core at the time of the event, the equilibrium state may or may not be reached prior to exceeding stress limits on the components of the primary boundary.

The ATWS rule (10CFR50.62) is based on maintaining component stresses below the ASME Level C limits. This equates to a RCS pressure of 3200 psi. The concern with exceeding ASME C stress levels is not primarily one of component rupture, (although this will happen at very high stress levels) but is that elastic behavior is not ensured above stress Level C limits. Thus, valve and pump operability can not be assured after exceeding these stress levels.

A mitigable ATWS scenario will reach an equilibrium state at an elevated temperature (about 620° F) in a close to saturated condition, at a few percent power, with steam generator heat removal just matching decay heat plus power. This state is presumed to be reached in about 2 min. for the full-power loss of feedwater ATWS. From that point, it is necessary to provide reactor shutdown by boron injection with the charging pumps. As boron is injected into the RCS, reactivity is reduced and, the temperature of the entire RCS will proceed back to the no-load T_{avg}. Continued boron injection will ensure subcriticality even at cold-shutdown conditions.

From the PRA perspective, the risk important aspects of ATWS are over after successful initiation of boron injection. Within the scope of the accident description discussed above, the physical constraint which dictates the required timing for boron injection is when the AF pumps run out of condensate. However, the assumed requirement for boron injection is usually 10 min. The reason is that the thermal hydraulics analysis to evaluate pressure rise, upon which the ATWS success criteria are based, only takes the event out to a time shortly after the equilibrium state is reached (about ten minutes using one charging pump).

The pressure rise during an ATWS can be affected by success or failure of four other events. The event tree is structured to question the occurrence of these events. First, feedwater must be supplied to the SG to remove decay heat; second, the pressurizer relief valves must open to relieve steam; third, under some conditions, the turbine must be tripped to prevent overcooling, which would add to reactivity and preserve SG inventory (minimize peak RCS pressure); and fourth, the moderator temperature coefficient (MTC) must be negative enough to provide enough temperature feedback to bring the reactor subcritical before the saturation temperature of the pressure corresponding to stress limits is reached.

The success criteria for each of these items are interrelated. For example, failure to trip the turbine is not critical in itself, but a higher value of MTC can be sustained if turbine trip is successful. Similarly, failure of one feedwater pump is not critical, but a higher (less negative) value of MTC can be sustained if both feedwater pumps are operable.

Figure 4.3-10 presents the core damage event tree for ATWS. The following subsections describe the individual elements on the tree.

4.3.11.2 Sequence Elements

4.3.11.2.1 ATWS Initiators

ATWS is defined to be an anticipated operational occurrence coupled with failure to insert negative reactivity via the control element assemblies. The anticipated operational occurrence is a function of whether a turbine trip has occurred. A simplification was performed by categorizing the PVNGS initiators into the three bins: two are a turbine trip or no turbine trip (See Section 6.1.4) for the grouping of the initiators and the third containing the LOOP and station blackout. The three categories are:

a) LOOP and Station Blackout

b) Initiators with turbine trip

c) Initiators without turbine trip.

These general categories contain initiators which have a range of impacts on the systems (elements) called in the ATWS event tree. For example, loss of class 125V DC Channel A fails a train of AF and SI. This initiator has a more severe impact on ATWS mitigating systems than a miscellaneous reactor trip which does not significantly impact any mitigating system. However, for each initiator within a category, preliminary sequence analysis was performed to assess the importance of such dependencies on the sequence frequency. For initiators that have a major impact on the systems called to mitigate it, this analysis showed that their contribution to CDF was negligible due to their low frequency value. As a result, it was judged that such initiators could be categorized with other initiators having less severe impact on ATWS mitigating systems. This then allowed the ATWS event tree to be analyzed with seemingly one initiator without understanding the impact of initiator-plant system dependencies.

4.3.11.2.2 Reactor Trip (RPS Electrical)

This element is defined as the probability that the right combinations of two trip breakers (#1 and #2, or #1 and #4, or #3 and #2, or #3 and #4) will not receive a signal to open. The event includes failure of sensors, instrumentation, signal processors, and output signals in the RPS and the supplementary protective system (SPS). It also includes failures of the shunt trip coils and the UV coils.

Failure of this top event is dominated by common-cause failure of the reactor trip breakers (both the shunt and UV coils must fail).

4.3.11.2.3 Reactor Trip (Trip Circuit Breakers)

This top event considers reactor trip failure due to circuit breaker faults. Top event probability is dominated by common-cause failure of the breakers. The trip breakers are separated from all other faults, because these failures can be mitigated by operator actions by de-energizing the control cabinet MG sets.

4.3.11.2.4 Reactor Trip (CEA Mechanical)

Successful insertion of 75 of the 76 full-length CEAs. (The 13 power-shaping CEAs are not credited.)

4.3.11.2.5 Manual Trip Late (De-energize CEDM MG Sets)

The operator fails to remove power to the 480V AC buses that provide power to the CEDM MG sets. This is an in-control room action, except in the cases of LOOP and SBO, where the buses are de-energized due to the initiator. The CE analysis performed for PVNGS (Reference 4.4.20) indicates that for the most limiting event, a loss of MFW peak RCS pressure occurs at 100 secs. It is conservatively assumed here that operators must act to manually trip the reactor within 1 min.

Attempts to manually trip the reactor by this method will be unsuccessful (and hence are not credited) if the RPS failure is due to rods failing to insert for mechanical reasons.

4.3.11.2.6 Secondary Cooling (Train A or B Auxiliary Feedwater)

This event is defined as the success of auxiliary feedwater to at least one SG in conjunction with the functioning of at least one MSSV. The Palo Verde Nuclear Generating Station has two safety-grade AF pumps which can match 200% of the decay heat load. Since AFAS does not actuate the Train N pump, and activation of the Train N pump is not directed in the ATWS procedure, it was not credited for AF success. The choice for AF is then to use two AF pumps and use the highest MTC value, or use one AF pump and use a lower MTC value. Provision of higher AF flows during ATWS allows accommodation of a higher moderator temperature coefficient and thus a smaller percentage of time spent in the unfavorable condition. However, for this study, the one out of two success criterion was used and as a result a larger percentage of time spent in the unfavorable MTC condition was applied. Reference 4.4.20 identifies minimum requirements for heat removal on the secondary side.

4.3.11.2.7 Pressure Relief and Operation in Adverse MTC range

This portion of the event tree combines two factors impacting the peak RCS pressure reached:

a) The MTC window at the time of the ATWS for which success of one AF train to provide cooling is attained

b) Successful opening of four out of four primary safety valves so as to provide adequate pressure relief.

The operation in adverse MTC range reflects the relationship between the auxiliary feedwater success criteria, whether the turbine has tripped and percent time the core is operating in adverse MTC. As mentioned in Section 4.3.11.1, the conditions of an ATWS are based on the amount of energy that is in the coolant and the heat generation rate in the core. The amount of water delivered to the SGs via the auxiliary feedwater pumps is the limiting factor in successfully maintaining sufficient heat removal. Competing factors for how much feedwater is needed (the amount of energy in the system to be removed) or whether a turbine trip has occurred and what MTC is when the ATWS occurs. Using the one of two auxiliary feedwater pump success criterion, the MTC value range for when core melt will always occur due to insufficient feedwater inventory can be calculated. Once the ranges have been determined, the percentage of operating time in each of these MTC ranges is calculated. For this analysis, the percentage of time the unit will be within the unfavorable MTC regime based on only one AF pump providing feedwater is 3.3% with turbine trip and 11% with no turbine trip.

4.3.11.2.8 Maintain RCS Integrity

If Level C RCS stress limits have not been exceeded, maintaining RCS integrity during an ATWS is defined as the closing of the primary safety valves after they have been demanded to open. The success criterion is that all four must close.

4.3.11.2.9 Emergency Boration Using Charging Pumps

This event is comprised of the human action to start emergency boration and the success of one charging pump to inject borated water into the RCS.

The human action is dependent on whether or not a manual reactor SCRAM has been tried. It is assumed that if the Control Room operators fail to diagnose the need to manually SCRAM the reactor, they will also fail to initiate emergency boration via the charging system.

4.3.11.2.10 High Pressure Safety Injection (HPSI)

HPSI is needed only for sequences where a safety valve has stuck open and a small LOCA has been created. One of two HPSI pumps will provide sufficient inventory makeup. Emergency boration is not needed, since the HPSI system supplies sufficient borated water to bring the plant to shutdown.

4.3.11.3 Major Assumptions

The following functional dependencies are important for the ATWS Event Tree:

a) Failure to SCRAM coupled with an adverse MTC is assumed to result in peak pressures exceeding Level C stress limits. This is assumed to cause a LOCA with safety injection disabled, which leads directly to core damage

b) Failure of HPSI is presumed to result in a return to power on cooldown due to insufficient negative reactivity. Emergency boration is not capable of supplying sufficient inventory to the RCS with a failed open primary safety. The core would become uncovered within approximately 35 min. of the lifting of the safety valves

c) To maintain primary pressure below reactor vessel rupture (5200 psig is conservatively assumed), all four safety valves must open

d) Only one charging pump is required for sufficient boron injection to bring the reactor to shutdown

e) If an operator attempted to SCRAM the reactor, but was not able to via the control rods, no dependency was placed on the operator then attempting to proceed with emergency borating

f) One HPSI pump is required for adequate boron injection and cooldown of the core during an ATWS

g) Credit for having main feedwater (FW) available at the time the initiating event occurs was not taken

h) Initiators were grouped by whether a turbine trip had occurred. Solution of the event tree events was determined by assuming the most dominant initiator conditions (See Section 4.3.11.2.1)

i) HPSR was not included in the event tree because preliminary analysis resulted in accident sequence numbers dropping below 1.0E-10.

4.3.12 Interfacing System LOCA (ISL)

Interfacing System LOCA refers to a LOCA that occurs due to failure of the boundary between the Reactor Coolant System and a system with which it interfaces. Subsequent pressurization of the interfacing system causes a breach of its pressure boundary. LOCAs of this sort can be categorized as inside containment and outside containment, depending upon the location of the breach. Section 6.1.3 provides a full discussion of how possible ISL locations were determined and calculations of initiating event frequencies. A brief summary of this discussion is presented here.

4.3.12.1 Inside Containment ISL

Five paths for potential ISL inside containment were identified:

1. RCS cold-leg to Safety Injection Tank
2. RCS cold-leg drains to the Reactor Drain Tank (RDT)
3. RCS cold-leg to RDT via Safety Injection System drains
4. RCS hot-leg through Shutdown Cooling System to RDT
5. Reactor Coolant Pump Seal LOCA.

The behavior and mitigation requirements for inside containment ISLs are generally the same as for an equivalent sized RCS boundary LOCA. Therefore, calculated initiating event frequencies for ISLs inside containment were added to the initiating event frequency for the equivalent sized LOCA (Large, Medium or Small).

4.3.12.2 Outside Containment ISL (Event V)

Four scenarios were identified that could lead to a potential ISL outside containment (V-Sequences) during power operation or Hot Standby:

1. RCS cold-leg to the High and Low Pressure Safety Injection systems
2. RCS hot-leg to Shutdown Cooling suction line
3. RCS letdown line rupture outside containment
4. RCS to Nuclear Cooling Water system.

The initiating event frequency for each of the above scenarios was calculated. All were well below 1E-7/year. The conservative assumption was made that any ISL outside of containment would lead to core damage; i.e., no credit was taken for any mitigation. Therefore, the core damage frequency values are equal to the initiating event frequency values, and an event tree for ISLs outside of containment was not constructed.

4.4 References

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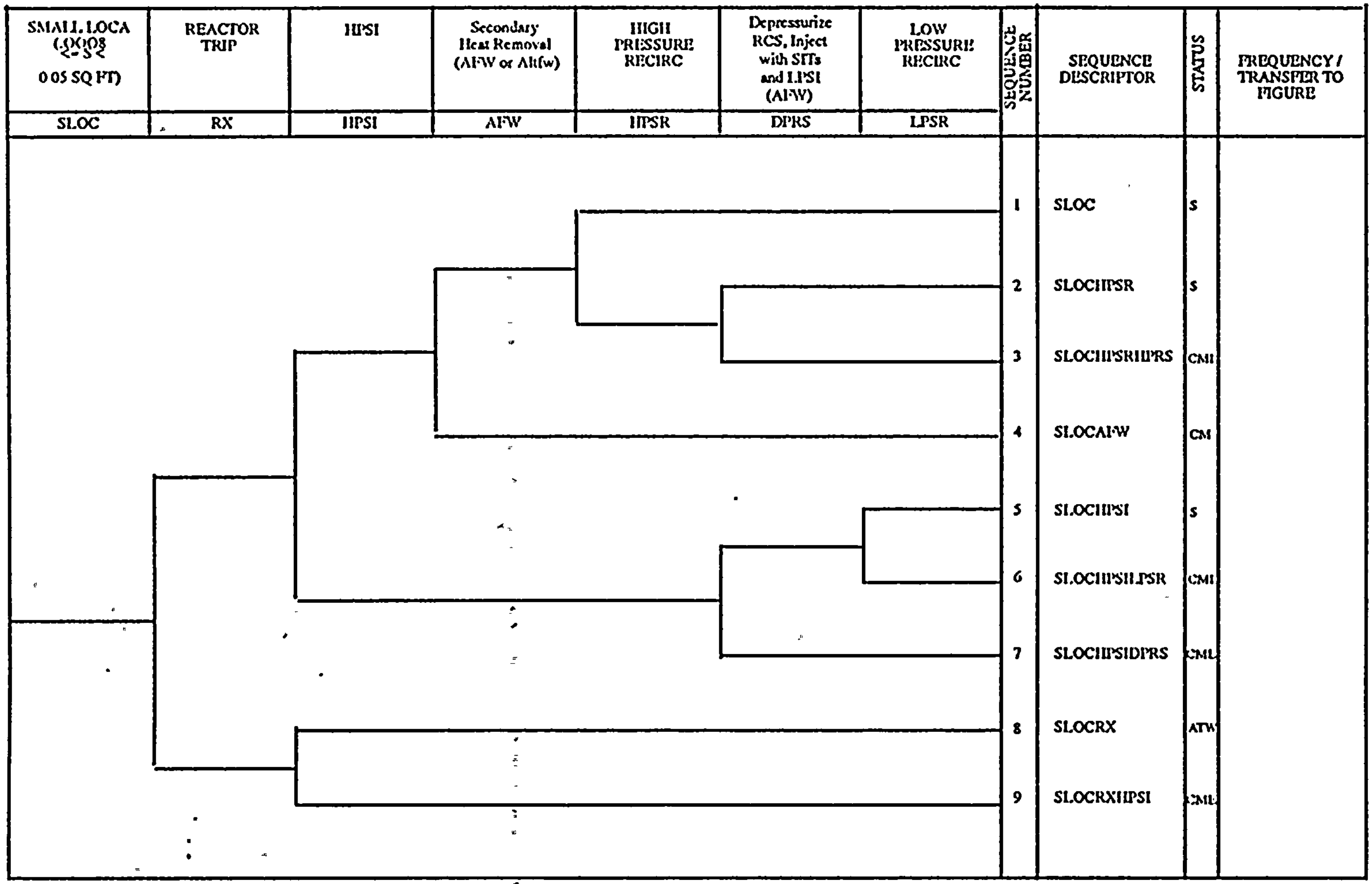

Figure 4.3-1

Small LOCA Event Tree

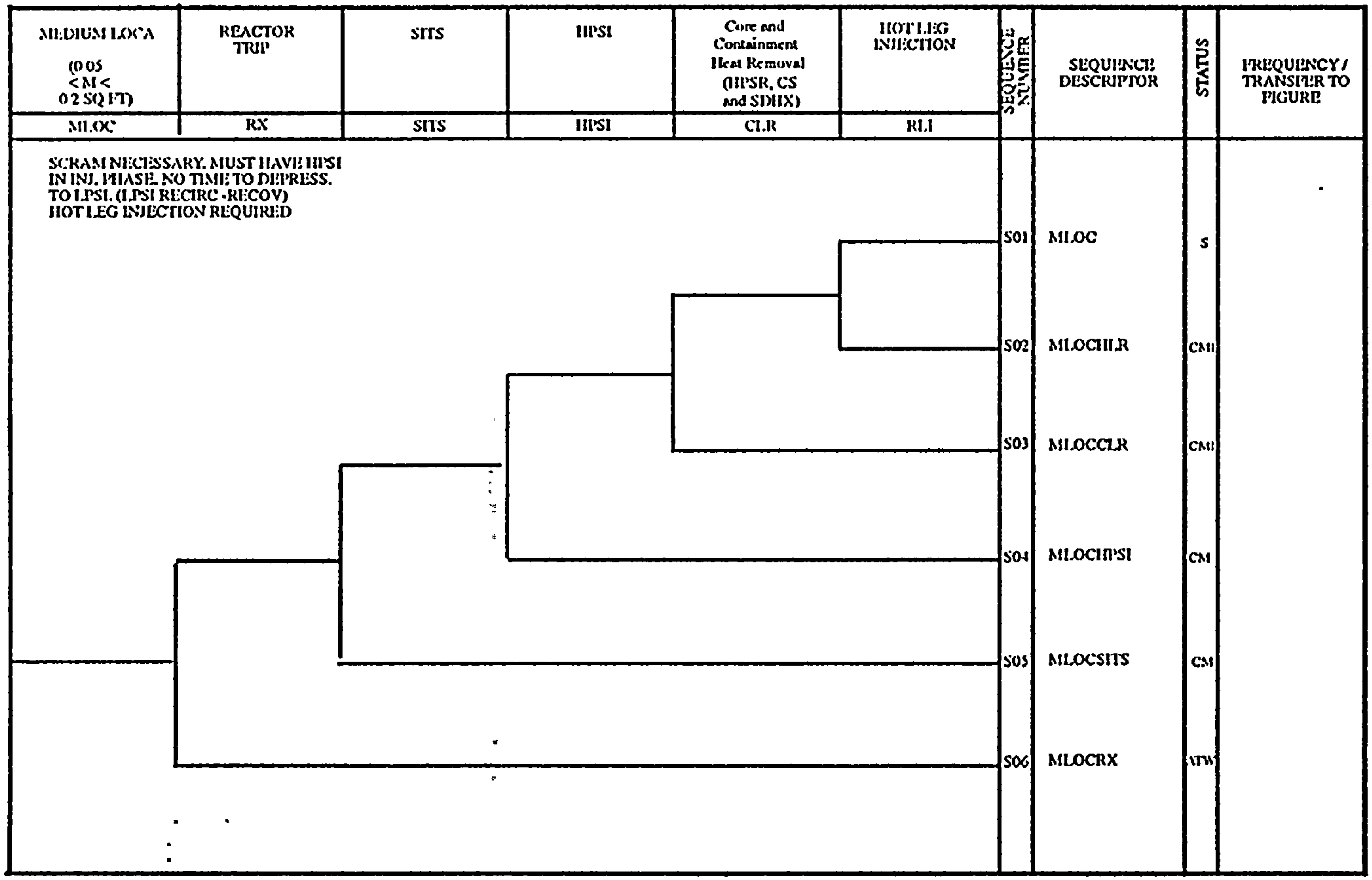

Figure 4.3-2

Medium LOCA Event Tree

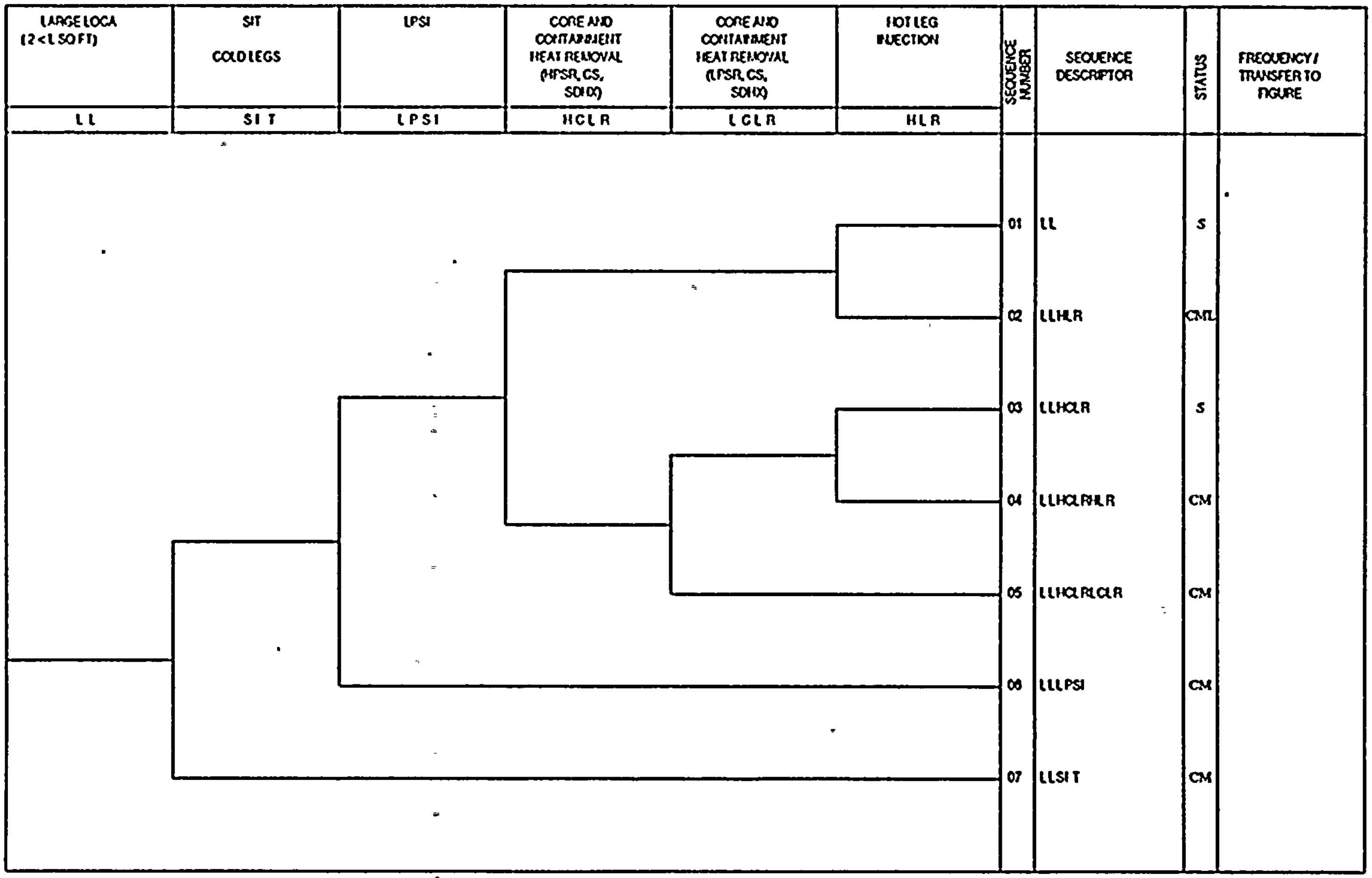

Figure 4.3-3

Large LOCA Event Tree

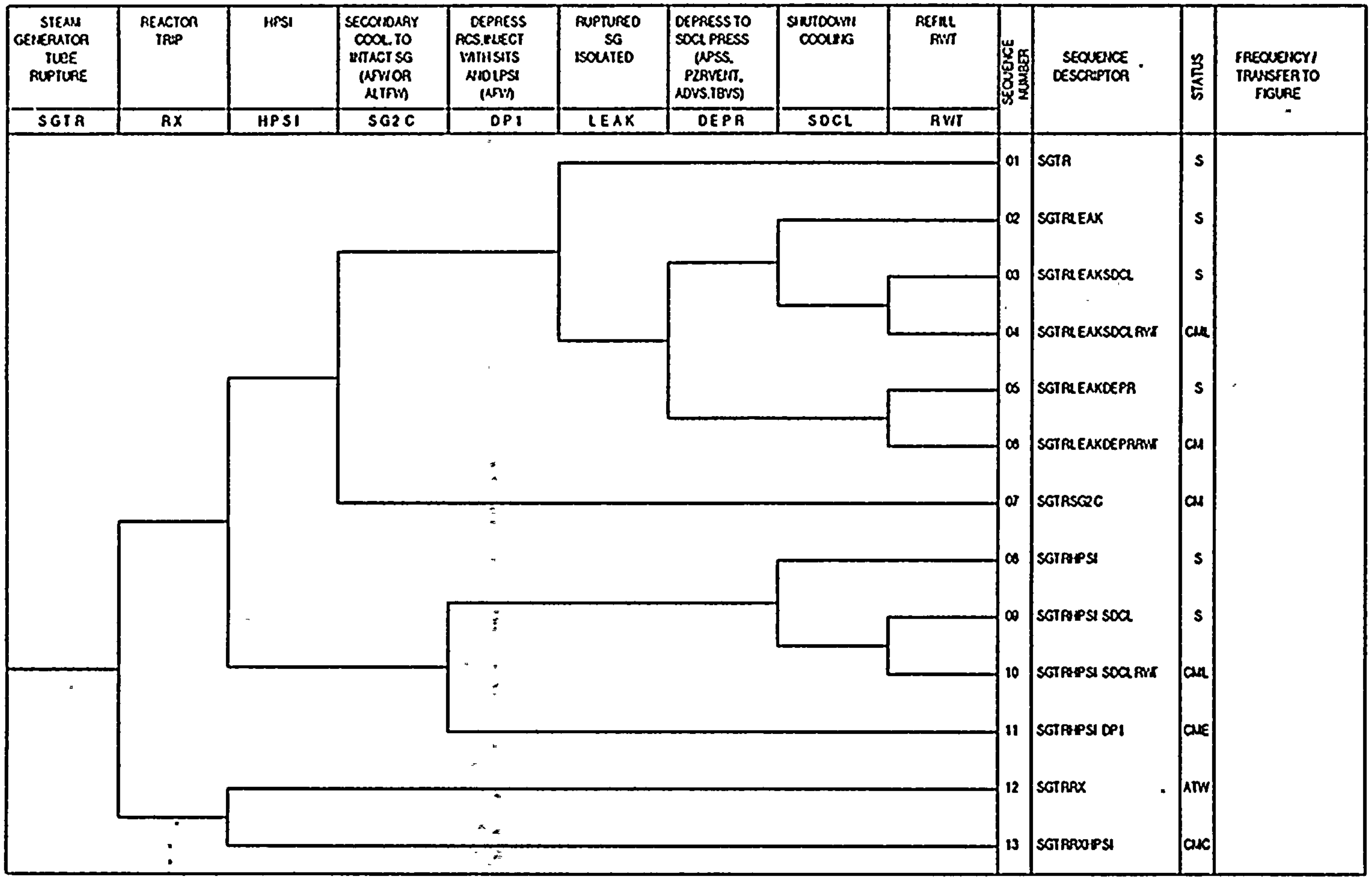

Figure 4.3-4

Steam Generator Tube Rupture Event Tree

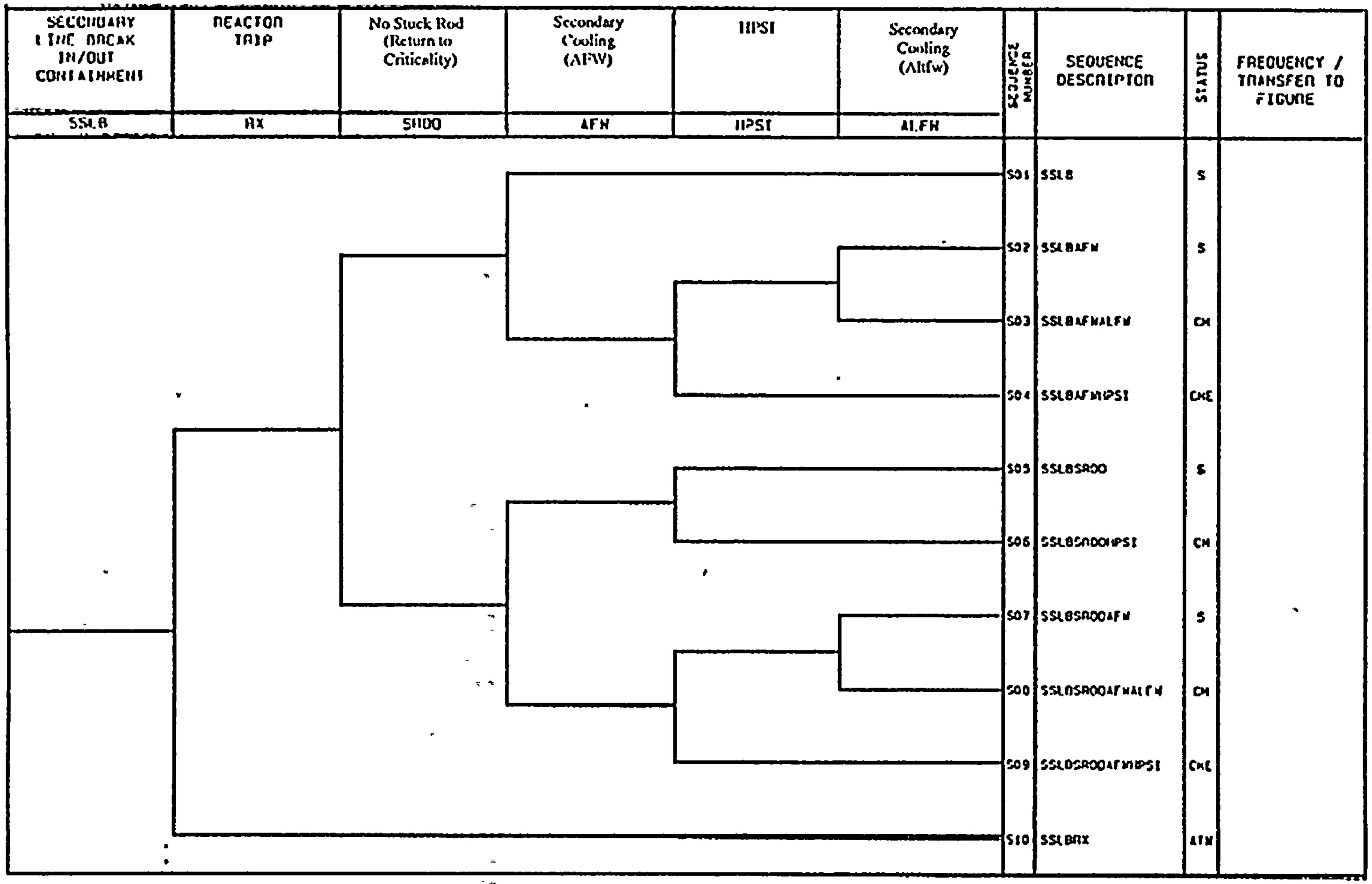

Figure 4.3-5

Secondary Line Break Event Tree

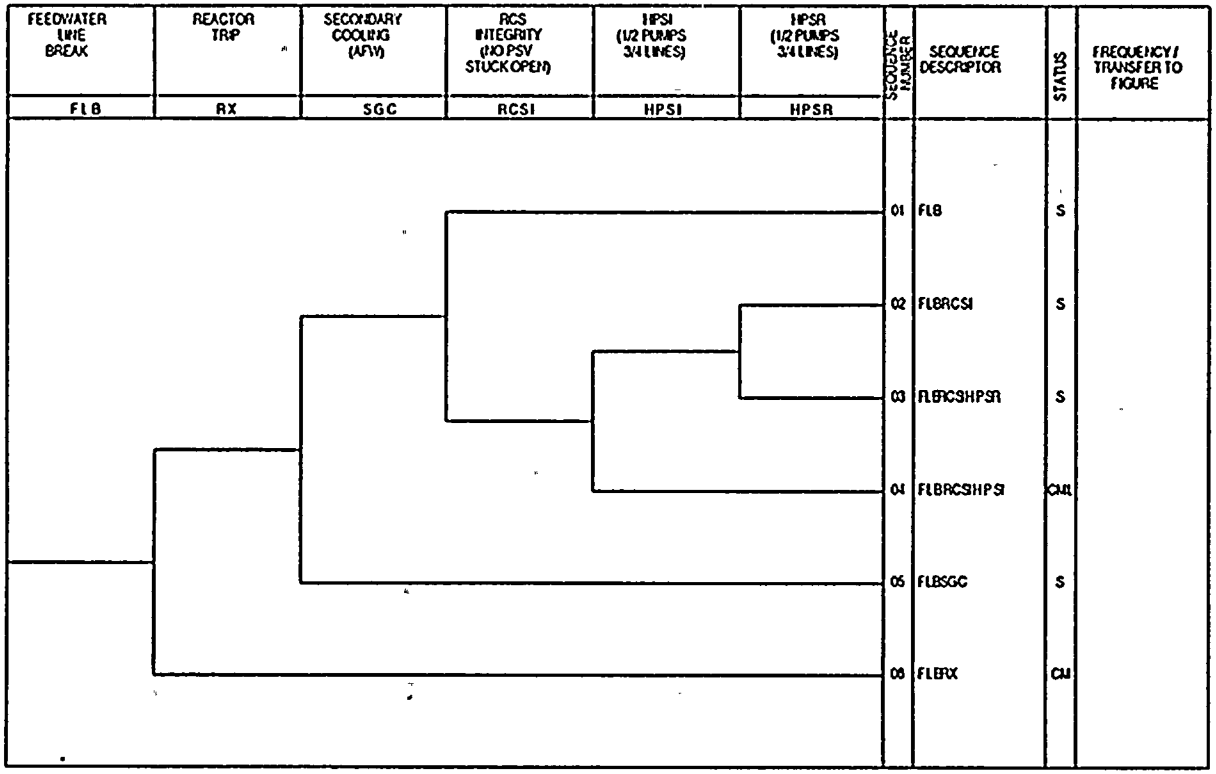

Figure 4.3-6

Feedwater Line Break Event Tree

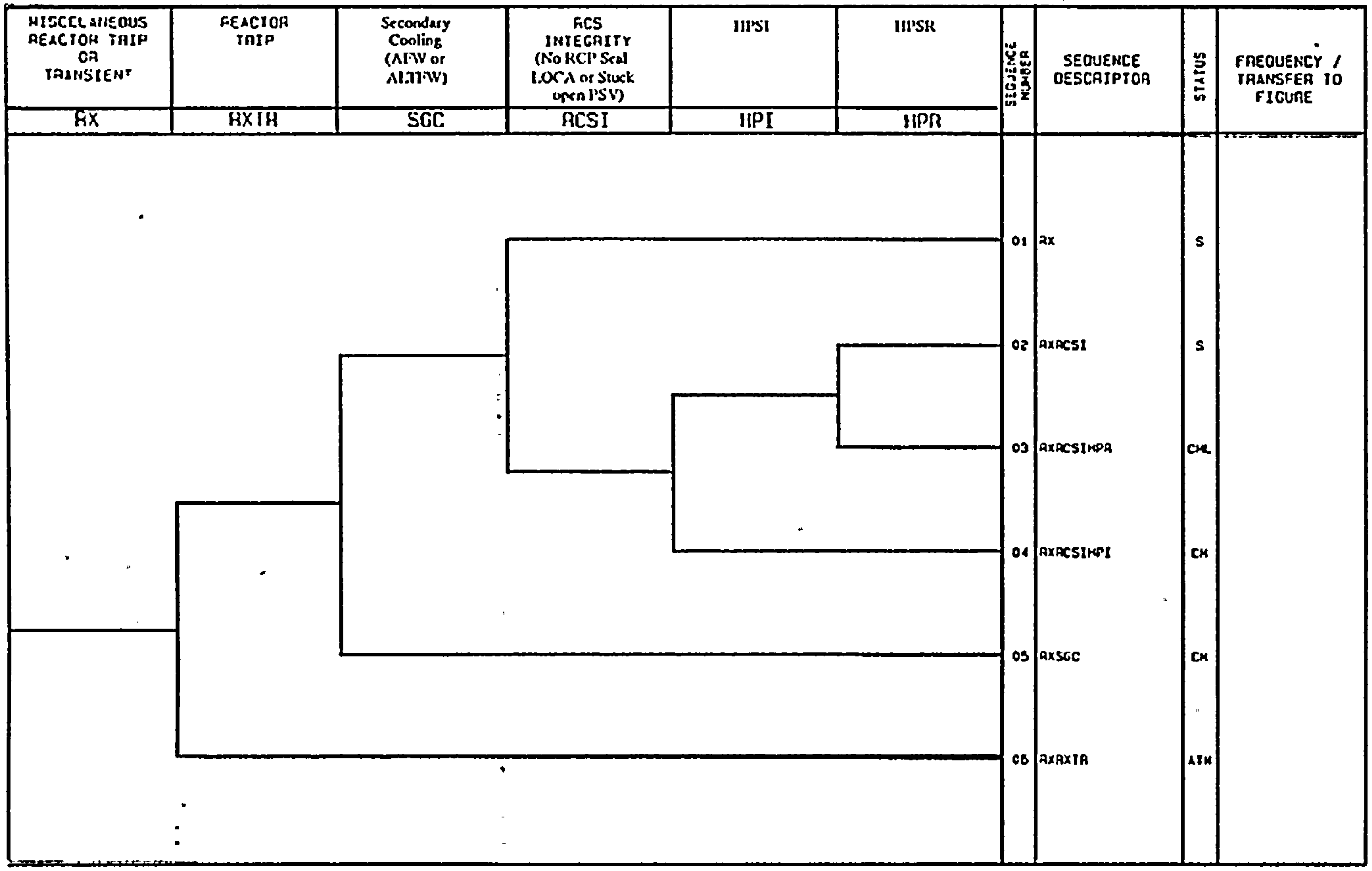

Figure 4.3-7

Grouped Transients Event Tree

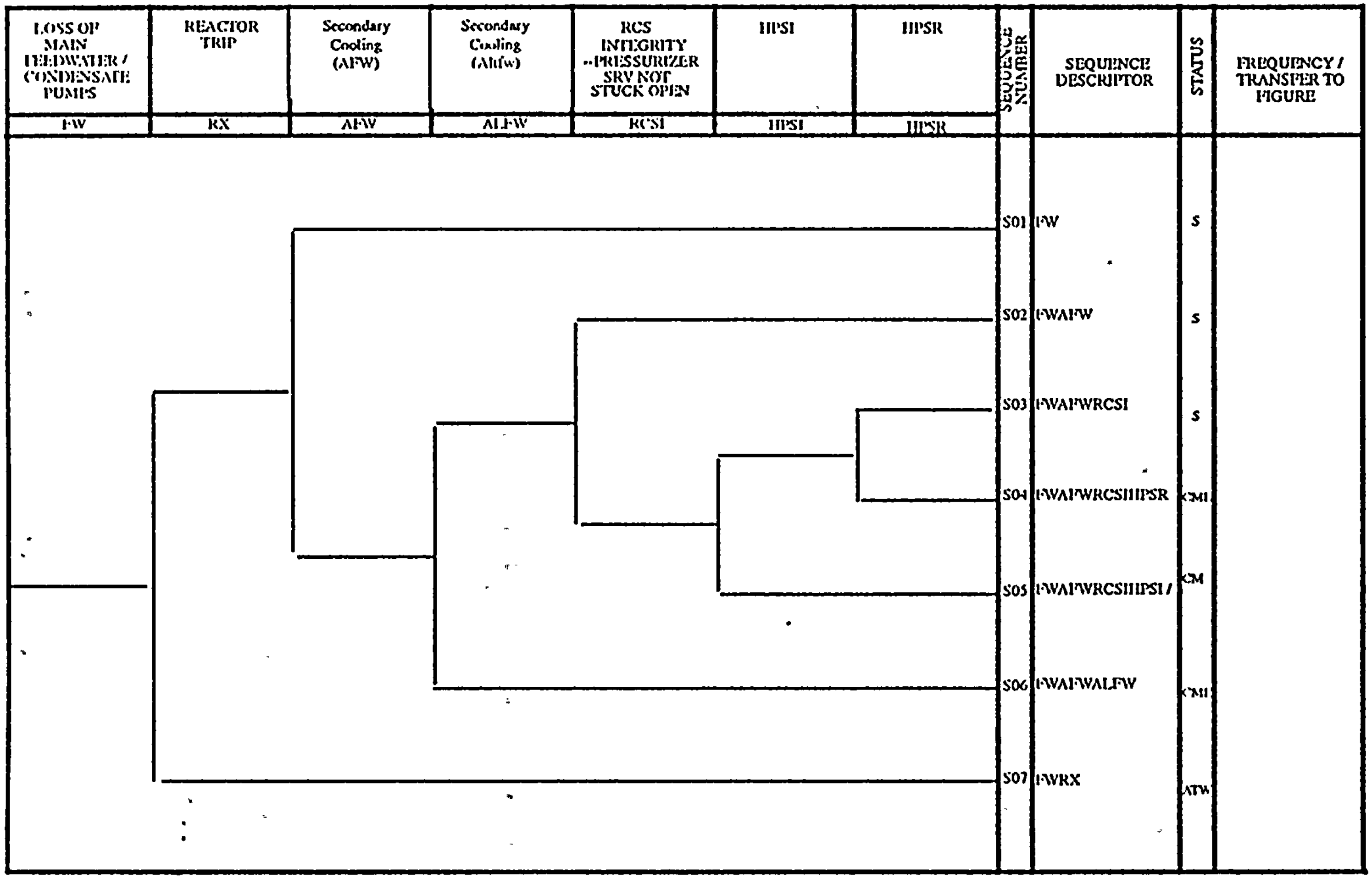

Figure 4.3-8

Loss of Main Feedwater/Condensate Pumps Event Tree

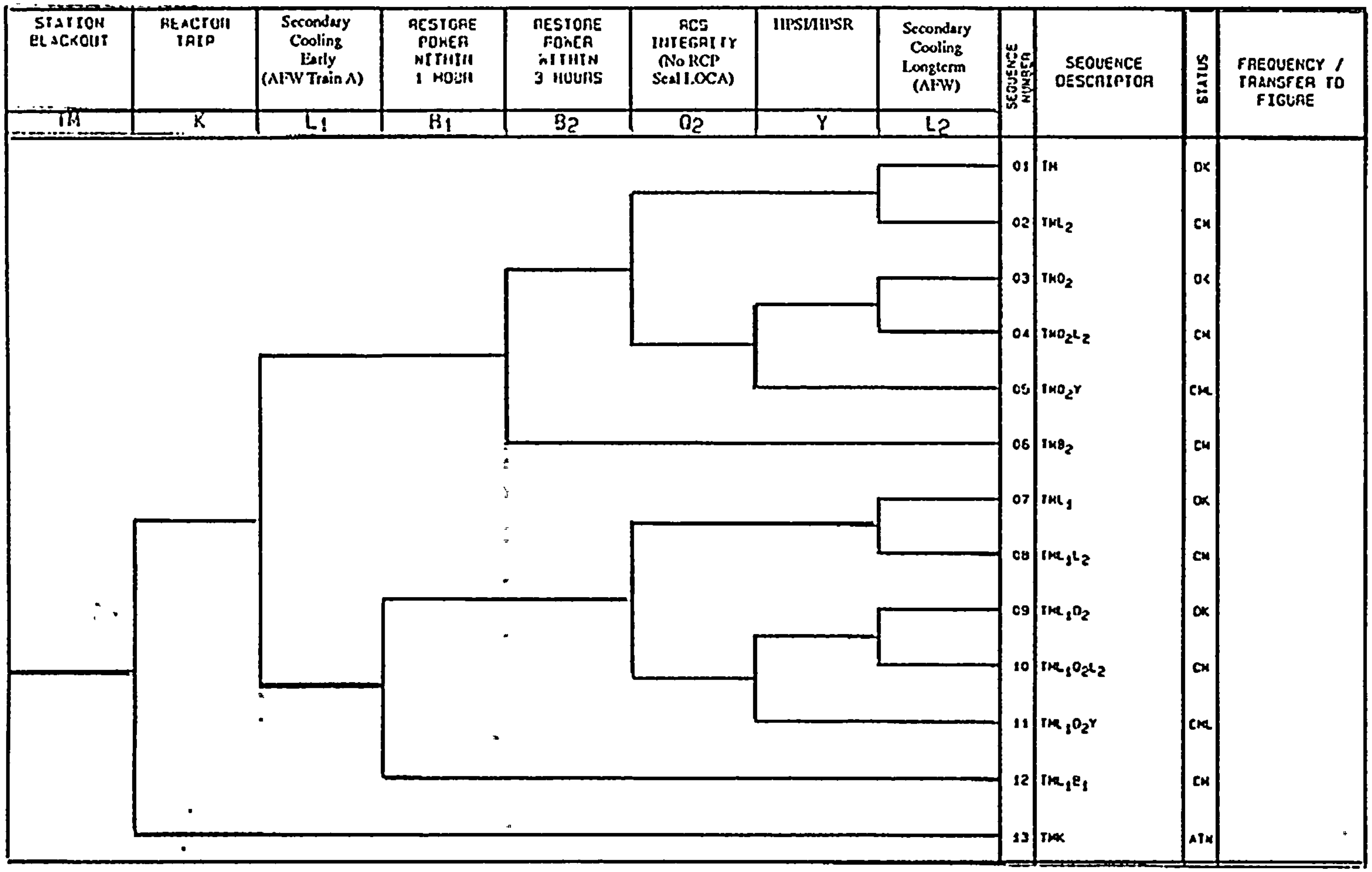

Figure 4.3-9

Station Blackout Event Tree

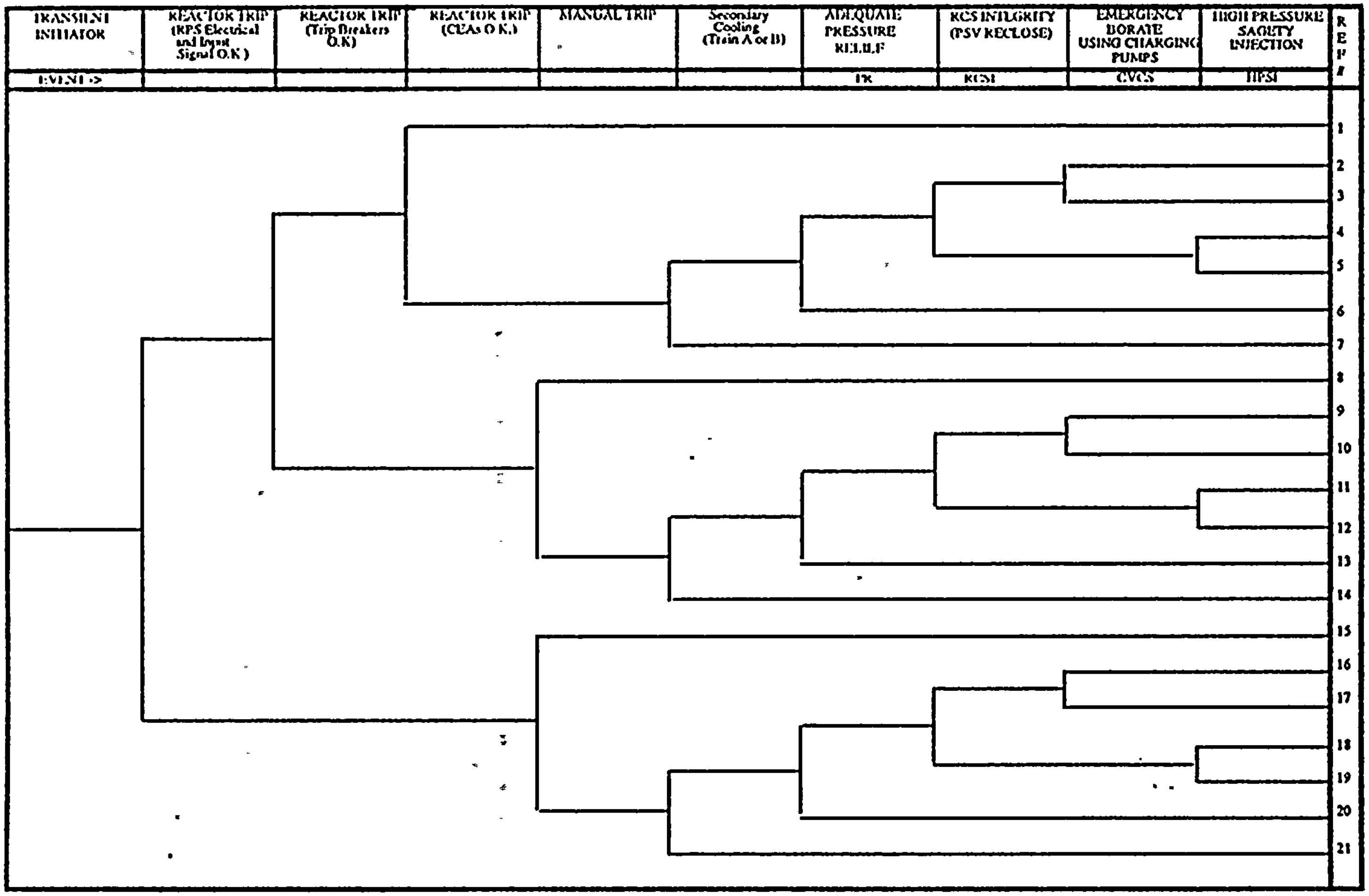

Figure 4.3-10

ATWS Event Tree

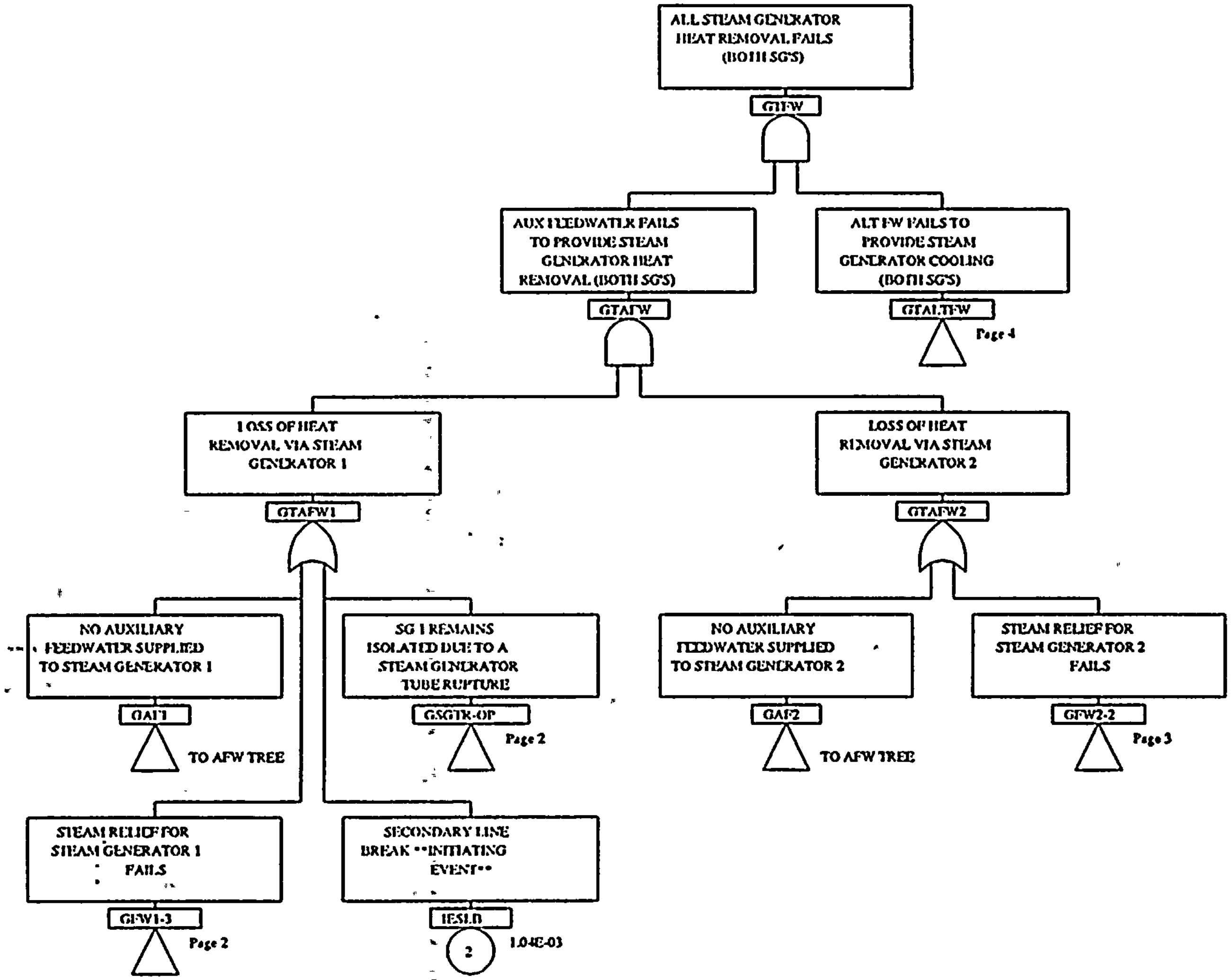

Figure 4.3-11 (page 1 of 7)

Steam Generator Heat Removal (AFW, ALTFW, ADVS, MSSVS)

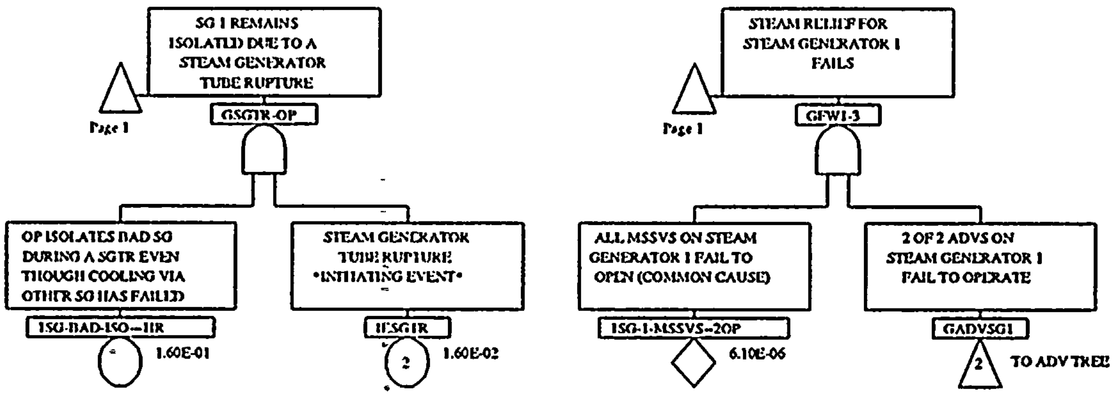

Figure 4.3-11 (page 2 of 7)

Steam Generator Heat Removal (AFW, ALTFW, ADVS, MSSVS)

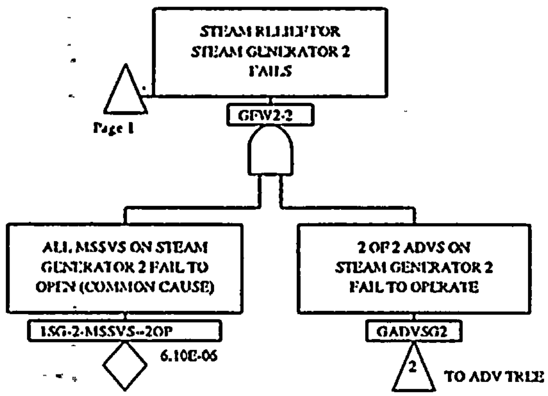

Figure 4.3-11 (page 3 of 7)

Steam Generator Heat Removal (AFW, ALTFW, ADVS, MSSVS)

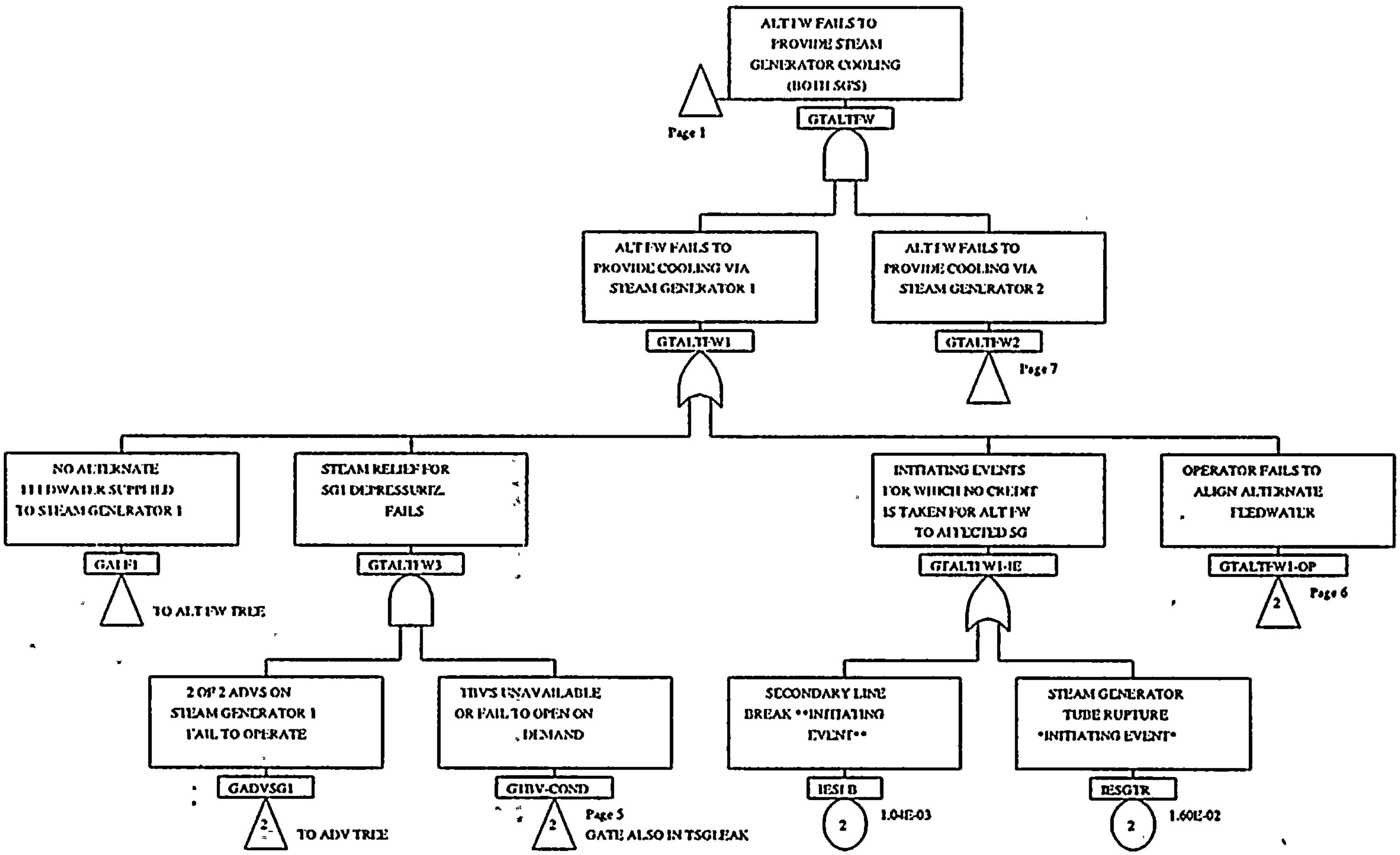

Figure 4.3-11 (page 4 of 7)

Steam Generator Heat Removal (AFW, ALTFW, ADVS, MSSVS)

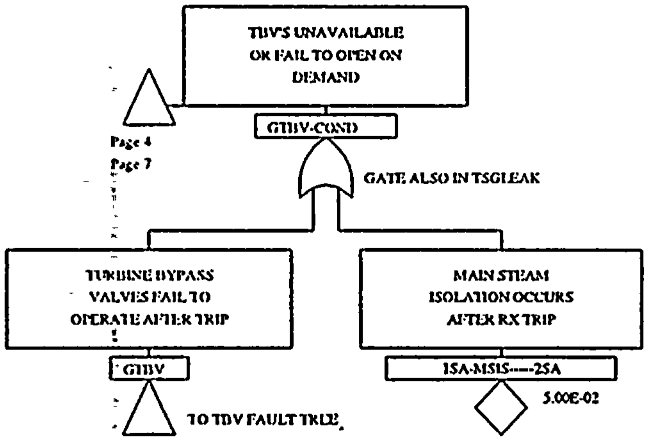

Figure 4.3-11 (page 5 of 7)

Steam Generator Heat Removal (AFW, ALTFW, ADVS, MSSVS)

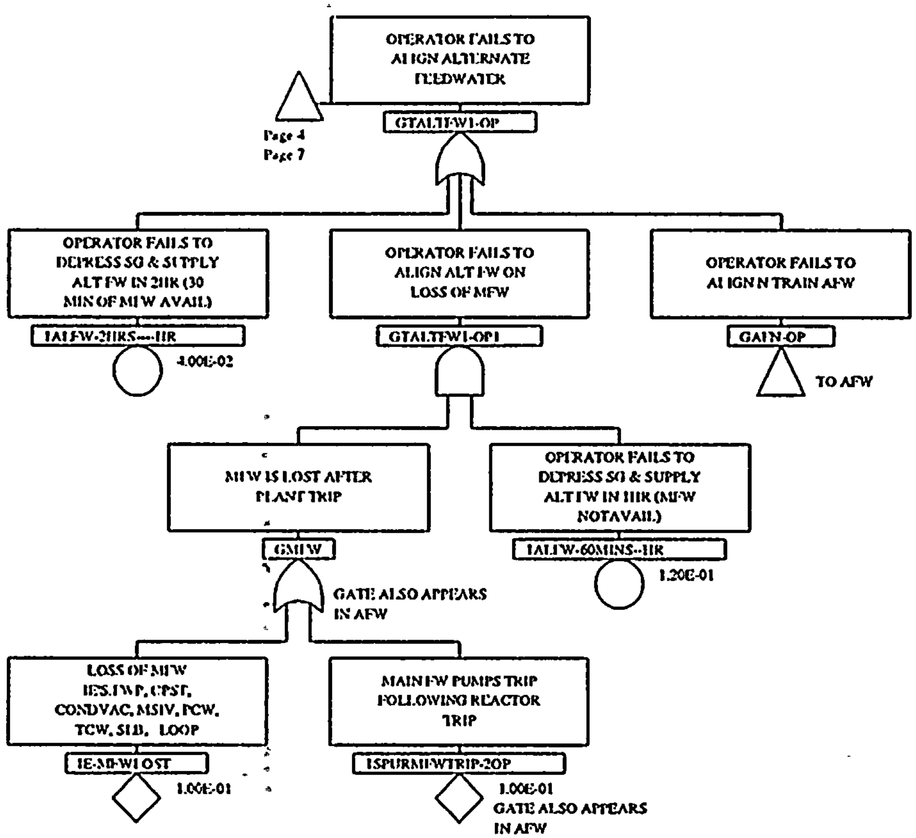

Figure 4.3-11 (page 6 of 7)

Steam Generator Heat Removal (AFW, ALTFW, ADVS, MSSVS)

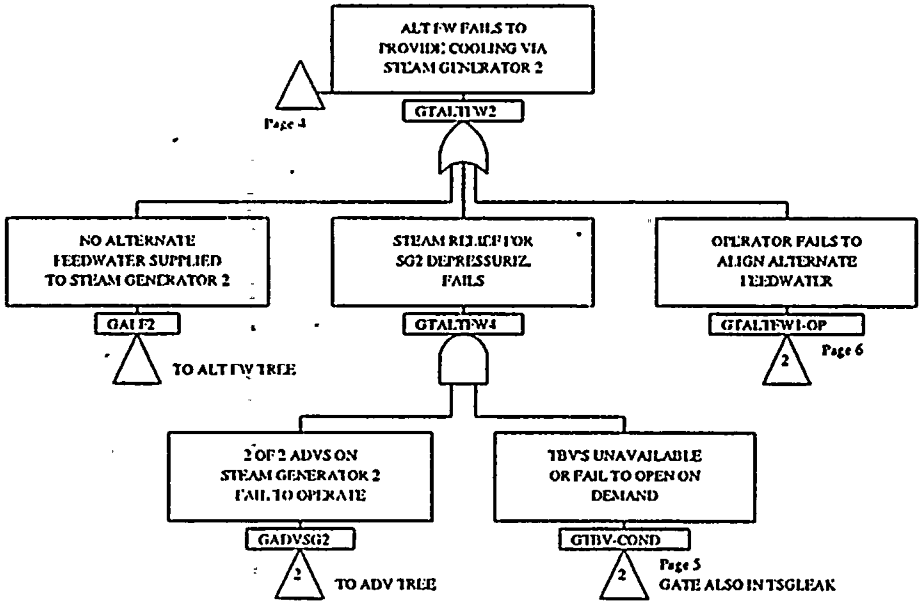

Figure 4.3-11 (page 7 of 7)

Steam Generator Heat Removal (AFW, ALTFW, ADVS, MSSVS)

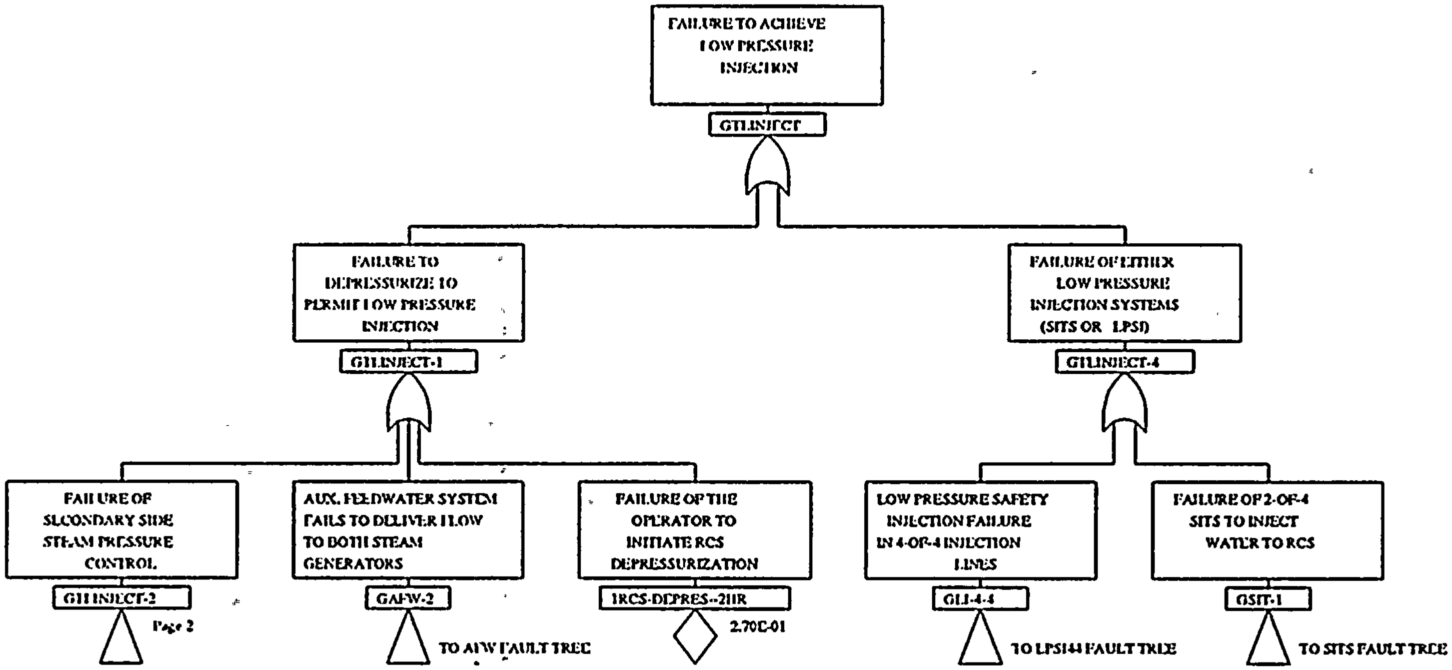

Figure 4.3-12 (page 1 of 2)

Low Pressure Injection

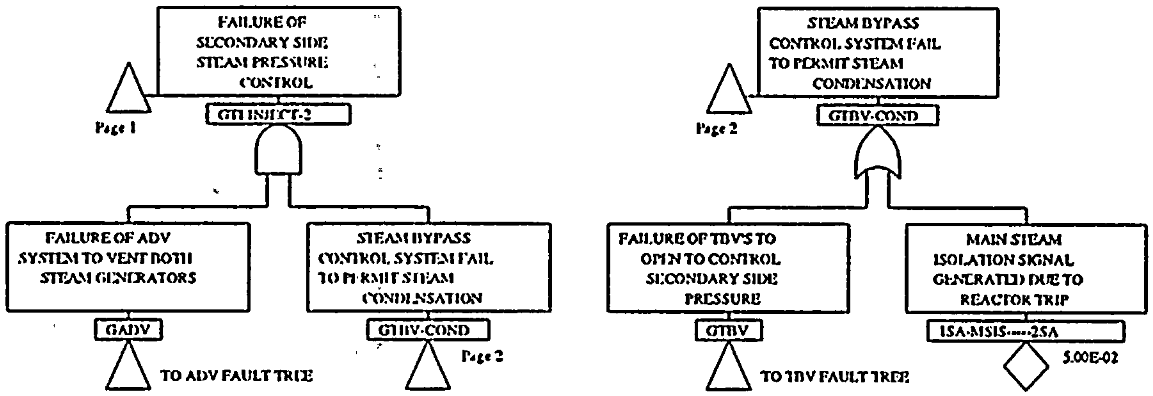

Figure 4.3-12 (page 2 of 2)

Low Pressure Injection

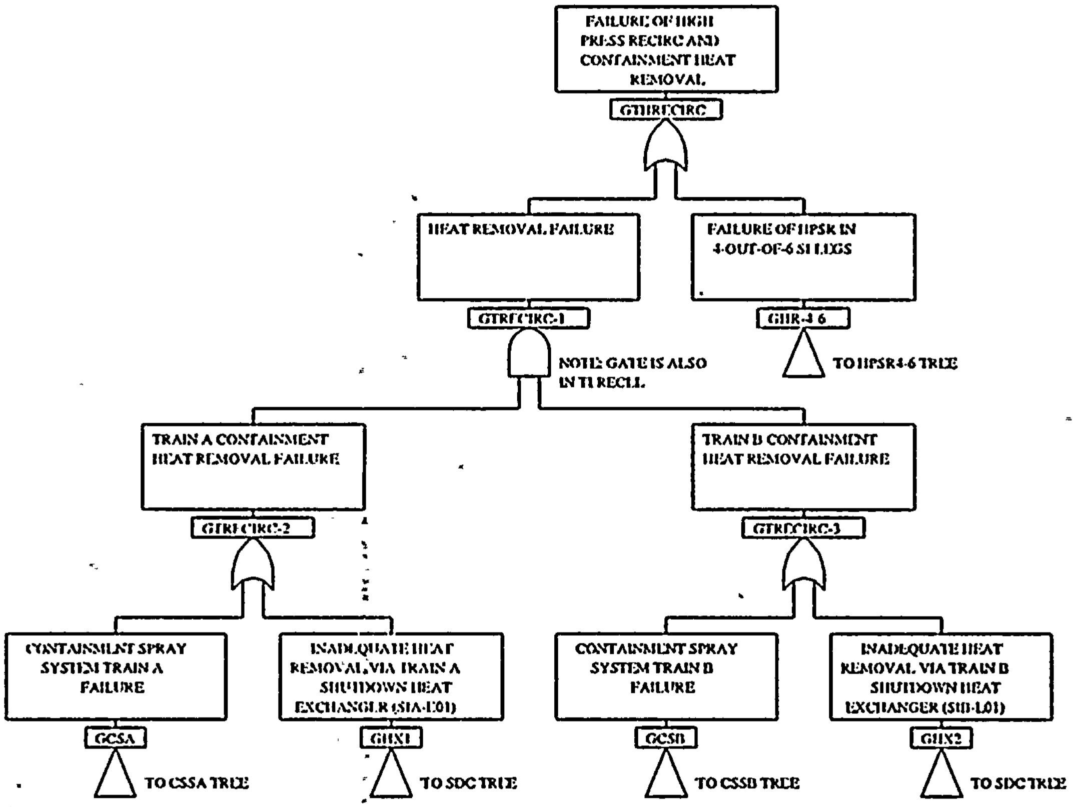

Figure 4.3-13

High Pressure Recirculation Heat Removal

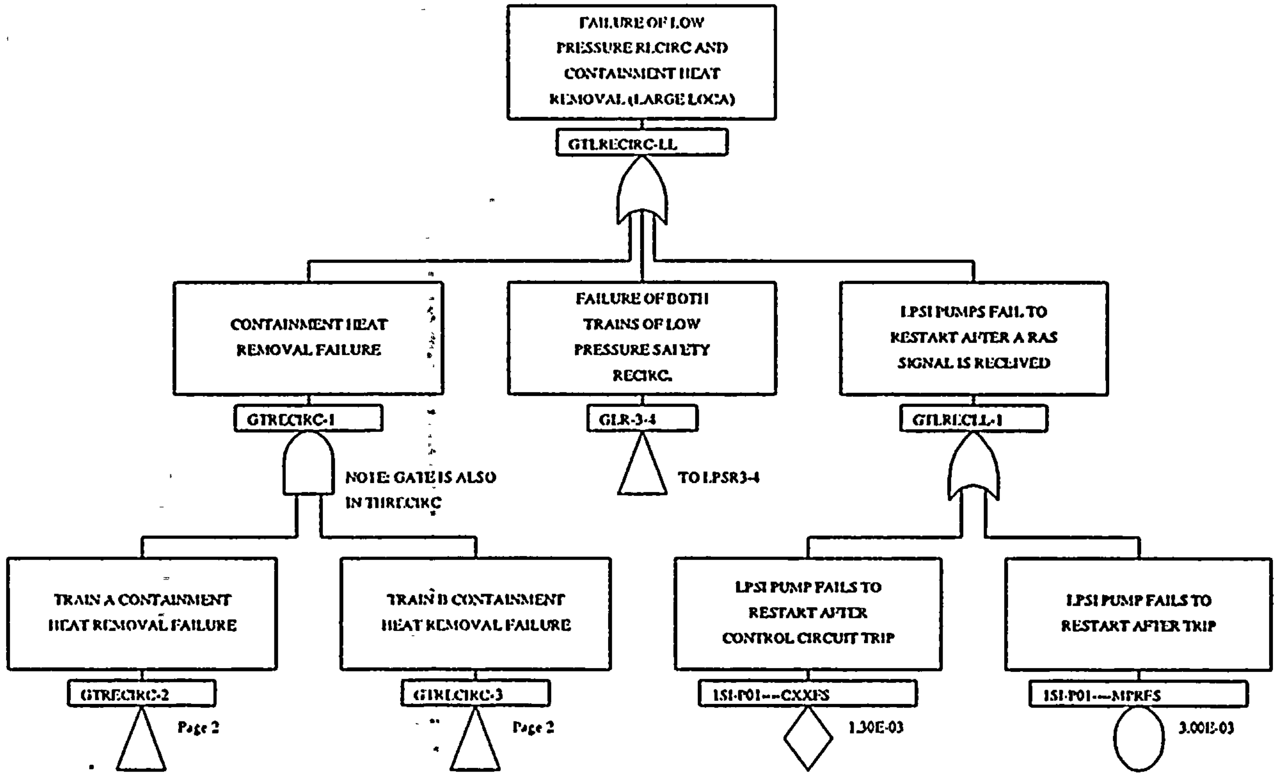

Figure 4.3-14 (page 1 of 2)

LPSR and Heat Removal - Large LOCA

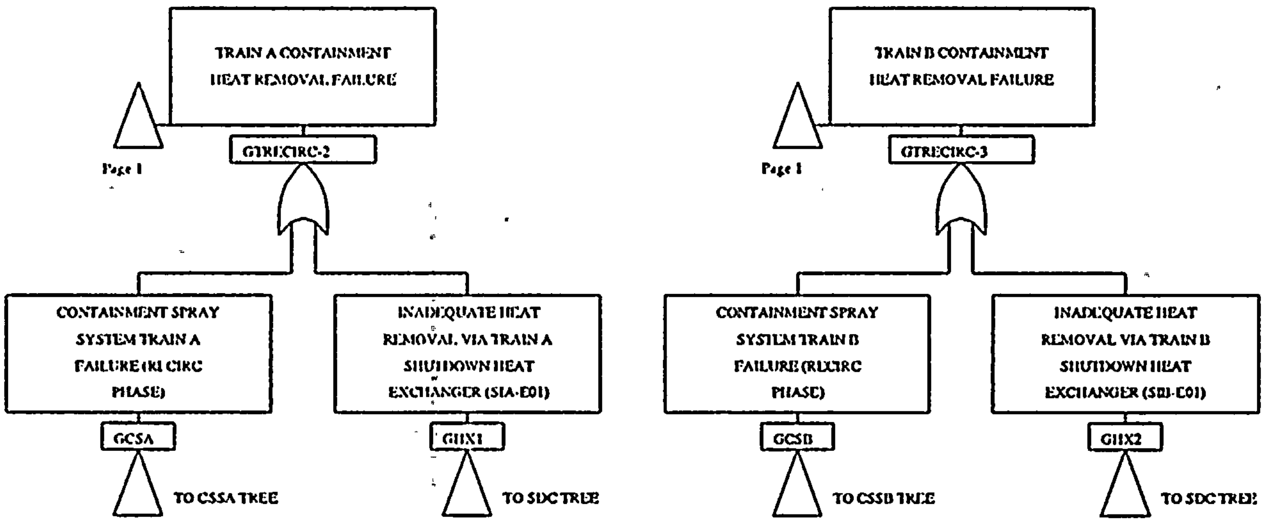

Figure 4.3-14 (page 2 of 2)

LPSR and Heat Removal - Large LOCA

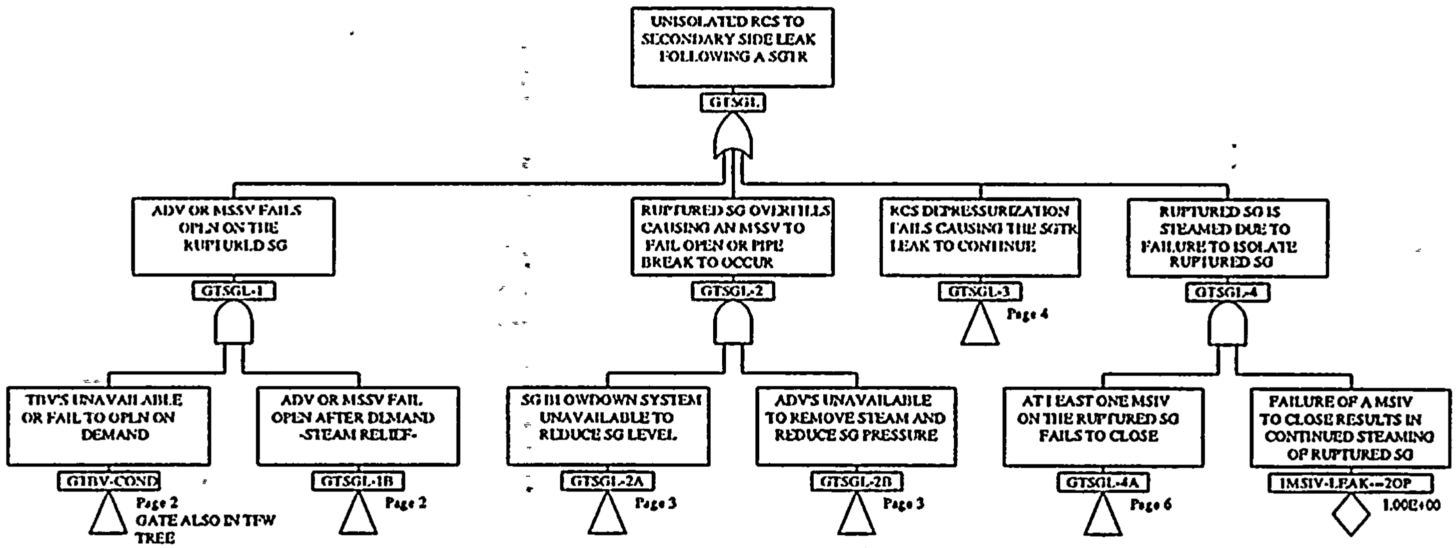

Figure 4.3-15 (page 1 of 6)

Unisolated Leak During SGTR

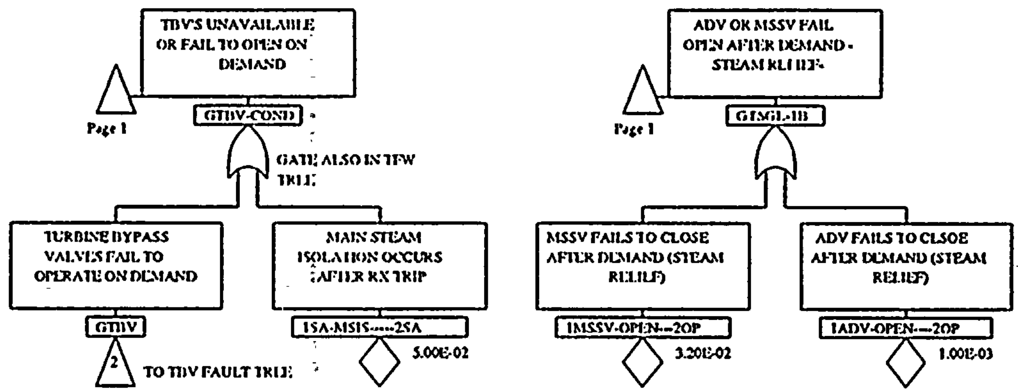

Figure 4.3-15 (page 2 of 6)

Unisolated Leak During SGTR

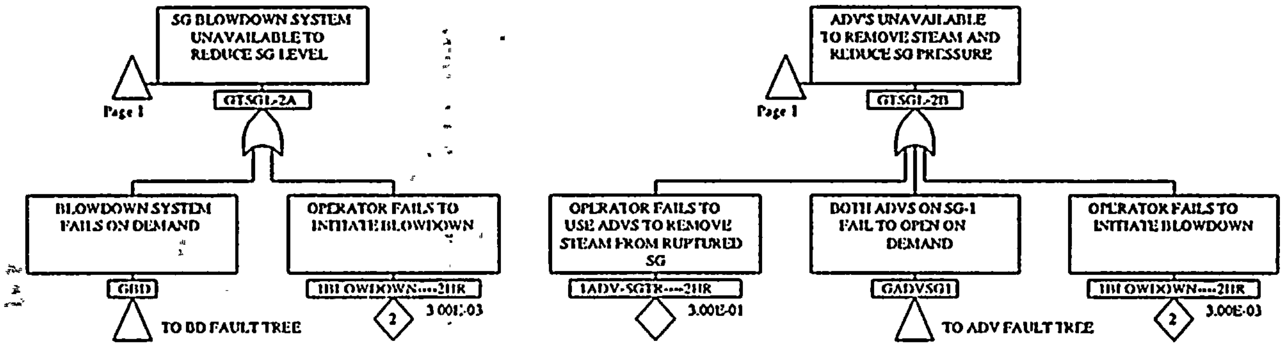

Figure 4.3-15 (page 3 of 6)

Unisolated Leak During SGTR

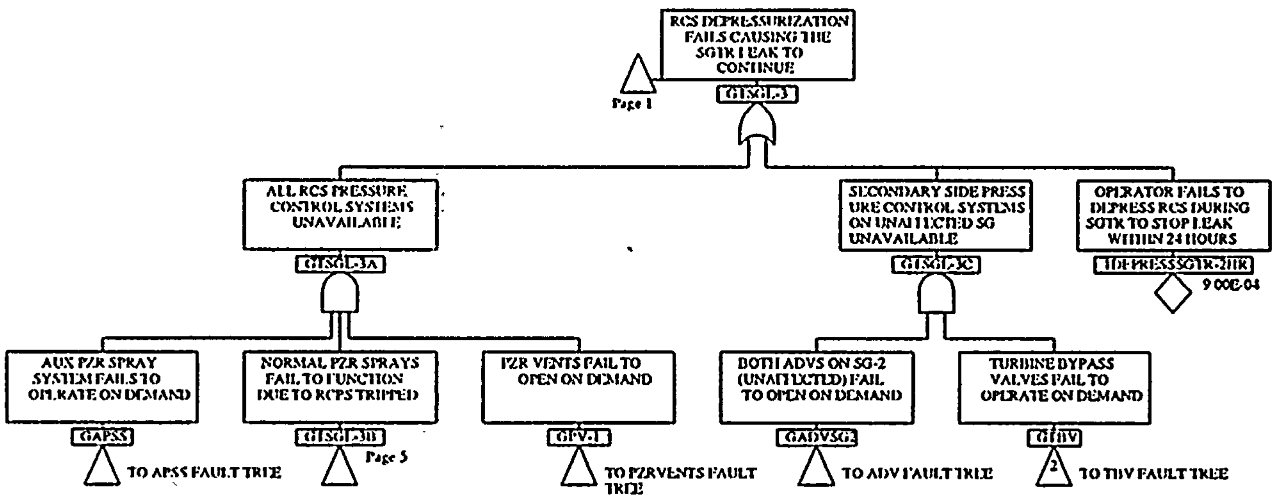

Figure 4.3-15 (page 4 of 6)

Unisolated Leak During SGTR

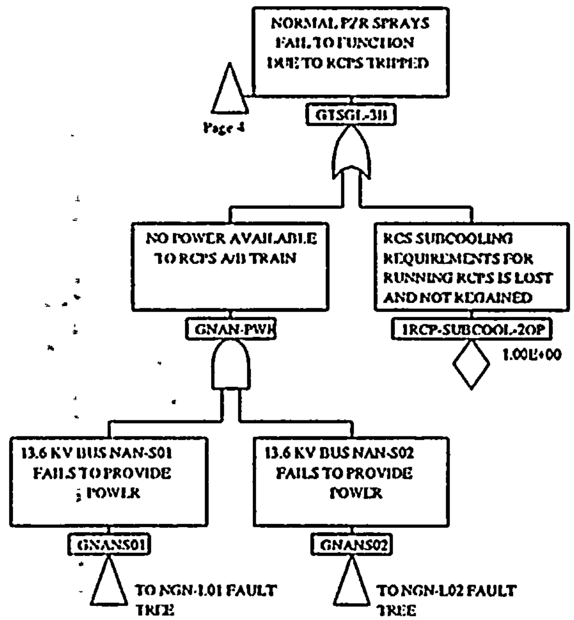

Figure 4.3-15 (page 5 of 6)

Unisolated Leak During SGTR

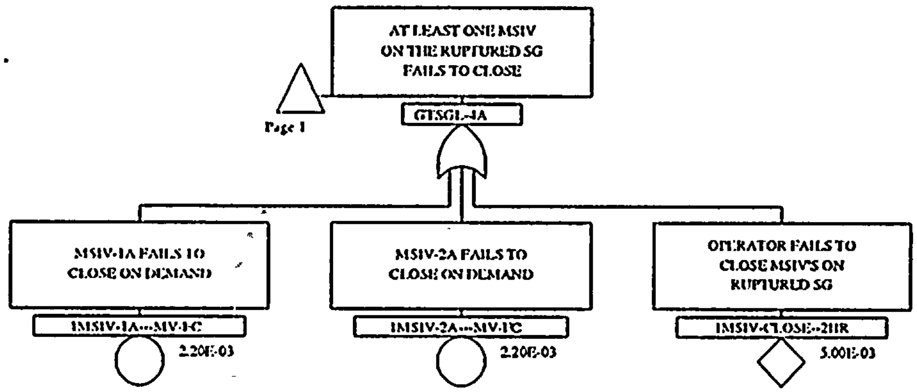

Figure 4.3-15 (page 6 of 6)

Unisolated Leak During SGTR

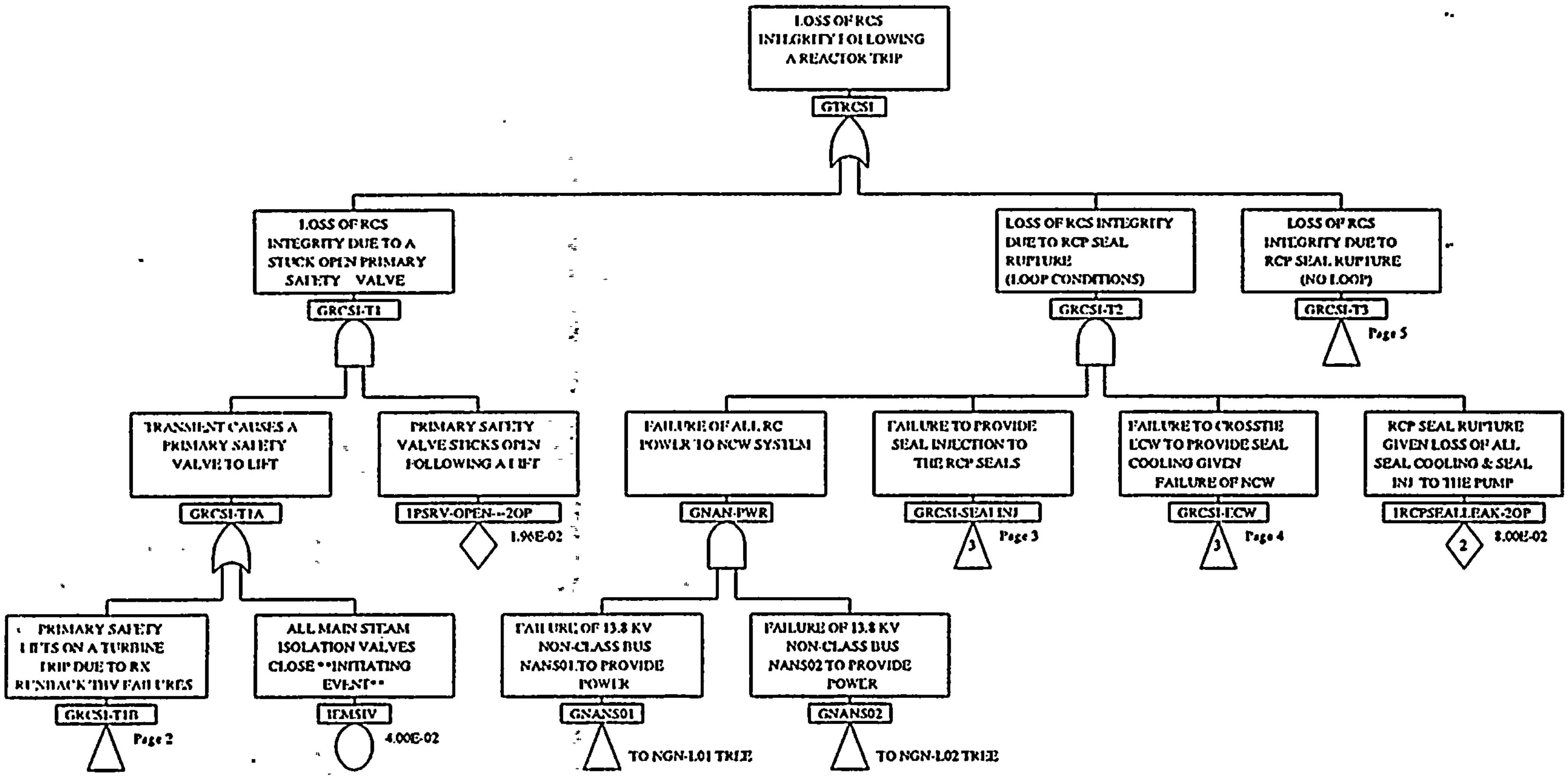

Figure 4.3-16 (page 1 of 7)

RCS Integrity Loss

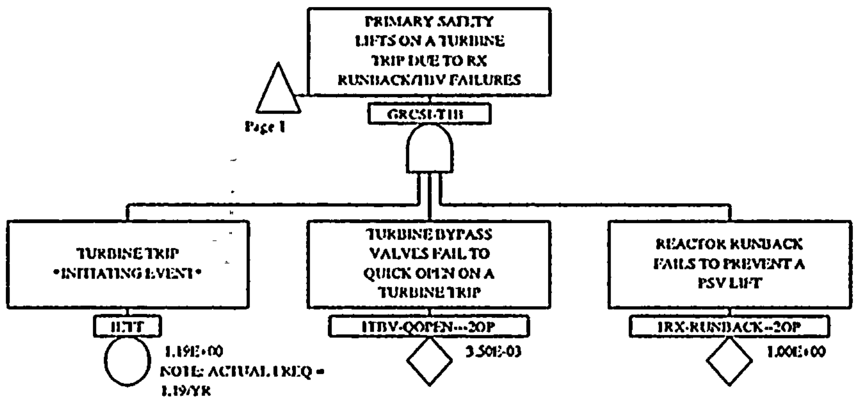

Figure 4.3-16 (page 2 of 7)

RCS Integrity Loss

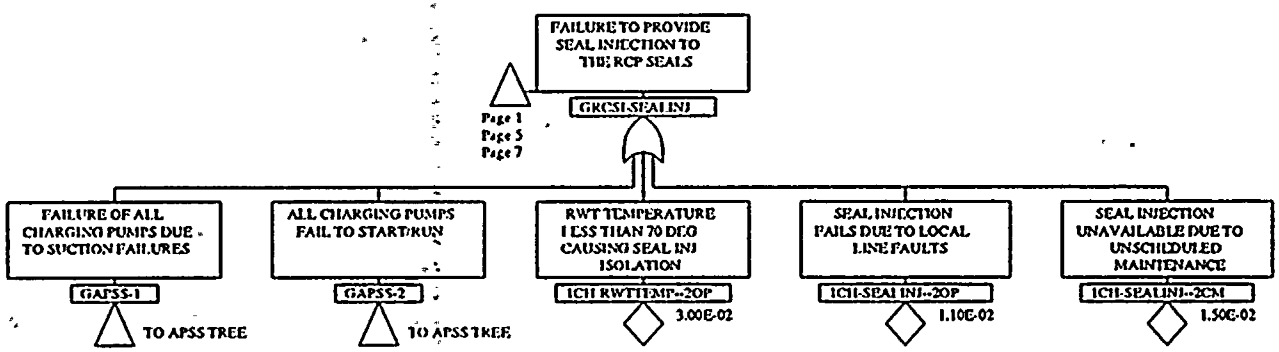

Figure 4.3-16 (page 3 of 7)

RCS Integrity Loss

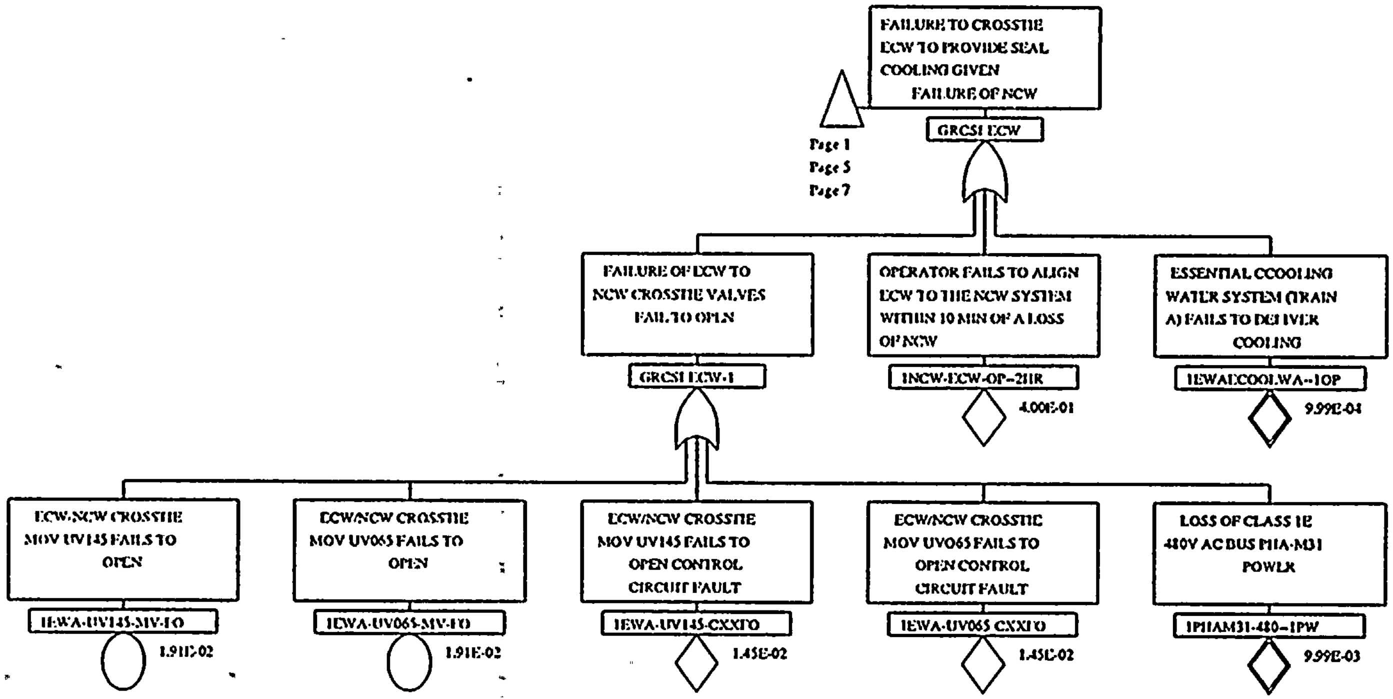

Figure 4.3-16 (page 4 of 7)

RCS Integrity Loss

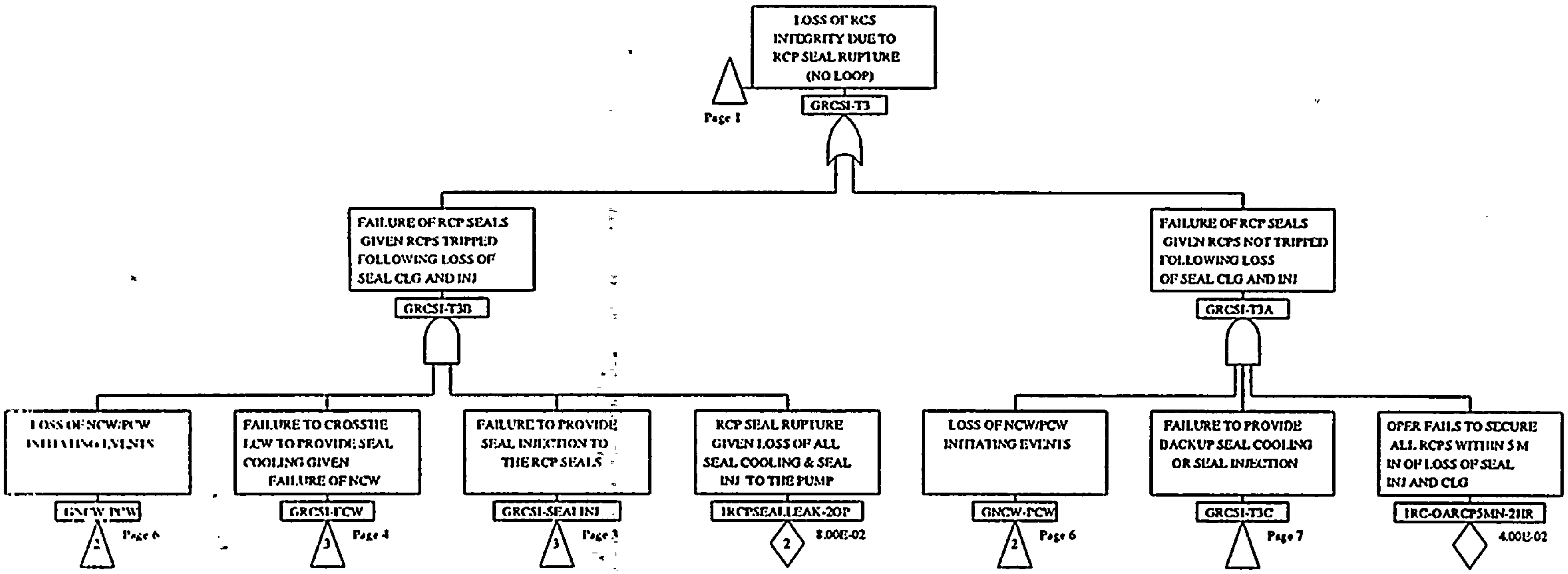

Figure 4.3-16 (page 5 of 7)

RCS Integrity Loss

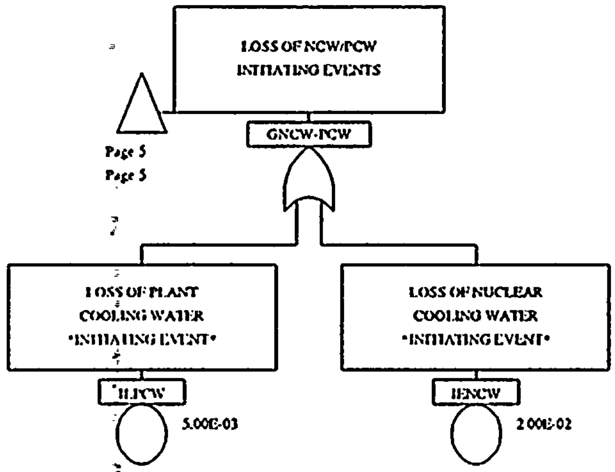

Figure 4.3-16 (page 6 of 7)

RCS Integrity Loss

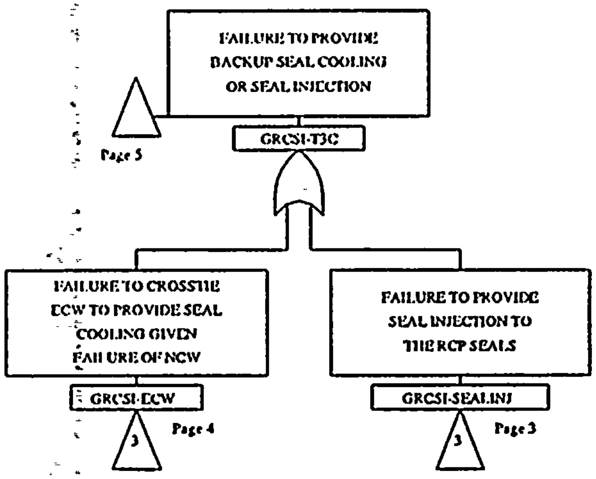

Figure 4.3-16 (page 7 of 7)

RCS Integrity Loss

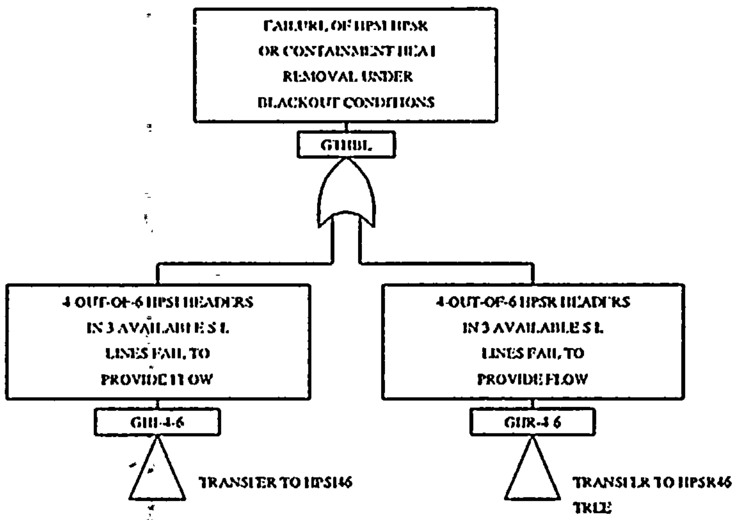

Figure 4.3-17

HPSI, HPSR, & Containment Heat Removal

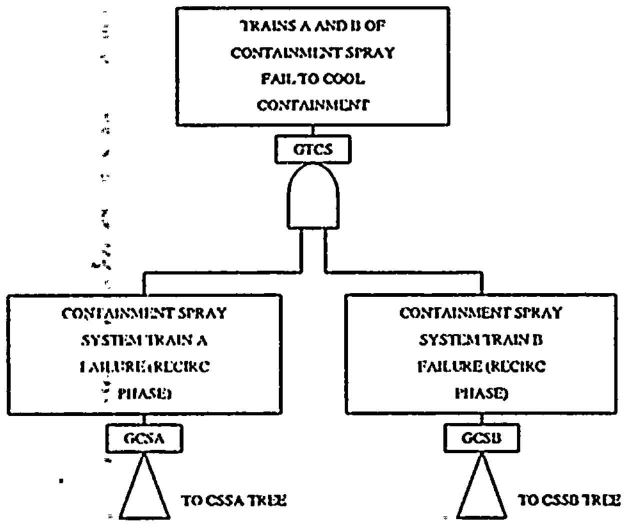

Figure 4.3-18

Loss Of Containment Spray

Table 4.1-1 Initiating Events Screening List

Potential Initiating Event	Effects
A. EPRI NP-2230 Events	
1. Loss of RCS Flow (1 loop)	Loss of any pump trips reactor.
2. Uncontrolled Rod Withdrawal	Rod withdrawal would not affect any other mitigating systems and looks like a reactor trip with a higher initial RCS pressure.
3. CRDM Problems and/or Rod Drop	Manual or CEAC/CPC[a] trip.
4. Leakage from Control Rods	Small leaks would lead to a reactor trip. Larger leaks are covered by Small LOCA.
5. Leakage in Primary System	Covers leaks smaller than 0.38 in. diameter that eventually lead to a reactor trip. All others treated under LOCAs.
6. Low Pressurizer Pressure	Leads to reactor trip.
7. Pressurizer Leakage	Same as 5 above.
8. High Pressurizer Pressure	Leads to reactor trip.
9. Containment Pressure Problems	Reactor trips on high containment pressure.
10. CVCS Malfunction - Boron Dilution	Most probable boron dilution would eventually lead to Reactor Protection System (RPS) trip. Events leading to core melt directly due to extended dilution are judged to be very small in probability.
11. Pressure, Temperature, Power Imbalance-Rod Position Error	Trip on high or low pressure, temperature or neutron power imbalance.
12. Total Loss of RCS Flow	Dominated by loss of off-site power. If off-site power is available, then event is a reactor trip with natural circulation cooling.
13. Loss or Reduction in FW Flow (1 loop)	Event may lead to a reactor trip or could be handled by a reactor power cutback.
14. Full Closure of MSIV (1 loop)	Temperature or power imbalance. Manually reduce power to 70% power.
15. Closure of All MSIVs	Large-load rejection.
16. Increase in FW Flow (1 loop)	Temperature or power imbalance or high SG level.
17. Increase in FW Flow (all loops)	High SG level.
18. FW Flow Instability - Operator error	High or low SG level.

Table 4.1-1 Initiating Events Screening List (Continued)

Potential Initiating Event	Effects
19. FW Flow Instability - Hardware fault	High or low SG level.
20. Steam Generator Leakage	May lead to manual trip.
21. Miscellaneous Leakage in System	Large secondary leakage treated under large secondary line break. Others assumed to trip reactor.
22. Sudden Opening of a Steam Relief Valve	Low SG pressure.
23. Loss of Component Cooling Water	Broken up into loss of nuclear cooling water and loss of turbine cooling water.
24. Loss of Service Water	Loss of plant cooling water.
25. Turbine Trip, Throttle Valve Closure, EHC problems	Event may lead to a reactor trip or could be handled by a reactor cutback.
26. Generator Trip or Generator Caused Faults	Event may lead to a reactor trip or could be handled by a reactor cutback.
27. Total Loss of FW Flow (all loops)	Trip on low steam generator level.
28. Loss of Condensate Pumps (all loops)	Trips all FW pumps.
29. Loss of Condenser Vacuum	Trips all FW pumps.
30. Condenser Leakage	Assumed to lead to a loss of condenser vacuum.
31. Loss of Circulating Water	Treated as a loss of condenser vacuum.
32. Pressurizer Spray Failure	Trips reactor on low pressure.
33. Loss of Power to Necessary Plant Systems	Most loss of power events are treated as separate events. Only those loss of power events that do not affect mitigating systems are included here.
34. Spurious Trips - Cause Unknown	
35. Automatic Trip - No Transient Condition	
36. Manual Trip - No Transient Condition	
37. Loss of Off-site Power	
38. Inadvertent Safety Injection Signal	Since the HPSI pumps have a discharge pressure significantly less than normal RCS pressure, an inadvertent SIS has no effect on operating conditions.
39. Startup of Inactive Coolant Pump	All RCPs run during reactor operation.

Table 4.1-1 Initiating Events Screening List (Continued)

Potential Initiating Event	Effects
40. Loss of Condensate Pumps (1 loop)	Three condensate pumps total. Loss of one may cause operators to slightly reduce power; should not result in trip.
41. Fire Within Plant	Considered in IEEE.
B. Plant-specific Events	
42. Loss of 125V Class 1E DC Power	Four separate events considered: Loss of any of four DC control centers or distribution panel powered from its respective DCCC.
43. Loss of 120V Class 1E AC Instrument Power	Two events considered: Loss of either Channel A or B vital AC distribution panel.
44. Loss of Instrument Air System	Does not directly trip reactor; however, extended loss will lead to manual trip.
45. Loss of Control Room HVAC	Leads to spurious load sheds.
46. Loss of DC Equipment Room HVAC	Includes loss of Division 1 DC Equipment Room HVAC and loss of Division 2 DC Equipment Room HVAC. Leads to loss of class 120V AC and 125V DC power.
47. Large Secondary Line Break	Unisolable from steam generator.
48. Steam Generator Tube Rupture	
49. Interfacing Systems LOCA	
50. Large Feedwater Line Break	Undercooling event.
51. Small, Medium, and Large LOCAs	

a. Control Element Assembly Calculator and Core Protection Calculator function to trip reactor under certain abnormal CEA configurations.

Table 4.1-2 Initiating Events for PVNGS

Initiating Event	Potential IE Category Table 4.1-1	Name	Event Tree
1. Total Loss of FW Flow (all loops)	16	IEFWP	Loss of Main Feedwater/ Condensate Pumps
2. Loss of Condensate Pumps (all loops)	28	IECPST	Loss of Main Feedwater/ Condensate Pumps
3. Loss of Condenser Vacuum	29, 30, 31	IECONDVAC	Loss of Main Feedwater/ Condensate Pumps
4. Large Secondary Line Break	47	IESLB	Large Secondary Line Break
5. Steam Generator Tube Rupture	48	IESGTR	Steam Generator Tube Rupture
6. Feedwater Line Break	50	IEFLB	Feedwater Line Break
7. Loss of Off-site Power	37	IELOOP	Group Transient
8. Small LOCA	51	IESMLOCA	Small LOCA
9. Medium LOCA	51	IEMLOCA	Medium LOCA
10. Large LOCA	51	IELLOCA	Large LOCA
11. Station Blackout		IEBLACK	Station Blackout
12. Spurious Closures of all MSIVs	15	IEMSIV	Group Transient
13. Loss of Plant Cooling Water	24	IEPCW	Group Transient
14. Loss of Instrument Air	44	IEIAS	Group Transient
15. Loss of Turbine Cooling Water	23, 24	IETCW	Group Transient
16. Loss of Nuclear Cooling Water	23, 24	IENCW	Group Transient
17. Turbine Trip	25	IETT	Group Transient
18. Miscellaneous Trip	1-36	IEMISC	Group Transient
19. Loss of Class 125V DC Channel A	42	IEPKAM41	Group Transient
20. Loss of Class 125V DC Channel B	42	IEPKBM42	Group Transient
21. Loss of Class 125V DC Channel C	42	IEPKCM43	Group Transient
22. Loss of Class 125V DC Channel D	42	IEPKDM44	Group Transient

Table 4.1-2 Initiating Events for PVNGS (Continued)

Initiating Event	Potential IE Category Table 4.1-1	Name	Event Tree
23. Loss of Class 120V AC Channel A	43	IEPNAD25	Group Transient
24. Loss of Class 120V AC Channel B	43	IEPNBD26	Group Transient
25. Loss of Control Room HVAC	45	IECRHVAC	Leads directly to core melt.
26. Loss of DC Equipment Room HVAC Division 1	46	IEDCRHVAC-1	Group Transient
27. Loss of DC Equipment Room HVAC Division 2	46	IEDCRHVAC-2	Group Transient
28. Interfacing Systems LOCA	49	IEISLOCA	Inside Containment treated under LOCA; Outside Containment leads directly to core melt.
29. Anticipated Transient without SCRAM		See Section 4.1.3.16	ATWS

SECTION 5

System Analysis

5.1 General Approach

5.1.1 Introduction

The system analysis for the PVNGS Probabilistic Risk Assessment (PRA) included two groups of system fault trees. First, the front-line system fault trees required by the event-tree development were modeled. Subsequently, all of the required support systems were modeled to the extent required by the front-line system fault trees.

The analysis and development of each fault tree, along with the number of system fault trees required, went through several stages. As the front-line systems were fine-tuned to include as much detail as possible, more support system models were developed. Additionally, as the event tree system requirements were reviewed for various initiators, it required the creation of several fault trees for a front-line system.

Component data base development progressed in conjunction with the system modeling. The level of detail in the system fault trees was directly influenced by the level of available data. A data base was originally developed before the system analysis was modified and expanded to accommodate new component failures and failure modes. Many of these component failure rates were later modified as better data sources became available.

5.1.2 The Analysis Process

The first step in analyzing a specific system was creation of a system notebook using the System Notebook Format Guide. This guide was derived for the PVNGS PRA from EPRI report Documentation Design for Probabilistic Risk Assessment, October 1983, RP2171-3, and from the IREP Program Procedures Guide, NUREG/CR-2728. This notebook included the following information:

a) Updated Final Safety Analysis Report (UFSAR) system information

b) Applicable system description information

c) Mechanical Piping and Instrumentation Diagram (P&ID) and applicable isometrics

d) Electrical and Instrumentation and Control (I&C) drawings for system components including loop and logic diagrams

e) Test and maintenance procedures

f) Technical specifications applicable to the system

g) Operation procedures including system lineups

h) Additional information relating to system operation including comparative data from other plants.

Conformation of the information used in the modeling was provided by the following means:

a) Walkdowns of the areas where the systems are located

b) Discussions with the System engineers regarding operation of the equipment, problems experienced by the system, and any other information which would have an impact on the system model

c) Discussions with the Design engineers regarding the design capabilities of the equipment

d) Discussions with Senior Reactor Operators regarding actions which would be or are taken to operate systems or perform tasks during accident scenarios

e) Discussions with Safety Analysis engineers regarding plant responses

f) Discussions, as warranted, with other departments such as Maintenance, Fire Protection, and Training.

To insure continued accuracy within the PRA Model, the PRA group receives plant/technical specification documents pertaining to plant trips, incident investigations, plant design changes, and daily plant statuses. The group is also made aware of industry occurrences which may have significant affect on the PVNGS PRA Model. A representative is on the Engineering Design Review Board to review all design change packages and assess their impacts on the PRA. Arizona Public Service plans to incorporate plant configuration and administrative practice changes in the PRA on a refueling basis, that is, approximately every 18 months.

5.2 System Descriptions .

A matrix of the front-line and support system dependencies is represented in Matrix 5.2-1.

5.2.1 Front-Line Systems

5.2.1.1 High Pressure Safety Injection

5.2.1.1.1 System Function

The High Pressure Safety Injection System (HPSI) is part of the Safety Injection (SI) System, which includes Low Pressure Safety Injection (LPSI), Safety Injection Tanks (SIT), and the shutdown cooling heat exchangers. The SI system includes the following functions:

- Inject borated water into the Reactor Coolant System (RCS) to flood and cool the core following a loss of coolant accident (LOCA), thus preventing a significant amount of cladding failure along with subsequent release of fission products into the containment.
- Provide for the removal of heat from the core for extended periods of time following a LOCA.
- Inject borated water into the RCS to increase shutdown margin following a rapid cooldown of the system due to a secondary line break.
- HPSI initiation is also required to inject borated water in the event of a steam generator tube rupture and to provide negative reactivity for a CEA ejection incident.

The primary function of the HPSI system is to inject borated water into the RCS in the event of a small break in the RCS boundary. For small LOCAs, where RCS pressure is expected to remain at approximately 1255 psig for long periods of time, the HPSI pumps ensure sufficient injection flow. The HPSI system increases the shutdown margin by injecting borated water in the event of a severe overcooling accident.

The HPSI system also provides hot-leg injection (HLI) for long term cooling during LOCAs. HLI insures cooling water flow across the core and serves to prevent the concentration of boric acid which could result in a blockage of flow to the core. HLI is initiated by procedure for all LOCAs, however it is only required for Medium and Large LOCAs. HPSI also provides injection flow during the recirculation phase once the Refueling Water Tank (RWT) is depleted and the source of water for the Safety Injection (SI) system is from the containment sump.

5.2.1.1.2 System Success Criteria

The HPSI system is needed to inject borated water only in the event of a Small or Medium LOCA, Steam Generator Tube Rupture (SGTR), or a rapid cooldown of the RCS due to steam line rupture. The Updated Final Safety Analysis Report (UFSAR) indicates that 75% of the flow of one of the HPSI pumps is sufficient to maintain adequate RCS inventory and boration for any of these scenarios. Since the HPSI system injects via eight lines, this criteria could be restated as obtaining design flow in at least three of the eight injection paths, irrespective of how many pumps provide it. Note that if both pumps are involved in supplying flow to only three paths, i.e., the remaining paths are obstructed, the flow in each line is likely to exceed nominal design flow. Hence, this is a conservative interpretation of the UFSAR criteria.

The success criteria for the HPSI system, for associated Small or Medium LOCA and Feedwater Line Break events, is given below:

- Small LOCA — Three HPSI injection lines available to provide makeup to the RCS
- Medium LOCA — Same as Small LOCA
- Feedwater Line Break — Same as Small LOCA.
- HLI — One train of HPSI is aligned within two hours to provide injection flow into a RCS hot-leg (during Medium and Large LOCA events)

For SGTR and main steam line rupture events, all HPSI flow will enter the RCS and all injection lines will be credited as initially available. In addition, even if only one HPSI injection line was unobstructed, the flowrate would exceed 350 gpm (pump design flowrate is 850 gpm).

The secondary line break event also makes relatively minor demands on the HPSI system. (See Section 4.1.3 for a discussion of secondary line break initiating event). Successful HPSI via one line again provides adequate RCS inventory makeup and boration to mitigate the brief localized return to power or short term RCS volume shrinkage that may develop in certain steam line break sequences.

The success criteria for the HPSI system for associated SGTR and Secondary Line Break events, is given below:

- SGTR — One HPSI injection line available to provide makeup to the RCS
- Secondary Line Break — One HPSI injection line available to provide makeup to the RCS

5.2.1.1.3 System Description

The HPSI system consists of two redundant, full capacity injection trains. Each train consists of one HPSI pump, one hot-leg injection line, and four branch headers with each discharging through a HPSI valve to a RCS cold-leg. During the injection phase following a LOCA, each HPSI pump takes separate suction from the RWT via a 20-in. suction header common to the Low Pressure Safety Injection (LPSI) system and the Containment Spray system (operation of the HPSI system during the recirculation phase is discussed in Section 5.2.1.2). The HPSI pumps discharge into the four safety injection lines common to the LPSI and Safety Injection Tank (SIT) discharges and then into the RCS through the four safety injection nozzles, one in each of the four RCS cold-legs. A simplified diagram of the HPSI system in the injection mode is shown in Figure 5.2-1.

The HPSI system is in standby during normal plant operations but automatically actuates when a Safety Injection Actuation Signal (SIAS) is received. A SIAS is produced upon two-out-of-four coincident low pressurizer pressure (<1837 psia) or high containment pressure signals (>3 psig). SIAS provides direct actuation of the HPSI Motor Operated Valves (MOVs) and indirect actuation of the HPSI pumps via the ESF load sequencers.

When RCS pressure drops below HPSI pump shutoff head (approximately 1900 psi), check valves in the injection lines open to pass flow to the RCS cold-legs. In order to ensure the HPSI pumps are not damaged while RCS pressure remains above their shutoff head, a minimum flow line back to the RWT is provided. A MOV in this line closes automatically when pump suction switches over to the sump for the recirculation phase to prevent a depletion of the containment sump inventory.

Two to three hours following a LOCA, Control Room operators establish HLI by aligning the HPSI system such that approximately 50% of the flow delivered by each train goes into the hot-legs and 50% goes into the cold-legs. Although this will occur while the HPSI system is still in injection phase for many Small LOCA scenarios, HLI is only of importance for Medium and Large LOCAs and initiation will occur in the recirculation phase. A simplified diagram of the HPSI system in the HLI mode is shown in Figure 5.2-2.

5.2.1.1.4 Major Components

The two HPSI pumps are located outside containment in the Auxiliary Building on the 40-ft. level in individual pump rooms. They are horizontal, multistage, centrifugal pumps driven by 1000 hp motors. The shutoff head of the HPSI pumps (approximately 1900 psig) is selected so that for small breaks, the RCS pressure can be maintained above the setpoint of the steam generator safety valves, thus enabling decay heat to be removed by blowing steam through these valves. Maximum HPSI pump discharge pressure is not high enough to lift the primary safety relief valves. Design flowrate for each pump is 850 gpm including 35 gpm bypass flow back to the RWT via the minimum flow line. The pump shaft seals are mechanical and are cooled by pumped water, like the bearing housings. The pump is designed for operation at pumped fluid temperatures of up to 350° F.

Each HPSI pump takes suction from a ten-inch line and discharges to a four-inch high pressure (2050 psig) line. Downstream of the pump discharge check valves, Train A piping pressure rating increases to 2485 psig while Train B piping maintains the 2050 psig rating of the pump discharge up to the injection MOV. Downstream of the injection MOVs, the piping pressure rating is 2485 psig.

The four HPSI header injection MOVs per train are used to initiate HPSI flow to the RCS cold-legs. The valves are 2-in. motor operated globe valves which open fully on a SIAS. The valves are located outside containment and may be operated and throttled from the control room or manually operated locally.

The four high-pressure headers in each train are orificed such that a break downstream in one of the injection MOVs does not divert all HPSI pump flow from the three intact headers.

For HLI, HPSI flow is injected onto the RCS hot-leg via a 3-in. header which includes two 3-in. MOVs: one a gate and the other a globe valve. The gate valve provides isolation and the globe valve is throttled from the control room to establish the desired hot-leg flow.

Instrumentation for the HPSI system includes control room indication of pump and major valve status. HPSI system pressure, flows, RWT, and Containment Sump level indication is also available to the control room operator.

5.2.1.1.5 Testing and Maintenance

The HPSI pumps are tested quarterly per PVNGS Technical Specifications. A HPSI system valve verification and Emergency Core Cooling System (ECCS) piping fill verification is performed every 31 days. The HPSI MOVs are stroked by the performance of Engineered Safety Features Actuation System (ESFAS) relay testing every 62 days. Testing is performed on HPSI valves each 92 days or every 18 months, as required, in accordance with American Society of Mechanical Engineers Standards (ASME), Section XI.

Equipment unavailability due to unscheduled maintenance is included for HPSI valves used for cold and hot-leg injection. Unscheduled maintenance is also included for the HPSI pumps and supply breakers.

5.2.1.1.6 System Dependencies and Interfaces

<u>Actuation</u>

The normally closed HPSI header MOVs receive their actuation signal to open directly from SIAS. The Train A HPSI valves receive the SIAS Train A signal while B Train HPSI valves are actuated by SIAS Train B.

The HPSI pumps are each actuated by their respective Engineered Safety Features (ESF) emergency load sequencers whenever the load sequencers receive a SIAS or Containment Spray Actuation Signal (CSAS). Each load sequencer automatically load sheds the HPSI pump along with numerous other safety loads from its associated 4.16kV emergency bus whenever it receives a LOP signal. After the emergency Diesel Generator (DG) is up to speed and supplying power to the 4.16kV emergency bus, the HPSI pump is sequenced on if a SIAS or CSAS signal is present.

<u>Electric Power</u>

Each HPSI pump receives motive power from the Class 1E 4.16kV AC bus of its own division. Control power for the Train A pump breaker is provided by Class 1E 125V DC distribution panels PKAD21 while PKBD22 provides control power for the Train B pump breaker.

The HPSI MOVs receive motive and control power from the Class 1E 480V AC Motor Control Centers (MCCs) associated with their respective power divisions.

HLI MOVs SIC-HV321 and SID-HV331 receive motive and control power from Class 1E 125V DC buses PKC-M43 and PKD-M44, respectively.

HVAC
The Auxiliary Building HVAC system cools the HPSI pump cubicles during normal plant operation. If a SIAS signal should occur, normal HVAC to these rooms is tripped and a dedicated emergency room cooler in each cubicle is actuated. The essential room coolers consist of an air cooling coil and fan. The fan is powered by a Class 1E 480V AC MCC of the appropriate electrical division and the coil carries chilled water from the appropriate Essential Chilled Water (EC) train. (The SIAS signal also actuates the Essential Chilled Water, Essential Cooling Water, and Essential Spray Pond Systems.)

Loss of HPSI pump room HVAC will result in actuation of alarm in Control Room when the room temperature reaches 105° F.

Water Sources
The HPSI, Low-Pressure Safety Injection (LPSI), and Containment Spray (CS) system all take suction from the RWT during the injection phase following a SIAS. This subsystem, which is common to all three ECCS systems, includes the RWT and the two separate SI suction lines up to the common junction at the suction of each train of the HPSI, LPSI, and CS pumps.

The RWT is a 750,000 gallon tank located outside the Containment Building. It is required by Technical Specifications to contain at least 573,744 gallons of water with a boron concentration between 4000 and 4400 ppm and a temperature between 60 and 120° F during operations in Modes 1, 2, 3, and 4. The basis for the minimum allowed volume is a requirement that the RWT provide at least 20 mins. (plus a 10% margin) of full flow to all ESF pumps prior to reaching a low-level switchover to the containment sump. The required boron concentration of the RWT guarantees that the reactor will remain subcritical in the cold condition once the RWT and RCS water volumes mix, even if the most reactive Control Element Assembly (CEA) is stuck out of the core.

RWT water is passed through a fine strainer before being drawn into either of the two 20-in. ESF pump suction lines. One line supplies Train A while the other supplies Train B pumps. Each line contains a check valve and a normally open MOV which can be manually operated from the control room. The operator is directed to isolate the RWT following a Recirculation Actuation Signal (RAS) actuation once flow from the containment sump is verified. RWT isolation is achieved by closure of the RWT isolation MOVs. Operator failure to isolate the RWT does not fail the Safety Injection pumps.

Operator Action
Control room operators are required to align the HPSI system for HLI within 2-3 hrs. from the initiation of a Medium or Large LOCA event. Operator failure to align HLI is described in Section 7.4.

Control Room operators throttle HPSI after SIAS actuation provided all of the following criteria can be met:

1. RCS subcooled greater than 28° F.
2. Reactor vessel level indicators show void restricted to upper head

3. Pressurizer level greater than 33% and controllable
4. Once steam generator is capable of maintaining heat removal.

Operator action is required to provide backup cooling to the HPSI pump room in the event of a loss of room cooling. Operator failure to provide backup cooling to the HPSI pump room given a failure of room cooling is described in Section 7.4.

5.2.1.1.7 Technical Specifications

The following PVNGS Technical Specifications are applicable to the HPSI system operation:

a) Specification 3/4.5.2 concerning ECCS Subsystems requires that both HPSI trains be operable. If one train is inoperable, the inoperable HPSI system should be restored within 72 hrs. or be in hot standby in 6 hrs. Surveillance requirements necessitate a valve alignment and that system fill procedures be performed every 31 days. Automatic valves are verified in correct position due to an actuation signal (SIAS or RAS) every 18 months. HPSI pump auto start on SIAS and CSAS is required to be performed every 18 months. A flow test through each header is required every 18 months.

b) Specifications 3/4.1.2.6 and 3/4.5.4 require that the RWT be operable with the proper volume, temperature, and boron concentration. The boron concentration and water volume are required to be verified every seven days and the temperature is required to be checked every 24 hrs.

5.2.1.1.8 System Operation

During normal operation at reactor power, the HPSI system does not operate. During this mode, the HPSI system is in the standby condition and aligned for possible emergency operation.

The HPSI system is automatically initiated by low pressurizer pressure (<1837 psia) or high containment pressure (>3 psig), which starts the HPSI pumps and opens the HPSI valves. HPSI can also be manually initiated. The pumps initially take suction from the RWT and, when a low level is reached in the RWT, a RAS automatically transfers the pump suctions to the containment sumps. Operators are directed to close RWT isolation MOVs once flow is verified from the containment sump.

Initially, HPSI provides makeup flow into each of the RCS cold-legs, but within two to three hours of a LOCA, the operator is directed to align half of the HPSI flow into the hot-legs to prevent boron precipitation in the core.

5.2.1.1.9 Major Modeling Assumptions

a) In the process of developing HPSI success criteria for LOCA events, it was determined that the amount of SI water actually reaching the core could be significantly impacted by the location and size of the piping rupture. Each of the four SI lines injects into one of the four RCS cold-legs. Thus, a cold-leg rupture or a rupture in an SI line itself could result in a LOCA in which some or all of the injection flow of one SI line is lost out the rupture, never serving to flood and cool the core. Since two HPSI lines deliver flow to each SI line, it follows that two of the eight HPSI paths will be diverted. While it is true that most LOCA break locations and sizes would divert only a fraction of the flow in an SI line (or none at all), it is conservatively assumed that all LOCA events result in the loss of injection flow from one SI line.

b) Availability of the HPSI pump minimum flow recirculation line following an accident requiring SI is not judged to be important to successful HPSI system operation. The minimum flow line protects against a dead-headed condition of the pumps while RCS pressure remains above HPSI shutoff head (1900 psig). However, RCS pressure drops to this level within minutes of any accident that generates a SIAS and since the HPSI pump can be run in a dead-headed condition for at least 20 mins., the availability of a minimum flow line is not considered to be an important factor in the successful operation of HPSI in the injection mode.

c) Ruptures of the piping and components of a HPSI train are generally not considered as failure modes due to the extremely low probability of sustaining a large enough break to divert significant flow and the high likelihood of detection within a shift (the HPSI lines are maintained water solid). However, catastrophic rupture of the RWT tank represents a common-cause failure of all SI trains. In addition, rupture of the two suction pipe segments between the SI pumps of each train and the RWT is modeled since a catastrophic rupture in one of these segments would fail HPSI, LPSI, and Containment Spray (CS) in the associated train.

d) Two potential diversion paths for HPSI flow are modeled. Both paths involve the failure of a check valve and could divert all HPSI flow in one SI line. Diversion via the low pressure injection header will occur if the LPSI check valve either failed to close after it was last opened or the injection check valve undergoes catastrophic internal rupture and RCS pressure remains above Low Pressure Safety Injection (LPSI) pressure. Rupture of the check valve could occur at anytime during standby (although no pressure differential exists) without being detected since the LPSI MOV is normally closed. Given an accident that generates a SIAS, the LPSI MOV opens automatically and HPSI flow will be diverted out one or more of the LPSI pressure relief valves if the LPSI check valve has failed. A second potential diversion via the SIT tanks exists. The check valve in each SIT line is verified closed during startup. Therefore, the only failure mode of concern is catastrophic internal rupture. Given a ruptured SIT check valve, HPSI flow in that SI line will be diverted to the SIT tank and eventually out the SIT relief valve as long as RCS pressure remains above the relief valve setpoint of 700 psig.

e) Failure of the HPSI pumps due to extreme environment (loss of pump room cooling) is included in the HPSI fault tree. The maximum HPSI pump room temperature reached in 24 hrs. with no HVAC is 199° F. If the HPSI pump room door is opened within 2 hrs., the maximum temperature reached is 165° F (see Section 6.2.5). As discussed in Section 6.2.5, room temperatures which result from loss of HVAC were determined not to immediately threaten pump operability, although reliability is significantly degraded. Accordingly, the probability of pump failure due to loss of

HVAC was adjusted as described in Section 6.2.5.

f) Backup HVAC cooling for the HPSI pump room consists of an operator blocking open the pump room door thereby providing natural convection cooling to the room.

g) The mission time used in the model for HPSI phase is 16 hrs. The mission time is based upon the time to deplete the RWT inventory for the most limiting small break LOCA. The mission time for HPSI in the injection phase for Medium LOCA events is 1 hr.

h) There is a long term HPSI line that operators are directed to use 2-3 hrs. from the initiation of a LOCA. When the valves are aligned correctly, half of the pump flow passes to the hot-leg and half continues to inject into the cold-leg. This will help prevent boron precipitation in the core for large cold-leg breaks. It is assumed that the long term hot-leg alignment of HPSI is not needed to prevent core melt for Small LOCA.

i) Common-cause failures are included in the HPSI fault tree for HPSI pumps and HPSI MOVs. Common-cause failures for the injection valves include failure of a single train and both trains.

5.2.1.1.10 System Analysis Results

The major system malfunctions of HPSI include common-cause failure of both HPSI pumps and common-cause failure of the HPSI valves to open. Also important in the system cutsets is failure of both trains of the SIAS system to actuate followed by an operator failure to manually actuate HPSI. Common-cause failure of SIAS includes failure of the RCS pressure transmitters or failure of the transmitter bistables. Electrical failures resulting in failure of the HPSI system are only important during loss of off-site power sequences.

Major system malfunctions for HLI include failure of operators to align HLI following a LOCA, common-cause failure of the hot-leg injection valves, and random failures of the hot-leg injection valves. These are important only for Medium and Large LOCAs.

5.2.1.2 High Pressure Safety Recirculation

5.2.1.2.1 System Function

High Pressure Safety Recirculation (HPSR) is a function of the High Pressure Safety Injection (HPSI) system. The function of HPSR is to make up RCS inventory for the removal of heat from the core for extended periods of time following a LOCA.

In the recirculation mode, the HPSI pumps recirculate the inventory from the containment sump back to the RCS. HPSR can provide adequate decay heat removal for those LOCAs in which the RCS pressure after refill (<538 psia) is not sufficient to allow for shutdown cooling operation.

5.2.1.2.2 System Success Criteria

The success criteria for the HPSI system during recirculation for associated LOCA events is:

> One HPSI train with a suction on the containment sump provides makeup through three HPSI injection lines to the RCS. To provide for long term cooling and prevention of boron precipitation in the core, one HPSI train will be aligned within 2-3 hrs. to provide hot-leg injection flow that is simultaneous with cold leg injection flow.

5.2.1.2.3 System Description

The HPSI system supplies borated water to the RCS to maintain core cooling during LOCAs and main steam line breaks when RCS inventory is lost or an overcooling transient occurs. For larger break LOCAs and those LOCAs for which break flow is not terminated, the RWT will eventually be depleted.

Once the RWT reaches the low level setpoint of 7.4%, the ESFAS generates a RAS signal which automatically aligns the HPSI and CS pump suction to the containment sump. The HPSI, CS, and LPSI minimum recirculation flow lines to the RWT are automatically isolated on a RAS to prevent a loss of inventory from the containment sump (RCS routed back to RWT). A simplified drawing of the HPSI system in the recirculation mode is shown in Figure 5.2-3.

5.2.1.2.4 Major Components

Except for the containment sump valves, the major components of the HPSI system are described in Section 5.2.1.1.4. Each SI train has a containment recirculation line which connects the containment sump with the SI pump suction. Each containment sump recirculation line consists of a 24-in. header with two normally closed 24-in. motor operated gate valves (one located in containment) and a 24-in. check valve. Each containment sump isolation MOV is opened upon receipt of a RAS.

Baffles and intake screens are installed to limit the maximum particle size entering the recirculation piping to 0.09-in. diameter to prevent flow blockage in the safety injection components and in the reactor.

5.2.1.2.5 Testing and Maintenance

The containment sump recirculation MOVs are tested per ASME Standards, Section XI, every 92 days.

Equipment unavailability due to unscheduled maintenance is included for the containment sump recirculation MOVs (UV-674/676) which are located outside containment.

5.2.1.2.6 System Dependencies and Interfaces

The system dependencies and interfaces for the HPSI system, as described in Section 5.2.1.1.6, apply to HPSR. The following are associated with the containment sump MOVs.

Actuation

The containment sump isolation MOVs open and the HPSI pump mini-flow recirculation MOVs close upon receiving a RAS once the RWT reaches a low level of 7.4%.

Electric Power

The containment sump isolation MOVs and the HPSI pump mini-flow recirculation MOVs receive motive and control power from Class 1E 480V AC MCCs associated with their respective power divisions.

Operator Action

Operator action is required by procedure to close the RWT MOVs once a RAS occurs and flow is verified from the containment sump.

5.2.1.2.7 Technical Specifications

The PVNGS Technical Specifications applicable to HPSR are described in Section 5.2.1.1.7.

5.2.1.2.8 System Operation

When the RWT level drops to its predetermined low level (7.4%) at the end of the safety injection phase, a RAS is generated. This signal transfers the HPSI and CS pump suction from the RWT to the containment sumps. The RAS signal also stops the LPSI pumps. Once initiated, recirculation continues until terminated or modified by the operator.

5.2.1.2.9 Major Modeling Assumptions

a) RAS realigns HPSI pump suction from the RWT to the containment sumps and closes both the HPSI mini-flow MOVs (UV-666-667) and the SOVs in the mini-flow lines common to LPSI and CS (UV-660,659). If these lines are not isolated by successful closing of at least one of the isolation valves, recirculating sump water will gradually begin refilling the RWT. This diversion of HPSR flow was negated in the model for the following reasons: (1) It requires either failure of RAS (which already fails HPSR) or failure of two MOVs, in series, to close, (2) There are indications that HPSR flow is being diverted to the RWT and considerable time is available to correct the problem, and (3) The diverted inventory is not lost and can be resupplied to the pump suction.

b) The HPSR fault tree uses much of the same logic as the HPSI tree. The injection phase is estimated to last approximately 16 hrs. and recirculation is alloted the remaining 8 hrs. for a total mission time of 24 hrs. For Medium LOCAs the injection phase is estimated to last 1 hr. and recirculation is alloted the remaining 23 hrs.

c) No maintenance is assumed to be permitted on the MOVs (UV-673, 675) in the containment sump during power operation.

d) Spurious close faults for the HPSI MOVs are not modeled for either HPSI or HPSR. These faults are considered negligible due to low probability and redundancy of the HPSI valves.

e) Emergency procedures require the RWT isolation valves to be closed following a switch-over to the containment sump as a suction source. This prevents the backflow of radioactive sump water to the RWT, which is vented to the Fuel Building. Early isolation of the RWT due to an inadvertent RAS failing the HPSI pumps is not modeled. This is based upon the low probability of receiving an inadvertent RAS during a LOCA event when insufficient level exists in the containment sump.

f) Common-cause failures are included in the HPSR fault tree for HPSI pumps, HPSI MOVs, and containment sump recirculation valves. Common-cause failures for the injection valves include failure of a single train and both trains.

5.2.1.2.10 System Analysis Results

The major system malfunctions for HPSR include mechanical and control circuit failures for the containment sump recirculation valves as well as common-cause failures of the RWT level transmitters and containment recirculation sump valves. Also important to this analysis is failure of RAS to open the containment recirculation sump valves on RWT low level.

5.2.1.3 Low Pressure Safety Injection

5.2.1.3.1 System Function

The Low Pressure Safety Injection System (LPSI) is part of the Safety Injection (SI) System, which includes High Pressure Safety Injection (HPSI), Safety Injection Tanks (SIT), and the shutdown cooling heat exchangers. The function of the SI system is described in Section 5.2.1.1.1.

The primary function of the LPSI system is to inject large volumes of borated water into the RCS in the event of a Large LOCA. LPSI is also used for Small LOCA and SGTR events which result in a failure of HPSI.

5.2.1.3.2 System Success Criteria

The success criteria for the LPSI system for associated events is:

- Large LOCA — One train is available to inject borated water into two SI injection headers.
- Small LOCA/ SGTR — One LPSI train through one injection header is sufficient to prevent core damage once the control room operators have depressurized the RCS to <140 psia to permit LPSI flow.

5.2.1.3.3 System Description

The LPSI system consists of two full-capacity injection trains. Each train has one LPSI pump and two branch headers, each discharging through its own injection MOV to a RCS cold-leg. Depending on system conditions, the LPSI pump suction may be from either the RWT or the containment sump once the RWT inventory is depleted (LPSI pumps are tripped by RAS on a RWT low level). Operation of the LPSI system during recirculation is discussed in Section 5.2.1.4. A simplified diagram of the LPSI system in the injection mode is shown in Figure 5.2-4.

The LPSI pumps inject large volumes of borated water into the RCS during an emergency involving a Large LOCA. During a Large LOCA, after the safety injection tanks (SITs) have emptied, LPSI keeps the reactor vessel annulus filled to maximize reflood and eventually quenches the core. LPSI is also used when HPSI failures have occurred during Small LOCAs and SGTR events. Upon failure of HPSI, the Control Room operators will depressurize the RCS to approximately 140 psia, using the steam generators, to allow LPSI flow into the RCS. The other function of the LPSI pumps is to provide shutdown cooling flow through the reactor core and shutdown cooling heat exchangers for normal plant shutdown cooling operation or as required for long term core cooling. Shutdown cooling is discussed in Section 5.2.1.6.

During normal operation, the LPSI pumps are isolated from the RCS by the injection MOVs. The LPSI system automatically goes into operation when a Safety Injection Actuation Signal (SIAS) or Containment Spray Actuation Signal (CSAS) is received. SIAS is produced due to two out of four coincident low pressurizer pressure (<1837 psia) or high containment pressure (>3.0 psig) signals.

SIAS or CSAS provide indirect actuation of the LPSI pumps via the ESF load sequencers and a SIAS provides direct actuation of the LPSI MOVs.

When RCS pressure drops below LPSI pump shutoff head, check valves in the injection lines open to pass flow to the RCS cold-legs. In order to ensure that the LPSI pumps are not damaged while RCS pressure remains above their shutoff head, a minimum flow line back to the RWT is provided. This line is automatically isolated during the recirculation phase to prevent a depletion of the containment sump inventory.

5.2.1.3.4 Major Components

The two LPSI pumps are located outside containment in the Auxiliary Building on the 40-ft. level in individual pump rooms. They are vertical, single stage, centrifugal pumps driven by 470 hp motors. Design flowrate for each pump is 4300 gpm including 100 gpm bypass flow back to the RWT via the minimum flow line. The pump shaft seals are mechanical and, like the bearing housing, are cooled by pumped water. The pump is designed for operation at pumped fluid temperatures of up to 400° F.

Each LPSI pump takes suction from a 20-in. suction header from the RWT, which is common to the same train HPSI and CS pumps. The LPSI pumps discharge into a 10-in. discharge header, which splits into two 12-in. headers containing the LPSI MOVs. The LPSI MOVs are 12-in. motor operated globe valves that open fully on a SIAS. The valves are located outside containment and may be operated and throttled from the control room or manually operated locally.

The LPSI injection headers in each train have orifices such that a malfunction downstream in one of the injection MOV does not divert all LPSI pump flow from the train.

Instrumentation for the LPSI system includes Control Room indication of pump and major valve status. LPSI system pressures, flows, and RWT and containment sump level indication is also available to the Control Room operator.

5.2.1.3.5 Testing and Maintenance

The LPSI pumps are tested quarterly per PVNGS Technical Specifications. A valve position verification is performed every 31 days. ASME Standards, Section XI, are utilized to perform tests on the LPSI valves every 92 days or every 18 months.

Equipment unavailability due to unscheduled maintenance is included for LPSI suction, minimum flow recirculation, and injection valves. Unscheduled maintenance is also included for the LPSI pumps and supply breakers.

5.2.1.3.6 System Dependencies and Interfaces

<u>Actuation</u>

The normally closed LPSI injection header MOVs receive their actuation signal to open directly from SIAS. The Train A LPSI valves receive the SIAS Train A signal while Train B LPSI valves are actuated by SIAS Train B.

The LPSI pumps are actuated by their respective ESF emergency load sequencers whenever the load sequencers receive a SIAS or CSAS signal. Each load sequencer automatically load sheds the LPSI pump along with numerous other safety loads from its associated 4.16kV emergency bus whenever it receives a LOP signal. After the emergency DG is up to speed and supplying power to the 4.16kV emergency bus, the LPSI pump is sequenced on if a SIAS or CSAS signal is present.

There are no other automatic actuations of LPSI components while in the injection phase.

Electric Power
Each LPSI pump receives motive power from the Class 1E 4.16kV AC bus of its own division. Control power to start and stop the Train A pump is provided by Class 1E 125V DC distribution panel PKAD21. Panel PKBD22 provides control power for the Train B pump.

The LPSI MOVs receive motive and control power from the Class 1E 480V AC MCCs associated with their respective power divisions.

HVAC
The Auxiliary Building HVAC system cools the LPSI pump cubicles during normal plant operation. If a SIAS signal should occur, normal HVAC to these rooms is tripped and a dedicated emergency room cooler in each cubicle is actuated. The essential room coolers consist of an air cooling coil and fan. The fan is powered by a Class 1E 480V AC MCC of the appropriate electrical division and the coil carries chilled water from the appropriate Essential Chilled Water Train. (The SIAS signal also actuates the Essential Chilled Water, Essential Cooling Water, and Essential Spray Pond Systems.)

Loss of LPSI pump room HVAC will result in actuation of an alarm in Control Room when the room temperature reaches 105° F.

Operator Action
For Small LOCAs and SGTR events where both trains of HPSI fail, the operator is required to depressurize the RCS using the steam generators to approximately 140 psia to allow LPSI flow for RCS makeup. This operator action is described in Section 7.4.

Operator action is required to provide backup cooling to the LPSI pump room in the event of a loss of room cooling. Operator failure to provide backup cooling to the LPSI pump room given a failure of room cooling is described in Section 7.4.

No operator action of the LPSI system is required for Large LOCA events.

5.2.1.3.7 Technical Specifications
The following PVNGS Technical Specifications are applicable to the LPSI system operation:

a) Specification 3/4.5.2 requires both LPSI trains to be operable. If one train is inoperable, the inoperable LPSI system should be restored within 72 hrs.

or be in hot standby in 6 hrs. It also requires that a valve alignment and system fill procedures be performed every 31 days and RAS and SIAS valves be verified operable every 18 months. LPSI pump auto start on SIAS and CSAS is required to be performed every 18 months. A flow test through each header is required every 18 months.

b) Specifications 3/4.1.2.6 and 3/4.5.4 require that the RWT be operable with the proper volume, temperature and boron concentration. The boron concentration and water volume are required to be verified every seven days and the temperature is required to be checked every 24 hrs.

5.2.1.3.8 System Operation

During normal operation at reactor power, the LPSI system does not operate. During this mode, the LPSI system is in the standby condition and aligned for possible emergency operation.

LPSI is automatically initiated by low pressurizer pressure or high containment pressure, which starts the LPSI pumps and opens the LPSI MOVs. LPSI can also be manually initiated. If the LOCA break is not of sufficient magnitude to depressurize the RCS below the shutoff head of the LPSI pumps, then a minimum recirculation flowpath must be provided to the LPSI pumps or pump damage could occur. The LPSI pumps can be operated for 1 hr. on minimum recirculation. The pumps initially take suction from the RWT and, when a low level is reached in the RWT (7.4%), a RAS automatically trips the LPSI pumps and aligns the pump suction to the containment sump.

For Small LOCAs and SGTR events, if both trains of HPSI fail, the Control Room operators must depressurize the RCS using the steam generators down to where the SITs and LPSI flow will occur.

5.2.1.3.9 Major Modeling Assumptions

a) Ruptures of the piping and components of a LPSI train are generally neglected as failure modes in the LPSI fault trees due to the extremely low probability of sustaining a large enough break to divert significant flow and the high likelihood of detection within a shift (the LPSI lines are maintained water solid). However, catastrophic rupture of the RWT tank represents a common-cause failure of all SI trains. In addition, rupture of the two suction pipe segments between the SI pumps of each train and the RWT was modeled since a catastrophic rupture in one of these segments would fail HPSI, LPSI, and CS in the associated train.

b) Failure of the LPSI pumps due to extreme environment (resulting from loss of pump room cooling) is included in the LPSI fault tree. The maximum LPSI pump room temperature reached in 24 hrs. with no HVAC is 189° F. If the door is opened the maximum temperature reached is 168° F (see Section 6.2.5). If no backup cooling is established to the LPSI pump room, then the LPSI pump will fail within the 24 hrs. If the LPSI pump room door is opened within 2 hrs. following a loss of room cooling, then pump reliability is significantly degraded and the pump failure probability is increased above what it would be with room cooling available.

c) The LPSI fault tree is modeled such that failure of any component in the LPSI pump minimum flow recirculation line to the RWT during the injection phase will fail the pump due to overheating.

d) Backup HVAC cooling for the LPSI pump room consists of an operator blocking open the pump room door, thereby providing natural convection cooling to the room.

e) Common-cause failures are included in the LPSI fault tree for LPSI pumps and LPSI MOVs. Common-cause failures for the injection valves include failure of a single train and both trains.

f) LPSI pump fail to run malfunctions are modeled for inadvertent RAS Actuation which results from: 1) DC Equipment switchgear room HVAC failure, 2) Spurious RAS relay actuation and 3) Common-cause failure of RWT level instruments.

g) The mission time for LPSI in the injection phase is 1 hr. for Large LOCA events. The mission time for LPSI in the injection phase is 16 hrs. for Small LOCA and SGTR events.

5.2.1.3.10 System Analysis Results

The major system malfunctions of LPSI include common-cause failure of both LPSI pumps and LPSI MOVs to open. Also important to this analysis is failure of SIAS (actuation relays and load sequencer) to actuate LPSI components and control circuit faults which fail to start the LPSI pumps. For Small LOCAs and SGTR events, the predominate failure mode of LPSI is that the Control Room operator fails to depressurize the RCS to allow LPSI flow.

5.2.1.4 Low Pressure Safety Recirculation

5.2.1.4.1 System Function

Low Pressure Safety Recirculation (LPSR) is a function of the Low Pressure Safety Injection (LPSI) system. The function of LPSR is to provide RCS inventory for the removal of heat from the core for extended periods of time following a LOCA in the event that both trains of HPSI fail or HPSI fails during the recirculation mode. If the LPSI pumps are to be used during recirculation, then the LPSI pumps must be restarted by the Control Room operator. In the recirculation mode, the LPSI pumps recirculate the inventory from the containment sump back to the RCS.

5.2.1.4.2 System Success Criteria

The success criteria for the LPSI system during recirculation for associated events is given below:

- Large LOCA: One LPSI train is available to take suction from the containment sump to inject borated water into two SI injection headers.
- Small LOCA: One LPSI train is available to take suction from the containment sump to inject through one injection header. This is sufficient to prevent core damage once the Control Room operators have depressurized the RCS to permit LPSI flow.

5.2.1.4.3 System Description

The LPSI system supplies borated water to the RCS to maintain core cooling during LOCAs when RCS inventory is lost. During large break LOCAs and those LOCAs which are long in duration, enough RCS inventory is lost out of the break to deplete the volume of borated water in the RWT.

Once the RWT reaches the low level setpoint of 7.4%, the ESFAS generates a Recirculation Actuation Signal (RAS) which trips both LPSI pumps and automatically aligns the HPSI and CS pump suction to the containment sump. The HPSI, CS, and LPSI minimum recirculation flow lines to the RWT are automatically isolated on a RAS to prevent a depletion of containment sump inventory. If both trains of HPSI fail, the LPSI pumps must be restarted by the Control Room operators to ensure that containment sump inventory is injected into the RCS to maintain a covered core. A CS pump can be used to back up a LPSI pump given its failure, though this is not credited in the analysis. A simplified diagram of the LPSI system in the recirculation mode is shown in Figure 5.2-5.

5.2.1.4.4 Major Components

Except for the containment sump valves, the major components of the LPSI system are described in Section 5.2.1.3.4. Each safety injection (SI) train has a containment recirculation line which connects the containment sump with the SI pump suction. Each containment sump recirculation line consists of a 24-in. header with two normally closed 24-in. motor operated gate valves (one located in containment) and a 24-in. check valve. Each containment sump isolation MOV is opened upon receipt of a RAS.

Baffles and intake screens are installed to limit the maximum particle size entering the recirculation piping to 0.09-in. diameter to prevent flow blockage in the safety injection components and in the reactor.

5.2.1.4.5 Testing and Maintenance

The containment sump recirculation MOVs are tested per ASME Standards, Section XI, every 92 days. Equipment unavailability due to unscheduled maintenance is included for the containment sump recirculation MOVs (UV-674/676) located outside containment.

5.2.1.4.6 System Dependencies and Interfaces

The system dependencies and interfaces for the LPSI system described in Section 5.2.1.3.6 apply to LPSR. The following are associated with the containment sump MOVs.

Actuation

The containment sump isolation MOVs open and the LPSI pump mini-flow recirculation MOVs close upon receiving a Recirculation Actuation Signal (RAS) once the RWT reaches a low level of 7.4%. RAS also trips both LPSI pumps.

Electric Power

The containment sump isolation MOVs and the LPSI pump mini-flow recirculation MOVs receive motive and control power from Class 1E 480V AC MCCs associated with their respective power divisions.

Operator Action

Operator action is required by procedures to close the RWT MOVs once a RAS occurs and flow is verified from the containment sump. Operator action is required to restart LPSI pumps during recirculation given a failure in HPSI recirculation. Operator failure to restart LPSI pumps during recirculation is described in Section 7.4.

5.2.1.4.7 Technical Specifications

The PVNGS Technical Specifications applicable to LPSR are described in Section 5.2.1.3.7.

5.2.1.4.8 System Operation

When the RWT level drops to its predetermined low level (7.4%) at the end of the injection phase, a recirculation actuation signal (RAS) is generated. This signal transfers the HPSI and CS pump suction from the RWT to the containment sumps. The RAS signal also stops the LPSI pumps.

If both trains of HPSI fail during the recirculation period, then the LPSI pumps are manually restarted by the Control Room operators to provide the necessary recirculation flow. This recirculation flow must be continued until at least one train of HPSR is restored.

For a Small LOCA event, if both trains of HPSI fail, the Control Room operators must depressurize the RCS, using the steam generators, down to where SITs and LPSI flow will occur. If the Small LOCA event progresses long enough to deplete the RWT, and a RAS occurs, then the LPSI pumps must be restarted to provide recirculation flow.

5.2.1.4.9 Major Modeling Assumptions

a) The LPSR fault tree uses much of the same logic as the LPSI fault tree. The mission time for LPSI in the recirculation phase is 23 hrs. for Large LOCA events. The mission time for LPSI in the recirculation phase is 8 hrs. for Small LOCA events.

b) No maintenance is assumed to be permitted on the MOVs (UV-673, 675) in the containment sump during power operation.

c) Common-cause failures are included in the LPSR fault tree for LPSI pumps, LPSI MOVs, and containment sump recirculation valves. Common-cause failures for the injection valves include failure of a single train and both trains.

5.2.1.4.10 System Analysis Results

Major LPSR malfunctions include those failures in Section 5.2.1.3.10 and failures of the containment sump recirculation MOVs. These malfunctions encompass mechanical failures, control circuit faults, and RAS actuation failures which prevent MOVs to open. Common-cause failure of the containment sump recirculation MOVs and RWT level transmitters are also significant.

5.2.1.5 Containment Spray System

5.2.1.5.1 System Function

The Containment Spray (CS) system functions after a LOCA, steam line break (SLB), or feedwater line break (FLB) to provide a cool spray of water into the containment via the containment spray header nozzles. The spray of water acts to maintain containment integrity by reducing containment pressure and temperature, and it limits the leakage of airborne activity from the containment.

Each CS train is normally aligned to pass flow through a Shutdown Cooling (SDC) heat exchanger. Once the recirculation phase begins, the CS system functions to remove decay heat from the containment sump water which it circulates. Heat is removed from the SDC heat exchangers through the Essential Cooling Water (EW) system.

5.2.1.5.2 System Success Criteria

The success criteria for the CS system for associated events is given below:

- Large LOCA — One of the two CS trains operates to supply flow through the associated SDC heat exchanger to the containment spray nozzles for at least 24 hrs. Inventory is initially taken from the RWT and then from the containment sump following a RAS, as required.
- Medium LOCA — Same as Large LOCA
- Steam Line Break — Same as Large LOCA
- Feedwater Line Break — Same as Large LOCA

5.2.1.5.3 System Description

The CS system provides cooling sprays of borated water to the upper regions of the containment to reduce containment pressure and temperature during either a LOCA or a large steam or feed line break inside containment. The spray flow is provided by the CS pumps which take suction from the RWT during the injection mode and from a common suction line with HPSI/LPSI during the recirculation mode of operation. There are two independent CS trains. The pumps provide flow through the SDC heat exchangers and the spray control MOV, and discharge borated water into the containment atmosphere through a dual set of spray nozzle headers. A simplified diagram of the CS system is shown in Figure 5.2-6.

The main spray headers are located in the upper part of the Containment Building to allow the falling spray droplets time to reach thermal equilibrium with the steam-air atmosphere. Additionally, auxiliary spray headers are located below concrete decks at 120 and 140-ft. elevations to provide spray coverage to containment volumes not reached by the main spray. The condensation of the steam by the falling spray results in a reduction of containment pressure and temperature. Each spray header train provides 94% coverage of the containment volume. Only one train of CS is required during a LOCA or SLB accident.

The CS system is initiated by a Containment Spray Actuation Signal (CSAS), which occurs on high-high containment pressure (8.5 psig). CSAS provides direct actuation of the CS spray control MOV and indirect actuation of the CS pumps via the ESF load sequencers. The load sequencers will also start the CS pumps given a SIAS signal, but the spray control valves to the containment do not open until a CSAS occurs. In order to ensure the CS pumps are not dead-headed and subsequently damaged in a LOCA scenario where containment pressurization occurs slowly, a minimum flow line back to the RWT is provided.

When low RWT level is reached (7.4%), a recirculation actuation signal (RAS) is generated and the pump suction is automatically transferred to the containment recirculation sump to maintain continuous containment spray. Additionally, a MOV in the minimum flow line automatically closes during the recirculation phase to conserve RCS inventory. The recirculated containment sump water is cooled by the SDC heat exchangers prior to discharge into the containment atmosphere. Once initiated, recirculation spray continues until terminated or modified by the operator.

If the offsite AC power sources are lost, the CS pumps automatically receive power from the DGs. One pump and its spray control valve are connected to each DG. Once the DG has reached proper speed and voltage, the pump is loaded by the ESF load sequencer along with the other ESF loads.

5.2.1.5.4 Major Components

The two CS pumps are located in the Auxiliary Building on the 40-ft. level. The CS pumps are vertical, single stage, centrifugal pumps driven by 800 hp motors. The pump motors are designed to reach rated flow within 5 secs. following a start signal. The pump seals are cooled by pump water and are designed for operation at fluid temperatures up to 350° F. A seal throttle bushing is provided to restrict the loss of fluid in the event of a gross seal failure. The pumps provide a design flow of 3890 gpm per pump to the CS header nozzles. To minimize the CS delivery time to containment, the CS header is always kept full up to at least the 105-ft. level in containment. Level transmitters are located on each CS header and provide signals to both a local instrument and a Control Room annunciator which activates an alarm on low header level.

The CS delivery control valves, UV-671/672, are motor operated flow control valves that open fully on a CSAS and can be manually opened or closed from the Control Room.

The spray nozzles located in the CS headers in the dome of containment serve to disperse the spray solution in droplets throughout containment. The nozzles in both the upper containment and below the 140-ft. containment level are oriented to maximize the spray area to provide at least 94% coverage of the containment volume.

The shutdown cooling heat exchangers provide cooling to the CS injection water during the injection and recirculation modes. The heat exchangers are cooled by EW. There are two inlet and one outlet MOVs that are used to isolate or throttle flow through the SDC heat exchanger. These valves are normally open. Each heat exchanger also has a bypass MOV that is left normally closed through all spray modes. There is no cross-tie capability between the heat exchangers. EW to each heat exchanger is automatically started on a SIAS or CSAS.

The CS pump mini-flow line has three main components: the mini-flow orifices which restrict the flow from the CS pump to the RWT, the CS pump mini-flow isolation MOV, and the Safety Injection common mini-flow solenoid valves. Both sets of valves close on a RAS to prevent the flow of contaminated sump water back to the RWT during the CS recirculation mode. Failure of these valves to close is not considered a system failure. Two motor operated butterfly valves isolate the CS, HPSI, and LPSI pumps from their respective containment sump. These valves open on an RAS to allow water to flow to each pump from the sumps. (The LPSI pumps are automatically shut off on an RAS.) The sumps are located in the lower containment and are surrounded by baffles and intake screens that limit the maximum particle size entering the recirculation piping to 0.09 in. diameter. The sumps are designed to preclude the entrainment of air and/or steam into the sump suction lines.

The Refueling Water Tank (RWT) provides the initial supply of borated water for the CS system. Following a RAS, the RWT is manually isolated by the Control Room operator following verification of adequate flow from the sump. Isolation is provided by MOV CH-HV530/531, which also isolates LPSI and HPSI pumps from the RWT.

Instrumentation for the CS system includes Control Room indication of pump and major valve status. System pressure, header level, and flow indications are available in the Control Room. Indication is also provided in the Control Room for the containment sump temperature as well as the SDC heat exchanger inlet and outlet temperatures.

5.2.1.5.5 Testing and Maintenance

Each of the CS MOVs are stroke tested at least once every 3 months per ASME Standards, Section XI. The SDC heat exchanger isolation valves are not tested to the ASME Standards. The CS pump, flowrate through the SDC heat exchanger isolation valves, and CS pump discharge check valves are verified at least once every 3 months. The CS injection MOV, UV-671/672, are tested at least once every 2 months per the ESFAS Subgroup Relay monthly functional tests.

Unscheduled maintenance is modeled for the CS pumps, pump breakers, minimum flow recirculation valves, and the CS injection isolation valves, UV-671/672. Equipment unavailability due to unscheduled maintenance is included for the containment sump recirculation MOVs, UV-674/676, which are located outside containment.

5.2.1.5.6 System Dependencies and Interfaces

Actuation Signals

The pumps are automatically started on either a SIAS or CSAS, but the injection valves only open on a CSAS. Since the pumps start on a SIAS and run on mini-flow recirculation until a CSAS occurs, the CS pumps will deadhead and can fail if the CS pump mini-flow is not open and CSAS does not occur until later in the sequence. The containment sump valves also require a RAS to automatically open on low RWT level.

Electric Power

The CS pumps require 125V DC Class 1E (breaker control power) to start and 4.16kV AC Class 1E power to continue running. The injection valves and the sump isolation valves all require 480V AC Class 1E power to open. Train A CS requires Train A Class 1E AC/DC while Train B requires Train B Class 1E AC/DC.

HVAC

The Auxiliary Building HVAC system cools the CS pump room during normal plant operation. If a SIAS should occur, normal HVAC to these rooms is tripped and a dedicated emergency room cooler in each pump room is actuated. The essential room coolers consist of an air cooling coil and fan. The coil carries chilled water from the appropriate essential chilled water train while the fan is powered by Class 1E 480V AC electrical power. SIAS also actuates the essential chilled water, cooling water, and spray pond systems.

Loss of CS pump room HVAC will result in actuation of an alarm in Control Room when room temperature reaches 105° F.

Operator Action

Operator failure to shut off the CS pumps following a SIAS (no CSAS signal) is included in the model. If the minimum recirculation is unavailable, the operator has 20 mins. to secure the pump before pump damage occurs. If the minimum recirculation line is available, then the time available to the operator is 1 hr.

Operator failure to secure the CS pump, given failure or success of the CS pump mini-flow line to remain open and a SIAS event with no CSAS, is described in Section 7.4.

Operator action is required to provide backup cooling to the CS pump room in the event of a loss of room cooling. Operator failure to provide backup cooling to the CS pump room given a failure of room cooling is described in Section 7.4.

5.2.1.5.7 Operator Technical Specifications

The following PVNGS Technical Specifications are applicable to the CS system operation:

a) Specification 3/4.6.2 requires both CS trains to be operable. If one train is inoperable, the inoperable spray system should be restored within 72 hrs. or be in hot standby in 6 hrs. It also requires that valve verification and system fill procedures be performed every 31 days and RAS and CSAS valves be tested for operability every 18 months. CS pump auto start on SIAS and CSAS is required to be performed every 18 months. A smoke flow test through each spray header is required every 5 years.

b) Specifications 3/4.1.2.6 and 3/4.5.4 require that the RWT be operable with the proper volume, temperature, and boron concentration. The boron concentration and volume is required to be verified every 7 days and the temperature is required to be checked every 24 hrs.

5.2.1.5.8 System Operation

During normal operation at reactor power, the CS system does not operate. During this mode, the CS system is in the standby condition and aligned for possible emergency operation.

The containment spray is automatically initiated by the high-high containment pressure signal (8.5 psig), which starts the CS pumps (if not already started by SIAS) and opens the spray isolation valves. CS can also be manually initiated. The pumps initially take suction from the RWT in the CVCS, and when a low level is reached in the RWT, a RAS automatically transfers the pump suctions to the containment sumps. Operator action closes the valves at the outlet of the RWT. During the recirculation mode, the spray water is cooled by the SDC heat exchangers prior to discharge into the containment.

During plant shutdown, the CS pumps can be aligned to discharge through the shutdown cooling lines in place of or in parallel with the LPSI pumps. In this mode, the pump is aligned so that the spray injection lines are isolated and the CS pumps can provide SDC pumping requirements.

5.2.1.5.9 Major Modeling Assumptions

a) No credit is given in the fault trees for the backup of the CS pumps with LPSI or the backup of LPSI pumps with CS pumps.

b) Emergency procedures require that the RWT isolation valves be closed following a switchover to the containment sump as a suction source. This procedure prevents the backflow of radioactive sump water to the RWT, which is vented to the Fuel Building. Early isolation of the RWT due to an inadvertent RAS, which fails the CS pumps, is not modeled. This is based upon the low probability of receiving an inadvertent RAS during a LOCA event when insufficient level exists in the containment sump.

c) A CS train is assumed to be unavailable when in the test mode, since no automatic realignment of the RWT recirculation flow path occurs.

d) The CS pumps are assumed to fail on continued operation under the following conditions: more than 1 hr. of operation on mini-flow and more than 20 mins. deadhead with failed mini-flow.

e) Common-cause failures are modeled for the CS pumps, CS injection valves, and the containment sump isolation valves.

f) Failure of the CS pumps due to extreme environment (resulting from loss of pump room cooling) is included in the CS fault trees. The maximum CS pump room temperature that can be reached in 24 hrs. with no HVAC is 189° F. If the door is propped open, the maximum temperature that can be reached is 168° F (see Section 6.2.5). If no backup cooling is established to the CS pump room, the CS pump will fail within 24 hrs. If the CS pump room door is opened within 2 hrs. following a loss of room cooling, pump reliability is significantly degraded and pump failure probability is increased above what it is when room cooling is available.

g) Backup HVAC cooling for the CS pump room consists of an operator blocking open the pump room door thereby providing natural convection cooling to the room.

5.2.1.5.10 System Analysis Results

The major system malfunctions of both trains of CS comprise of common-cause and independent failures of the containment sump isolation valves and containment spray header MOV. Common-cause failures include failures of the RAS/RWT level transmitters, containment spray pumps, CS injection valves, and the containment sump isolation valves. Major failures of the sump valves include the opening of the valves in both control circuits as well as mechanical problems in the opening operation. Major failures of the containment spray header MOV consist of maintenance, control circuit, and mechanical failures. Independent pump failures, including maintenance unavailability, mechanical, or electrical malfunctions, are not as important as those noted above.

5.2.1.6 Shutdown Cooling System

5.2.1.6.1 System Function

The Shutdown Cooling System (SDC) reduces the temperature of the RCS in post shutdown periods from approximately 350° F to the refueling temperature, 125° F, and maintains heat removal for extended periods of time. The SDC system can operate during post accident conditions to remove core heat through the SDC heat exchanger. The LPSI pumps are normally used during shutdown cooling. The CS pumps may be used instead of or in conjunction with the LPSI pumps.

5.2.1.6.2 System Success Criteria

The success criteria for the SDC system for an associated SGTR event, is given below:

> One SDC train provides cooling to the RCS for 16 hrs. Either the LPSI or CS pumps can be used for SDC; however, only the LPSI pump is credited in the analysis.

5.2.1.6.3 System Description

During SDC operation, a portion of the reactor coolant flows out of the SDC nozzles, located on each RCS hot-leg, and is circulated by the LPSI or CS pumps (used when RCS temperature is below 200° F). The pumps circulate the coolant through the SDC heat exchanger and return it to the RCS through the four LPSI injection lines. The SDC line suction is initially isolated from the RCS hot-leg by three (per train) normally closed MOVs, two of which are in containment.

Either SDC train is sufficient to provide decay heat removal from the RCS. Due to pressure interlocks for each train, the alignment of the SDC cannot be performed until the RCS pressure has been reduced to approximately 370 psia. A simplified diagram of the SDC system is shown in Figure 5.2-7. SDC is initiated and controlled from the Control Room by operator action. The rate of cooling can be varied by adjusting the SDC heat exchanger bypass and discharge valves accordingly.

5.2.1.6.4 Major Components

The pumps and discharge valves used by SDC are described in the LPSI and CS Sections 5.2.1.3.4 and 5.2.1.5.4, respectively. The SDC suction valves are the major components which are not covered in the above discussions. Two of the suction valves, one per SDC train, are Class 1E 125V DC powered MOVs, while the other four are Class 1E 480V AC powered MOVs. Each loop has a LTOP (low temperature over pressurization) relief valve to provide RCS LTOP protection and to ensure that the LPSI or CS lines are not overpressurized by RCS pressure fluctuations. The LTOP relief valves are located in containment. They have a setpoint of 467 psig and relieve to the containment recirculation sump.

Each loop is interlocked to remain closed until the RCS pressure is below 410 psia. Train A is interlocked through PT-103 (PT-105 for SIA-UV653) and Train B is interlocked through PT-104 (PT-106 for SIB-UV654). If these interlocks do not clear once the RCS pressure is below 410 psia, the operator may override the train B interlock by local action at the valve breakers. Train A SDC has no manual override.

5.2.1.6.5 Testing and Maintenance

Valves used in SDC are tested per ASME Standards, Section XI, every quarter or 18 months. The SDC suction MOVs are tested every 18 months.

5.2.1.6.6 System Dependencies and Interfaces

Electric Power

The CS and LPSI pumps require 125V DC Class 1E (breaker control power) to start and 4.16kV AC Class 1E power to continue running. The SDC suction MOVs are powered from 480V AC Class 1E power (PHA-M35 or PHB-M36) or through a 480V AC inverter from 125V DC Class 1E power (PKC-M43 or PKD-M44). Additionally, each RCS pressure transmitter requires Class 1E 120V AC instrument power. Malfunction of the instrument power fails the interlock so that the MOV may not be opened. Operator action is required to override the failed interlock signal to align Train B SDC.

HVAC

The Auxiliary Building HVAC system cools the CS and LPSI pump rooms during normal plant shutdown operation. If a pump is in operation, a dedicated essential room cooler in each pump room is actuated. The essential room coolers consist of an air cooling coil and fan. The coil carries chilled water from the appropriate essential chilled water train while the fan is powered by Class 1E 480V AC electric power.

Loss of LPSI or CS pump room HVAC will result in actuation of alarm in Control Room when room temperature reaches 105° F.

Operator Action

Operator action is required to align the LPSI system for SDC once the entry conditions are met. Operator failure to align SDC is described in Section 7.4. Operator failure to close the breakers for SDC suction valves UV-653/654 is described in Section 7.4. Operator action to override the failed pressure interlock signal and align Train B SDC is not credited.

5.2.1.6.7 Technical Specifications

The following PVNGS Technical Specifications are applicable to the shutdown cooling system (see LPSI, Section 5.2.1.3, and CS, Section 5.2.1.5 for additional Technical Specification references):

a) Specifications 3/4.4.1.4.1 and 3/4.4.1.4.2 require at least one SDC loop to be operable during cold shutdown, another SDC loop to be operable if the RCS loops are not filled, and two SGs to be available with water levels greater than 25% of the indicated wide range.

b) Specification 3/4.4.1.3 requires that the SDC loop shall be in operation during hot shutdown if the applicable RCS loop and SG are not operating.

c) Specification 3/4.4.8.3 requires that both SDC LTOP relief valves with lift setpoints less than or equal to 467 psig shall be aligned to provide overpressure protection of the RCS when the reactor vessel head is on and when the RCS temperature is less than or equal to: 214° F during cooldown or 291° F during heatup.

d) Specification 3/4.7.11 requires that two independent SDC systems shall be operable, each system consisting of one operable LPSI pump and an independent operable flow path capable of taking suction from the RCS hot-leg and discharging coolant through the SDC heat exchanger and back through the cold-leg injection lines.

e) Specification 3/4.9.8.1 requires that at least one SDC loop shall be operable and in operation when in Mode 6 and when the water level above the top of the reactor pressure vessel flange is greater than or equal to 23 ft.

f) Specification 3/4.9.8.2 requires that two independent SDC loops shall be operable and one SDC loop in operation when in Mode 6 and when the water level above the top of the reactor pressure vessel flange is less than 23 ft.

5.2.1.6.8 System Operation

Shutdown cooling is normally in the standby mode during operation. Once cooldown has commenced, and the RCS is below 350° F and 410 psia, SDC operation can be commenced per Procedure 41OP-1SI01, "Shutdown Cooling Initiation". While the RCS temperature is between 200 and 350° F, a CS train valve alignment is modified to allow a SDC loop to be used for removing core decay heat. When the RCS temperature falls below 200° F, the CS system is realigned such that CS pump flow can be utilized to augment the heat removal capability of the SDC system. Either one or two loops of SDC cooling can be initiated with either the LPSI or CS pumps, although LPSI is normally used.

During an SGTR event, SDC operation is required to reduce the RCS pressure sufficiently to minimize the RCS to secondary side leak. Upon detection of a SGTR, the operators would cooldown and depressurize to RCS entry conditions. SDC would then be established, and the RCS cooled down to refueling temperature and pressure.

5.2.1.6.9 Major Modeling Assumptions

a) The mission time used in SDC is 16 hrs. since a minimum cooldown time of 8 hrs. prior to SDC operation is expected.

b) Where LPSI or CS components are used, a mission time of 24 hrs. is used since these systems have 24 hr. mission time requirements.

c) Suction during initial warm-up of the SI pump piping for SDC is from the RWT. Therefore, RWT failures are conservatively included in the SDC model.

d) LPSI pump fail to run malfunctions are modeled for inadvertent RAS actuations which result from: (1) DC Equipment switchgear room HVAC failure, (2) Spurious RAS relay actuation and (3) Common-cause failure of RWT level instruments.

e) Loss of either LPSI or CS pump room HVAC and associated effects on pump operation are described in Sections 5.2.1.3.9 and 5.2.1.5.9.

f) Common-cause failure is considered for any combination of two MOVs that would fail both trains of SDC. Even though two of the MOVs are DC powered valves, common-cause failure between either of these valves and the AC powered valves is conservatively considered.

5.2.1.6.10 System Analysis Results

The SDC failures are dominated by three sets of failures including pressure interlock failures, common-cause failure of the suction MOVs, and mechanical MOV failures.

5.2.1.7 Safety Injection Tanks

5.2.1.7.1 System Function

The Safety Injection Tanks (SITs) flood and cool the core with borated water following a Large, Medium or Small LOCA if rapid depressurization due to failure of HPSI is used. This function prevents a significant amount of cladding failure along with subsequent release of fission products into containment. The SITs are designed to function as a passive injection device without requiring support systems.

5.2.1.7.2 System Success Criteria

The success criteria for the SIT system for associated events is given below:

- Large LOCA — Two out of three SITs are required to inject borated water into the RCS.
- Medium LOCA — Two out of three SITs are required to inject borated water into the RCS.
- Small LOCA — The SITs are required only during a failure of both HPSI trains and after the Control Room operators have depressurized the RCS to less than 610 psig. Two out of three SITs are required to inject borated water into the RCS.
- SGTR — The SITs are required only during a failure of both HPSI trains and after the Control Room operators have depressurized the RCS to less than 610 psig. Two out of four SITs are required to inject borated water into the RCS.

5.2.1.7.3 System Description

There are a total of four SITs, each connected to a RCS cold-leg. The SITS are initially pressurized to 610 psig and do not normally function during operation, heatup, or cooldown. If a transient occurs in the RCS such that pressure goes below 610 psig, each SIT injects borated water through its injection line which is initially isolated from the RCS by two isolation check valves. The SITs are a passive system which includes two normally closed check valves, the only equipment required to change position. A drawing of the SITs showing their relationship to other parts of the SI system is shown in Figure 5.2-8.

5.2.1.7.4 Major Components

The major components of each SIT include the tank, two isolation check valves, and a normally opened isolation MOV. Each SIT contains a minimum of 1802 cubic feet of water, borated to a concentration between 2300 and 4400 ppm. The isolation MOVs are "fail as is" units that are powered by 480V AC. The valves are normally key-locked in the open position with power removed (circuit breaker open).

Instrumentation for the SITs include Control Room indication for SIT level, pressure, and isolation valve position.

5.2.1.7.5 Testing and Maintenance

The SIT isolation MOVs and check valves are tested per ASME Standards, Section XI, every 18 months.

5.2.1.7.6 System Dependencies and Interfaces

Actuation

The SITs are a passive system during normal operation without an actuation signal for SIT injection. The SIT injection MOVs receive an open signal (the valve is already key-locked open) during a SIAS. The injection MOVs have an interlock to prevent them from closing if the RCS pressure is greater than 415 psig.

Electric Power

The SIT isolation MOVs receive motive and control power from the Class 1E 480V AC MCCs associated with their respective power divisions.

Nitrogen

The SIT tanks are pressurized to 610 psig by nitrogen. The nitrogen system is not required for operation of the SIT but may be required if the SIT pressure decreases during normal operation due to a small leak or temperature changes in containment.

Operator Action

Operator action is required to depressurize the RCS to <610 psig to allow for SIT injection during Small LOCA and SGTR events in which both trains of HPSI have failed. Operator failure to depressurize the RCS is described in Section 7.4.

5.2.1.7.7 Technical Specifications

PVNGS Technical Specification (T/S) 3/4.5.1 is applicable to the operation of the SITs. When the plant is in Modes 1 to 4, the SITs shall be operable with:

a) Isolation valve key-locked open and power removed

b) Water level between 1802 and 1914 cubic ft.

c) Boron concentration between 2300 and 4400 ppm

d) Nitrogen cover pressure between 600 and 625 psig

e) Nitrogen vent valves closed with power removed

f) Nitrogen vent valves capable of being operated upon restoration of power.

With one SIT inoperable, the SIT must be restored to operability within 1 hr. or the plant placed in hot standby within the next 6 hrs. and hot shutdown within the following 6 hrs. If the SIT is inoperable due to the isolation valve being closed, the valve must be reopened immediately or the plant must be in hot standby within 1 hr. and in hot shutdown within the next 12 hrs.

5.2.1.7.8 System Operation

During RCS heatup, when RCS pressure is greater than 500 psig, the isolation MOV in each discharge line is key-locked open and the power is removed from the valve to prevent spurious movement. The isolation MOV is equipped with redundant and diverse position indicators and an alarm which alerts the operator when the valve is closed and RCS pressure is above 700 psig. During normal plant operation the SITs are in a passive lineup and SIT operation is automatic.

SIT operation is expected to occur only in larger LOCAs where the RCS pressure decreases below 610 psig or when rapid depressurization, as in the case of Small LOCA or SGTR events, is performed by the Control Room operators. During Large LOCAs, the function of SITs is to keep the core covered until LPSI can begin injection.

5.2.1.7.9 Major Modeling Assumptions

a) Failure of two of the four SITs is assumed to fail the system. It is conservatively assumed that one of the remaining SITs will feed the primary break (during a LOCA).

b) No unscheduled maintenance is included in the system fault tree for the SITs.

c) Common-cause failures are included in the SITs fault tree for failure of 2 of 4 SIT discharge check valves to open.

5.2.1.7.10 System Analysis Results

The common cause failure of two of the four check valves is the dominant failure of the SITs with independent mechanical failures of the MOVs approximately one order of magnitude lower.

For Small LOCAs and SGTR events, the predominate failure mode involving SITs which leads to core damage is Control Room operator failure to depressurize the RCS to allow SIT flow.

5.2.1.8 Auxiliary Feedwater System

5.2.1.8.1 System Function

The Auxiliary Feedwater (AF) system provides water to the Steam Generators (SGs) during normal operations (Hot Standby, plant heatup/cooldown, reactor startup/shutdown) and, under abnormal or emergency conditions, for Decay Heat Removal (DHR).

5.2.1.8.2 System Success Criteria

The success criteria for the AF system for specific Initiating Events (IEs) is given below:

- Small LOCA — For secondary-side heat removal, AF must be delivered to one SG from one of three AF pumps. For RCS depressurization, in the event of HPSI failure, AF flow must be delivered to two SGs from one of three AF pumps.
- SGTR — On the SGTR event tree, the success/failure paths for establishing AF flow to each SG were separated into: AF to the intact SG and AF to the ruptured SG. The AF success/failure path followed on the event tree affects operator/system responses required later in the event as discussed in Section 4.3.4.
- SLB — AF flow must be delivered from at least one AF pump to the unaffected SG (Note: For many SLB events, the affected SG may be used for DHR, in the event that feedwater to the unaffected SG fails).
- FLB — One AF pump must deliver flow to the intact SG. ESFAS will prevent automatic feeding of the ruptured SG once a differential pressure develops between the two SGs.
- Group Transient — AF flow must be supplied from at least one of three AF pumps to one SG.
- LOOP — AF flow must be supplied from at least one of three AF pumps to one SG.
- Loss of MFW — AF flow must be supplied from at least one of three AF pumps to one SG.
- SBO — AF flow must be supplied from the turbine-driven AF pump to at least one SG for a period of no less than 2 hrs. In the later phase of this event, AF flow must be supplied from one of three AF pumps for a period of up to 24 hrs. after off-site power recovery.
- ATWS — AF flow must be delivered from one of two Seismic Category I, Class 1E AF pumps to one SG. Although AF is only required for short-term under ATWS, conditions, the PRA Model conservatively used a 24 hr. mission time for AF events. Further discussion is included in Section 4.3.

5.2.1.8.3 System Description

The AF system consists of three AF pumps (two safety and one non-safety), associated piping, valves, and instrumentation necessary to deliver feedwater to the SGs as shown in Figure 5.2-9. Each AF pump takes independent suction from the Condensate Storage Tank (CST) and discharges to one or both SGs through the downcomer feedwater lines. A backup water source, requiring local-manual operation, is provided to each of the essential AF pumps via connections to the Reactor Makeup Water Tank (RMWT).

Two completely redundant trains make up the safety related portion of the AF system. The Train A AF pump (AFA-P01) is a Class 1E, turbine-driven pump with turbine steam supply available from each SG, upstream of the Main Steam Isolation Valves (MSIVs). The Train B AF pump (AFB-P01) is a class-powered, motor-driven pump. The essential AF pumps are housed in separate compartments at the 80-ft. elevation of the Main Steam Support Structure (MSSS).

Discharge flow from the two safety related AF pumps is mixed downstream of the pump discharge isolation valves. From this point, two separate feedwater lines are routed into containment where they join the SG downcomer feedwater lines, downstream of the Containment Isolation Valves.

The AF system is in standby mode during plant power operations, but the two safety related AF trains are automatically actuated upon receipt of an Auxiliary Feedwater Actuation Signal (AFAS). AFAS occurs when two out of four low SG level signals are received (at 25.8% by wide range).

The non-essential portion of the AF system consists of a class-powered, non-seismically-qualified, motor-driven pump (AFN-P01) located at the 100-ft. elevation of the Turbine Building. The non-essential AF pump is used during dedicated plant startup as well as during emergency conditions.

5.2.1.8.4 Major Components

The safety related portion of the AF system consists of two completely redundant, 100%-capacity, automatically-actuated pumps with independent minimum flow recirculation lines to prevent pump overheating. These pumps are Class 1E powered and are designed to Seismic Category I Standards.

The Train A essential AF pump is an eight-stage, centrifugal, self-cooled (including turbine bearings), turbine-driven pump rated for 1010 gpm discharge flow at 1420 psig. This pressure is above the point at which the first Main Steam Safety Valves (MSSVs) lift. Typically, 750 gpm discharge flow is provided to the SGs with the remainder discharged to the CST via the pump mini-flow recirculation line. The pump turbine (AFA-K01) is a single-stage, non-condensing turbine rated for 3590 rpm at 1250 hp. The turbine is capable of fast starts from a cold condition using steam supplied by either SG. During operation of the Train A pump, steam enters the turbine through either of two automatically-actuated, motor-operated steam admission valves (SGA-UV134 and SGA-UV138). These valves are provided with 1-in., solenoid-operated bypass valves (SGA-UV134A and SGA-UV138A) which are used during turbine startup. Steam continues through the turbine trip/throttle valve (AFA-HV54) before entering the turbine. Steam exiting the turbine exhausts to atmosphere. The AF pump turbine is capable of supplying discharge flow over the range of 1010 gpm at 1420 psig with steam pressure at 1170 psig, to 550 gpm at 140 psig with steam pressure at 135 psig. The latter steam pressure corresponds to a primary temperature of 350° F; shutdown cooling entry condition. The turbine is equipped with a self-contained lube oil system which uses cooling water from the first stage of the AF pump. The Train A Class 1E DC system supplies power to the valves/instrumentation associated with turbine/pump operation. The Train A AF pump is credited with supplying feedwater to the SGs during Station Blackout (SBO) conditions.

The Train B essential AF pump is an eight-stage, centrifugal, self-cooled, motor-driven pump powered from the Division 2 Engineered Safety Features (ESF) switchgear (PBB-S04). This pump is rated for 1010 gpm at 1420 psig.

Each essential AF pump discharges to one or both SGs through a motor-operated throttle valve and a motor-operated isolation valve.

The Train N (non-essential or startup) AF pump receives Class 1E power from the Division 1 ESF switchgear (PBA-S03). The non-essential AF pump is an eight-stage, centrifugal pump rated for 1010 gpm discharge flow at 1280 psig. This pump delivers water from the CST to the downcomer feedwater lines. Flow control is accomplished using either the pneumatically-operated downcomer feedwater-regulating valves (SGN-FV1113 and SGN-FV1123) or the motor-operated feedwater regulating bypass valves (SGN-HV1143 and SGN-HV1145). Pump discharge flow enters the downcomer feedwater lines in the Turbine Building, upstream of the containment isolation valves (SGA-UV172/-UV175 and SGB-UV130/-UV135); therefore, Train N pump flow is terminated by a Main Steam Isolation Signal (MSIS). Due to the non-seismic qualification of the Train N AF pump, its suction is normally isolated from the CST by two Train A-powered, motor-operated valves (CTA-HV001 and CTA-HV004).

The CST (CTE-T01) provides water to the AF system for SG makeup. Of the CST 550,000 gallon capacity, 300,000 gallons is specifically designated for AF system supply. The three AF system pump suction lines penetrate the tank at the lowest elevation while all other water outlets, such as the condenser hotwell makeup, penetrate the tank above the level required to maintain 300,000 gallons available for long-term emergency operation of the AF system.

Control Room controls/instrumentation for the AF system include control switches and operating status indication for all three AF pumps. Essential AF pump status and discharge regulating valve status are also indicated on the Safety Equipment Actuation System (SEAS) panel on the Main Control Board. Indication is also provided for presence/absence of AFAS signal to each essential pump. Indications of Train B and Train N AF pump trip, i.e., electrical fault, loss-of-power, are provided in the Control Room on the Safety Equipment Inoperable Status (SEIS) panel, Control Room annunciator, and plant computer.

Potentiometer control for the Train A turbine-driven AF pump is provided in the Control Room, at the Remote Shutdown Panel (RSP), and at the pump local control panel. In addition, control switches for the Train A pump trip/throttle valve (AFA-HV54) are provided at all three locations. Trip/throttle valve status is also annunciated on the SEIS panel.

Control and position indication for the Train A AF pump turbine Main Steam (SG) system supply valves is provided in the Control Room and at the RSP. These valves are provided with SEIS alarms from the electrical/torque protection logic. Override capability for these valves is provided at both locations.

The essential AF pump discharge throttle/isolation valve controls and position indication are provided in the Control Room and at the RSP. Override capability for these valves as well as Train A pump turbine steam admission valve controls and position indication are provided at both locations.

Control switches and indication for the non-essential AF pump normal suction valves are provided in the Control Room. In addition, a control switch and indication for the non-essential AF pump minimum-flow recirculation isolation valve are provided in the Control Room.

Control Room annunciation of AF system faults includes Train B AF pump overload/trip and low discharge pressure alarms. In addition, a low discharge pressure alarm is provided for the non-essential AF pump.

Control and position indication for the Train N AF pump CST isolation valves is provided in the Control Room. These valves are provided with SEIS alarms from the electrical protection logic.

Position indication for the SG downcomer flow control valves is provided in the Control Room while valve control and position indication for the downcomer flow control bypass valves are provided in the Control Room. Downcomer feedwater flow indication is also provided in the Control Room. In addition, SG downcomer isolation valve control switches and position indication are provided in the Control Room.

5.2.1.8.5 Testing and Maintenance

Testing is required for each pump on a monthly basis per ASME Standards, Section XI, guidelines. Valve alignment is also verified monthly. Full-flow capacity testing is performed at least once every 18 months on the two Class 1E AF pumps. No full-flow specification exists for the Train N AF pump.

5.2.1.8.6 System Dependencies and Interfaces

Actuation

Normally, each of the essential AF pump discharge lines is isolated from the SGs by normally-closed, motor-operated throttle and isolation valves connected in series. In response to low water inventory in a SG (25.8% by wide range; see Technical Specification, Table 3-4), an Auxiliary Feedwater Actuation Signal (AFAS) automatically starts and aligns the essential AF pumps to the appropriate SG.

The Train B AF pump receives a start signal on AFAS and following a Train B Loss Of Power (LOP), Safety Injection Actuation Signal (SIAS), or Containment Spray Actuation Signal (CSAS) via the ESF load sequencer (see Section 5.2.2.21). In addition, the Train A AF pump starts on AFAS via automatic positioning of the turbine steam admission valves. The essential pump discharge valves open only upon receipt of the appropriate AFAS signal. A start signal to either of the essential AF pumps will also start the respective room essential Air Conditioning Unit (ACU). The Train N AF pump has no automatic-start features and is automatically load shed on SIAS or Train A LOP.

Operator Action

The Train N AF pump is typically available during abnormal and emergency conditions; however, as the pump and its associated valves receive no automatic start signal, operator action is required to place it in service. Operator actions include opening the two CST isolation valves and manually starting the pump. After the pump has started, the operator must verify proper operation of the downcomer feedwater regulating valves. If the downcomer feedwater regulating valves are not operating properly, the operator may either take manual control of the valves or use the downcomer feedwater regulating bypass valves to maintain feedwater flow control.

Water Sources

All three AF pumps receive water through independent supply lines from the CST. The CST has a capacity of 550,000 gallons. Part of this capacity, 300,000 gallons, is specifically designated for AF system supply. Of this volume, 195,000 gallons provide sufficient emergency feedwater reserve to allow orderly plant cooldown to shutdown cooling entry conditions. The remaining CST volume furnishes sufficient reserve to maintain Hot Standby (Mode 3) conditions for 8 hrs.

The flowpaths to the two Class 1E AF pumps are provided with normally-open, manual isolation valves. The Train N pump is normally isolated from the CST by two remotely-operated, class-powered, motor-operated isolation valves (CTA-HV001/-HV004). If the CST is unavailable, a backup water supply is available to the two essential AF pumps via separate, manually-isolated, normally-closed connections to the Reactor Makeup Water Tank (RMWT). The PRA takes no credit for the RMWT backup supply.

HVAC

Normal cooling to the essential AF pump rooms is provided by the Auxiliary Building Normal Air Handling Units (AHUs) (HAN-A01A/B). Cooling water to the normal AHUs is provided by the Normal Chilled Water (WC) system. Normal HVAC to the AF pump rooms is tripped upon receipt of a SIAS or CSAS. For the PRA, normal HVAC is credited for reducing the likelihood of AF pump failure.

For abnormal operation, Train A and B AF pump room essential cooling is provided by their respective room essential ACUs (HAA-Z04 and HAB-Z04). The Essential Chilled Water (EC) system supplies cooling water to the AF pump room essential ACUs. Each ACU includes a fan, which circulates room air across the cooling coils.

An analysis was performed to determine the degree to which the essential AF pumps are dependent upon room cooling. The results of this analysis as summarized in Section 6.2.5 indicate high probability of AF pump continued operation with limited HVAC supply (See Section 5.2.1.8.9).

The essential AF pump rooms are provided with high temperature alarms which annunciate in the Control Room. The PRA Model credits these alarms in the analysis of AF system human error (See Section 7.4). When an essential AF pump is manually started, i.e., in anticipation of an AFAS initiation, the operator must manually start the appropriate EC system chiller to provide chilled water to the AF pump room essential ACU. The aforementioned AF pump room high temperature alarm provides indication to the operator that the required essential chiller has not been started as required.

The Train N AF pump requires no room cooling as it is located in an open area within the Turbine Building.

Instrument Air

The Train N AF pump discharge joins each of the two downcomer feedwater lines in the Turbine Building, upstream of the pneumatically-operated, spring-closed downcomer flow control valves (SGN-FV1113 and SGN-FV1123). These valves are controlled by the Feedwater Control System (FWCS) during normal plant operation and may also be used to control Train N pump discharge flow. Instrument Air (IA) at 110 psig is used for operation of the downcomer flow control valves. These valves fail "locked" (as-is) on loss of pneumatic supply.

The downcomer Feedwater Isolation Valves (FWIVs) (SGA-UV172 and SGB-UV130 to SG1; SGA-UV175 and SGB-UV135 to SG2) are held open by high-pressure nitrogen at 240 psig, (via SGN-PCV1147) from the Service Gas (GA) system. These valves fail-closed on loss of pneumatic supply and are also closed on MSIS. The IA system provides pneumatic supply at 110 psig to operate pilot valves which port nitrogen for FWIV position control.

High-pressure nitrogen backup is provided to IA for the above functions. Nitrogen is provided through a pressure regulator (SGN-PCV1130), which is normally-closed (on-line), but opens at a pressure lower than the normal IA header pressure (85 psig per Procedure 41OP-1IA01); thus, if IA pressure drops, high-pressure nitrogen provides immediate backup.

IA also supplies the air-operated isolation dampers (HAA-M04/-M05 and HAB-M04/-M05) in the Auxiliary Building Normal HVAC supply ducts; therefore, loss of IA or IA compressor support systems: Turbine Cooling Water (TC) or Plant Cooling Water (PW), will result in loss of normal HVAC to the essential AF pump rooms.

A dedicated nitrogen accumulator (SGN-X02) provides pneumatic supply in the event of simultaneous failure of IA and high-pressure nitrogen systems. This accumulator is rated for approximately 10.5 hrs. of nitrogen demand by the downcomer flow control and containment isolation valves. The accumulator is normally isolated, but is automatically aligned when solenoid valve SGN-PV1128 opens in response to low nitrogen supply pressure. The downcomer FWIVs fail closed on either loss of high-pressure nitrogen or on concurrent loss of IA and failure of the high-pressure nitrogen backup supply.

Motive Power

Operation of the turbine-driven AF pump requires steam supply from one of the Main Steam (SG) headers. A Secondary Line Break (SLB) event eliminates AF pump turbine steam supply from the associated SG.

Electric Power

Power to the Train A AF pump valves and instrumentation is provided by Class 1E power systems. The Train A AF pump turbine-governor valve receives control power from Channel A 125V DC distribution panel, PKA-D21. Turbine steam supply valves (SGA-UV134 and SGN-UV138) are powered from Channel A 125V DC control center, PKA-M41, which also supplies power to PKA-D21. Two of the pump discharge valves (AFA-HV032 to SG1 and AFA-UV037 to SG2) are also powered from PKA-M41. The two remaining discharge valves (AFC-HV033 to SG2 and AFC-UV036 to SG1) are powered from Channel C 125V DC control center, PKC-M43.

The Train B AF pump motor receives power from the Division 2 ESF switchgear (PBB-S04). Channel B 125V DC distribution panel, PKB-D22, provides control power for breaker operation. The two pump discharge throttle valves (AFB-HV030 to SG1 and AFB-HV031 to SG2) are powered from Division 2 480V AC MCC, PHB-M34. The two pump discharge isolation valves (AFB-UV034 to SG1 and AFB-UV035 to SG2) are powered from Division 2 480V AC MCC, PHB-M38.

Train N AF pump power is supplied from the Division 1 ESF switchgear, PBA-S03. Breaker control power is supplied from Channel A Class 1E 125V DC distribution panel, PKA-D21. Because of the commonality of this pump's power supply with that of the Train A AF pump, plant changes are being implemented to provide alternate control power to the Train N pump breaker via direct connection to the Train A Class Battery Charger, PKA-H11. These changes are included in the AF system model. The two normally-closed Train N AF pump CST suction isolation valves are powered from Train A 480V AC MCCs (PHA-M33 supplies CTA-HV001 while PHA-M35 supplies CTA-HV004).

Non-class 120V AC instrument and control panel, NNN-D11, (normally aligned to its emergency power source, PHA-M31, per Procedure 41OP-INN01) provides power to the FWCS SOVs (SGN-FY1113 and SGN-FY1123), which control pneumatic supply to the downcomer flow control valves. These SOVs fail-closed on loss-of-power, causing air to be trapped between the SOV and the flow control valve; thus, the flow control valves fail "locked" (as-is) on loss-of-power to the associated SOVs.

Train N pump flow control may also be accomplished using the downcomer flow control motor-operated bypass valves (SGN-HV1143 and SGN-HV1145). Power to these valves is provided from non-class 480V AC MCC, NHN-M71, which normally receives power from Train A Class 1E 480V AC bus, PGA-L33. Non-class MCC, NHN-M71, is automatically load-shed upon receipt of a Safety Injection Actuation Signal (SIAS); however, the operator can reload the bus after load shed occurs.

Single solenoid valves (SGA-UY172/-UY175 and SGB-UY130/-UY135) exist in the IA supply line to each downcomer feedwater containment isolation valve's "pilot" valve. Currently, the Train A SOVs (powered from Class 1E 125V DC bus, PKA-D21) are "energize-to-open" and vent on loss of power causing their respective containment isolation valves to close. The Train B SOVs, powered from Class 1E 125V DC bus, PKB-D22, are "energize-to-close" and fail "through" on loss of power, causing their respective isolation valves to open. Plant changes are being implemented to change the failure mode of the Train A containment isolation valves. Upon completion of plant changes, all downcomer feedwater containment isolation valves will fail-open on loss of power. This is the configuration evaluated in this IPE submittal. The downcomer FWIVs will continue to close on Main Steam Isolation Signal (MSIS).

Solenoid valve, SGN-PV1128, automatically aligns a dedicated nitrogen accumulator (SGN-X02) to provide backup pneumatic supply to the downcomer flow control valves and the FWIVs. This solenoid is powered from the non-class DC power system (ZAN-C01 via NKN-D42).

Power to the Auxiliary Building Normal AHUs (HAN-A01A and HAN-A01B), which provide normal HVAC supply to the essential AF pump rooms, is provided from non-class 480V AC MCCs (NHN-M25 and NHN-M26, respectively). The common discharge duct isolation damper (HAN-MO3) is powered from non-class 125V DC distribution panel, NKN-D42. Damper HAN-MO3 fails-closed on LOP to NKN-D42.

The Train A AF pump room essential ACU (HAA-Z04) is powered from Train A 480V AC MCC, PHA-M37, while the Train B AF pump room essential ACU (HAB-Z04) is powered from Train B 480V AC MCC, PHB-M38.

5.2.1.8.7 Technical Specifications

PVNGS Technical Specification 3/4.7.1.2, "Auxiliary Feedwater System," directly addresses the AF system. It requires that all three AF pumps be operable during normal plant operations (Modes 1 through 4 until the SGs are no longer required for DHR). 72 hrs. are allowed for repair of one inoperable AF pump. If the inoperable pump is not repaired within the allotted time, the plant is required to be in at least Hot Standby (Mode 3) within the following 6 hrs. With two inoperable AF pumps, no outage time is permitted and the plant is required to shut down to at least Hot Standby within 6 hrs. With three inoperable pumps, immediate action is required to restore at least one AF pump. Shutdown is not advisable without an available AF pump.

A related PVNGS Technical Specification is 3/4.7.1.3, "Condensate Storage Tank." This specification requires a dedicated volume of 300,000 gallons of water in the CST. Other water outlets, such as condenser hotwell makeup, penetrate the tank above the level required to maintain a dedicated and available volume of 300,000 gallons. An outage time of 4 hrs. is permitted without an available backup water source; seven days are allowed if the Reactor Makeup Water Tank (RMWT) can be demonstrated operable as a backup water source within the initial 4-hr. period. No volume requirement is given for the backup water source.

5.2.1.8.8 System Operation

During power operations, the AF system is in standby mode. The Train N AF pump is used to supply feedwater during normal plant heatup/cooldown and during reactor startup and shutdown, below about 1% of reactor power. The Class 1E AF pumps are not used for normal operation unless the Train N pump is unavailable.

Following a plant trip, an AFAS is generated in response to a low level in either SG. Upon receipt of the AFAS, the ESF load sequencers start both Class 1E pumps (see Section 5.2.2.21). The AFAS signals directly activate the MOVs that align AF flow to the appropriate SG. Each pump is provided with continuous minimum-flow recirculation, which discharges to the CST. Once the AF pumps are started, SG level is controlled between the trip and reset level setpoints by automatic operation of the AF isolation and throttle valves. AFAS controls SG level without operator intervention; however, the operator may choose to manually start an AF pump and manually control flow in order to avoid an AFAS. In addition, the operator, according to PVNGS Recovery Operations Procedures, is directed to override automatic control of the pump discharge throttle valves in order to more closely control SG level. In order to guard against SG overfill when the operator takes manual control of the AF pump discharge throttle valves, the discharge isolation valves are left in automatic mode. AFAS closes the isolation valves at the AFAS reset-level setpoint. This is in accordance with the Safety Function Flowchart of the Emergency Operations procedure, which directs the operator to restore SG level and to match steam/feed rates to existing reactor heat load.

In the event of a normal reactor trip or loss of secondary coolant (per procedures 41R0-1ZZ01 and 41RO-1ZZ03, respectively), the Train N AF pump is the preferred means of feeding the SGs after a plant trip unless a MSIS occurs, isolating the pump. The second preferred source is the Train B (motor-driven) pump and the third is the Train A (turbine-driven) pump. The Train A pump is the least preferred, principally due to the potential for unmonitored radioactive steam release via the pump turbine atmospheric discharge in the event of a SG tube leak.

Operation of the Train A pump requires proper operation of the Terry Turbine (AFA-K01). The turbine steam supply valves (SGA-UV134 and SGA-UV138) are each provided with a 1-in. solenoid-operated bypass valve (SGA-UV134A and SGA-UV138A), which open on receipt of a pump start signal or AFAS. This small steam admission allows the turbine to gain speed (an overspeed trip shuts the steam admission valves if turbine speed reaches 4058 rpm. A turbine overspeed trip must be reset locally). The turbine increases control-oil pressure, which throttles the normally-open turbine-governor valve toward the closed position prior to opening of the steam supply valve after a 10 sec. time delay. Steam passes through either of the steam admission MOVs, and then through the normally-open turbine trip/throttle valve AFA-HV54, before entering the turbine. Steam exiting the turbine is exhausted to atmosphere.

5.2.1.8.9 Major Modeling Assumptions

The following is a list of assumptions made during the development of the AF fault-tree model:.

a) Certain plant Initiating Events (LOCAs, FLB, SLB, and SGTR) cause an MSIS initiation, which results in closure of the downcomer FWIVs, disabling the Train N AF pump flowpath. The PRA Model includes human error associated with operator failure to override the MSIS signal and remotely start the Train N AF pump (see Section 7.4).

b) The PRA Model includes human errors associated with operator failure to align the AF system, and the following: (1) the Control Room operator fails to manually align AF, per procedure, from the Control Room, given failure of AFAS due to common-cause failure of SG level sensors. The timing requirements associated with these errors are as follows: (1) if neither FW pump continues to operate after reactor trip, AF alignment must be accomplished within 40 mins. (see Section 7.4), and (2) if at least one FW pump continues to operate for 30 mins. after reactor trip, AF alignment must be accomplished within 100 mins. (see Section 7.4). A higher reliability was assigned to two similar events having identical timing requirements which account for operator failures to align AF flow given proper operation of AFAS signals (see Section 7.4).

c) The PRA Model includes human error associated with operator failure to open the appropriate downcomer feedwater regulating bypass valve (SGN-HV1143/-HV1145) within 20 mins. of the associated downcomer regulating valve (SGN-FV1113/-FV1123) failure to open (see Section 7.4).

d) The PRA Model includes a human error associated with the following scenarios: (1) the Control Room operator fails to direct the Auxiliary Operator to manually open the Train C powered essential AF pump discharge valves (AFC-HV33/-HV36) following an alarmed loss of the Channel C DC Vital Bus, or (2) the auxiliary operator fails to properly carry out the Control Room operator instructions. Two hours are allowed (see Section 7.4).

e) The PRA Model includes common-cause events including common-cause failure of three out of three AF pumps and two out of two motor-driven AF pumps. In addition, common-cause failure of two out of two AF system valves is included for the essential pump discharge check valves (AFA-V137 and AFB-V138), the in-containment essential supply header check valves (AFA-V079 and AFB-V080), and the Train A essential pump turbine-driver steam supply MOVs (SGA-UV134 and SGA-UV138). Common-cause of selective four out of eight essential pump discharge MOVs accounts for all combinations of MOV failures that would result in loss of flow through each of the four essential pump discharge lines. Common-cause failure of AFAS-1 and AFAS-2 due to SG level indication failure is also included in the Model.

f) The Auxiliary Building Normal HVAC units which also supply normal cooling to the essential AF pump rooms, are disabled by SIAS resulting from LOCA, FLB, SLB, SGTR, due to the fact that isolation dampers HAA-M04 and HAB-M04 close on SIAS.

g) The essential AF pump faults include failures of the normal and essential pump room HVAC units. Essential AF pump room HVAC failures include failure of the appropriate EC system Train to supply the room essential AHU. This failure includes the failure of the associated SP/EW system

Trains to supply cooling to the EC system.

h) Analysis results (see Section 6.2.5) indicate a high probability that the essential motor-driven AF pump will survive for at least 12 hrs. with no HVAC supplied, and a 50% probability that the pump would survive 24 hrs. A similar analysis of the turbine driven AF pump indicates a high probability that the essential turbine-driven AF pump will survive for at least 24 hrs. with no room cooling provided. With normal HVAC supplied, but essential HVAC unavailable, both class AF pumps are likely to survive for at least 24 hrs.

i) The PRA Model includes failures associated with the Train N pump backup control power (currently being installed in all PVNGS units, as discussed in Section 5.2.1.8.6). Associated failures include transfer-switch failures and failure of the fuse located between the class battery charger (PKA-H11) and the pump control circuit.

j) Modeled human errors include operator failure to align backup control power (from PKA-H11 via the manual transfer switch) to the Train N AF pump. If both of the FW pumps fail to run, post-trip, the operator must align Train N backup control power within 60 mins. (see Section 7.4). If at least one FW pump continues to run (for 30 mins.) post-trip, the operator must align Train N backup control power within 2 hrs. (see Section 7.4).

k) Closure of the Train N AF pump minimum-flow recirculation line is not necessary to ensure adequate feedwater flow to provide Decay Heat Removal (DHR). This is based on maximum DHR requirements (~300 gpm) and Train N AF pump discharge capacity (approximately 750 gpm half of this flow is provided to each SG).

l) The PRA Model includes CST supply failures including manual isolation valve failures (plus post-maintenance restoration), check valve failures, and excessive leakage of the CST.

m) Per the PVNGS Functional Recovery Procedure, 300 gpm of SG supply is required to provide adequate DHR when SG flow is initially re-established. Based on this information, and on reduced flow requirements over the first 24 hrs. after the event, the 300,000 gallon CST volume is sufficient to allow 24 hrs. of AF system operation. This conclusion is also based on UFSAR studies, and is confirmed by Modular Accident Analysis Program (MAAP) analysis.

n) The current PRA Model does not take credit for operator recovery action to align the RMWT backup AF supply upon failure of CST supply (see Section 7.4).

o) Modeled failures of the IA/nitrogen system supply to the downcomer FWIVs and flow control valves include appropriate failures of check valves, manual isolation valves, and pressure control/relief valves. In addition, failure of the backup nitrogen accumulator (SGN-X02) and failures of the accumulator auto-actuation components (SGN-PV1128/-PSL1128) are modeled.

p) Existing analysis indicates that there is sufficient pneumatic capacity available from the dedicated accumulator (SGN-X02) to supply the downcomer FW control valves and FWIVs for 8 hrs. following a LOOP; however, the accumulator was, conservatively, not credited in the PRA Model.

q) The PRA Model includes Train A essential pump turbine-governor valve failures, and failure of the Class 1E 125V DC power (This malfunction includes the failure of long-term DC equipment room HVAC). In addition, the model includes electrical faults which fail the turbine-governor valve speed control select relay, causing the turbine-driven pump to fail to start or run.

r) The PRA Model includes failure to restore after maintenance the following manual isolation valves: the essential AF pump suction manual isolation valves (AFA-V006 and AFB-V021), the essential AF pump discharge manual isolation valves (AFA-V016 and AFB-V025), and the Train N AF pump suction/discharge manual isolation valves (AFN-V001/-V013). Failure to restore after maintenance was also included for the essential AF pump turbine steam admission manual isolation valve (AFA-V002) and the turbine steam admission "start-up" line manual isolation valve (SGE-V889).

s) Corrective maintenance unavailability was modeled for all three AF pumps, the essential pump discharge throttle/isolation MOVs, and the Train A essential pump trip/throttle valve (AFA-HV054). In addition, corrective maintenance unavailability was included for the Train A turbine-driver steam supply MOVs (SGA-UV134/-UV138). Corrective maintenance unavailability is also modeled for the two motor-driven AF pump circuit breakers and for the Train B Load Sequencer. The Train A AF pump start is not associated with the Train A Load Sequencer; pump start occurs as a result of the AFAS relays opening the turbine-driver steam admission valves.

t) The AF pump suction strainers were removed after plant start-up; thus, these components are not modeled.

u) Control circuit faults were modeled for the essential pump discharge throttle/isolation MOVS and for the Train N pump's CST suction motor-operated (normally-closed) isolation valves (CTA-HV001/-HV004). In addition, control-circuit faults were modeled for the Train A turbine-driver steam supply MOV/SOVs (SGA-UV134/-UV134A and SGA-UV138). Control circuit faults were also modeled for the downcomer feedwater flow control bypass valves (SGN-HV1143/-HV1145) and for the downcomer FWIV SOVs (SGA-UY172/-UY175 and SGB-UY130/-UY135). Control circuit faults were also modeled for the two motor-driven AF pumps.

v) Modeled AFAS actuation relay faults include failure to actuate/transfer. Load sequencer faults include improper/spurious load shed signals and load shed signal failure to clear.

5.2.1.8.10 System Analysis Results

AF system malfunctions are dominated by several specific human errors including operator failures to align/initiate the Train N AF pump and operator failure to override MSIS and remotely align the Train N AF pump. Another dominant human error is as follows: In anticipation of AFAS, the operator starts an essential AF pump, but neglects to start the appropriate EC system chiller which serves the pump room essential air cooler. The essential AF pump subsequently fails due to extreme environment conditions. ,

Common-cause failures also dominate loss of the AF system. These failures include common-cause failure of all three AF system pumps and common-cause failure of ESFAS actuation signals (AFAS-1 and AFAS-2) due to failure of SG level indication.

Other dominant AF system failures include fail to start of either or both essential AF pumps and either of the essential AF pumps in corrective (unscheduled) maintenance. Failure to start is most prevalent for the Train A turbine-driven pump.

5.2.1.9 Alternate Feedwater System

5.2.1.9.1 System Function

The Alternate Feedwater (AltFW) system provides an alternate means of restoring the feedwater level in the Steam Generator (SG) in the event of simultaneous unavailability of both the Main Feedwater (FW) and Auxiliary Feedwater (AF) systems. This is accomplished using one of three low pressure Condensate (CD) pumps (CDN-P01A, -P01B, -P01C), which operates to deliver flow to a depressurized SG via the downcomer feedwater lines. The CD pumps are located at the 100-ft. elevation of the Turbine Building.

5.2.1.9.2 System Success Criteria

The success criteria for the AltFW system for associated Initiating Events (IEs) is given below:

- Small LOCA — One of three CD pumps must operate to deliver flow to one SG within 60 min. if FW is not initially available, or within 100 min. following loss of FW.
- SGTR — AltFW flow is credited to the intact SG. System success is associated with flow supplied from one of three CD pumps to the intact SG within 60 min.
- SLB — Flow is delivered from one of three CD pumps to the intact SG within the required time (see Section 7.4 for time requirements) following the reactor trip.
- Group Transient — Flow must be supplied from one of three CD pumps to at least one SG within the time required (see Section 7.4 for time requirements) following the reactor trip.
- Loss of MFW — AltFW must be aligned from at least one-of-three CD pumps to at least one SG within 60 min. following a reactor trip.

5.2.1.9.3 System Description

The AltFW system is actually a combination of two systems: the CD system and the FW system, as shown in Figure 5.2-10. Because no automatic actuation exists for this system, alignment and operation is performed per Emergency Procedure 41RO-1ZZ10, "Functional Recovery Procedure."

The AltFW system requires operation of at least one of three CD pumps to supply CD flow to one depressurized SG. Successful operation of this system requires depressurization of the SG (to approximately 500 psig) via either the Atmospheric Dump Valves (ADVs) or the Turbine Bypass Valves (TBVs). Therefore, availability of either the ADV or TBV systems is required to reduce SG pressure so that the CD pumps can deliver adequate flow.

All three main condenser hotwells provide water to the AltFW system, while the Condensate Storage Tank (CST) supplies makeup to the Condenser hotwells via vacuum draw or gravity feed.

The FW downcomer lines deliver flow to the depressurized SG, while the FW downcomer regulating valves (or the downcomer regulating bypass valves) control

SG level. Both the downcomer regulating valves and the downcomer regulating bypass valves are operated from the Control Room. Only 5% of normal full-power flow is required to maintain SG level using AltFW.

5.2.1.9.4 Major Components

The three CD pumps are vertical, canned, mixed-flow, six-stage pumps rated for 91,000 gpm (normal full-power flow) at approximately 450 psig. The pumps are driven by vertical, 3500 hp induction motors, and are provided with minimum-flow recirculation protection.

CD pump seal cooling water is supplied from the CD pump discharge, downstream of the Condensate Polishing Demineralizers. The CD pump motor upper-bearing oil is cooled by water provided by the Turbine Cooling Water (TC) system.

The Condenser Hotwells are divided into halves, each of which is capable of providing water to the CD pump suction lines. The hotwells provide a storage volume of approximately 100,000 gallons. As hotwell inventory is depleted, water is drawn from the 550,000 gallon CST through air-operated, fail-closed, automatic makeup control valves (CDN-LV81 and CDN-LV82). In the event of makeup control valve failure (or loss of condenser vacuum), hotwell level can be maintained via manual bypass supply valves (CDN-HCV154 and CDN-HCV155).

The High Pressure Feedwater Heater bypass valve, FWN-HV103, is a normally-closed, motor-operated, globe valve. This valve can be remotely-operated from the Control Room.

The downcomer Feedwater Flow Control Valves (SGN-FV1113 and SGN-FV1123) are pneumatically-operated, stacked-disk type drag valves, which have position indication in the Control Room. Each downcomer Feedwater Control Valve is provided with a motor-operated bypass valve (SGN-HV1143 and SGN-HV1145), which may be operated upon failure of the associated flow control valve. Indication of feedwater flow, SG level, and SG pressure are also provided in the Control Room.

Instrumentation for the CST, Condenser, and CD pumps includes Control Board indication of condenser pressure, hotwell level, CD pump operating status, and CD pump discharge pressure.

5.2.1.9.5 Testing and Maintenance

No on-line planned maintenance or testing is performed on the CD pumps; however, CD pump unscheduled (corrective) maintenance is modeled in the system fault tree.

The PRA Model also accounts for unscheduled (corrective) maintenance on the High Pressure Heater Train Bypass Valve (FWN-HV103).

5.2.1.9.6 System Dependencies and Interfaces

<u>Actuation</u>

The AltFW system has no auto-actuation features.

Electric Power

The non-class 4.16kV AC Power system supplies power to the CD pumps (NBN-S01 serves CD pumps A and B, while NBN-S02 serves CD pump C); therefore, AltFW system operation requires off-site power or success of Fast Bus Transfer (FBT).

The non-class 480V AC Power system supplies power to multiple CD system components including isolation MOVs on the CD pump common suction lines, CD pump discharge valves, Low Pressure Heater Train isolation valves, and the High Pressure Heater Train bypass valve. Only the High Pressure Heater Train bypass valve requires power to permit successful AltFW system operation (all other MOVs are normally-open and fail "as-is" on Loss-Of-Power).

Control power to the CD pumps is supplied by the non-class 125V DC Power system buses NKN-D41 (CD pumps A & B) and NKN-D42 (CD pump C).

HVAC

CD pump operation does not require room cooling.

Operator Action

Operation of AltFW requires both local and Control Room actions. The Control Room operator must perform several actions including: 1) decrease SG secondary pressure to approximately 500 psia using ADVs or TBVs, 2) open the High Pressure Feedwater Heater bypass valve, and 3) close the SG economizer isolation valves. The entire system alignment process is expected to take 15-30 min.

Local auxiliary operator action is required to initiate manual condenser hotwell fill. Failures associated with the multi-step system alignment are discussed in Section 7.4.

Instrument Air

Operation of the condenser automatic makeup supply valves (CDN-LV81 and CDN-LV82) and the CD pump seal water supply valve (CDN-PV200) require availability of the IA system.

Cooling Water

Operation of the CD pumps requires TC system supply to the CD pump motor upper-bearing oil cooler. The Plant Cooling Water (PW) system provides cooling to the TC system heat exchangers; therefore, failure of either of these two systems will result in subsequent failure of the CD pumps.

5.2.1.9.7 Technical Specifications

PVNGS Technical Specifications do not directly affect the AltFW fault tree model.

5.2.1.9.8 System Operation

During normal plant operation, at least two CD pumps must operate to provide flow to the FW pumps' suction. During AltFW system operation, only one CD pump is required to supply water to the SG downcomer lines. The High Pressure Feedwater Heater bypass valve is normally closed.

When a reactor trip occurs, the Control Room operator continues to cool the SGs (using the FW pumps) until AF is aligned, per Functional Recovery Procedure. Upon AF system failure, the operator attempts to align AltFW per Functional Recovery Procedure. The time available for AltFW alignment depends upon the specific scenario, and upon the post-trip availability of the FW pumps.

The FW pumps (FWN-P01A and FWN-P01B) are turbine-driven, and their continued operation requires sufficient steam supply from the SGs. Eventually, reactor decay-heat will decrease below the level required to sustain FW pump operation.

Once the necessary system alignment is properly established, water from the Condenser Hotwell is supplied to the depressurized SG. Air-operated, fail-closed, automatic control valves provide makeup from the CST to each Condenser Hotwell, while the FW downcomer regulating valves maintain SG level control. In the event of makeup control valve failure (or loss of condenser vacuum), manual bypass supply valves are provided for hotwell fill.

5.2.1.9.9 Major Modeling Assumptions

The following is a list of assumptions made during the development of the AltFW fault tree model:

a) AltFW does not function if off-site power is unavailable.

b) All three CD pumps are normally running when power is available (at the beginning of a plant transient). It is assumed that they continue to run after a reactor trip, except in the event of a subsequent Loss Of Off-site Power (LOOP), or failure of FBT.

c) When FW is available, it is conservatively assumed to operate for an average of 30 min. subsequent to a reactor trip. This is based on a survey of PVNGS experience.

d) Alignment of AltFW is assumed to require an average of 20 min.

e) AltFW system failure is defined as the inability to provide flow to one SG using at least one operating CD pump, within the following time frames: 1) If at least one FW pump continues to run for 30 min. following a reactor trip, an additional 70 min. (100 min. total) are available to complete AltFW system alignment and, 2) If both FW pumps trip concurrent with (or shortly after) the reactor trip, then 60 min. are available to complete AltFW system alignment.

f) In accordance with the analysis performed in support of CEN-239 (page 278), the "Time to initiate SG depressurization and feed via a low head pump to prevent core uncovery" is 59 min., therefore, the PRA Model assumes that the operator has 1-hr. to establish AltFW flow if both FW and AF are unavailable.

g) The condensate in the Condenser Hotwell at the time of the reactor trip may be quickly depleted; therefore, makeup flow from the CST to the Condenser Hotwell is required for sustained AltFW operation. Manual makeup is required either upon failure of automatic makeup, or when condenser vacuum is lost. This assumption provides conservatism in cases where the TBVs are successful in relieving secondary system pressure (no CST makeup would be required).

h) Based on the Functional Recovery Procedure requirement of 300 gpm SG supply for Decay Heat Removal (DHR), the volume of CST water available to the CD pumps (approximately 60,000 gal.) will provide approximately 3.5 hrs. of AltFW system operation. In combination with the volume of water existing in the Condenser hotwell, the total volume immediately available to the AltFW system is sufficient to provide several hours of adequate SG supply if the ADVs are being used for secondary system cooling. If the TBVs are in service (allowing recycling of water to the Condenser hotwell), this volume of water will provide sufficient SG supply indefinitely. In addition, several means exist for extending the availability of CST inventory, such as: normal CST makeup systems, CD system Unit cross-tie capability, or restoration of the Condenser Vacuum system.

i) Four flowpaths (8-in. lines) exist between the CST and the Condenser Hotwell. Two of these are normally-closed via manual isolation valves, while flow through the other two is controlled by SOVs/AOVs in response to hotwell level changes. Because no pump exists between the CST and the Main Condenser, makeup flowrate is determined by the elevation and pressure head existing between the two. The elevation difference is small; thus, loss of condenser vacuum results in a significant reduction in CST flowrate. Upon loss of condenser vacuum, the procedure for AltFW alignment (41RO-1ZZ10) directs the operator to manually align hotwell fill via the level control bypass valves. The flowrate to the Condenser Hotwells remains insufficient unless the operator opens the manual valves in both of the CST bypass supply lines. Once these valves are open, the availability of the automatically controlled makeup lines is irrelevant, since the combined flow area of the two manual lines is greater than the area of the common pipe that feeds all four hotwell fill lines. Failure of the operator to manually align the CST supply lines results in the failure of AltFW system.

j) Flowpath availability through one Low Pressure Heater Train is assumed adequate to provide sufficient flow for SG cooling.

k) During AltFW system alignment, the operator is directed to ensure that either one of the FW pump discharge valves is open, or one of the FW pump bypass valves is open. The PRA assumes that during full-power operation, both of the FW pump discharge valves are open; therefore, no operator action is required. Appropriate failures of the FW pump discharge valves are included in the PRA Model.

l) The High-Pressure Heater train bypass valve must open in order to pass adequate condensate flow through the high pressure heater section. The operator is directed to perform this action when time permits. This assumption is conservative because, even without the open bypass valve, significant CD flow continues to pass through the high-pressure heaters.

m) Certain support system failures will result in failure of AltFW including the following: 1) Failure to supply TC to the CD pump lube oil coolers, 2)

Upon failure of PW, the operator is directed to remove all heat loads from the TC system; thus, failing the AltFW system as in the above event, and 3) failure of IA results in loss of CD pump seal water flowpath, and loss of automatic Condenser Hotwell makeup. These three conditions result in the failure of AltFW.

n) The PRA Model does not include alignment of an alternate unit's CD pumps, although a written procedure exists for this purpose.

o) AltFW does not function following a loss of all CD Pumps Initiating Event.

5.2.1.9.10 System Analysis Results

Major contributors to AltFW system failure are attributed to operator failure to align the CD and FW systems, and failure of FBT (FBT must occur in order to supply power to the CD pumps upon unit trip). An additional contributor to AltFW system failure is the loss of IA supply, which supports the air-operated makeup valves (between the CST and the Main Condenser), and the CD pump seal water supply line. Common cause failures do not play as major a role in this system because of its susceptibility to several single failures. Overall reliability of the AltFW system is low.

The AltFW system is failed by the following initiating events: LOOP, loss of all CD pumps, loss of IA, loss of PW, and loss of TC systems.

5.2.1.10 Chemical and Volume Control System (Charging and Auxiliary Pressurizer Spray)

5.2.1.10.1 System Function

The Chemical and Volume Control System (CVCS) performs many diverse functions. Functions that are relevant to the PRA are:

a) CVCS provides seal injection to the reactor coolant pump seals and controls the bleedoff from the pump seals.

b) CVCS provides the source of borated water used in shutting down the reactor during an Anticipated Transient Without SCRAM (ATWS) condition.

c) CVCS provides water to the Auxiliary Pressurizer Spray System (APSS). APSS provides spray to the steam space in the pressurizer for maintaining operator control of Reactor Coolant System (RCS) pressure when the normal spray is unavailable. The APSS is used in normal operation during the final stages of shutdown and during emergency operations when the Reactor Coolant Pumps (RCPs) have been tripped.

5.2.1.10.2 System Success Criteria

The success criteria for the CVCS system for associated events is given below:

- RCS Integrity — To maintain RCS integrity (prevention of a RCP seal LOCA), seal injection or nuclear cooling water is required to be supplied to the RCP seals to maintain seal integrity. If a loss of nuclear cooling water occurs, the operator must secure the RCPs within 10 mins. if seal injection is available or within 5 mins. if seal injection is not available. The success criterion for RCS integrity is one charging pump providing seal injection flow for 24 hrs.
- ATWS — One charging pump supplying 40 gpm of borated water for 1 hr. is required for ATWS. The charging flow must be supplied from the RWT and can be from either the Boric Acid Makeup (BAM) pumps or from the gravity flow line. There is a timing requirement in that charging flow must be initiated within 10 mins. of the initiation of the ATWS to ensure proper shutdown margin. The 1 hr. mission time ensures that the required shutdown margin is achieved.
- SGTR — For a steam generator tube rupture, the RCS must be depressurized to reduce the primary to secondary leak rate and get the plant on shutdown cooling so the steam generators are not required for heat removal. The APSS requirement for depressurization is that at least one charging pump is supplying borated water from the RWT through one of the APSS valves for 8 hrs. This 8 hr. criterion is based upon an 8 hr. cooldown to shutdown cooling entry conditions.

5.2.1.10.3 System Description

The Chemical and Volume Control System (CVCS) removes RCS water via the letdown line and passes it through the regenerative heat exchanger, letdown heat exchanger, and purification ion exchanger to the Volume Control Tank (VCT). A simplified diagram of the CVCS system is shown in Figure 5.2-11. Letdown flow is controlled by the letdown control valve and letdown backpressure valves. The letdown control valve and letdown backpressure valve positions are controlled based upon pressurizer level and intermediate letdown system pressure. The VCT also receives flow from the reactor coolant pump control bleed-off lines and gas stripper return. The VCT water is then returned to the RCS using one or more of the charging pumps. The water returning to the RCS passes through the shell side of the regenerative heat exchanger where it removes heat from the incoming letdown. Flow upstream of the heat exchanger is directed to the RCP seal line while flow downstream of the heat exchanger supplies normal charging and can be diverted to the APSS line. During normal operation, seal injection and normal charging is aligned while APSS is isolated.

The RWT can also be used as a source of suction for the charging pumps in either of two ways. First, the BAM pumps can be aligned to provide flow from the RWT to the VCT or to the charging pump suction. Second, the RWT can be aligned to gravity feed the charging pump suction via HV-536.

APSS is initiated and controlled in the Control Room by operator action. APSS can be used with or without normal charging supplying flow to the RCS depending on the sequence. APSS can be initiated by opening either of two APSS control valves (HV-203/205).

In the analysis presented in this study, APSS is only credited during the SGTR event when RCPs are unavailable to control and reduce RCS pressure to mitigate the primary to secondary leak.

5.2.1.10.4 Major Components

The three charging pumps are positive displacement pumps. Each charging pump is aligned in one of three modes of operation: "Always Running", "Normally Running", and "Standby". The "Always Running" pump will only stop due to a loss of power or a ESFAS load shed signal. The "Normally Running" and "Standby" charging pumps are automatically started and stopped based upon a pressurizer level program error. All three pumps can operate simultaneously if required. The charging pumps normally take suction from the Volume Control Tank (VCT). The VCT is used to accumulate letdown water from the RCS to provide for control of hydrogen concentration and a reservoir of reactor coolant for the charging pumps. VCT makeup is from the Reactor Makeup Water Tank (RMWT) and the Refueling Water Tank (RWT). The VCT is pressurized using either the hydrogen or nitrogen (cold shutdown) gas supplies.

If the VCT is unavailable during a transient, the charging pumps can take suction from the RWT. The RWT can hold up to 750,000 gallons of water with a boron concentration of 4000 to 4400 ppm. Water from the RWT can be supplied to the charging pumps by either the BAM pumps or by gravity feed. There are two BAM pumps, each supplying a design flow of 165 gpm. Only one BAM pump is required to provide flow to all three charging pumps.

Prior to reaching the RCP seals, the seal injection water travels through a seal injection filter and heat exchanger. There are two redundant filters, which remove insoluble particles from the seal injection flow to the RCPs. The charging line flow is controlled by a 2-in. air-operated pressure control valve, PDV-240, which maintains a 105 psi differential backpressure to insure that reactor coolant pump seal injection pressure is higher than the reactor coolant system pressure.

The APSS isolation valves, HV-203/205, are 2-in. solenoid valves which are manually opened and closed from the Control Room.

The charging pumps and VCT are located in the Auxiliary Building. The charging pumps are on the 100-ft. level, and the VCT is on the 120-ft. level. The APSS isolation valves are located in the pressurizer valve cubicle in Containment.

Instrumentation for the CVCS includes Control Room indication of pump and major valve status as well as RWT and VCT level and temperature indication. System flowrates for charging and seal injection/return are also available.

5.2.1.10.5 Testing and Maintenance

The charging pumps are tested per ASME, Standards, Section XI, every quarter. Valves in the CVCS system are tested every quarter or 18 months per Section XI. APSS isolation valves are tested every 18 months per Section XI. Unscheduled maintenance is included for seal injection.

5.2.1.10.6 System Dependencies and Interfaces

Actuation

Two of the charging pumps are normally running but are load shed on a Loss of Power (LOP) to Class 1E 4.16kV AC bus PBA-S03 or PBB-S04. The previously running charging pumps are restarted once power is restored or after 40 secs. (sequencer times out) if a SIAS is present with a LOP.

The seal injection line is automatically isolated on RWT low/high temperature (70° F/150° F). Therefore, failure of this temperature loop could fail seal injection. The RWT gravity feed valve, HV-536, opens automatically on low VCT level and loss of power to BAM makeup to VCT valve, HV-514.

Electrical Power

The charging pumps require 125V DC Class 1E (breaker control power) power to start/stop and 480V AC Class 1E motive power for pump operation. The Train E charging pump can be aligned to either Train A or B. The BAM pumps are supplied from non-class 480V AC. The gravity makeup valve from the RWT, HV-536, is supplied from Train A 480V AC power. The normal charging valve, PDV-240, is powered from non-class 125V DC power. The APSS isolation valves require long term DC power. HV-203 requires Train B DC power and HV-205 requires Train A DC power.

Instrument Air

Various valves in the CVCS require Instrument Air (IA) for operation. The normal charging valves, HV-239/240, require IA and fail closed on a loss of IA, which isolates the normal charging line. Charging to the RCS is still available through spring loaded check valve, CH-V435, which bypasses HV239/240.

HVAC

Each Charging Pump Room is supplied by the Auxiliary Building Normal Ventilation System. Additionally, each pump room has its own room cooling unit, which is in operation when its associated charging pump is running. Analysis performed in Engineering Evaluation Request (EER) 90-CH-040 shows that the charging pump mission time requirements can be met in the event of a loss of pump room cooling. Loss of HVAC to the charging pumps does not fail the charging system.

Operator Action

Operator action is required to initiate boration within 10 mins. during an ATWS. Operator action is controlled per Procedure 41AO-1ZZ01, "Emergency Boration". Operator failure to emergency borate during an ATWS is described in Section 7.4.

Operator action is required during normal operation and during transients to ensure that seal injection is supplied to the RCPs. For events that result in a loss of cooling to the RCP motors or seals, operator action is required to trip the RCPs in accordance with Procedure 41AO-1ZZ29, "RCP and Motor Emergency", to prevent RCP damage. The RCPs are tripped as a result of loss of seal cooling to prevent an RCP seal LOCA. Operator failure to trip the RCPs in event of a loss of seal cooling is described in Section 7.4.

Operator action is required during a SGTR event to depressurize the RCS using APSS to reduce the primary to secondary leak rate if RCPs are unavailable. Operator failure to depressurize the RCS in the event of a SGTR is described in Section 7.4.

5.2.1.10.7 Technical Specifications

The following PVNGS T/Ss are applicable to the CVCS operation:

a) Specification 3/4.1.2.2 requires that at least two of three boron injection flowpaths be operable including gravity feed to the CH pumps from the RWT (two paths) or spent fuel pool through the BAM filter bypass to the charging pumps.

b) Specification 3/4.1.2.4 requires that at least two of three charging pumps be operable during operation.

c) Specifications 3/4.1.2.6 and 3/4.5.4 require that RWT be operable with the proper volume, temperature, and boron concentration.

d) Specification 3/4.4.3.2 requires that both APSS valves be operable during normal operations including a 72-hr. Action if one valve is inoperable and a 6-hr. Action if both valves are inoperable.

5.2.1.10.8 System Operation

Seal injection for the RCPs is provided during RCP pump operation. Seal injection flow passes through the seal injection heat exchanger and then the seal injection filters. Part of the flow passes through the seal assembly. It cools the seal cavity and returns to the VCT. The remainder of the flow is directed towards the RCP casing and provides a flushing flow which minimizes deposition of radioactive crud in the seal cavity. On high or low temperature levels for the injection flow, temperature sensor, TE-231, sends a signal to close UV-231P, stopping injection flow. In both cases, the extreme temperatures would do more damage to the seals than zero flow would do. Seal injection flow must be manually reinstated by the operator once the temperature extremes have been eliminated.

Normal charging flow from the VCT is provided during normal operations using one or two charging pumps. On an ATWS condition, an emergency boration will be initiated per Procedure 41AO-1ZZ01, "Emergency Boration". There are several ways to emergency borate. When accomplished at operation it is done via gravity feed from the RWT through the gravity feed line (via HV-536) to the charging pump suction. A flow rate of at least 40 gpm is required by the emergency boration procedure and is continued until the required shutdown margin is reached.

The APSS is used during natural circulation cooldown when the normal pressurizer spray is unavailable due to the RCPs being tripped. When this occurs, the operator will use APSS to control RCS pressure per "Emergency Operations Procedure," 41EP-1ZZ01, Appendix E, "Natural Circulation Verification." In the PRA Model, APSS is only required during a SGTR event. Appendix E will be used during the performance of Procedure 41RO-1ZZ06, "Steam Generator Tube Rupture" if the RCPs are not available due to plant conditions.

5.2.1.10.9 Major Modeling Assumptions

a) For charging pump operation, it was assumed that letdown has been isolated following the reactor trip and, therefore, the VCT was not taken credit for as a suction source. Additionally, it was assumed that if APSS was required for cooldown, RCS subcooling is lost and letdown was isolated due to low pressurizer level. Therefore, for simplification, the VCT was not taken credit for as a source of water.

b) The A charging pump was considered running prior to an event while the other two charging pumps were in standby. Charging pumps A, B, and E are required to restart on a LOOP.

c) The only two suction sources taken credit for in this analysis are BAM pump supply to the charging pumps and gravity feed from the RWT through HV-536. Only one BAM pump is required to supply water from the RWT.

d) Seal injection can be placed in maintenance for short periods of time without affecting the RCPs as long as NC supplies seal cooling.

e) Common-cause failure is included for APSS injection valves and VCT level instrumentation. VCT level instrumentation failure results in a loss of automatic suction switchover to the RWT for the charging pumps.

5.2.1.10.10 System Analysis Results

Loss of RCS integrity events are dominated by operator failure to trip the RCPs once seal injection and/or seal cooling is lost. Both charging and seal injection failures are dominated by charging line failures, seal injection line failures, and common-cause failures, which include both valve failures and VCT level instrument failures. On a loss of off-site power, failure of the Train A DG fails charging (loss of power to HV-536). Seal injection line failures including maintenance and temperature interlock failures, are also significant contributors to seal injection system failures.

The APSS failures are dominated by three sets of failures including common-cause and charging line. The common-cause failures include both the APSS injection valve failures and the VCT level instrument failures. The charging line failures include all manual valve, check valve, and flow element failures between charging pump discharge and the APSS injection line and are dominated by check valve failures.

Failure to provide emergency boration following an ATWS is dominated by operator failure to establish the necessary charging flow.

5.2.1.11 Steam Generator Blowdown System

5.2.1.11.1 System Function

The Steam Generator Blowdown (SGBD) system is a subsystem of the Secondary Chemical Control (SC) system. The SGBD system compensates for the concentrating effect of the Steam Generators (SGs) through continuous blowdown, processing, and reuse of a portion of the secondary fluid from each SG. The SGBD can also be used in wet-layup mode or in the event of a Steam Generator Tube Rupture (SGTR) to aid in the removal of contaminated secondary water. The analysis performed for the PRA is concerned solely with SGBD function during an SGTR event.

5.2.1.11.2 System Success Criteria

The success criteria for the SGBD for SGTR events is given below:

- SGTR — The system success criterion is availability of the SGBD system to receive flow from the ruptured SG (SG1) as necessary to prevent SG overfill. A 24-hr. mission time is assumed to allow time for the operations staff to bring the plant to a stable condition.

5.2.1.11.3 System Description

Each SG has two blowdown nozzles: one from the hot-leg side and one from the cold-leg side (see Figure 5.2-12). Only one line is open at a time with blowdown normally drawn from the hot-leg side. These two lines combine in Containment and proceed through flow control valves (SCN-HV1A/B/C and SCN-HV2A/B/C) to the Blowdown Flash Tank (SCN-X01). The common line has two Containment Isolation valves: one inside and the other outside Containment. Both of these valves close on MSIS, AFAS, or SIAS.

The primary flowpath to the Blowdown Flash Tank is via the "normal" flowrate line; however, two additional flowpaths ("abnormal" and "high-rate") are also available. The Flash Tank cools the incoming blowdown liquid. A level control valve regulates Flash Tank outlet flow to blowdown processing equipment. The Flash Tank steam space is vented to the Heater Drain Tank.

Flow from the Flash Tank is normally routed through the Blowdown Heat Exchanger and the Blowdown Filter. Flow then proceeds through the Blowdown Demineralizer, which removes impurities. The water then discharges to the Main Condenser for reuse, or to the blowdown Total Dissolved Solids (TDS) sumps for disposal.

5.2.1.11.4 Major Components

Each hot-leg and cold-leg blowdown line includes a motor-operated isolation valve; the hot-leg isolation is normally-open during plant operation, while the cold-leg isolation is normally-closed. These isolation valves are motor-operated, fail as is valves, and are not required to change position during an SGTR event. The Containment Isolation valves, located downstream on the common blowdown line, are air-operated, fail-closed valves that would most likely close automatically on an SGTR event due to a subsequent SIAS or AFAS. Containment Isolation valve closure results in a complete loss of SGBD capability.

The Flash Tank is a vertical, cylindrical, 9250-gallon tank designed for 275 psig at 400 ° F. The tank is sized to accommodate a continuous blowdown flowrate of approximately 172,000 lbm/hr. and to accommodate increased (high-rate) blowdown for a 2-min. duration. The tank inlet consists of three separate lines, each equipped with a fail-closed, non-modulating, air-operated isolation valve. These lines are for "normal", "abnormal", and "high-rate" flow operation (0.2%, 1.0%, and 8.5% of the maximum steaming rate of 8,600,000 lbm/generator-hr., respectively) with the "normal" flowrate line typically in service. The "normal" and "abnormal" lines flow into a common header, which leads to the Blowdown Flash Tank while the "high-rate" line enters separately.

The Blowdown Heat Exchanger (SCN-E02) uses condensate to cool the blowdown fluid before it enters the Blowdown Demineralizer bed, preventing resin breakdown. The SGBD filter is sized to accept 141,000 lbm/hr. blowdown flowrate. The filter removes 95% of suspended solids larger than 5 microns before the blowdown liquid enters the demineralizer bed where two mixed-bed regenerative resin-type units further purify the blowdown fluid.

Control Room indications and control functions for the SGBD system include control switches and position indication for the hot/cold-leg blowdown valves and the blowdown Containment Isolation valves. In addition, a rate-select switch and path-select switch exist for each SG. The rate-selector switch (normal, abnormal, and high-rate) and path-selector switch (Blowdown Flash Tank, Condenser, and Off) logic provides valve position indication of the Blowdown Flash Tank (and Condenser) "normal", "abnormal", and "high-rate" control valves. Indication of Blowdown Flash Tank pressure and flash tank equalizing line (vapor) flow is also provided.

5.2.1.11.5 Testing and Maintenance

The Containment Isolation valves are stroke tested quarterly per ASME Standards, Section XI, testing program, and are normally-open during plant operation.

Maintenance time on the high-rate valve is assumed to be 116 hrs., since the valve is not crucial to system operation (continued power operation). Test time for the high-rate valve is assumed to be 18 months, even though the valve is opened more often (once per week) to improve SG chemistry (the high-rate valve is open for only 2 mins. each week).

PVNGS Technical Specifications require SGBD system surveillance including demonstration of valve operability prior to returning a Containment Isolation valve to service.

5.2.1.11.6 System Dependencies and Interfaces

Actuation

The Blowdown Containment Isolation valves close automatically upon receipt of an AFAS, SIAS, or MSIS.

Operator Action
Operator action per the SGTR Emergency Procedure (41RO-1ZZ06) is required for SGBD operation in the event of an SGTR. When the level in the ruptured SG approaches 90% (by wide range), the operator is directed to drain the SG via the Blowdown Demineralizers to 72% wide range. The operator is later directed to cooldown the isolated (ruptured) SG. In proceeding with this cool down, the operator is instructed to adjust blowdown rate and feedrate to prevent exceeding RCS cooldown rate of 75° F per hr.

Electric Power
The SG hot/cold-leg blowdown valves require non-class 480V AC power (NH) to change position, but valve transfer is not normally required (no loss of blowdown flowpath) since the hot-leg blowdown valve is normally-open.

The Blowdown Flash Tank inlet flow control valves require non-class 125V DC power to operate. Failure of electrical supply to these valves results in loss of blowdown flowpath to the Blowdown Flash Tank. The valves in the alternate flowpath (the blowdown flowpath leading directly to the Main Condenser, upstream of the flash tank inlet flow control valves) are not modeled; however, these valves are also supplied by the same electrical source as the flash tank inlet valves. Failure of this non-class 125V DC supply results in the loss of all blowdown.

The Blowdown Containment Isolation valves require long-term Class 1E 125V DC power (PKA-D21 to SGA-UY500P and PKB-D22 to SGB-UY500Q) to operate. It is assumed that, prior to the SGTR, these valves are open, but close upon receipt of a SIAS later in the event. The valves are, therefore, required to open for blowdown to function during this event. Loss of power to either of these valves results in a complete loss of the blowdown flowpath.

Instrument Air
The Blowdown Containment Isolation valves and the blowdown flow control valves require Instrument Air (IA) to open or remain open. Loss of IA to either of these valves results in a complete loss of the blowdown flowpath.

Cooling Water
The Blowdown Heat Exchanger requires condensate for cooling, but cooling is not required during an SGTR since the system will still function to lower the SG level after failure of the condensate (CD) system.

5.2.1.11.7 Technical Specifications
PVNGS Technical Specification 3/4.6.3, "Containment Isolation Valves," applies to the SGBD Containment Isolation valves in Modes 1 through 4. The following requirements apply to the Containment Isolation valves of the SGBD system.

The Technical Specification requires that all Containment Isolation valves specified in the associated table (Technical Specification Table 3.6-1) be maintained operable. With one or more valves inoperable, the following requirements apply to each affected open containment penetration: maintain at least one isolation valve operable and perform specific actions to (1) restore the inoperable valve to operable status within 4 hrs., or (2) isolate the affected penetration within 4 hrs., or (3) reduce the unit to Hot Standby (Mode 3) conditions within the next 6 hrs., and to Cold Shutdown (Mode 5) within the following 30 hrs.

5.2.1.11.8 System Operation

Normal operation of the SGBD system is controlled by Operating Procedure 41OP-1SG03.

During normal operation, a continuous blowdown rate of 0.2% of the maximum steaming rate (17,200 lbm/SG-hr.) flows through the Blowdown Demineralizer beds to the Condenser Hotwell.

Abnormal blowdown is manually established when abnormal SG chemistry is present. High-rate blowdown is manually established on a weekly basis for a short period of time (approximately 2 mins.) to remove accumulated solids from the SG tube sheets. (High-rate blowdown is provided at 8.5% of the maximum steaming rate.)

An event involving SGTR is controlled by Procedure 41RO-1ZZ06. In order to reduce SG level during an SGTR event, blowdown is operated manually to control SG level between 60 and 90% by wide range. Blowdown is required in the event of a ruptured SG only after the SG has been isolated. Blowdown (to reduce level in the SG) may be established through any of the flow lines to the Blowdown Flash Tank.

During wet-layup mode, the blowdown system maintains SG chemistry by providing the capability to adequately mix, sample, and add chemicals to the SGs.

5.2.1.11.9 Major Modeling Assumptions

The following is a list of assumptions made during the development of the SGBD fault-tree model:

a) If a SGTR occurs, it is assumed to occur in SG-1; therefore, blowdown is only required for SG-1.

b) Prior to the reactor trip event, blowdown on SG-1 is operating normally (flowpath is via SGE-HV43, and is later isolated by SGA-UV500P and SGB-UV500Q on receipt of a SIAS).

c) Blowdown fails on a Loss Of Off-Site Power (LOOP).

d) The PRA Model assumes that an SGTR event results in a SIAS condition; therefore, the SGBD Containment Isolation valves close on an SGTR event.

e) For simplicity, only two of three flowpaths entering the Blowdown Flash Tank are modeled (the normal and high-rate lines). It is assumed that the normal valve (SCN-HV1A) is open at the start of the transient, and the high-rate valve (SCN-HV1C) is closed.

f) One of the three flowpaths exiting the Blowdown Flash Tank fails open; therefore, these lines are not modeled due to the high reliability associated with having three parallel lines. In addition, the large volume of the Blowdown Flash Tank provides sufficient collection volume for an extended period of time, and if blowdown processing equipment is unavailable, blowdown flow can be directed to the condenser.

5.2.1.11.10 System Analysis Results

The major system malfunction resulting in failure of the SGBD system (from SG-1) is failure of the Containment Isolation valves to re-open. This failure includes mechanical valve failures and IA system failure. IA system failure also affects the flash tank inlet valves. In addition, blowdown fails on LOOP, which results in failure of both IA and non-class AC and DC power.

5.2.1.12 Pressurizer Vent Valves

5.2.1.12.1 System Function

The pressurizer vent (PV) valves provide a redundant vent path from the top of the pressurizer to either the Reactor Drain Tank (RDT) or the Containment atmosphere. The vent allows an operator to remove steam from the pressurizer steam space during accident conditions in order to control Reactor Coolant System (RCS) pressure. In the PRA, PVs are credited as a means to achieve RCS depressurization following an SGTR if auxiliary pressurizer spray (APSS) is unavailable.

5.2.1.12.2 System Success Criteria

The success criteria for the PV system for SGTR events is given below:

- Pressurizer vents open to allow flow from the top of the pressurizer to either the RDT or the Containment atmosphere. The system must operate for 8 hrs. following initiation.

5.2.1.12.3 System Description

The pressurizer and reactor vessel head vents remove water or steam from the RCS. The venting process can occur through a redundant series of solenoid valves to the RDT or Containment. Flow is limited by using 1-in. solenoid valves for isolation. One of the lines is limited by a 7/32-in. flow orifice. A simplified drawing of the PV system is shown in Figure 5.2-13.

5.2.1.12.4 Major Components

The system consists of five 1-in. SOVs. The minimum number of valves required for venting is two for both RDT and Containment atmospheric venting, while an orifice bypass line consisting of two valves can be opened for increased flow. A normally-opened manual isolation valve separates the pressurizer from the vent lines.

Instrumentation for pressurizer vents include Control Room indication of solenoid valve position.

5.2.1.12.5 Testing and Maintenance

The vent valves are tested every 18 months by ASME, Standard, Section XI, testing. Maintenance of the system is not considered since all components are in containment.

5.2.1.12.6 System Dependencies and Interfaces

<u>Electrical Power</u>

All of the solenoid valves require Class 1E 125V Class DC power from either PKA-D21 or PKB-D22. Failure of either DC power train will not fail the vent system due to the redundant line being connected to the opposite electrical train. Since all of the solenoid valves are identical, common-cause failure of the valves is considered.

Operator Action

Operator action is required to open the pressurizer vent valves to depressurize the RCS in the event of a SGTR. Operator failure to depressurize the RCS in the event of a SGTR is described in Section 7.4.

5.2.1.12.7 Technical Specifications

PVNGS Technical Specification 3/4.4.10 requires both vent paths from each source (pressurizer and reactor vessel head) to be operable and closed during Modes 1 through 4.

5.2.1.12.8 System Operation

The PVs are used during emergency conditions to remove steam from the pressurizer. Operation would normally only occur upon a loss of both normal and auxiliary pressurizer sprays. The operator would first attempt to establish flow to the RDT and only vent to the Containment atmosphere if the line to the RDT fails. Pressure control would occur by opening and closing the vent valves, as required, to reduce RCS pressure. Due to the size of the vent lines, pressure reduction is extremely limited and slow. Analysis performed by Combustion Engineering (CE) shows that pressurizer vent valves are effective as a means of depressurization following an SGTR.

5.2.1.12.9 Major Modeling Assumptions

a) A mission time of 8 hrs. for RCS pressure reduction is assumed for all components

b) Either of the redundant vent paths is adequate for system success

c) Plugging of the 7/32-in. orifice is considered

d) Common-cause failures are included in the PV fault-tree for failure of both trains of vent valves.

5.2.1.12.10 System Analysis Results

The PV failures are dominated by the common cause failure of both redundant vent lines to open. Additionally, failure of the RCS isolation valve to remain open affects the reliability of the vents. No other system failures are dominant.

5.2.1.13 Turbine Bypass Valves

5.2.1.13.1 System Function

The Turbine Bypass Valves (TBVs) function as part of the Steam Bypass Control System (SBCS) to reject steam in the main steam header to the Main Condenser and/or to atmosphere. The purpose of the SBCS is to maximize plant availability following a turbine load-rejection event. Use of the TBVs during a load-rejection event, in conjunction with the Reactor Power Cutback (RPCB) system, allows the operator to avoid unnecessary reactor trips and lifting of primary/secondary safety valves. The SBCS is designed to complement the Pressurizer Pressure Control system (PPCS) and the Pressurizer Level Control system (PLCS) to extend load-follow capability.

The TBVs are provided with Quick Open capability via the SBCS to avoid challenging the Main Steam Safety Valves (MSSVs), and RCS heatup in the event of a large load-rejection, or turbine trip event.

Steam rejection, via TBVs, occurs during turbine load-rejection and turbine trip events, to sufficiently control main steam header parameters to avoid a reactor trip (assuming proper operation of RPCB). In the event of a turbine trip, TBV operation alleviates the need for MSSV operation, thus minimizing the possibility of incurring a radioactive release as a result of a stuck-open safety valve.

In the event of a single Main Feedwater (FW) pump trip, the SBCS operates the TBVs to control main steam header pressure (assuming proper operation of RPCB).

5.2.1.13.2 System Success Criteria

The success criteria for the TBV system, for associated Initiating Events (IEs), are given below:

- Small LOCA — At least one of eight TBVs (with successful HPSI) must open, as needed, to vent secondary steam. If a rapid depressurization is necessary (upon HPSI failure), two TBVs are required.
- SGTR — At least one of eight TBVs must operate to relieve secondary steam pressure. Use of one of the six valves to the Main Condenser is preferred to avoid environmental release.
- Group Transient — One of eight TBVs must open to relieve secondary steam pressure.
- Loss of MFW — In conjunction with proper Alternate Feedwater (AltFW) system operation, one of eight TBVs must open to relieve secondary steam pressure.

5.2.1.13.3 System Description

The TBV system provides a maximum steam dump capacity of 55% of rated main steam flow. This amount of steam bypass capacity, in conjunction with RPCB system operation, dissipates enough energy from the Nuclear Steam Supply System (NSSS) to permit load-rejection of any magnitude, without tripping the reactor, lifting the MSSVs, or lifting the Pressurizer Safety Valves (PSVs). Each of the eight TBVs operates automatically upon receipt of a control signal from the SBCS, a subsystem of the Reactor Control System. The TBVs may also be operated in remote-manual mode from the Control Room.

Six of the TBVs open in banks of one or two valves, releasing steam directly to the Main Condenser as shown in Figure 5.2-14. These TBVs are automatically locked-out by the SBCS if condenser vacuum is inadequate (>5.0 in HgA per Alarm Response Procedure, 41AL-1RK6A).

Two of the TBVs discharge directly to the atmosphere. The TBVs are sequentially controlled, such that these two valves open last and close first; minimizing the loss of secondary system inventory to the atmosphere.

The SBCS modulates the TBVs using a complicated control system, which takes inputs from main steam pressure, steam flow, pressurizer pressure, RCS temperature, reactor power, turbine load index, main feedwater pump status, and automatic rod control. Initially following a load-rejection event, the TBVs open using a quick-open response, which allows the TBVs to react quickly to plant changes. Once the TBVs open sufficiently to respond to a load-rejection, the valves control secondary steam pressure via modulation control. Modulation control varies the TBV steam rejection-rate slowly to maintain a smooth transient response.

Because the ASME Code MSSVs provide the ultimate overpressure protection for the SGs, the SBCS is defined as a "Control System." The special requirements applicable to protection systems are, therefore, not applicable to the SBCS. Failure of the SBCS will have no detrimental effect on RCS operation, other than resulting in a reactor trip subsequent to a large load-rejection or turbine trip event.

5.2.1.13.4 Major Components

For automatic operation, the eight TBVs are grouped into five sequentially-operated control banks: PV-1001 (Bank 1) is the first TBV to open, followed by PV-1004 (Bank 2); TBVs PV-1003 and PV-1006 (Bank 3) operate next, followed by PV-1002 and PV-1005 (Bank 4); and the atmospheric dump TBVs, PV-1007 and PV-1008 (Bank 5) open last. Valve closure sequence is the reverse of the opening sequence. In manual mode, the Control Room operator may choose to operate any combination of TBVs using either the Master/Auto controller or individual valve controllers.

The TBVs are air-operated, fail-closed, stacked-disc type drag valves capable of quick opening within 1 sec. and quick closing within 5 secs., or modulating open/closed in 15 to 20 secs. Each TBV is provided with a handwheel for local-manual operation, and may be mechanically isolated from the Main Steam (SG) system by manually closing the associated TBV's upstream isolation valve.

The SBCS incorporates a series of logic modules and interlocks that control TBV operation during a transient. The main logic channels combine to send modulation signals to each bank of TBVs, given proper SG system parameters. The permissive channels verify appropriate RCS and secondary conditions, and send permissive signals for modulation and/or quick open to each TBV. The logic modules are configured such that no single component failure nor single operator error will result in spurious opening of more than one TBV.

5.2.1.13.5 Testing and Maintenance

At-power testing of the TBVs is performed once per refueling cycle per procedure 36MT-9SF09, "SBCS Valve Dynamic Response Time Test." This test is performed to verify SBCS valves operate in modulation mode within specific time requirements.

During shutdown (Modes 5 and 6), "SBCS Functional Test," (36MT-9SF03), is performed every 4 months during extended periods of time in Modes 5 and 6. SBCS calibration is also performed during Modes 5 and 6 per procedure 36MT-9SB04.

5.2.1.13.6 System Dependencies and Interfaces

Actuation

The TBVs receive the following automatic control signals from the SBCS:

a) Permissive Controller Output (PCO)

b) Modulation Control Demand (MCD)

c) Quick Open Demand (QO)

Operator Action

Automatic actuation signals may be manually overridden; operator may place the system in "Emergency Off." In addition, the TBVs can be manually opened by the Control Room operator via Auto/Manual control stations provided for each valve.

During plant cooldown, a manual reduction in steam pressure can be performed by gradually reducing the SBCS setpoint. This can also be accomplished by operating the SBCS Master Controller.

In addition to the automatic functions, the TBVs may be operated in remote-manual mode from the Main Control Board, or in local-manual mode using the handwheel provided for each TBV.

Instrument Air

The TBVs are pneumatically-operated valves requiring Instrument Air (IA) to operate. Nitrogen backup to the IA system will maintain sufficient pneumatic supply pressure for several hours, although this is not credited in the analysis.

Circulating Water

Because six of the eight TBVs discharge to the Main Condenser, the Circulating Water (CW) system must be operational to maintain condenser vacuum. Although the atmospheric TBVs (Bank 5) are available for steam relief after a loss of condenser vacuum event, the PRA Model conservatively assumes that all TBVs fail to operate.

Electric Power

Electrical power to the TBV system is provided by non-class 125V DC power and non-class 120V AC Instrument power. Non-class 125V DC power is supplied (via bus NKN-D42) to the TBV permissive and QO SOVs. Non-class 125V AC power is supplied to the SBCS Master Controller and the individual TBV Manual/Auto controllers via NNN-D11, which is normally aligned (per Procedure 41OP-1NN01) to its emergency power source, PHA-M31. Rack power to the SBCS NSSS Control System cabinet (SFN-C03) is supplied via NNN-D12.

The TBVs are not credited following a Loss Of Off-site Power (LOOP) because condenser vacuum is lost, and because long-term pneumatic pressure is unavailable.

5.2.1.13.7 Technical Specifications

PVNGS Technical Specifications do not directly affect the TBV fault-tree model.

5.2.1.13.8 System Operation

The TBVs are operated per Procedure 41OP-1SF05, "Operation of the Steam Bypass Control System," and are normally-closed during plant operation. At low power levels, or following a Reactor trip, the TBVs modulate to regulate secondary system pressure within an acceptable range. The TBVs are capable of modulating to handle a step load decrease of 10%, or a continuous load decrease of 5% per minute, without resulting in a reactor trip.

5.2.1.13.9 Major Modeling Assumptions

The following is a list of assumptions made during development of the TBV fault-tree model:

a) The TBVs do not operate during a loss of condenser vacuum, loss of IA (long-term availability of the pneumatic supply is not assured), LOOP, or loss of the PW or TC systems. In the event that condenser vacuum is lost, the two atmospheric TBVs would still be available, but no credit is taken for this.

b) The probability of TBV failure (2.0E-2) was taken from CEN-239, Supplement 3, "Probabilistic Risk Assessment of the Effect of PORVs on Depressurization and Decay Heat Removal for PVNGS Units 1, 2, and 3," p. 6-57, September 1983. In this study, the TBVs were fully modeled including control system and human errors. The TBV fault-tree, developed for the PVNGS PRA, is a simplified version of the more detailed model. The PRA Model includes all support systems required by the TBVs, but only one event is used to represent the TBV mechanical and control system faults.

c) Spurious closure of all MSIVs isolates the SG system from the Main Condenser, causing TBV failure. The Control Room operator can manually override the MSIS and open an MSIV bypass valve. This would allow steaming from the TBVs; however, this action is not credited in the PRA.

5.2.1.13.10 System Analysis Results

The TBV failures are dominated by three sets of failures: closure of all MSIVs, failure of the TBVs to open (CEN-239), and electrical failures.

Electrical malfunctions are dominated by failure of long-term non-class 125V DC power, and failure of Class 1E 480V AC (supplies power to the non-class 120V AC power system).

5.2.1.14 Atmospheric Dump System

5.2.1.14.1 System Function

The Atmospheric Dump Valves (ADVs) provide a means of removing NSSS decay heat in the event that the Turbine Generator and Main Condenser are unavailable, and in the event of loss of AC Power. This alleviates the need to use the Main Steam Safety Valves (MSSVs). The Atmospheric Dump (AD) system facilitates bringing the plant from Hot-Standby (Mode 3) to Shutdown Cooling entry temperature. The ADVs are used as a means of performing secondary depressurization so that Alternate Feedwater (AltFW) can be aligned if Auxiliary Feedwater (AF) fails. In addition, the ADVs can be used following a Small LOCA (with HPSI) as a means of depressurizing the RCS such that the LPSI pumps can provide RCS inventory control.

5.2.1.14.2 System Success Criteria

The success criteria for the AD System for associated Initiating Events (IEs), are given below:

- Small LOCA — One out of two ADVs opened as needed to vent steam from a SG receiving AF flow (with successful HPSI).
- SGTR — One out of two ADVs on the intact SG opens to vent secondary steam.
- SLB — One out of two ADVs on the intact SG opens on demand.
- FLB — One out of two ADVs on the intact SG opens on demand.
- Group Transients — One out of two ADVs on a SG being fed must open to relieve secondary steam pressure.
- LOOP — One out of two ADVs on the SG to which AF flow is being supplied must open to relieve secondary system pressure.
- Loss of MFW — One out of two ADVs on the SG being used for heat removal must open to relieve secondary system pressure.
- SBO — One out of two ADVs on the SG to which AF is being supplied operates under operator control.

5.2.1.14.3 System Description

The AD system consists of four manually-operated Atmospheric Dump Valves (ADVs) and associated support equipment, located in the Main Steam Support Structure (MSSS) (shown in Figure 5.2-15). Each of the two SGs has two redundant ADVs, one per main steam line. The ADV dissipates NSSS decay heat by venting steam directly to the atmosphere. Each ADV is sized to pass required steam flow to hold the unit at Hot-Standby or to permit a maximum reactor cooldown rate of 75° F per hour. Each valve's capacity is approximately 6.5% of the maximum steaming rate. The ADVs are pneumatically operated, each possessing two separate permissive control circuits. This design ensures that no single failure in an ADV control circuit will result in an ADV spurious open or prevent the operation of more than one ADV on each SG.

The ADVs are normally operated from the Control Room, but may also be operated from the Remote Shutdown Panel. Remote valve control is accomplished using a thumbwheel position controller having a continuous range of 0-100%. Valve position indication is provided at each remote control station. Each ADV is also equipped with a local handwheel for local-manual operation.

Each ADV incorporates four solenoid-operated valves (two permissive solenoids and two closing solenoids). In Close mode, all four solenoid valves are de-energized, allowing full air pressure to be applied to the top of the actuator piston, while the bottom of the actuator piston vents to the atmosphere. An internal spring is provided above the actuator piston to assist in valve closure.

When an ADV is placed in the Open mode, all four solenoid valves are energized. The two permissive solenoid valves (solenoids R and S) align controlled air to the bottom of the actuator piston, while one of the Closing solenoids (solenoid A) aligns controlled air to the top of the actuator piston. During valve modulation, an I/P Control Unit (one per ADV) admits controlled air to the valve positioner, which simultaneously controls air pressures to the top and bottom of the actuator piston. This correctly modulates the ADV in response to the position indicated on the ADV position controller.

Air supply to the ADVs is provided via the Turbine Building IA header. Nitrogen accumulators (one per ADV) designed to Seismic Category I Standards, supply motive power if IA is unavailable. A solenoid valve energizes on low air header pressure to automatically place an accumulator on line. Long-term ADV operation (24 hrs.) requires IA system availability/recovery. The ADVs fail closed on loss of pneumatic supply.

AD system failure does not affect any other safety-related systems.

5.2.1.14.4 Major Components

Two redundant ADVs, one per main steam line (SGA-HV184 and SGB-HV178 on SG-1 and SGA-HV179 and SGB-HV185 on SG-2), and associated support equipment are provided for each SG. No automatic initiating circuits are provided for ADV operation. Each ADV is provided with remote-manual control capability, and a handwheel allowing local-manual operation. Each valve is designed to fail-closed, and is sized to maintain the plant in Hot-Standby conditions while dissipating NSSS decay heat, or to allow a sufficient flow of steam to maintain a controlled reactor cooldown (maximum cooldown rate of 75° F per hr.).

Each ADV nitrogen accumulator (one per ADV) is provided a direct, normally-closed, connection to the Service Gas (GA) system (high-pressure nitrogen) for ADV pneumatic backup in the event of Instrument Air (IA) system failure. The backup accumulators are rated to 700 psig, and are normally pressurized to 600 psig. Upon loss of the IA system, the accumulators are sized to provide 4 hrs. of steaming at Hot-Standby, plus 6.5 hrs. of plant operation to reach Cold Shutdown (Mode 5) under natural circulation conditions (per Technical Specification Bases 3/4.7.1.6). Low accumulator pressure (< 600 psig) is annunciated in the Control

Room via system pressure transmitters. Instrumentation for the AD system includes pressure transmitters for actuation of the backup nitrogen supply.

5.2.1.14.5 Testing and Maintenance

ADV testing is performed on a quarterly basis; this testing does not prevent the ADVs from performing their primary function.

The PRA assumes that no scheduled maintenance is performed on the ADVs during plant operations. The model accounts for unscheduled (corrective) maintenance on each of the ADVs. Unscheduled maintenance on two ADVs on opposite SGs is permitted by Technical Specifications; however, simultaneous unscheduled maintenance on both ADVs on the same SG would place the Unit in a 72-hr. Action Statement. An average time in maintenance of 21 hrs. is incorporated into ADV Corrective Maintenance event probabilities, based on the Technical Specification 72-hr. Action Statement.

The PRA model uses 18 months as the test period for certain components associated with ADV backup pneumatic supply (including manual valves, pressure relief valves and spring-loaded check valves). This is based on the fact that backup nitrogen supply component testing is performed on a quarterly basis, but is restricted to Plant Mode 3. The PRA conservatively assumes that each unit enters Mode 3 once per 18-month refueling cycle.

PVNGS Technical Specification 3/4.7.1.6 requires that system surveillance, including verification of nitrogen accumulator pressure $\geq$ 400 psig (once per 24 hrs.) and verification of operability of specific system valves, be performed prior to plant startup after Refueling (Mode 6) shutdown or Cold Shutdown of 30 days or longer.

5.2.1.14.6 System Dependencies and Interfaces

Actuation

There are no automatic functions associated with the AD system.

Electric Power

Power to the AD system is provided from both Class 1E 120V AC and Class 1E 125V DC Power systems. The ADVs receive control power from the Class 120V AC power supply; ADVs SGA-HV179 and SGA-HV184 require control power from Channel A, while ADVs SGB-HV178 and SGB-HV185 require control power from Channel B. The ADV solenoid valves require Class 125V DC power; ADVs SGA-HV179 and SGA-HV184 require power from both Channels A and C, while ADVs SGB-HV178 and SGB-HV185 require power from both Channels B and D. Upon loss of Class 125V DC power supply to any of the four solenoid valves, the associated ADV fails closed.

The backup nitrogen accumulator solenoid valves are also powered from Class 125V DC Channels A or B. DC power is provided by batteries (2 hr. capacity) or 480V AC via the battery chargers.

The Class 1E 120V AC Instrument Power system supplies power to the I/P Control Units which control air pressure to the ADV solenoid valves. In addition, this system provides power to the pressure sensors/transmitters, which control automatic operation of the ADV backup nitrogen accumulator system. Upon loss of Class 120V AC power supply to any of the four I/P Control Units, the associated ADV fails closed. Upon loss of Class 120V AC power supply to any of the four pressure sensors/transmitters, the associated nitrogen accumulator will be unavailable for pneumatic backup.

Instrument Air

ADV operation is dependent upon the availability of pneumatic supply, which is normally provided by the IA system. In the event of a loss of IA, nitrogen accumulators provide short-term (8 hrs.) backup for operation of ADVs.

Operator Action

The ADVs may be remotely actuated, controlled, and monitored from either the Control Room or, if necessary, the Remote Shutdown Panel (RSP). That is, in either the Control Room or at the RSP, two separate hand switches must be operated to energize and open all solenoids necessary to open a single ADV. An ADV cannot be operated from the Control Room while the controller at the RSP is in Local. The RSP must be in the CR position for Control Room operation to occur.

A handwheel is provided on each ADV for local-manual operation; however, the PRA model does not take credit for local-manual operation of the ADVs. The AD system is designed such that in the combined event of either a SLB or SGTR, with a loss of power to the ADVs, the manual operators of the intact valves on the other SG are still accessible. This allows the auxiliary operator to manually operate the ADVs without risking exposure to steam or radiation environment.

5.2.1.14.7 Technical Specifications

PVNGS Technical Specification 3/4.7.1.6, "Atmospheric Dump Valves," applies to ADV operability in Modes 1 through 3, and also in Mode 4 when the SGs are being used for DHR.

The Technical Specification requires that a minimum of one ADV per SG be operable in the above modes, or that at least one ADV per SG be restored within 72 hrs. If the system cannot be appropriately restored within the allotted time, the Unit must be placed (at least) in Hot-Standby within the following 6 hrs.

5.2.1.14.8 System Operation

AD system operation is governed by Operating Procedure 41OP-1SG01 Main Steam. System operation requires remote-manual or local-manual operation as no provision is made for automatic ADV operation.

Each ADV has two separate permissive SOV control circuits, both of which must be activated to open an ADV. These control circuits energize the four solenoid valves, which control pneumatic pressure to the associated ADV actuator piston. Failure of any one of the four solenoids will result in ADV closure.

Upon loss of IA supply pressure, each ADV nitrogen accumulator is automatically placed in service through the operation of a solenoid valve on the accumulator supply line.

5.2.1.14.9 Major Modeling Assumptions

The following is a list of assumptions made during the development of the ADV fault-tree model:

a) One of two ADVs on each SG is necessary and sufficient to depressurize the Reactor Coolant System (RCS) to 200 psig.

b) One of two ADVs on either SG is sufficient to maintain the plant in Hot-Standby conditions.

c) Control circuit faults for the ADV pneumatic supply SOVs are modeled, in general, as an undeveloped event.

d) The PRA Model includes electrical faults up to Class 1E 125V DC distribution panels, including the circuit breakers located between the AD system, and the associated DC distribution panels. Electrical failures upstream of the DC distribution panels are modeled as developed events.

e) The PRA Model includes events involving a circuit breaker spurious trip. A time factor of 26 hrs. is incorporated into these event probabilities (assumes a 24-hr. mission time and a 2-hr. detection time).

f) The PRA model does not account for failures of the ADV block isolation valves. These block valves are administratively controlled (locked open) and are not operated for ADV testing. After ADV maintenance is complete, testing is performed before the ADV is placed back into service. It is highly unlikely that the block valve could be inadvertently closed or left closed after maintenance.

g) The PRA Model for ADV operation requires that long-term DC power, as well as ADV pneumatic supply, be available. This is because the Model requires ADVs to be available for 24 hrs.

h) A 2-hr. mission time is used for events involving air supply filter plugging ("1SGN-F02A--FXAPG" and "1SGN-F03A--FXAPG"). The filters are assumed to be susceptible to plugging only during the time period when air flow through them is present. The 2-hr. mission time is based on the requirement of a 2-hr. period of ADV operability to accomplish primary/ secondary system depressurization.

i) Upon loss of the IA system, nitrogen accumulators provide sufficient gas reserve for 10.5 hrs. of operation. It is assumed that IA could be restored within this 10.5-hr. time period by one of the following: 1) recovery of the IA compressors, 2) operator alternates use of ADVs on each SG to maintain equal air supply remaining in each accumulator throughout the event, or 3) use of a portable air compressor.

j) The PRA Model includes events involving ADV backup nitrogen supply PSVs failing open. In these events, nitrogen from an accumulator is diverted to atmosphere through the open PSV. It is, therefore, not available to the associated ADV. The PRA Model assumes a 10-hr. mission time, based on the nitrogen accumulator sizing to provide 10.5 hrs. of nitrogen demand. No failure detection period was included in these event probabilities.

k) Common-cause failures considered for the ADVs include two events: the first is failure of four out of four ADVs and the second is failure of two out of two ADVs on the same SG, given that there is not a common-cause four out of four event.

l) Should an ADV support system fail, i.e., electric, or pneumatic, the operator can open the associated ADV manually via the local handwheel. Conservatively, this action is not credited.

5.2.1.14.10 System Analysis Results

Failure of the AD system is dominated by several types of failures including mechanical failure of the ADVs. Lesser failures include failure of AC power or pneumatic supply systems.

Mechanical failures are comprised of local faults of both ADVs on one SG, common-cause failures of all four ADVs, or common-cause failure of two ADVs on one SG. Other cutsets contain failures such as 1) failure of one ADV due to local faults, in conjunction with unscheduled maintenance on the ADVs on the opposite SG, and 2) local faults of opposing ADVs.

In addition, failure of IA, failure of nitrogen accumulators (associated with both ADVs on one SG), and failure of the nitrogen backup system (long-term), are significant contributors to ADV-related cutsets.

In regard to the physical effect of plant events, only LOOP or SBO have any direct effect on the AD system. A LOOP event would result in a loss of the IA system. The ADV backup nitrogen accumulators are designed to provide adequate pneumatic supply for 10.5 hrs.

A SBO event would have the same effect as LOOP, but would include additional failures associated with the loss of power to the Class AC battery chargers due to failure of the Emergency Diesel Generators. Upon loss of the class battery chargers, the class batteries have a 2-hr. design capacity. If onsite/off-site power is not recovered within this time, the batteries will be fully discharged, and the ADVs will fail-closed on loss of DC power to the solenoid valves. The ADVs would then require local-manual operation using the valve handwheel; however, the current PRA Model does not take credit for local-manual ADV operation.

5.2.2 Support Systems

5.2.2.1 Essential Chilled Water System

5.2.2.1.1 System Function

The Essential Chilled Water (EC) system supplies chilled water to the essential heating, ventilation, and air-conditioning (HVAC) systems for the Control Building, Auxiliary Building, and main steam support structure for cooling of safety related equipment rooms during emergency situations.

5.2.2.1.2 System Success Criteria

The success criterion for each EC train is that chilled water flow is provided to each EC header for at least 24 hrs. Failures of the individual essential ACUs are not included in the EC system fault trees. Each of these ACUs is modeled with the system which they support. The EC fault trees only model the supply of chilled water to the header providing a supply to the various ACUs.

5.2.2.1.3 System Description

The EC system is normally in standby and is automatically actuated by an auto start signal from the ESF load sequencer if the load sequencer receives an Auxiliary Feedwater Actuation Signal (AFAS), Safety Injection Actuation Signal (SIAS), Loss of Power (LOP), Containment Spray Actuation Signal (CSAS), Control Room Ventilation Isolation Actuation Signal (CRVIAS), or Control Room Essential Filtration Actuation Signal (CREFAS). The EC system can also be started manually from the CR or locally from its switchgear.

The EC system consists of two 100% capacity, redundant, chilled water trains. Each train includes a chiller unit, pump, expansion tank, chemical addition tank, control valves, piping, and instrumentation. The trains are not cross-connected. See Figure 5.2-16 for a simplified drawing of the essential chilled water system.

Each train is a closed-loop system with the pump circulating water through the chillers to the HVAC units being cooled and returning to the pump suction.

The EC system provides chilled water to the following essential air-cooling units (ACUs):

- Control Room AHU HJA(B)-F04
- High Pressure Safety Injection (HPSI) pump room A(B) ACU HAA(B)-Z01
- Low Pressure Safety Injection (LPSI) pump room A(B) ACU HAA(B)-Z02
- Engineered Safety Features (ESF) switchgear room (including battery rooms A, B, C, and D, and the RSP room) ACU HJA(B)-Z03
- DC equipment rooms A and C (B and D) ACU HJA(B)-Z04
- Electrical penetration rooms ACU HAA(B)-Z06
- Auxiliary feedwater pump room A(B) ACU HAA(B)-Z04
- Containment spray pump room A(B) ACU HAA(B)-Z03
- Essential cooling water (EW) pump room A(B) ACU HAA(B)-Z05

The EC system is actuated automatically when the ESFAS system starts the ESF components that are being served by the above ACUs.

The EC system can also be manually initiated locally or from the Control Room. A two-position (START/STOP) control switch for each chiller is provided in the Control Room. When momentarily placed in the START position, the associated essential chilled water circulation pump starts, and the chiller internal control circuit is activated if low essential chilled water and essential cooling water flow signals are not present. A program timer in the internal control circuit starts the chiller lube oil pump, and approximately 28 seconds later it starts the chiller compressor. A second timer is also activated which prevents restarting the chiller within approximately 20 mins. (unless an ESF start signal is received). A start signal from the ESF sequencer will bypass the 20 min. time delay and motor overload trip and allow the chiller to restart within approximately 165 seconds.

Makeup water for the system is normally supplied from the Demineralized Water system. A secondary or backup source is furnished by a line from the condensate transfer pumps. Cooling water for the chiller condensers is supplied by the essential cooling water (EW) system.

5.2.2.1.4 Major Components

The two essential chillers are self contained, package-refrigeration type chillers with centrifugal compressors. The chillers require Class 1E 4.16kV AC power. Each chiller has a rated capacity of 235 tons refrigeration. The chiller unit consists of a compressor, evaporator, refrigerant, condenser/receiver unit, controls, and instrumentation. The condenser is cooled by the EW system as is the chiller oil lubrication system oil cooler. The EC pumps are 20 hp, 400 gal/min., centrifugal pumps requiring Class 1E 480V AC power.

The EC system expansion tanks are vertical-cylindrical types with a capacity of 80 gallons per tank. A low-pressure nitrogen blanket is maintained to exclude oxygen and to control pressure. The expansion tanks automatically accommodate contraction and expansion of the EC system due to cooldown or heatup. Level makeup is normally provided by the Demineralized Water system, with the condensate transfer and storage system as a backup.

The EC pumps, chillers, expansion tanks, and chemical addition tanks are located on the 74-ft. level in the Control Building.

The EC system includes instrumentation for monitoring pressure, temperature, level, and flow. Instrumentation includes both local and Control Room indication, and Control Room alarms.

The main chilled water line at the discharge of each EC pump is provided with local pressure indication. The pump bearing temperature is monitored by thermocouples for computer input.

The expansion tank has local pressure indication and high and low-pressure alarms that alarm in the Control Room. The expansion tank is also provided with instrumentation for level control and high and low-level alarms that alarm in the Control Room.

The essential ACUs are provided with pressure safety valves for the EC system.

The main chilled water supply line, downstream from the chiller, has temperature instrumentation that provides indication and a high temperature alarm in the control room.

If the chiller fails, the rooms requiring HVAC have high room temperature alarms that alarm in the Control Room if the room temperatures rise above the setpoint for the temperature switch. The SI pump rooms, CS pump rooms, EW pump rooms, AF B pump room, and electrical penetration rooms have alarm setpoints of 105° F. The AF A pump room has an alarm setpoint of 112° F, and the DC equipment rooms have alarm setpoints of 95° F. The ESF switchgear rooms have local temperature indication.

The main EC supply line has a flow transmitter that transmits a signal to a flow switch in the Control Room which in turn provides a permissive signal for automatically starting the essential chiller. The EW system also has a flow switch in the Control Room which, once proper EW flow has been established, sends a permissive signal for starting the essential chiller. The flow transmitters and switches for both the EC and EW systems are modeled in the EC system fault trees, since failure of the flow permissive signal from either system can fail the EC system.

5.2.2.1.5 Testing and Maintenance

The EC pumps and chillers are started once per month. A valve verification is performed once per 31 days by checking that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position. Once per 18 months during shutdown, each valve (manual, power-operated, or automatic) servicing safety-related equipment that is locked, sealed, or otherwise secured in position, is verified to be in its correct position.

Unscheduled maintenance for the EC chillers, pumps, chiller breakers, and pump breakers is included in the EC system fault trees. Normally, one EC train may be placed in maintenance for up to 72 hrs. Maintenance of the ESF load sequencer does not make the associated EC train unavailable, because procedures dictate that the cooling water systems be started and run during such maintenance.

Failure to restore the EW manual supply valves after maintenance is included in the EC system fault trees.

5.2.2.1.6 System Dependencies and Interfaces

Actuation

The EC system is normally in standby but starts automatically on an auto start signal from the ESF load sequencer if the load sequencer receives an Auxiliary Feedwater Actuation Signal (AFAS), SIAS, LOP, CSAS, CRVIAS, or CREFAS. At the same time, the EW system, which supports the EC system, and the SP system, which supports the EW system, are also started automatically by the ESF load sequencer. The EC pumps start immediately on an auto start signal with the chiller automatically loading once proper EC and EW flows have been established. The EC system can also be started manually from the Control Room or its switchgear (see Section 5.2.2.1.3).

Given a LOP signal, the load sequencer first sends a load shed signal to the chillers and EC pumps, and then later sequences them back on after the DG starts and its output breaker closes to re-power the ESF bus.

Electric Power

The Train A chiller receives motive power from the Class 1E 4.16kV AC bus, PBA-S03, and the Train B chiller receives motive power from the Class 1E 4.16kV AC bus, PBB-S04. The Train A chilled water pump receives motive power from the Class 1E 480V MCC, PHAM31, and the Train B pump receives motive power from the Class 1E 480V MCC, PHBM32. Control power for starting the chiller and the pump on Train A is provided by the Class 1E 125V DC panel PKAD21, and the Train B chiller and pump receive control power from the Class 1E 125V DC panel, PKBD22. The EC flow permissive instrumentation receives power from Class 1E 120V AC instrument panels, PNAD25 for Train A and PNBD26 for Train B.

Cooling Water

Each chiller requires essential cooling water (from the same train) for heat rejection. Essential cooling water flow to an essential chiller can fail if either the manual valve on the inlet side, or the manual valve on the outlet side of the chiller fails to remain open or is not restored to its open position after maintenance. The chiller can also fail due to failure of the EW flow permissive instrumentation.

Operator Action

Operator action is considered in failure of the chillers. For transients where a SIAS or CSAS does not occur, the operator may manually start AF pump A or B prior to an AFAS and fail to manually start the respective cooling water systems. An AF pump room high temperature alarm would eventually be expected in the Control Room.

5.2.2.1.7 Technical Specifications

There are many PVNGS Technical Specification that affect the EC system due to the dependence of ESF equipment on the system. However, the only Technical Specification that directly pertains to the operation of the EC system is 3/4.7.6.

LCO 3.7.6 states:

a) At least two independent essential chilled water loops shall be operable.

b) With only one EC loop operable, return the other loop to operation within seven days, or be in at least hot standby within the next six hours and cold shutdown within the following 30 hrs.

c) With only one EC loop operable, verify within one hour that the normal HVAC system is providing space cooling to the vital power distribution rooms that depend on the inoperable essential chilled water system for space cooling, and

d) Within eight hours, establish operability of the safe shutdown systems which do not depend on the inoperable essential chilled water system (one train each of boration, pressurizer heaters and auxiliary feedwater), and

e) Within 24 hrs., establish operability of all systems, subsystems, trains, components, and devices that depend on the remaining operable essential chilled water system for space cooling.

If these conditions are not satisfied within the specified time, be in at least hot standby within the next 6 hrs. and in cold shutdown within the following 30 hrs.

Surveillance Requirement 4.7.6 states:

a) At least two essential chilled water loops shall be demonstrated operable at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b) Once per 18 months during shutdown, verify that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is locked, sealed, or otherwise secured in position, is in its correct position.

Given that the AF and ECCS pumps depend on the EC system, the seven day inoperability limit for one train of EC is cascaded down to 72 hrs. so that it will coincide with the inoperability limit for one train of AF or ECCS.

5.2.2.1.8 System Operation

During normal operation at reactor power, the EC system is in the standby condition aligned for possible emergency operation. The EC system operates during emergency conditions and during a normal plant shutdown.

The EC system is initiated and controlled automatically by the load sequencer if the load sequencer receives an AFAS, SIAS, CSAS, LOP, CREFAS, or CRVIAS. The EC system can also be manually started from the Control Room or locally.

When started, each flow train operates with the pump circulating water through the chiller to the redundant essential ACUs in the Control Room, ESF switchgear rooms, electrical penetration rooms, EW pump rooms, CS pump rooms, HPSI pump rooms, LPSI pump rooms, AF pump rooms and DC equipment rooms.

Cooling water for the chiller condenser is supplied by the EW system. The water is constantly pumped through the chillers with no modulating control necessary. Once the cooling water flow to the chiller condenser and the chiller water flow to the system are established, flow transmitters on the EW and EC systems send signals to flow switches in the Control Room, which in turn provide permissive signals for activating the chiller control circuit (see Section 5.2.2.1.3).

One of the trains can be deactivated when the other train has demonstrated its capacity, by manual switches in the control room. A minimum 165-sec. delay is required for restarting the chiller compressor. In addition to the control switches in the Control Room for each circulation pump, each pump also has a switch on the local panel in the switchgear room.

5.2.2.1.9 Major Modeling Assumptions

a) Two separate fault trees were developed for the essential chilled water system; one for Train A and one for Train B. Each fault tree provides support system logic to the respective front-line system fault trees.

b) Twenty-four hours is the mission time for the EC system. This is a conservative assumption since for most accident scenarios where room cooling is required, even a few hours of successful EC operation is adequate to keep room temperatures low enough to prevent equipment failure over the 24-hr. mission time of the front-line system. For demand failures, exposure times are used. The exposure time is based on the test period for the component.

c) The EC system requires the EW system for cooling and the EW system in turn depends on the Essential Spray Ponds. Rather than chaining these cooling water systems together, fault trees for systems requiring EC explicitly model EW and SP also.

d) Local failure of the EW system flow permissive is modeled in the EC system fault trees because failure of the EW flow permissive will fail the essential chiller on the respective train.

e) Neither the Demineralized Water nor the nitrogen systems are needed by the EC model since they are not required for normal system operation, and failure of these systems does not fail EC over the 24-hr. mission time.

f) Common-cause failure of the chillers and pumps is included in each EC system fault tree.

g) Extreme environment failures of the EC system pumps or chillers are not modeled in the fault trees. The pumps and chillers for the chilled water system are located in two large rooms on the lowest elevation of the Control Building. Based on the loss of HVAC analyses for the other ESF pump rooms (AF, HPSI, LPSI, CS, and EW), it is concluded that rooms containing the EC equipment are so large by comparison that they will not exceed the equipment qualification temperature limit within 24 hrs.

h) CSAS, CREFAS, and CRVIAS are not credited in the model as possible actuation systems for the EC, EW, and SP systems.

5.2.2.1.10 System Analysis Results

The EC system failures (failure of both EC trains) are dominated by common cause failure of the chillers and common cause failure of the EC pumps. When EW and SP failures are considered, common cause failures of the EW and SP pumps also affect the EC system. In scenarios where one train of EC has already failed due to the initiator, or one train of ESF equipment has failed due to system failures other than the EC system, the dominant EC system failures are auto start failures due to load sequencer faults, maintenance unavailabilities of the pump and chiller, control circuit failures of the pump and chiller, and failure of the chiller to run for 24 hrs.

[illegible]

[illegible]

5.2.2.2 Essential Cooling Water System

5.2.2.2.1 System Function

The essential cooling water (EW) system removes heat from all essential components required for normal and emergency plant shutdown, with the exception of the diesel generator. The EW system removes heat from the essential chillers and the shutdown cooling heat exchangers, and rejects heat to the essential spray ponds through the EW heat exchangers.

The EW system also serves as a backup to the nuclear cooling water (NC) system. When the NC system is unavailable, the EW system provides cooling water to the fuel pool cooling heat exchangers, reactor coolant pumps, control element drive mechanisms (CEDM), and normal chillers. The EW system provides an intermediate barrier between the RCS (while aligned through shutdown cooling) and the spray pond to reduce the probability of radioactive leakage to the environment.

5.2.2.2.2 System Success Criteria

The success criterion for Train A of the EW system is that EW flow is provided to the header for the Train A SDC heat exchanger, Train A EC chiller, and the cross-tie for the NC system for 24 hrs. The success criterion for Train B of the EW system is that EW flow is provided to the header for the Train B SDC heat exchanger and the Train B EC chiller for 24 hrs.

5.2.2.2.3 System Description

The EW system is normally in standby and is automatically actuated by an auto start signal from the ESF load sequencer if the load sequencer receives an AFAS, SIAS, LOP, CSAS, CRVIAS, or CREFAS. The EW system can also be manually actuated from the CR or locally from its switchgear.

The EW system consists of two independent, identical, closed-loop, safety-related, flow trains. One flow train supplies cooling water required for plant shutdown to safety Train A shutdown cooling heat exchanger and essential chiller, and the other flow train supplies cooling water to the same items in safety Train B. See Figure 5.2-17 for a simplified drawing of the EW system.

Each train includes a heat exchanger, surge tank, pump, chemical addition tank, piping, valves, controls, and instrumentation. Either of the two flow trains will supply sufficient cooling water to allow a safe plant shutdown independent of the other flow train.

Water is cooled by the EW heat exchanger and then pumped to both the essential chiller and the shutdown cooling heat exchanger, with the majority of the flow being provided to the shutdown cooling heat exchanger. The flows from the chiller and heat exchanger then recombine, and flow to the EW heat exchanger for cooling.

Makeup water is normally supplied to the EW surge tanks by the Demineralized Water system. The condensate transfer and storage system provides makeup when the DW system is not available.

Each EW train is connected to the NC system by supply and return cross-tie lines, each with a normally closed isolation valve. The Train A cross-tie valves are remotely actuated, while the Train B valves are manually operated and normally locked closed. A SIAS signal automatically closes the Train A isolation valves.

Each flow train of the EW system also has a supply and return line, with normally closed valves, for each corresponding fuel pool heat exchanger. This is to provide a capability of cooling the fuel pool heat exchanger when the NC system is not available.

5.2.2.2.4 Major Components

The EW pumps are horizontal-single-stage, double-suction-centrifugal pumps with direct-coupled, 800 hp motors. Each pump is rated to 14,550 gallons per minute (gpm) at 154 ft. total differential head. The EW pumps are at the 70-ft. elevation in the Auxiliary Building.

The EW heat exchangers are straight-single-pass, counterflow, shell and tube type. They are designed to transfer 145,200,000 BTU per hour each. EW flow passes through the shell side. The EW heat exchangers are located at the 100-ft. elevation in the Auxiliary Building.

The EW surge tanks are vertical-cylindrical type. Each surge tank has a 1000 gallon capacity. A low pressure nitrogen gas blanket is maintained on the tanks to exclude oxygen. The primary function of the surge tanks is to provide a volume within the closed loop system for fluid expansion and contraction. They also serve as a convenient location for adding makeup water. The surge tanks are at the 120-ft. elevation in the Auxiliary Building.

The EW chemical addition tanks are located at the 70-ft. elevation in the Auxiliary Building.

The EW system includes instrumentation for pressure, temperature, level, and flow.

EW pump pressure instrumentation includes local pump discharge pressure indication and pump discharge pressure switches that provide alarm signals to the Control Room and common computer input on high or low pump discharge pressure.

The EW pump discharge has temperature detection instrumentation that signals the Control Room annunciator panel and computer when an abnormally high temperature exists. A dual temperature indicator is provided in the Control Room to monitor EW pump discharge and shutdown cooling heat exchanger outlet temperature.

The EW supply header just downstream of the EW pump has both local and Control Room flow indication. EW flow on the outlet side of the essential chiller is indicated locally and in the Control Room. A flow transmitter on the outlet side of the essential chiller transmits a signal to a switch in the Control Room, which in turn provides a permissive signal for automatically starting the essential chiller.

The surge tanks have both local pressure indication and high and low pressure alarms in the Control Room.

The surge tanks also have local level indication and high and low-level alarms in the Control Room.

5.2.2.2.5 Testing and Maintenance

A valve verification is performed once per month. Each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is verified to be in its correct position. At least once per 18 months, during shutdown, each automatic valve servicing safety-related equipment is verified to correct position operation on a SIAS test signal. At least once per 18 months, during shutdown, each valve (manual, power-operated, or automatic) servicing safety-related equipment, that is locked, sealed, or otherwise secured in position, is verified to be in its correct position.

The EW pumps are started once per month when the EC system is tested.

Unscheduled maintenance is included in the model for the EW pumps and the pump breakers. Normally, one EW train may be placed in maintenance for up to 72 hrs. Maintenance of the ESF load sequencer does not make the associated EW train unavailable because procedures dictate that the cooling water systems be started and run during such maintenance.

Failure to restore the EW pump discharge and suction valves, and failure to restore the EW heat exchanger inlet and outlet valves after maintenance are also included in the model.

5.2.2.2.6 System Dependencies and Interfaces

Actuation

The EW pumps start automatically on an auto start signal from the load sequencer when the load sequencer receives a SIAS, CSAS, AFAS, LOP, CREFAS, or CRVIAS. The EW system can also be actuated manually from the Control Room or from its switchgear.

Given LOP signal, the load sequencer first sends a load shed signal to the EW pumps, and then later sequences them back on after the DG starts and its output breaks closes to re-power the ESF 4.16kV bus.

Electric Power

The Train A EW pump receives motive power from the Class 1E 4.16kV bus, PBAS03, and control power from the Class 1E 125V DC panel, PKAD21. The Train B EW pump receives motive power from the Class 1E 4.16kV bus, PBBS04, and control power from the Class 1E 125V DC panel, PKBD22.

HVAC

The EW pumps may fail due to high room temperature if the HVAC system fails to cool the pump rooms. The Train A EW pump room is cooled by the essential ACU, HAA-Z05, which receives chilled water from Train A of the EC system, and electric power from the Class 1E 480V MCC, PHAM35. The Train B EW pump room is cooled by the essential ACU, HAB-Z05, which receives chilled water from Train B of the EC system, and electric power from the Class 1E 480V MCC, PHBM38.

Cooling Water

The EW heat exchangers require the essential spray ponds for heat rejection. Essential spray pond flow to either heat exchanger can fail if either the manual valve on the inlet side, or the manual valve on the outlet side of the heat exchanger fails to remain open or is not restored to its open position after maintenance.

Operator Action

For transients where a SIAS or CSAS does not occur, the operator may manually start AF pump A or B prior to an AFAS and fail to manually start the respective cooling water systems. An AF pump room high temperature alarm would eventually be expected in the Control Room.

Given a failure of essential HVAC, the operator may fail to provide backup cooling to the EW pump room. An EW pump room high temperature alarm would eventually be expected in the Control Room. Operator local recovery action involves opening the door to the EW pump room to permit natural air circulation.

5.2.2.2.7 Technical Specifications

There are many PVNGS Technical Specification that affect the EW system due to the dependence of the EC and SDC systems on the EW system. The only Technical Specification that directly pertains to the operation of the EW system is 3/4.7.3.

LCO 3.7.3 states:

At least two independent essential cooling water loops shall be operable. With only one essential cooling water loop operable, restore the other loop within 72 hrs. or be in hot standby within 6 hrs. and cold shutdown within 30 hrs.

Surveillance Requirement 4.7.3 states:

a) At least once per 31 days verify that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b) At least once per 18 months during shutdown, verify that each automatic valve servicing safety-related equipment actuates to its correct position on a SIAS test signal.

c) At least once per 18 months during shutdown, verify that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is locked, sealed, or otherwise secured in position, is in its correct position.

The most limiting PVNGS Technical Specification for systems depending on the EW system is the 72-hr. inoperability limit. The AF and ECCS pumps, which have 72-hr. inoperability limits for one train, depend on the EC system for room cooling, which in turn depends on the EW system for cooling.

5.2.2.2.8 System Operation

During normal power operation the EW system is in standby. The system operates only during cooldown, cold shutdown, emergency conditions, or upon failure of the NC system.

The EW has two redundant and separate trains. Each EW train interfaces with its corresponding SP system train at the EW heat exchanger, which serves as a pressure-thermal barrier between the SP and EW systems. Each train has a 100% heat dissipation capacity through heat transfer from the shell side to the tube side of the EW heat exchanger, and through the dissipation of the transferred heat load by the SP system to the atmosphere. Although an emergency reactor shutdown is normally accomplished with the initial operation of both trains of the EW and SP systems, shutdown and cooldown with only one train over an extended period of time is possible and permissible.

During shutdown, the EW pumps and the spray pond pumps are started to remove heat from the shutdown cooling heat exchanger.

During accident conditions, the EW system is started automatically by the load sequencer when the load sequencer receives a SIAS, CSAS, AFAS, LOP, CREFAS, or CRVIAS.

During non-LOCA transients, the EW system is required to remove heat from the essential chillers which in turn cool the AF pump rooms and other equipment rooms. Under these conditions, the system is either started manually or by the ESF load sequencer if the load sequencer receives an AFAS or LOP.

During a LOCA, the EW system provides cooling to the essential chillers, which in turn cool the ECCS and AF pump rooms, and to the shutdown cooling heat exchangers, which remove heat from CS or LPSI during the recirculation phase. Under these conditions, EW is either started manually or by the ESF load sequencer if the load sequencer receives an AFAS, SIAS, or CSAS.

For non-LOCA conditions the EW system also serves as a backup to the NC system when NC is unavailable (see Section 5.2.2.2.1).

5.2.2.2.9 Major Modeling Assumptions

a) Two separate fault trees were developed for the essential cooling water system; one for each train. Each fault tree provides support system logic to the respective front-line system fault trees.

b) The EW system fault trees use both mission times and exposure times. The components that have mission times all use a 24-hr. mission time. Components that have demand failures use exposure times based on the test periods for the components.

c) The essential cooling water system provides cooling water to the essential chillers and the shutdown cooling heat exchangers via two branch flow paths coming off a pump discharge. Each path has a manual valve upstream and one downstream of the component being cooled, which, if they fail to remain open, will prevent the EW system from providing cooling water flow to the component. Rather than generate separate EW system models for each path, the manual valves associated with a branch path are included in the fault tree of the system being supported by the EW system. Similarly, the RCS Integrity Loss top logic fault tree models failure to cross-tie EW to NC to provide seal cooling given failure of NC. Failures of the EW to NC cross-tie valves are included in the RCS Integrity Loss top logic fault tree. Only Train A of EW is modeled in the RCS Integrity Loss top logic fault tree.

d) The EC system requires the EW system for cooling, and the EW system in turn depends on SP. Rather than chaining these cooling water systems together, fault trees for systems requiring EC explicitly model EW and SP. Similarly, fault trees for systems requiring EW explicitly model SP.

e) The EW pumps require EC chillers for pump room cooling. Therefore, the EW fault tree models the EC system under EW pump failures.

f) Due to the fact that makeup is not needed unless there is a leak in the EW system, failure of the surge tank and makeup systems are not assumed to fail the EW system over the 24 hr. mission time and are not included in the PRA model.

g) Failure of the chemical addition tank is not assumed to fail the EW system over the 24 hr. mission time.

h) The EW system has cross-tie capability to the NC system, but failure of the EW system due to a diversion of EW water out of the NC system is not considered in the PRA model. This is because the valves that cross-tie the EW and the NC systems are normally closed and must be manually aligned. A failure of this type would require both alignment of the cross-tie valves and a NC piping failure. The same reasoning applies to the fuel pool heat exchanger cross-ties.

i) The possible failure of the EW pumps due to extreme environment (resulting from loss of pump room cooling) is included in the EW fault trees. The maximum EW pump room temperature reached in 24 hrs. with no HVAC is 189° F. If the door is propped open, the maximum temperature reached is 168° F. As discussed in Section 6.2.5, room temperatures which result from loss of HVAC were determined not to immediately threaten pump operability, although pump reliability is significantly degraded. Accordingly, the probability of the pump failing to run due to loss of HVAC was adjusted, as described in Section 6.2.5.

j) Common-cause is considered for failure of the EW pumps to start and run.

k) CSAS, CREFAS, and CRVIAS are not credited in the model as possible actuation systems for the EC, EW, and SP systems.

5.2.2.2.10 System Analysis Results

Failure of both EW trains is dominated by common-cause failure of the EW pumps. In scenarios where one EW train has already failed due to the initiator, or one train of ESF has failed due to failures other than the EW system, the dominant EW system failures are auto start failures due to load sequencer failures, maintenance unavailability of the EW pumps, and control circuit faults of the EW pumps.

5.2.2.3 Essential Spray Pond

5.2.2.3.1 System Function

The essential spray pond (SP) system removes heat from the essential cooling water (EW) system and the diesel generator (DG) cooling heat exchangers during normal shutdown and emergency conditions. The heat removed is dissipated into the atmosphere by the essential spray ponds. The essential spray ponds are the "ultimate heat sink."

The SP system operates only during a plant shutdown or emergency conditions, or when a diesel generator is running, and does not operate during normal power generation.

5.2.2.3.2 System Success Criteria

The SP trees only model the SP cooling water supply up to the pipe header providing a supply to the various heat exchangers being cooled. Therefore, the success criterion for each SP train is that cooling water is provided from each spray pond, using the spray mode, to the respective DG/EW header for at least 24 hrs.

5.2.2.3.3 System Description

The SP system is normally in standby and is automatically actuated by an auto start signal from the ESF load sequencer if the load sequencer receives an AFAS, SIAS, LOP, CSAS, CRVIAS, CREFAS. The SP system can also be started manually from the Control Room or locally from its switchgear.

The SP system consists of two redundant spray ponds and two separate, redundant, flow trains. Each flow train takes suction from and returns to its respective spray pond. Each spray pond also has separate filtration trains and chemical addition equipment.

Each flow train consists of a SP pump, pump structure, piping, valves, controls, and instrumentation required for supplying cooling water to the EW heat exchanger and the diesel generator cooling heat exchangers in one safety train. Each train is capable of supporting 100% of the cooling functions required for a safe reactor shutdown. See Figure 5.2-18 for a simplified drawing of the SP system.

Water from each spray pond is pumped, via the SP pump, to the DG cooling heat exchangers and the EW heat exchangers. The DG cooling heat exchangers include the fuel oil cooler, jacket water cooler, air-after-coolers/heaters, governor oil cooler, and lube oil cooler. Each is required for DG operation. Flow from the coolers recombines and returns to the spray pond via the SP system cooling nozzles which spray into the spray pond.

The spray ponds function as independent and redundant units. However, the combined water inventory of both is required for a nominal 27 day emergency-shutdown without makeup. Two butterfly valves are provided in the common wall between the ponds to allow water transfer. Normal position of these valves is closed to maintain independence of the two trains. During safe shutdown or accident recovery, and with only one spray system operating, it will be necessary to open at least one of the spray pond cross-connect valves to access the combined water inventory for long term recovery.

Two makeup water sources are available for each spray pond: one from the domestic water system, and the other from the station reservoir. The normal source for makeup is the domestic water system.

5.2.2.3.4 Major Components

The spray ponds are rectangular, reinforced concrete, Seismic Category I basins holding approximately 6.0E+06 gallons of water. There are four headers per spray pond with 80 nozzles per header.

Each spray pond is provided with a bypass line for diverting 100% of the flow from the spray nozzle headers directly into the pond. Motor operated valves, actuated from the Control Room, provide this diversion.

The spray ponds are located at plant west of each Unit, approximately 200-ft. from the fuel building.

The SP pumps are 600 hp, vertical, wet-pit pumps with a rated flow of 16,300 gallons per minute, and a pump discharge pressure of 50 psig. The pump motors require 4.16 kV power for operation.

The SP pump discharge pipes are furnished with check valves SPA-V041 and SPB-V012 located outside the pond walls.

Essential cooling water heat exchangers EWA-E01 and EWB-E01 can be isolated with manually operated butterfly valves SPA-HCV-45, SPA-HCV-47, SPB-HCV 46, and SPB-HCV-48, respectively.

The spray pond water return lines are furnished with remote motor operated butterfly valves. Two valves are provided in each train. Valves SPA-HV-49A (Train A) and SPB-HV-50A (Train B) are normally locked in the open position and provide alignment of each train into the spray pond cooling nozzles. Valves SPA-HV-49B (Train A) and SPB-HV-50B (Train B) are the normally locked-closed valves in the bypass line for diverting the flow from the spray nozzle headers directly into the pond. These bypass valves can be aligned locally or from the Control Room during cold weather conditions, when spray nozzles are not needed.

SP system instrumentation includes spray pond level instrumentation, pump flow instrumentation and various local and remote temperature and pressure sensors.

The spray pond level sensing system includes a level transmitter, which provides a signal to a level indicator in the Control Room, and a level switch, which actuates an alarm in the Control Room on high or low pond level.

The main SP system supply line from the pump and return line to the spray pond each contain a flow element and flow indicating transmitters. The two transmitters output to a dual flow indicator in the Control Room, and to a differential flow switch which actuates an alarm in the Control Room in the event of differential flow caused by a pipe break in the loop.

SP pump suction and discharge lines have temperature sensors, which provide signals for Control Room indication and alarms.

The EW heat exchanger inlet and outlet lines are provided with local temperature indication for the SP system water, and the outlet nozzle is provided with instrumentation that sends a signal to the annunciator panel in the Control Room when an abnormally high temperature exists at the heat exchanger outlet.

The discharge piping of the essential spray pond pump has a local pressure indicating transmitter, which provides Control Room indication, and a pressure switch, which provides a Control Room alarm on high or low pump discharge pressure.

5.2.2.3.5 Testing and Maintenance

An SP system valve verification is performed once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

Once per 18 months during shutdown, a valve verification is performed by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is locked, sealed, or otherwise secured in position, is in its correct position.

The SP pumps are started once per month when the EC system is tested. The spray pond is also started to support DG and EW operation or testing.

Unscheduled maintenance is included in the model for the SP pumps and the spray nozzle header inlet MOVs. Normally, one SP train may be placed in maintenance for up to 72 hrs. Maintenance of the ESF load sequencer does not make the associated SP train unavailable because procedures dictate that the cooling water systems be started and run during such maintenance.

5.2.2.3.6 System Dependencies and Interfaces

<u>Actuation</u>

Both trains of the SP system are started automatically by the ESF load sequencer when it receives an AFAS, SIAS, CSAS, LOP, CRVIAS, or CREFAS. The SP system is also actuated by a DG start signal. The SP system can also be started manually from the Control Room or from its switchgear.

Given a LOP signal, the load sequencer first sends a load shed signal to the SP pumps, and later sequences them back on after the DG re-powers the 4.16kV ESF bus.

<u>Electric Power</u>

The Train A spray pond pump receives motive power from the Class 1E 4.16kV AC bus, PBA-S03. Control power for starting the pump is provided by the Class 1E 125V DC panel, PKAD21. The Train B spray pond pump receives motive power from the Class 1E 4.16kV AC bus, PBB-S04, and control power from the Class 1E 125V DC panel, PKBD22.

Operation Action

For transients where a SIAS or CSAS does not occur, the operator may manually start AF pump A or B prior to an AFAS and fail to manually start the respective cooling water systems. An AF pump room high temperature alarm would eventually be expected in the Control Room.

5.2.2.3.7 Technical Specifications

There are many PVNGS Technical Specification that affect the SP system due to the dependence of EW and DG systems on SP. The only Technical Specification that directly pertain to the SP system are 3/4.7.4 and 3/4.7.5.

LCO 3.7.4 states:

If one SP train is inoperable for 72 hrs., be in Hot Standby within 6 hrs. and cold shutdown within the following 30 hrs.

Surveillance Requirement 4.7.4 states:

a) At least two essential spray pond loops shall be demonstrated operable at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b) Once per 18 months during shutdown, verify that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is locked, sealed, or otherwise secured in position, is in its correct position.

LCO 3.7.5 states:

The ultimate heat sink shall be operable with two essential spray ponds, each with:

a) A minimum usable water depth of 12 ft., and

b) An average spray pond water temperature of less than or equal to 89° F.

With specification 3.7.5 not satisfied, be in at least hot standby within 6 hrs. and in cold shutdown within the following 30 hrs.

Surveillance Requirement 4.7.5 states:

a) The ultimate heat sink shall be determined operable at least once per 24 hrs. by verifying the average water temperature and water depth to be within their limits for each essential spray pond.

5.2.2.3.8 System Operation

During normal operation at reactor power, the SP system is in standby, aligned for possible emergency operation. The SP system operates during emergency conditions, when the diesel generator is running, and during a normal plant shutdown to support shutdown cooling decay heat removal.

During an emergency, the SP system can be started automatically by the load sequencer if the load sequencer receives a SIAS, AFAS, CSAS, LOP, CREFAS, or CRVIAS. The SP system also starts on a DG start signal, or can be started manually from either the Control Room or the switchgear room.

Cooling water is pumped from the spray ponds by the SP pumps to the DG and EW heat exchangers. The water is returned from the components being cooled to the spray ponds through the spray nozzles for reuse.

Although an emergency reactor shutdown is usually accomplished by initial operation of both SP trains, shutdown and cooldown over an extended period of time is possible and permissible by using a single train.

During long term operations, flow can be diverted periodically from the spray nozzles to flow directly into the spray pond. This reduces the amount of water consumption due to evaporation. Temperature instrumentation at the pump intake structure in each pond, with temperature set point alarms in the Control Room, inform the operator to use the spray nozzle headers and close the bypass. According to the operating procedure 40OP-9SP01(2) Essential Spray Pond (SP) Train A(B), if the temperature is less then 79° F, the bypass mode is to be used. If the temperature is greater than or equal to 79° F, the spray mode is to be used. Because the bypass mode cannot be used all of the time, only the spray mode is credited in the PRA.

During non-LOCA, non-LOP conditions the SP system is started by the ESF load sequencer when the load sequencer receives an AFAS. During LOCA conditions, the SP system can be started by the load sequencer on an AFAS, SIAS or CSAS. During a LOP, the SP system can be started by the load sequencer on an AFAS, LOP, or on a DG start signal.

5.2.2.3.9 Major Modeling Assumptions

a) Two separate fault trees were developed for the essential spray pond system; one for Train A and the other for Train B. Each fault tree provides support system logic to the respective front-line system fault trees.

b) Twenty-four hours is the mission time for the SP system. For demand failures, the exposure time is based on the test period for the component.

c) The spray pond system supports two different systems in parallel flow paths. One flow path goes to a set of coolers (jacket water cooler, lube oil cooler, governor oil cooler, and air-after coolers/heaters) associated with the diesel generator, and the other path goes through the EW heat exchangers. Both of these paths have locked open manual valves, which, if they fail to remain open, will prevent the SP system from providing flow to the DG coolers or the EW heat exchanger. Rather than generate separate SP system fault trees for each path, the manual valves associated with a branch path were included in the fault tree of the system being supported by the SP system.

d) Since the DG requires SP cooling and SP requires AC and DC power, which both require the DG, the electrical requirements of the SP system were simplified to avoid a logic loop. Only DC from the batteries was considered for start of the SP pumps while no AC power was required. Since similar AC power requirements are modeled in the EC and EW models, the models remain accurate in the cutsets.

e) No makeup is required for SP system operation unless there is a leak in the system; therefore, the domestic water system and the station reservoir are not included in the SP system model.

f) Common-cause failure of the SP pumps is included in the model.

g) CSAS, CREFAS, and CRVIAS are not included in the model as possible actuation systems in the EC, EW, and SP system models.

h) The SP system bypass mode, in which the spray pond flow is diverted from the spray nozzles to flow directly into the spray pond, was not credited in the SP system model. This decision was based on the fact that the bypass mode cannot be used all of the time.

5.2.2.3.10 System Analysis Results

Failure of both spray pond system trains is dominated by common cause failure of the SP pumps. In scenarios where one SP train has already failed due to the initiator, or one ESF equipment train has failed due to failures other than SP system failures, the dominant SP system failures are auto start failures due to load sequencer failures, maintenance unavailabilities of the SP pumps, and control circuit faults of the SP pumps.

5.2.2.4 Instrument Air System

5.2.2.4.1 System Function

The Instrument Air (IA) system provides a continuous supply of filtered, dry, and oil-free compressed air for pneumatic instrument operation and control of pneumatic actuators. Instrument air provides control air to valves such as the ADVs, TBVs, control valves on HVAC isolation dampers, and containment isolation valves.

5.2.2.4.2 System Success Criteria

The system success criteria for IA is that air is supplied to the IA header from at least one of three air compressors for at least 24 hrs.

5.2.2.4.3 System Description

The IA system, located in the Turbine Building, consists of three identical, parallel trains. Each train is composed of an intake air filter, a compressor, an aftercooler with moisture separator, and, an air receiver with interconnecting piping and valving. One air compressor train is in service during normal operation while the other two are in standby. Each compressor is designed to supply 100% of the IA requirements. The three air receivers are connected on the discharge side by a header. Two branches from the discharge header direct the IA supply through one of two 100% capacity prefilters to a duplex dryer. Next, the air passes through one of two 100% capacity afterfilters. This air is then distributed to the various control systems and buildings.

The IA system is required for normal operation and startup but is not essential for safe plant shutdown. As stated, one air compressor train is in service during normal operation while the other two are in standby. A pressure switch installed in the instrument air supply main header provides an actuation signal for the standby air compressor on low header pressure.

The Turbine Cooling Water System provides cooling for the instrument air compressor jackets, intercoolers, and after coolers. Simplified diagrams of the IA System is provided in Figure 5.2-19.

5.2.2.4.4 Major Components

The system includes three compressors, each capable of delivering 500 ft^3/min. at 125 psig. Compressor size is based upon providing 50% of instrument air requirements when the unit is shut down, i.e., when the load is largest, plus a 25% margin. One compressor therefore, is able to deliver all air requirements during normal plant operation.

Instrumentation for the IA system include pressure switches, alarms, and temperature instrumentation for the compressor-filter trains. Modeling includes instrumentation that trips the compressors, specifically: high-pressure discharge, low oil pressure, and vibration and pressure-indicating switches that start standby compressors on low-pressure signals.

5.2.2.4.5 Test and Maintenance

Unscheduled maintenance of standby compressors is considered in the model. Each train is rotated into service every eight months. No routine testing is performed on the system.

5.2.2.4.6 System Dependencies and Interfaces

Actuation

Actuation within the system consists of internal system monitoring which maintains the system pressure level above a set point.

Electric Power

Two air compressors are powered from Division 1 Non-class 480V AC power, while the third compressor is powered from Division 2. All three compressors required Non-class 1E 125V DC from distribution panel NKN-D41 to start.

Cooling Water

The compressors require turbine cooling water for cooling.

Operator Action

Operator recovery action is credited for aligning a diesel driven air compressor during events which result in a loss of the IA compressors.

5.2.2.4.7 Technical Specifications

No specific Technical Specifications exist that directly affect the Instrument Air system.

5.2.2.4.8 System Operation

One of the three compressors supplies all instrument air requirements while the other two compressors are on standby. In the event of a loss of the operating compressor or a heavy air demand, the resulting low pressure initiates the standby compressor(s) to automatically start. Automatic start occurs only on low pressure. Depending on the air demand, one or both of the standby compressors may be automatically started. Standby compressors automatically stop after running unloaded for ten minutes. To equalize wear, base load operation is alternated between compressors. Manual control of each compressor is possible from the local panel and from the Control Room.

One of the two prefilter-dryer-afterfilter trains is normally in service while the other is on standby. The dryer automatically alternates airflow through each of its two towers to permit air drying in one tower while the desiccant in the other tower is being regenerated. The filter-dryer trains are interchanged for service on a programmed basis.

Maximum demand for instrument air is expected to occur during a load rejection or a turbine trip from full load. It is estimated that about 75% of all air-operated valves in the condensate, feedwater, and steam systems will be actuated from a fully closed to a fully open position, or vice versa, in approximately 60 secs. The inventory in the air receivers meet this transient requirement.

The Instrument Air Containment Isolation Valve, IAA-UV2, closes automatically upon receipt of a containment isolation signal. Should a branch rupture inside the containment, air flow is limited to 50 ft^3/min. by orifice IAN-FO-30.

5.2.2.4.9 Major Modeling Assumptions

a) System failure is defined as the inability to maintain sufficient compressed air supply or nitrogen in the Instrument Air lines. One operating compressor is adequate to provide sufficient compressed air.

b) System boundaries for Instrument Air are defined to be from the air intake filters to the tie-in to the Turbine Building and main steam support structure.

c) The compressor train A (C01A) is assumed to be in service during normal operation. Compressor trains B and C are in the standby mode.

d) Operator action to establish a compressed air supply, in case of Instrument Air failure, is not credited within the model.

e) The Instrument Air dryer/filter train A (dryer M01A) is assumed to be in service. The train containing air dryer M01B is isolated and would require local manual operator action to bring into service. Credit for aligning air dryer M01B is not taken. It should be noted the air dryers are modeled only as flow paths. It is assumed that over the 24-hr. mission time of requiring IA, the drying function of the dryers is not critical.

f) The common-cause failure of all three instrument air compressors is split into two parts: 1) Common-cause failure of all three compressors to run 24 hrs. 2) Common-cause failure-to-start of the two standby compressors. This is done to show that two air compressors are normally in standby and one is continuously running.

g) A mission time of 24 hrs. for the normally running compressor is used in the component unavailability calculation while the standby compressors are assumed to have a testing period of eight months. This is based on rotation of compressors B and C per operating procedure 41OP-1IA01 Instrument Air system.

h) Failure to restore after maintenance is considered in respect to the inlet and outlet air receiver isolation valves for compressors B and C.

i) Spurious opening of any one of the six pressure relief valves in the system is assumed to fail IA.

j) Instrument Air is assumed failed during either a loss of turbine cooling water, a loss of plant cooling water or a LOOP initiating event.

5.2.2.4.10 System Analysis Results

Total malfunction of the Instrument Air System following a reactor trip is dominated by several failures, including both electrical and mechanical. Electrical failures include the failure of power of both Non-class AC divisions due to bus failures, fast-bus transfer (failure to switch to off-site power), and failure of Non-class DC power Control Center NKN-M41. Local faults of the air dryer, and common-cause failure of all three air compressors to run 24 hrs. Also in the cutsets are several sequences where Train B compressor is unavailable due to maintenance and both A and C compressors fail on electrical failure of Train A non-class power.

5.2.2.5 ESF Switchgear "DC Equipment" Room HVAC

5.2.2.5.1 System Function

The major function of the Engineered Safety Features Switchgear Room Heating, Ventilating, and Air-conditioning (ESF switchgear room HVAC) system is to provide room cooling to the 100-ft. elevation of the control building. The rooms include the ESF switchgear, DC equipment, and battery rooms. Based upon detailed evaluations, modeling of only the DC equipment rooms was deemed necessary. The other areas are not as greatly impacted as the DC equipment rooms are on a loss of HVAC.

5.2.2.5.2 System Success Criteria

The success criterion for ESF switchgear room normal and essential HVAC is to provide sufficient cooling to the class DC equipment rooms so that room temperature can be maintained below 122° F. Failure of equipment in the Channel A and C DC equipment rooms is a result of losing both the normal HVAC and the Division 1 essential train of HVAC. Failure of equipment in Channel B and D DC equipment rooms is the result of losing both the normal HVAC and Division 2 essential train of HVAC.

This success criterion is based on evaluations conducted on losing HVAC in a particular room with the subsequent failing of the room equipment. The decision to model HVAC in an area was determined by what effect the failed equipment would have on the plant and whether room heat-up would cause equipment failures. From these evaluations, HVAC modeling was developed for the safety system pump rooms, the class DC equipment rooms, and the Control Room.

5.2.2.5.3 System Description

The ESF electrical distribution is separated into two divisions, each containing a switchgear room, two Class 1E battery rooms, and two DC equipment rooms. The major components in the switchgear rooms are the Class 1E 4.16kV buses, three ESF switchgear 480V. AC load centers, and one motor control center. The battery rooms each contain one of the four Class 1E battery banks. The DC equipment rooms contain class battery chargers, the Class 120V AC inverters and voltage regulators, the 125V DC distribution panels and control centers, and some of the non-class 120V AC voltage regulators.

The "normal" HVAC systems service both switchgear room divisions while separate "essential" HVAC systems are provided for each of the divisions.

During normal plant operation and shutdown, the 100-ft. elevation of the Control Building is serviced by two normally running air-handling units (AHUs), HJN-A03 and HJN-A01. Normal ESF switchgear room AHU HJN-A03 handles most of the heat load and is assisted by normal Control Building AHU HJN-A01 in maintaining all ESF switchgear, DC equipment, and battery rooms within the required temperature limits. The simplified diagram of the ESF switchgear room HVAC is provided in Figure 5.2-21.

In case of a SIAS or LOOP, the ESF switchgear area will be isolated from the normal AHUs by closing air-operated HVAC dampers. The normal AHU HJN-A01 is tripped off, while HJN-A03 will either continue to run or be shed upon loss of its power and the area is then served by one or both essential HVAC systems: ESF switchgear room HVAC Divisions 1 and 2. The Division 1 main switchgear room and the Channel A and C DC equipment rooms and class battery rooms are cooled by Division 1 essential HVAC. The Division 2 main switchgear room and the Channel B and D DC equipment rooms and class battery rooms are cooled by Division 2 essential HVAC. Each division contains two essential ACUs, HJx-Z03 and HJx-Z04 (x = A or B), which are started automatically. The ACUs have independent flowpaths and somewhat different functions. The Z03 ACU provides intake and exhaust air to the ESF switchgear and battery rooms and draws return air from the DC equipment rooms for its respective division. The Z04 ACU supplies only the respective train's DC equipment rooms.

The HVAC system contains several types of dampers. These include fire dampers, backdraft dampers, and air operated isolation dampers. Fire control dampers, which when dropped, isolate the rooms from each other and from the AHUs servicing the room, are dropped by either the Fire Protection (FP) system (CO_2 portion) or by room temperature. Backdraft dampers control flows through the air ductwork, while air-operated dampers isolate the normal AHUs and unisolate the essential ACUs during emergency operation.

5.2.2.5.4 Major Components

ESF switchgear room normal AHU HJN-A03 is comprised of a cooling coil and centrifugal fan with an electric motor which has a capacity of 18,000 CFM and a rating of 600,000 BTU/hr. The AHU is designed to deliver sufficient conditioned air, in conjunction with HJN-A01, to maintain room temperatures between 60° F and 77°F. The unit is powered by non-class 480V AC and is located on the 74-ft. elevation in the Control Building. Chilled water is supplied by the Normal Chilled Water (WC) System. Indication is provided in the Control Room and locally.

Control Building normal AHU HJN-A01 is also a cooling coil and centrifugal fan with an electric motor which has a capacity of 27,000 CFM and a rating of 1,271,504 BTU/hr. It is located in the same area as A03 and has the same design requirements. The unit is powered by non-class 480V AC and the Normal Chilled Water System supplies the unit with chilled water. Indication is provided in the Control Room and locally.

The ESF switchgear room essential ACUs HJA-Z03 and HJB-Z03 are designed to provide conditioned air during essential operation to maintain room temperatures between 40° F and 104° F in the ESF switchgear, DC equipment, remote shutdown, and battery rooms. The ACUs are comprised of a coil cooling and centrifugal fan with an electric motor which have a capacity of 3900 CFM and are rated for 180,000 BTU/hr. The ACUs are 100% capacity units, where each unit is sized for the heat load of the rooms associated with the same train as the unit. Each unit receives power from separate Class 1E 480V AC power trains. The ACUs are located in the air handling equipment rooms at the 74-ft. elevation in the Control Building.

The DC equipment room essential ACUs HJA-Z04 and HJB-Z04 help the ESF switchgear room essential ACUs provide adequate conditioned air during essential operations. The ACUs are comprised of a coil cooling and centrifugal fan with an electric motor which have a capacity of 5000 CFM and a rating of 265,000 BTU/hr. Air is drawn from the ESF switchgear room and is directed into the DC equipment rooms associated with the same train as the unit. Each unit receives power from separate Class 1E 480V AC power trains. The ACUs are located on the 100-ft. elevation in the ESF switchgear rooms.

The HVAC system also contains fire dampers, which isolate the rooms from air flow during a fire. The fire dampers are interlocking blade, accordion-type, fusible-link dampers. These normally open dampers are either dropped by high room temperature or by the FP system. The room temperature controlled dampers drop when the room temperature reaches the melting point of the fusible links. The dampers actuated by the FP system are dropped when a control signal is generated and an electric current is sent out that melts the fusible links. The FP system uses a solid state-logic system to monitor the presence of heat or smoke via thermocouples and smoke detectors. The logic system consists of a master module, which interprets data received from each of the divisions solid-state logic modules. The divisions solid-state logic module samples each of the detectors and transmits a status signal to the master module. The master module processes the signals and determines what action should be taken, i.e., detector failure alarm, fire alarm, etc. Once the master module has determined the presence of fire, it transmits a drop signal out to the dampers. This isolates the rooms from any outside sources of air and to all of the AHUs.

Counter-weight backdraft dampers are used to prevent the air flow from returning to the AHU before passing through the rooms.

In support of the automatic actuation of the essential ACUs, air-operated dampers isolate the normal AHUs from the system. These isolation dampers are controlled by class-powered solenoid valves. On a loss of power or a loss of instrument air, the isolation dampers on the normal exhaust and intake lines fail close and the dampers on the essential lines fail open.

5.2.2.5.5 Testing and Maintenance

Unscheduled maintenance is considered for AHUs, dampers, and the WC isolation valve. Before performing maintenance on the normal HVAC system, the normal practice is to start-up the essential HVAC.

Testing is performed on the essential ACUs, the isolation dampers, and the fire dampers which are a part of the FP CO_2 system. Fire dampers and back draft dampers are not tested; however, they are verified operational on a periodic basis.

5.2.2.5.6 System Dependencies and Interfaces

Actuation

In the event of a LOOP or a SIAS, normal AHUs are shed or isolated and essential ACUs are started. Actuation signals also realign the duct ways by opening or closing isolation dampers.

In case of fire, the FP system will isolate the affected room by transmitting a drop signal to the fire dampers.

Electrical Power
The ESF switchgear HVAC depends on both the class and the non-class power systems. The normal AHUs require 480V AC non-class power to start and run. The essential ACUs require 480V AC Class power to start and run. Class 1E 125V DC power is required for the isolation damper solenoids for both the normal AHUs and essential ACUs. In the case of losing Channel A DC power, normal HVAC is isolated via the isolation dampers. A loss of class DC power does not fail the essential HVAC system's ability to cool the rooms. A loss of the non-class 125V DC fails normal chill water to the normal AHUs.

Cooling (Chilled) Water
The normal AHUs require chilled water from the WC System and essential ACUs require chilled water from the EC system.

Instrument Air
Motive force for the system's isolation dampers comes from instrument air. Instrument air is also needed to maintain the open position of the isolation valve in the normal chilled water supply to the normal HVAC AHUs. A loss of instrument air fails the normal HVAC, but does not fail the essential HVAC's ability to provide cooling.

Operator Action
Operator interfacing consists of several actions. They are:

- Operator action to indicate essential HVAC when normal HVAC fails due to a non-SIAS/LOOP initiator
- Operator action to unisolate normal HVAC including WC when essential HVAC fails after a SIAS or LOOP signal has been received
- Operator action to provide temporary backup cooling to the DC equipment room when FP spuriously actuates. Actions include opening doors and setting up portable fans.

These actions are described in Section 7.4.

5.2.2.5.7 Technical Specifications
None apply to the ESF switchgear room HVAC system.

5.2.2.5.8 System Operation
During normal plant operation, the temperature in the ESF switchgear area is maintained between 60° F and 77° F by the normal ESF switchgear and normal control building AHUs. The same distribution ductwork is shared by the essential ACUs and the normal ESF switchgear AHUs. The essential units are isolated during normal operation by low-leakage dampers and backdraft dampers. The normal ESF switchgear AHUs run continuously. Operation of the AHUs is automatic and controlled by room thermostats. Control Room indication upon the loss of the normal HVAC occurs when the AHU motor experiences an overload or the DC equipment room temperature reaches a specified setpoint.

Receipt of a SIAS will actuate both divisions of the essential ESF switchgear room ACUs. Simultaneously, the normal Control Building AHU will automatically stop and isolation dampers will close to isolate the ESF switchgear area from the normal HVAC AHUs.

Upon a LOOP occurrence, the following happens:

- If a single electrical division is lost, the appropriate division of the essential ESF switchgear room ACUs is started. The normal AHU A03 will be isolated by the isolation dampers for that train and isolate the ESF switchgear area from the normal HVAC AHU.
- If total, the system's response is like that of the SIAS actuation.

5.2.2.5.9 Major Modeling Assumptions

a) Two fault trees were created for the ESF switchgear room HVAC, one for Division 1 and one for Division 2.

b) The model does not credit the availability of the normal Control Building AHU, HJN-A01.

c) It is assumed that the normal AHU (HJN-A03) is operating at the time the initiating event occurs whereupon a demand for the essential ACU could be made. Essential HVAC ACU mission time is assumed to be 24 hrs. even though failure of all HVAC after approximately 16 hrs. into an event would still allow the DC equipment rooms to reach 24 hrs. without experiencing high temperature problems.

d) The most temperature sensitive equipment in the DC equipment rooms are "qualified" to operate at temperatures of 104° F. The failure temperature of this equipment is assumed to occur at 122° F based on investigated results. For ease in modeling, it was assumed that all solid state equipment fails at 122° F.

e) The loss of chilled water to the AHU, whether normal or essential, fails the HVAC system, even though with fans running it would take approximately 24 hrs. before the room temperature would reach 122° F.

f) It is assumed that the dropping of one damper fails the delivery of air from that respective AHU and that room cooling ceases, even though other secondary paths exist through which cooling air could flow.

g) Mission times for dampers are assumed to be 24 hrs. Additional standby exposure time was added to dampers that lack Control Room indication to reflect the possibility that the closed damper goes undetected before plant trip.

h) Cooling to the ESF switchgear area can be lost for different lengths of time before loss of equipment occurs based upon the condition the plant is in at the time of loss and what room in the area is being evaluated. Operators have much more time for recovering HVAC to the area during normal operation than during a post-accident condition. Even during post-accident conditions the time before equipment failure can be as little as 45 mins. during a LOCA to as much as 12 hrs. during a LOOP. These time lengths are also dependent on the types of failures within the HVAC system. Dampers, spuriously dropping, causing a loss of air flow, have a greater impact than does a loss of the chilled water system which causes a loss of the AHU cooling capability. As a result of the complexities in dealing with these various scenarios, simplifications during the modeling were made. The room heatup curve used was the Channel B DC equipment room. Upon loss of HVAC to this room, 12 hrs. are available before equipment begins to fail.

i) Common cause failure of Division 1 and 2 essential ACUs was modeled.

j) Human actions as identified in Section 5.2.2.5.6 were based on the timing identified in the above assumption. See Section 7.4.

5.2.2.5.10 System Analysis Results

The major system failure for failure of ESF switchgear room HVAC is the loss of the normal HVAC (A03 only) system (loss of WC to the AHU) coupled with the failure to start the essential HVAC upon loss of normal HVAC. Other contributors to the loss of the HVAC are spurious actuation of the FP system causing loss of both the normal and the essential HVAC systems and electrical failures.

5.2.2.6 Control Room HVAC

5.2.2.6.1 System Function

Control Room heating, ventilating and air-conditioning (Control Room HVAC) system provides cooling to the 140-ft. elevation of the Control Building. At the 140-ft. level is the Control Room, the control instrumentation cabinets, the computer room and various office spaces.

5.2.2.6.2 System Success Criteria

The success criterion for the Control Room normal and essential HVAC is to provide sufficient cooling to the Control Room, so that a room temperature below 120° F can be maintained. This success criterion is based on losing HVAC in the Control Room with subsequent failing of the load sequencers. In a loss of Control Room HVAC the largest impact to the plant is a failure of the load sequencer in a continuous load shed mode. This sheds all vital and non-vital loads which are on the class 4.16kV AC buses prior to loading the DGs. The signal must clear before loads can be added back on to the bus once the DGs are connected to the bus. Success criterion is met by either the normal HVAC system supplying the conditioned air or on the loss of normal by one of the two essential HVAC system AHUs providing cooling.

5.2.2.6.3 System Descriptions

The Control Room HVAC consists of a normally running system and a two-train essential system. During normal plant operation and shutdown, the 140-ft. elevation of the Control Building is serviced by one normally running air-handling unit (AHU HJN-A02.) Room cooling is maintained at or below 80° F. The simplified diagram of the Control Room HVAC is provided in Figure 5.2-22.

In the case of a SIAS, CRVIAS, CREFAS or LOOP, the Control Room area will be isolated from the normal AHU by the closure of air-operated HVAC dampers. Both of the essential AHUs will be started on a SIAS, CRVIAS or CREFAS. A LOOP signal will start one or both trains depending on the location of the LOOP. The system contains several types of dampers. These include fire dampers, backdraft dampers, and air-operated isolation dampers. Fire dampers are dropped by room temperature. Backdraft dampers control flows through the air ductwork. The air-operated dampers isolate outside air to the control room and unisolate the essential AHUs during emergency operation.

5.2.2.6.4 Major Components

Control Room normal AHU HJN-A02 is comprised of a cooling coil and a electric motor-driven fan. The AHU is designed to deliver sufficient conditioned air to maintain room temperatures below 80° F. The unit is powered by non-class 480V AC and is located on the 74-ft. elevation in the Control Building. Chilled water is supplied by the Normal Chilled Water (WC) System. Indication is provided in the Control Room and locally.

The Control Room essential AHUs HJA-F04 and HJB-F04 are designed to provide conditioned air during emergency operation to maintain room temperatures below 80° F. The AHUs consist of a cooling coiling and a two-stage direct-drive, manually adjustable-pitch vane-axial fan. The AHUs are 100% capacity units. Each unit receives power from separate Class 1E 480V AC power trains. The AHUs are located on the 74-ft. elevation in the Control Building. Chilled water is supplied by the Essential Chilled Water (EC) System.

The fire dampers are interlocking blade, accordion-type fusible-link dampers. These normally open dampers are dropped by high room temperature.

The counter-weight backdraft dampers prevent air flow from returning to the AHU before passing through the rooms.

In support of the automatic actuation of the essential AHUs, air-operated dampers isolate the normal AHU from the system. Isolation also ensures Control Room habitability. The isolation dampers are controlled by class-powered solenoid valves. On a loss of power or instrument air, the isolation dampers on the normal exhaust and intake lines fail closed and the dampers on the essential line fail open.

5.2.2.6.5 Testing and Maintenance

Unscheduled maintenance is considered for AHUs, dampers and the WC isolation valve. Before performing maintenance on the normal HVAC system the normal practice is to start the essential HVAC.

Testing is performed on the essential AHUs and the isolation dampers. Fire dampers and backdraft dampers are not tested; however, they are verified operational on a periodic basis.

5.2.2.6.6 System Dependencies and Interfaces

Actuation

Control Room HVAC interfaces with portions of ESFAS via CREFAS, CRVIAS and SIAS signals. These signals cause the isolation dampers to close, thus isolating the Control Room from outside air sources and starts the essential AHUs. Essential AHUs are also started on LOOP signals.

Electrical Power

The Control Room HVAC depends upon both class and non-class power systems. The normal AHU requires 480V AC non-class power to start and to run. Class 1E 480V AC is the power source to start and to run the essential AHUs. Class 1E 125V DC power is required to change the state of all the isolation damper solenoid valves.

Cooling (Chilled) Water

The normal AHU requires chilled water from the WC System and the essential AHUs require chilled water from the EC system.

Instrument Air

Motive force for the system's isolation dampers comes from instrument air. Upon failure of instrument air, isolation dampers of the essential AHUs fail open, and isolation dampers of the normal AHUs fail close. IA is also needed to operate and keep open the isolation valve in the WC System which services the normal AHU.

Operator Action

Operator interfacing consists of several actions. They are:

- Operator action to initiate essential HVAC when normal HVAC fails due to a non-SIAS/LOOP initiator
- Operator action to unisolate normal HVAC including WC when essential HVAC fails after a SIAS or LOOP signal has been received.

These actions are described in Section 7.4.

5.2.2.6.7 Technical Specifications

PVNGS Technical Specification 3/4.7.14 states that the Control Room temperature is not to exceed 80° F. Should it exceed 80° F, reduce the temperature below 80° F within 30 days.

5.2.2.6.8 System Operation

During normal plant operation, the Control Room temperature is maintained below 80° F by the normal Control Room AHU. The essential units are isolated during normal operation by zero-leakage dampers and backdraft dampers. The normal Control Room AHU runs continuously. Operation of the AHU is automatic and is controlled by room thermostats. Control Room indication upon a loss of normal HVAC occurs when the unit experiences an overload or a high differential pressure. The room is maintained at a positive one-quarter in. H_2O above ambient.

Upon receipt of a SIAS, CREFAS or CRVIAS, the Control Room is isolated from the normal AHU system. Both trains of essential HVAC are actuated. Simultaneously, the isolation dampers will close to isolate the Control Room area. The positive air pressure of one-quarter in. H_2O above ambient is maintained. Upon the occurrence of a LOOP, the following occurs:

- If a single electrical division is lost, the appropriate division of the essential control room AHU is started. The isolation dampers for that train will close and isolate the Control Room from the normal HVAC AHU.
- If total, the system's response is like that of the SIAS, CREFAS or CRVIAS actuation.

5.2.2.6.9 Major Modeling Assumptions

a) It is assumed that the normal AHU is operating at the time the initiating event occurs, whereupon a demand for the essential AHUs could be made. Essential HVAC AHU mission time is assumed to be 24 hrs. even though failure of all HVAC after approximately 16 hrs. into an event would still allow the control room to reach 24 hrs. without experiencing high temperature problems.

b) The equipment of concern (the load sequencers) is qualified to operate up to temperatures of 120° F. For ease in modeling, it is assumed that the equipment fails at 120° F.

c) It is assumed that the dropping of one damper fails the delivery of air from that respective AHU and that room cooling ceases, even though other secondary paths exist through which cooling air could flow.

d) Failure of auto-actuation of essential Control Room AHUs (via SIAS, CREFAS, CRVIAS) is neglected due to high probability the HVAC will be manually started by operators before the Control Room reaches 120° F.

e) Only flow paths within the Control Room are modeled in the tree.

f) Common-cause failure of the essential AHUs is modeled.

g) Human actions as identified in Section 5.2.2.6.6 are based on calculated heatup curve which show that the Control Room will reach a temperature of 120° F in approximately 15 hrs. As a conservative estimate 12 hrs. for operator actions is used. See Section 7.4.

5.2.2.6.10 System Analysis Results

Dominant failures in the Control Room HVAC fault tree are dampers dropping and going undetected, or dampers that fail to operate upon demand. Additional failures are normal HVAC failure due to the WC isolation valve failing and the operator fails to initiate essential HVAC. Less prominent failures are those associated with loss of power to various components.

5.2.2.7 Normal Chilled Water System

5.2.2.7.1 System Function

The Normal Chilled Water (WC) system supplies chilled water at 45° F to the normal heating, ventilation, and air-conditioning (HVAC) systems for the Control Room, ESF Switchgear rooms, the Auxiliary Building ESF pump rooms, and other areas not modelled in the PRA.

It also supplies chilled water to non-nuclear process sample coolers and the collector housing on the unit's electric generator.

5.2.2.7.2 System Success Criteria

The success criterion for WC is that two of the four chillers and chilled water pumps function to provide chilled water flow to those Air Handling Units (AHUs) modelled in the PRA (listed above) for at least 24 hrs.

5.2.2.7.3 System Description

The WC system is a non-class system normally operating during power operation. The system consists of four chiller units, each with a chilled water circulating pump feeding a common header. Chilled water is distributed to AHUs associated with environmental control for the Control Room, the ESF Switchgear rooms, other areas of the Control Building, Auxiliary Building (including the bottom level of the Main Steam Support Structure (MSSS), where the Auxiliary Feedwater (AF) pumps are located), the Radwaste Control Room, and the Containment Building.

Post-transient or accident, the system can maintain acceptable environmental conditions for equipment in the ESF Switchgear rooms and the Control Room, and is credited in this analysis. It is also credited for reducing the failure probability of ESF pumps (AF, HPSI, LPSI) due to extreme environmental conditions should the Essential room coolers for those pump rooms fail.

Normal HVAC, including the WC system, is credited in situations where off-site power is available and a Safety Injection Actuation Signal (SIAS) has not occurred. SIAS isolates normal HVAC for the ESF pump rooms, the Control Room and the ESF switchgear rooms, and starts the essential HVAC systems.

5.2.2.7.4 Major Components

Three of the chillers (WCN-E01A, -E01B and -E01C are 800-ton refrigeration units, approximately 50% capacity each, and the fourth (WCN-E02) is a 213-ton unit, approximately 10% capacity. Two large units are most always adequate to supply sufficient cooling.

The chillers are self-contained, package-refrigeration-type chillers with centrifugal compressors. The chillers require 4.16kV AC power. The chiller unit consists of a compressor, evaporator, refrigerant, condenser/receiver unit, controls, and instrumentation. The condenser is cooled by the NC system as is the chiller oil lubrication system cooler. The WC pumps are centrifugal 50 hp, 1200 gpm for the larger units and 20 hp, 320 gpm for the small unit, requiring 480V AC power.

To provide cooling to other than essential spaces following a Loss Of Off-site Power (LOOP), chiller E01A is powered from Train A Class electrical power. Its circulating water pump is fed from a non-class MCC, which is supplied from a Class 1E load center. However, these and other non-class loads on the Class electrical supplies are shed by a SIAS, whether accompanied by LOOP or not.

The WC system expansion tank is a vertical-cylindrical tank with a capacity of 276 gallons. A low-pressure nitrogen blanket is maintained to exclude oxygen and to control pressure. The expansion tank automatically accommodates contraction and expansion of the WC fluid due to cooldown or heat-up. Level makeup is provided by the Demineralized Water system.

The WC pumps, chillers, expansion tank, and chemical addition tank are located on the Auxiliary Building roof.

The WC system includes instrumentation for monitoring pressure, temperature, level, and flow. Instrumentation includes both local and Control Room indication, and Control Room alarms.

The main chilled water line at the discharge of each WC pump has local pressure indication.

The expansion tank has local pressure indication, and high and low pressure alarms that alert the Control Room. The expansion tank also has instrumentation for level control, and high and low level alarms that alert the Control Room.

The AHUs have pressure safety valves to relieve thermal expansion when the units are isolated.

The main chilled water supply line, downstream from the chiller, has temperature instrumentation that provides indication and a high temperature alarm in the control room.

5.2.2.7.5 Testing and Maintenance.

Testing and preventative maintenance that would disrupt normal system operation is performed during plant outage periods. Corrective maintenance on chillers and pumps can be done on line without disrupting normal system operation, since only two chillers are typically required to be in operation at any given time.

Two chiller units are assumed to be in operation at the time of a transient or accident initiating event. Therefore, unscheduled corrective maintenance for the other two WC chillers and pumps, which may be called upon to start if one of the running chillers fails, is included in the WC system fault tree.

5.2.2.7.6 System Dependencies and Interfaces

Actuation

The WC system is normally operating during plant operation, and continues to operate following a transient, except for a LOOP condition or after a SIAS occurs. Upon a LOOP, a load shed signal from BOP ESFAS strips the ESF buses from which Normal Chiller E01A is powered. The sequencer does not restart it. However, it can be restarted by the operator. Upon an SIAS, a separate load shed action is done directly by the NSSS ESFAS to disconnect all non-safety-related loads from the Class Electrical systems, including Normal Chiller E01A and MCC NHN-M19, from which chilled water pump P01A is powered.

Electric Power

Normal Chiller E01A receives motive power from Train A Class 1E 4.16kV AC ESF bus, PBA-S03. Normal Chiller E01B receives power from non-class 4.16kV bus NBN-S01, and Normal Chillers E01C and E02 receive power from non-class 4.16kV bus NBN-S02. The chilled water pump for chiller E01A, WCN-P01A, receives motive power from the non-class 1E 480V MCC NHN-M19, which receives power from Class 1E load center PGA-L35. Control power for starting E01A is from Channel A Class 1E 125V DC distribution panel PKA-D21. Chilled water pump P01B receives power from non-class MCC NHN-M25. Chilled water pumps P01C and P02 receive power from non-class MCC NHN-M26. Control power for starting the E01B chiller is provided by the non-class 1E 125V DC panel NKN-D41, while NKN-D42 starts E01C and E02. The condenser outlet valve (for NC) on each chiller is powered from the same MCC as the associated chilled water pump.

Nuclear Cooling Water

Each chiller requires NC for heat rejection from the chiller condenser. No modulation of NC flow is required. The condenser outlet valve on the NC side opens when the chiller is started and closes when it is stopped. A flow switch for NC through the condenser furnishes an interlock for compressor operation. Nuclear Cooling water flow to a chiller can fail if either the manual valve on the inlet side of the condenser, or the motor-operated valve on the outlet side of the condenser fails to open or remain open.

Instrument Air

Instrument Air (IA) is required to operate the temperature control valves on each AHU served by WC. It is also necessary to maintain open isolation valves and dampers. These are modelled in the various HVAC system fault trees.

5.2.2.7.7 Technical Specifications

There are no PVNGS Technical Specifications applicable to the Normal Chilled Water system.

5.2.2.7.8 System Operation

During normal plant operation, the WC system is in operation. Room temperatures are automatically controlled by throttle/bypass valves on the chilled water supply to each AHU. Normally, two of the large chillers are running, with the other two off, but available. To stop or start a chiller unit only requires the operator to turn a single switch. Turning a switch to ON starts the associated chilled water pump, opens the NC outlet valve to establish flow through the condenser, and starts a timing sequence in the chiller controller. This ends with the compressor starting once all permissives, including chilled water flow through the evaporator and NC flow through the condenser, are satisfied. Turning a control switch to OFF shuts down the compressor, turns off the chilled water pump and closes the condenser NC outlet valve.

5.2.2.7.9 Major Modeling Assumptions

a) Two chiller units are assumed operating at the time of an accident or transient initiator.

b) Two chillers are assumed adequate to handle the heat loads. Therefore, it takes three of the four chillers to fail WC.

c) The WC system requires the NC system for cooling, which in turn depends upon the Plant Cooling Water (PW) system. Neither of these systems is modeled in detail. However, LOOP and initiating events that fail NC or PW are included in the WC fault tree and will fail it also.

d) Local failure of the NC system flow permissive and the WC flow permissives are modeled in the WC system fault tree, because failure of a flow permissive will fail the associated chiller.

e) Neither the Demineralized Water nor the nitrogen systems are required by the WC model since they are not required for normal system operation. Failure of these systems does not fail WC over the 24 hr. mission time.

f) Common-cause failure of the chillers and pumps is included in the WC system fault tree.

g) Operator action to restart a chiller that has stopped for any reason is not credited in the analysis. (Operator action to start normal HVAC upon failure of Essential HVAC, including two normal chillers that were not previously running, is credited).

5.2.2.7.10 System Analysis Results

External failures dominate failure of the WC system, principally, loss of non-class power due to LOOP or fast bus transfer failures. Chiller E01A, because of its class power supply, is affected by SIAS and LOOP due to automatic load shedding actions by the ESFAS. Internal WC system failures are dominated by common cause failure of the chillers and common cause failure of the pumps.

5.2.2.8 Class 1E 4.16kV AC Power System (PB)

5.2.2.8.1 System Function

The Class 1E 4.16kV power system provides reliable AC power to two divisions of safety-related loads from the preferred off-site power source or the standby diesel generators. The load groups include Class 1E motors for Emergency Core Cooling System pumps, Auxiliary Feedwater pumps, support systems, and three load centers, which supply power to smaller loads.

5.2.2.8.2 System Success Criteria

The system must transfer 4.16kV power from either an off-site or Emergency DG supply to each load it feeds.

5.2.2.8.3 System Description

The PB system is shown in Figure 5.2-23. PB consists of two separate, redundant and independent class 1E 4.16kV buses. PBA-S03 and PBB-S04. These buses are powered from off-site power through the non-class 1E 13.8kV (NA) and 4.16kV (NB) systems via the ESF Service Transformers, NBN-X03 and NBN-X04, respectively. Sections 5.2.2.14 and 5.2.2.15 discuss these systems. (Figure 5.2-26 and 5.2-27 show the off-site power supplies to the ESF buses, including the normal supply breaker alignments.) If either ESF Service transformer is unavailable, the bus normally fed by that transformer may be supplied from the alternate transformer through its alternate off-site power supply breaker. However, this operator action is not credited in the analysis. Each bus is also automatically supplied standby power (PE) from its respective diesel generator, PEA-G01 or PEB-G02, in the event off-site power is not available. No breaker operation is necessary to maintain off-site power to the ESF buses upon a unit trip.

5.2.2.8.4 Major Components

4.16kV switchgear buses PBA-S03 and PBB-S04 are enclosed, indoor, metal-clad type with DC electrically-operated, draw-out circuit breakers. Each of the two redundant buses is located in separate rooms on the 100-ft. (grade) elevation of the Seismic Category I Control Building. Each bus is provided with electrical protection including bus undervoltage and negative sequence relays, motor feeder ground fault and phase overcurrent relays, and bus feeder phase and neutral residual overcurrent relays. Control indication and controls include bus voltage and current, breaker position and control, synchronization meter and various system trouble alarms. Electrical protection reset capability is also provided.

Separate and distinct from the normal Control Room annunciators is a two train, Class 1E alarm system called the Safety Equipment Status System (SESS). Individual safety-related components (pumps, valves, AHUs, etc.) have dedicated alarm windows. Each window has two alarms associated with it. One is a Safety Equipment Inoperable Status (SEIS), which alarms on such conditions as loss of motive power or loss of control power. The second alarm is a Safety Equipment Actuation Status (SEAS), which alarms if a component does not reach the state called for by an actuation signal. The operators give high priority to SEIS alarms during plant operation, and following a trip, the primary operator evaluates any

SESS alarms by the Critical Safety Functions flowchart in the Emergency Procedure.

The standby emergency diesel generators are discussed in Section 5.2.2.9.

5.2.2.8.5 Testing and Maintenance

Scheduled tests and maintenance involving bus de-energization are only done during plant cold shutdown/refueling. Corrective maintenance during power operation is possible and allowed for up to 72 hrs. by PVNGS Technical Specifications. Surveillance for proper breaker alignment and voltage is performed at least once per 7 days.

5.2.2.8.6 System Dependencies and Interfaces

Power Supply and Breaker Control

The Class 1E 4.16kV switchgear buses require Class 1E 125V DC Power system (PK) for switchgear control.

Upon loss of DC power, breakers fail as-is. Off-site power is supplied through one of two ESF service transformers, part of the non-class 4.16kV system (NB). These transformers are fed from 13.8kV buses NAN-S03 and NAN-S04 (NA). Should off-site power not be available from the normal supply, power is supplied from the standby emergency diesel generator (PE).

Loads

Class 1E 4.16kV loads supplied by the PB system include the Auxiliary Feedwater (AF) (Train B only), Essential Spray Pond (SP), Containment Spray (CS), High and Low Pressure Safety Injection (HPSI and LPSI) and Essential Cooling Water, (EW) pumps, and the Essential Chiller (EC). Each bus supplies power to three Class 1E load centers (PG), which step the voltage down to 480V AC for smaller loads. In addition, the Division 1, or Train A, bus supplies the non-essential auxiliary feedwater pump and normal chiller A (WC). These two non-class loads are automatically shed by a Safety Injection Actuation Signal (SIAS) and are not reloaded automatically. Figure 5.2-23 lists loads on each ESF bus.

Actuation

During an accident situation i.e., one demanding a Safety Injection Actuation Signal (SIAS), automatic sequencing of loads is provided by the BOP (Balance of Plant) ESF Actuation System (ESFAS) to assure that quality of the 4.16kV power supply is maintained.

Upon loss of or degrading power to either bus, the respective bus undervoltage relays (two out of four logic), through the BOP ESFAS system, initiate tripping of normal and alternate off-site power supply breakers and DG output breaker, standby diesel generator start, bus load shed, closure of DG output breaker, and load sequencing. An interlock exists to prevent closing the alternate off-site power supply breaker when the diesel generator breaker is closed or vice-versa. This prevents paralleling the two ESF buses to maintain their independence and prevent overloading a diesel generator. The actuation is train-specific; that is, loss of power to Train A ESF bus only results in Train A actuations. Section 5.2.2.21 describes the BOP ESFAS system in greater detail.

HVAC

The PB system is indirectly dependent upon Control Room HVAC. If Control Room HVAC is lost, the BOP ESFAS cabinets heat up and a spurious (and continuously applied) load shed signal can be generated. Alternatively, failure of cooling fans in either BOP ESFAS cabinet can lead to the same consequences through overheating of the electronics. Operator action to terminate the load shed signal and reload the bus is included in the fault trees. Refer to Section 5.2.2.6, Control Room HVAC) for a more thorough discussion.

HVAC analysis indicates that the 4.16kV buses and breakers do not require room cooling for the 24-hr. mission time.

5.2.2.8.7 Technical Specifications

PVNGS Technical Specification 3.8.1.1 requires, as a minimum, the following operable AC electrical power sources: two physically independent circuits from the off-site transmission network to the switchyard, two physically independent circuits from the switchyard to the on-site Class 1E distribution system, and two separate and independent diesel generators. The action statement is complex, requiring verification of remaining sources through periodic surveillance testing should one tank be inoperable and differing allowed outage times depending upon what and how many power sources are inoperable. If a diesel generator is inoperable for any reason other than planned preventive maintenance, the other train's DG is required to be tested periodically. Following allowed outage times, Hot-Standby (Mode 3) is required within 6 hrs. and Cold Shutdown (Mode 5) within the following 30 hrs.

PVNGS Technical Specification 3.8.3.1 specifies onsite (in plant) power distribution alignment. Both ESF buses are required to be energized and not cross-tied during Modes 1 through 4. A bus must be re-energized within 8 hrs., or the unit must shutdown to Mode 3 within the following 6 hrs. and Mode 5 within the following 30 hrs.

5.2.2.8.8 System Operation

During normal plant operations, PB is supplied power by its associated ESF service transformer through breakers PBA-S03L (Train A) and PBB-S04K (Train B), and distributes power to its connected loads. Normal breaker operation to activate certain loads or parallel power supplies is done remotely from the Control Room. Local operation, either electrically or mechanically is also possible, except those requiring synchronization. Breaker operation is not normally required during plant operation, except during surveillance testing of various ESF systems.

On degraded or loss of power to a 4.16kV Class 1E bus, operation of bus undervoltage relays initiates a signal in the BOP ESFAS to effect the following for that load group:

- Trip all load breakers except load center (LC) 4.16kV supply breakers

- Trip the bus supply breakers, both normal and alternate, from the ESF service transformers
- Start the standby diesel generators
- Set up the load sequencing system.

When the diesel generator is ready to load, the generator output breaker (PBA-S03B, Train A or PBB-S04B, Train B) is automatically closed, and the load sequencing system automatically applies load in incremental steps. When off-site power is restored, the bus is manually transferred back to it.

The load sequencing also occurs as a result of other actuation signals: SIAS/CSAS, AFAS, CREFAS (Safety Injection/Containment Spray, Auxiliary Feedwater, Control Room Essential Filtration Actuation Signals). No load shed signal goes out. The DG is started, but not loaded, on SIAS/CSAS and AFAS. Actuations and load sequencing is described in Section 5.2.2.21.

5.2.2.8.9 Major Modeling Assumptions and Dependencies

a) Two fault trees are used, one for Train A, PBA-S03, and one for Train B, PBB-S04

b) The alternate off-site power supply requires operator action, which is not credited, since upon loss of off-site power from the normal supply, the diesel generator is automatically aligned to the bus

c) ESF switchgear room cooling is not necessary to maintain system availability. Heat sources are minimal in the switchgear rooms. (Reference Section 5.2.2.5, ESF Switchgear "DC Equipment Room" HVAC).

d) Operator recovery of circuit breakers that spuriously trip open is not credited.

e) Unscheduled corrective maintenance unavailability is modeled.

5.2.2.8.10 System Analysis Results

Loss of power to a 4.16kV ESF bus is dominated by a spurious off-site power breaker trip in the NA system, combined with failure of the diesel generator to start or failure of its output breaker to close. Also of importance are a common cause failure of the off-site supply breaker and the DG output breaker, both located on the ESF bus; a spurious off-site power breaker trip with battery failure (which causes the DG to fail); and a spurious load shed signal from the BOP ESFAS with operator failure to terminate.

Failure of power to both ESF buses (Station Blackout) is dominated by Loss Of Off-site Power (LOOP) with common-cause DG failure or DG failure on one train with breaker failure or support system failure on the other.

LOOP is modeled both as an initiating event and as an event unrelated to the trip occurring during the 24-hr. mission time.

5.2.2.9 Class 1E Standby Generating System (PE)

5.2.2.9.1 System Function

The Class 1E standby generation system provides an independent source of on-site power for each of the two trains of engineered safety features (ESF) equipment.

5.2.2.9.2 System Success Criteria

The PE system is not modeled in detail in the PRA. Only three failures of the DG itself are included: fail to start, fail to run with a seven-hr. mission time, and common-cause failure. Unavailability due to unscheduled corrective maintenance, BOP ESFAS failure to send a start signal, and failure to restore certain Spray Pond cooling water supply valves are also included. These failures are contained in the fault trees for the ESF buses. The success criteria are that, upon a loss of off-site power, the diesel generator starts, runs, closes onto the ESF bus, and delivers adequate power for 7 hrs.

5.2.2.9.3 System Description

The PE system consists of two diesel generators connected to the two 4.16kV ESF buses as shown in Figure 5.2-23. The DGs are physically and electrically isolated from each other. Physical separation for fire and missile protection is provided by installing the DGs in separate rooms of a Seismic Category I structure.

The engines are 20 cylinder, turbocharged diesels. Each has two 100% capacity redundant air start systems. Each air start system has enough stored air for five engine starts. Crankcase lube oil and jacket cooling water are heated to help maintain the units in a constant ready state.

The units are rated for 5500kW continuous output, 6050kW for 2 out of 24 hrs., at a power factor of 0.8 lagging, and a voltage of 4.16kV +/- 10%.

5.2.2.9.4 Major Components

Major components for each DG include the engine itself, lube oil skid, jacket water cooling skid, intake air filter, exhaust muffler, turbocharger, two air start systems, fuel oil day tank and fuel delivery equipment, generator, local control panel, and a large capacity neutral grounding resistor. Control Room indication and controls include field voltage and current; output voltage, current frequency, and power factor; synchronization meter; start/stop switch, engine speed control, field excitation control and mode selector (isochronous or droop).

5.2.2.9.5 Testing and Maintenance

Each DG is start/load tested monthly. A large number of preventive maintenance tasks are performed at reactor refueling intervals, with a complete engine overhaul performed every 5 yrs. Integrated Safeguards Testing, which includes the DG's ability to start and load automatically given the various emergency signals, is performed at each reactor refueling.

The possibility that a diesel generator is unavailable due to unscheduled corrective maintenance is included in the model. The possibility that both DGs are in corrective maintenance is discounted since the plant may not operate in this condition. The monthly start and load test does not affect the availability, because

BOP ESFAS was designed to accommodate a situation where a DG is already running when on emergency actuation occurs.

5.2.2.9.6 System Dependencies and Interfaces

Power Supply and Control
The PE system requires Class 1E 125V DC power for engine/generator control and for field flashing.

Loads
The diesel generators supply 4.16kV AC power to the ESF buses (PB). One generator is dedicated to one bus. Interlocks exist to prevent paralleling the two DGs in order to maintain their independence.

Fuel Oil
For long-term operation, the diesel fuel oil system (DF) is required to maintain fuel supply in the day tank from the train-related underground fuel oil storage tank.

Actuation
The DG is started under the following emergency conditions by the BOP ESFAS: Bus undervoltage (degraded of Loss of Off-site Power), Auxiliary Feedwater Actuation Signal (AFAS) on either steam generator, Safety Injection or Containment Spray Actuation Signal (SIAS/CSAS). Manual starts can be in either the normal or emergency mode. An emergency manual trip capability is also provided at the local control panel.

Cooling
Each DG depends on the associated train's Essential Spray Pond Pump (SP) to remove heat from the intake air intercoolers, fuel oil, lube oil, and jacket water.

5.2.2.9.7 Technical Specifications
PVNGS Technical Specification 3.8.1.1 requires two emergency diesel generators to be operable during power operation. Operability includes 550 gallons of fuel oil in the day tank, 71,500 gallons in the underground storage tank, and a separate fuel oil transfer pump. An allowed outage time for a single DG of 72 hrs. is provided. If it cannot be restored, the plant must achieve Hot-Standby in the next 6 hrs. and be in cold shutdown within the following 30 hrs.

5.2.2.9.8 System Operation
During normal plant operation, the diesel generators are in standby. Electric heaters and circulating pumps maintain the lube oil and jacket water (and therefore the engine block) heated to enhance engine starting reliability. Air compressors maintain a supply of stored air for engine starting.

The DG has two modes of operation: normal and emergency. In the normal mode (used for testing when the DG will be paralleled to the grid), 15 engine/generator trips are enabled. In the emergency mode, only three automatic trips are enabled: generator differential, engine overspeed, and low engine lube oil pressure. The other trips are bypassed, since they are not considered to lead to immediate or catastrophic damage to the DG. The DG is capable of operating with a sustained ground fault on one phase by virtue of its high capacity neutral grounding resistor. This helps provide additional assurance that, even with a bus or load ground fault, the plant can mitigate accidents and transients.

Upon a DG start signal, compressed air is distributed to the cylinders to roll the engine. As fuel oil is delivered, combustion commences and the engine accelerates to 600 rpm. The generator field will be automatically flashed, and the voltage regulator will establish an output voltage of 4.16kV. Speed regulation has two modes, speed droop and isochronous. The generator is always started in the isochronous mode, meaning that it will attempt to maintain set speed regardless of how much load it has to pick up. However, if the generator is to be paralleled to the grid for surveillance testing, the operator places the speed control in the droop mode. This allows a speed variation as a function of load, so that the engine will not attempt to carry the entire grid. Emergency starts disable the speed droop mode.

If the DG starts in response to any emergency signal other than LOP, it will not be connected to the ESF bus, but will idle in standby. If started in response to LOP the BOP ESFAS sends out a load shed signal, which trips any bus supply breaker that happens to be closed as well as all bus loads except the three load centers. Once proper engine speed and voltage are established, the generator output breaker is automatically closed to supply power to the associated ESF bus. The load sequencer then starts the appropriate large loads in a sequence. When off-site power is regained, the operator places the DG under manual control, parallels with off-site power, unloads the engine, opens its output breaker and shuts it down. Section 5.2.2.21 describes the BOP ESFAS sequencer in more detail.

5.2.2.9.9 Major Modeling Assumptions

a) DGs are modeled in the two 4.16kV bus fault trees

b) DG Building HVAC is not required to maintain operability over the 7 hr. mission time

c) DG support systems for maintaining standby readiness are not required to maintain operability during the mission time (air compressors, air dryers, jacket water heaters, lube oil heaters, and circulating pumps for both)

d) The dependence upon Class IE 125V DC power is modelled as a dependence on the battery only (not the whole DC System) to break a logic loop in the fault trees

e) No credit is taken for recovering a DG after it has failed

f) Common-cause failure to start and run both DGs is modeled.

5.2.2.9.10 System Analysis Results

The two failures included in the model, fail to start and fail to run, are comparable in magnitude. They tend to dominate core damage sequences involving a LOOP. Common-cause failure is important for the Station Blackout initiator. Also of some importance is failure of the associated battery or DC bus/distribution panel to provide field flash and control power.

5.2.2.10 Class 1E 480V Power Switchgear System (PG)

5.2.2.10.1 System Function

The Class 1E 480V power switchgear system receives power from the Class 1E 4.16kV power system (PB), transforms it to 480V, and distributes the power to large Class 1E 480V loads and motor control centers (MCC), as well as certain important non-class 480V loads.

5.2.2.10.2 System Success Criteria

The PG system must supply power to its various connected loads for the 24 hr. mission time.

5.2.2.10.3 System Description

The Class 1E 480V power switchgear system of each load group consists of three load center unit substations to supply the ESF 480V auxiliaries. Load centers PGA-L31, L33 and L35 are associated with Train A or Division 1 load group, and load centers PGB-L32, L34 and L36 are associated with Train B or Division 2 load group, as shown in Figure 5.2-23. In addition, each load group feeds some large non-class 480V loads, essential lighting distribution panels, and two non-class Motor Control Centers (M19 and M71 on Train A, and M20 and M72 on Train B). All load centers are located in the ESF switchgear rooms, at the 100-ft. elevation of the Control Building.

5.2.2.10.4 Major Components

The transformer in each load center is rated at 4160/480V, 750kVA and are ventilated, dry type. A main feeder breaker is supplied on the low voltage side of the transformer. The high voltage supply breaker is located in the 4.16kV ESF bus. The load centers are located in the same room as their respective 4160V supply buses.

The switchgear is metal-enclosed, draw-out type with electrically operated air circuit breaker and bus bar construction. The switchgear is not interchangeable with breakers in the non-class 480V switchgear. Each breaker has electrical protection appropriate for its load i.e., large motor, MCC, lighting distribution panel, duct heater, etc. Relaying is intended to effect isolation as close to a fault as possible; normally only one breaker will open. However, a fault sensed in the stepdown transformer will trip both the main 480V feeder breaker and the 4.16kV supply breaker.

Control Room indications and controls include bus current and voltage, supply and feeder breaker position, and controls. Electrical protection reset capability is provided in the Control Room. The SESS also monitors conditions on each load center.

5.2.2.10.5 Testing and Maintenance

Weekly surveillance testing is required to verify proper alignment and voltages. Other tests and inspections are performed periodically in accordance with the manufacturer's specifications, typically at refueling intervals (18 months). Integrated Safeguards testing, performed at refueling intervals, verifies proper load shedding and load sequencing of various equipment powered from the PG system. Corrective maintenance on a load center is possible during plant operation and is allowed for up to 72 hrs. by PVNGS Technical Specification unscheduled. Unavailability due to unscheduled corrective maintenance is modeled. Replacement breakers are readily available.

5.2.2.10.6 System Dependencies and Interfaces

Power Supply and Control Power

The PG system receives power from the 4.16kV switchgear. Breaker control power is supplied by the Class 1E 125V DC power system. Upon loss of DC powers, breakers fail as-is.

Loads

Each PG system division supplies power to four motor control centers in the Class 480V MCC system and two MCCs in the non-class 480V MCC system. It also supplies power to equipment in many systems, such as Charging, various HVAC systems, etc.

Actuation

Various load circuit breakers receive load shed signals from the BOP ESFAS system upon loss of off-site power. Table 5.2-2 shows loads that are shed. The only PG system equipment modeled in the PRA that receives this signal are the charging pumps and the Control Room Essential AHU, which is not normally operating. The sequencer automatically starts the Control Room Essential AHU and allows charging pump restart, both at 40 sec. after sequencing begins.

In addition, many loads not essential for safe shutdown are shed directly by the Nuclear Steam Supply System (NSSS) ESFAS on a Safety Injection Actuation Signal. These loads include the non-class MCCs (NHN-M19, 20, 71 and 72), essential lighting panels, class-powered pressurizer heaters, fuel pool cooling pump, containment normal ACUs, and the CEDM normal ACUs.

5.2.2.10.7 Technical Specifications

LCO 3.8.3.1 delineates the required electrical lineup for the Class 1E power distribution. All three load centers in each load group are required to be energized when the plant is in power operation (Mode 1) through Hot-Shutdown (Mode 4). With one division (train) of AC power not fully energized, the allowed outage time is 8 hrs. Hot-Standby is required within the following 6 hrs. and cold shutdown within the following 30 hrs.

5.2.2.10.8 System Operation

During normal system operation, the PG system is fully energized. Each power division's three load centers are fed from the respective 4.16kV Class 1E switchgear bus. Load feeder breakers for various pumps, fans, etc., are remotely operated, either from the Control Room or locally at the load. Other load feeder breakers, such as for emergency lighting distribution panels and motor control centers are operated at the load center breaker.

During abnormal or emergency conditions, several load feeder breakers receive automatic open and/or close signals. Non-class loads are tripped by a SIAS. When off-site power is lost to the 4.16kV switchgear, a LOP/load shed occurs. Table 5.2-3 lists the equipment receiving the 1-sec. load shed pulse. Immediate necessary equipment is then automatically sequenced back on by the BOP ESFAS load sequencer. Some equipment is not automatically loaded, but must be manually reconnected by the operator, as time permits, and as directed by various procedures.

5.2.2.10.9 Major Modeling Assumptions

a) Room cooling is not necessary to maintain system availability. Heat sources are minimal in the ESF switchgear rooms.

b) Load shed failure at the 480V level is not modeled.

5.2.2.10.10 System Analysis Results

The more important malfunctions leading to loss of power to an individual load center are: spurious trip of the 4.16kV supply breaker, spurious trip of the 480V feeder breaker, unscheduled corrective maintenance on the load center or its supply breaker, and step-down transformer failure.

5.2.2.11 Class 1E 480V Motor Control Centers (PH System)

5.2.2.11.1 System Function

The Class 1E Motor Control Centers (MCCs) distribute 480V AC power from the Class 1E 480V switchgear system to various class valve motors, small fans, battery chargers, voltage regulators, and other small 480V loads. In addition, each MCC has a single-phase 120/240V distribution panel to supply power to loads, such as motor space heaters on Class 1E motors.

5.2.2.11.2 System Success Criteria

The MCCs transfer power from its load center supply (PG) to the various individual loads. The PH system is successful if it transfers power to necessary loads for the 24 hr. mission time.

5.2.2.11.3 System Description

The Class 1E 480V power MCC system consists of eight MCCs (four per load group). Two MCCs (M31 and M32) are in the Control Building ESF switchgear rooms. The other six are located in the Auxiliary Building class containment electrical penetration rooms.

5.2.2.11.4 Major Components

The MCCs consist of vertical sections, joined together to form a rigid, free-standing, metal-enclosed assembly. The vertical sections are front accessible and divided into six or fewer unit compartments for housing combination motor starters, feeder taps, and other associated equipment.

The position of each MCC supply breaker is shown on the Electrical Distribution control board in the Control Room. Trouble alarms on that panel alert the operator to problems related to a MCC (loss of voltage, electrical protection trip, etc.) The SESS also monitors conditions on each MCC and the components it feeds.

5.2.2.11.5 Testing and Maintenance

Weekly surveillance testing verifies proper alignment and voltages. Other tests and inspections are performed periodically in accordance with the manufacturer's specifications, typically at refueling intervals (18 months). Integrated safeguards testing, performed at refueling intervals, verifies proper load shedding and load sequencing of various PH system powered equipment. A MCC may be out of service during plant operation for corrective maintenance for up to 72 hrs. by PVNGS. This maintenance unavailability is modeled.

5.2.2.11.6 System Dependencies and Interfaces

Power Supply and Control Power

The class MCCs receive power from the class load centers (PG system). Control power is internally supplied.

Loads

Power is supplied to many systems, such as Auxiliary Feedwater, Safety Injection, HVAC, 125V DC battery chargers, and voltage regulator power supplies, etc.

Actuation

Upon LOOP, the battery chargers and voltage regulators are load shed and reloaded by the BOP ESFAS system. Other PH system equipment actuated by various safety signals from both the BOP and the NSSS ESFAS includes:

a) AFAS: auxiliary feedwater system valves, room cooling fans

b) SIAS: HPSI and LPSI injection valves, room cooling fans

c) CSAS: containment spray valves

d) RAS: SI-pump mini-flow recirculation valves, containment sump suction valves.

5.2.2.11.7 Technical Specifications

LCO 3.8.3.1 delineates the required electrical lineup for the Class 1E power distribution. All three load centers in each load group are required to be energized when the plant is in power operation (Mode 1) through Hot-Shutdown (Mode 4). With one division (train) of AC power not fully energized, the allowed outage time is 8 hrs. Hot-Standby is required within the following 6 hrs. and cold shutdown within the following 30 hrs.

5.2.2.11.8 System Operation

The Class 1E MCCs are energized manually by closing the 480V incoming feeder breaker at the respective load center. The MCC feeder is tripped on overcurrent or ground fault through a hand reset lockout relay. The relay blocks re-closure of the incoming feeder until the relay has been reset.

Controls for the individual loads fed from the MCCs are located at the main control room, local control panel, remote shutdown panel or on the MCC as appropriate.

5.2.2.11.9 Major Modeling Assumptions

a) The eight class 480V AC MCCs are modeled in separate fault trees. Each includes the respective load center from which it is powered

b) Room cooling is not required for the mission time of 24 hrs.

c) Failures of individual contactors and breakers are contained in the respective system fault trees, rather than the MCC system (PH) fault trees.

5.2.2.11.10 System Analysis Results

Loss of power to a MCC is dominated by failure of its supply breaker in the load center. Only two local failures are modeled: bus failure and maintenance unavailability.

5.2.2.12 Class 1E 125V DC Power System (PK)

5.2.2.12.1 System Function

The PK system provides separate, reliable sources of continuous power for the four independent groups of Class 1E DC loads and vital AC inverters, both during normal operation and post-trip.

5.2.2.12.2 System Success Criteria

The PK system successfully performs if it delivers a minimum of 105V DC to its connected loads for the required mission times (2 or 22 hrs).

5.2.2.12.3 System Description

The PK system is shown in Figure 5.2-24. There are four channels of 125V DC power, two associated with each load group. Channels A and C are part of the Train A, or Division 1, Load Group, and Channels B and D are part of the Train B, or Division 2, Load Group. Each channel consists of a battery, a DC Control Center, and one dedicated battery charger. In addition, each Train has a "swing" charger, which can supply power to either (but not both) DC Control Centers of that load group. All equipment is located on the 100-ft. elevation of the Control Building. Each battery is in a separate room and each DC channel's equipment is in a separate room.

5.2.2.12.4 Major Components

Battery chargers are three phase, constant voltage units using solid state electronic circuitry with thyristor silicon-controlled rectifiers (SCR) to convert AC input to DC output.

Batteries are lead-calcium, sealed and assembled in heat-resistant, shock absorbing, clear plastic containers with permanent, leak-proof seal covers. Normal operating voltage is approximately 130V, which will supply power for at least 2 hrs. following loss of charging.

The DC Control Centers consist of vertical, free-standing National Electric Manufacturers Association (NEMA) Type 1 enclosures with gasketed door sections. The incoming section houses the electrically operated draw-out type air circuit breaker for the battery supply and instrumentation units. The control center sections consist mainly of manually-operated, molded case breakers and starters, and a distribution panel. Distribution panels on Channels A and B are protected by fuses, and those on Channels C and D by circuit breakers. Ground detection capability is provided.

Control Room indications and controls include battery charger output current, battery charge/discharge current, bus voltage, battery breaker control, and various alarms.

5.2.2.12.5 Testing and Maintenance

Various surveillance testing is performed at 7 day, 92 day, 18 month and 60 month intervals. Correct alignment is verified at seven day intervals, although Control Room alarms would alert the operator to almost any abnormal situation. The surveillance tests required during plant operation do not affect the systems operation. Only absolutely necessary corrective maintenance is done during plant operation, first because of the limited time outage allowed for the bus and battery specified in PVNGS Technical Specification, and secondary, because of the impact on a wide train of safety equipment. There is less restrictive maintenance on battery chargers because each train has a swing charger. Unavailability of a battery or battery charger due to maintenance is modeled.

5.2.2.12.6 System Dependencies and Interfaces

Power Supply and Control Power

The battery chargers receive power from the Class 1E 480V MCC system (PH), each from a different MCC. Control power for individual load contactors is provided from the load side of the respective circuit breaker.

Loads

The DC Control Centers supply power to various DC motor-operated valves, an inverter for the 120V vital AC power system, and a DC distribution panel. Each channel's distribution panel provides power for various reactor protection and ESF actuation system functions, and DC solenoid valves. The Channel A and B distribution panels also supply power to 4.16kV and 480V switchgear breaker controls and diesel generator field flash and control power. Channel A supplies power for the turbine-driven auxiliary feedwater pump speed governor.

Actuation

The BOP ESFAS system sheds and reloads the class normal battery chargers.

HVAC

During normal plant operation, environmental conditions in the DC equipment rooms are maintained by the Control Building Normal HVAC (HJ) system. Following LOOP or during accident conditions, the environment is maintained by the Essential HVAC system (also part of HJ), which consists of Class 1E Air Cooling Units (ACUs) supplied by Essential Chilled Water. EC in turn depends upon EW and SP systems.

The components most sensitive to room ambient temperature are the solid state devices in battery chargers, the vital AC inverters and back-up voltage regulators, and associated static transfer switches. Their failure temperature has been estimated to be 122° F. (See Section 5.2.2.5, ESF switchgear DC equipment room HVAC.)

5.2.2.12.7 Technical Specifications

PVNGS Technical Specification 3.8.2.1 requires all four channels of DC power be energized in Modes 1 through 4, normally from the dedicated battery charger. Action Statement allows a channel to be powered from the swing charger indefinitely. If neither charger is available, the battery must be surveilled within one hr. and every 8 hrs. thereafter to verify its operability. When it is no longer operable, the channel must be declared inoperable. It must be restored within 2 hrs., or the plant must be in Mode 3 (Hot-Standby) within the next 6 hrs. and in Mode 5 (cold shutdown) within the following 30 hrs.

PVNGS Technical Specification 3.8.3.1, requires each DC channel to be energized from its battery bank. With one DC bus not energized from its battery bank, it must be restored within 2 hrs., or the unit must be in Mode 3 within the next 6 hrs. and Mode 5 within the following 30 hrs.

5.2.2.12.8 System Operation

Each Class 1E DC Channel is normally energized with the battery and the dedicated charger connected to the DC Control Center through their respective breakers. Should the dedicated charger fail, Control Room alarms are activated and a plant operator must energize and line up the swing charger to the DC Control Center. The DC Control Center remains energized from the battery during this time. The battery capacity is sized for 2 hrs. supplying safe shutdown loads. (Normal operating loads are considerably less.)

Each charger is sized to provide enough power to supply safe shutdown DC loads and recharge the battery from its design minimum charge state (105V) to fully charged within 12 hrs.

Each swing charger has a dual output switch with a mechanical interlock to prevent it being aligned to both DC channels simultaneously, and thus prevent paralleling two independent DC power channels. It is sized for the larger of the two DC channels served.

5.2.2.12.9 Major Modeling Assumptions

a) The four Class 1E 125V DC channels are modeled in eight fault trees. Four short-term fault trees model 2 hrs. of battery-backed operation, four trees model 22 hrs. of operation on the battery chargers only.

b) Batteries do not depend upon HVAC during the required mission time. The heat generated in the rooms is minimal. The major concern is buildup of hydrogen to explosive levels. However, hydrogen is not generated during normal battery discharge, and multiple vents and fans exist to prevent high concentrations in these rooms. Reference Section 5.2.2.5, ESF switchgear DC equipment room HVAC

c) Operator action to align the swing charger is not credited on the short term fault tree, because it requires local operator action

d) The batteries are not credited in the long term fault trees, because they are conservatively assumed to be discharged after 2 hrs.

e) Class DC power does not depend upon HVAC for the short-term (2 hrs.). It depends upon HVAC for the long-term (22 hrs.). Operator recovery is credited to install temporary backup room cooling

f) Those loads requiring DC power in the short term include the Train A Auxiliary Feedwater pump and valves, breaker control for electric AF pumps B and N, breaker control for other ESF equipment, such as HPSI, LPSI, EW and SP pumps and diesel generator control and field flashing. Loads requiring long-term DC power include Train A AF pump and valves, shutdown cooling isolation valves, and the vital AC inverters.

5.2.2.12.10 System Analysis Results

Channels C and D of the PK system are relatively unimportant. Their loss does not directly result in any transient. In addition, the associated distribution panels are more reliable than the Channel A and B distribution panels because a circuit breaker, rather than a pair of fuses, is used in the supply from the DC Control Center.

The Channel A and B distribution panels are far more important, from an initiating event and a mitigating system support standpoint. This is because the control power is dependent upon so many ESF systems on these two channels. Channel A is more important than Channel B, because two of the three auxiliary feedwater pumps receive control power from this source.

For the short term, both a battery charger failure and battery failure are necessary to fail the system. Charger failure is dominated by unscheduled corrective maintenance followed by AC supply breaker failure and upstream power supply failures. Battery failure is also dominated by unscheduled maintenance, followed by common cause battery failure. (The manually aligned backup charger is not credited for short term DC power.)

Long term malfunctions in the PK system involve failure of the normal charger with failure of the backup charger. The battery is not credited. Normal charger failures are described above. Backup charger failure is dominated by operator failure to align it within 2 hrs. and failure of its supply breaker to the DC bus. Electrical supply failures at the PB (4.16kV) system level fail both chargers to a given channel. Air conditioning failures affecting the DC equipment rooms also will impact both chargers associated with a channel.

Power supply failures at the 4.16kV level, HVAC failures and BOP ESFAS sequencer failures can lead to a loss of two DC channels (both on the same train) upon battery depletion or heat-induced equipment damage.

5.2.2.13 Class 1E Instrument AC Power System (PN)

5.2.2.13.1 System Function

The Class 1E instrument AC power system supplies 120V AC power to the four independent channels of Class 1E vital instrumentation and control loads, including the Reactor Protection System, Engineered Safety Features Actuation

System, Atmospheric Dump Valve controllers and process instruments for ESF functions.

5.2.2.13.2 System Success Criteria

The PN system is successful if it delivers power from either the inverter or the backup voltage regulator to its loads.

5.2.2.13.3 System Description

The PN system is shown in Figure 5.2-25. Each of the four channels of the Vital Instrument AC Power System consists of one inverter that converts 125V DC from a PK channel to 120V AC, one backup voltage regulated supply consisting of a 480/120V transformer and voltage regulator, a distribution panel, and a transfer switch to provide for power source transfer between the inverter and the voltage regulator.

All equipment is located in the respective channel's DC equipment room.

5.2.2.13.4 Major Components

The inverters are static type using silicon-controlled rectifiers, rated at 25kVA with a supply voltage of 105 to 140V DC. Output is single phase, 60 ±0.5 Hz, 120V AC with a tolerance of 2%.

Transfer switches are of two types. Unit 1 has manual transfer switches. If the inverter power fails, the PN channel remains de-energized until an operator manually transfers the supply to the backup voltage regulator. Units 2 and 3 have bumpless static transfer switches, which allow an uninterrupted transfer (manual or automatic) of power from the inverter to the voltage regulator or vice versa. Automatic transfer is modeled.

The distribution panels are enclosed, two-wire ungrounded with a thermal-magnetic trip circuit breaker for main feeder and a fuse-switch for each branch circuit. The main bus is rated for 400A continuous. Ground detection capability is provided.

The voltage regulators are ferroresonant type constant voltage rated for 25kVA, 480/120V single phase, 60Hz.

There are no direct indications or controls for this system in the Control Room. Trouble alarms annunciate on various abnormal conditions, such as AC or DC undervoltage on the inverter, loss of synchronization with the back-up voltage regulator and electrical protection trips. If power is actually lost to a PN distribution panel, several power supplies within the Plant Protection System (PPS) de-energize, which results in "half-leg trips" for reactor trip and all ESFAS actuations. If back-up power supplies within PPS (which are powered from other PN channels) function properly, no actuations occur. However, loss of Channel A or B PN panel is treated as an initiating event. This occurs because in addition to possibly causing a plant trip, mitigating systems are also affected, specifically the Essential Chilled Water Systems. Loss of Channel C or D does not affect any mitigating equipment.

5.2.2.13.5 Testing and Maintenance

PVNGS Technical Specification requires an electrical alignment verification for all Class 1E power distribution once per seven days. A PN distribution panel is unlikely to be out of service during plant operation, because of the impact that power loss (to a 120V AC distribution panel) has on the plant. Therefore, corrective maintenance on the panel itself is not modeled. Maintenance unavailability of the bus power supplies (inverter and back-up voltage regulator) is modeled.

5.2.2.13.6 System Dependencies and Interfaces

Power Supply

The PN system normally receives power from the Class 1E 125V DC Power System, with backup power from the Class 1E 480V MCC system (PH) through normally energized voltage regulator transformers.

Loads

The PN distribution panels supply power chiefly to Plant Protection systems, class process instrumentation, class radiation monitoring equipment, and class valve position indicators. The critical mitigating equipment requiring power from the PN system are the Essential Chillers (flow interlocks), Atmospheric Dump Valves (valve positioners), load sequencers, BOP ESFAS cabinet cooling fans, and shutdown cooling system isolation valve interlocks.

Actuation

The PN system is usually not affected by actuation signals, its normal power supply is the PK system. However, the backup voltage regulators are load shed and reloaded by the BOP ESFAS.

HVAC

During normal plant operation, environmental conditions in the DC equipment rooms are maintained by the Control Building Normal HVAC (HJ) system. Following LOOP or during accident conditions, the environment is maintained by the Essential HVAC system (also part of HJ), which consists of Class 1E Air Cooling Units (ACUs) supplied by Essential Chilled Water. EC in turn depends upon EW and SP systems.

The PN system is also indirectly dependent on Control Room HVAC, another subsystem of the HJ system. A loss of Control Room HVAC can lead to heatup of the BOP ESFAS cabinet and a spurious load shed on both trains of safety equipment. In this event, all PN system voltage regulators will be shed along with the operating Class 1E battery chargers. If the transient is not terminated, each PN and PK bus will lose power when its associated battery bank depletes. Operator action is required to terminate the load shed signal, open DC equipment room doors and install temporary fans and restore power to equipment.

5.2.2.13.7 Technical Specifications

Technical Specification 3.8.3.1 specifies on-site power distribution system alignment. Each PN channel requires energizing from its associated inverter. If it is not energized from its inverter, it must be re-energized (from either the inverter or voltage regulator) within 2 hrs. It must be re-powered from its inverter within 24 hrs. If either of these conditions cannot be met, the unit must be in Mode 3 within the following 6 hrs and in Mode 5 within the following 30 hrs.

5.2.2.13.8 System Operation

The distribution panels are normally energized from their respective 125V DC Control Center through static inverters, which provide reliable power for reactor protection and monitoring equipment. This power source is unaffected by AC power losses in the PB, PG or PH systems. If the inverter power supply becomes unavailable, it may be powered from the backup voltage regulator for up to 24 hrs. (Only one channel at any given time is allowed by Technical Specifications to be powered from the voltage regulator.)

Transfer to the backup voltage regulator is accomplished manually in Unit One in accordance with Abnormal Operating Procedure 41AO-1ZZ15, Loss of Class 1E Instrument AC Power. This procedure also describes what equipment has lost power, the resulting effects on the plant, how to restore and recover power, or shut down the Unit if recovery is not possible.

5.2.2.13.9 Major Modeling Assumptions

a) The four Class 1E 120 V AC instrument power channels are modeled (long-term only) in four fault trees.

b) A 24 hr. mission time is assumed. For this reason the inverters are assumed to require long-term Class DC power.

c) The PRA models the static transfer switch between the inverter and voltage regulator, which is used in Units 2 and 3. Unit 1 relies on operator action to effect the transfer. It was assumed that Unit 1 would eventually be backfitted with the static transfer switch.

d) No credit is taken for operator action to manually transfer power to the voltage regulator if the static transfer switch fails to automatically transfer.

e) Operator action to provide temporary, backup room cooling to the DC equipment rooms is credited, since room temperature alarms will alert the Control Room operators. Several hours are available before equipment failure temperatures are reached.

5.2.2.13.10 System Analysis Results

Only two single failures result in loss of a PN distribution panel: bus fault and spurious main circuit breaker trip, both relatively unlikely. A common mode failure is loss of air conditioning to the DC equipment room in which both the inverters and voltage regulators reside. Other ways to lose a PN panel involve multiple failures, since two power supplies are available. Inverter failure is dominated by maintenance unavailability, followed by internal failures. Backup power failure is dominated by the static transfer switch failing to transfer followed by maintenance unavailability and power supply breaker failure.

There are common mode failures that affect two or more PN channels. Loss of HVAC to one train's DC equipment room, if unmitigated, can lead to a loss of both

PN channels in that train. Loss of Control Room HVAC, if unmitigated, can lead to BOP ESFAS continuous load shed. This, if not addressed by the operators, could result in battery depletion and loss of all four PN channels. High temperature alarms in the DC equipment rooms alert the operators so that overheating is avoided in the rooms. The discomfort level in the Control Room due to a loss of HVAC there should lead the operators to resolve this condition before equipment failures. Loss of multiple PN channels causes reactor trip and all ESFAS actuations.

5.2.2.14 Non-Class 13.8kV Power System (NA)

5.2.2.14.1 System Function

The non-Class 1E 13.8kV power system:

a) receives off-site power from the 525kV switchyard through the Start-up Transformers to supply all station loads during plant start-up and shutdown conditions and safety-related loads during all plant modes

b) receives power from the Unit Auxiliary Transformer to supply non-safety-related station auxiliary loads during power operation

c) distributes power to all station loads.

5.2.2.14.2 System Success Criteria

The NA system must successfully deliver power to the equipment it supplies for 24 hrs. This includes a successful fast bus transfer of NAN-S01 and -S02 to off-site power when a unit trip occurs.

5.2.2.14.3 System Description

Off-site power distribution is shown in Figure 5.2-26 and the in-plant 13.8kV/4.16kV distribution is shown in Figure 5.2-27. A portion of the system is plant-wide, i.e., supplies power to all three PVNGS units. This section consists of the three start-up transformers, which have two secondary windings, each of which can supply two of six intermediate switchgear buses, two associated with each unit (NAN-S05 and -S06). This arrangement allows for two independent sources of off-site power to be supplied to each unit, and provides flexibility in keeping buses energized to allow for start-up transformer outages. This equipment is all located in the start-up transformer yard.

Unit 1 intermediate switchgear, in addition to supplying Unit 1 with off-site power, also supplies other site common loads, such as the Water Reclamation Facility, Service Building, and various administration and support buildings. As stated earlier, each of these two intermediate switchgear buses may receive power from one of two start-up transformers. NAN-S05 and -S06 supply power to switchgear buses NAN-S03 and -S04, respectively. These are located in the unit's power block on the south side of the Turbine Building and are connected to S05 and S06 via overhead transmission lines.

NAN-S03 and -S04 supply power to the Train A and Train B, respectively, ESF load groups through the ESF Service Transformers. They also supply power to 13.8kV switchgear NAN-S01 and -S02 for plant auxiliary loads when the unit electrical generator is not producing power. These buses are powered from the Unit

Auxiliary Transformer during power operations. An automatic fast bus transfer to the off-site power source occurs when the generator trips in order to maintain uninterrupted power to station auxiliary loads. These loads include Reactor Coolant Pumps and steam plant equipment necessary to maintain condenser vacuum. This allows the normal heat sink to be maintained so that reactor heat can be removed through the Steam Bypass system, and the standby ESF equipment need not be brought into service.

In the event off-site power is not available when the unit trips, a generator coastdown feature maintains power to the reactor coolant pumps for a short time. This serves to limit both the pressure peak on the RCS and the thermal peaks in the fuel.

The units auxiliary loads are divided into two groups, so that loss of either has a minimal as possible impact on the units ability to maintain power operation. Even with a reduced level, the unit could still maintain equipment in a satisfactory state (lube oil cooling and circulation, for example) and allow using the condenser as a heat sink if the turbine and/or reactor trip.

5.2.2.14.4 Major Components

Start-up Transformers

Start-up transformers are three phase, four winding (primary, buried tertiary, two secondary). The primary winding is rated at 525kV, 84/112/140 MVA-OA/FOA/FOA. The two secondary windings are each rated at 42/56/70 MVA-OA/FOA/FOA. Each winding is sized to start and carry half of one unit's auxiliary loads and half the ESF loads of a second unit. The buried tertiary winding is furnished to avoid third harmonic problems.

Each start-up transformer has differential current relays, phase and ground overcurrent relays, and sudden pressure relay protection. When a fault is sensed, the transformer is disconnected from its load and power source.

Control Room indications and controls include high voltage supply breaker status and control (control in Unit 1 only), and transformer secondary winding output current. Startup transformer trouble alarms annunciate in all three Palo Verde units. Unit 1 has responsibility for high voltage switching operations, coordinating startup transformer loading, and for local operations in the startup transformer yard.

13.8kV Switchgear NAN-S01 through -S06

All of the 13.8kV switchgears are metal-clad, of the vertical lift draw-out type.

All switchgear is protected by bus feeder phase overcurrent and bus feeder neutral residual overcurrent relaying. Bus undervoltage and negative sequence relaying is provided for S01 and S02 for several functions. This includes motor load protection, synchronization check for fast bus transfer, and generator coastdown interlock.

Control Room indications and controls include bus voltage, NAN-S05 and -S06 supply breaker status, and control and trouble alarms.

5.2.2.14.5 Testing and Maintenance

Off-site power breaker alignment is checked weekly per PVNGS Technical Specification. Corrective maintenance unavailability of the buses and breakers in the off-site power supply is modeled. Startup transformer unavailability is not modeled because power supply can be aligned to another startup transformer if one fails or must be removed from service. Loss of an off-site power feed to the unit is not expected to result in a plant trip.

Preventive maintenance is only done during outages, and includes bus and breaker cleaning, and off-line testing of the breakers.

5.2.2.14.6 System Dependencies and Interfaces

Power Source and Control Power

The 13.8kV system receives power from both the high voltage switchyard for off-site power and from the unit main generator for station auxiliary loads during power operation. The start-up transformers receive power for oil cooling and circulation from two load centers located in the start-up yard and powered from Unit One's S05 and S06. One load center serves as the primary power supply and the other as the alternate.

Control power for all 13.8kV switchgear and the two load centers previously mentioned is from the non-class 125V DC power system. Breakers fail as-is on loss of control power.

Loads

The 13.8kV system provides power directly to large motors, specifically the reactor coolant pumps and condenser cooling water pumps, the non-class 4.16kV system (NB), and a number of load centers (NG). The system does not directly supply power to loads modeled in the PRA. These loads are supplied indirectly by the NB and NG systems.

5.2.2.14.7 Technical Specifications

PVNGS Technical Specification 3.8.1.1 applies to the portion of the system that supplies off-site power to the two ESF load groups. Two independent sources of off-site power are required, both with respect to transmission lines connected to other switchyards, and to start-up transformer supplies to the ESF buses. There are two transmission lines connecting Palo Verde to the Westwing switchyard. These are not considered to be independent. Any other two lines are adequate to satisfy the Technical Specification. Similarly, both ESF buses may not receive power from the same start-up transformer.

An allowed outage time of 72 hrs. to restore one inoperable source of off-site power is provided. 24 hrs. are given if both sources are lost. Additional surveillance on the diesel generators is also required. Hot-Standby is required in the following 6 hrs., with cold shutdown required within the next 30 hrs.

5.2.2.14.8 System Operation

The entire NA system is normally energized. During power operation, buses S01 and S02 are powered from the unit main generator through the unit auxiliary transformer. S03/S05 are powered from one of two secondary windings of one start-up transformer, and S04/S06 are powered from a secondary winding of another start-up transformer. Following a reactor and/or turbine trip, the power supply to S01 and S02 is automatically transferred to S03 and S04, respectively, by opening breakers NAN-S01N and -S02N and closing NAN-S03B and -S04B, thus maintaining power to station auxiliary loads. If off-site power is not available, and the generator has not tripped due to a fault condition, it will continue to supply S01 and S02 until such time as underfrequency or undervoltage leads to shedding the reactor coolant pumps and other bus loads.

Manual bus transfers may also be accomplished. During unit start-up, power to S01 and S02 is transferred from off-site to the unit auxiliary transformer by the operator after the generator is synchronized to the grid and brought on line. Such paralleling operations include an automatic trip of the breaker from the transferred source, in this case, the supply from S03/S04, to preclude operating with dual power sources to any bus. This prevents circulating current and relaying problems. The operator turns the switch to close the desired breaker. When the switch is released, the other source supply breaker trips. If this auto trip fails, a "power sources paralleled" alarm will annunciate, and the operator would trip the breaker by using its control switch. During unit shutdown, station auxiliary power is transferred back to off-site at about 20% power.

The power supply to S05 or S06 may also be transferred during operation from the normal to backup supply and visa-versa. The same auto trip feature discussed for S01 and S02 exists here.

5.2.2.14.9 Major Modeling Assumptions

a) The NA system is modeled in several fault trees. The portion of the system supplying off-site power to the ESF buses is included in the two fault trees for the ESF buses. The portion that supplies power to only the non-safety related station auxiliaries is modeled in fault trees for the load centers fed from NAN-S01 and -S02.

b) Testing interval for all equipment in the non-class electrical systems is assumed to be 18 months. It is not practical from a power generation standpoint to take major buses out of service for preventive maintenance or testing purposes.

c) Corrective maintenance on the 13.8kV buses and circuit breakers is modeled. Is is assumed that all lines between the component in maintenance and ESF 4.16kV bus will be de-energized for the duration of the maintenance.

d) Corrective maintenance of the startup transformer for a given 13.8kV load division is not modeled because it is assumed that the operators would energize the bus from its alternate startup transformer.

e) No credit is taken for operator alignment of the alternate startup transformer upon failure of the normally aligned startup transformer.

5.2.2.14.10 System Analysis Results

The major cause for NAN-S01 or -S02 unavailability is failure of the fast bus transfer. Startup transformer failures and spurious trips of breakers on NAN-S03, -S04, -S05 and -S06 bringing off-site power into the unit are also important failures. A breaker failure on one of these buses would also result in LOOP to one of the ESF buses. However, no single failure of plant equipment can result in a complete LOOP, since independence of the two load groups is maintained directly from the switchyard. Only disturbances on the grid or major switchyard faults have the potential of disrupting both sources of off-site power to the plant. LOOP, as a transient initiating event, is discussed in Sections 4.1 and 4.3. Loss Of Off-site Power is also modeled as a failure occurring subsequent to another initiating event during the 24-hr. mission time assumed in the PRA.

5.2.2.15 Non-Class 1E 4.16kV Power Distribution System (NB)

5.2.2.15.1 System Function

The NB system receives power from the 13.8kV power distribution system through two normal service transformers which supply two divisions of non-class 4.16kV loads. The NB system also receives power through two ESF service transformers to supply the two divisions of safety-related loads.

5.2.2.15.2 System Success Criteria

The system must deliver power to its loads for 24 hrs., and if called upon, a successful fast bus transfer occurs between NBN-S01 and -S02.

5.2.2.15.3 System Description

The NB system is shown in Figure 5.2-27.

Normal Service Power System

Two normal service transformers, NBN-X01 and -X02, step down voltage from 13.8kV buses NAN-S01 and -S02 to two 4.16kV buses, NBN-S01 and -S02, which distribute power to 4kV motor loads. The two buses can be tied together by a single tie breaker, so that each bus can act as an alternate power supply to the other. This tie breaker is normally open.

ESF Off-site Power System

Two ESF service transformers, NBN-X03 and -X04, step down voltage from 13.8kV buses NAN-S03 and -S04 to supply the two Class 1E, safety-related 4kV buses, PBA-S03 and PBB-S04 (PB system). Each transformer serves as a primary power source for one safety bus and as a backup source for the other bus. No fast bus transfer is necessary to maintain off-site power to the ESF buses when a unit trip occurs.

5.2.2.15.4 Major Components

Normal Service Power System

This system consists of two GE supplied 5kV switchgear of the vertical lift draw-out type. The normal service transformers, manufactured by Westinghouse, are 13.8/4.16kV rated 15/20 MVA OA/FOA. Each can handle both load groups.

Transformers and switchgear are interconnected by a 3000A non-segregated phase bus duct. The bus tie between the switchgear is a 2000A rated non-segregated phase bus duct. Transformers are protected by feeder ground fault overcurrent, feeder phase overcurrent relaying, low side neutral overcurrent, and phase differential overcurrent relaying. The buses are protected by transformer neutral overcurrent relays and bus undervoltage relays, which shed the large motor loads upon decaying voltage. They also act as permissives for automatic bus transfer, along with a synchronism check relay. The bus is protected indirectly by the fault sensing relays on the loads.

<u>ESF Service Transformers</u>
These Westinghouse transformers are rated 10/12.5 MVA OA/FOA. Each can accommodate both load groups. Power from each transformer is brought to both PBA-S03 and PBB-S04 by two non-segregated phase bus ducts rated at 2500A initially, splitting to two 1200A-rated bus ducts, one to each safety bus. Transformer and bus protection are discussed in Sections 5.2.2.14 (NA) and 5.2.2.8 (PB).

Control Room indication and control consists of supply and output breaker status and control, secondary output current, and trouble alarms for various transformer abnormalities and NB bus or breaker problems.

5.2.2.15.5 Testing and Maintenance
Off-site power breaker alignment is checked weekly per PVNGS Technical Specification.

5.2.2.15.6 System Dependencies and Interfaces

<u>Normal Service Power System</u>
An automatic bus transfer is provided between buses NBN-S01 and -S02 to maintain power under certain fault conditions, given that permissives, such as synchronization and voltage availability, are met.

Power is received from the 13.8kV power distribution system, specifically, buses NAN-S01 and -S02. Power is delivered to condensate pumps, extraction drain pumps, normal chillers E01B, C and E02, Nuclear Cooling Water, Turbine Cooling Water, and Plant Cooling Water system pumps. The system is modeled in the PRA as a support system for the condensate pumps and normal chillers. Breaker control power is supplied by the non-class DC power system (NK). Breakers fail as-is on loss of control power. Transformer cooling depends upon the non-class 480V load centers (NG).

This system is not dependent upon HVAC.

<u>ESF Service Transformers</u>
No automatic functions are associated with the ESF service transformers.

The transformers receive power from 13.8kV buses NAN-S03 and NAN-S04. Each can supply either or both ESF buses, but X03 normally supplies PBA-S03 and X04 normally supplies PBB-S04. This portion of the NB system is modeled in the PRA as part of the off-site power supply for the ESF buses. Breaker control power for the supply breakers is from the non-class DC power system. The feeder breakers are located in the ESF switchgear. Control power is supplied by the appropriate Class 1E DC power channel (PK). Transformer cooling depends upon the non-class 480V load centers (NG).

The transformers are located outdoors and are not dependent on any plant HVAC systems.

5.2.2.15.7 Technical Specifications

PVNGS Technical Specification 3.8.1.1 applies to that portion of the NB system supplying off-site power to the ESF buses. See Section 5.2.2.8 on the Class 1E 4.16kV system (PB) for a complete discussion.

5.2.2.15.8 System Operation

All portions of the NB system are normally energized. Aside from the automatic bus transfer described earlier, all switching operations are done manually from the Control Room. Each circuit breaker also has a local control switch for local operation. However, paralleling operations are not done locally, no synchronizing indication is available. As with the 13.8kV system, an automatic breaker trip from the source being transferred occurs during paralleling to avoid operating with two power sources to a bus.

5.2.2.15.9 Major Modeling Assumptions

a) As stated previously, each NB bus can act as a backup power supply to the other. Modeling this feature in the PRA can lead to logic loop problems, so the backup function is only modeled one way.

b) The alternate power source for each ESF bus from the opposite train's ESF service transformer is not credited.

c) Corrective maintenance unavailability for NB system transformers and non-class bus is not modeled.

5.2.2.15.10 System Analysis Results

The single failure modeled is a bus electrical fault. Important multiple failures involve a spurious normal supply breaker trip or normal service transformer fault with an additional failure of the backup power supply.

5.2.2.16 Non-Class 1E 480V Power System (NG)

5.2.2.16.1 System Function

The non-Class 480V power switchgear system receives power from the non-Class 1E 13.8kV switchgear system (NA), transforms it to 480V and distributes the power to large 480V auxiliary loads, motor control centers, and lighting distribution panels.

5.2.2.16.2 System Success Criteria

The NG system must supply power to its various connected loads for 24 hrs.

5.2.2.16.3 System Description

The system consists of a number of load center unit substations associated with each of the two major power divisions. Sets of three load centers are supplied from one breaker on the 13.8kV switchgear. Each load center consists of a supply side disconnect switch, a 13.8kV/480V transformer, main feeder breaker and several load supply breakers. Load centers are located throughout the plant, except in the Containment Building.

5.2.2.16.4 Major Components

The transformer in each load center is rated at 13.8kV/480V, 95kVA. Those located indoors are mostly the ventilated dry type; a few are sealed freon-filled.

The switchgear is metal-enclosed, draw-out type with electrically operated air circuit breaker and bus bar construction. The breakers are not interchangeable with those in the Class 480V switchgear system. Each breaker has electrical protection appropriate for its load i.e., large motor, MCC, lighting distribution panel, duct heater, etc.

Control Room indication and control consists of load center supply and feeder breaker status and control, transformer secondary side current, and trouble alarms for electrical protection trips.

5.2.2.16.5 Testing and Maintenance

Supply breaker and load center unavailability due to corrective maintenance is modeled. Preventive maintenance is done during outages, and includes activities such as bus and breaker cleaning, and off-line breaker testing.

5.2.2.16.6 System Dependencies and Interfaces

Power Supply and Control Power

The NG system receives power from the 13.8kV non-class power switchgear (NA). Circuit breaker control power is from the non-class 125V DC (NK) system. Breakers fail as-is on loss of control power.

Loads

Few loads on the NG system are modeled in the PRA. Those that are, include certain HVAC fans and non-class motor control centers, which power valves in AF and Condensate Systems, non-class battery chargers, and non-class instrument AC buses.

5.2.2.16.7 Technical Specifications

No PVNGS Technical Specification apply to the NG system.

5.2.2.16.8 System Operation

During normal system operation, the NG system is fully energized. Load feeder breakers for various equipment are controlled at the switchgear, at a local control panel, automatically, or from the Control Room, as appropriate.

Following a plant trip, the system should remain energized if off-site power is available and the 13.8kV fast bus transfer was successful.

5.2.2.16.9 Major Modeling Assumptions

Corrective maintenance unavailability of load centers is modeled.

5.2.2.16.10 System Analysis Results

The most likely local failure for a load center is a spurious trip of the 480V feeder breaker. Other less probable local failures are maintenance unavailability, bus faults, and transformer failures. Failures in power systems upstream also contribute to the unavailability of any load center.

5.2.2.17 Non-Class 1E 480V Motor Control Centers (NH)

5.2.2.17.1 System Function

The non-Class 1E Motor Control Centers (MCCs) distribute 480V AC power from the non-class load centers (NG system) to various valve motors, small fans, battery chargers, voltage regulators, and various other small 480 V loads.

5.2.2.17.2 System Success Criteria

The MCCs transfer power from their respective load centers to the various individual loads. The NH system is successful if it supplies power to its modeled loads for the 24 hr. mission time.

5.2.2.17.3 System Description

The non-Class 1E MCC system consists of a number of motor control centers located throughout the power plant, except in the Containment Building.

5.2.2.17.4 Major Components

The MCCs each consist of vertical sections, joined together to form a rigid, free-standing, metal-enclosed assembly. The vertical sections are front accessible and are divided into six or fewer unit compartments for housing combination motor starters, feeder taps, and other associated equipment.

All MCC motor circuits are fed from combination starters, each comprised of a magnetic-only trip molded case circuit breaker, starter with 3-phase overload relay, auxiliary relays where required, and control power transformer. For equipment other than motors, dual element thermal-magnetic type circuit breakers are provided.

Control Room indication consists of supply breaker status and trouble alarms.

5.2.2.17.5 Testing and Maintenance

MCC unavailability due to corrective maintenance is modeled. Preventive maintenance is done during outages, and includes such functions as bus and breaker cleaning.

5.2.2.17.6 System Dependencies and Interfaces

Power Supply and Control Power

Most Non-class MCCs receive power from the Non-class load centers (NG). Four MCCs receive power from Class 1E Load Centers (PG), two from each train. M19 and M71 are powered from Train A and M20 and M72 from Train B. Control power for individual load starters and indication is supplied by a single-phase step-down transformer on the load side of each load circuit breaker.

Loads

Power is supplied to many systems. Those of importance in the PRA are control valves associated with the Train N auxiliary feedwater pump, normal chilled water valves and circulating pumps, non-class battery chargers, and voltage regulators for the 120V AC instrument buses.

Actuation

M19, M20, M71 and M72 are load shed upon a SIAS.

5.2.2.17.7 Technical Specifications

No PVNGS Technical Specification apply to the NH system.

5.2.2.17.8 System Operation

The non-class MCCs are energized manually by closing the 480V incoming feeder breaker at the respective load center. All MCCs are normally energized during plant operation. The MCC feeder is tripped on overcurrent or ground fault through a hand reset lockout relay. The relay blocks re-closure of the incoming feeder until the relay has been reset.

Controls for the individual loads fed from the MCCs are located at the MCC, a local control panel, or in the Control Room, as appropriate.

5.2.2.17.9 Major Modeling Assumptions

a) Corrective maintenance unavailability of MCCs is modeled.

b) Failures of individual contactors and breakers are contained in the respective system fault trees, rather than the MCC system fault trees.

5.2.2.17.10 System Analysis Results

Unscheduled maintenance and bus fault are the only two failures modeled for the MCCs. Other failures are in upstream power supplies.

5.2.2.18 Non-Class 1E 125V DC System (NK)

5.2.2.18.1 System Function

The NK system provides a reliable source of DC power for station auxiliary loads, such as control power for non-class switchgear, the plant computer, subsynchronous resonance protection equipment, and emergency bearing lube oil pumps for rotating equipment.

5.2.2.18.2 System Success Criteria

The NK system must deliver power to its loads on demand for the 24 hr. mission time.

5.2.2.18.3 System Description

The NK System is shown in Figure 5.2-28. The system consists of two DC Control Centers, three distribution panels, four battery chargers, and two battery banks. DC Control Center M46 primarily supplies power for DC motors and is connected to one of the two station batteries. One of the four chargers is dedicated to this DC Control Center. One of the other chargers can supply either DC Control Center. DC Control Center M45 supplies the three major DC distribution panels located throughout the plant. It is connected to the second station battery. The two remaining chargers are dedicated to supplying M45. All equipment, except the distribution panels, is located in the Turbine Building switchgear room.

5.2.2.18.4 Major Components

Battery chargers are three phase, constant voltage units using solid state electronic circuitry with thyristor silicon-controlled rectifiers (SCR) to convert AC input power to DC output.

Batteries are lead-calcium, sealed and assembled in heat-resistant, shock absorbing, clear plastic containers with permanent, leak-proof seal covers. Normal operating voltage is approximately 130V, which will supply power for at least 2 hrs. following loss of charging.

The DC control centers consist of vertical, free-standing NEMA Type 1 enclosures with gasketed door sections. The incoming section houses the electrically operated draw-out type air circuit breaker for the battery supply and instrumentation units. The control center sections consist mainly of manually-operated, molded case breakers and starters, and a distribution panel. Ground detection capability is provided.

Control Room indication and controls include battery charger output current, battery charge/discharge current, bus voltage and battery breaker status. Trouble alarms alert the operator to various abnormalities.

5.2.2.18.5 Testing and Maintenance

Corrective maintenance unavailability is modeled for batteries, battery chargers and their supply breakers.

5.2.2.18.6 System Dependencies and Interfaces

The battery chargers receive power from various motor control centers in the Non-class 480V MCC system (NH). Power is supplied to many systems throughout the power plant. Of primary interest in the PRA is control power to various circuit breakers, including those for bringing off-site power into the Unit, and Normal Chillers (WC).

5.2.2.18.7 Technical Specifications

No PVNGS Technical Specification apply to the NK system.

5.2.2.18.8 System Operation

The system is normally fully energized with the exception of the swing charger. The other battery chargers supply the DC loads and maintain a float charge on the batteries.

Following a Loss Of Off-site Power (LOOP), the battery chargers are not energized, and the batteries supply non-vital DC loads for a period of approximately 2 hrs. The emergency bearing oil pumps powered from M46 allow coastdown of the main feedwater pumps and turbines, and the main turbine generator. The emergency seal oil pump maintains the generator shaft seals long enough to safely depressurize the generator (of hydrogen).

5.2.2.18.9 Major Modeling Assumptions

a) Corrective maintenance unavailability of battery chargers and the battery associated with M45 is modeled.

b) Only DC Control Center M45 and two of the three distribution panels it supplies, D41 and D42, are modeled in the PRA.

5.2.2.18.10 System Analysis Results

As with the Class 1E DC system, only a few unlikely single failures can disable the system. With multiple power supplies to the bus, its reliability is quite high, at least in the short term. Long term availability is lower, since the diesel generators do not supply back-up power to any of the non-class battery chargers, and the batteries are good for only about 2 hrs. However, there are multiple battery chargers with diverse power supplies.

For either distribution panel modeled, single failures that could lead to its unavailability are unscheduled corrective maintenance, blown fuse, panel faults or control center faults. Multiple failures involve combinations of charger failure, breaker failure or spurious trip and upstream power supply failures. These include fast bus transfer failure and loss of off-site power.

5.2.2.19 Non-Class 1E Instrument Power (NN)

5.2.2.19.1 System Function

The NN system provides 120V AC power to various power plant controls and instrumentation.

5.2.2.19.2 System Success Criteria

The NN system must supply power to its loads for 24 hrs.

5.2.2.19.3 System Description

The system consists of four distribution panels, each one having two voltage regulating transformers for its supply, (one normal and one backup). There are two subsystems.

One subsystem consists of two ungrounded 120V AC distribution panels, D11 and D12. One of the two voltage regulators for each distribution panel is powered from a Class 1E MCC (PH) (one from Train A, and the other from Train B), so that the panels can be energized from the emergency diesel generators. The alternate voltage regulator is non-class powered. These panels feed reactor control systems and non-safety-related reactor indications and process instrumentation.

The other subsystem consists of two grounded 120V AC distribution panels, D15 and D16. Both voltage regulator transformers for each panel are non-class powered (NH). These panels feed control systems and instrumentation associated with the steam/electric conversion equipment, Control Room annunciators and communication equipment. This subsystem is not modeled in the PRA.

An automatic/manual transfer switch is provided between the two power sources for each panel.

5.2.2.19.4 Major Components

The D11 and D12 distribution panels are two-wire ungrounded, with a thermal-magnetic trip circuit breaker for main feeder and a fuse-switch for each branch circuit. The main bus is rated for 400A continuous. Ground detection capability is provided.

Each distribution-panel contains a bus transfer switch of the break-before-make type, which transfers to the backup supply upon a loss of voltage on the normal supply, provided power is available from the backup supply. Transfer occurs if voltage drops below 70% rated. The switch can also be operated manually.

The voltage regulators are ferroresonant type constant voltage rated for 25kVA, 480/120V single phase, 60Hz. Those that supply D11 and D12 from the Class 1E distribution system are themselves Class 1E and act as the isolation devices between the Class 1E distribution system and the non-class panels. The Class 1E regulators are located in the Class DC equipment rooms (Channels A and B) in the Control Building. The non-class backup regulators and the distribution panels themselves are located in the plant computer inverter room on the 120 ft. level of the Control Building.

No direct indications or controls are available in the Control Room for this system. There are trouble alarms for the voltage regulators and transfer switches.

5.2.2.19.5 Testing and Maintenance

Corrective maintenance unavailability of the voltage regulators and their supply breakers is modeled. However, it is not modeled for the distribution panels themselves because the plant cannot operate with either of these panels out of service.

5.2.2.19.6 System Dependencies and Interfaces

The system receives 480V power from the PH and NH systems, and distributes power to many systems, principally control systems for the reactor, chemical and radwaste processing systems, and various turbine generator auxiliary control systems. Those systems in the PRA requiring NN are Turbine Bypass Valves and Feedwater Control System, which operates downcomer throttle valves for MFW and Train N AF pump.

5.2.2.19.7 Technical Specifications

No PVNGS Technical Specification apply to the NN system.

5.2.2.19.8 System Operation

All components are normally energized during plant operation. The backup voltage-regulating transformers are ready to pick up the load should the normal supply fail, and the automatic bus transfer switch transfers to the backup. D11 and D12 are normally powered from the Class 1E supply, which is picked up by the emergency diesel generators upon a LOOP.

5.2.2.19.9 Major Modeling Assumptions

a) Operator action to transfer to the alternate power supply upon failure of the normal is not credited.

b) Only panels D11 and D12 are modeled, since no component powered from D15 or D16 are modeled in the PRA.

5.2.2.19.10 System Analysis Results

The only single failures that can disable either distribution panel are bus fault and main feeder breaker spurious trip. Because of the multiple power supplies to these panels, their reliability is quite high, especially with one of the power supplies from a Class 1E MCC, which is backed up by a diesel generator. The dominant combinations of malfunctions are a voltage regulator failure or corrective maintenance unavailability with a failure of the automatic transfer switch to function. Fast bus transfer failure at the 13.8kV level and loss of off-site power also contribute to failure of the non-class power supply.

5.2.2.20 Actuation Systems (CIAS,CSAS,MSIS,SIAS,RAS,AFAS)

5.2.2.20.1 System Function

The Engineered Safety Features Actuation System (ESFAS) uses two out of four (2/4) logic to provide initiating signals for components which require automatic actuation. This occurs when predetermined setpoints are exceeded on selected monitored plant parameters. These initiating signals are as follows:

- Containment Isolation Actuation Signal (CIAS)
- Containment Spray Actuation Signal (CSAS)
- Main Steam Isolation Signal (MSIS)
- Safety Injection Actuation Signal (SIAS)
- Recirculation Actuation Signal (RAS)
- Auxiliary Feedwater Actuation Signal (AFAS)

The system actuates ESF systems equipment if selected abnormal conditions are detected. The setpoints for the actuation signals are selected to minimize the consequences of Design Basis Events. These include:

- Reactor Coolant System pipe break
- Single CEA injection
- Steam System pipe break
- Feedwater pipe break
- Reactor Coolant pump shaft seizure
- Depressurization due to inadvertent actuation of primary or secondary safety valves at 100% power

5.2.2.20.2 System Success Criteria

The system success criteria for ESFAS is to provide actuation signals to actuate components in the ESF systems, as required, when predetermined setpoints are exceeded. This includes successful signal generation from measurement channels, initiation relay transfer, trip contact functionality, logic matrix relay transfer, bistable signal transfer, and coincidence signal generation from respective channels.

5.2.2.20.3 System Description

The ESFAS 2/4 consists of the sensors, logic, and actuation circuits which monitor selected plant parameters. It also provides signals to actuate components in the ESF systems, as required, when predetermined setpoints are exceeded. There is an actuation system for each ESF system, all of which are identical, with the exception that specific inputs and logic vary from system to system and the activated devices are different.

The measurement channels continuously monitor each selected process variable. They consist of a sensor/transmitter, current loop and resistors, converter/power supply, indicators, outputs for the Plant Monitoring System, and interconnecting wire. This equipment indicates operational availability of each sensor. Secondly, it converts the measured parameters to analog voltages that are subsequently transmitted to comparators in the measurement circuits. Each protective parameter is measured by four independent measurement channels, which are physically and electrically isolated from each other.

The analog signal produced in the measurement channel is sent to the comparator where it is compared with the predetermined trip levels. Bistable trip signals are generated when values rise above high-level setpoints or fall below low-level setpoints. These trip signals are then applied to the systems logic. The system uses a two-like trip signal coincidence logic. Four channels of protection provide the capability of bypassing one channel and maintaining a two out of three system. When matrix logic trip is generated, an initiation signal is sent to the respective ESF train auxiliary cabinet. In addition to automatic actuation, each initiation logic can be tripped by manual switches.

5.2.2.20.4 Major Components

The ESFAS consists of measurement channels, trip units, logic matrices, initiation logic, manual trip initiators, and actuation logic. Because each actuation signal is identical, except for varied inputs and different actuated devices, a generic block model of the ESFAS is presented in Figure 5.2-29. Figure 5.2-30 shows a functional diagram of a typical Engineered Safety Feature actuation.

<u>Measurement channels</u>

Each measurement channel provides a signal representative of the state of each monitored parameter to the appropriate trip unit blocks. Each measurement channel includes process measuring devices, signal transmitters, their respective power supplies, and calculator modules required to determine derived conditions. This includes associated power supplies.

<u>Trip Unit Blocks</u>

Each trip unit block includes the individual trip units which, for a given channel, compare measured plant parameter values with pre-established trip setpoints. They generate a channel trip signal whenever the input signal reaches the setpoint for any parameter (or combination of parameters). The power supplies associated with the trip units are considered to be integral. Each trip unit (bistable or auxiliary) includes any pre-trip indicating lights. Additionally, each trip relay includes a relay trip indicating light.

<u>Logic Matrix</u>

Each logic matrix block includes one of six logic matrices, its associated logic matrix relays, the logic matrix power supplies, logic matrix testing circuitry, and the channel bypass and bypass indication circuitry. The bistable trip unit contacts in the logic matrices are included with the bistable trip units. The logic block contains one of six logic matrices, required to form all possible combinations for two out of four coincident signals from the four measurement Channels A, B, C, and D, respectively. Each logic matrix consists of a number of parallel sets of bistable trip unit relay contacts in series, a power supply for each of the series contact sets, and the logic matrix relays.

Initiation Logic
Each initiation logic block includes one of the four initiation circuits, its associated initiation relays, initiation circuit power supply, logic testing circuitry and the channel bypass and bypass indication circuitry. The logic matrix relay contacts in the initiation logic circuitry are included with the logic matrix blocks. Each initiation logic consists of a set of six logic matrix relay contacts in series, a power supply for the initiation relays, and the initiation logic relays themselves.

Manual Trips
Each manual trip block is composed of one control switch and its contact. Each of the blocks interfaces with the operator via its control switch and with the initiation logic.

Actuation Logic
Each actuation block includes one of the two actuation circuits, its associated actuation relays, and logic testing circuitry. The initiation logic relay contacts are included with the initiation logic. Each actuation logic consists of a set of four initiation logic relay contacts, two manual trip buttons, and a group of actuation relays.

The group actuation logic is physically located in two ESFAS Auxiliary Relay Cabinets in the Control Building. Receipt of initiation channel signals results in the de-energizing of the ESF subgroup relays. This in turn, actuates all the valve and pump components required by the particular train of ESF systems. These components generally consist of solenoid operated valves, motor operated valves, or pump motors.

5.2.2.20.5 Testing and Maintenance

Trip bistables, initiation relays and logic matrix relays are tested on a monthly basis. Only one measurement channel of a given ESFAS signal can be in a bypass condition at any given time. Unavailability contributions due to a channel in bypass are included in the models for measurement Channel A, converting the ESFAS to a two out of three logic (Channels B, C, D). (See Section 5.2.2.20.9).

5.2.2.20.6 System Dependencies and Interfaces

Measurement channels
The measurement channel blocks interface with the plant via their respective process variable measurement devices. They interface with the trip unit blocks via the process variable signal provided to the individual trip units. Power for the signal transmitters and calculators is provided by their respective power supplies, which interface with the 125V DC bus system. The operator interfaces with the measurement channel block for maintenance and calibration.

Trip Unit Blocks
The trip unit blocks interface with the process measuring block, the logic matrix blocks, the 120V AC vital bus system, and the operator. Each trip unit within a given unit block receives a signal from a process monitoring device in the corresponding process measuring block. In turn, each trip unit in a trip unit block

provides an output to three of six logic matrix blocks. The operator interfaces with the trip unit blocks to perform maintenance and testing, and to input the fixed setpoints.

Logic Matrix

Each logic matrix block interfaces with the trip unit blocks from two channels via the bistable relay contacts and with the initiation logic blocks via the logic matrix relay contacts. Each logic matrix block also interfaces with two of the four vital buses, e.g. the AB logic matrix relays are powered by two auctioneered power supplies, one powered from PNA and one from PNB. Since these relays are normally energized and de-energize to actuate, power supply failures do not prevent actuation. The operator interfaces with this block include testing, maintenance and the insertion, and removing channel bypasses.

Initiation Logic

Each initiation logic block interfaces with each of the logic matrix blocks via the logic matrix relay contacts and with each of the actuation logic blocks via the initiation relay contacts. The interface with the actuation logic blocks is arranged to produce a selective two out of four coincidence circuitry. Each initiation logic block also interfaces with one of four vital buses. The initiation relays (four per ESFAS signal) are normally energized and de-energize to actuate. Therefore, loss of power does not prevent ESFAS actuation. The operator interfaces with this block include testing, maintenance and initiation of a signal to actuate the actuation circuitry.

Manual Trips

Each of the blocks interfaces with the operator via its switch and with one of the initiation logic blocks. The interface with the initiation logic block is arranged in series with the logic matrix relay contacts.

Actuation Logic

Each actuation logic block interfaces with each of the initiation logic blocks via the initiation logic relay contacts. These actuation logic blocks also interface with the individual actuated ESF system component via the group relay contacts. The actuation relays are normally energized and de-energize to actuate. Therefore, signal actuation does not depend on the availability of electrical power.

5.2.2.20.7 Technical Specifications

PVNGS Technical Specification Limiting Condition for Operation (LCO) for ESFAS, requires instrumentation channels and bypasses to be operable with their trip setpoints consistent with the predetermined values and response times. The LCO also requires that an instrumentation channel be declared inoperable if a channel trip setpoint is less conservative than the predetermined values. If a channel is declared inoperable, the LCO requires that appropriate actions be taken. Most actions require that, with the number of operable channels being one less than the total number of channels, the inoperable channel be restored within 48 hrs., or be in Hot- Standby within 6 hrs. and in Hot-Shutdown within the following 6 hrs.

5.2.2.20.8 System Operation

The ESFAS systems are maintained in a standby mode during normal operation. The following actuation signals to the Engineered Safety Features (ESF) equipment are generated when applicable monitored variables reach levels requiring protective action. Some setpoints are externally variable to avoid inadvertent initiation during normal operations such as startup, shutdown, and cooldown, and evolutions such as low power testing. The setpoints given below are typical actuation setpoints.

Containment Isolation Actuation Signal

Containment Isolation Actuation Signal (CIAS) actuates the Containment Isolation System by providing signals to close valves on selected containment penetration lines. Therefore, any radioactivity released to the containment following a postulated Design Basis Accident would be confined. The CIAS initiates isolation of the process lines penetrating the containment by actuating the appropriate valves when two out of four HIGH (3.0 psig) containment pressure signals or two out of four LOW (1837 psia) pressurizer pressure signals are received by CIAS actuation logic. Manual initiation can occur on two out of four selected switches on Control Room B05 and at the Auxiliary Relay Cabinets, Cabinet A for Train A, and Cabinet B for Train B. (See Figure 5.2-31).

Containment Spray Actuation Signal

Containment Spray Actuation Signal activates the Containment Spray System (CSS) and Iodine Removal System (IRS) to remove heat from the containment atmosphere in the event of a LOCA or main steam line break accident. A Containment Spray Actuation Signal (CSAS) actuation starts the containment spray pumps, opens the containment spray isolation valves and opens valves in the IRS. The CSAS is initiated by receipt of two out of four HIGH-HIGH (8.5 psig) containment pressure signals. Manual initiation can occur on two out of four selected switches on Control Room B05 and at the Auxiliary Relay Cabinets, Cabinet A for Train A, and Cabinet B for Train B.

Main Steam Isolation Signal

Main Steam Isolation Signal (MSIS) isolates the affected steam generator by closing the MSIVs, FWIVS, blowndown and SG sample valves. This assures that a heat sink is maintained in the event of a secondary pressure boundary rupture. The MSIS is actuated by receipt of two out of four HIGH (3.0 psig) containment pressure, LOW (919 psia) Steam Generator pressure, or a HIGH (91.0% NR) Steam Generator level. Manual initiation can occur on two out of four selected switches on Control Room B05, at the Auxiliary Relay Cabinets, Cabinet A for Train A, and Cabinet B for Train B, or two out of four selected switches at the Remote Shutdown Panel (RSP).

Safety Injection Actuation Signal

Safety Injection Actuation Signal (SIAS) actuates both HPSI and LPSI pumps and opens injection valves in the Safety Injection System to provide core cooling in the event of a LOCA. As with a CIAS, a SIAS is initiated on two out of four HIGH (3.0 psig) containment pressure. Also, a SIAS will occur on two out of four LOW (1837 psia) pressurizer pressure. Manual initiation can occur on two out of four selected switches on Control Room B05 and at the Auxiliary Relay Cabinets, Cabinet A for Train A, and Cabinet B for Train B.

Recirculation Actuation Signal

Recirculation Actuation Signal (RAS) changes suction of the safety injection and containment spray pumps from the refueling water tank to the containment recirculation sump. The RAS is initiated by two out of four LOW (7.4% of span) Refueling Water Tank level. Manual initiation can occur on two out of four selected switches on Control Room B05 and at the Auxiliary Relay Cabinets, Cabinet A for Train A, and Cabinet B for Train B.

Auxiliary Feedwater Actuation Signal

Auxiliary Feedwater Actuation Signal (AFAS) starts the essential auxiliary feedwater pumps which initiates auxiliary feedwater flow to the intact steam generators to maintain a heat sink in the event of a loss of the normal feedwater supply. The AFAS is initiated upon receipt of a LOW (25.8%) water level trip from an unruptured Steam Generator. However, if there is a large (185 psia) differential pressure between the two SGs, indicating a ruptured SG, the SG with the lower pressure (ruptured SG) will not generate an AFAS. Manual initiation can occur on two out of four selected switches on Control Room B05.

Actuation Logic

The four initiation circuits in the Plant Protection System (PPS) initiate a selective two out of four logic in the ESFAS Auxiliary Relay Cabinets. Receipt of two selective ESFAS initiation channel signals will de-energize the ESF subgroup relays, which generate the actuation channel signals. This is done independently in both ESFAS Auxiliary Relay Cabinets generating both Train A and Train B actuation signals (see Figure 5.2-31).

In an actuation matrix, each signal also de-energizes the lockout relays when the train's group relays are actuated. The lockout relays assure that the actuation signal is not automatically reset once it has been initiated. In order to monitor the current through each leg of the selective two out of four logic matrix, four diodes are arranged in series to provide voltage for a local status light, the PPS status panel, and a remote annunciator.

The ESFAS actuation systems are designed so that loss of electrical power to two out of four measurement channels, initiation logic channels, or actuating logic channels of a system causes actuation of that system. However, loss of power to initiation circuits one and three (1-3 leg) exclusively or two and four (2-4 leg) exclusively will only cause that leg to trip and not actuate (see Figure 5.2-31).

ESFAS bistable relays, initiation relays, logic matrix relays, and actuation relays are normally energized and are de-energized to actuate and therefore, ESFAS actuation does not depend on electrical power availability.

The actuation systems include of redundant Trains A (load group 1), and B (load group 2). The instrumentation and controls of the two trains are physically and electrically separate and independent, so that the loss of one train will not impair the ESF system's safety function.

5.2.2.20.9 Major Modeling Assumptions

a) The ESFAS consists of various actuation signals. System failure is therefore defined at the signal level and represents the failure of the ESFAS signal to activate the required ESF system components.

b) System boundaries extend from the selected plant parameter sensor to, but not including, the ESFAS actuation relays. The actuation relays and manual actuation of selected group (or groups) of ESF system components are considered outside the system boundaries.

c) Since only one measurement channel of a given ESFAS signal can be in a bypass condition at any given time, unavailability contributions, due to a channel in bypass, are included for measurement channel A. (The bypass condition includes bypass for test and maintenance).

d) The contribution to a given ESFAS signal unavailability, due to coincidence logic matrix testing, is represented by the testing of the CD coincidence logic matrix. (Only one coincidence logic matrix may be tested at any given time).

e) A manual blocking capability is provided for certain ESFAS signals such as SIAS and CIAS to prevent spurious ESF system actuations during normal shutdown operations. Spurious manual blocking of an ESFAS signal was not modeled in the fault trees.

f) Individual relays are modeled for each of the ESFAS trees except for CIAS and SIAS which share the same matrix relays.

5.2.2.20.10 System Analysis Results

ESFAS actuation failure for each of the signals considered (AFAS, SIAS, CSAS, MSIS, CIAS, RAS) is dominated by common cause failure of the sensors and associated signal conditioning circuits. The probability of failure from random independent faults is very unlikely because there is sufficient redundancy (failure requires three of four channels to fail in order to function).

5.2.2.21 BOP/ESFAS Load Sequencer System

5.2.2.21.1 System Function

The ESF Load Sequencer functions as part of the Balance of Plant/Engineered Safety Features Actuation Signal (BOP/ESFAS) system to generate Loss Of Off-site Power (LOOP) signal, Load Shed (LS) signal, Diesel Generator Start Signal (DGSS), and load sequencer start and permissive signals, as required by plant operating conditions.

The Load Sequencer actuates in response to the following "Sequencer Modes:"

Mode 0	Sequencer in Standby.
Mode 1	Safety Injection Actuation Signal/Containment Spray Actuation Signal (SIAS/CSAS).
Mode 2	SIAS/CSAS, with a LOOP.
Mode 3	LOOP (no SIAS/CSAS).
Mode 4	Auxiliary Feedwater Actuation Signals (AFAS-1 or AFAS-2).
	Control Room Essential Filtration Actuation Signal (CREFAS), or Control Room Ventilation Isolation Actuation Signal (CRVIAS).
	Fuel Building Essential Ventilation Actuation Signal (FBEVAS).
	Diesel Generator Run Signal.

In response to the above Sequencer Modes, the sequencer initiates appropriate LS signals, starts the associated Emergency Diesel Generator (DG), and sequentially starts ESF and forced shutdown loads, as required. LS, and auto-sequencing of loads, is necessary to prevent over-current instability on the associated Class 1E 4.16kV switchgear (PBA-S03 and PBB-S04). The above Sequencer Modes are discussed in greater detail in "System Operation.".

The systems/components associated with CREFAS, CRVIAS, and FBEVAS, are not included in the PRA Model, therefore, this discussion will be limited to other actuations (combinations) indicated above.

5.2.2.21.2 Success Criteria

The success criteria for the BOP/ESFAS Load Sequencer system requires that all system modules function, as designed, to initiate appropriate signals to provide DG start, component LS, and component auto-sequencing.

5.2.2.21.3 System Description

The ESF Load Sequencer module consists of two redundant, independent trains, associated with each of the Class 1E 4.16kV Divisions. Each sequencer train is powered from a separate 120V AC vital bus, and a Class 1E 125V DC bus. Each Load Sequencer train is composed of a LOP/LS module, DG Start module, and BOP/ESFAS Sequencer module. Figure 5.2-32 shows a simplified diagram of the Load Sequencer system, and major interconnections between the various system modules. Sequencer logic modules actuate ESF components, or generate component permissive signals. Sequencer logic allows loading of specific components, based on appropriate combinations of ESFAS signals (as indicated by the previously noted Sequencer Mode list), or signals generated by other system modules. The ESF Load Sequencer modules are located in the BOP/ESFAS control cabinets at the 140-ft. elevation of the Control Building, adjacent to the Control Room.

In the event of a Sequencer system actuation in the absence of a LOOP, (applies to Sequencer Modes 1 and 4), no Sequencer LS signal is generated; only auto-sequencing of appropriate loads occurs. In Mode 1 (SIAS/CSAS), shedding signals from the SIAS Auxiliary Relays (not associated with ESF Sequencer) generate load shed of appropriate non-ESF loads.

In the event of a LOOP, with or without an appropriate ESF signal present (applies to Sequencer Modes 2 and 3), the Load Sequencer system monitors power at the Class 1E 4.16kV switchgear (PBA-S03, and PBB-S04). Upon sensing an undervoltage condition (on 2 out of 4 undervoltage relays) on either of the associated Class switchgear (indicative of a LOOP), a LS on the affected train(s) takes place. The LS signal causes appropriate sequencer module alarms, and associated LOP/LS relay change of state, prior to initiation of component loading.

Major components that are tripped by a LS signal include: the Safety Injection (SI) pumps, the motor-driven Auxiliary Feedwater (AF) pumps (Train B and Train N), the Essential Spray Pond pumps, the Essential Cooling Water (EW) pumps, the Essential Chilled Water (EC) chillers, the Class 1E battery chargers, the Class 1E voltage regulators, and the circuit breakers that normally supply off-site power to the 4.16kV ESF switchgear. Key components that are actuated by the LOP relays include the Emergency DG output circuit breakers, ESF switchgear room AHUs, and switchgear and Control Room normal, and essential HVAC dampers.

The BOP/ESFAS Sequencer module loads necessary ESF components, including: the SI pumps; the Train B AF pump; the EW pumps, the EC system chillers, the essential Spray Pond (SP) system pumps, the Charging pumps (permissive actuation relays are blocked, however, pumps can be manually started), the DG Building essential exhaust fans, the Control Room and Fuel Building essential ventilation units, and the Control Element Drive Mechanism (CEDM) normal AHUs (these units will restart only if they were running before the sensed LOOP condition). The Load Sequencer does not control any valves or dampers, thus, it does not cause ESF system actuation.

5.2.2.21.4 Major Components

Each ESF Load Sequencer train is composed of three inter-connected, solid-state logic modules: a LOP/LS module, a DG Start module, and a BOP/ESFAS Sequencer module. The Train A modules are located in BOP/ESFAS cabinet, SAA-C02A, and the Train B modules are in BOP/ESFAS cabinet, SAB-C02B. The BOP/ESFAS cabinets also contain the electro-mechanical relays that provide LS, align HVAC dampers, and actuate ESF components. These 10 amp, spring-return (to de-energized position), rotary relays may also be considered part of the Load Sequencer system.

5.2.2.21.5 Testing and Maintenance

The ESF Load Sequencer permits periodic system testing. Per Procedure 41OP-1SA01, BOP ESFAS Modules Operation, Control Room operators perform weekly tests from the Control Room, to check Load Sequencer input/output signal status. This test provides trip action verification from signal input, through the Load Sequencer system, and to the component actuation devices. The Load Sequencer test verifies the continuity of component loading relay coils (by applying a brief signal), without testing the mechanical function of the relay rotors. Full actuation of the BOP/ESFAS Load Sequencer system is performed at least once per 18-month period, per Intergrated Safeguards Surveillance Tests, 73ST-1DG01 and 73ST-1DG02.

Load Sequencer maintenance may be performed on only one sequencer at a time. Load Sequencer removal from service entails a complex process, involving jumpering of specific connections to prevent auto-actuation of certain systems. Load Sequencer de-energization is controlled by Operation Procedure 41OP-1SA02 "De-Energization of BOP/ESFAS", Maintenance Procedure 36MT-9SA03 "BOP/ESFAS Cross Train A Jumper Installation and Removal" controls installation/removal of cross-train jumpers in preparation for de-energization/re-energization of the BOP/ESFAS cabinets.

The procedure for Load Sequencer removal from service directs the Control Room operator to first perform the following steps: place the associated train's SP and EW system in service, rack-out the associated train's SI and AF system pump circuit breakers, and place the associated train's emergency DG in "OFF."

5.2.2.21.6 System Dependencies and Interfaces

Actuation

The actuation signals associated with the ESF Load Sequencer system are indicated on Figure 5.2-32. The following information should be noted:

- The DGs will start directly on AFAS-1, AFAS-2, or SIAS, but the DG output circuit breaker will not close onto the associated 4.16kV switchgear unless a LOP signal (from the LOP/LS module) is also present. With an AFAS or SIAS present, and no loss of preferred power, the Control Room operator may manually override the AFAS or SIAS signal. The DG can then be manually shut down (locally or remotely).
- The AFAS and SIAS signals are unaltered as they pass through the DGSS module.
- FBEVAS, CREFAS, and CRVIAS functions are not included in the PRA Model.

Electric Power

Each of the ESF Load Sequencer trains receives power from an auctioneered power supply, via its associated Class Power Division. The Train A Load Sequencer modules are normally powered from Class 1E 120V AC vital/instrument power bus, PNA-D25. Train A Load Sequencer backup power from Class 1E 125V DC bus, PKA-D21, is immediately available, via an inverter. The

Train B Load Sequencer is similarly powered from Class 1E 120V AC vital bus, PNB-D26, and Class 1E 125V DC bus, PKB-D22.

The fans that provide forced air circulation through the BOP/ESFAS cabinets are also powered from the associated Class 1E 120V AC vital bus, PNA-D25 or PNB-D26.

HVAC

The two power supply modules, and approximately 30 relays, contained in each BOP/ESFAS cabinet, present a substantial heat load. This load has the potential to degrade the operation of the solid-state logic modules. Each cabinet power supply, therefore, contains its own cooling fan, which ejects heat to the outside of the vented cabinet. Failure of these fans is locally alarmed.

Early operations experience at one of the PVNGS Units indicated that the BOP/ESFAS logic modules could malfunction if the cabinets were cooled only by natural convection; therefore, each BOP/ESFAS cabinet (SAA-C02A and SAB-C02B) was provided with dual fans mounted in the top panel of the cabinet. These fans provide forced air cooling of the Load Sequencer modules, and associated BOP/ESFAS equipment contained within the cabinet. BOP/ESFAS cabinet high-temperature is alarmed in the Control Room as part of the BOP/ESFAS cabinet trouble alarm.

The HVAC analysis performed for PVNGS systems and rooms includes analysis of appropriate Control Room (and cabinet area) ventilation systems. Because the cabinet area room air is circulated through the BOP/ESFAS cabinets (via the cabinet cooling fans), the ESF Load Sequencers depend upon Control Room HVAC, in addition to the cabinet cooling unit dependency. Analysis indicates the equipment in the cabinets is not threatened until cabinet area room temperature reaches approximately 119° F. Above this temperature, various BOP/ESFAS modules could fail to function. In addition, the BOP/ESFAS modules could generate spurious LOP/LS signals which could significantly affect plant/system operating conditions.

Operator Action

Upon a BOP/ESFAS Load Sequencer actuation, the Control Room operator is required, per Emergency Operation Procedure 41EP-1ZZ01, to verify proper ESF system component shed and auto-sequencing.

When the Load Sequencer enters Modes 1, 2, or 4, the operator must manually reset associated ESFAS signals (SIAS, CSAS, etc.) before the Load Sequencer can return to Mode 0.

5.2.2.21.7 Technical Specifications

PVNGS Technical Specification 3/4.8.1.1.2, "Electrical Power Systems," directly addresses ESF Load Sequencer surveillance. This Technical Specification requires that each DG be demonstrated operable, at least once per 18 months, by the following:

- Verify that the Load Sequencers are operable (interval tolerance between load blocks: 1 sec. of its design interval).

- Verify de-energization of the emergency busses, and load shedding from the emergency busses.
- Verify that DG start occurs, emergency bus permanently-connected loads are energized within 10 secs., and auto-connected shutdown loads are energized through the Load Sequencers.
- Verify that on ESF actuation test signal (without LOP), the DG starts on its associated auto-start signal, and operates (in standby) for a minimum of 5 mins.

The aforementioned list contains only those DG testing/surveillance requirements which are directly applicable to operation of the ESF Load Sequencers.

In addition, specifications pertaining to ESFAS response times (Technical Specification 3/4.3, Table 3.3-5) require that certain SI and AF system responses occur within specific time constraints. DG start and sequencer loading delays are also included within some of these limits, placing requirements on Load Sequencer performance.

5.2.2.21.8 System Operation

Normal BOP/ESFAS Load Sequencer system operation is indicated on Figure 5.2-33. The following provides a detailed discussion which supplements the information provided on this figure.

During normal at-power operation, the BOP/ESFAS Load Sequencer system is in "standby" mode (Sequencer Mode 0). The Load Sequencer system is ready to respond to SIAS/CSAS, LOOP, AFAS, CREFAS/CRVIAS, FBEVAS, and DG run signals, as necessary. The Load Sequencer has four independent "operating" modes. In response to the changing mode conditions, the Load Sequencer must always "reset" to Sequencer Mode 0, before entering a different operating mode.

<u>Sequencer Mode 1 - SIAS/CSAS (no LOOP)</u>

Upon sensing a SIAS or CSAS (in the absence of a LOOP condition), the SIAS Auxiliary Relays first shed specific non-ESF loads, as indicated in Table 5.2-1. The ESF Load Sequencer then actuates specific components according to the appropriate loading sequence, also provided in Table 5.2-1. When component loading is completed, the load sequencer remains in Mode 1 until either the SIAS/CSAS signal clears (must be manually reset by the Control Room operator), or a LOOP occurs, at which time, the Load Sequencer immediately returns to Mode 0.

<u>Sequencer Mode 2 - SIAS/CSAS coincident with a LOOP</u>

When a SIAS (or CSAS) exists concurrently with a LOOP, an ESF LS signal is generated on the affected train (via a 1 sec. LS pulse), thereby, shedding all equipment indicated in Table 5.2-2. Automatic component loading is initiated when the associated Diesel Generator output breaker closes. The ESF Load Sequencer then actuates specific components according to the sequence, also provided in Table 5.2-2. If either the SIAS/CSAS signal clears (must be manually reset by the Control Room operator), or the LOOP condition clears (after the 60 sec. lock-in expires), the Load Sequencer returns to Mode 0. The Load Sequencer senses power restored to the associated ESF switchgear when the DG output breaker closes. After component loading is completed (following the 60 sec. LOOP signal lock-in), the Load Sequencer returns to Mode 0.

Sequencer Mode 3 - LOOP (no SIAS/CSAS)
When an undervoltage condition is sensed (on two out of four undervoltage relays) on either of the associated Class 4.16kV ESF bus, an ESF LS signal is generated on the affected train (via a 1 sec. LS pulse), shedding the same equipment as for Sequencer Mode 2. Automatic component loading is initiated when the associated DG output breaker closes. The ESF Load Sequencer then actuates specific components according to the sequence provided in Table 5.2-3. If the LOOP condition clears, or if a SIAS or CSAS signal is received by the Load Sequencer, the Load Sequencer immediately returns to Mode 0. The Load Sequencer senses power restored to the associated ESF switchgear when the DG output breaker closes. After component loading is completed (following the 60 sec. LOOP signal lock-in), the Load Sequencer returns to Mode 0.

Sequencer Mode 4 - AFAS-1 or AFAS-2 (no SIAS/CSAS, and no LOOP)
After an AFAS-1 or AFAS-2 signal is received, the ESF Load Sequencer generates signals for automatic loading of specific components, according to the sequence provided in Table 5.2-4. If the AFAS signal(s) clear (must be manually reset by the Control Room operator), or if a SIAS, CSAS or LOOP signal is received by the Load Sequencer, the Load Sequencer immediately returns to Mode 0.

Sequencer Mode 4 - Diesel Generator Run (no SIAS/CSAS, and no LOOP)
Upon receipt of a DG run signal, the ESF Load Sequencer generates signals for automatic loading of specific components, according to the sequence provided in Table 5.2-4. If the DG run signal clears (i.e., DG trips), or if a SIAS, CSAS, or LOOP signal is received by the Load Sequencer, the Load Sequencer immediately returns to Mode 0.

After the Load Sequencer has entered a given mode, receipt of a subsequent input signal may require a change of Sequencer Mode. In this event, the Load Sequencer resets, transfers to the required Mode (in the case of a LOOP, the 60-sec. "lock-in" must also clear before Sequencer transfer to a new Mode), and initiates sequencing of the required loads. Reset of the Load Sequencer will not cause shedding of components loaded during a previous Mode condition.

If a Load Sequencer actuation condition occurs while the associated DG is supplying power to the associated ESF bus, the Load Sequencer will initiate appropriate component loading, without shedding any previously running equipment.

If a LOOP occurs at some time after a Load Sequencer actuation, and component loading has occurred (DG is up to rated speed and voltage, and auto-actuated ESF equipment is running), the sequencer initiates restart of the associated SI and Train B essential AF pump, etc. This provides uninterrupted flow to the reactor core, and to the SGs.

5.2.2.21.9 Major Modeling Assumptions

a) The BOP/ESFAS Load Sequencer system consists of closely integrated, vendor-supplied units. These units rely, primarily, on solid-state logic modules; therefore, this system is modeled as a series of Undeveloped Events (UEs) representing each of the modules. All Load Sequencer modules which may contribute to a particular system failure, are explicitly modeled the appropriate system Fault Tree (UEs are included in the logic for each component affected by failure of the Load Sequencer). Table 6.2-7 lists Load Sequencer system events used in the system Fault Trees.

b) Major ESFAS systems which provide actuation signals to the Load Sequencer system were developed separately, and appear as developed "support" systems in the system Fault Trees.

c) The PVNGS PRA, conservatively, takes no credit for Load Sequencer inputs from the FBEVAS, CREFAS, and CRVIAS systems.

5.2.2.21.10 System Analysis Results

All ESF Load Sequencer faults, modeled in the PRA, are single failures. Their relative importance depends entirely on the front-line/support system Fault Tree in which the Load Sequencer or LS event(s) appear. Table 6.2-7 gives the failure probabilities for each of the Load Sequencer faults modeled in the various system Fault Trees.

5.3 References

5.3.1 EPRI, "Documentation Design for Probabilistic Risk Assessment", RP2171-3, October 1983

5.3.2 D. Carlson, "Interim Reliability Evaluation Program Procedures Guide", NUREG/CR-2728, January 1983

5.3.3 Combustion Engineering Design Document, 14273-PE-IR-30, Rev 03, Section 4.3.1.1

5.3.4 Combustion Engineering, "Probabilistic Risk Assessment of the Effect of PORVs on Depressurization and Decay Heat Removal for PVNGS Units 1, 2, and 3," CEN-239, Supplement 3, September 1983

Matrix 5.2-1 PVNGS System Dependencies Matrix

SUPPORT SYSTEM	FRONT-LINE SYSTEM																															
	HPSI Pump A	HPSI Pump B	HPSR Train A	HPSR Train B	LPSI Pump A	LPSI Pump B	LPSR Train A	LPSR Train B	CS Pump A	CS Pump B	AF Pump A	AF Pump B	AF Pump N	AltFW Pump A	AltFW Pump B	AltFW Pump C	APSS	BD	PRZVENT	TBV	ADV V178	ADV V179	ADV V184	ADV V185	HLI Train B	HLI Train B	SDC Train A	SDC Train B	SITS	RPS	Charging	CMT Isolation
EW Train A																																
EW Train B																																
EC Train A																																
EC Train B																																
SP Train A																																
SP Train B																																
ESFAS Train A	A		A		A				A		A																					A
ESFAS Train B		A		A		A				A		A																				A
HVAC	B	B	B	B	B	B	B	B	B	B	B	B								C	D	D	D	D	B	B	B	B			O	
Instrument Air													E	E	E	E		X		X	F	F	F	F								
HP Nitrogen													G	G	G	G													H			
Off-site Power														P	P	P		P		P												
4.16kV AC PBA-S03	X		X		X		X		X		X		X												X		X				J	X
4.16kV AC PBB-S04		X		X		X		X		X		X														X		X			J	X
DG Train A											X		X																			
DG Train B												X																				
125V DC PKA-D21	X				X				X		X		Q				X	X	X			X	X							L		
125V DC PKB-D22		X				X				X		X					X	X	X		X			X						L		
125V DC PKC-D23											X											X	X		X		X			L		
125V DC PKD-D24																					X			X		X		X		L		
120V AC PNA-D25																						X	X				X			N		N
120V AC PNB-D26																					X			X				X		N		N
120V AC PNC-D27																											X			N		N
120V AC PND-D28																												X		N		N

SUPPORT TO FRONT-LINE SYSTEM DEPENDENCY

A) The ESFAS 2/4 provides initiating signals for components which require automatic actuation following rupture of a primary or secondary pressure boundary. These signals are as follows:

- Containment Isolation Actuation Signal (CIAS)
- Containment Spray Actuation Signal (CSAS)
- Main Steam Isolation Signal (MSIS)
- Safety Injection Actuation Signal (SIAS)
- Re-circulation Actuation Signal (RAS)
- Auxiliary Feedwater Actuation Signal (AFAS)

B) Pump room cooling.

C) Cooled by control room ventilation (not modeled).

D) ADV E/P dependence in AF pump room (not modeled).

E) Backed up by HP Nitrogen for feed reg. valve and downcomer isolation valve operation.

F) Each valve has its own backup Nitrogen accumulator.

G) Provides motive force to hold open downcomer isolation valves.

H) Safety Injection Tanks pressurized with Nitrogen.

J) 480V AC dependency.

L) Trip breaker depends on DC power to energize trip coil or maintain UV coils energized.

N) Half leg actuations through RPS AC to DC power supplies. Loss of any two results in actuations.

O) Pump room cooling (not modeled).

P) Off-site Power includes Non-class power systems within the power block.

Q) N pump is also dependent on non-class 125V DC via the downcomer bypass valves.

Matrix 5.2-1 PVNGS System Dependencies Matrix (Continued)

SUPPORT SYSTEM	SUPPORT SYSTEM (dependent)																							
	EW Train A	EW Train B	EC Train A	EC Train B	SP Train A	SP Train B	ESFAS Train A	ESFAS Train B	Instrument Air	HP Nitrogen	Off-site Power	HVAC	4.16kV ACPBA-S03	4.16kV ACPBB-S04	DG Train A	DG Train B	125V DC PKA-D21	125V DC PKB-D22	125V DC PKC-D23	125V DC PKD-D24	120V AC PNA-D25	120V AC PNB-D26	120V AC PNC-D27	120V AC PND-D28
EW Train A	-		X																					
EW Train B		-		X																				
EC Train A			-									A												
EC Train B				-								A												
SP Train A	X				-										X									
SP Train B		X				-										X								
ESFAS Train A	B		B		B		-								C		D		D					
ESFAS Train B		B		B		B		-								C		D		D				
Instrument Air									-			X												
HP Nitrogen										-														
Off-site Power									H		-	H	H	H										
HVAC	E	E										-	F	F	G	G	F	F	F	F	F	F	F	F
4.16kV AC PBA-S03	X		X		X							X	-				L		L		N		N	
4.16kV AC PBB-S04		X		X		X						X		-				L		L		N		N
DG Train A													P		-									
DG Train B														P		-								
125V DC PKA-D21	X		X									X	S		X		-				N			
125V DC PKB-D22		X		X								X		S		X		-				N		
125V DC PKC-D23																			-				N	
125V DC PKD-D24																				-				N
120V AC PNA-D25			X				T	T													-			
120V AC PNB-D26				X			T	T														-		
120V AC PNC-D27							T	T															-	
120V AC PND-D28							T	T																-

SUPPORT TO SUPPORT SYSTEM DEPENDENCY

A) Essential Chillers provide cooling water to HVAC units.

B) Cooling water provided to HVAC components upon receipt of the following signals:

  Containment Isolation Actuation Signal CIAS)

  Containment Injection Actuation Signal (CSAS)

  Auxiliary Feedwater Actuation Signal (AFAS)

  Loss of Off-site Power (LOP)

C) DG's have weak dependency on ESFAS (Loss of Off-site Power).

D) Chargers reloaded on bus following LOP and/or SIAS.

E) Pump room cooling.

F) Switchgear room cooling.

G) DG room cooling (strong dependence during DG operation).

H) Off-site Power includes Non-class power systems within the power block.

L) Battery can supply loads for two hours given loss of charging.

N) 120V AC normally depends on DC power, 480V AC is backup.

P) DGs supply emergency on-site power upon LOP.

S) Breakers depend on DC power for closure.

T) Loss of any two channels actuates ESFAS.

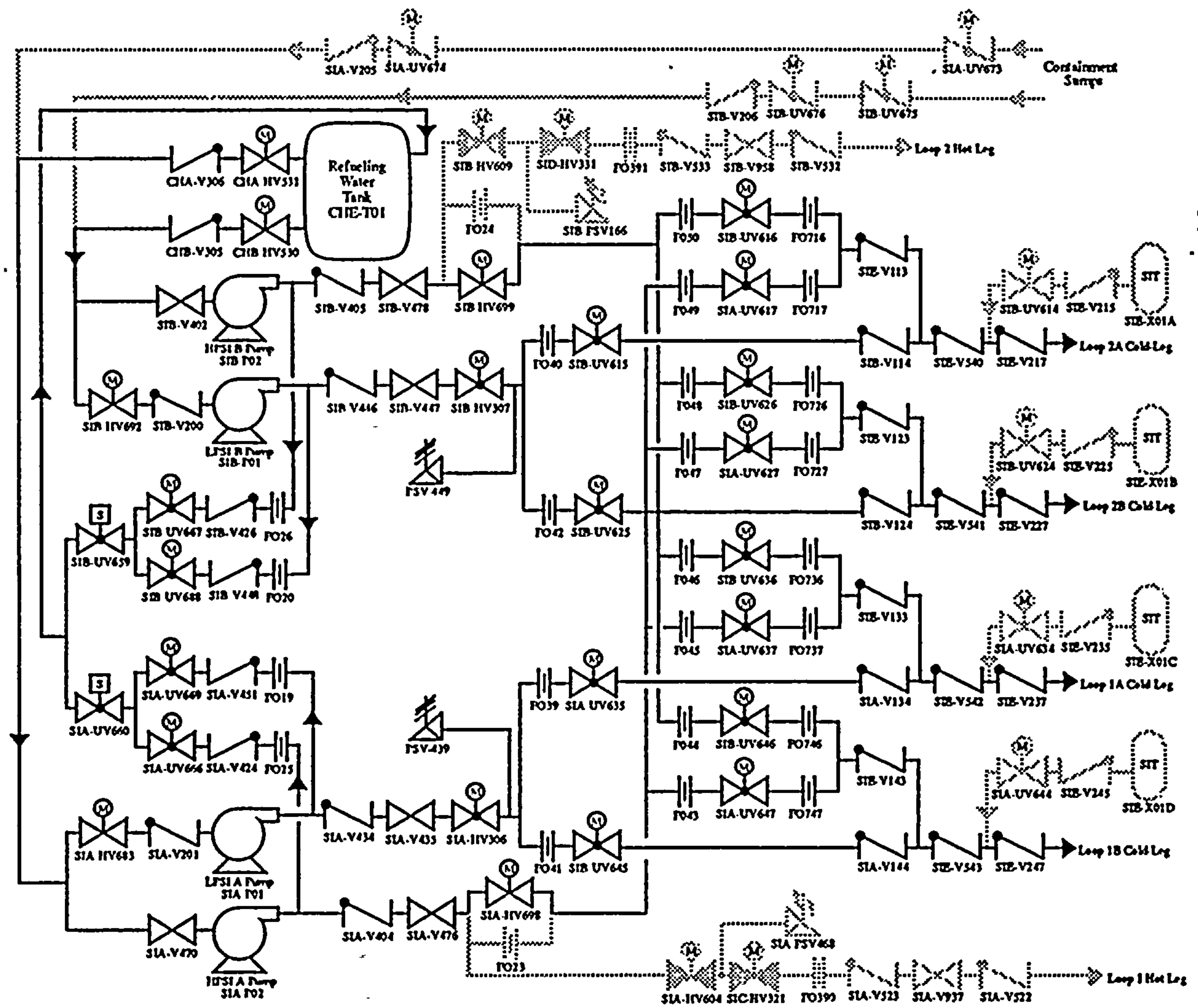

Figure 5.2-1

High/Low Pressure Safety Injection System

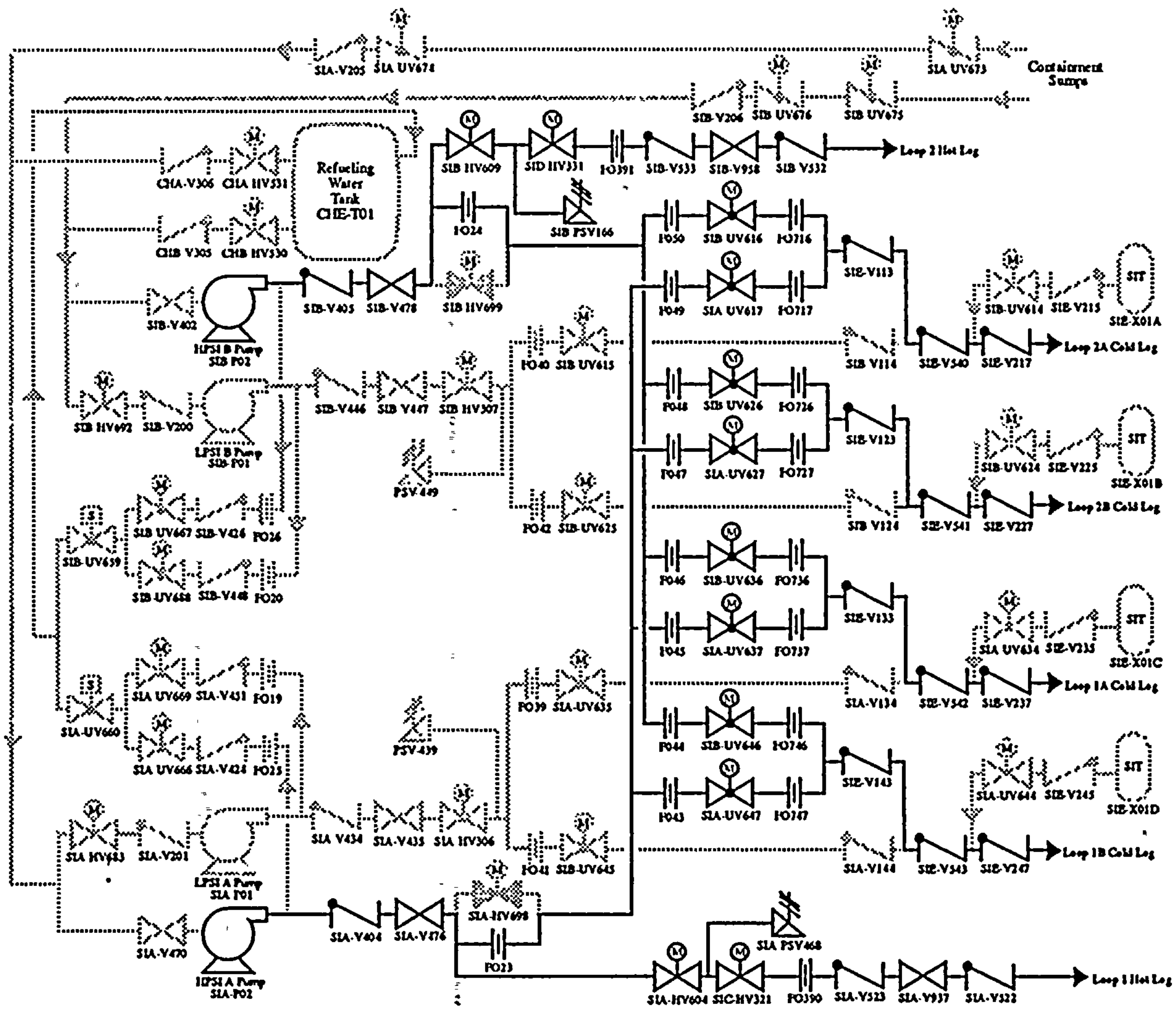

Figure 5.2-2

Hot-Leg Injection

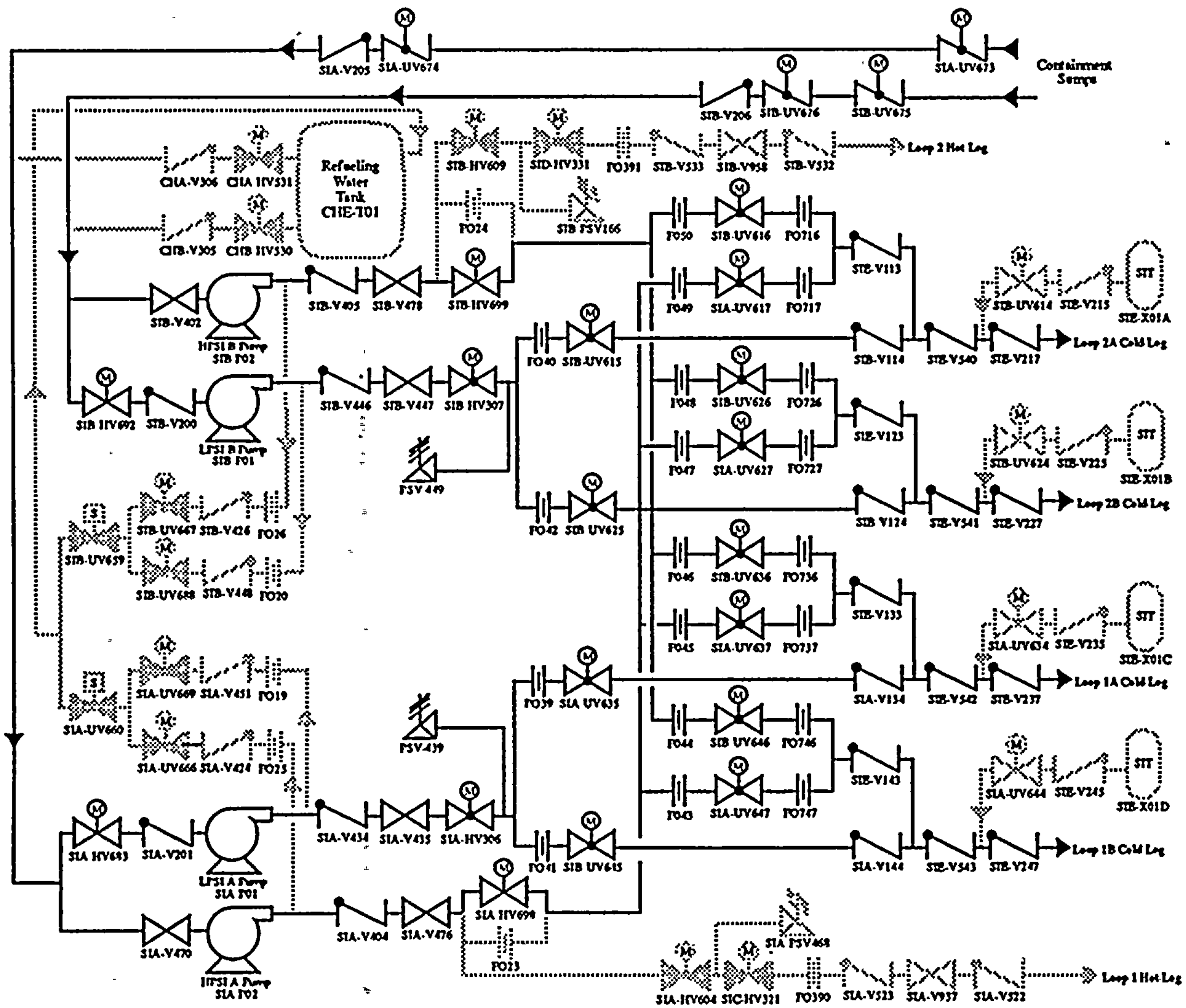

Figure 5.2-3

High/Low Pressure Safety Recirculation

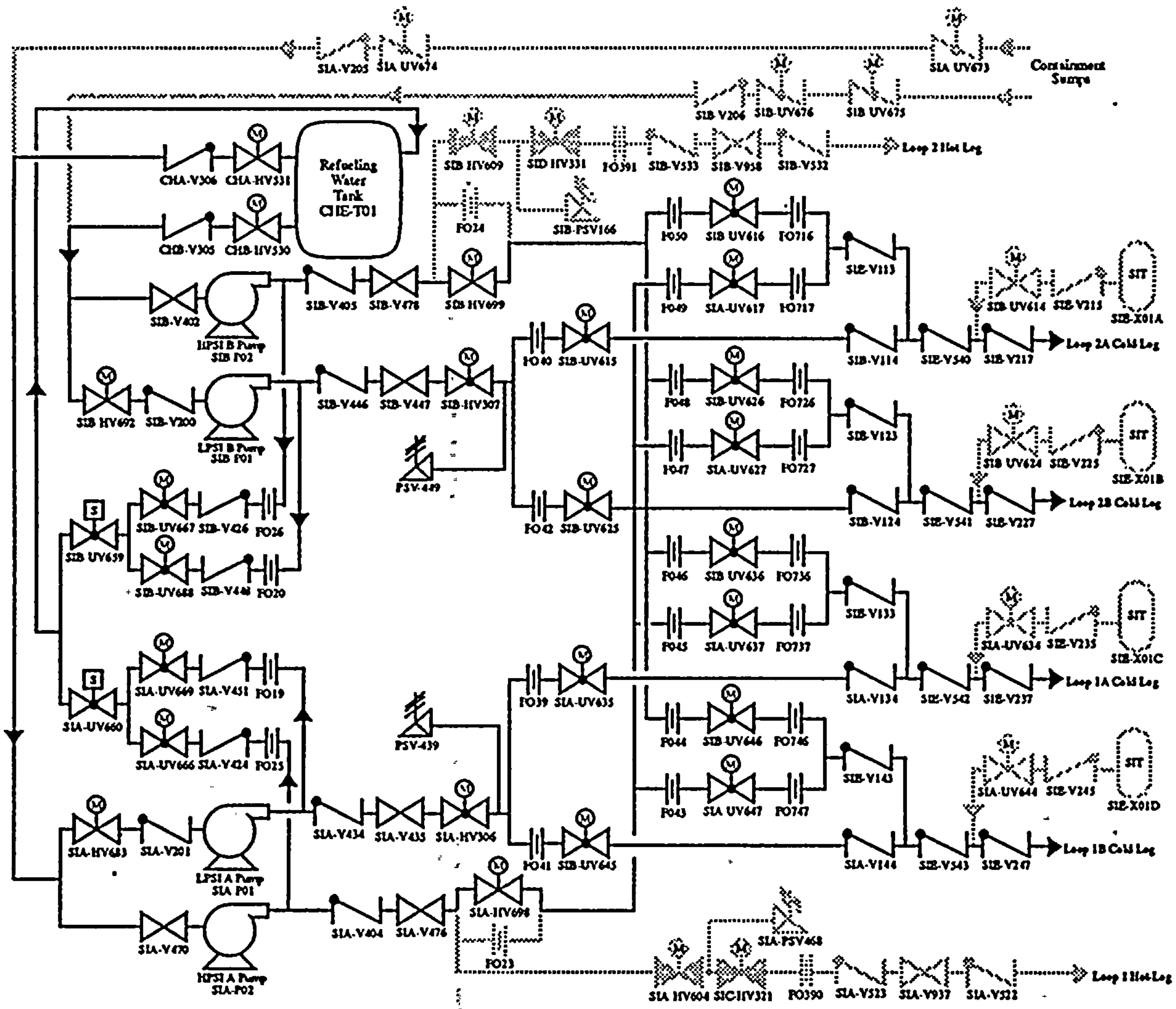

Figure 5.2-4

High/Low Pressure Safety Injection System

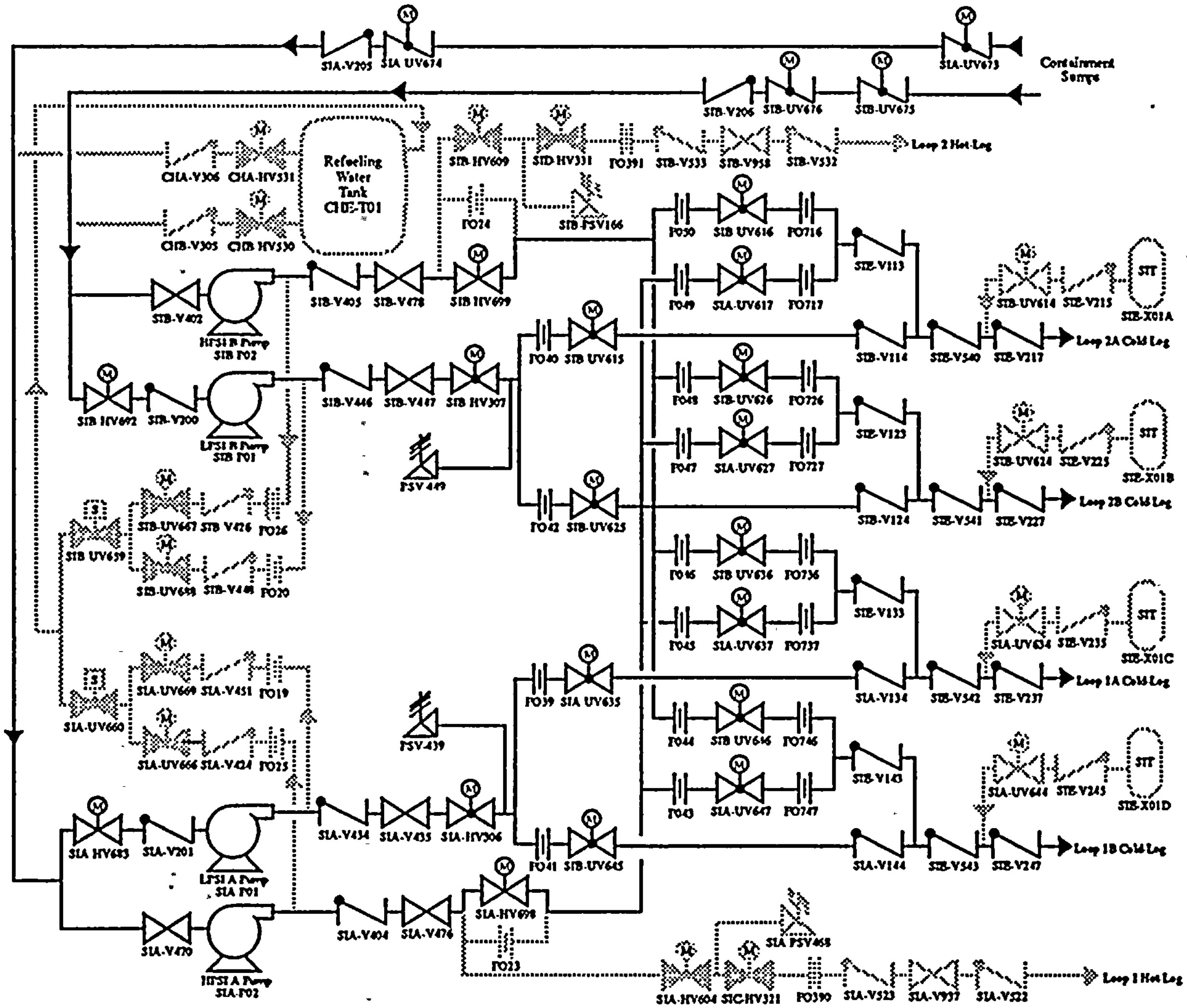

Figure 5.2-5

High/Low Pressure Safety Recirculation

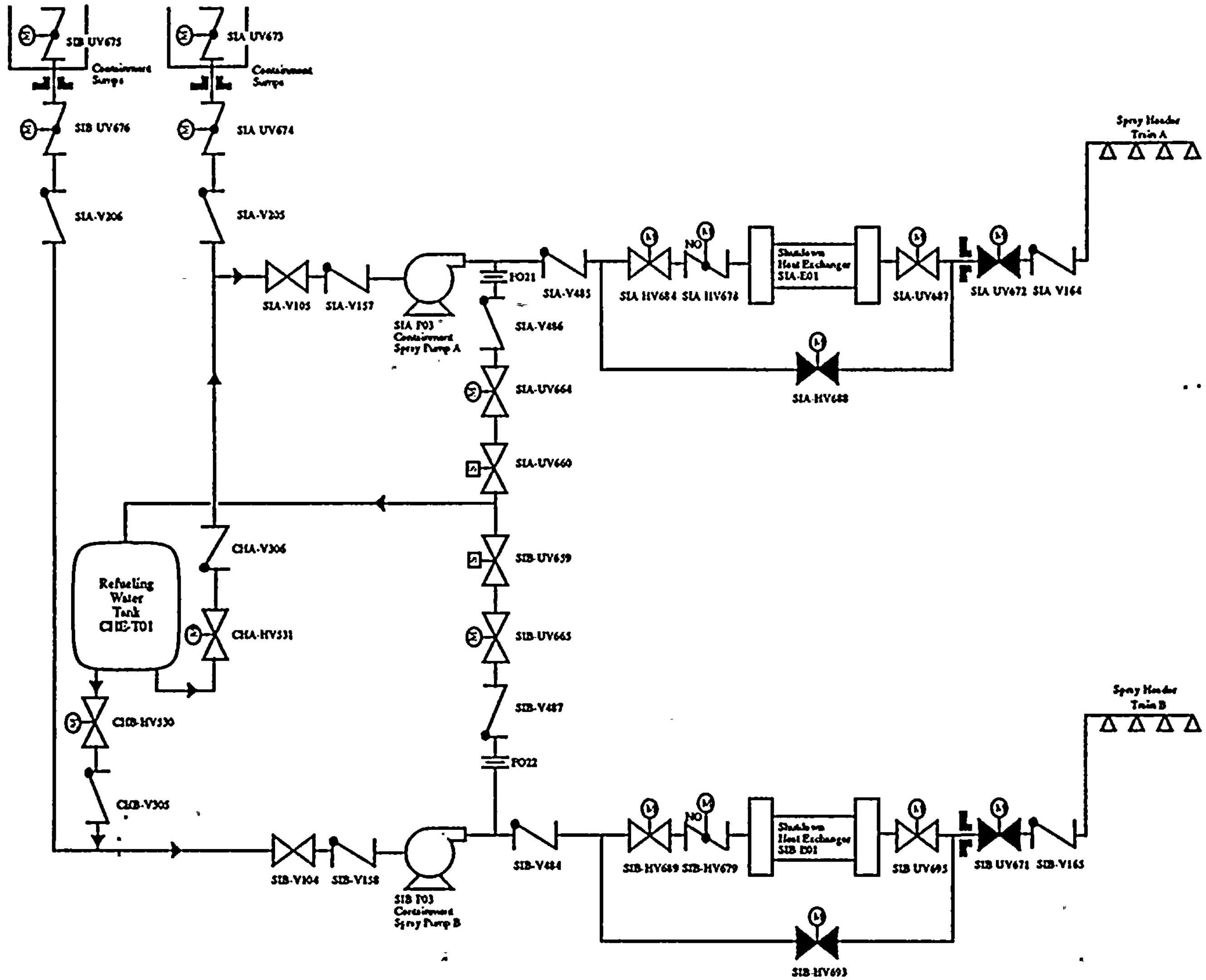

Figure 5.2-6

Containment Spray System

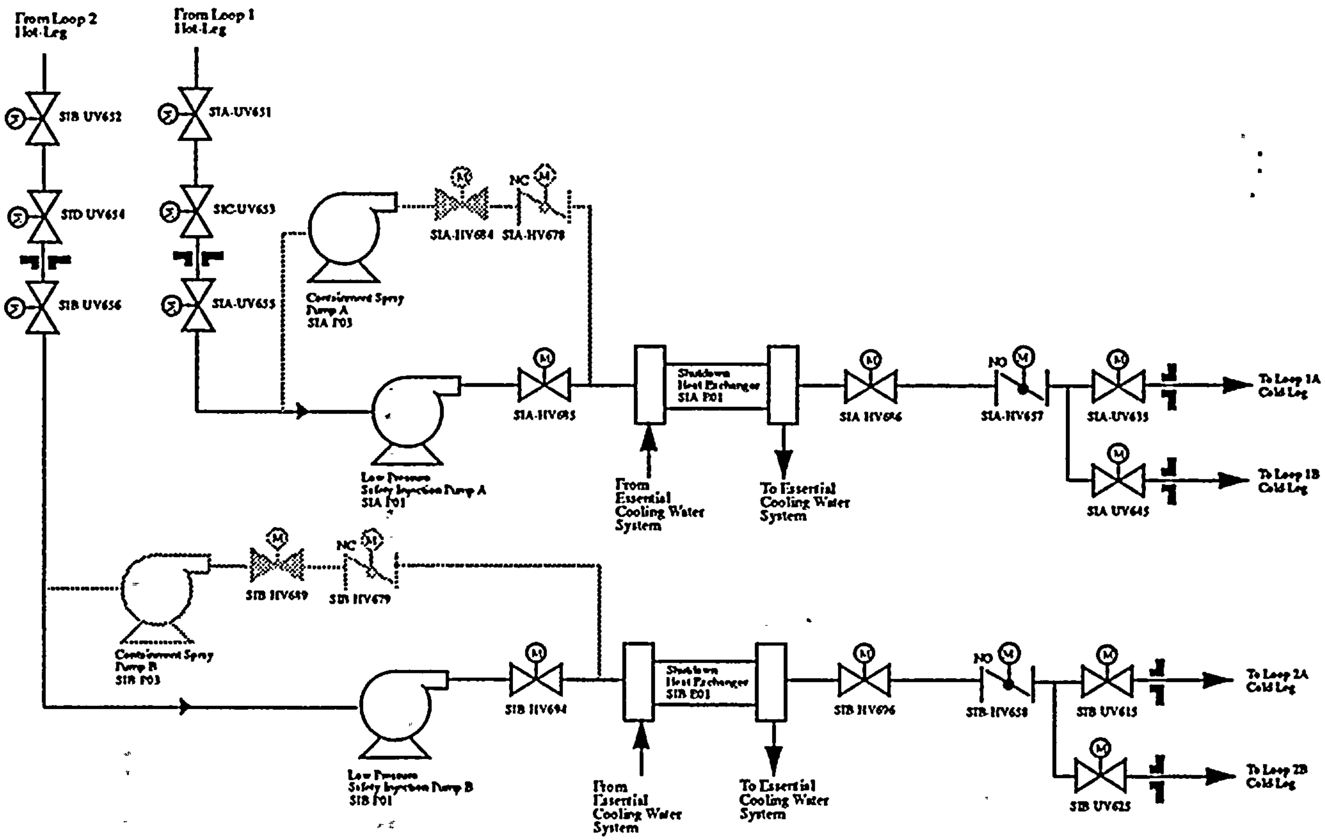

Figure 5.2-7

Shutdown Cooling System

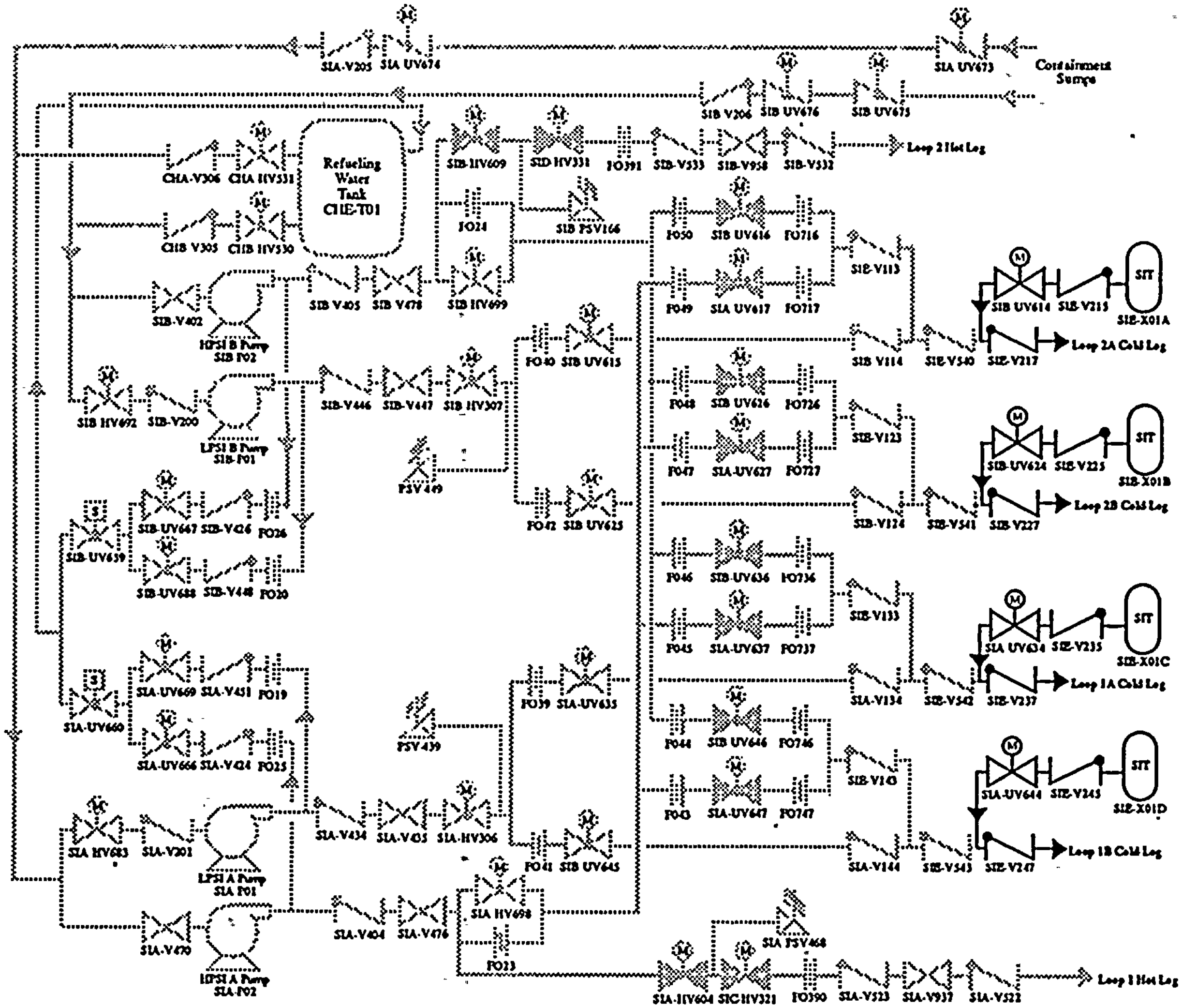

Figure 5.2-8

Safety Injection Tanks

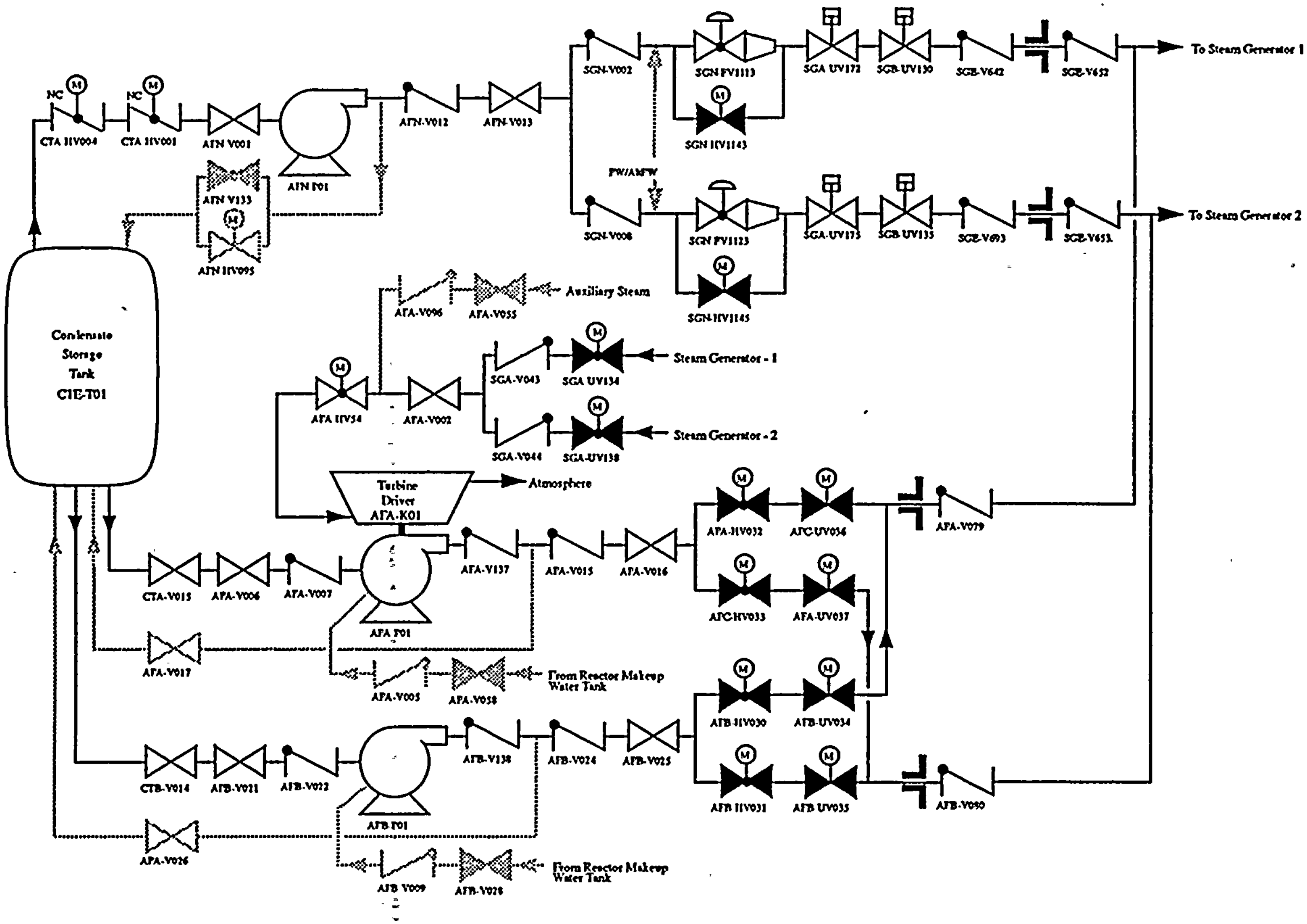

Figure 5.2-9

Auxiliary Feedwater System

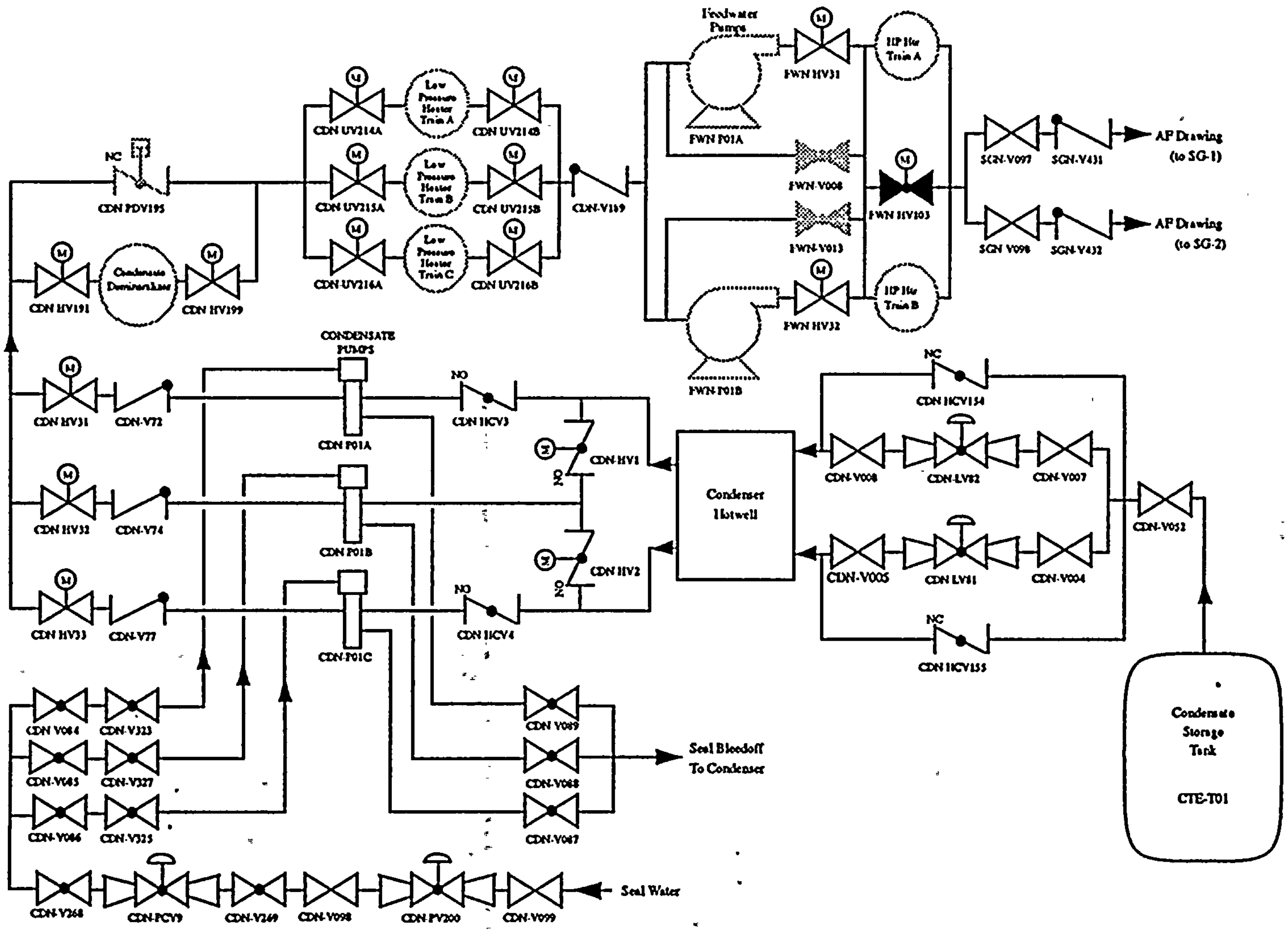

Figure 5.2-10

Alternate Feedwater System

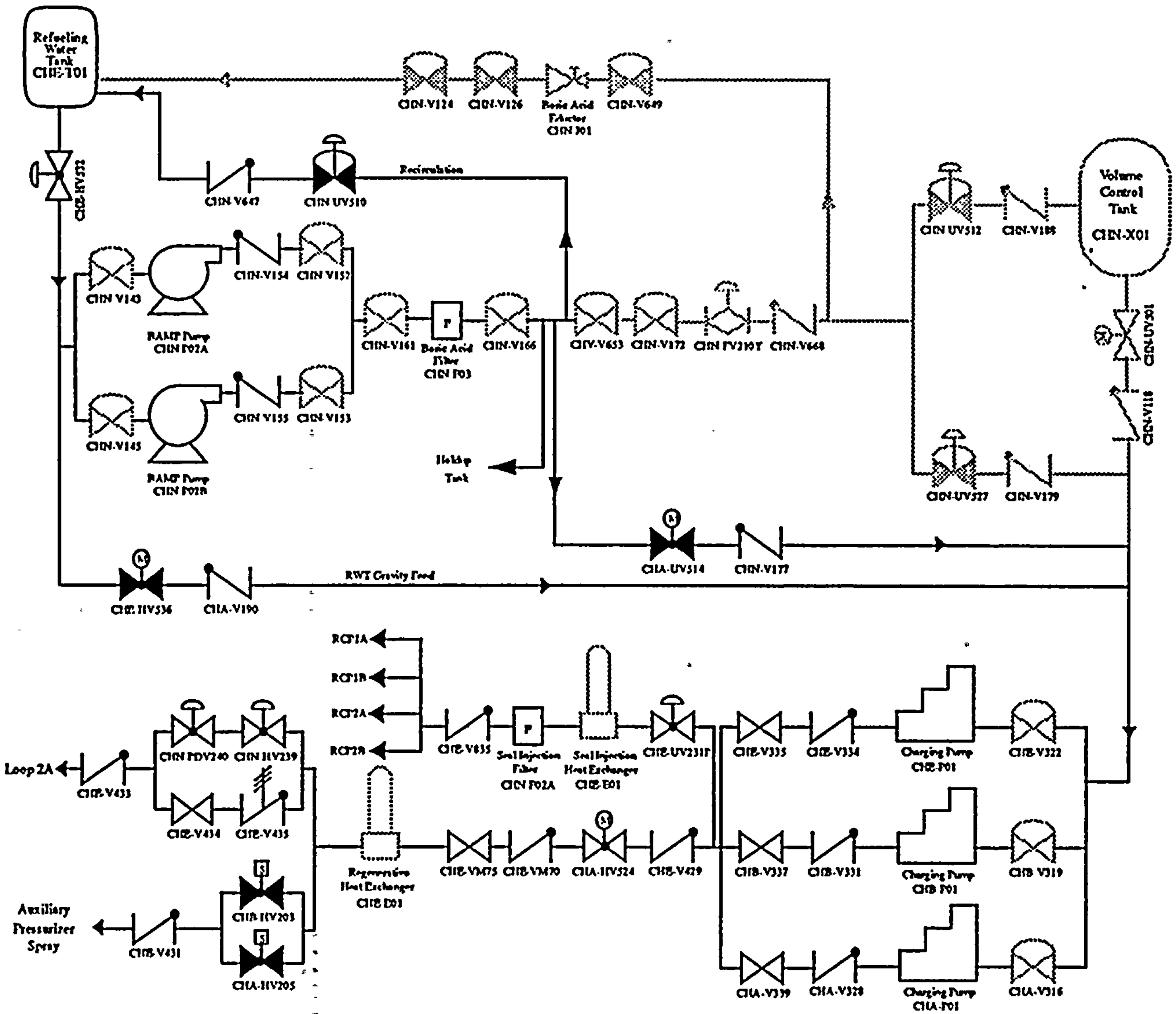

Figure 5.2-11

Chemical and Volume Control System

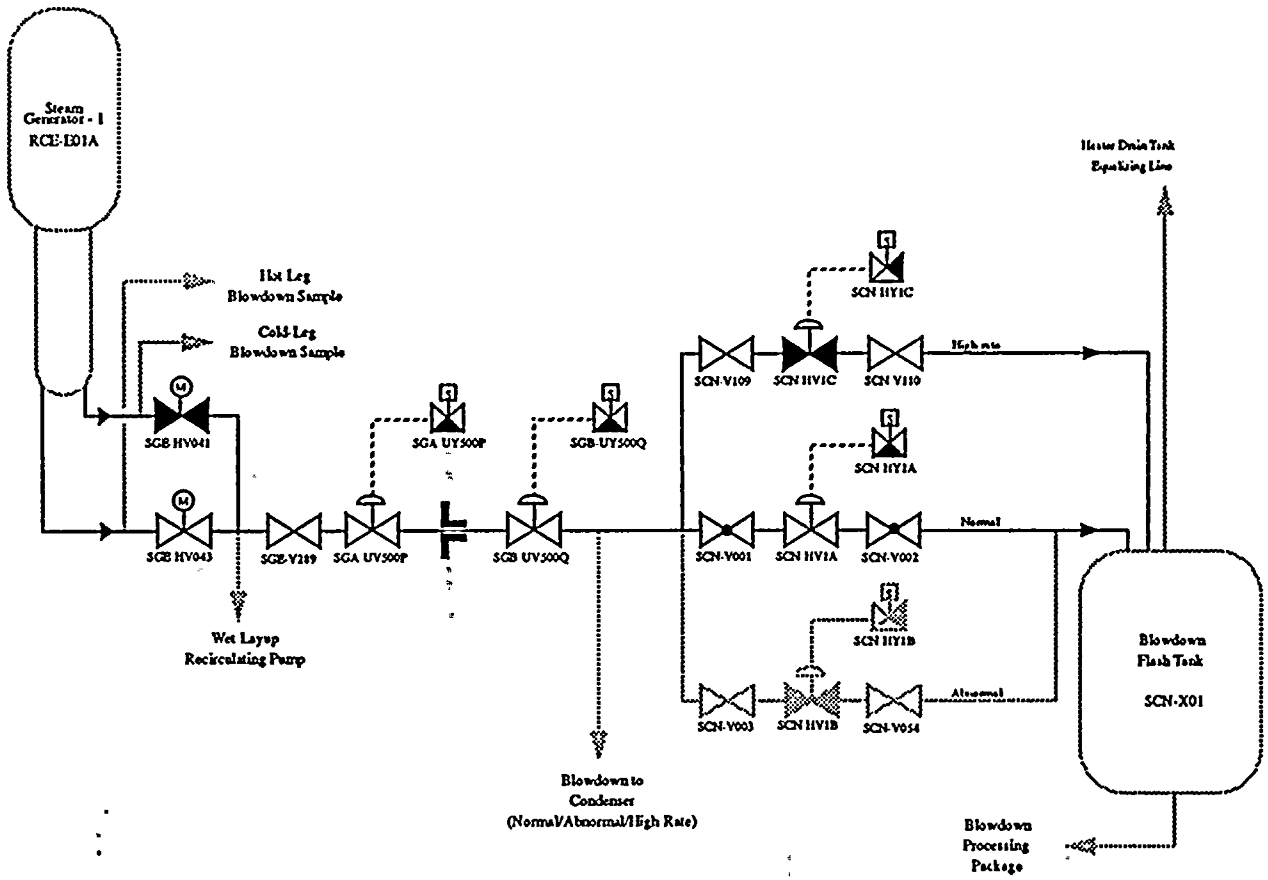

Figure 5.2-12

Steam Generator Blowdown System

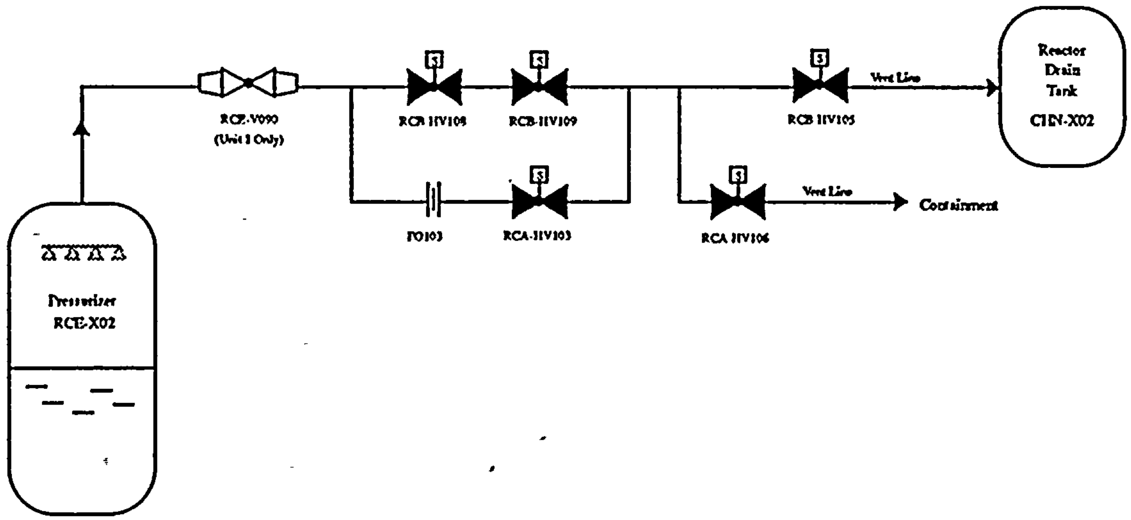

Figure 5.2-13

Pressurizer Vent System

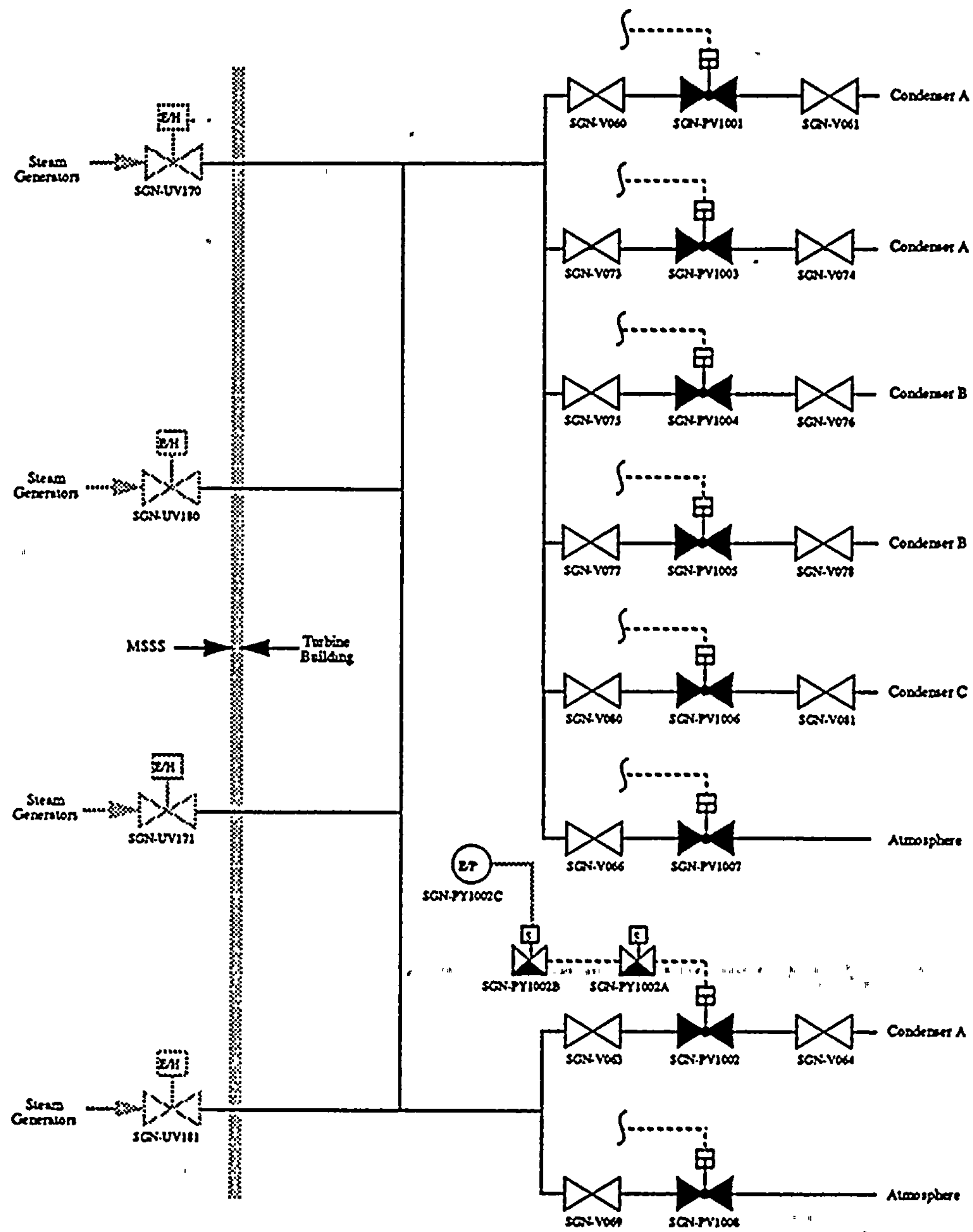

Figure 5.2-14

Turbine Bypass Valve System

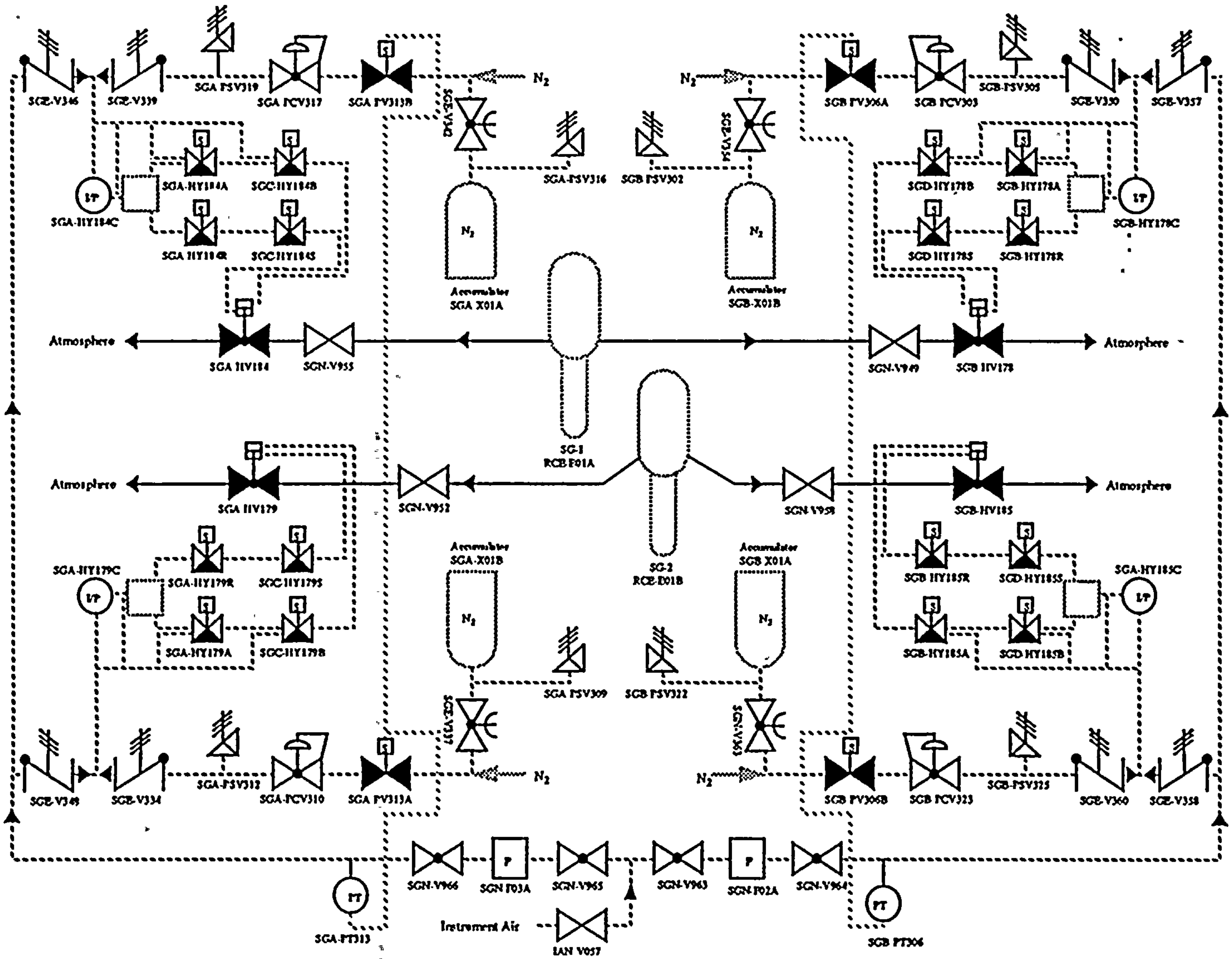

Figure 5.2-15

Atmospheric Dump System

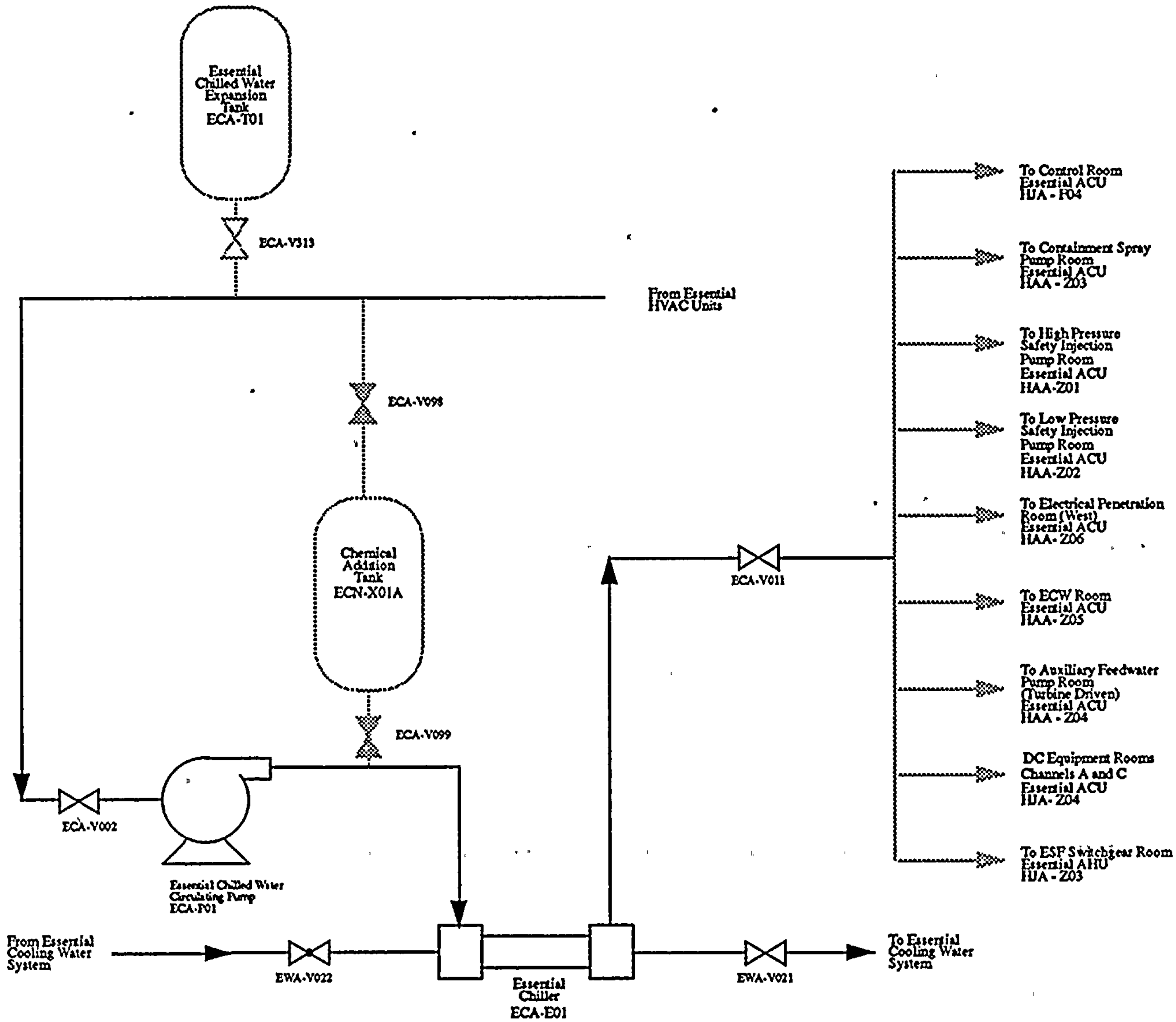

Figure 5.2-16

Essential Chilled Water System - Train A

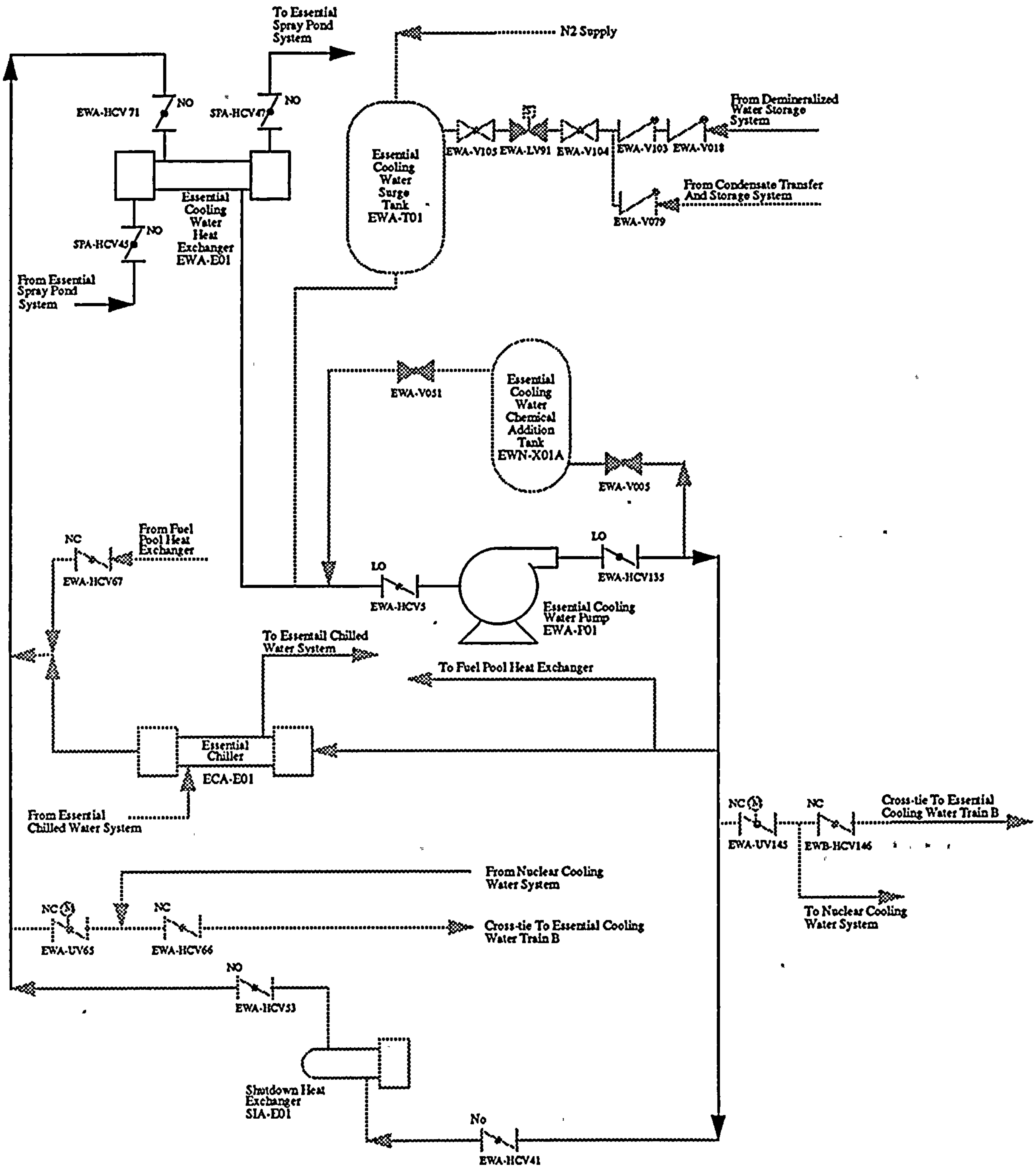

Figure 5.2-17

Essential Cooling Water System - Train A

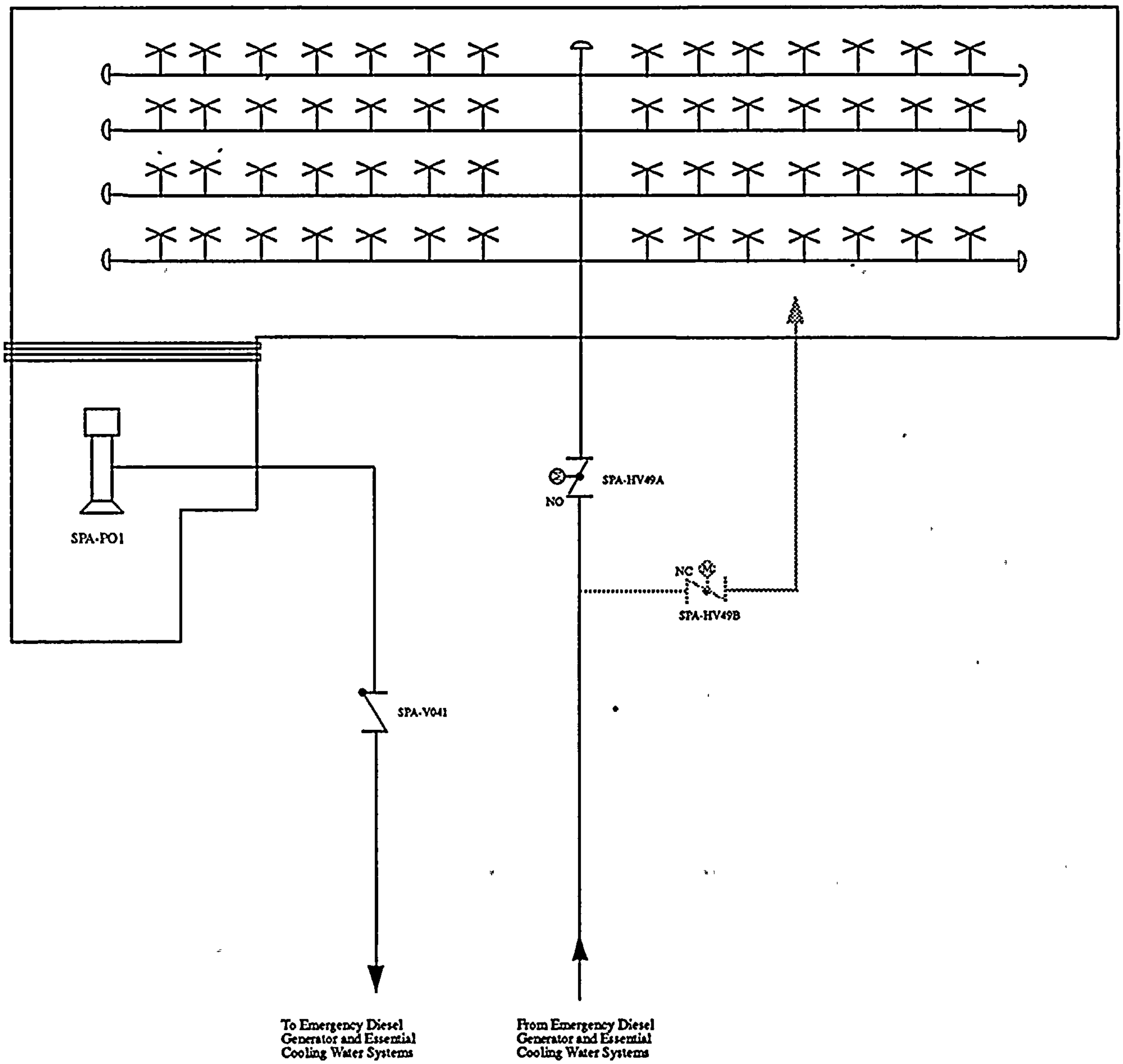

Figure 5.2-18

Essential Spray Pond System - Train A

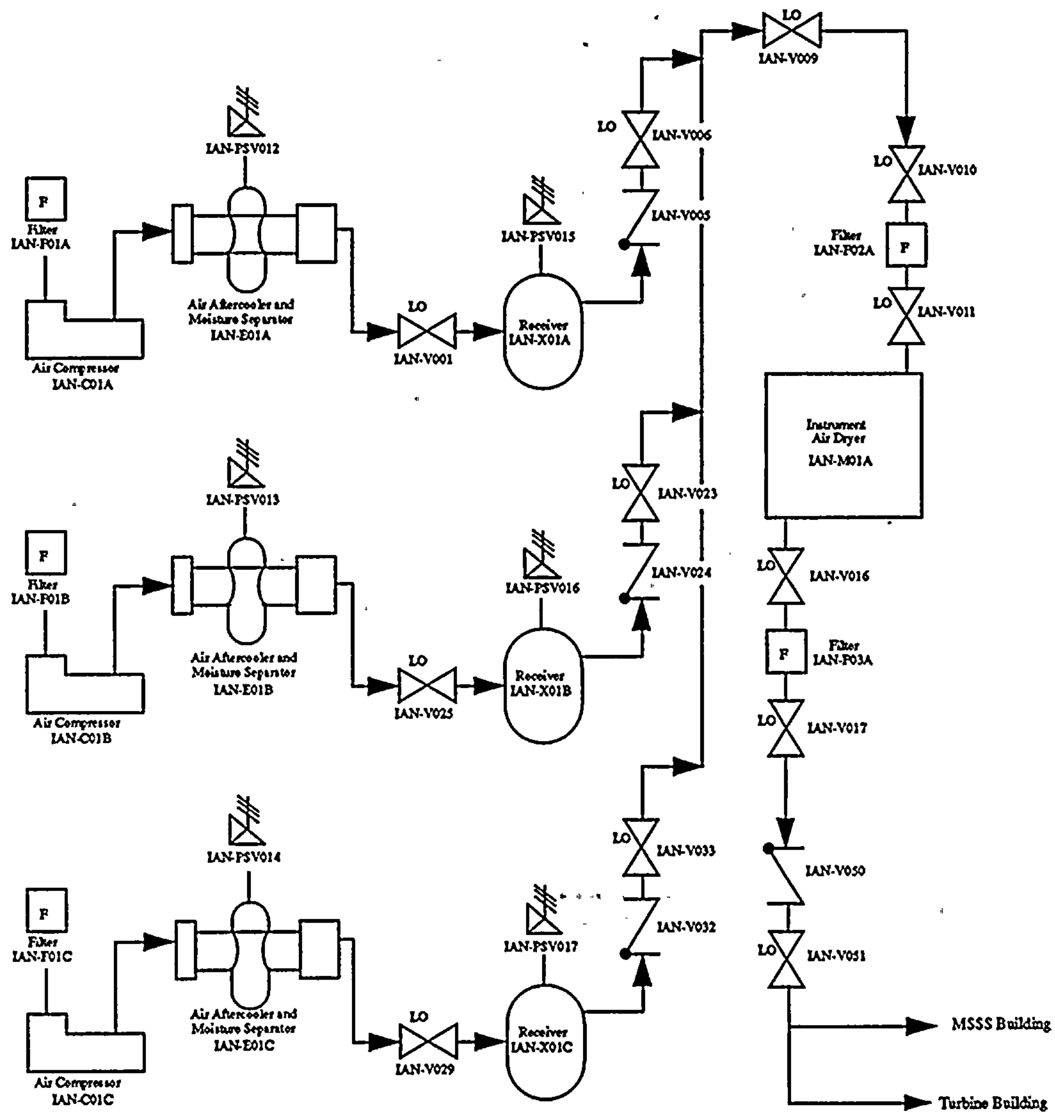

Figure 5.2-19

Instrument Air System

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Figure 5.2-20

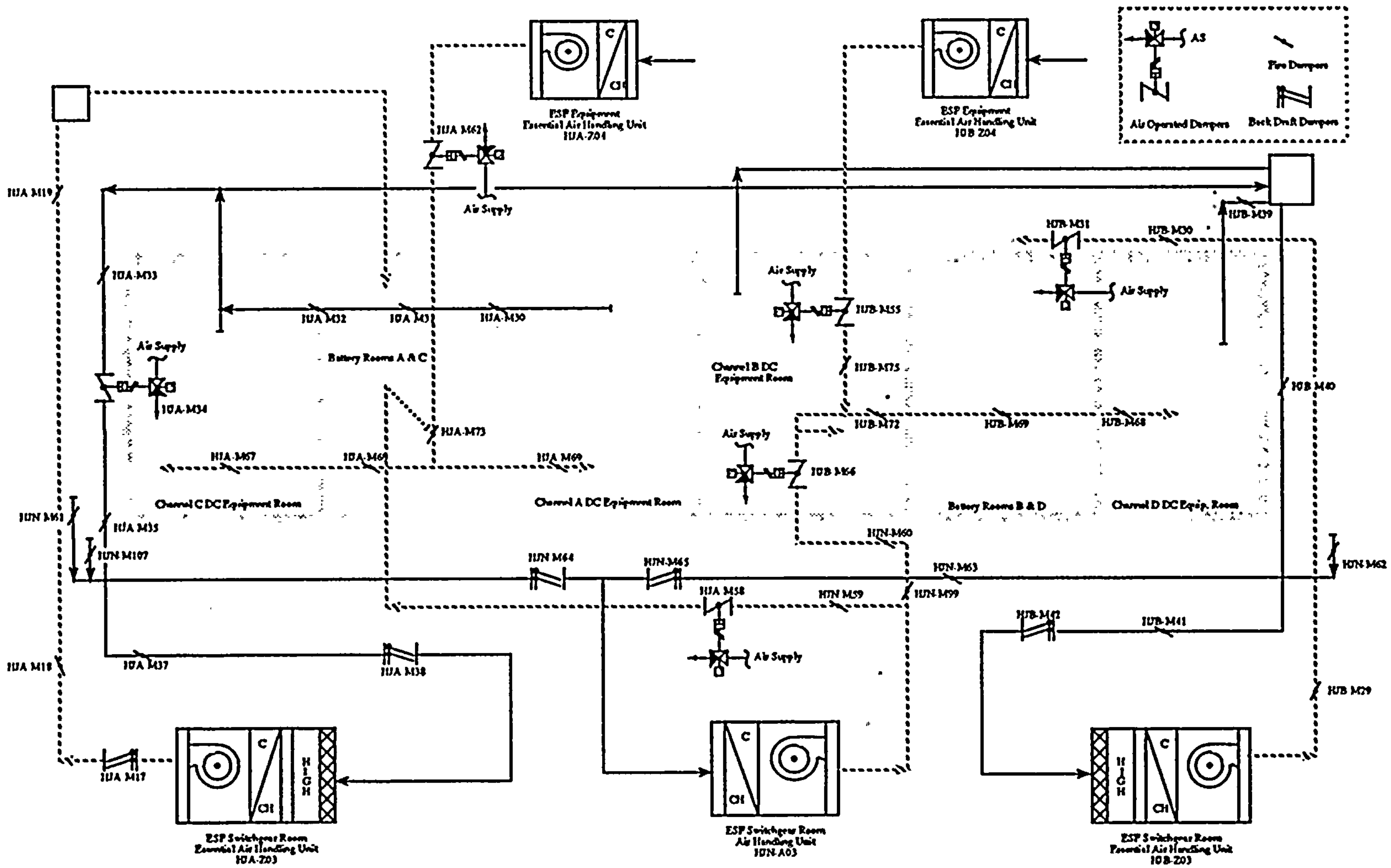


Figure 5.2-21

ESF Switchgear "DC Equipment" Room HVAC

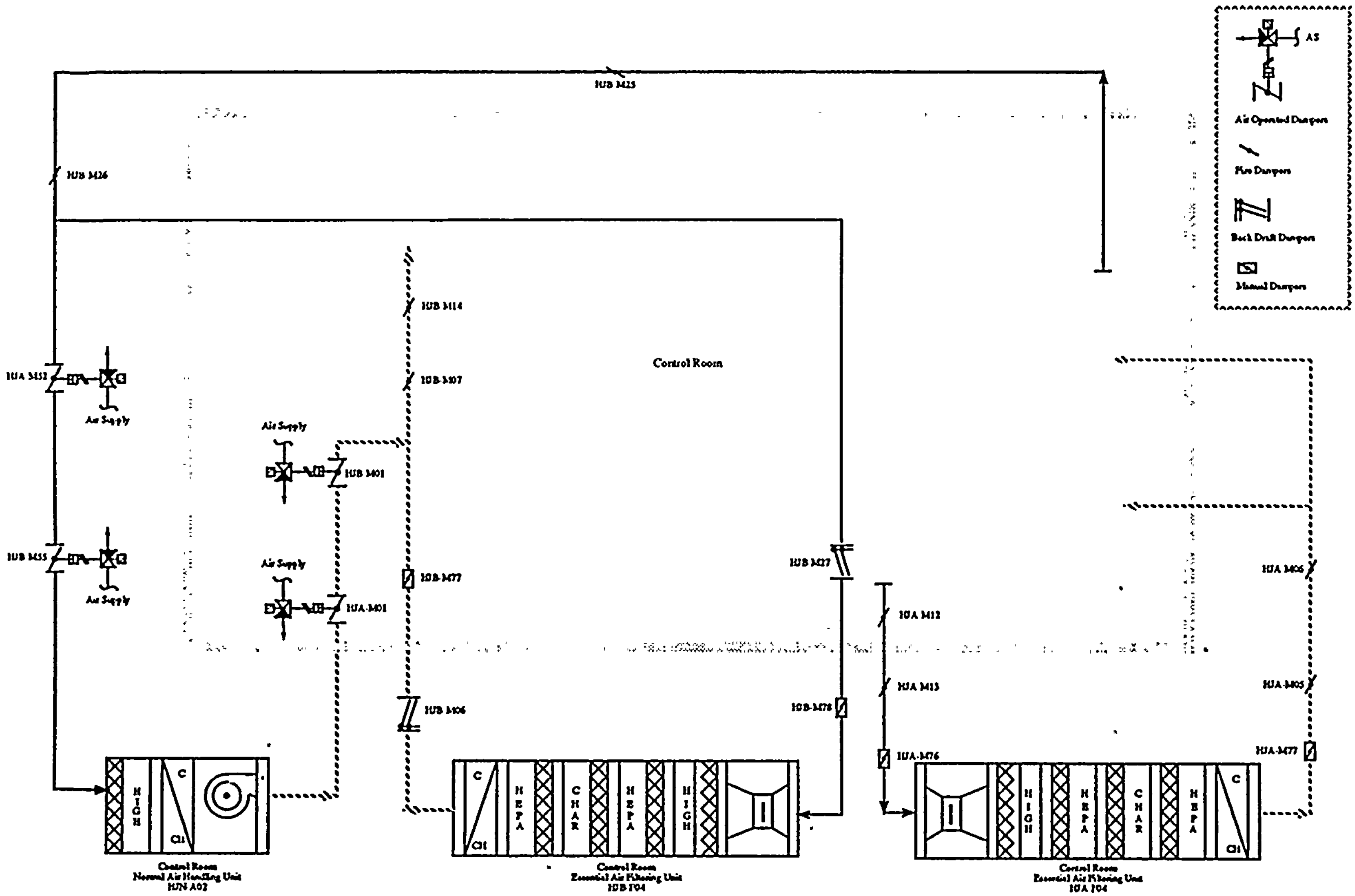
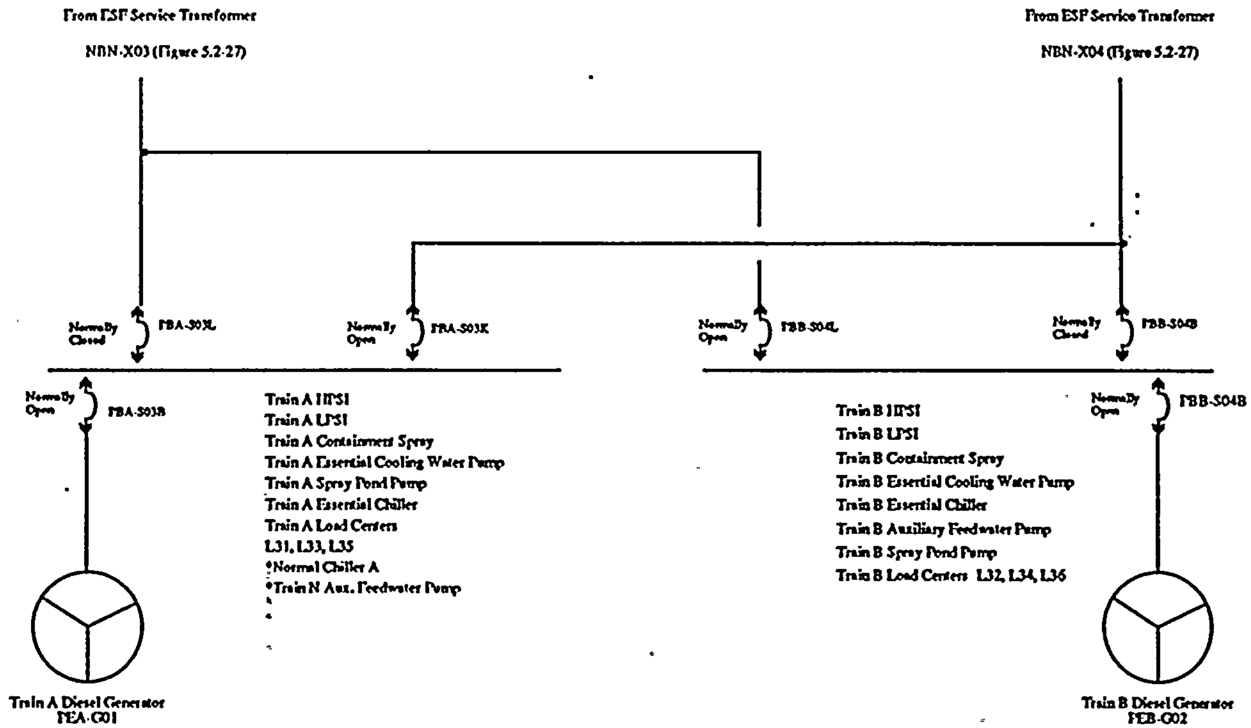


Figure 5.2-22

Control Room HVAC



*Non-Safety Related Load Shed on SIAS

Figure 5.2-23

Class 1E 4.16 kV Power System (PB)

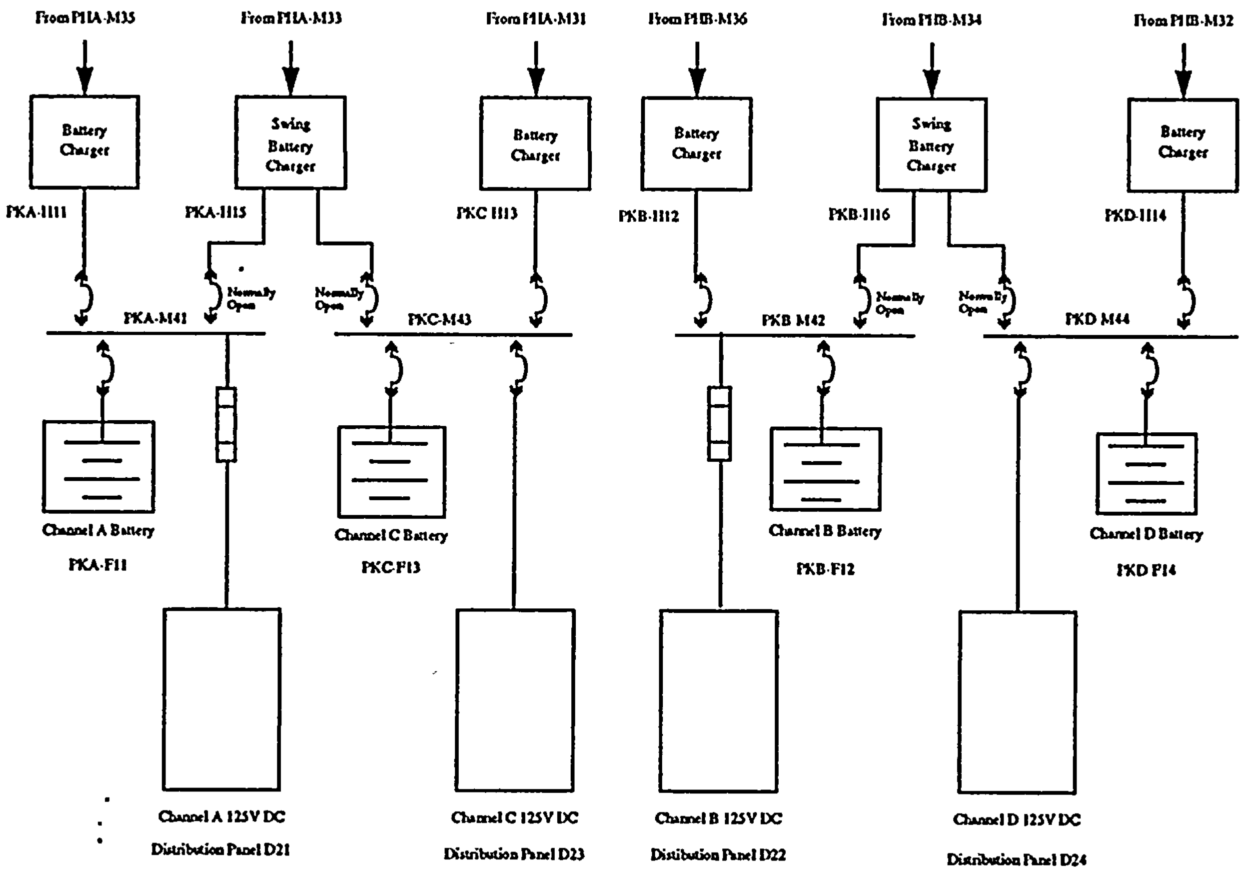


Figure 5.2-24

Class 1E 125V DC Power System (PK)

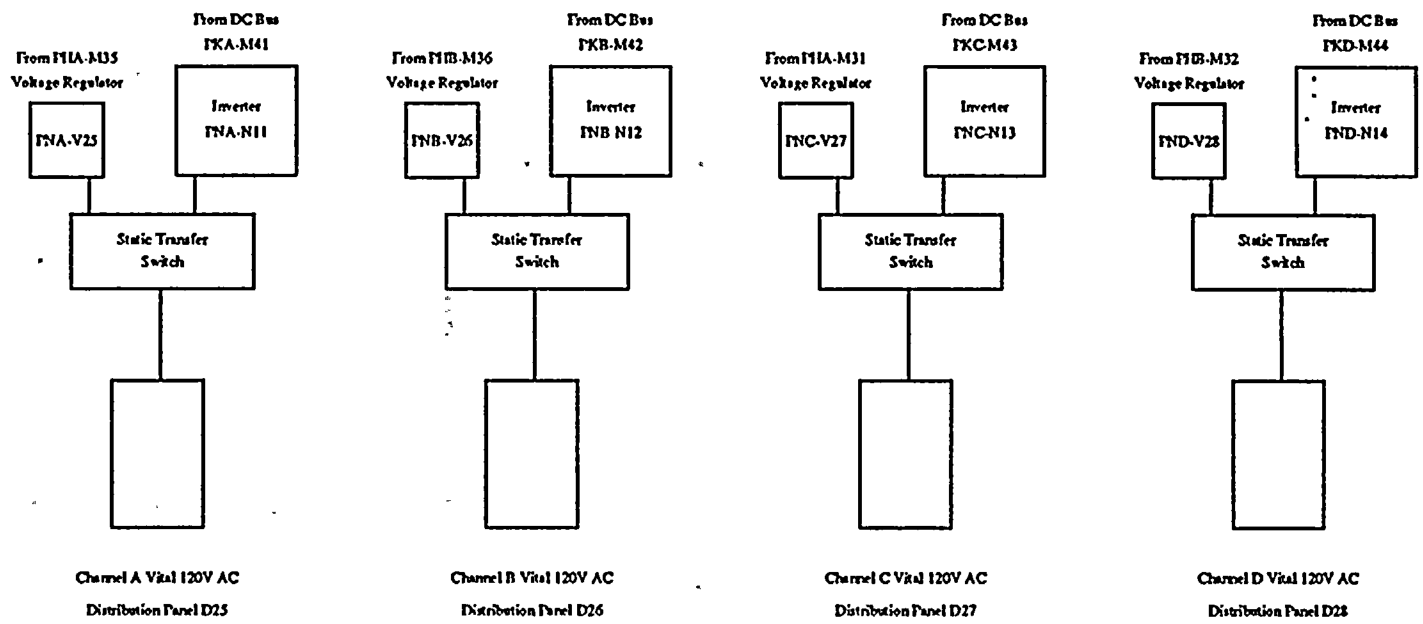
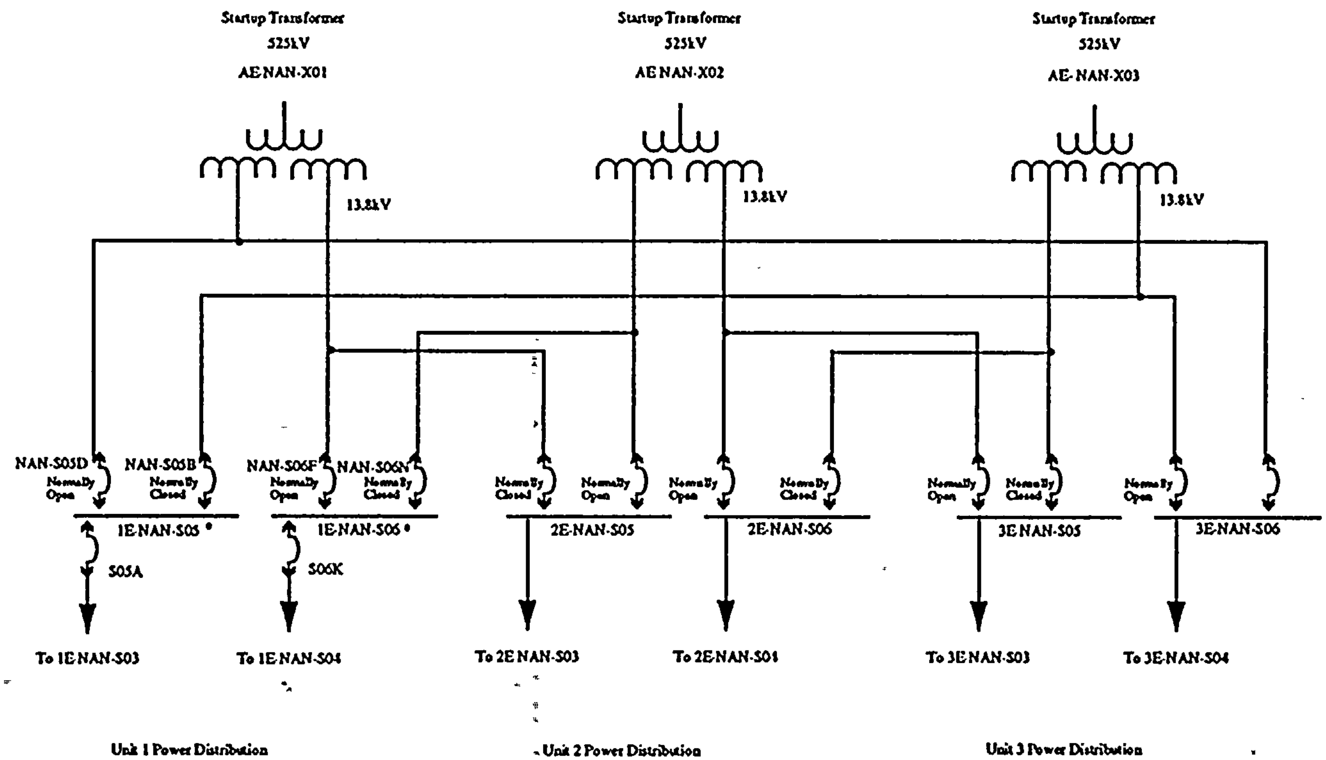


Figure 5.2-25

Class 1E Instrument AC Power System (PN)



* Site Common Loads also powered from these buses.

Figure 5.2-26

Off-site Power Supplies For Palo Verde Units 1, 2 and 3

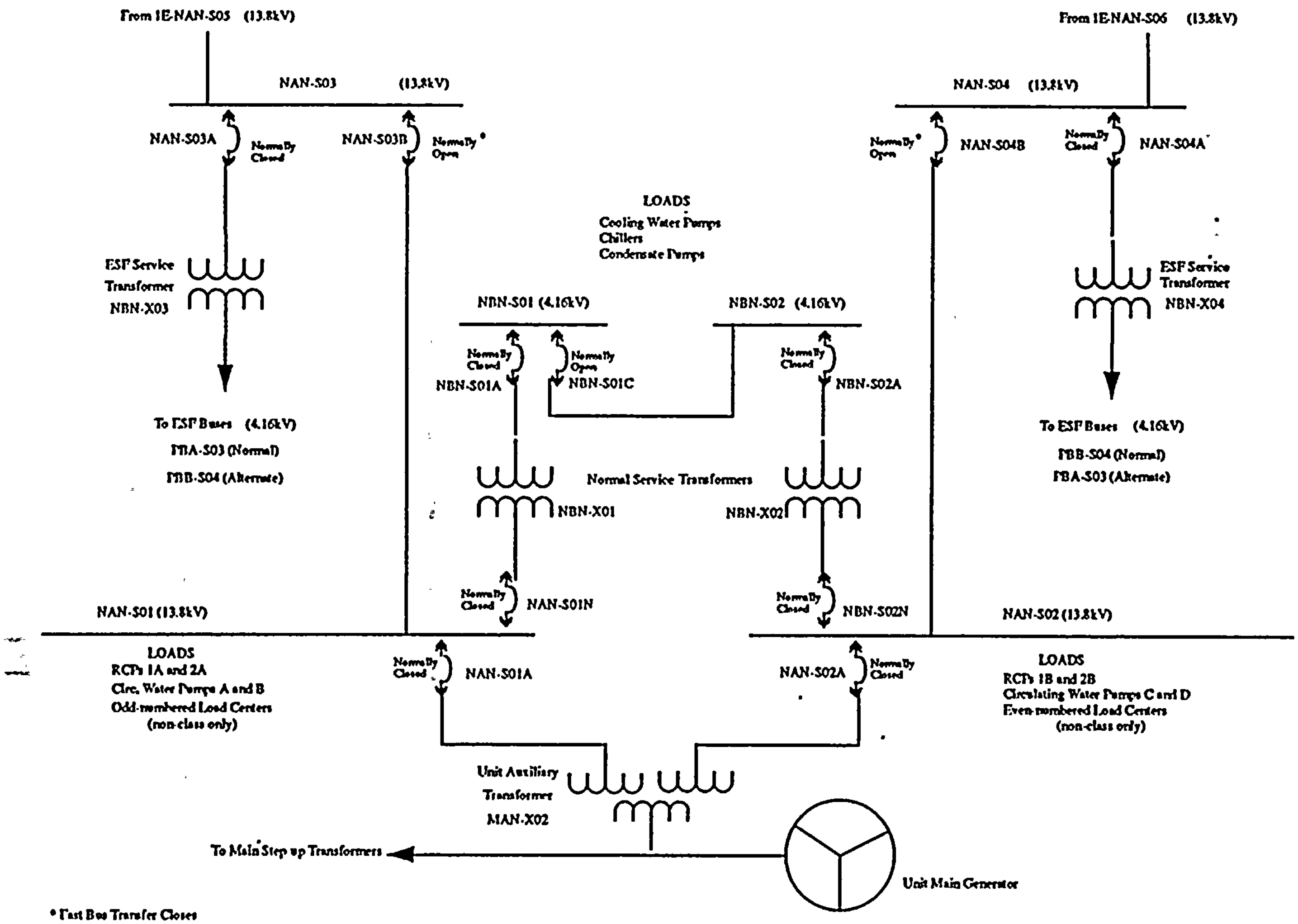


Figure 5.2-27

Non-class 13.8 kV and 4.16 kV In-plant Power Distribution (NA)

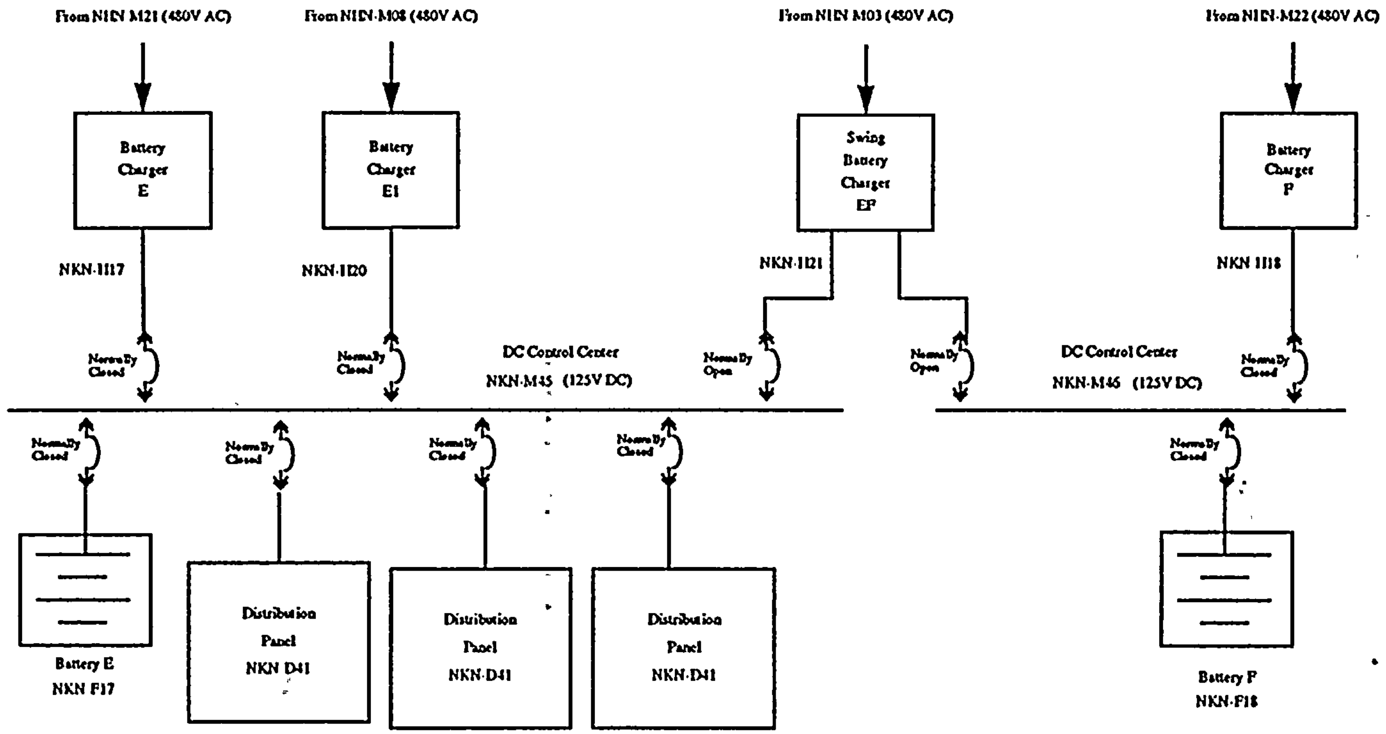


Figure 5.2-28

Non-class 1E 125V DC Power Distribution (NK)

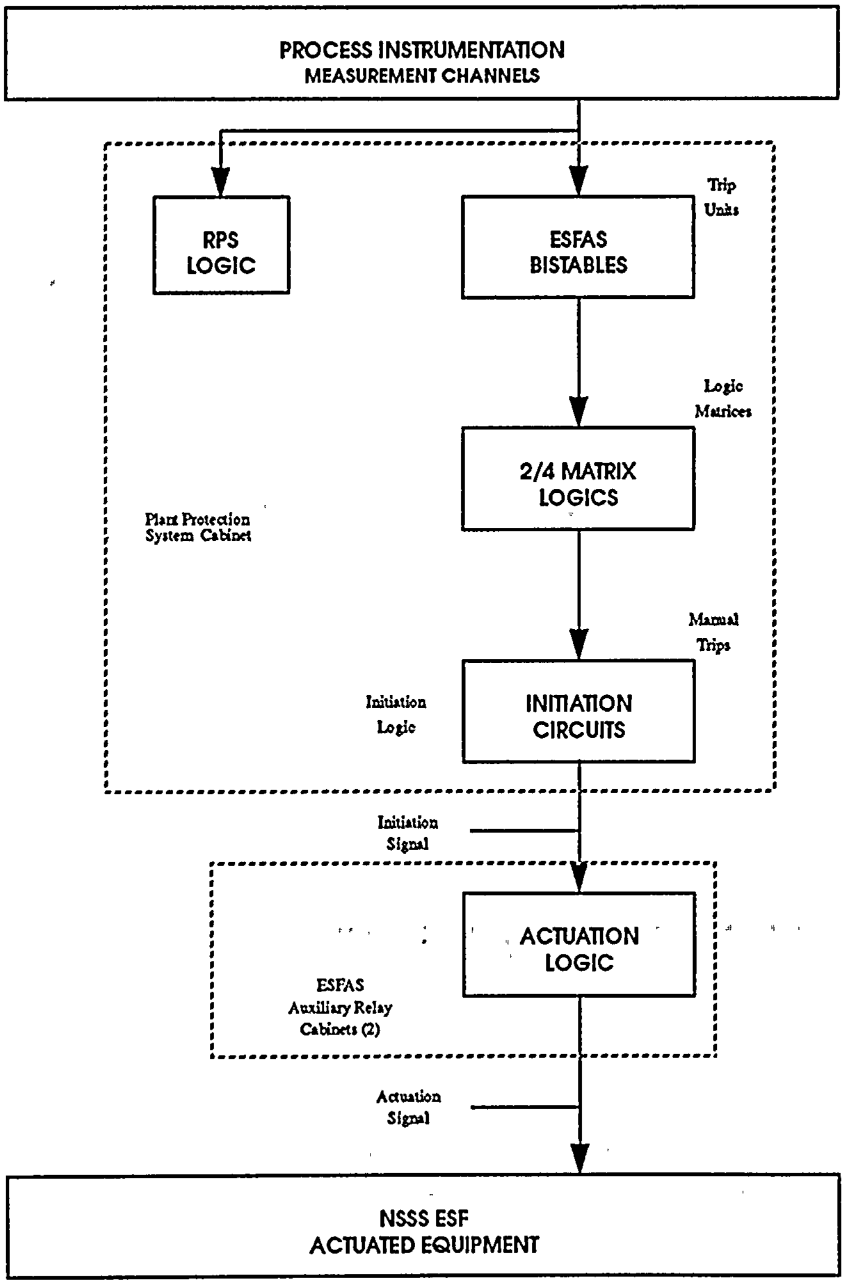


Figure 5.2-29

Engineered Safety Features Actuation Signal Block Diagram

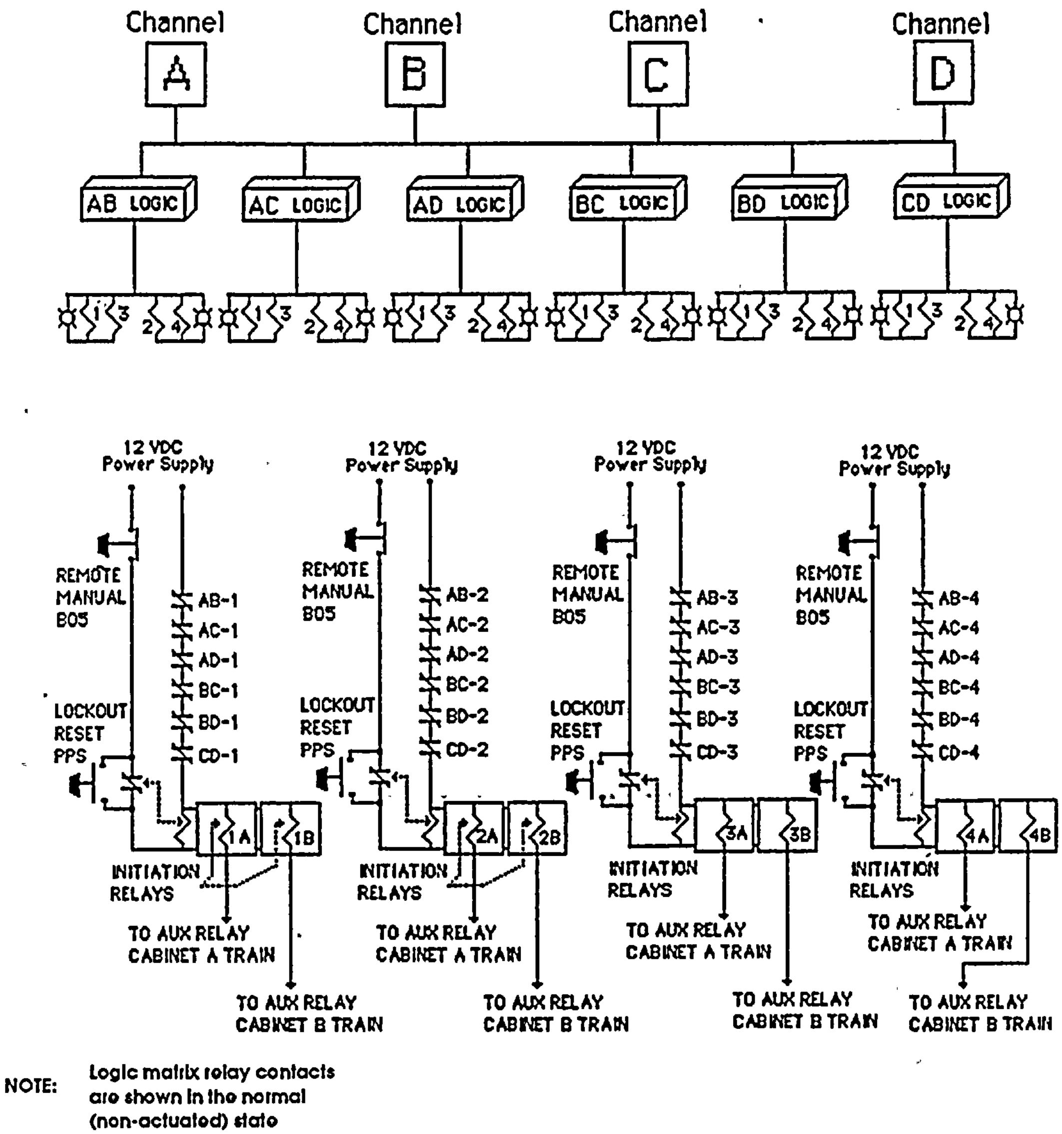


Figure 5.2-30

Functional Diagram of a Typical Engineered Safety Feature Actuation

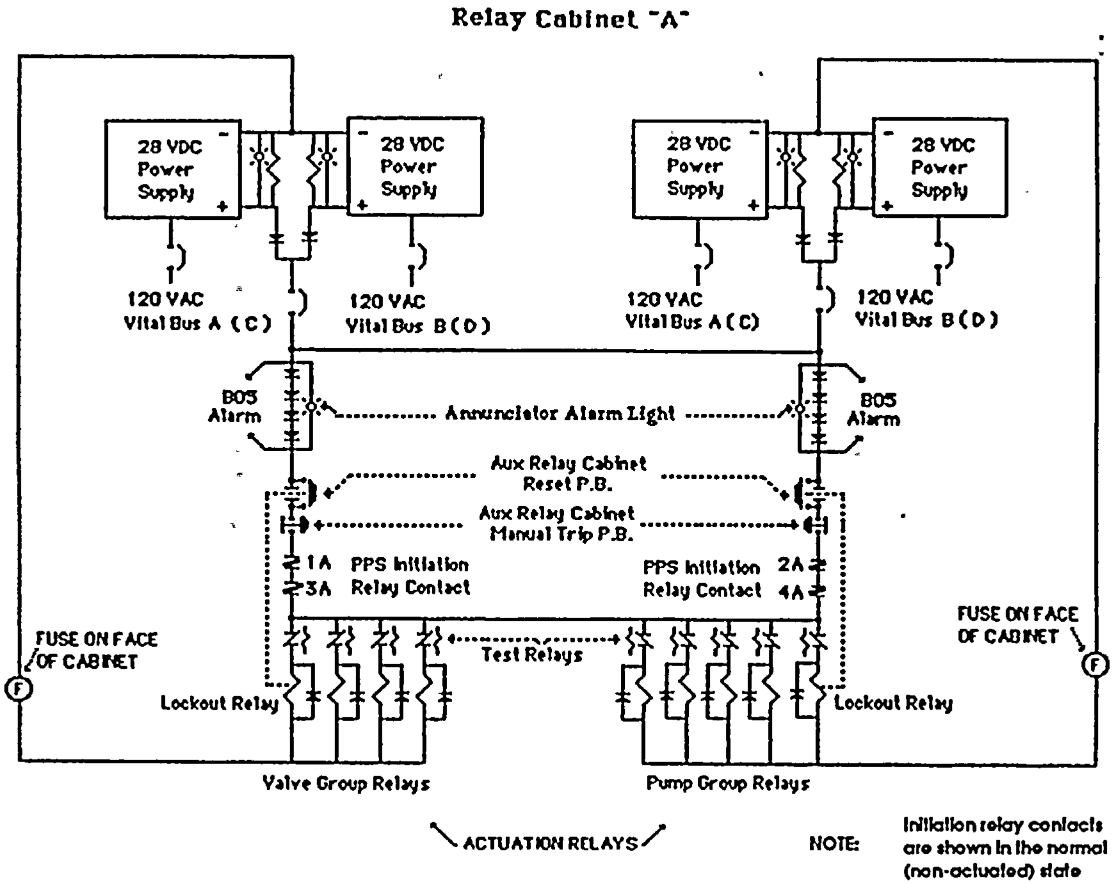


Figure 5.2-31

ESFAS Auxiliary Relay Cabinet Functional Diagram

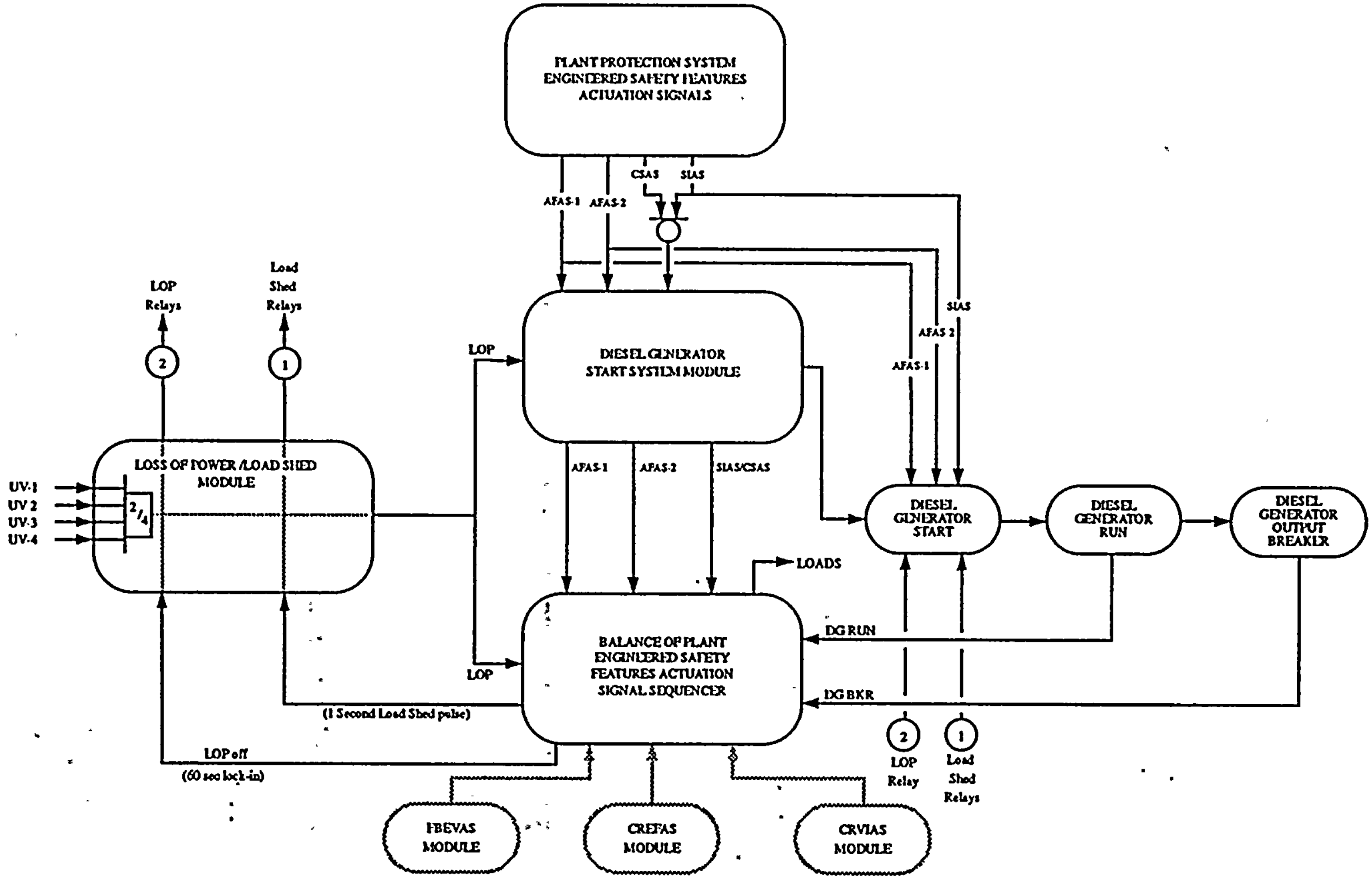


Figure 5.2-32

BOP/ESFAS Load Sequencer Module Interconnections

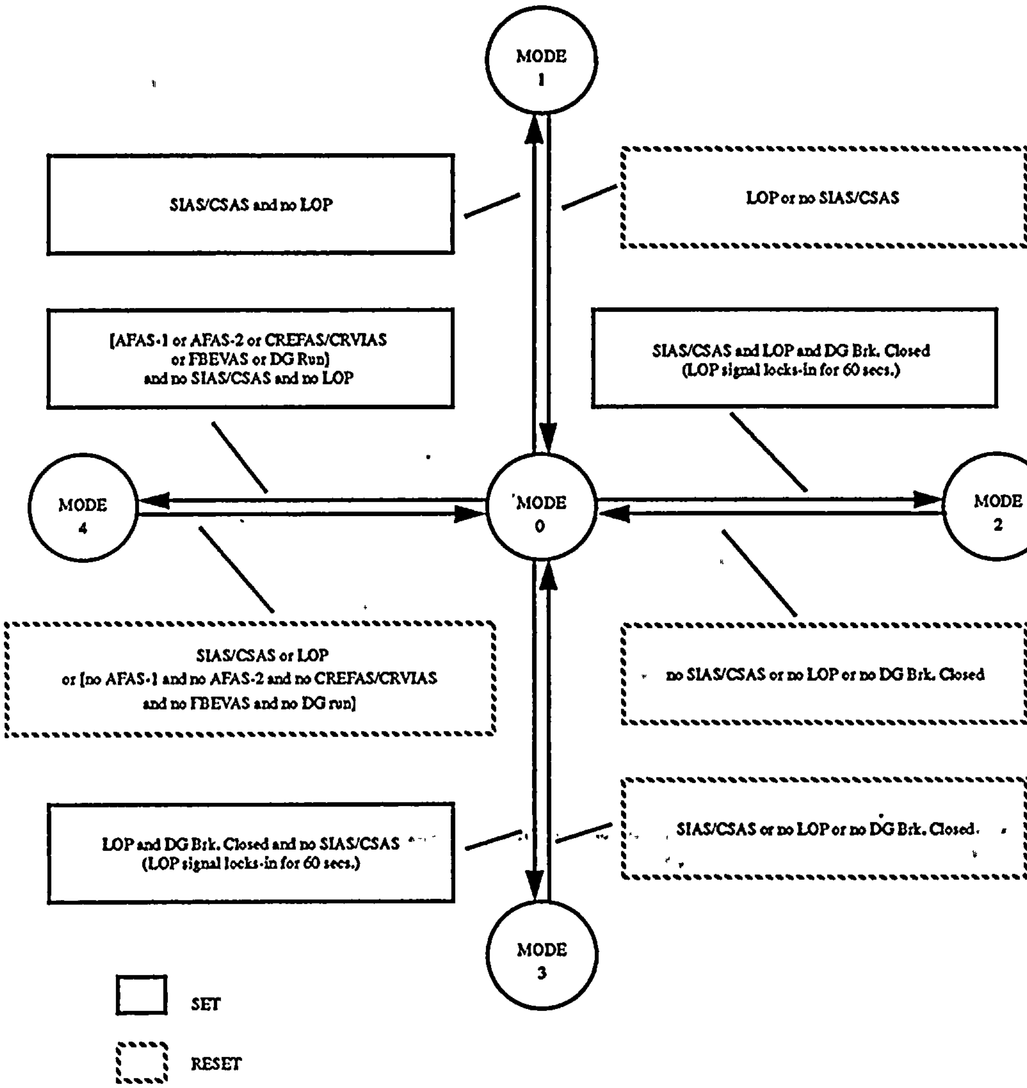


Figure 5.2-33

Sequencer Operational Logic Diagram

Table 5.2-1 Sequencer Mode 1 (SIAS/CSAS) Operation

Relay	Equipment ID	Component Description
NON-ESF LOAD SHED (from SIAS Auxiliary Relays)		
N/A	PBA-S03	4.16kV Class Switchgear (Train A Only)
N/A	PBB-S04	4.16kV Class Switchgear (Train B Only)
N/A	Various	Essential Lighting A / B
N/A	Various	Class-Powered Pressurizer Backup Heaters
N/A	WCN-E01A	Normal Chiller A (Train A Only)
N/A	AFN-P01	Non-essential Auxiliary Feedwater Pump (Train A Only)
N/A	HCN-A01A / B HCN-A01C / D	Containment Normal ACUs
N/A	HCN-A01A / B HCN-A02C / D	CEDM Normal ACUs
COMPONENT LOADING SEQUENCE - TRAIN A / B		
	DGA-H01 / DGB-H01	Emergency Diesel Generator A / B Starts
K125	SIA-P02 / SIB-P02	High Pressure Safety Injection Pump A / B
K231	CHA-P01 / CHB-P01	Charging Pump A / B (Permissive. Actuation Relay Blocked)
K231	CHE-P01	Charging Pump E (Permissive Block from Train A or B)
K126	SIA-P01 / SIB-P01	Low Pressure Safety Injection Pump A / B
K128	HDA-J01 / HDB-J01	Diesel Generator Room Essential Exhaust Fan A / B
K127	HJA-F04 / HJB-F04	Control Room Essential Air Handling Unit A / B
K221	HJA-J01 / HJB-J01	Fuel Building Essential Air Filtration Unit A / B
K222	AFB-P01	Essential Auxiliary Feed Pump (Train B Only)
K223	SIA-P03 / SIB-P03	Containment Spray Pump A / B
K225	EWA-P01 / EWB-P01	Essential Cooling Water Pump A / B
K226	SPA-P01 / SPB-P01	Essential Spray Ponds Pump A / B
K227	ECA-E01 / ECB-E01	Essential Chiller A / B
K231	CHA-P01 / CHB-P01	Charging Pump A / B (Perm. Actuation Relay Unblocked)
K231	CHE-P01	Charging Pump E (Permissive from Train A or B)

Table 5.2-2 Sequencer Mode 2 (SIAS/CSAS + LOP) Operation

Relay	Equipment ID	Component Description
		LOAD SHED - TRAIN A / B
K204	PBA-S03K / PBB-S04K	4.16kV Class Switchgear Alternate Supply Breaker Opens
K204	PBA-S03L / PBB-S04L	4.16kV Class Switchgear Normal Supply Breaker Opens
K202	SIA-P02 / SIB-P02	High Pressure Safety Injection Pump A / B
K202	SIA-P01 / SIB-P01	Low Pressure Safety Injection Pump A / B
K202	SIA-P03 / SIB-P03	Containment Spray Pump A / B
K202	EWA-P01 / EWB-P01	Essential Cooling Water Pump A / B
K204	SPA-P01 / SPB-P01	Essential Spray Pond Pump A / B
K202	ECA-E01 / ECB-E01	Essential Chiller A / B
K204	PCA-P01 / PCB-P01	Fuel Pool Cooling Pump A / B
K202	CHA-P01 / CHB-P01	Charging Pump A / B
K202	HE-P01	Charging Pump E (Train A or B)
K204	HCN-A02 A / B	CEDM Normal ACU Fan A / B
K204	HCN-A02 C / D	CEDM Normal ACU Fan C / D
K204	HCN-A01 A / B	Containment Normal ACU Fan A / B
K204	HCN-A01 C / D	Containment Normal ACU Fan C / D
K204	HJA-F04 / HJB-F04	Control Room Essential AHU A / B
K204	HDA-J01 / HDB-J01	Diesel Generator Room Essential Exhaust Fan A / B
K204	WCN-E01A	Normal Chiller A (Train A Only)
K202	AFB-P01	Essential Auxiliary Feedwater Pump (Train B Only)
K202	AFN-P01	Non-essential Auxiliary Feedwater Pump (Train A Only)
K202	PKA-H11 / PKB-H12	Class 1E Battery Charger - Train A / B
K202	PKC-H13 / PKD-H14	Class 1E Battery Charger - Train A / B
K202	PKA-H15 / PKB-H16	Class 1E AC / BD Swing Battery Charger - Train A / B
K202	PNA-V25 / PNB-V26	Class 1E Voltage Regulator - Train A / B
K202	PNC-V27 / PND-V28	Class 1E Voltage Regulator - Train A / B
		COMPONENT LOADING SEQUENCE - TRAIN A / B
	DGA-H01 / DGB-H01	Emergency Diesel Generator A / B Starts
	PBA-S03B / PBB-S04B	Diesel Generator Output Breaker Closes
K231	CHA-P01 / CHB-P01	Charging Pump (Permissive Actuation Relay Blocked)
K231	CHE-P01	Charging Pump E (Permissive Block from Train A or B)
K125	SIA-P02 / SIB-P02	High Pressure Safety Injection Pump A / B

Table 5.2-2 Sequencer Mode 2 (SIAS/CSAS + LOP) Operation (Continued)

Relay	Equipment ID	Component Description
K126	SIA-P01 / SIB-P01	Low Pressure Safety Injection Pump A / B
K127	HJA-F04 / HJB-F04	Control Room Essential Ventilation A / B
K128	HDA-J01 / HDB-J01	Diesel Generator Room Essential Exhaust Fan A / B
K221	HFA-J01/ HFB-J01	Fuel Building Essential Ventilation A / B
K232	PKA-H11 / PKB-H12 PKC-H13 / PKD-H14 PKA-H15 / PKB-H16 PNA-V25 / PNB-V26 PNC-V27 / PND-V28	Class 1E Battery Chargers Re-energized Class 1E Voltage Regulators Re-energized
K222	AFB-P01	Essential Auxiliary Feed Pump (Train B Only)
K223	SIA-P03 / SIB-P03	Containment Spray Pump A / B
K225	EWA-P01 / EWB-P01	Essential Cooling Water Pump A / B
K226	SPA-P01 / SPB-PO1	Essential Spray Ponds Pump A / B
K227	ECA-P01 / ECB-P01	Essential Chiller A / B
K231	CHA-P01 / CHB-P01	Charging Pump A / B (Perm. Actuation Relay Unblocked)
K231	CHE-P01	Charging Pump E (Permissive from Train A or B)
K234	HCN-A02 A / B HCN-A02 C / D	CEDM Normal Air Handling Units Restart (Previously running units restart, units in "Auto" are enabled for Auto-Start)

Table 5.2-3 Sequencer Mode 3 (LOP) Operation

Relay	Equipment ID	Component Description
	LOAD SHED - TRAIN A / B	
	Same as for Sequencer Mode 2	
	COMPONENT LOADING SEQUENCE - TRAIN A / B	
	DGA-H01 / DGB-H01	Diesel Generator A / B Starts
	PBA-S03B / PBB-S04B	Diesel Generator A / B Output Breaker Closes
K127	HJA-F04 / HJB-F04	Control Room Essential Ventilation A / B
K128	HDA-J01 / HDB-J01	Diesel Generator Room Essential Ventilation A / B
K232	PKA-H11/ PKB-H12 PKC-H13 / PKDH14 PKA-H15 / PKB-H16	Class 1E Battery Chargers Re-energized
	PNA-V25 / PNB-V26 PNC-V27 / PND-V28	Class 1E Voltage Regulators Re-energized
K235	HCN-A01 A / B HCN-A01 C / D	Containment Normal Air Handling Units Restart (Previously running units will restart, units in "Auto" are enabled for Auto-Start)
K234	HCN-A02 A / B HCN-A02 C / D	CEDM Normal Air Handling Units Restart (Previously running units restart, units in "Auto" are enabled for Auto-Start)
K222	AFB-P01	Essential Auxiliary Feed Pump (Train B Only)
K225	EWA-P01 / EWB-P01	Essential Cooling Water Pump A / B
K226	SPA-P01 / SPB-P01	Essential Spray Ponds Pumps A / B
K227	ECA-E01 / ECB-E01	Essential Chiller A / B

Table 5.2-4 Sequencer Mode 4 (AFAS-1 or AFAS-2, and Diesel Generator Run)

Relay	Equipment ID	Component
	AFAS-1 or AFAS-2 COMPONENT LOADING SEQUENCE	
	DGA-H01 and DGB-H01	Diesel Generators Start
N/A	AFA-P01	Essential A Auxiliary Feed Pump[a]
K222	AFB-P01	Essential B Auxiliary Feed Pump
K225	EWA-P01 and EWB-P01	Essential Cooling Water Pumps
K226	SPA-P01 and SPB-P01	Essential Spray Pond Pumps
K227	ECA-E01 and ECB-E01	Essential Chillers
	DIESEL GENERATOR RUN COMPONENT LOADING SEQUENCE - TRAIN A / B	
	DGA-H01 / DGB-H01	Diesel Generator Running
K128	HDA-J01 / HDB-J01	Diesel Generator Building Essential Exhaust A / B
K226	SPA-P01 / SPB-P01	Essential Spray Ponds Pump A / B

a. The Train A Auxiliary Feedwater Pump is started from the NSSS ESFAS System

SECTION 6

Data Analysis

This section presents the failure data analysis performed for the Palo Verde Nuclear Generating Station (PVNGS) Probabilistic Risk Assessment (PRA). Section 6.1 discusses initiating event frequencies and provides the details for obtaining each initiating event frequency and its data source. Identification and definition of each initiating event is described in Section 4. The basic event data in Section 6.2 includes the data for failure rates and derivations for specific events not fully discussed elsewhere including maintenance unavailability, control circuit failures, and recovery of off-site power. This section includes the treatment of hourly failure rates, common cause, a description of the basic event naming convention, and a description of the Bayesian updated data.

The data in the initial PVNGS PRA was based entirely on generic failure rates. The update of the generic data using a plant specific Bayesian update was performed on the more important events. The generic data base was compared with several sources during its development and most values were found to be within acceptable range of available industry data sources. Justification for those that differ from other data sources is included in the discussion for that event.

6.1 Initiating Event Frequencies

Each of the accident sequences analyzed in the PVNGS PRA is initiated by an event or transient that causes the plant to react in other than a steady state mode. The identification and definition of each initiating event used in the PVNGS PRA is described in Section 4.1 The derivation and the frequency values of the initiators are discussed in the following sections:.

6.1.1 Methods of Determining Initiating Event Frequencies

As stated, PVNGS accident initiators are identified and listed in Section 4.1 Once identified, a method of determining a valid frequency for each of the initiators was required. PVNGS initiator frequency modeling consists of several different methods. Depending on the type of initiator, one or more of the methods were used to determine the frequency. The following sections explain what the methods are and, in general, to which types of initiators the methods were applied.

6.1.1.1 Generic point estimate

Generic point estimate initiator frequencies are based upon industry experience estimates. PVNGS PRA frequencies that are quantified using generic point estimates typically share few or no failure event dependencies with the front line systems used to mitigate the accident. Additionally, the initiator should not have any PVNGS system dependencies/peculiarities that are atypical. In other words, system dependencies/peculiarities resemble most other industry-wide system designs; therefore, extensive industry-wide failure data is applicable for such systems. Sources of generic data are identified in Section 6.2.

6.1.1.2 Plant specific point estimate

Plant specific point estimate initiators can be derived from either a survey of actual trips, caused by the initiator and experienced at the PVNGS, or via Bayesian update of industry initiator event frequencies based on actual PVNGS trips. No plant specific initiator frequency calculations are performed for the present PRA Model.

6.1.1.3 Plant-based tabular OR point estimate

The plant based tabular OR point estimate is used when any single event in a system can lead to the initiating event of concern. An example of this is the frequency calculation for Loss of Coolant Accident (LOCAs). The initiating event frequency is calculated from the sum of the frequency estimates for each single event. The frequency for each event may be estimated from either generic data, bayesian updated failure data, or plant specific data. For the PVNGS PRA, plant-based tabular OR point estimates were used for initiating event frequencies for all LOCAs except steam generator tube rupture. See following sections for detailed methodology and sources of failure frequencies.

6.1.1.4 Plant-based fault tree estimate

When an initiating event frequency can not be appropriately estimated using a generic frequency and the failures making up the initiator are too complex to be represented with the tabular OR estimate, a fault tree model is used. The fault tree model is representative of all single or multiple faults that could lead to the initiating event. The top event is in terms of yearly frequencies. Frequencies and failure estimates for the events in the Model can be based on either generic or plant specific failure rates, depending on whether plant specific data can be obtained for the components being modeled. The Model is solved by Boolean Algebra and a single frequency obtained. Initiators, for which plant based fault tree estimates were calculated, are generally representative of failures of systems with designs considered unique in some way to the PVNGS. These initiators also affect front-line systems to such an extent that the initiator is potentially a major contributor to total Core Damage Frequency (CDF). As a result, a plant specific model of the initiator is deemed appropriate. Table 6.1-1 identifies the initiator frequencies which were estimated using this method.

6.1.1.5 Plant-based equation estimate

The final method used in the PVNGS PRA for calculating an initiator frequency is called the plant based equation estimate. This method uses the same approach as the plant based fault tree estimate except that instead of obtaining a single frequency, the solution of the Initiating Event (IE) fault tree is left as an equation. This method does not result in a single frequency event for the IE, but in a Boolean equation containing multiple initiator events with associated frequencies. Initiators to which this method would be applied are plant specific initiating events that are in themselves highly dependent on the support systems common to the front-line systems. It is important to treat these initiators in this manner in order to fully account for dependencies between the initiator and the front-line systems. The method explicitly models failures of certain components that could potentially lead to the initiator and failure of the front-line system at the same time. Failure to account for IEs with dependencies like this could result in the total CDF being underestimated.

6.1.2 Quantification of Initiating Event Frequencies Other than for LOCAs

This section discusses the derivation of frequencies for each of the initiators used in the PVNGS PRA that are not considered to be LOCAs. LOCAs including SGTR and event V-Sequences are discussed in Section 6.1.3. Anticipated Transients Without SCRAM (ATWS) are discussed in Section 6.1.4. Table 6.1-1 summarizes each of the initiators, the frequency used in the Model, and the method of deriving the estimated frequency.

6.1.2.1 Loss of Main Feedwater/Condensate Pumps or Loss of Condenser Vacuum - IEFWP, IECPST, IECONDVAC

The frequencies for loss of Main Feedwater (FW), all Condensate (CD) pumps, and Condenser Vacuum are calculated using the generic point estimate method. This method is applicable because these three initiators do not have a significant effect on any of the front-line systems. The systems that the initiators represent are typical of others in the industry and operating experience for them is minimal at PVNGS. These IE frequencies will be updated with PVNGS-specific experience in a future revision to the PRA.

The source for the numbers is NUREG/CR-3862, Development of Transient Initiating Event Frequencies for Use in Probabilistic Risk Assessments, (Reference 6.3.3). Mean values are used in the development data. From NUREG/CR-3862, the following initiating frequencies are obtained:

- Loss of Main Feedwater (IEFWP) - 0.16 events per year
- Loss of Condenser vacuum (IECONDVAC) - 0.23 events per year
- Loss of Condensate pumps (IECPST) - 0.01 events per year

6.1.2.2 Large Secondary Line Break - IESLB

The initiator, as defined in Section 4.1, can result from a pipe break or from failure of the system pressure boundary (spurious openings of valves). The frequency of the initiator is then simply the sum of the frequencies of each of these occurrences. The method used to calculate the frequency of the initiator is the plant based tabular OR point estimate method. This methodology is judged appropriately because the frequency value is sensitive to the contribution of the line break frequency.

The pipe break frequency is calculated from a compilation of the number of pipe sections of the applicable steam, downcomer feed, and auxiliary feedwater return lines. Pipe failure frequencies are from the Reactor Safety Study, WASH-1400 (Reference 6.3.15). The failure rate is 8.5E-10/section-hr. The results are tabulated in Table 6.1-2. The mean frequency was found to be 4.3E-4/year.

The C-E System 80™ PRA (Reference 6.3.5) estimated the frequency value of spurious openings of multiple MSSVs, ADVs, or TBVs during steady state power. The frequency value was judged to be applicable to the PVNGS. The mean frequency for MSSVs is 3.7E-4/year, for ADVs 1.2E-4/year, and for TBVs 1.2E-4/year.

For the purpose of this analysis, a large secondary line break (SLB) occurrence frequency is the sum of the frequencies for pipe break and multiple openings of MSSVs, ADVs, or TBVs. The mean value is estimated at 1.4E-3/year.

6.1.2.3 Feedwater Line Break - IEFLB

This initiator, as defined in Section 4.1, is a pipe break of feedwater piping downstream of the last feedwater check valve. The method used to calculate the frequency is the plant specific based tabular OR point estimate. This methodology is judged to be applicable because the initiator is entirely dependent on plant design. The pipe break frequency is calculated from a compilation of the number of pipe sections in the applicable Blowdown and Economizer feed lines. Failure frequencies are calculated from WASH-1400 failure rates (Reference 6.3.15). The failure rate is 8.5E-10/section-hr. The results are tabulated in Table 6.1-3. The mean frequency was found to be 3.1E-4/year.

6.1.2.4 Loss of Off-site Power - IELOOP

The initiating event frequency for Loss of Off-site Power (LOOP) was calculated from data in NSAC-111 (Reference 6.3.4). The frequency was calculated (1959 through 1986) as 732.3 reactor years and 57 LOOPs greater than a minute in duration yielding a frequency of 7.8E-02/year.

6.1.2.5 Station Blackout - IEBLACK

Station Blackout is defined at PVNGS as a LOOP and of the DGs or their related circuitry. One of the possible ways to fail the DGs is to lose Class 1E 125V DC power. This also fails a train of the AF system. Because of the common dependency between the DGs and AF, the plant-based equation method was selected.

Calculation of the frequency equation is performed by first creating an equation of the failure of Train A and B emergency power supply system. This equation contains failure events of the Diesel Generators (fail to start and run), the associated circuitry which allows power from the DGs to be delivered to the class 4160V buses (failure of circuit breakers and buses), and the support systems for the DGs (failure of class 1E DC power or the Spray Pond System). This equation is then multiplied by the loss of off-site power initiating event frequency. The resulting equation is then a set of terms each containing loss of off-site power, a loss of Train A failure event, and a loss of Train B failure event. This equation is then applied to the Station Blackout sequence equations for a CDF to be calculated. For the purpose of providing some indication of the impact of the initiator on plant risk, an estimated value of 2.6E-4/year can be used.

6.1.2.6 Loss of Class 1E 125V DC Power - IEPKAM41, IEPKBM42, IEPKCM43, IEPKDM44

The frequencies for all four initiators are calculated using the plant based fault tree estimate method. This is due in part to the uniqueness of the class DC system at PVNGS and because of the importance of the system in supporting the front line systems used to mitigate the accident. See Section 4.1 for system impacts.

Normally only one calculation would be needed for use as a frequency for all four initiators because of symmetry; however, the A and B channel DC power supplies have two fuses between the distribution panel and bus, while the C and D channels have a circuit breaker and, therefore, two initiating event frequency calculations were performed. The frequencies were calculated by solving the class DC fault trees with yearly frequencies used as the basic event data for the normal power supply and demand failure rates used for the battery backup.

The resulting frequency for IEPKAM41 and IEPKBM42 is 2.0E-2/year and 4.7E-3/year for IEPKCM43 and IEPKDM44.

6.1.2.7 Loss of Instrument Air - IEIAS

The frequency used for the loss of instrument air is calculated by using the plant based fault tree estimate method. As stated in Section 4.1, the loss of instrument air fails or degrades several systems, some of which are needed for accident mitigation purposes. Since there is the interaction between instrument air and the front-line systems, it is important to obtain a number that accurately reflects the unavailability of the initiating system. Since representative generic data was not available, the plant-based fault tree estimate method was considered more applicable.

The frequency for instrument air is calculated by solving the PRA system fault tree with yearly frequencies applied to the normally running compressor and dryer and demand rates applied to the standby equipment. This is the same method as was used in the loss of class 1E 125V DC initiators.

The initiator frequency for IEIAS is calculated at 2.2E-2/year.

6.1.2.8 Loss of Plant Cooling Water, Loss of Nuclear Cooling Water, Loss of Turbine Cooling Water - IEPCW, IENCW, IETCW

The initiating frequencies for the loss of plant cooling water, turbine cooling water, and nuclear cooling water are obtained using generic point estimates. Generic data is used for the three initiators for two reasons: (1) loss of the initiators causes a manual trip and minimal impact to front-line systems and (2) the modeling effort needed to obtain a plant-based fault tree frequency for each of the initiators greatly overshadows the benefit of having a more plant-specific frequency value.

Values for the frequencies are obtained from NUREG/CR-3862, Table 8 (Reference 6.3.3) categories 31 and 32 and Loss of Component Cooling and Service Water System. Loss of component cooling is applied to loss of turbine and nuclear cooling, while loss of service water is applied to loss of plant cooling water. The frequency for IEPCW is estimated at 5.0E-3/year. The frequency for IENCW and IETCW is estimated at 2.0E-2/year.

6.1.2.9 Closure of All Main Steam Isolation Valves -IEMSIV

For this initiating event, (closure of all MSIVs), the frequency was obtained by generic point estimate. The frequency value is from NUREG/CR-3862, Table 8 (Reference 6.3.3), Category 18. The frequency for IEMSIV is estimated as 4.0E-2/year.

6.1.2.10 Loss of DC Equipment Room HVAC - IEDCRHVAC-1, IEDCRHVAC-2

As was mentioned before, the DC equipment room HVAC initiator is highly complex and, as a result, the plant-based equation estimate method is judged as the most appropriate method for dealing with this initiator. The following is a general description and is applicable to either of the initiators.

Calculation of the frequency equation is performed by first creating an equation of the failure of normal and essential HVAC. The equation contains failure events of the normal HVAC portion of the fault tree logically AND-ED with failure events of the essential HVAC portion. Failure events include loss of all HVAC due to the Fire Protection (FP) system either by a random failure or by FP testing, loss of flow due to random failures of dampers which result in dropping the dampers, and loss of support system random failures and operator failures to restore cooling to the room. Creating an initiator requires that a yearly frequency be used. By definition, the initiator is the cause of the transient; therefore, for the loss of DC equipment room HVAC initiators, the normal HVAC portion of the fault tree has yearly frequencies applied to all events which fail it. The essential portion contains failure probabilities. Sources of the frequencies used in the normal HVAC logic are based upon hourly generic data and a mission time of 1 year, with the exception of the frequencies applied to the FP modeling. These values are based upon PVNGS operating experience.

The final equation is then applied to the loss of DC equipment room event sequence equation and a CDF is calculated.

For the purposes of providing some indication of the impact of the initiator on plant risk, an estimated value of 2.5E-1/year for IEDCRHVAC-1 or IEDCRHVAC-2 can be used.

6.1.2.11 Loss of Control Room HVAC -IECRHVAC

Since the loss of Control Room HVAC has such a large impact of the plants' ability to respond to a transient and because little or no industry data is available for determining an initiator frequency, the plant-based equation estimate method is judged as the most appropriate method.

Calculation of the frequency equation is performed by creating an equation of the failure of normal and essential HVAC. The equation contains failure events of the normal HVAC portion of the fault tree logically AND-ED with failure events of the essential HVAC portion. Failure events include loss of flow due to random failures of dampers, which result in dropping the dampers, loss of support system random failures, and operator failures to restore cooling to the room. Creating an initiator requires that a yearly frequency be used. By definition, the initiator is the cause of the transient; therefore, for the loss of Control Room HVAC initiators, the normal HVAC portion of the fault tree has yearly frequencies applied to all events which fail it. The essential portion contains failure probabilities based upon a 24-hr. mission time. Sources of the frequencies used in the normal HVAC logic are based upon hourly generic data and a mission time of 1 year.

This equation is solved to obtain minimal core damage frequency cutsets. For the purposes of providing some indication of the impact of the initiator on plant risk, an estimated value of 3.3E-4/year can be used.

6.1.2.12 Loss of 120V Class 1E AC Instrument Power - IEPNAD25, IEPNBD26

A loss of the 120V AC instrument power system degrades a number of front-line systems used to mitigate the accident. The nature of the design of the power system (see Section 5.2) is such that it depends on systems that the front-line systems also depend on. This interdependency between the initiator and the front-line systems requires that a more sophisticated approach for determining an initiator frequency be made. Hence, the plant-based equation estimate method was used.

The power system models are set up in the same manner as for the HVAC initiators. This includes linking non-initiator support systems called in by the power system, which themselves are initiators, and applying failure probabilities to the normally aligned part of the system. Probabilities are applied to basic events based upon the definition of the initiator. In the case of a loss of 120V AC, that definition is the failure (in yearly frequency terms) of the normally aligned portion of the system and the loss of the backup portion of the system in the following 24 hrs. The model was then solved and an equation generated. Each initiator, because of different train dependencies, has its own equation and these equations were then used in the appropriate accident sequences to obtain their contribution to total CDF. For the purpose of providing some indication of the impact of the initiator on plant risk, an estimated value of 2.5E-2/year for either of the initiators can be used.

6.1.2.13 Turbine Trip - IETT

The initiator frequency for turbine trip was obtained from generic data. The source is NUREG/CR-3862, Table 8, Category 33, (Reference 6.3.3), which provides a turbine trip frequency estimated at 1.19/year.

6.1.2.14 Miscellaneous Trips -IEMISC

Miscellaneous trips is a broad category of IEs that trip the reactor, but do not significantly impact any of the systems that must respond to the IE. Such initiators are relatively frequent events within the industry and a generic point estimate is judged to be a reasonable representation of the expected frequency at PVNGS. Thus, the miscellaneous trip frequency is the sum of various generic point estimates for initiators, which were not addressed anywhere else in the model. Table 6.1-4 lists the initiators, their value, and source of the number.

Two of the initiator frequencies were reduced by one half. These initiators at PVNGS cause the Reactor Power Cutback System (RPCS) to actuate. It is assumed, that the cutback system will only be successful 50% of the time in these particular situations.

The frequency for IEMISC is estimated as 5.67/year.

6.1.3 Quantification of Loss of Coolant Accident (LOCA) Initiating Event Frequencies

The terminology, Loss of Coolant Accident (LOCA) refers to transients which are initiated by breach of the Reactor Coolant System (RCS) boundary. A LOCA for the PVNGS PRA is defined as any pressure boundary leakage in excess of the three charging pumps capacity (132 gpm). This can be converted into a 0.38-in. or greater equivalent diameter break. The seven possible ways the PVNGS can initiate a LOCA are as follows:

1. Pipe rupture
2. Reactor Coolant Pump (RCP) seal LOCA
3. Instrument guide tube rupture
4. Pressurizer safety relief valve failure to close
5. Interfacing system LOCA
6. Reactor vessel rupture
7. Steam generator tube rupture

Because of plant design, the location and size of the break determine plant response. It is not possible to evaluate every break or failure event. As a result, PVNGS has categorized its LOCAs into five LOCA initiators: Small LOCA, Medium LOCA, Large LOCA, Steam Generator Tube Rupture, and Interfacing LOCA Outside of Containment. These events have been defined in the PVNGS Updated Final Safety Analysis Report and in Section 4 of the PVNGS PRA report. The following sections discuss the calculation of the initiating frequencies of all PVNGS LOCAs.

6.1.3.1 Sources for LOCA Initiating Event Frequencies

Five sources were used to calculate LOCA Initiating Event frequencies.

- Plant experience, which uses the plant specific history based on License Event Reports (LERs), Safety Evaluation Reports (SERs) and Significant Operation Experience Reports (SOERs). This method uses plant operating experience and failures for calculation of the LOCA or transient Initiating event Frequencies (IEF).

- Reactor Safety Study (RSS), WASH-1400. The RSS has generated LOCA frequencies for different break sizes.
- Bayesian update using historical data. In this method, various data, such as the RSS LOCA distributions, are updated with the relevant historical data to obtain the posterior distributions.
- Use of plant specific parameters. In this method, generic data is applied to the plant specific parameters, such as pipe or valve disk rupture, etc., to generate an IEF.
- Industry experience.

One or more of the above methods is used to calculate the initiating frequencies of the different types of LOCAs. The type of methodology used is identified in each of the LOCA sections.

6.1.3.2 Small, Medium, and Large LOCA - IESMLOCA, IEMLOCA, IELLOCA

The calculation of Small, Medium, and Large LOCA frequencies combines various failure mode calculations. As identified at the beginning of Section 6.1.3, LOCAs can be initiated in several different ways. The size of the LOCA is important because of different plant responses to these three types of LOCAs. The following sections discuss the types of possible breaks and their contribution to one or more of the three LOCA initiating events.

6.1.3.2.1 Pipe Rupture

In the interest of deriving LOCA frequencies more closely based on the PVNGS RCS design, it was appropriate to perform a piping inventory and use a Bayesian updated pipe failure rate. In order to determine the LOCA frequencies due to pipe failure, the primary system and all the interfacing systems, such as Chemical Volume Control System (CVCS), Emergency Core Cooling Systems (ECCS), etc., were examined. The pipe rupture probability was evaluated on a section basis, where a section was defined as the piping between major components, such as the Steam Generator and the Reactor Coolant pumps or between the primary system and the first motor operated or manual valve, such as the 2-in. letdown line between the RCS and the two letdown isolation valves. The RCS piping isometric drawings were used to determine the number of pipe sections in each segment.

Pipe failure contributions to the initiating frequencies of each of the LOCAs were calculated using plant specific information (the amount of piping of a given size) and Bayesian-updated RSS (Reference 6.3.15) piping failure rates. The Bayesian update was based on past industry experience as documented in NUREG-4407 (Reference 6.3.23) and NUREG-1150 (Surry) (Reference 6.3.45). Table 6.1-5 shows the list of the piping segments, and their length in sections. (A section is the length of the piping between major discontinuities.)

Table 6.1-5 also presents the total contribution of pipe failure to the Small, Medium, and Large LOCA IEFs.

6.1.3.2.2 Instrument Guide Tube Rupture

Permanently installed incore instrument guide tubes provide support for the 61 incore assemblies. The tubes run from the seal table down through an instrument chase to the bottom of the reactor vessel where tubes are seal welded to instrument nozzles, which pass through the lower vessel. When the RCS is filled, the guide tubes are filled with primary coolant, thus forming a non-flowing primary pressure boundary. All tubes are of equal size and diameter to allow for placement of standardized instruments. Each guide tube is doubled-walled and designed to support the weight of the instrument plus the water. Tubes are also constructed to withstand a design pressure of 2500 psia and design temperature of 650° F. In addition, the guide tubes are designed to meet operating specifications during a safe shutdown earthquake (SSE) or loss of coolant accident (LOCA) conditions.

The total length of the instrument guide tube extends 90.1 ft., from the vessel nozzle to the seal table. The instrument guide tube ID is 0.75 in. and its OD is 1.05 in.

The possible rupture points of the instrument guide tube would be the welded sections at the vessel nozzle connection of the curved and straight sections and at the seal table.

Guillotine rupture of a single guide tube may cause the incore instrumentation inside the tube to be blown out, therefore generating a direct RCS flow path to containment atmosphere. This will be equivalent to a 3/4-in. pipe break LOCA, which causes the loss of 600 gpm of reactor coolant. If the incore instrumentation is not ejected from the guide tube, the break would be limited to the clearance between the instrumentation and the guide tube. For this PRA, it is conservatively assumed that the instrumentation is ejected.

Depending on the location of the failed guide tube, one or more other guide tubes could be damaged due to the failed tube whipping. Whether one tube ruptures or pipe whipping results in multiple ruptures for the equivalent break, size of the failure still falls within the Small LOCA category. This is because it would take more than ten complete tube ruptures to make an equivalent Medium LOCA; thus, all Instrument Guide Tube Ruptures (IGTRs) are small LOCAs.

Since the break is at the bottom of the reactor vessel, it is possible that it might impair decay-heat removal (DHR) even though the loss of inventory is as little as 600 gpm. This possible reduction in heat removal is judged to have insignificant effect on the system responses required for accident mitigation. As discussed in Section 4.3, Steam Generator (SG) cooling is required and expected to be present for all Small LOCAs. Because of this condition, Safety Injection (SI) flow for these LOCAs is only required for inventory control. The loss of SI flow through the break should therefore have no major impact on RCS heat removal. Later in the accident, when the RCS is depressurized and SG cooling is not present, the flow out through the break will be small and, again, should have no effect on the RCS heat removal.

The failure probability was calculated for the instrumentation guide tube and is presented in Table 6.1-5. Using the Bayesian updated WASH-1400 small bore pipe failure data and assuming two sections for each instrument guide tube, a probability of 2.2E-3/year for all 61 tubes is derived. Since it is assumed that the mitigating system success criteria are the same as for Small LOCA, this initiating event frequency is added to the Small LOCA IEF.

6.1.3.2.3 Pressurizer Safety Relief Valve Failure

Four primary safety relief valves (PSRVs), located at the top of the pressurizer, provide overpressure protection for the RCS. They are totally enclosed, backpressure compensated, spring-loaded safety valves, which meet ASME Standards, Section III, Class 1 requirements. The PSRVs discharge through the relief line piping into the Reactor Drain Tank (RDT). Each valve is designed to lift at 2500 psia ±1%. At their fully open condition, they pass 50,000 lbm/hr. of saturated steam. The PSRVs are tested every 5 years (third refueling outage) in accordance with the ASME test program. However, the valves are monitored from the Control Room by acoustic monitors for any leakage.

According to C-E System 80™ Safety Analysis Report (CESSAR), Chapter 6 (Reference 6.3.19), a fully open PSRV would be equivalent to a 2.34-in. diameter LOCA break size. This is within the Small LOCA category.

There are two PSRV failure modes that could result in a LOCA:

1. Catastrophic leakage failure
2. Premature open and failure to reclose

Initiating events that result in a PSRV lift with potential failure to reclose are treated in the event tree and fault tree top logic for each IE, and are therefore not considered here.

From a Nuclear Plant Reliability Data System (NPRDS) search of nuclear power plant data, there have been 87 leakage failures in an estimated 2086 safety valve years of operation.

$$\text{Leakage Rate} = \frac{\text{87 Failures}}{\text{2086 years} \times \text{8760 hr./year}} = \text{4.5E-6/hr.}$$

None of these 87 failures resulted in catastrophic leakage. However, based on engineering judgement, it is assumed that one in 1000 failures will result in catastrophic leakage.

Therefore, the frequency of catastrophic leakage from a PSRV is estimated as:

F(PSRV-leak) = 4 Valves/Unit * 4.47E-9 failure/valve-hr. * 8760 hr./year

= 1.7 E-4/year

From a NPRDS search of nuclear power plant data, there have been nine premature openings in an estimated 2086 PSRV years of operation. From Table 6.2-1, the probability of failure to reclose a PSRV after it has been open is 4.9E-3/d.

Therefore, the frequency of PSRV premature open and fail to reclose is estimated as:

= (9/2086) * 4 Valves * 5.0E-3

= 8.6E-5/year

The total contribution to Small LOCA due to primary safety valve failure is:

Total PSRV LOCA = 1.7E-4/year + 8.6E-5/year = 2.5E-4/year

6.1.3.2.4 Interfacing System LOCAs (ISLs) - Inside Containment

Interfacing System LOCA (ISL) refers to a LOCA that occurs due to failure of the boundary between the RCS and a system that interfaces with it. Subsequent pressurization of the interfacing system causes a breach of its pressure boundary. LOCAs of this type can be categorized as inside containment or outside containment, depending on the location of the breach. Identifying ISLs was accomplished by a review of PVNGS design and surveying PVNGS operating history to identify any potential ISL precursors. The results of the design review for inside containment ISLs are discussed in Sections 6.1.3.2.4 and for outside containment ISLs in Section 6.1.3.3.2.

The IEF for inside and outside containment ISls are calculated using methodology similar to that recommended by the IPE Methodology Report, Appendix B (Reference 6.3.6), but modified to include consideration of common cause failure of multiple isolation check valves.

The behavior and mitigation requirements for inside containment ISLs at PVNGS are generally the same as for an equivalent sized RCS boundary LOCAs. Potential differences lie in the impact of the break on a front-line system that must respond to the LOCA. However, the success criteria for safety injection systems responding to any LOCA presumes that all injection flow from one SI line is lost out of the break. For this reason, the success criteria, given an ISL in one of these systems, remains unchanged. Thus, calculated initiating event frequencies for inside containment ISLs are added to the IEF for the equivalent sized LOCA.

Four paths were identified for potential ISL inside containment:

1. RCS cold-leg to Safety Injection Tank (SIT)
2. RCS cold-leg loop drains to RDT
3. RCS cold-leg to RDT via SI
4. RCS hot-leg to Shutdown Cooling (SDC) Reactor Drain Tank

Each of these possible paths is discussed in the following sections.

6.1.3.2.4.1 ISLs in the RCS Cold-Leg to SIT lines

The RCS cold-leg to SIT path for an ISL involves RCS backflow through two check valves in a 14-in. injection line and subsequent rupture of the 700 psig design pressure tank or its relief line. The path from RCS loop 1A, for example, includes the RCS isolation check valve (V-237), a normally-open, key-locked open (when the RCS pressure is greater than 700 psig) motor-operated valve (UV-634), and a SIT isolation check valve (V-235). The check valves are backflow leak tested to ensure they have closed after each shutdown, after valve maintenance, and after an Engineered Safety Features Actuation System (ESFAS) actuation or any operation that results in flow through the valve. Pressure between the primary RCS check valve and the SI check valves is monitored and alarmed in the Control Room via a pressure transmitter (PT-339). The 1-in. O.D. pressure sensing line contains two locked open manual valves (V-566 and V-236). The SIT tank is protected against overfill rupture due to refill operations by a 2-in. pressure relief valve (PSV-231) on a 2-in. line connected to the tank. Tank pressure is monitored and alarmed in the Control Room. Loops 1B, 2A, and 2B have the same configuration.

Due to the PVNGS Technical Specification (PVNGS T/S) requirement that the RCS pressure isolation check valves be leak tested, ISL scenarios based on failure to reclose one or both of the check valves in this flow path are neglected. The only credible scenarios involve common cause or dependent-internal ruptures of the check valves after they have seated. The SIT isolation check valve has an insignificant pressure drop across it (the failure is assumed as a negligible risk of catastrophic rupture) as long as the RCS isolation check valve is seated. Should the primary check valve disk rupture, the SIT isolation check valve will be exposed to RCS pressure and temperature and a high pressure alarm will be activated. Operator response to this alarm would be to perform a leak rate test on the failed check valve and proceed to Cold Shutdown within 40 hrs. if failure of the check valve is confirmed.

Internal rupture of both the RCS isolation and the second SIT isolation check valves will cause a sudden surge in the SIT pressure (normally 610 psia during full power operations). The 2-in. PSV on the SIT will open to relieve tank pressure, but if the most restricting of the two ruptured check valves has an equivalent rupture size greater than the PSV flow area, catastrophic failure of the SIT or associated low pressure lines is possible.

Three ISL sequences involving SIT LOCAs are considered:

1. Roughly, simultaneous common cause internal rupture of both check valves followed by continuous SIT relief via the 2-in. PSV or, for larger check valve ruptures, tank/piping rupture
2. Internal rupture of the primary isolation check valve, failure of the pressure alarm that would notify the operators, and rupture of the second check valve
3. Internal rupture of the primary isolation check valve and success of the alarm and rupture of the second isolation check valve within the 40-hr. shutdown period.

Since the SIT isolation Motor Operated Valve (MOV) is located between the two check valves, a LOCA caused by internal rupture of the check valves could conceivably be terminated if the operator diagnosed the condition and closed the MOV from the Control Room. However, depending on the equivalent break size of the check valve ruptures, little time may be available for this recovery before some form of at least short-term safety injection will be needed to prevent core uncovery. It is also possible that the SIT MOV would not close against full RCS pressure. Possible isolation of the LOCA break using the SIT MOV is neglected for this analysis.

Testing for the SI check valves is performed in accordance with Procedure 73ST-9SI03 and Technical Specifications Surveillance Requirement 4.4.5.2.2. These check valves are leak tested every 18 months or after a Safety Injection Actuation Signals (SIAS), or prior to entering Mode 2. Eighteen months is conservatively assumed for the test period. The mean catastrophic failure rate for a internal ruptured check valve is 4.0E-9/hr. (λ). The beta factor (β_2) for two check valves is

1.5E-2. Using these values, the frequency of a SIT ISL via the three sequences can be represented as follows:

$$F_{SIT} = [P_{cv\text{-}cc2} + (P_{cv1} \times P_{foa} \times P_{cv2}) + (P_{cv1} \times P_{cv2\text{-}72})] \times 4\,loops$$

where:

$P_{cv\text{-}cc2}$ = probability of roughly simultaneous internal rupture of both primary and secondary check valves (in 18 months)

= $\lambda t \beta_2$ = 4.0E-9 * 13,140 hrs. * 1.5E-2

= 7.9E-7/18 months

P_{cv1} = probability of primary check valve disk rupture (in 18 months)

= λt = 4.0E-9 * 13,140 hrs.

= 5.3E-5/18 months

P_{foa} = probability of failure of the alarm

= $1/2(\lambda_1 + \lambda_2 + 2{*}\lambda_3)t$ = 1/2(4.6E-6 + 1.0E-6 + 2*3E-8)* 13,140 hrs

= 3.7E-2/18 months

(Here, λ_1 is the failure rate for a pressure sensing instrument channel from Table 19 of Reference 6.3.31; λ_2 is the alarm/ indicator failure rate from Table 4 of Reference 6.3.32; and λ_3 is the manual valve plugging failure rate, Table 6.2-1, for two valves in sensing line.)

P_{cv2} = probability of secondary check valve disk rupture given the first valve fails

= $1/2\lambda t$ = 1/2 * 4.0E-9 * 13,140 hrs.

= 2.6E-5/18 months

$P_{cv2\text{-}72}$ = probability of secondary check valve disk rupture within 40 hrs. given the first valve fails

= 4.0E-9 *40 hrs.

= 1.6E-7

The conditional probability of the second check valve failure (P_{cv2}) is calculated here as half the primary check valve failure probability. This is due to the assumption of negligible valve rupture probability for the period during which there is no pressure drop across the valve.

The frequency of an ISL from the cold leg via a SIT can now be calculated:

F_{SIT} = [7.9E-7 + 5.1E-11 + 8.4E-12] * 4 loops

= 3.2E-6/18 months

= 2.1E-6/year

Common cause internal rupture of the check valves clearly dominates this frequency.

As discussed previously, F_{SIT} represents an inside containment ISL that does not affect front-line systems to any greater extent than was assumed for LOCAs in general. As such the above frequency is considered as a contributor to a LOCA initiating event frequency. In order to assign the probability to the appropriate LOCA frequency, the equivalent break size of this ISL must be characterized.

The equivalent break size is determined by the smallest internal rupture opening in the two check valves. The absence of any occurrences of this type of check valve failure in industry experience makes characterization of the rupture size speculative. Intuitively, it seems highly likely that at least one of the two ruptured check valves will have an equivalent internal rupture opening less than the Medium LOCA size of 3-in. diameter. This would imply that the majority of these events would fall in the Small LOCA category. Some support for this position can be found in Reference 6.3.30, Figure C.2-15, which shows an expert's assessment of check valve reverse leak rate versus frequency. All of the plotted data points fall within the PVNGS Small LOCA break flowrate and even the extrapolated fit barely reaches into the flowrate regime characterizing a Medium LOCA. As such, the following equivalent break size distribution for ISLs due to internal rupture of check valves is:

Small LOCAs (0.38 - 3.0-in. diameter) 90%

Medium LOCAs (3.0 - 6.00-in. diameter) 9%

Large LOCAs (>6.00-in. diameter) 1%

Here, it is judged that, although it must be extremely separating unlikely, the possibility of two check valve discs or pivot arms completely separating could not be entirely ruled out. Thus, the fraction of internal check valve ruptures that result in an equivalent Large LOCA sized break is conservatively estimated at 1%.

Finally, the contribution of SIT ISLs to each of the LOCA initiating event frequencies is calculated as:

Small LOCA	0.90 * 2.1E-6 = 2.0E-6/year
Medium LOCA	0.09 * 2.1E-6 = 2.0E-7/year
Large LOCA	0.01 * 2.1E-6 = 2.1E-8/year

6.1.3.2.4.2 ISLs in Cold-Leg Loop Drains to RDT

This path contains two 2-in. normally-closed manual valves (V-333 and V-233 in loop 1), which prevent flow to the RDT. Each of the 4 loops have the same configuration. The frequency of catastrophic internal leakage for a manual valve is given in Table 6.2-1. There is no historical evidence of common cause backflow through two initially closed manual valves; therefore, it is not modeled. The calculation for the frequency of the "Cold-Leg Loop Drains To RDT" ISL, based upon a valve test interval of 18 months, is as follows:

$$F_{\text{Cold-Leg Loop Drains to RDT}} = P_{mv1} * P_{mv2} * 4 \text{ loops}$$

where:

P_{mv1} = probability of primary manual valve disk rupture (in 18 months)

= λt = 1.0E-7 * 13,140 hrs.

= 1.3E-3/18 months

P_{mv2} = probability of secondary manual valve disk rupture given the failure of the first manual valve

= $1/2\lambda t$ = 1/2*1.0E-7 * 13,140 hrs.

= 6.6E-4/18 months

Therefore, the contribution due to all four loops is:

$F_{\text{Cold-Leg Loop Drains to RDT}}$ = 3.4E-6 events/18 months

= 2.3E-6 events/year

The yearly value was added to the Small LOCA frequency.

6.1.3.2.4.3 ISLs in RCS Cold-Leg to RDT via SI

This ISL occurs through the pressure bleed-off line between the primary and secondary RCS isolation check valves on each SI line. In Loop 1A, internal rupture of isolation check valve (V-237) exposes a normally-closed solenoid operated valve (UV-638) to RCS pressure. In case of a catastrophic failure of the solenoid valve, a 1-in. equivalent diameter flowpath will be opened to the RDT through a pressure relief valve (PSV-473). However, a 2500 psig rated flow orifice in the line between the Solenoid Operated Valve (SOV) and the RCS isolation check valve (FO-29) has a 0.335-in. restricting bore which would limit the equivalent break size to less than the minimum for a Small LOCA. Loops 1B, 2A, and 2B have similar configurations. Since the charging pumps can effectively handle a leak of this size, it need not be considered as a contributor to inside containment ISL.

6.1.3.2.4.4 ISLs in the Shutdown Cooling Suction Line

Two normally closed key locked MOVs (UV-651 and UV-653 in Loop 1), in series and in each SDC suction line, isolate low pressure piping from the RCS hot-legs (Figure 6.1-1). Loop 2 has a similar configuration. Between each two valves in series, a 1-in. relief valve (PSV-469 for Loop 1 with setpoint at 2485 psig) provides overpressure protection for the 2485 psig piping, but would not be expected to open in the event of exposure to normal RCS operating pressure of 2250 psig. Should the relief valve open prematurely upon RCS leakage past the first isolation MOV, the Control Room operators would detect the leak either by decreasing primary pressure or by RDT indication alarms. Reactor shutdown and depressurization would be required within 40 hrs. Without such a failure of the relief valve, it is assumed that operators would not be able to detect a primary MOV disc rupture and the secondary MOV would be exposed to RCS pressure until shutdown.

Between the second MOV and a third MOV, located outside containment (UV-655 in Loop 1), there is approximately 41 ft. of piping which has a pressure rating of 485 psig. Eight feet of this piping is outside containment. A large capacity pressure relief valve for Low Temperature Overpressure Protection (LTOP) (PSV-179 in a 6-in. line in Loop 1) with a 467 psig setpoint is designed to protect against pressure surges that might occur during shutdown cooling system operation. The relief lines drain to the containment recirculation sumps. In the remote event of catastrophic internal rupture of both primary and secondary MOVs in the shutdown cooling suction line, the LTOP line would most likely prevent piping rupture by venting to the containment sump. The low pressure piping would be in jeopardy only in an extremely rare scenario involving greater than 6-in. equivalent diameter internal ruptures in both isolation MOVs. And even in such a scenario, the piping most susceptible to rupture would be the 6-in. relief line, which would be experiencing extremely high flowrates. Since the plausible break locations for this class of LOCAs are all within the containment, they are classified as inside containment ISLs.

$F_{Hot\text{-}Leg2} = [P_{mov1} * P_{psv\text{-}rc} + (P_{mov1} * P_{mov2})] * 2$ loops

where:

P_{mov1} = probability of disk rupture of the primary MOV (in 18 months)

= $\lambda t = 1.0E\text{-}7 * 13{,}140$ hrs.

= 1.3E-3/18 months

P_{mov2} = probability of disk rupture of the secondary MOV sometime after primary MOV fails

= $1/2\lambda t = 1/2 * 1.0E\text{-}7 * 13{,}140$ hrs.

= 6.6E-4/ 18 months

$P_{psv\text{-}rc}$ = probability that pressure relief valve fails to remain closed when exposed to normal RCS pressure

= $\lambda t = 4.0E\text{-}6 * 13{,}140$ hrs.

= 5.3E-2 /18 months

(Here, the failure rate comes from Table 6.2-1 for relief valves and it is conservatively assumed that the mechanism leading to premature opening is present for the entire period between PSV calibration checks.)

The possibility of spurious command faults that open these Shutdown Cooling (SDC) suction MOVs is discounted here for three reasons: (1) the control circuits include pressure interlocks that prevent the valves from opening whenever RCS pressure is above SDC design pressure, (2) PVNGS procedures call for circuit breakers to the secondary MOVs in each line (UV-653,UV-654) to be racked out during power operation (precluding the possibility of spurious control circuit faults that could open the valves), and (3) the valve operators are not designed to open against 2250 psig RCS pressure.

Assuming that no significant mechanism exists that could induce rupture of the secondary MOV internals until rupture of the primary MOV exposes it to RCS pressure and discounting common cause rupture of two closed MOVs (no historical evidence exists), the following calculations are made.

$$F_{Hot\text{-}Leg2} = [1.3E\text{-}3 * 5.3E\text{-}2 + 1.3E\text{-}3 * 6.6E\text{-}4]*2$$
$$= 1.4E\text{-}4/18 \text{ months}$$
$$= 9.3E\text{-}5/\text{year}$$

Again, it is necessary to speculate as to the distribution of such MOV internal rupture ISLs amongst the three PVNGS LOCA classes. All ISLs via the 1-in. relief valve fall into the Small LOCA category since the associated piping exposed upon MOV rupture is rated higher than normal RCS operating pressure. However, for scenarios involving internal rupture of both SDC suction MOVs the LOCA size would depend on the size of the smallest opening in the ruptured valves. In the absence of applicable empirical data, the same proportioning scheme devised for the SIT check valve ruptures is used for these scenarios. The contribution to each of the LOCA IEs due to ISL via the SDC suction lines is thus determined to be:

Small LOCA	9.2E-5 +.90 * 1.1E-6 =	9.3E-5/year
Medium LOCA	.09 * 1.1E-6 =	9.9E-8/year
Large LOCA	.01 * 1.1E-6 =	1.1E-8/year

6.1.3.2.4.5 Total Contribution from ISLs Inside Containment

The total contribution of interfacing LOCAs inside the containment to the initiating event frequencies for the three LOCA classes may now be summarized as follows:

Small LOCA	(2.0E-6 + 2.3E-6 + 9.3E-5) =	1.0E-4/year
Medium LOCA	(2.0E-7 + 9.9E-8) =	3.0E-7/year
Large LOCA	(2.1E-8 + 1.1E-8) =	3.2E-8/year

6.1.3.2.5 RCP Seal LOCA

The forced circulation of the RCS is achieved by four reactor coolant pumps (RCPs). The RCPs (CE-KSB) are vertical, single-stage motor driven, centrifugal pumps. Each RCP is supplied with three tandem mechanical face seals (Reference 6.3.17).

The three tandem mechanical face seals consist of a series of two similar rubbing face seals plus a third low pressure vapor face seal. Each seal is a rotating carbon face riding over a tungsten carbide ring. External seal injection water is supplied to the seals. Part of the seal injection water flows into the pump casing with the remaining portion flowing into the seals to form the seal controlled bypass leakage. Reactor coolant in the seal cavity is forced by an auxiliary impeller through a high-pressure cooler, where it is cooled with Nuclear Cooling Water (NC). The controlled bypass flow passes through flow restrictions, which are designed to divide the total pressure drop across the three seals so that each seal has about the same pressure differential. Since each seal is designed to accept the full pressure differential, this feature extends their operating life. The seal leakage and controlled bypass flow past the second seal is piped to the Volume Control Tank (VCT) in the Chemical and Volume Control System. Any leakage past the third seal is collected and piped to the Reactor Drain Tank (RDT).

Due to the lack of extensive data regarding PVNGS RCP seal reliability, seal failure frequencies had to be made by inference. Based on work done in a PVNGS study (Reference 6.3.24), it was determined that the PVNGS pump seals (CE-KSB) are similar to CE-Byron Jackson (BJ) pump seals. This fact allows two assumptions to be made:

- Failure of all three stages of the seal leads to a LOCA, which will not exceed 600 gpm per pump equates to an equivalent diameter size of 3/4-in.
- Because of the similar seal designs of the two types of pumps, failure frequencies can be applied to the CE-KSB pump seals.

The value derived for the CE-KSB pump seal leak is from NUREG/CR 4550, Vol. 3, Part 2, Appendix D, which estimates a frequency of 3.9E-3/year. This value is based upon five seal failures between 1974 and 1980 and zero seal failures between 1981 and 1988.

6.1.3.3 Other LOCAs

In addition to the Small, Medium, and Large LOCAs evaluated in the PVNGS PRA, three other types of LOCAs are evaluated:

- Reactor Vessel Rupture
- RCS Interfacing System LOCA - Outside of Containment
- Steam Generator Tube Rupture

These three initiators are discussed in the following sections.

6.1.3.3.1 Reactor Vessel Rupture

Several PRAs have previously postulated reactor vessel rupture as an initiating event. The rupture is typically assumed to be in a location and of a magnitude such that safe shutdown is not possible after the initiator. The WASH-1400 study, Oconee PRA, the Millstone III PRA, and the Seabrook PRA have calculated a frequency for reactor vessel rupture ranging from 1.0E-7 to 1.1E-6/year. These calculations were based on statistical interpretation of historical data. Most studies calculate a median value of 1E-7 to 3E-7, but assume different error factors to yield different mean values. More recently, the NUREG/CR-4550 methodology document did not even specify a value for reactor vessel rupture, although the Pressurized Water Reactor (PWR) studies used a 1E-7 value and the Boiling Water Reactor (BWR) studies used a 1E-8 value.

With the exception of pressurized thermal shock, no specific failure mechanisms have been identified which can be related to the calculated frequencies in the 1E-7 range. Pressurized Thermal Shock (PTS) for PVNGS is a minimal contributor to risk, because of the very low value of reactor vessel reference temperature for nil ductility transition (RTN_{DT}). These studies show no measurable contribution to core damage if RTN_{DT} is less than 270° F. Combustion Engineering has calculated the RTN_{DT} for PVNGS to be:

40° F in Year 1

102° F in Year 10

116° F in Year 40

With such low temperatures, pressurized thermal shock at PVNGS is a negligible contributor to vessel failure.

Summary

1. Reactor vessel rupture has typically been shown to be an insignificant contributor to core damage frequency.
2. There have been no occurrences of large vessel rupture in vessels designed to the American Society of Mechanical Engineering (ASME) Code. The available data for prediction of vessel rupture yields a frequency in the low E-7/year range.
3. Pressurized thermal shock has been postulated to be the most significant contributor to reactor vessel rupture at some plants. PTS at PVNGS is considered to be a minimal contributor because of the low RTN_{DT}.

Reactor vessel rupture at PVNGS is a small and minimal contributor to core damage. The frequency is estimated to be a less than 1E-7/year. As a result, the failure frequency will not be included in the PVNGS analysis.

6.1.3.3.2 RCS Interfacing System LOCA-Outside Containment (Event V)

All ISLs are of particular concern because they can adversely impact a system required to mitigate the accident. However, ISLs outside of the reactor Containment Building are of the greatest concern because ejected cooling water does not return to the Engineered Safety Features (ESF) sumps for reinjection/recirculation. In addition, because containment has been bypassed, radiological releases are likely to be significantly higher. These event scenarios have been historically labeled "V-Sequences".

An interfacing LOCA outside containment occurs due to a breach in the RCS pressure boundary, which bypasses all containment safeguard systems. For PWRs, this might occur, for example, due to faults that permit an RCS leak back through high pressure piping into a low pressure system. The low pressure system is then presumed to rupture at some location outside containment resulting in an ISL.

For PVNGS, four scenarios are identified that lead to a potential ISL outside containment during power operation or hot-standby:

- RCS Cold-Leg to the High Pressure Safety Injection/Low-Pressure Safety Injection (HPSI/LPSI) systems
- RCS Hot-Leg to Shutdown Cooling Suction Line
- RCS Letdown Line Rupture Outside Containment
- RCS to Nuclear Cooling Water System

6.1.3.3.2.1 ISLs in RCS Cold-Leg to HPSI/LPSI Systems

In order to induce an outside containment LOCA via this path, backflow must occur through three check valves and a normally-closed MOV (Figure 6.1-2). The first check valve in the path is the primary RCS isolation check valve (V-217 for Loop 2A). Internal rupture of this valve exposes a SI header isolation check valve (V-540) to RCS pressure and temperature. A high pressure alarm is activated when RCS high pressure is detected by the pressure transmitter (PT-319) downstream of normally locked open manual valves (V-559 and V-216) in the bleed-off line. Operator response to this alarm would be to perform a leak rate test on the suspect check valve. If it is determined that the valve has failed, the operator would be required to proceed to Cold Shutdown within 40 hrs. Failure of the pressure alarm would likely result in the second check valve being exposed to RCS pressure until cold shutdown. Subsequent failure of this secondary check valve exposes the LPSI header check valve (V-114) and the HPSI header check valve (V-113) to the RCS pressure. If either of these check valves permits backflow, normally-closed LPSI or HPSI injection MOVs (located just outside containment) are exposed to RCS pressure. If one of the injection MOVs ruptures internally or is opened, a LOCA outside containment will be induced either due to rupture of downstream low pressure piping or continual venting out small relief valve lines.

ISL scenarios via the HPSI cold-leg injection lines were dropped from further consideration due to inherent LOCA mitigating effects of the SI system design. The HPSI headers contain two flow orifices, the smallest of which would restrict any LOCA flow to an equivalent 1.08-in. diameter break. A 1-in. HPSI system pressure relief line would open to vent RCS pressure should the three check valves fail and the HPSI MOV rupture or open. Since the lowest design pressure of the HPSI piping upstream of the injection MOVs is for Train A at 2485 psig (Train B piping is 2050 psig) and there would inevitably be significant pressure drop from the RCS (at roughly 2300 psig) back through the three failed SI check valves, the relief valve should prevent catastrophic rupture of the HPSI system piping. Once RCS pressure drops below 2485 psig, the relief valve will close and terminate the LOCA. Even if pressure relief is inadequate and the HPSI system ruptures at some location upstream of the injection MOVs, when the RCS depressurizes to the SIAS setpoint, both HPSI pumps will be started and all injection MOVs will open. Once RCS pressure drops into the range of the HPSI shut-off head (~ 1900 psig), pressure from both operating HPSI pumps will effectively terminate RCS coolant flow out through a piping break upstream of the 1-in. flow orifices. Subsequent operator action to close the HPSI MOV (if it was opened) would terminate such a LOCA.

For the LPSI system, the flow orifices in the 12-in. diameter injection lines are much larger than the 1-in. relief lines and it was assumed that exposing the low pressure LPSI piping to RCS pressure would produce a rupture. Two scenarios were identified for potential ISL consideration via the LPSI system:

1. SI systems are in standby, the three check valves rupture internally, and the normally closed MOV either ruptures internally or opens inadvertently
2. A LOCA or RCS overcooling event occurs, which actuates the SI pumps and opens the injection MOVs, and then pre-existing or subsequent failure of check valves results in an ISL in the LPSI system

For the first class, it is apparent that while the SI systems are in standby, only a series of low probability failures could lead to an ISL via this path. Within this class, the scenarios identified for analysis were:

- Three RCS/SI line check valves undergo catastrophic internal rupture within a relatively short interval (due to common cause) and the LPSI MOV, in that line, has either ruptured internally or received a spurious open signal in the 40 hrs. before operators are required to enter Cold Shutdown
- Three RCS/SI line check valves undergo catastrophic internal rupture (due to common cause), the high pressure alarm in the SI line fails in an undetectable manner, and the LPSI MOV in that line is opened during quarterly surveillance testing

In defining these scenarios, only common cause failures of the three check valves were considered, since common cause failures greatly dominate any of the possible random valve failure sequences. It was also assumed that the LPSI MOVs would open if commanded against the high pressure that would be present if the three isolation check valves had failed. This is a highly conservative assumption for the LPSI MOVs, which are in the 12-in. LPSI headers and are not designed specifically to operate with large differential pressures across the discs. No credit was taken for the operators quickly diagnosing the presence of a LOCA via a LPSI system line and closing the appropriate LPSI injection MOV to terminate the event. However, it should be noted that if the LPSI MOV opened against RCS pressure, there is a fair likelihood that it could be reclosed by operators once they determine the nature and location of the LOCA break.

The ISL frequency for the first class of LPSI scenarios was therefore estimated as:

$F_{LPSI1} = F_{cv\text{-}cc3} * [(P_{MOV} + P_{SIAS/CX}) + P_{foa} * P_{MOV\text{-}test}] * 4$ loops

where:

$F_{cv\text{-}cc3}$ = frequency of roughly simultaneous internal rupture of three RCS and SI isolation check valves (per 18 months)

= $\lambda t \beta_2 \beta_3$

= 4.0E-9 * 13,140 hrs. * 1.5E-2 * .9

= 7.1E-7/18 months

(Here, the beta factors for two and three common cause failures of similar check valves is estimated by taking the geometric average of the five beta estimates from NUREG/CR-4550)

P_{MOV} = probability the MOV has ruptured internally at the time the check valves fail

= $1/2\lambda Mt$ = 1/2 * 1.0E-7 * 13,140 hrs.

= 6.6E-4/ 18 months

(Here, λM is the fail to remain closed rate for MOVs from Table 6.2-1.)

$P_{SIAS/CX}$ = probability of a spurious SIAS or control circuit MOV open command during 40 hrs. prior to entry into cold shutdown conditions

$= (2*\lambda_1 + \lambda_2)t$

$= (2 * 5.7E\text{-}6 + 6.0E\text{-}7) * 40$ hrs.

$=$ 4.8E-4/18 months

(Here, λ_1 is based on the Inadvertent safety injection signal frequency from NUREG/CR-3862. Since the NUREG value reflects only events that result in plant trips and spurious safety injection signals do not necessarily cause trips at all plants, like PVNGS, the reported failure rate was conservatively increased by a factor of 2. The rate λ_2 is the control circuit spurious open failure rate for the LPSI MOV.)

$P_{foa} =$ probability that pressure alarm has failed in an undetectable state when check valve ruptures occur .

$= 1/2(1/2 * \lambda_4 + \lambda_5 + 2*\lambda_6)t$

$= 1/2(1/2 * 4.6E\text{-}6 + 1.0E\text{-}6 + 2*3E\text{-}8) * 13{,}140$ hrs.

$=$ 2.2E-2/18 months

(Here, λ_4 is based on the "inoperable" failure rate for an analog pressure sensing instrument channel from Table 19 of Reference 6.3.31. It is conservatively assumed that one half of the faults would be such that they would be undetectable prior to a demand or test. The failure rate λ_5 is the alarm/indicator failure rate from Table 4 of Reference 6.3.32; λ_6 is the manual valve plugging failure rate, Table 6.2-1, two valves in sensing line.)

$P_{MOV\text{-}test} =$ probability that LPSI MOV is stroke-tested sometime after the check valves and the pressure detection fail. Since the MOVs are tested quarterly, this was assigned a value of 1.0

Therefore, the contribution to outside-containment ISL due to this path is estimated as:

$F_{LPSI1} = 7.1E\text{-}7 * [6.6E\text{-}4 + 4.8E\text{-}4 + (2.2E\text{-}2*1.0)]*4$ loops

$=$ 6.6E-8/18 month

$=$ 4.4E-8/year

For the second class of ISLs via the LPSI lines, an initiating event that generates a SIAS signal must first occur. Events that fall in this category include any LOCA, Steam Generator Tube Rupture (SGTR), and RCS overcooling events (main steam line breaks). As soon as the SIAS signal is generated, all HPSI and LPSI injection MOVs will open. If the three isolation check valves between any of the LPSI MOVs and the RCS have already ruptured internally, the low pressure LPSI piping will be exposed to the much higher RCS pressure. For major ruptures of the isolation check valves, the two 1-in. LPSI pressure relief lines will probably not prevent a rupture of the low pressure system boundary.

The possibility of the isolation check valves permitting backflow due to failure to close sometime after the initiating event occurs was also investigated. This was of some concern because fail to close rates for check valves historically have been found to be higher than catastrophic rupture failure rates for valves that are first verified to have seated. One of the few plausible scenarios that could induce such failures would begin with a primary system LOCA, initiation of HPSI flow, which opens certain safety injection check valves, and a subsequent loss of off-site power, which temporarily terminates SI flow. RCS pressure would then act to force coolant back through the SI lines.

Due to the PVNGS system design, any event that initiates safety injection flow causes the primary and secondary RCS Isolation check valves to open first once RCS pressure drops below the HPSI shut-off head of ~1900 psig. Even though the LPSI MOVs open as soon as a SIAS occurs, the LPSI isolation check valve will not open until RCS pressure drops below the pump shut-off head of ~200 psig. Thus, in order for a LOCA (or RCS overcooling event) to degrade into a LPSI system ISL outside containment, both HPSI pumps must stop after initiating SI flow (most likely due to a LOOP), both RCS isolation checks must subsequently fail to close, and one of the LPSI isolation check valves must rupture internally. A cursory calculation of this combination of failures gave a sequence probability that is insignificant.

Similar scenarios that were discounted included those which postulate one or more LPSI pumps stopping once LPSI flow has been initiated (HPSI flow assumed terminated) and subsequent failure to close all three check valves in the LPSI injection flow path. This was because, even given this remote combination of events, the LPSI system piping is obviously designed to handle the RCS pressure it would be exposed to under these conditions.

Thus, for the second class of ISLs via the LPSI system, the scenarios identified for analysis were:

- Three RCS/SI line check valves undergo catastrophic internal rupture within a relatively short interval (due to common cause) and a LOCA, SGTR, or RCS overcooling event occurs in the 40 hrs. before operators are required to enter Cold Shutdown
- Three RCS/SI line check valves undergo catastrophic internal rupture (due to common cause), the high pressure alarm in the SI line fails in an undetectable manner, and a LOCA, SGTR, or RCS overcooling event occurs prior to the next reactor shutdown

As was done for the first class of scenarios, only common cause failure of the three check valves was considered. It was conservatively assumed that the LPSI MOVs would open even if commanded against the high pressure that would be present if the three isolation check valves had failed.

The ISL frequency for the second class of LPSI scenarios is estimated as:

$F_{LPSI2} = F_{cv\text{-}cc3} * [P_{SI1} + (P_{foa} * P_{SI2})] * 4$ loops

where:

$F_{cv\text{-}cc3} =$ frequency of roughly simultaneous internal rupture of three RCS and SI isolation check valves (per 18 months)

$= \lambda_1\beta_2\beta_3 = 4.0E\text{-}9 * 13{,}140 \text{ hrs.} * 1.5E\text{-}2 * .9$

$= 7.1E\text{-}7/18$ months

P_{SI1}= probability that an initiating event that requires Safety Injection occurs during 40 hrs. prior to entry into cold shutdown conditions

= $(\lambda_{SMLOCA}+\lambda_{MLOCA}+\lambda_{LLOCA}+\lambda_{SGTR}+\lambda_{SLB})t$

= (9.1E-7 +5.1E-8 +2.4E-8 +1.8E-6 +1.1E-7)* 40 hrs.

= 1.2E-4

(Here, λ_{SMLOCA},λ_{MLOCA},λ_{LLOCA},λ_{SGTR}, and λ_{SLB} are the PVNGS hourly frequencies for Small, Medium, and Large LOCAs, steam generator tube ruptures, and steam line breaks, respectively. The values are derived from the yearly frequencies given for these initiating events in Table 6.1-1.)

P_{foa}= probability that pressure alarm has failed in an undetectable state when check valve ruptures occur

= 2.2E-2 (As derived for L_{LPSI1})

P_{SI2}= probability that an initiating event that requires Safety Injection occurs sometime between check valve ruptures and next reactor shutdown

= $1/2(\lambda_{SMLOCA}+\lambda_{MLOCA}+\lambda_{LLOCA}+\lambda_{SGTR}+\lambda_{SLB})t$

= 1/2 *(9.1E-7 +5.1E-8 +2.4E-8 +1.8E-6 +1.1E-7)* 40 hrs.

= 1.9E-2/18 months

F_{LPSI2}= 7.1E-7 *[1.2E-4 + (2.2E-2*1.9E-2)]*4 loops

= 1.5E-9/18 months

= 1.0E-9/year

The total frequency for outside-containment ISLs via the LPSI system was estimated to be:

F_{LPSI}= F_{LPSI1} + F_{LPSI2}

= 4.5E-8/year

Again, it should be noted that the majority of the ISL sequences in this section involve a LPSI MOV opening against RCS operating pressure. If the MOV causes the ISL by opening, it is quite possible that the ISL could be terminated by operator action to close the MOV if it is diagnosed in a timely manner. However, no credit is taken here for this potential recovery.

6.1.3.3.2.2 ISLs in RCS Hot-Leg to Shutdown Cooling

An outside-containment ISL via this path requires catastrophic internal rupture of two normally-closed key locked MOVs in a SDC suction line (UV-651 and UV-653 in Loop 1) and subsequent rupture of the 8 ft. of low pressure piping between the containment wall and a third MOV. However, as discussed in the inside-containment section dealing with this scenario, rupture of this small section of piping is improbable due to the capacity of the large LTOP relief valve. As such this ISL path is considered to be a negligible contributor to the ISL outside containment frequency.

6.1.3.3.2.3 ISLs in RCS to Letdown Line

The 2-in. letdown line is designed for and normally pressurized to RCS pressure up to the letdown control valves, LV-110P and LV-110Q, (Figure 6.1-3). Within the containment, the line includes two air-operated, fail-closed containment isolation valves (UV-515,516) and the Regenerative Heat Exchanger. The isolation valves close automatically given a SIAS signal, with one of the valves also closing on CIAS and the other closing on high temperature in the piping downstream of the heat exchanger. All breaks in the letdown line inside containment fall into the normal Small LOCA category. However, breaks between the isolation valves and the containment wall were dropped from further consideration due to the high likelihood that the leak would be terminated by closure of one or both valves.

Outside containment between the penetration and the Letdown Heat Exchanger, the line contains another containment isolation AOV (UV-523), which automatically closes upon a CIAS, and two letdown control valves (LV-110P and LV-110Q) in parallel 2-in. lines. One of the letdown control valves is administratively isolated by procedure whenever RCS pressure exceeds the capacity of the relief valve (PSV-345) that was designed to protect the heat exchanger and associated piping. The letdown control valves limit the flow due to any downstream break to within the capacity of the charging pumps. For this reason and the fact that there are three containment isolation valves which would receive close signals given an outside-containment LOCA, all ISL scenarios downstream of the UV-523 isolation valve were dropped from further consideration.

Between the containment wall and the UV-523 isolation valve lies some short sections of 2-, 1-, and 0.5-in. high pressure piping that could initiate an outside-containment ISL. Only the two isolation AOVs within the containment would be available to terminate RCS flow out the break. The frequency of an unisolated letdown line ISL is estimated in the following manner:

$F_{Letdown} = F_{brk} * [(P_{AOV1} + P_{CX1}) * (P_{AOV2} + P_{CX2}) + P_{CC})]$

where:

F_{brk} = frequency of pipe rupture in letdown line between containment wall and UV-523, containment isolation AOV. Use pipe failure rate from Table 6.1-5

= 7 pipe sections * 13,140 hrs. * 2.01E-9/section-hr.

= 1.8E-4/18 months

P_{AOV1} = probability AOV UV-515 (or SOV UY-515) fails to close given letdown line rupture outside containment. Valve stroke tested during shutdowns.

= $1/2(\lambda_{AOV}+\lambda_{SOV})t$

= 1/2 (4.1E-7 + 8.2E-7) 13,140 hrs.

= 8.1E-3/18 months

P_{CX1} = probability AOV UV-515 fails to close due to control circuit fault. (Circuit single failures are one relay fail-to-de-energize and one relay spurious energize.)

= 1/2(4.0E-7 + 4.3E-7)13140 hrs.

= 5.5E-3/18 months

P_{AOV2}= probability AOV UV-516 (or SOV UY-516) fails to close given letdown line rupture outside containment. Valve stroke tested during shutdowns

= $1/2(\lambda_{AOV}+\lambda_{SOV})t$

= 1/2 (4.1E-7 + 8.2E-7) 13,140 hrs.

= 8.1E-3/18 months

P_{CX2} = probability AOV (UV-516) fails to close due to control circuit fault (Circuit single failures are one relay fail to de-energize and one relay spurious energize.)

= 1/2(4.0E-7 + 4.3E-7)13140 hrs.

= 5.5E-3/18 months

P_{CC}= probability of common cause failure to close containment isolation AOVs. (UV-516 & UV-515) Reference 6.3.8 gives 1.5E-7/hr. for 2 of 2 AOVs fail to open/close/operate, *including* command faults. Since the containment isolation AOVs are designed to fail closed, it is assumed here that only one of two of the overall common cause failure rate represents failure to close these AOVs:

= 1/2(1/2 *1.5E-7)13140 hrs.

= 4.9E-4/18 months

The contribution to outside-containment ISL due to RCS letdown line rupture scenarios was therefore estimated as:

$F_{Letdown}$ = 1.8E-4 *[(8.1E-3+5.5E-3)*(8.1E-3+5.5E-3)+ 4.9E-4)]

= 1.2E-7/18 months

= 8.1E-8/year

6.1.3.3.2.4 ISLs in RCS to Nuclear Cooling Water System

The Nuclear Cooling Water (NC) system interfaces with the RCS via the Letdown Heat Exchanger and the Reactor Coolant Pump (RCP) high pressure coolers and seal coolers. A tube to shell leak in any of these heat exchangers would result in high pressure RCS coolant entering the low pressure NC system. The NC pumps, which lie outside containment, circulate cooling water through the NC heat exchangers, into various components within containment, and back out in a closed loop (Figure 6.1-4). The lowest pressure relief point in the system is at the NC surge tank located on the roof of the Auxiliary Building. If the seal cooler LOCA or the NC system lines are not isolated such that all RCS inventory loss occurs outside containment, RCS makeup will fail once Refueling Water Tank (RWT) inventory is depleted. Core uncovery will follow with an open containment bypass path via the NC system.

There are many RCP seal cooler/NC LOCA scenarios that could result in some sort of off-site release of radioactivity but do not lead to core damage. Postulated scenarios that ultimately result in core damage are complex and long-term, with many opportunities for operator action to convert the event into a more benign inside containment LOCA or to terminate the LOCA entirely. In order to focus on only the scenarios with core damage and containment bypass potential, it is necessary to examine the NC and RCP seal cooler systems in detail.

Normal NC operating pressures range from 98 psig at the discharge of the NC pumps to less than 10 psig at the system's highest point in the surge tank on the roof of the Auxiliary Building. If an RCS interface leak occurs, the entire NC system will become pressurized causing some or all of 35 system relief valves to lift. Thirty-three of the NC relief valves are low capacity valves (< 67 gpm) designed to lift at various pressures between 10 and 150 psig to protect various components and pipes against thermal transients within the system. None of these relief valves were designed to protect system piping from the impact of an RCS to NC leak. There are two high capacity (250 gpm, with setpoint at 135 psig) NC system relief valves within containment, either of which could relieve the maximum leak flowrate from the largest NC interfacing LOCA (via the high pressure seal cooler). The other six relief valves within containment, where nominal NC pressure is roughly 50 psig, have setpoints of 110 psig and relief capacities of ~10 gpm. Almost all of the remaining NC pressure relief valves installed outside containment have setpoints at approximately 150 psig and relief capacities ranging from 10 to 67 gpm. The total capacity of all NC pressure relief valves is approximately 1000 gpm.

The surge tank relief valve (PSV-72), includes a 10 psig setpoint, and is an important exception to the ex-containment NC relief points. Even after accounting for the water head due to the difference in elevation and pressure loses through the NC lines from the break location to the surge tank, the tank relief valve would likely be the first to open. Once the ingress of reactor coolant causes the 1000 gallon capacity tank to fill, up to 67 gpm will be vented to the roof of the Auxiliary Building via the tanks safety relief valve. When this capacity is exceeded, the surge tank itself is likely to rupture, since design pressure is only 15 psig. The pressure increase needed to lift a relief valve at any other location in the NC system is at least 50 psig.

A number of other factors may determine where the NC pressure boundary actually fails given a heat exchanger tube rupture event. The actual evolution of the leak and fluid dynamics considerations, such as RCS coolant flashing to steam within the NC piping and pressure drops across NC components, may produce localized pressure spikes that open relief valves or even rupture piping at locations other than the surge tank. If the relief valves closest to the heat exchanger leak open first and provide sufficient relief capacity, the ISL will be confined within containment and hence will act much like any Small LOCA. However, because the surge tank relief scenario appeared to be both the most likely and the most severe in terms of safety system impact, it was conservatively assumed to represent the result of any significant High Pressure Cooler or Seal Cooler tube leak.

The NC system penetrates containment with two 10-in. diameter lines: a cooling water supply and a return line. The supply line contains a check valve inside containment and a class AC powered containment isolation MOV outside containment that is automatically actuated on Containment Spray Actuation Signal (CSAS). The return line contains two similar containment isolation MOVs: one inside and one outside containment. The MOVs are designed to close against pressure differentials up to 150 psid. For a NC/seal cooler ISLOCA, automatic actuation of these valves is not expected since significant increases in containment pressure are not expected.

Each of the four RCPs has one High Pressure Seal Cooler (HPSC) and two throttle coolers (Figure 6.1-5), which have NC cooled fluid chambers. RCP seal flow to the HPSC can be isolated via two non-class powered MOVs: one at the inlet and one at the outlet of the cooler. Flow to the throttle coolers cannot be isolated.

The only RCS/NC interface that is considered to have significant ISLOCA potential is in the RCP/HPSC. The HPSC is a 75-in. long, 12-in. diameter tank (NC side) with approximately 255-ft. of seamless internal tubing coils rigidly supported off the tanks center pipe. The tubing is 1.25-in. O. D. stainless steel. A double ended rupture of HPSC tubing would correspond to a break size of 0.62 sq. in. and a calculated maximum initial leakage flow rate of approximately 25 lbm/sec (250 gpm). As the RCS depressurizes, the flowrate will drop into the range of 10-15 lbm/sec. In addition, a catastrophic high pressure cooler tube rupture may simultaneously initiate degradation of the RCP seals of the affected pump because cooling and lubricating flow would be diverted to the break. This leakage is expected to be less than 120 gpm with all three seal stages failed. Thus, total leakage from the RCS would be no more than 370 gpm. This falls well within the range of a small LOCA and the HPSI pumps would be expected to provide RCS makeup for as long as the RWT inventory lasted.

Leakage from the RCS into the NC system may be expected to be detected by a combination of nuclear cooling water system radiation monitors and the high surge tank level switches. High radiation and surge tank levels cause an alarm to sound in the Control Room. The following indications are available to the Control Room operator to assist in identifying the nature of the RCS breach and its location:

- RCP HPSC Inlet Temperature
- RC HPSC Outlet Temperature
- NC-side HPSC Outlet Temperature
- NC-side HPSC Outlet Flow
- NC Surge Tank Level
- NC System Process Radiation Level
- Pressurizer Level
- Charging/Letdown Mismatch

As mentioned previously, the HPSCs are provided with inlet and outlet isolation MOVs on the RCS side (Figure 6.1-4). The motor operators are sized to close against a 2500 psi differential pressure and are supplied with non-class 1E AC power. RCP alarm response procedures would direct the operators to close the isolation valves on the HPSC serving the affected pump in order to terminate the event. In addition, as long as one of the two high capacity NC relief valves within containment opens at its design setpoint, the NC containment isolation MOVs would be closed, ensuring that all loss of the RCS inventory occurs within containment. If for some reason the affected HPSC could not be isolated, the RCS would be depressurized and shutdown cooling would be established, minimizing the HPSC leakage.

A logic model is used in order to assess the frequency of a HPSC/NC interfacing system LOCA evolving into a core damage event. The following issues and assumptions pertain to the logic model:

- The primary concern with this scenario from the PRA perspective is containing RCS leakage within containment such that the sumps can be used to provide RCS makeup once the RWT is depleted. Other HPSC LOCA scenarios may lead to release of radioactivity associated with normal reactor operations, but they do not present an accident significantly more challenging than the small LOCAs assessed in Section 4.3. Given the low likelihood and relatively low consequences of such accidents, they are considered to be enveloped by the analysis presented there. Thus, if the NC containment isolation valves successfully close and the event can transformed to an inside-containment LOCA, it is considered resolved in this analysis.
- HPSC isolation MOVs are assumed operated/tested at least once per 18 months.
- The NC high capacity SRVs are assumed to be shop tested during each refueling outage.
- No credit is taken for automatic actuation of the NC isolation valves. This is conservative in cases where an RCP seal LOCA evolves (generating a CSAS) subsequent to the HPSC tube rupture or if significant pressure relief via NC relief valves within containment occurs.
- If both NC high capacity Safety Relief Valves (SRVs) fail to open (and the HPSC isolation MOVs are not closed), the NC isolation MOVs cannot be closed due to high NC system pressure.
- In the event of initial failure of NC isolation due to failure of the high capacity SRVs, action to establish shutdown cooling entry conditions (~450 psia, 350° F) does not ensure the NC isolation MOVs can be closed. RCS leakage outside containment will continue, but at a lower rate. Cooldown/depressurization must continue until RCS pressure drops below about 200 psia such that (due to pressure drop through the seals, break, etc.) it does not exceed the differential pressure that the MOVs are designed to close against. It is assumed that if the LOCA is not diagnosed as a HPSC ISLOCA, operators will not bring the RCS pressure low enough to isolate NC prior to RWT depletion.
- If the nature of the HPSC ISLOCA is not realized within roughly 2 hrs. of the initiating event, diagnosis is assumed to become considerably more difficult due to the possibility of significant RCP seal failure. This would cause indications that it is an inside-containment LOCA and would complicate operator response.
- It is assumed that RWT inventory is sufficient to provide at least 48 hrs. of RCS makeup. This is based on the PVNGS Technical Specification required inventory of 600,000 gallons and a leak that continues at the rate

of 210 gpm. Although actions to refill the RWT are certainly feasible in this time frame, no credit is taken for this recovery.

- Operators are conservatively assumed to have 30 hrs. in which to diagnosis the presence of a HPSC interfacing LOCA and to close the HPSC isolation MOVs and/or the NC isolation MOVS. This diagnosis may become more complicated after the initial 2 hrs. if a RCP seal leak evolves, but a compensating factor is provided by Control Room crew turnover in this long period. Each new crew that is involved in mitigating the accident reduces the likelihood of dependent human failures to diagnose the HPSC rupture conditions.

The fault tree developed is provided in Figure 6.1-6 (page 2 of 6) and the failure data associated with the events in the model is detailed in Table 6.1-9. Details pertaining to the initiating event frequency and the human errors modeled are provided below.

HPSC Tube Initiating Event

The likelihood of a HPSC tube break was evaluated by several methods. Both generic failure data and prior operating experience based on the NPRDS and LER data bases were examined. The NPRDS search showed no prior United States PWR RCP seal cooler tube failures in approximately 25 million RCP operating hrs. There was one known seal cooler tube leak event in a non-US plant (Switzerland's Beznau Unit 1). The RCP manufacturer is Westinghouse Electric Corporation.

Using generic industry failure data, the tube rupture frequency for this type of heat exchanger can be estimated in two different ways. The rupture frequency based on the Interim Reliability Evaluation Program (IREP) (Reference 6.3.13) heat exchanger tube failure rate is 5.3E-5/year. (Although the HPSC has one long helical tube, it is assumed to be equivalent to two standard heat exchanger tubes for this calculation.) The rupture frequency based on a Bayesian updated WASH-1400 pipe failure rate (small diameter piping), and conservatively assuming 10 ft. of piping per section, results in a HPSC rupture failure rate of 4.5E-4 per heat exchanger year.

Based on the above information, a HPSC pipe rupture frequency of 1.0E-4 per heat exchanger year was judged appropriate. Since each unit has four HPSCs, the yearly frequency for each PVNGS unit is 4E-4/year.

Human Reliability Analysis

The key human interface in this ISLOCA scenario is diagnosis by the operators that an HPSC tube rupture has occurred. Subsequently, the operators will act to isolate flow through the HPSC that appears to have the ruptured tube. The Control Room indications listed above assist the operator in this task. If the isolation MOVs on the affected HPSC are successfully closed, the LOCA is terminated. Based on the RWT inventory discussed above, operators have at least 48 hrs. to take this action. There is some potential for isolating the MOVs on the wrong HPSC, but there is ample opportunity for feedback (the LOCA continues) and ample time available for correcting initial errors.

Based on these conditions, it is judged that failure to diagnose the interfacing system LOCA in the affected HPSC may be estimated from Table 12-4 of Reference 7.5.3. Because there will likely be several different problems being alarmed in the Control Room (possibly including conditions associated with an RCP seal leak if action is not taken within a couple hours), the human failure probabilities for a "third event" are used. The table gives failure to diagnose values only out to about 24-hrs. where the Human Error Probability (HEP) is 8.5E-5 (mean value). Based on this, a conservative estimate of 5E-5 is judged to be reasonable for failure of several different Control Room crews to diagnose the rupture in the correct HPSC.

The logic model developed to assess the probability of core damage due to a HPSC ISLOCA also considers the possibility of operator error in performing the HPSC isolation and NC containment isolation tasks once a correct diagnosis has been made.

The calculated CDF due to a HPSC/NC interfacing system LOCA based on this model is 5.7E-8/year.

6.1.3.3.2.5 Total Contribution form ISLs Outside of Containment

The total contribution of interfacing LOCAs outside the containment is 1.8E-7/year. Table 6.1-7 lists each of the contributors and their contribution.

6.1.3.3.3 Steam Generator Tube Rupture - IESGTR

The steam generator tube rupture event frequency is calculated in the C-E System 80™ PRA (Reference 6.3.5). The System 80™ PRA reports a median of 1.0E-2/year which yields a mean of 1.6E-2/year.

6.1.4 Quantification of Anticipated Transients without SCRAM

As discussed in Sections 4.1 and 4.3, the ATWS initiators were developed by binning the PVNGS initiators into categories. Table 6.1-8 identifies each initiator and the category into which the initiator has been binned.

6.2 Component Failure Data

This section discusses the approach utilized to estimate the probability of failure of the various component or system related basic events within the system fault trees. This section is subdivided as follows:

- 6.2.1 Development of Generic Component Failure Rate Distributions
- 6.2.2 Control Circuit Failure Data
- 6.2.3 Common Cause Failure Data
- 6.2.4 Maintenance Unavailability Data
- 6.2.5 Special Event Quantification
- 6.2.6 Incorporation of Plant Specific Failure Data

Data related to the reliability of the operating staff to perform required actions or to properly restore equipment to operation is discussed in Section 7.

6.2.1 Development of Generic Component Failure Rate Distributions

Generic failure data was obtained from a number of industry data sources including NUREG reports, other PRA reports, and industry data sources. In selecting industry failure data for application to the PVNGS PRA, the following factors were considered:

1. Consistency of component boundary definitions. For example, for the PVNGS fault tree models, the probability of a valve or pump failure was generally considered separately from the probability of failure of the associated control circuit. Therefore, the data sources utilized to estimate pump and valve failure rates had to provide failure data for pumps and valves, excluding control circuit faults.
2. Consideration of data validity and transferability to PVNGS. In selecting a data source for a certain component failure rate, a number of nuclear power plant sources were referenced as described in Tables 6.2-1 and 6.2-2. The selected sources of data were compared with a number of available data sources and were judged to be consistent with the ranges of applicable failure data available.

The generic failure data utilized for the PVNGS PRA is summarized in Table 6.2-1. In addition, the base reference from which the data value was obtained is listed in Table 6.2-2.

The failure rates summarized in Table 6.2-1 were input into the Computer-Assisted Fault Tree Analysis (CAFTA) data base. The CAFTA data base automatically links the appropriate failure rate based upon the last five characters of the basic event identifier (the basic event naming convention is described in Table 6.2-8), with an appropriate failure exposure period which is manually input into CAFTA. For example, the B Train AF pump discharge MOVs have a failure rate of 2.9E-6/hour (MV-FO from Table 6.2-1) and are cycled every 62 days. The 2-month test period is manually entered into the CAFTA data base. CAFTA calculates the basic event probability as 2.16E-3/year using the general equation $P_{failure} = \lambda t/2$. The entire PVNGS PRA data base is summarized in Appendix 6.D.

6.2.2 Control Circuit Failure Data

The PVNGS PRA fault tree models normally consider command and control circuit faults separately from component faults. For example, local failures of the MOV were considered separately from failures which are caused by control circuit faults, which originate in the associated motor control center. This was done in order that differences in control circuit design for the various PVNGS applications (remotely operated valves, electrical circuit breakers, motor driven pumps) could be properly and realistically accounted for within the PVNGS PRA. For example, by using this methodology, the PVNGS PRA is able to account for the fact that circuit breaker designs, which have one or more normally energized (de-energized to trip open the associated breaker) protective relays, generally have much higher spurious transfer rates than circuit breaker designs which do not rely on normally energized protective relays.

For the purposes of this report, the control circuit faults were defined to include all control circuit components located in remote panels such as the motor control center or remote actuation cabinets. Component and control circuit faults which are located in close proximity to the component are included with the component failure rate. For example the limit and torque switches on the valves and the motor operator are considered contributors to the MOV failure rate, and do not contribute to the associated control circuit event. Control circuit components which are used by more than one piece of PVNGS equipment, such as certain ESFAS actuation relays which actuate multiple components, were modeled separate from the control circuit so that the effect of component failure would be properly modeled.

Control circuit failure rates were estimated based upon the subcomponent (e.g., relays, fuses, remote actuation contacts), failure rates, depending upon the number of subcomponents contained within the control circuit, which are critical to the operation. In order to facilitate this process, control circuits were organized into groups that have similar circuit designs with each group assigned an appropriate component/failure mode code. For example, the control circuits for the MOVs are not identical, so it was not possible to lump them all together and calculate one failure rate for all MOVs. Therefore, the MOV control circuits were divided into groups that have similar designs. For example, the Nuclear Cooling (NC) system MOVs were assigned the code CX3FO. The "CX" means that the event of concern is a control circuit fault; the "3" signifies that it was assigned to MOV group number three; and the "FO" means that the failure mode of concern is fail to open. A total failure rate was calculated and entered into the CAFTA data base for each identified control circuit grouping. Since similar circuit designs were grouped together, the number of individual circuits modeled was minimized. If a control circuit was not grouped because of unique design features or because the control circuit contained components which were tested with different test periods, the control circuit failure probability was calculated based upon Table 6.2-1 data and the appropriate mission times. The control circuit event was given a type code of CXX and the event probability was directly entered into the CAFTA data base.

Table 6.2-3 summarizes the control circuit failure rates utilized in the PVNGS PRA.

6.2.3 Common Cause Failure Data

A number of common cause failure events were modeled within the PVNGS PRA, based upon the general quantitative screening approach described in section 3.2.1 of NUREG/CR-4780 (Reference 6.3.44). In particular, common cause was considered whenever components designed to identical specifications were utilized to achieve redundancy of a particular function.

The following common cause failure component group events were considered:

Component Group	Systems
Standby Motor Driven Pumps	AF, LPSI, HPSI, Essential Spray Pond (SP), CD, Containment Spray (CS), Essential Chilled Water (EC) System, Essential Cooling Water (EW) System pumps
Standby Pumps With Diverse Drivers	AF Pumps
Motor Operated Valves	HPSI MOVs LPSI MOVs AF Injection MOVs CS Injection MOVs Sump Recirculation MOVs
Emergency Diesel Generators	Emergency Diesel Generator (PE)
Instrument Air (IA) Compressors	IA
Essential Chillers	EC
Standby HVAC Fans	Control Building HVAC (HJ)
Class Electrical Batteries	DC Power System (PK)
Air Operated Valves	SG Atmospheric Dump Valves (ADVs)
Reactor Trip Breakers	Reactor Protection System (SB)
ESFAS Transmitters	Engineered Safety Features Actuation (SA), Reactor Coolant (RC) System, SG

The quantification process and failure data utilized for the major common cause events considered in the PVNGS PRA are summarized in Table 6.2-4.

6.2.4 Maintenance Unavailability Data

For the PVNGS PRA, maintenance unavailabilities for major components were generated either by reviewing plant specific data or by utilizing generic industry data on the frequency and duration of maintenance activities. For the most critical components e.g., Safety Injection and Auxiliary Feedwater components, a review of plant specific maintenance unavailabilities was performed in early 1989, which calculated the corrective and preventative maintenance unavailability for these key components, based upon operating experience accumulated in 1988.

For the remainder of events, the component maintenance unavailabilities were calculated as:

$$U_m = \lambda_m \text{ (MTTR)}$$

where

U_m = maintenance unavailability

λ_m = maintenance rate

MTTR = mean time to repair/maintain the component or shutdown the reactor to a stable condition

The major maintenance unavailability events; and the source of their quantification are summarized in Table 6.2-6. Additional background information on maintenance rate distributions is provided in 6.C.

6.2.5 Special Event Quantification

Within the event tree development described in Section , there were several elements which were quantified using data sources or methodologies unique to that element. The major basic events quantified in this manner are listed in Table 6.2-7 including the following events:

1. ATWS basic events representing the probability that sufficient control rods do not insert into the core to prevent primary overpressurization following an Initiating Event, and the probability that Moderator Temperature Coefficient (MTC) is insufficiently negative to prevent RCS pressure from exceeding ASME Class C limits following an ATWS event
2. Basic events representing the probability of non-recovery of off-site power as a function of time following a loss of off-site power event
3. Basic events representing the probability that an engineered safeguards pump fails to run without room cooling

6.2.6 Incorporation of Plant Specific Data

In general, the PVNGS PRA relied upon the generic failure data developed in section 6.2.1. However, for the components which were most important to the PRA results, plant specific experience was collected and the generic and plant specific data were combined by a Bayesian update process. The following components were selected for the Bayesian update process based upon risk important measures (e.g., Table 10.1-2):

- Turbine driven AF pump fail to start
- Turbine driven AF pump fail to run
- Diesel Generator fail to start

- Diesel Generator fail to run
- Motor driven AF pump fail to start
- Motor driven AF pump fail to run

The results of the Bayesian update process for these components is summarized in Table 6.2-5. In the longer term, Arizona Public Service will incorporate plant specific experience into the Initiating Events analysis and other important component failure events. However, it is not expected that this effort will significantly effect the results herein. If anything, it is expected that the overall risk profile may be slightly decreased as the high frequency Initiating Events (reactor trip initiator and turbine trip initiator) are adjusted downward based on plant experience.

As discussed in Section 6.2.4, plant specific experience was also considered during the process utilized to estimate the maintenance unavailability of the major pumps and valves created in the fault tree models. Plant specific experience was also considered in the quatification of several special event basic events, such as the probability that FW continues to be available for the first 30 min. following reactor trip. The data developed and utilized for these special events is discussed in Section 6.2.5.

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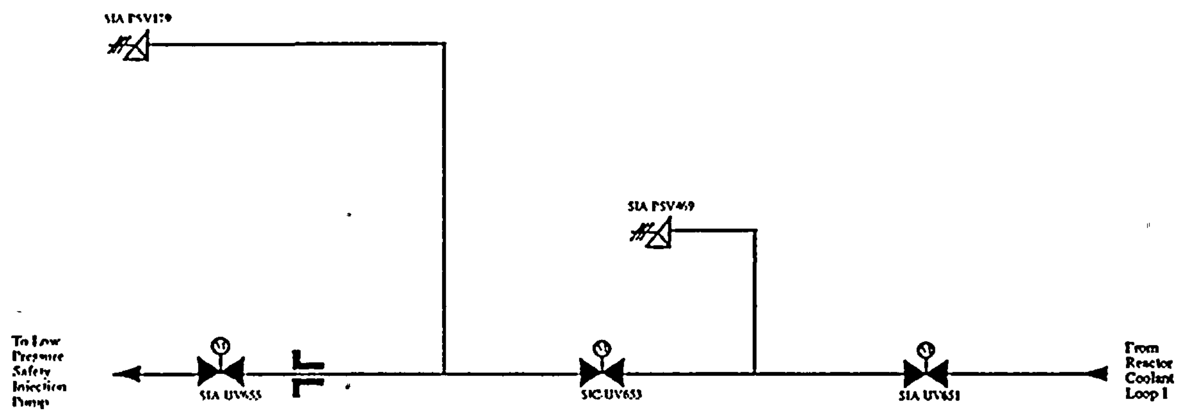

Figure 6.1-1

Simplified Diagram of Hot Leg Injection and Shutdown Cooling Suction Piping

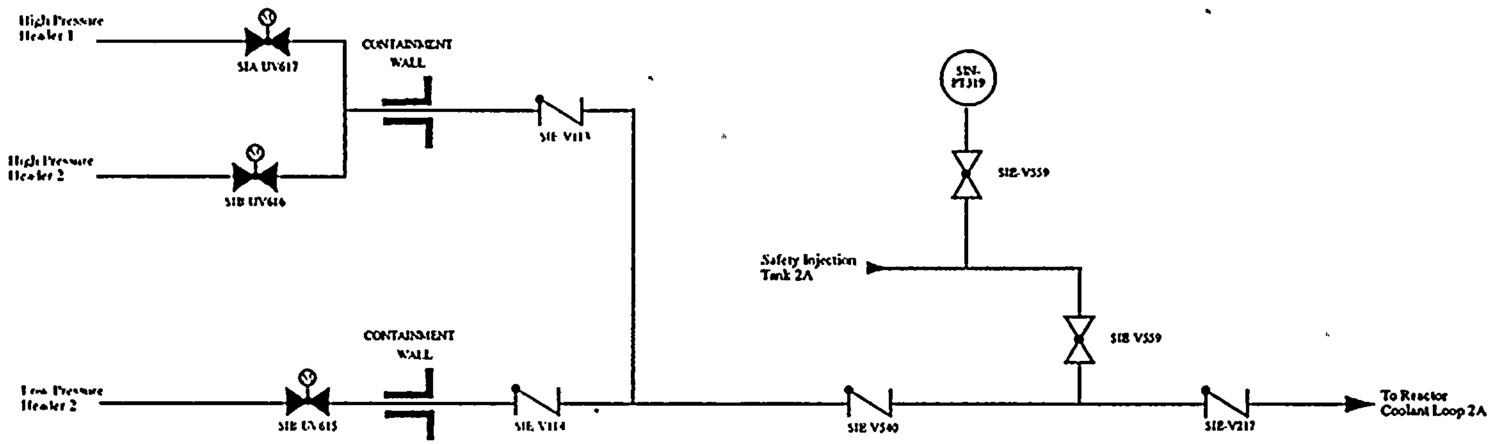

Figure 6.1-2

Simplified Diagram of the RCS Cold Leg to HPSI/LPSI System

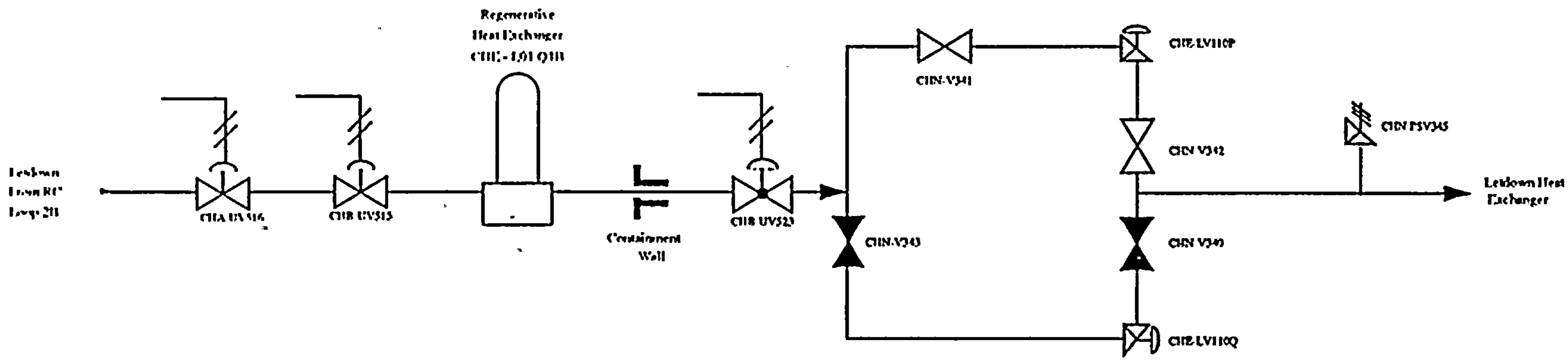

Figure 6.1-3

Simplified Diagram of Letdown Line Up to the Letdown Heat Exchanger

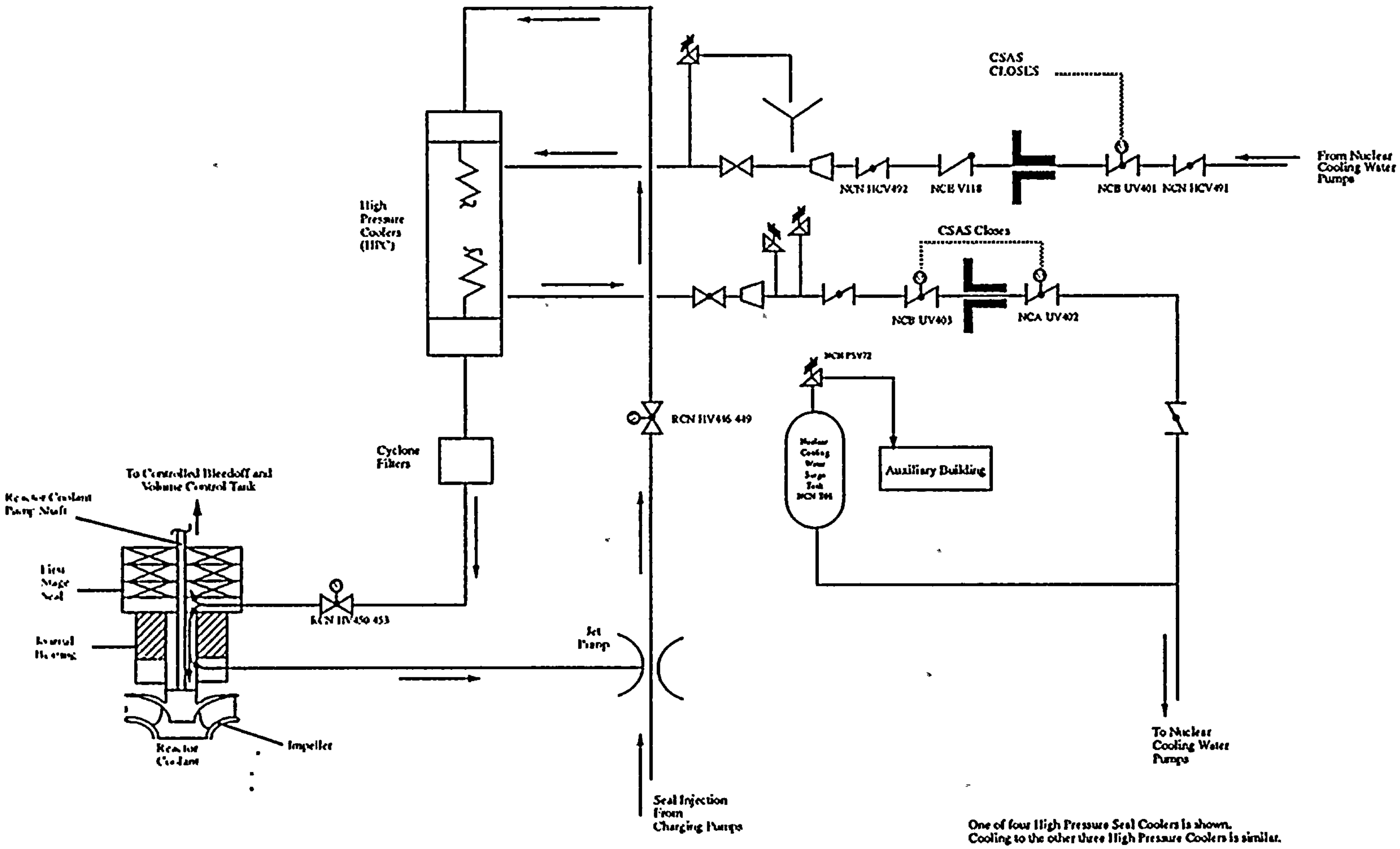

Figure 6.1-4

Simplified Diagram of Nuclear Cooling Water System Interface with RPC Seal Coolers

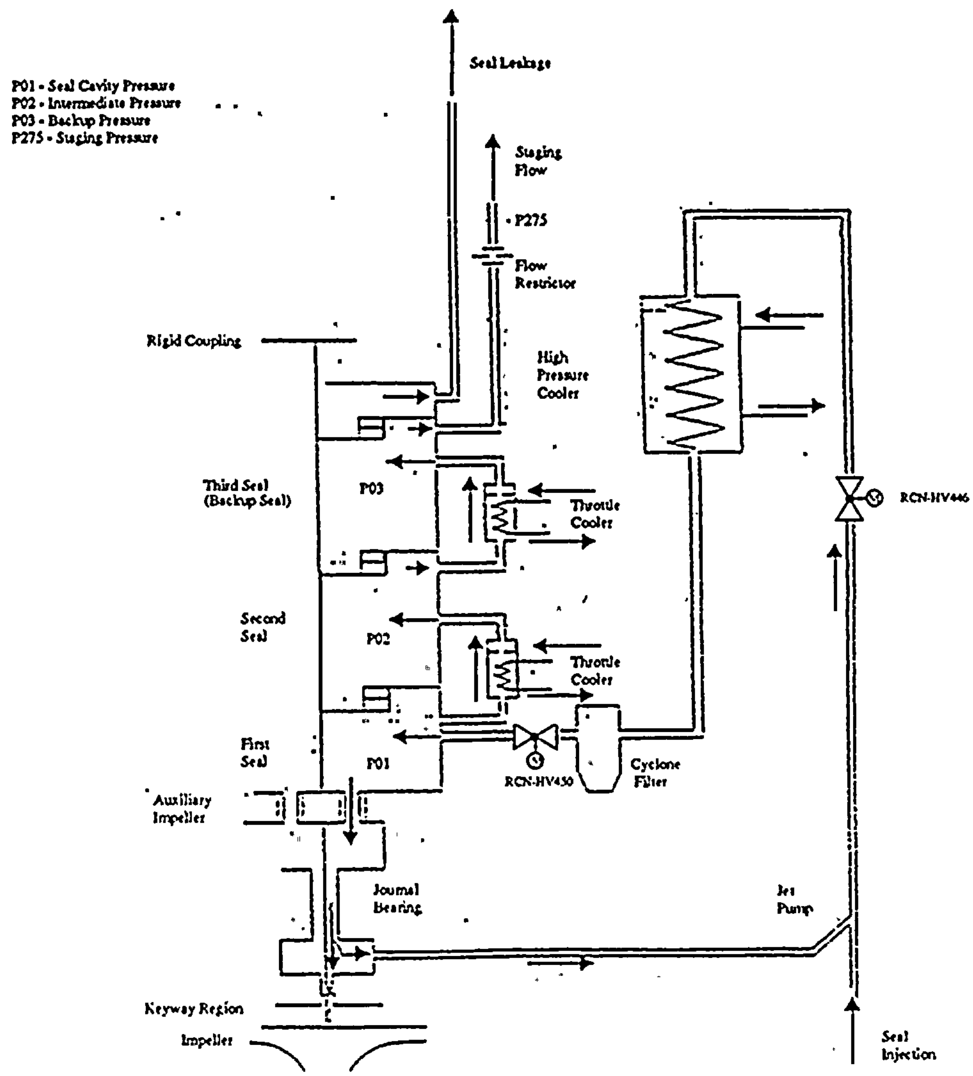

Figure 6.1-5

Reactor Coolant Pump Seal Injection Cooling

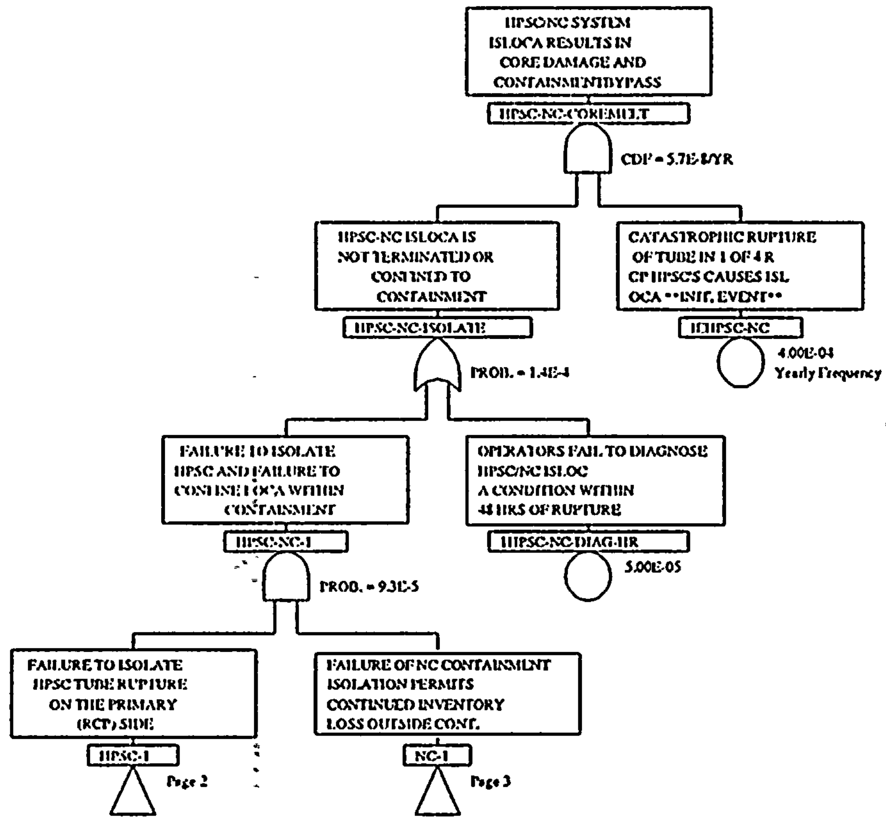

Figure 6.1-6 (page 1 of 6)

High Pressure Seal Cooler Interfacing Systems LOCA Fault Tree

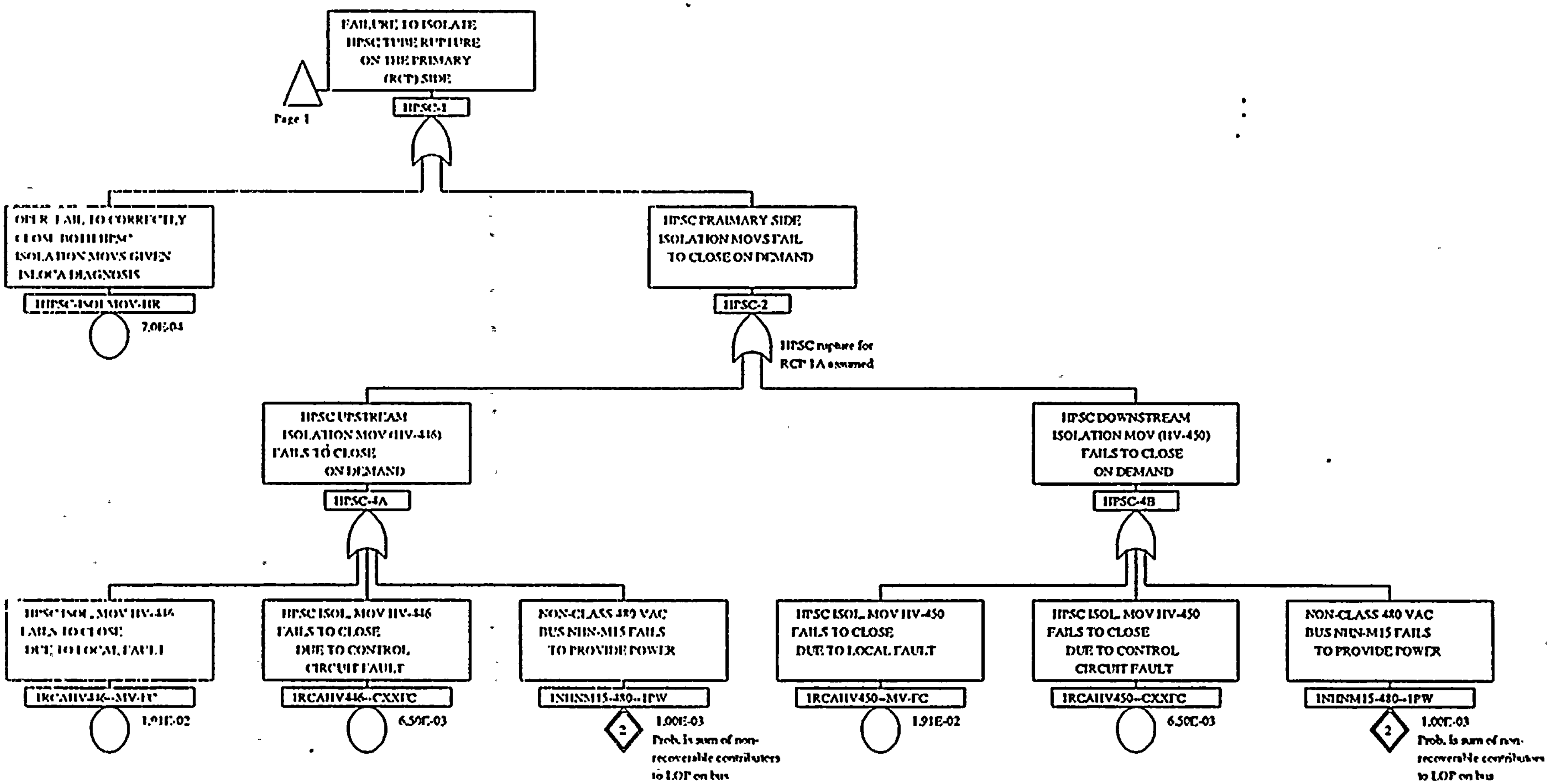

Figure 6.1-6 (page 2 of 6)

High Pressure Seal Cooler Interfacing Systems LOCA Fault Tree

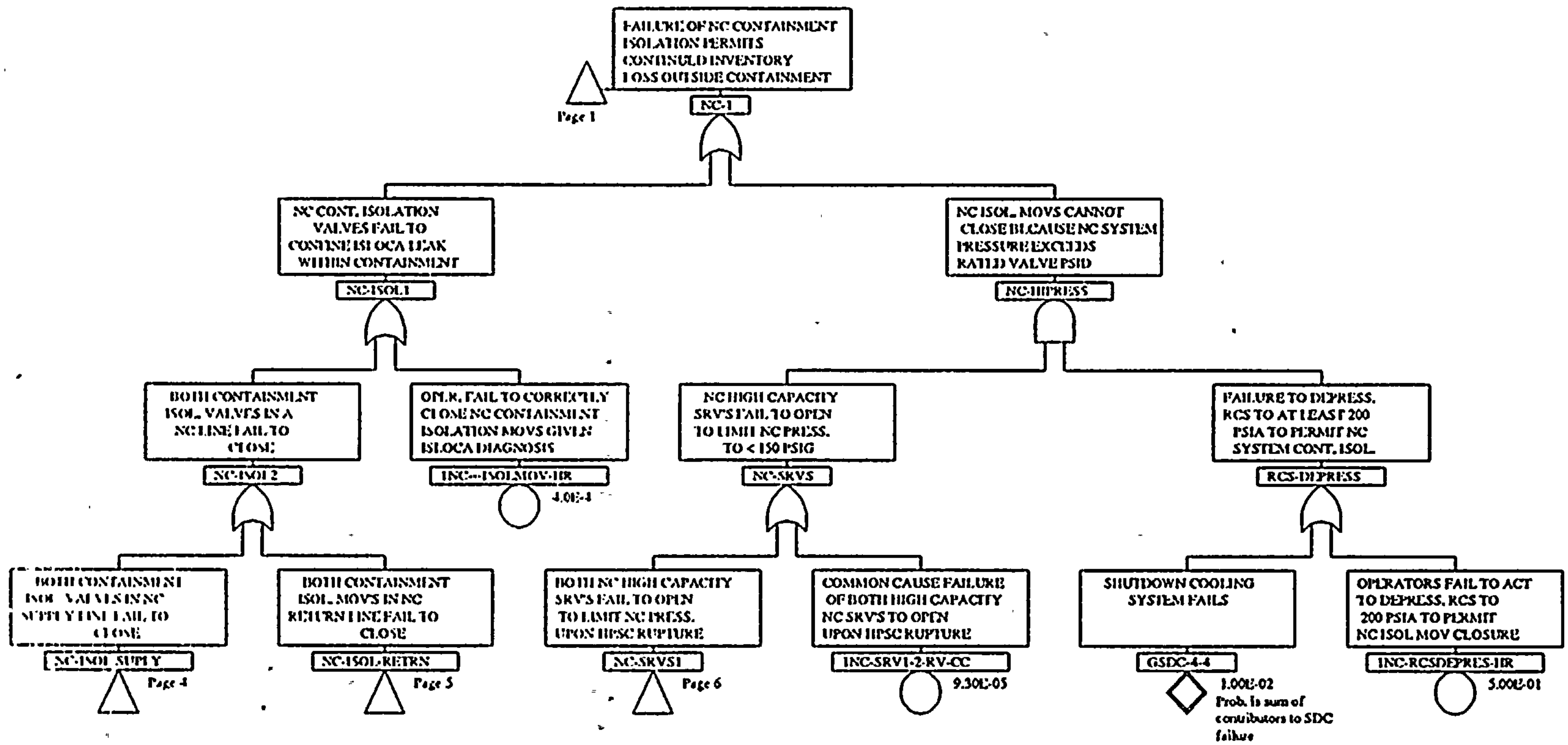

Figure 6.1-6 (page 3 of 6)

High Pressure Seal Cooler Interfacing Systems LOCA Fault Tree

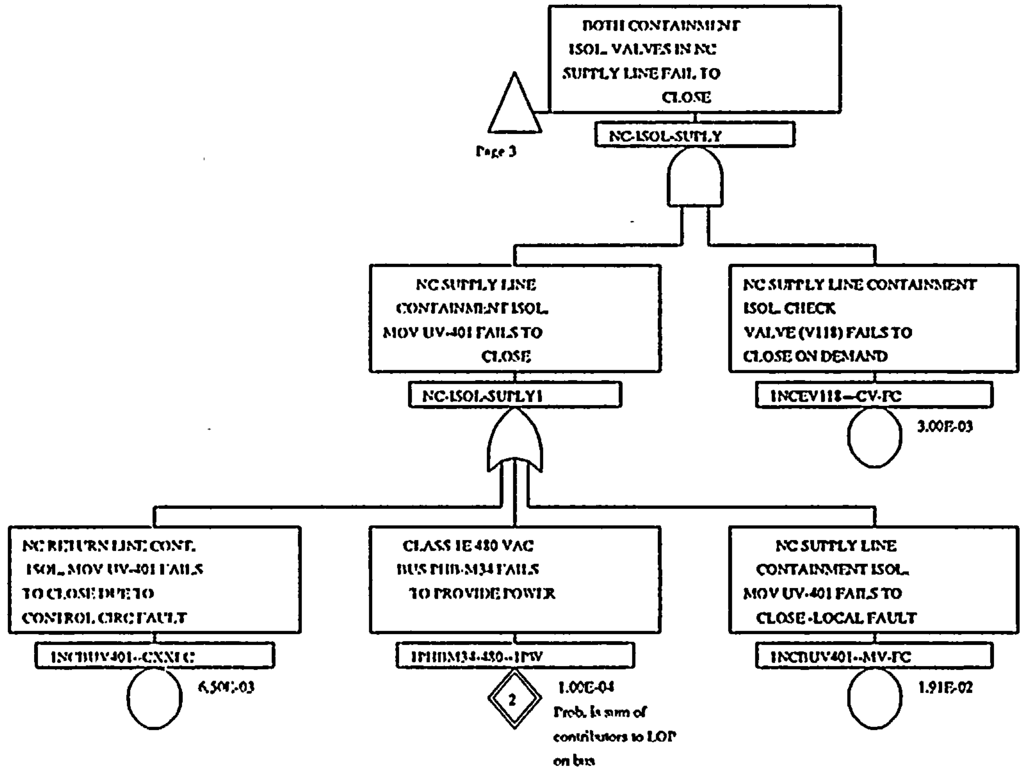

Figure 6.1-6 (page 4 of 6)

High Pressure Seal Cooler Interfacing Systems LOCA Fault Tree

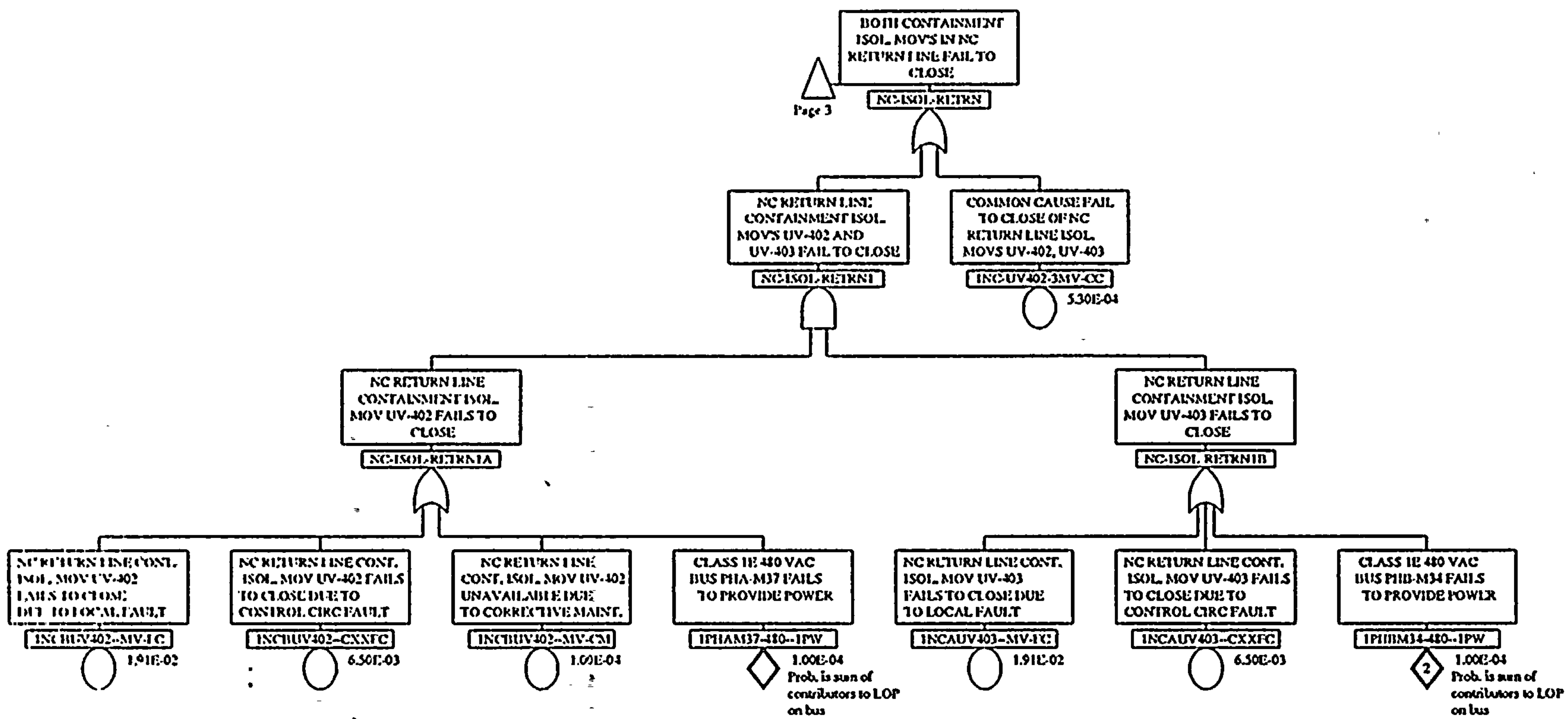

Figure 6.1-6 (page 5 of 6)

High Pressure Seal Cooler Interfacing Systems LOCA Fault Tree

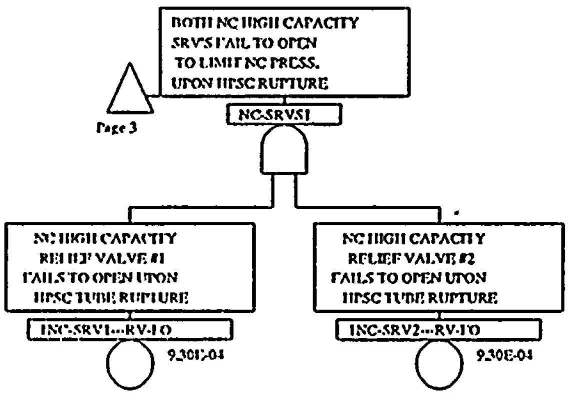

Figure 6.1-6 (page 6 of 6)

High Pressure Seal Cooler Interfacing Systems LOCA Fault Tree

Table 6.1-1 PVNGS Initiating Events and Frequencies

Initiating Event	Description	Frequency, per year	Method of Calculation
IEFWP	Loss of All (2) FW Pumps	1.6E-1	Generic Point Estimate
IECPST	Loss of All (3) Condensate Pumps	1.0E-2	Generic Point Estimate
IECONDVAC	Loss of Condenser Vacuum	2.3E-1	Generic Point Estimate
IESLB	Large Secondary Steam Line Break	1.0E-3	Plant-Based Tabular OR
IESGTR	Steam Generator Tube Rupture	1.6E-2	Plant-Based Tabular OR
IEFLB	Large Feedwater Line Break	3.1E-4	Plant-Based Tabular OR
IELOOP	Loss of Off-site Power	7.8E-2	NSAC-111
IESMLOCA	Small LOCA	8.0E-3	Plant-Based Tabular OR
IEMLOCA	Medium LOCA	4.5E-4	Plant-Based Tabular OR
IELLOCA	Large LOCA	2.1E-4	Plant-Based Tabular OR
IEBLACK	Station Blackout	2.6E-4[a]	Plant-Based Equation Estimate
IEMSIV	Closure of All MSIVs	4.0E-2	Generic Point Estimate
IEPCW	Loss of Plant Cooling Water	5.0E-3	Generic Point Estimate
IETCW	Loss of Turbine Cooling Water	2.0E-2	Generic Point Estimate
IENCW	Loss of Nuclear Cooling Water	2.0E-2	Generic Point Estimate
IEIAS	Loss of Instrument Air	2.2E-2	Plant-Based Fault Tree Estimate
IETT	Turbine Trip	1.19	Generic Point Estimate
IEMISC	Miscellaneous Reactor Trips	5.67	Generic Point Estimate[b]
IEPKAM41	Loss of PKA-M41 or PKA-D21, Class 125V DC	2.0E-2	Plant-Based Fault Tree Estimate
IEPKBM42	Loss of PKB-M42 or PKB-D22, Class 125V DC	2.0E-2	Plant-Based Fault Tree Estimate
IEPKCM43	Loss of PKC-M43, Class 125V DC	4.7E-3	Plant-Based Fault Tree Estimate
IEPKDM44	Loss of PKD-M44, Class 125V DC	4.7E-3	Plant-Based Fault Tree Estimate
IEPNAD25	Loss of PNA-D25, 120V INST AC	2.5E-2[a]	Plant-Based Equation Estimate
IEPNBD26	Loss of PNB-D26, 120V INST AC	2.5E-2[a]	Plant-Based Equation Estimate

Table 6.1-1 PVNGS Initiating Events and Frequencies (Continued)

Initiating Event	Description	Frequency, per year	Method of Calculation
IECRHVAC	Loss of Control Room HVAC	3.3E-4[a]	Plant-Based Equation Estimate
IEDCRHVAC-1	Loss of DC Equipment Room HVAC- Div. 1	2.5E-1[a]	Plant-Based Equation Estimate
IEDCRHVAC-2	Loss of DC Equipment Room HVAC- Div. 2	2.5E-1[a]	Plant-Based Equation Estimate
IEISLOCA	Interfacing System LOCA	1.8E-7	Plant-Based Tabular or Point Estimate
ATWS	Anticipated Transients Without SCRAM	c	c

a. This is an estimate. An equation is actually used in solving the accident sequence.
b. See Table (6.1-4)
c. See Section (6.1.4)

Table 6.1-2 PVNGS Secondary Line Break Sensitive Piping Inventory

Pipe Segment	Pipe I.D., in.	Number of Sections	Frequency, per year	Secondary Line Break Sensitive Piping Segment Boundary Components
Steam Lines	28	30	2.2E-4	MSIVs: UV 170, UV 171, UV 180,UV 181
	12	8	6.0E-5	ADVs: HV 178, HV 179, HV 184, HV 185
				Steam Generators No. 1 & 2
Downcomer Feed Lines	8	16	1.2E-4	V652, V653,SG 1 & 2
	6			
Auxiliary Feed Lines	6	4	3.0E-5	V079, V080
Total		58	4.3E-4	

Table 6.1-3 PVNGS Feedwater Line Break Sensitive Piping Inventory

Pipe Segment	Pipe I.D., in.	Number of Section	Frequency, per year	Secondary Line Break Sensitive Piping Segment Boundary Components
SG No. 1 Blowdown	6	14	1.0E-4	SG No. 1, UV 500P
SG No. 2 Blowdown	6	14	1.0E-4	SG No. 2, UV 500R
Economizer Feed Lines	24	6	4.5E-5	V003, V006, SG No. 1 & 2
	14 & 16	8	6.0E-5	
Total		42	3.1E-4	

Table 6.1-4 PVNGS Miscellaneous Transients/Reactor Trips Initiating Event Frequencies

EPRI NP-2230 Category	Event Description	NUREG-3862 Frequency, per year
1	Loss of RCS Flow	0.28
2	Uncontrolled Rod Withdrawal	0.28
3	CRDM Problems	0.5
4	Leakage From Control Rods	0.02
5	Primary Leakage	0.05
6	Low Pressurizer Pressure	0.03
7	Pressurizer Leakage	0.005
8	High Pressurizer Pressure	0.03
10	Containment Pressurizer Problems	0.005
11	CVCS Malfunction, Boron Dilution	0.03
12	Rod Position Error	0.13
14	Total Loss of RCS Flow	0.03
15[a]	Loss or Reduction in FW Flow (1 Loop)	0.75
17	Closure of 1 MSIV	0.17
19	FW Flow Increase 1 Loop	0.44
20	FW Flow Increase All Loops	0.02
21/22	FW Flow Instabilities	0.63
26	SG Leakage	0.03
28	Miscellaneous Secondary Leakage	0.09
29	MSSV Spurious Open	0.02
34[a]	Generator Trip	0.23
36	PZR Spray Failure	0.03
38	Spurious Trips Unknown	0.03
39	Auto Trip	1.42
40	Manual Trip	0.47
	Total	5.67

a. Frequency reduced by one half. PVNGS Reactor Power Cutback System normally prevents event from tripping reactor.

Table 6.1-5 PVNGS LOCA Sensitive Piping Inventory

Pipe Segment	Pipe I.D., in.	Number of Sections	Failure Rates per section-hr.	Frequency, per year	LOCA Sensitive Piping Segment Boundary Components	Comment
Hot-Leg Loops 1 & 2	42	2	6.4E-10	1.1E-5	Reactor Vessel, SGs 1 & 2	Includes elbow
Cold-Leg Loops 1A, 1B, 2A, 2B (suction)	30	12	6.4E-10	6.8E-5	SG 1, SG 2, RCPs 1A, 1B, 2A, & 2B (suction)	Includes elbow
Cold-Leg Loops 1A, 1B, 2A, 2B (discharge)	30	4	6.4E-10	2.3E-5	Reactor Vessel, RCP's 1A, 1B, 2A & 2B (discharge)	Includes elbow
Pressurizer Surge Line	12	5	6.4E-10	2.8E-5	Flow Orifice 724, Pressurizer (nozzle face)	
Hot-Leg to Shutdown Cooling	16 1 & 2	8 8	6.4E-10 2.0E-9	4.5E-5 1.4E-4	UV-651, CV-522, UV-652, CV-532,V-056, V-057,V-214, V-215	
Safety Injection Line to Cold-Leg	14	4	6.4E-10	2.3E-5	CV-237, CV-247, CV-217, CV-227	
Charging to Cold-Leg	2	7	2.0E-0	1.2E-4	CV-433	
Cold-Leg to Letdown	16 1 & 2	2 10	6.4E-10 2.0E-0	1.8E-5 1.8E-4	UV-515, V-061, V-063	
Cold-Leg to Reactor Drain Tank	2	4	2.0E-9	7.0E-5	V-332, V-333, V-334, V-335	These manual valves are normally closed
Cold-Leg to Pressurizer Spray Line (Loops 1A & 1B only)	3	23	2.0E-9	4.1E-4	V-056, V-057, V-058, V-001, V-062	
Pressurizer Spray Line to Spray Nozzle	4	4	6.4E-10	2.3E-5	V-058, Spray Nozzle Face	
Auxiliary Spray to Pressurizer	2	1	2.0E-9	1.8E-5	CV-431	

Table 6.1-5 PVNGS LOCA Sensitive Piping Inventory (Continued)

Pipe Segment	Pipe I.D., in.	Number of Sections	Failure Rates per section-hr.	Frequency, per year	LOCA Sensitive Piping Segment Boundary Components	Comment
Pressurizer to Safety Valves (4 lines)	6	4	6.4E-10	2.3E-5	PSV-200, 201, 202, & 203, Pressurizer	
Instrument Guide Tubes (61 Tubes)	0.78 (1.05 O.D.)	122	2.0E-9	2.2E-3	Seal Table	Double wall tube; inner tube contains instrument cable.
Temperature Instrument Line	11/32 (2 O.D.)					Diameter is too small for SI LOCA.
Hot Leg to Sample Heat Exchanger	3/4	1	2.0E-9	1.8E-5	Flow Orifice	7/32-in. orifice will limit flow
Vessel to Reactor Drain Tank	1	12	2.0E-9	2.1E-4	HV-403, V-217, Reactor Vessel	
RCS Vent	1	3	2.0E-9	5.3E-5	HV-108	7/32-in. orifice will limit flow (See Section 2.3.1 in RCS Vent System Component Description.
Safety Valves to Sample Heat Exchanger	3/4	7	2.0E-9	1.2E-4	Flow Orifice	7/32-in. orifice will limit flow
Instrument Nozzles on SGs, RCPs, Pressurizer, and Reactor Coolant Loops	3/4	30	2.0E-9	5.3E-4	Flow Orifice	7/32-in. orifice will limit flow

Table 6.1-5 PVNGS LOCA Sensitive Piping Inventory (Continued)

Pipe Segment	Pipe I.D., in.	Number of Sections	Failure Rates per section-hr.	Frequency, per year	LOCA Sensitive Piping Segment Boundary Components	Comment
Total						
Small LOCA	0.38 to	83	2.0E-9	1.5E-3		
Small LOCA/IGTR	<3.00	205	2.0E-9	3.6E-3		
Medium LOCA	3.00	23	2.0E-9	4.5E-4		
	>3.00 to 6.00	8	6.4E-10			
Large LOCA	>6.00	37	6.4E-10	2.1E-4		

Table 6.1-6 LOCA Contributors

Contributor Category	Small LOCA (0.38 - <3.00in.), per year	Medium LOCA (3.00 - 6.00), per year	Large LOCA (>6.00in), per year	Other LOCA Category, per year	Comment
Pipe Rupture	1.5E-3	4.5E-4	2.1E-4	NA	Based on Bayesian update of RSS pipe failure rate
Instrument Guide Tube Rupture	2.2E-3	NA	NA		Rupture of a guide tube results in a maximum 600 gpm RCS leak
RCP Seal LOCA	3.9E-3	NA	NA	NA	Based on 600 gpm maximum leak
Primary Safety Valve	2.5E-4	NA	NA	PSRV failure to reclose after RCS pressure relief probability steam = 4.9E-03, water = 1.0E-01	These numbers would be used in transients that require RCS pressure relief
Interfacing LOCA Inside Containment	1.0E-4	6.0E-7	6.7E-8	NA	From four ISL scenarios
Interfacing LOCA Outside Containment	NA	NA	NA	1.8E-7	From five ISL scenarios
Reactor Vessel Rupture	NA	NA	NA	<1.0E-7	
SGTR	NA	NA	NA	1.6E-2	
Initiating Event Total	8.0E-3	4.5E-4	2.1E-4		

Table 6.1-7 Probability for ISLOCA Outside Containment

Type of Occurrence	Probability, per year
HPSI/LPSI Cold-Leg Injection	4.5E-8
Hot-Leg to Shutdown Cooling	<1.1E-12
RCS to Letdown Line	8.1E-8
RCS to NCW System	5.7E-8
Event V Total	1.8E-7

Table 6.1-8 ATWS Initiating Event Categories

Category	Conditions	Initiators	Frequency, per year
1	LOOP	IELOOP IEBLACK	7.8E-02
2	Turbine Trip	IETT IESLB IEFLB IEMSIV IECONDVAC IEPCW IETCW	1.4
3	No Turbine Trip	IESMLOCA IESGTR IENCW IEMISC IECRHVAC IEPKAM41 IEPKBM42 IEPKCM43 IEPKDM44 IEPNAD25 IEPNBD26 IEDCRHVAC-1 IEDCRHVAC-2 IECPST IEFWP IEIAS	6.0

Table 6.1-9 Failure Data for HPSC/NC Logic Model

Event	Fail Rate	Exposure Time, months	Comment	Probability
INC-SRV1---RV-FO INC-SRV2---RV-FO	9.3E-4/d	18	Use 95% upper bound on PSRV valve, 3E-4/d (Table 6.2-1) due to long test interval	9.3E-4
INC-SRV1-2-RV-CC	B=.1	18	From NUREG/CR-4780 (Table 3-7) for PWR Safety/Relief	9.3E-5
INCEV118---CV-FC	3E-3/d	18	Use upper 95% confidence bound on demand rate (1E-3/d, EF-3) due to long test interval	3E-3 .
IRCAHV446--CXXFC IRCAHV450--CXXFC INCBUV401--CXXFC	1.0E-6/hrs.	18	Based on control circuit. analysis	6.5E-3
IRCAHV446--MV-FC IRCAHV450--MV-FC INCBUV401--MV-FC	2.9E-6/hrs.	18	Hourly failure rate from Table 6.2-1 used. Agrees well with 95% bound on NUREG/CR-1363 demand date if a reasonable EF of 3 or near that is assumed	1.9E-2
INC-UV402-3MV-CC	8.0E-8/hrs.	18	From NUREG/CR-2770, R2 with command faults	5.3E-4

Note: For discussion of HRA events and initiating event frequency, refer to the text.

Table 6.2-1 PVNGS Component Failure Rates

Component	Failure Mode	Component Mode Code [a]	Mean [b]	Median	E.F [c]	Percentiles [d] 5th	95th	Source [e]
Motor Operated Valve	Fails to close (no C.F.)[f]	MV-FC	2.9E-6	8.0E-7	14	2.2E-7	1.1E-5	M5
	Fails to open (no C.F.)	MV-FO	2.9E-6	8.0E-7	14	2.2E-7	1.1E-5	M6
	Fails to remain closed (no C.F.)	MV-RC	1.0E-7	2.7E-9	84	3.2E-11	2.2E-7	M7
	Transfer closed to remain open (no C.F.)	MV-RO	2.3E-7	9.4E-8	9	1.05E-8	8.5E-7	M8
Air Operated Valve	Fails to close (no C.F.)	AV-FC	4.1E-7	2.5E-7	5	5.1E-8	1.3E-6	A9
	Fails to open (no C.F.)	AV-FO	4.1E-7	2.5E-7	5	5.1E-8	1.3E-6	A10
	Transfer closed, fails to remain open (no C.F.)	AV-RO	2.3E-7	9.4E-8	9	1.05E-8	8.5E-7	A11
Manual Valve	Fails to close	NV-FC	2.9E-8	2.3E-8	3	7.7E-9	6.9E-8	N1
	Fails to open	NV-FO	2.9E-8	2.3E-8	3	7.7E-9	6.9E-8	N2
	Fails to remain closed	NV-RC	1.0E-7	2.7E-9	84	3.2E-11	2.2E-7	N3
	Fails to remain open	NV-RO	3.0E-8	1.1E-8	10	1.1E-9	1.1E-7	N4
Check Valve	Fails to close	CV-FC	3.0E-6	1.1E-6	10	1.1E-7	1.1E-5	C6
	Fails to open	CV-FO	3.0E-8	2.4E-8	3	8.1E-9	7.8E-8	C7
	Fails to remain closed/ catastrophic internal leakage	CV-RC	4.0E-9	1.1E-9	15	7.3E-11	1.7E08	C8
	Fails to remain open	CV-RO	2.3E-7	9.4E-8	9	1.1E-8	8.5E-7	C9
Relief Valve (general)	Fails to remain closed	RV-RC	4.0E-6	2.5E-6	5	5.0E-7	1.2E-5	R1
Safety Relief Valve	Fails to open	none	3.0E-4/d[g]	1.9E-4	5	3.7E-5	9.3E-4	R2
Primary Safety Valve	Fails to remain closed (premature opening)	none	3.4E-6	2.1E-6	5	4.2E-7	1.1E-5	R3
	Fails to reseat (steam relief)	none	5.0E-3/d	3.1E-3/d	5	6.2E-4/d	1.6E-2/d	R4
	Fails to reseat (water relief)	none	1.0E-1/d	3.8E-2/d	10	3.8E-3/d	3.8E-1/d	R5
Air Dryer	Plugged	ARD PG	1.0E-5	3.8E-6	10	3.8E-7	3.8E-5	A4
Solenoid Valve	Fails to close (no C.F.)	SV-FC	8.2E-7	6.6E-7	3	2.2E-7	2.0E-6	S1
	Fails to open (no C.F.)	SV-FO	8.2E-7	6.6E-7	3	2.2E-7	2.0E-6	S2
	Fails to remain open (no C.F.)	SV-RO	9.0E-7	7.2E-7	3	2.4E-7	2.2E-6	S3
Pressure Regulating Valve	Fails to remain open	PV-RO	4.2E-6	1.6E-6	10	1.6E-7	1.6E-5	P1

Table 6.2-1 PVNGS Component Failure Rates (Continued)

Component	Failure Mode	Component Mode Code [a]	Mean [b]	Median	E.F [c]	Percentiles [d] 5th	95th	Source [e]
Motor-Driven Pump	Fails to run given start (C.F.)	MP-FR	2.1E-5	7.9E-6	2	4.0E-6	1.6E-5	M1
	Fails to start (no C.F.)	MP-FS	1.0E-6	4.1E-7	2	2.1E-7	8.2E-7	M2
Motor-Driven Auxiliary Feedwater Pump	Fails to run (C.F.)	MPA FR	1.3E-5	1.2E-5	2	6.9E-6	2.8E-5	M3
	Fails to start (no C.F.)	MPA FS	5.7E-6	5.2E-6	2	3.0E-6	1.0E-5	M4
Turbine-Driven Auxiliary Feedwater Pump	Fails to run given start (C.F.)	TPA FR	4.9E-5	1.6E-5	12	1.3E-6	1.9E-4	T2
	Fails to start (C.F.)	TPA FS	5.6E-5	2.5E-5	8	3.2E-6	2.0E-4	T3
Fan (Motor-Driven)	Fails to run given start (C.F.)	ARF FR	6.0E-6	2.3E-6	10	2.3E-7	2.3E-5	A5
	Fails to start (no C.F.)	A FS	1.3E-7	4.9E-8	10	4.9E-9	4.9E-7	A6
Air Compressor	Fails to run given start (C.F.)	ARA FR	2.9E-4	4.3E-5	25	1.7E-6	1.1E-3	A1
	Fails to start (no C.F.)	ARA FS	1.0E-6	4.1-7	5	8.2E-8	2.1E-6	A2
Air Cooler	Internal leakage (HX per tube rate)	ARC IL	3.0E-9	1.1E-9	10	1.1E-10	1.1E-8	A3
Water Chiller	Fail to run given start (C.F.)	ARH FR	6.0E-5	8.9E-6	25	3.5E-7	2.2E-4	A7
	Fails to start (no C.F.)	ARH FS	1.0E-6	4.1E-7	5	8.2E-8	2.1E-5	A8
Dampers								
Air/Motor-Operated	Fails to open/close (no C.F.)	DM-FO	1.0E-6	2.4E-7	16	1.5E-8	3.9E-6	D1
	Fails to remain open (no C.F.)	DM-RO	2.5E-7	9.4E-8	10	9.4E-9	9.4E-7	D2
Manual (Backdraft)	Fails to open	DMM FO	1.1E-7	4.1E-8	10	4.1E-9	4.1E-7	D3
Manual (Fire)	Fails to remain open	DMM RO	2.5E-7	9.4E-8	10	9.4E-9	9.4E-7	D4
Filter - Wire Mesh/Screen	Plugged	FX-PG	3.0E-5	1.1E-5	10	1.1E-6	1.1E-4	F2
Air Filter	Plugged	FXA PG	6.8E-6	2.6E-6	10	2.6E-7	2.6E-5	F3
Heat Exchanger	Shell rupture/External leak	HX-EL	3.0E-6	1.1E-6	10	1.1E-7	1.1E-5	H1
	Tube rupture (per tube)	HX-IL	3.0E-9	1.1E-9	10	1.1E-10	1.1E-8	H2
	Plugged (unit/hr.)	HX-PG	2.7E-6	1.0E-6	10	1.0E-7	1.0E-5	H3

Table 6.2-1 PVNGS Component Failure Rates (Continued)

Component	Failure Mode	Component Mode Code [a]	Mean [b]	Median	E.F [c]	Percentiles [d] 5th	95th	Source [e]
Pipes								
> 3-in. diameter, per section	Leakage/rupture	PXL EL	8.5E-10	1.0E-10	30	3.3E-11	3.0E-9	P2
	Leakage/rupture	PXS EL	8.5E-9	1.0E-9	30	3.3E-10	3.0E-8	P4
< 3-in. diameter, per section	Plugged	PXO PG	8.3E-7	6.6E-7	3	2.2E-7	2.0E-6	P3
Flow orifice/reducer								
Tank	Catastrophic leakage/rupture	TK-EL	1.0E-9	1.2E-10	30	3.9E-12	3.5E-9	T2
Buses								
Bare/Outdoor AC	Catastrophic failure	BS-PW	8.3E-7	1.7E-7	19	8.8E-9	3.2E-6	B1
Metal Enclosed	Catastrophic failure	BSE PW	1.3E-7	8.1E-8	5	1.6E-8	4.0E-7	B2
Overhead Power Line	Fails to carry power (per 1000 circuit-ft.)	EXO PW	2.2E-6	1.4E-6	5	2.7E-7	6.8E-6	E1
Circuit Breaker								
AC <= 4.16 kV	Fails to close (no C.F.) [f]	CB-FT	1.2E-6	7.5E-7	5	1.5E-7	3.7E-6	C1
	Fails to carry power (no C.F.)	CB-ST	2.3E-7	8.7E-8	10	8.7E-9	8.7E-7	C2
AC > 4.16 kV	Fails to close (no C.F.)	CBO FT	2.4E-6	9.0E-7	10	9.0E-8	9.0E-6	C4
	Fails to carry power (no C.F.)	CBO ST	4.5E-7	1.7E-7	10	1.7E-8	1.7E-6	C5
DC 125V	Fails to carry power (no C.F.)	CBD ST	2.3E-7	8.7E-8	10	8.7E-9	8.7E-7	C3
Fuse	Open circuit, premature open	FU-OC	1.0E-6	3.8E-7	10	3.8E-8	3.8E-6	F1
Battery Power System	Fails to provide power	BX-PW	1.0E-6	8.0E-7	3	2.7E-6	2.4E-6	B3
Battery Charger	No output	BXC NO	3.1E-6	9.2E-7	13	7.1E-8	1.2E-5	B4
DC to AC Inverter	No output, Fails to operate	IN-NO	1.0E-4	8.0E-5	3	2.7E-5	2.4E-4	I3
Voltage Regulator	No output, Fails to operate	VR-NO	7.2E-6	4.3E-7	50	8.5E-9	2.2E-5	V1
Relays								
General	Failure to transfer (including contacts Fail to Close)	RX-FT	4.0E-7	1.5E-7	10	1.5E-5	1.5E-6	RX1
	Spurious de-energize	RX-DE	4.3E-6	1.0E-7	91	1.1E-9	9.1E-6	RX2
Bistable Relay	Fails to transfer (de-energize)	RXS FT	8.6E-6/d	6.9E-6/d	3	2.3E-6/d	2.1E-5/d	RX3

Table 6.2-1 PVNGS Component Failure Rates (Continued)

Component	Failure Mode	Component Mode Code [a]	Mean [b]	Median	E.F [c]	Percentiles [d] 5th	95th	Source [e]
Bistable	Failure to transfer	IB-FT	2.9E-6	1.8E-6	5	3.6E-7	9.0E-6	I1
Transformers								
Dry	Fails to provide power	XMD PW	9.1E-7	3.4E-7	10	3.4E-8	3.4E-6	X1
Liquid	Fails to provide power	XML PW	7.3E-7	3.3E-7	8	4.1E-8	2.6E-6	X2
Startup	Fails to provide power	XMS PW	1.7E-6	1.1E-6	5	2.1E-7	5.5E-6	X3
IP Converter	No output	IMC NO	1.1E-6	1.2E-7	33	3.6E-9	4.0E-6	I2
Flow transmitter	High output	ITF HO	1.3E-6	7.2E-7	6	1.2E-7	4.3E-6	I4
	No output	ITF NO	2.6E-6	1.4E-6	6	2.4E-7	8.6E-6	I5
Flow Switch	No output (Failure to operate)	IWF NO	1.6E-6	9.9E-7	5	2.0E-7	5.0E-6	I11
Level Transmitter	High output	ITL HO	5.1E-7	2.3E-7	8	2.9E-8	1.8E-6	I6
	Low output	ITL NO	3.2E-6	1.3E-6	9	1.5E-7	1.2E-5	I7
Pressure Switch	No output (Failure to operate)	IWP NO	1.4E-6	3.9E-7	14	2.8E-8	5.4E-6	I12
Pressure Transmitter	High output	ITP HO	5.7E-7	2.6E-7	8	3.2E-8	2.1E-6	I8
	Low output	ITP LO	2.7E-7	1.2E-7	8	1.5E	9.E-7	I9
	No output	ITP NO	2.1E-6	9.5E-7	5	1.2E-7	7.6E-6	I10
Relay	Fails to energize		4.0E-7	1.5E-7	10	1.5E-8	1.5E-6	RX1
	Fails to de-energize		4.0E-7	1.5E-7	10	1.5E-8	1.5E-6	RX1
	Spurious energize		4.3E-7	1.0E-8	91	1.1E-10	9.1E-7	CC1
	Spurious de-energize		4.3E-6	1.0E-7	91	1.1E-9	9.1E-6	RX2
Contact Pair	Fails to close		6.7E-8	1.3E-8	20	6.4E-10	2.6E-7	CC2
	Fails to open		6.7E-8	1.3E-8	20	6.4E-10	2.6E-7	CC2
	Fails to remain closed		1.3E-7	1.0E-7	3	3.5E-8	3.1E-7	CC3
	Fails to remain open		1.3E-7	1.0E-7	3	3.5E-8	3.1E-7	CC3
Manual Switch	Fails to close		2.2E-8	2.0E-8	2	1.0E-8	4.0E-8	CC4
	Fails to open		2.7E-7	2.6E-7	1.2	1.9E-7	3.7E-7	CC5
	Fails to remain open		1.7E-7	1.7E-7	1.2	1.2E-7	2.3E-7	CC6
Limit Switch	Fails to operate		3.8E-4/d	1.5E-4/d	9.9	1.6E-5/d	1.4E-3/d	CC7
	Spurious operation		4.7E-6	4.2E-6	2.2	1.9E-6	9.2E-6	CC8

Table 6.2-1 PVNGS Component Failure Rates (Continued)

Component	Failure Mode	Component Mode Code [a]	Mean [b]	Median	E.F [c]	Percentiles [d] 5th	95th	Source [e]
Fuse	Premature open		1.0E-6	3.8E-7	10	3.8E-8	3.8E-6	F1
DC Motor	Fails to start		3.8E-4/d	3.0E-4/d	3	1.0E-4/d	9.1E-4/d	CC9
Instrument Voltage Transformer	Fails to operate		3.7E-7	3.5E-7	1.7	2.1E-7	6.0E-7	CC10
Solid State Overcurrent Trip Device	Premature Open		6.6E-7	3.8E-7	5.6	6.8E-8	2.1E-6	CC11
Solid State Logic	Module failure		8.0E-8	9.4E-9	30	3.1E-10	2.8E-7	CC12
Bistable	Fails to transfer		2.9E-6	1.8E-6	5	3.6E-7	9.0E-6	I1

a. This code is the last five characters in the 16 character basic event name used in the fault tree models. It indicates component type and failure mode.
b. Failure rates are in failures/hr. unless otherwise indicated.
c. E.F. = Error Factor
d. All failure rate distributions are assumed to be log normal unless otherwise indicated.
e. See Table 6.9 for sources and derivations of failure parameters.
f. "No C.F." indicates command faults are excluded.
g. Indicates failures per demand.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates

Source Code	Type Code/ Failure Mode	Description/Data Source
A1	<ARA FR>	Air Compressor Fails to Run The data is from the Oconee PRA (Reference 6.3.1, Table B-1) which, in turn, derived it from NPRDS data published in 1980. Oconee analysts associated an error factor of 25 with the rate. This fail to run rate is assumed to INCLUDE command faults (NUREG/CR-1205 gives 2.1E-5/ hr. for alternating pump Does Not Operate Given Start WITH command faults. The Oconee value for compressors is a factor of 10 higher than this).
A2	<ARA FS>	Air Compressor - Fails to Start Compressor failure to start was judged to be similar to motor-driven pump fail to start. Failure rate was taken from NUREG/CR-1205, Rev. 1 (Reference 6.3.34, page 362), Standby Pumps, motor-driven, EXCLUDING command faults. The indicated error factor (<2) was rounded up to 5 due to design differences between pumps and compressors.
A3	<ARC IL>	Air Cooler - Internal Leakage Specific data for air coolers was not available. Data was taken from the IREP (Reference 6.3.13) for heat exchangers with tube leak (per tube).
A4	<ARD PG>	Air Dryer - Plugging The mean and median values for Air Dryer Plugging were estimated as one third of the values for filter plugging from the IREP (Reference 6.3.13) source. The estimation was based on engineering judgment. The same error factor of 10 was kept.
A5	<ARF FR>	Fan (Motor-driven) - Fails to Run Given Start The data is from the MONJU PRA (Reference 6.3.35) which in turn took the mean from NPRDS. The mean is an average of axial, centrifugal, and rotary vane blowers. It is judged to INCLUDE command faults. The MONJU PRA assigned a conservative error factor of 10.
A6	<ARF FS>	Fan (Motor-driven) - Fails to Start The data is from the MONJU PRA (Reference 6.3.35) which in turn derived a demand rate from the NPRDS hourly rate by assuming 1 month between demands. The NPRDS mean hourly rate is an average of axial, centrifugal, and rotary vane blowers. It is based on calendar hours and is judged to EXCLUDE command faults. The MONJU PRA assigned a conservative error factor of 10.
A7	<ARH FR>	Water Chiller - Fails to Run The failure data is from NUREG/CR-2787 (Reference 6.3.42). Typical of most fail to run data, the valve is assumed to INCLUDE command faults.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
A8	<ARH FS>	Water Chiller - Fails to Start Chiller failure to start was judged to be similar to motor-driven pump fail to start. The failure data is from NUREG/CR 1205 Rev. 1 (Reference 6.3.34, page 362), Standby Pump, motor-driven, Does Not Start, EXCLUDING command faults. The indicated error factor (<2) was rounded up to 5 due to design differences between pumps and water chillers.
A9	<AV- FC>	Air Operated Valve - Fails to Close The data is from NUREG/CR-1363 (Reference 6.3.33, page 422) AOV Fails to Operate WITHOUT Command Faults (Failure of an associated SOV is assumed to represent a command fault, hence, SOV faults are not covered here.) The overall hour rate was used. The error factor of 2 indicated in the NUREG was increased to 5 based on engineering judgment.
A10	<AV- FO>	Air Operated Valve - Fails to Open The data is from NUREG/CR-1363 (Reference 6.3.33, page 422) AOV Fails to Operate WITHOUT Command Faults (Failure of an associated SOV is assumed to represent a command fault, hence, SOV faults are not covered here.) The overall hour rate was used. The error factor of 2 indicated in the NUREG was increased to 5 based on engineering judgment.
A11	<AV- RO>	Air Operated Valve - Transfer Closed, Fails to Remain Open The data is from the Oconee PRA (Reference 6.3.1, Table B-1) AOV Transfer Closed data. The reference note indicates that the failure mode is actually "AOV Fails to Remain Open". The value is based on WASH 1400 data with a wider spread imposed and an assumption of one demand every 45 days. It is assumed that command faults are NOT included.
B1	<BS- PW>	Bus - Bare/Outdoor AC - Catastrophic Failure The data was taken from IEEE Standard 500, (Reference 6.3.36, page 802) for Composite of Bare and Insulated Buses, ALL failure modes. The recommended value is taken as the median; 5th and 95th percentiles are the low and maximum values.
B2	<BSE PW>	Bus - Metal Enclosed - Catastrophic Failure Metal enclosed bus failure. Data is from IEEE Standard 500 (Reference 6.3.36, page 811) for Metal Enclosed bus, Catastrophic failures. The recommended value is taken as the median; 5th and 95th percentiles are the low and maximum values.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
B3	<BX- PW>	Battery Power System - Fails to Provide Power The data is from IREP (Reference 6.3.13) for Battery Power System (Wet Cell), "Fail to Provide Proper Output". IREP assumes out-of-specifications cell replacement. The IREP rate is encompassed by various sources ranging from 9E-6/hr. (Yankee Rowe PRA) to 9E-8/hr. (Oconee PRA).
B4	<BXC NO>	Battery Charger - No Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Battery Charger (SCR Type), "Failure During Operation". Oconee, in turn, obtained the data from IEEE Standard 500.
C1	<CB- FT>	Circuit Breaker - AC <= 4.16 kV - Fails to Close This is an Indoor/Low Voltage (4.16 kV and less) AC circuit breaker. The mean value was calculated using the mean value of the high voltage circuit breaker (CBO FT) and the scaling factor of 2. This scaling factor is a ratio of the Outdoor mean value to the Indoor mean value derived from IEEE Standard 500 (Reference 6.3.36, pages 122 and 119). The error factor is the same as that of "CBO FT". The derived rate EXCLUDES command faults.
C2	<CB- ST>	Circuit Breaker - AC <= 4.16 kV - Fails to Carry Power, Spurious Trip This is an Indoor/Low Voltage (4.16 kV and less) AC circuit breaker, spurious trip fault. The mean value was calculated using the mean value of the high voltage circuit breaker (CBO ST) and the scaling factor of 2. This scaling factor is a ratio of the Outdoor mean value to the Indoor mean value derived from IEEE Standard 500, (Reference 6.3.36, pages 122 and 119). The error factor is the same as that of "CBO ST". The derived rate EXCLUDES command faults.
C3	<CBD ST>	Circuit Breaker - DC 125V - Fails to Carry Power, Spurious Trip Assumed to have same value as the AC breaker (CB-ST).
C4	<CBO FT>	Circuit Breaker - AC > 4.16 kV - Fails to Close This is an Outdoor/High Voltage (>4.16 kV) AC circuit breaker. The median 5th and 95th percentile values are taken as the IEEE Standard 500 (Reference 6.3.36, page 111) "RECOMMENDED", "LOW", and "HIGH" values respectively. The failure modes "Does not Close on Command" and "Does not Make the Current" were summed to arrive at a breaker fail to close rate WITHOUT command faults. This is interpreted to include faults on the AC device.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
C5	<CBO ST>	Circuit Breaker - AC > 4.16 kV - Fails to Carry Power, Spurious Trip This is an Outdoor/High Voltage (>4.16 kV) AC circuit breaker. The median, 5th and 95th percentile values are taken as the IEEE Standard 500 (Reference 6.3.36, page 111) "RECOMMENDED", "LOW", and "HIGH" values respectively. The failure modes "Fails to Carry Current", "Breakdown to Earth (Internal and External)", and "Breakdown Between Poles (Ext)" were summed to arrive at a breaker spurious trip rate WITHOUT command faults.
C6	<CV- FC>	Check Valve - Fails to Close This failure mode is NOT interpreted as including backflow through the check valve (i.e., internal leakage) AFTER the valve closes. (See CV-RC) The data is from IREP (Reference 6.3.13) for Check Valves, "Failure to Close". IREP indicates that the hourly rate is based on an assumed one actuation per month.
C7	<CV- FO>	Check Valve - Fails to Open The data is from NUREG/CR-1363 (Reference 6.3.33, page 438) for Check Valves Fail to Open for combined PWRs and BWRs. The source indicates that the upper bound (95%) on this mean is 7.8E-8/hr. while the lower bound (5%) is 8.1E-9/hr. The IREP hourly rate results in failure probabilities that are unrealistically high for exposure times greater than 3 months.
C8	<CV- RC>	Check Valve - FTRC/Catastrophic Internal Leakage The failure rate applies only to a check valve that is known to have seated and subsequently undergoes catastrophic rupture of the valve internals, permitting gross backleakage. The median value was calculated by taking the geometric average of the median failure rates for catastrophic check valve internal rupture from four sources: NUREG/CR-2728 (Reference 6.3.13), NUREG/CR-2815 (Reference 6.3.27), EPRI ALWR "Key Assumptions and Ground Rules", and NUREG/CR-4550, Vol. 2 (Reference 6.3.30). The error factor of 15 was chosen such that the associated 5% and 95% confidence bounds cover the range of the medians used in deriving the average.
C9	<CV- RO>	Check Valve - Fails to Remain Open The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for check valve "Transfer Closed". The reference note indicates that the failure rate is actually based on WASH-1400 data for an MOV or manual valve, "Fails to Remain Open" (plug). The Oconee analysts increased the 5th-95th percentile spread given in WASH-1400 to reflect their judgment of greater uncertainty in the data.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
CC1	<NONE>	Relay - Spurious Energize Data is taken from Oconee PRA (Reference 6.3.1, Table B-1), "Coil short to power". The Oconee source is WASH-1400 with a broader distribution imposed on the original data.
CC2	<NONE>	Relay Contacts - Shorted/Fail to Open - Fail to Close This failure mode and rate applies to a contact pair when it is modeled separately from its associated relay. The relay energize/de-energize failure rate is said to include contact pair faults. An NPRDS.search indicates 35 out of 205 relay failures were due to failures of contact pairs. Contact pair failure rate may thus be estimated as: 35/205 x 4.0E-7/hr. = 6.8E-8/hr. The relay fail to energize error factor of 10 is increased to 20 in recognition of the increased uncertainty.
CC3	<NONE>	Contact Pair - Fails to Remain Closed/Open Data is taken from WASH-1400 (Reference 6.3.15, Table III 4-2), failure to remain closed of NC contacts, relay not energized.
CC4	<NONE>	Manual Switch - Fails to Close Data is taken from IEEE Standard 500 (Reference 6.3.36, pages 214 - 226) Rotary Switches "Fails to Close". The "LOW", "RECOMMENDED" and "HIGH" values are taken as the 5th, median and 95th percentiles of the distribution, respectively.
CC5	<NONE>	Manual Switch - Fails to Open Data is taken from IEEE Standard 500 (Reference 6.3.36, pages 214 - 226) Rotary Switches. Combines "Fail to Open" and "Fails to Interrupt on Opening". The "LOW", "RECOMMENDED" and "HIGH" valves, are taken as the 5th, median, and 95th percentiles of the distribution, respectively.
CC6	<NONE>	Manual Switch - Fails to Remain Open Data is taken from IEEE Standard 500 (Reference 6.3.36, pages 214 - 226), Rotary Switches, "Spurious Operation". The "LOW", "RECOMMENDED" and "HIGH" values are taken as the 5th, median, and 95th percentiles of the distribution, respectively.
CC7	<NONE>	Limit Switch - Fails to Operate Data is taken from WASH 1400, (Reference 6.3.15, Table III 4-2). The adjustments made to WASH 1400 data by the Oconee PRA result in a failure rate that appears unrealistically high for control circuit use.
CC8	<NONE>	Limit Switch - Spurious Operation Data is taken from Oconee PRA (Reference 6.3.1, Table B-1) which derives it from the IEEE Standard 500 reference.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
CC9	<NONE>	DC Motor - Fails to Start Data is taken from WASH 1400 (Reference 6.3.15, Table III, 4-2), Electric motors.
CC10	<NONE>	Instrument Voltage Transformer - Fails to Operate Data is taken from IEEE Standard 500 (Reference 6.3.36, page 415) for 0-10kV potential transformer, "Open Circuit" and "Shorts" categories. The "LOW", "RECOMMENDED" and "HIGH" valves are taken as the 5th, median, and 95th percentiles respectively.
CC11	<NONE>	Solid State Overcurrent Trip Device - Premature Open Data is taken from IEEE Standard 500 (Reference 6.3.36, page 628). The failure rate is assumed to be the same as that for a "Bistable". Failure modes of concern include catastrophic "Function Without Signal" and from the degraded category "Function at Improper Signal Level" and "Premature or Delayed Action". It is assumed that half of each of the last two contributors represent failure that can be classified as "premature open" faults. The IEEE "LOW", "RECOMMENDED" and "HIGH" values are taken as 5th, median, and 95th percentile values, respectively.
CC12	<NONE>	Solid State Logic Module - Fail to Operate The failure rate is from the Monju PRA (Reference 6.3.35) data base. The Monju PRA data, in turn, is a consensus of several sources, but especially NPRD-2. The NPRD-2 value of 2.7E-8/hr. came from Military Handbook, MIL-HDBK-217D (January 15, 1982), for "random logic microelectronic semiconductor device (< 100 gates) in a ground-fixed environment."
D1	<DM- FO>	Damper - Air/Motor Operated - Fails to Open The failure rate applies to motor-operated dampers and air-operated dampers but DOES NOT INCLUDE the SOV controller for the later. The data is from NUREG/CR-2815 (NREP, Reference 6.3.27) and is judged to EXCLUDE command faults. The mean failure rate agrees well with the mean from IEEE Standard 500 (Reference 6.3.36, page 1226) 1.5E-6/hr. and also agrees with the value recommended in IREP (Reference 6.3.13) when the mean demand rate is converted to an hourly rate.
D2	<DM- RO>	Damper - Air/Motor Operated - Fails to Remain Open Data is from the Monju PRA (Reference 6.3.35), Damper, "Spurious Operation". For air-operated dampers, this value is not considered to include faults of the SOV controller which must be considered separately. The failure rate is judged to EXCLUDE command faults.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
D3	<DMM FO>	Damper - Manual (Backdraft) - Fails to Open The backdraft damper contains no operator but opens when air flows in the design direction. The IREP or Monju PRA failure rates were judged not applicable here since they pertain to motor-driven, control dampers. Such active mechanical devices are expected to fail with higher frequency than a passive backdraft damper. The 95% upper bound on the check valve fail to open rate was taken as a conservative estimate of the mean for manual damper fail to open with flow. The same error factor (10) was used.
D4	<DMM RO>	Damper - Manual (Fire) - Fails to Remain Open The fire damper contains no operator but is closed by spring return when air temperature reaches a setpoint. Although the Monju PRA "Spurious Operation" failure rate pertains to a motor-driven actuated damper it was conservatively used to represent premature opening/failure of the fire damper thermal links.
E1	<EXO PW>	Overhead Power Lines - Fails to Carry Power Line faults in 3-phase, outdoor, overhead lines. Data comes from IEEE Standard 500 (Reference 6.3.36, page 755) for Open Wire, 0-15 kV power cables, all failure modes, per 1000 ft. of cable. It is assumed that the IEEE table "Cycles" values actually represent Failures/1.E+6 hrs. This makes data consistent with other sources. The IEEE "RECOMMENDED", "LOW", and "HIGH" values were taken as the median, 5th and 95th percentile bounds, respectively. The resulting error factor of 4.5 was rounded to 5 and the bounds recalculated.
F1	<FU- OC>	Fuse - Open Circuit, Premature Open The failure rate is from the MONJU PRA (Reference 6.3.35) data base, which calculates a geometric mean of all rates from the sources it investigates. The failure rate is also the "HIGH" hourly rate from IEEE Standard 500 (Reference 6.3.36, page 214-47) for ALL MODES of fuse failures.
F2	<FXW PG>	Filter (General) - Plugged The failure rate data is from IREP (Reference 6.3.13) for strainer/filter plugging failure mode. IREP indicates this applies to filters for clear fluids without heavy chemical or contamination burdens.
F3	<FXA PG>	Air Filter - Plugged The data is from IEEE Standard 500 (Reference 6.3.36, page 1412) for Air Filters, "All Failure Modes". The data is a composite for several types of air filters of varying capacity and design. The "RECOMMENDED" valve is taken as the median and the implied EF of 1.1 is increased to 10 based on engineering judgment.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
H1	<HX- EL>	Heat Exchanger - Shell Rupture/External Leakage The data is from IREP (Reference 6.3.13) for a Heat Exchanger shell leak.
H2	<HX- IL>	Heat Exchanger - Tube Rupture (per tube) The data is from IREP (Reference 6.3.13) for a Heat Exchanger tube leak (per tube).
H3	<HX- PG>	Heat Exchanger - Plugged (Unit/Hr) The data is from the Clinch River Breeder Reactor PRA (Reference 6.3.9, EGG-EA-6162).
I1	<IB- FT>	Bistable - Failure to Transfer (Includes Setpoint Drift) CE NPSD-277 (Reference 6.3.38, page 3-17) indicates a mean bistable failure rate of 3.8E-6/hr. (obtained by Bayesian update of WASH-1400 data) which includes setpoint drift failures. EPRI NP-4483 (Reference 6.3.43, Vol. 1, page 2-3) indicates that about half of all bistable failures are due to setpoint drift outside the required limits. Since half of setpoint drift factors would be expected to make bistable functional success more likely, the best estimate failure rate is taken to be 3.8E-6 x .75 = 2.9E-6/hr.
I2	<IMC NO>	I-P Converter - No Output I-P Converter is a current to pressure signal converter. The data was taken from IEEE Standard 500 (Reference 6.3.36, page 731) for Pneumatic Proportional Controllers, All failure modes.
I3	<IN- NO>	DC to AC Inverter - No output, fails to operate. The data is from IREP (Reference 6.3.13) for inverter fails to operate mode.
I4	<ITF HO>	Flow Transmitter - High Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Flow Transmitter "High Output" failure mode. The base data is from IEEE Standard 500.
I5	<ITF NO>	Flow Transmitter - No Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Flow Transmitter general failure mode. Oconee derives the rate based on IEEE Standard 500 data.
I6	<ITL HO>	Level Transmitter - High Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Level Transmitter, "High Output" failure mode. Oconee derives the rate based on IEEE Standard 500 data.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
I7	<ITL NO>	Level Transmitter - Low Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Level Transmitter, general failure mode. Oconee derives the rate based on IEEE Standard 500 data.
I8	<ITP HO>	Pressure Transmitter - High Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Pressure Transmitter, "High Output" failure mode. Oconee derives the rate based on IEEE Standard 500 data.
I9	<ITP LO>	Pressure Transmitter - Low Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Pressure Transmitter, "High Output" failure mode. Oconee derives the rate from IEEE Standard 500.
I10	<ITP NO>	Pressure Transmitter - No Output The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for Pressure Transmitter, general failure mode, which is considered to include no output and no response to input. Oconee derives the rate from IEEE Standard 500.
I11	<IWF NO>	Flow Switch - No Output (Failure to Operate) The data is from IEEE Standard 500 (Reference 6.3.36, page 578) for Flow/Velocity Process Switch, "No Function with Signal". The "LOW", "RECOMMENDED", and "HIGH" valves are taken as the 5%, median, and 95% bounding valves respectively.
I12	<IWP NO>	Pressure Switch - No Output (Failure to Operate) The data is from IEEE Standard 500 (Reference 6.3.36, page 556) for Pressure Process Switch, "No Function with Signal." The "LOW", "RECOMMENDED", and "HIGH" valves are taken as the 5%, median, and 95% bounding valves respectively.
M1	<MP- FR>	Motor-Driven Pump - Fails to Run Given Start The data mean is from NUREG/CR-1205, Rev. 1 (Reference 6.3.34, page 335) for alternating pumps "Does Not Operate Given Start". This data INCLUDES the command faults. Alternating pump category was used because the standby pump category "Does Not Operate" includes "Fail to Start" events. The indicated error factor was rounded up to 2.
M2	<MP- FS>	Motor-Driven Pump - Fails to Start The data mean is from NUREG/CR-1205, Rev. 1 (Reference 6.3.34, page 362) for standby motor driven pump "Does Not Start" failure mode. The rate DOES NOT INCLUDE command faults. The overall hour rate was used. The indicated error factor was rounded up to 2.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
M3	<MPA FR>	Motor-Driven Auxiliary Feedwater Pump - Fails to Run The data is from NUREG/CR-2098, Rev. 0 (Reference 6.3.39, page 93), for motor-driven PWR Auxiliary Feedwater pumps "Failure to Operate Given Start". The failure rate INCLUDES command faults. The point estimate is taken as the mean value. The lower and upper bounds are taken as the 5% and 95% intervals per their description in the document. The failure rate is per critical hour.
M4	<MPA FS>	Motor-Driven Auxiliary Feedwater Pump - Fails to Start The data is from NUREG/CR-2098, Rev. 0 (Reference 6.3.39, page 91), for motor-driven PWR Auxiliary Feedwater pumps "Failure to Start". The failure rate DOES NOT INCLUDE command faults. The point estimate is taken as the mean value. The lower and upper bounds are taken as the 5% and 95% intervals per their description in the document. The failure rate is per critical hour.
M5	<MV- FC>	Motor-Operated Valve - Fails to Close The data is from NUREG/CR 2770 (Reference 6.3.40, page 73) for Remote Operated Valves - Failure to Open, Close, or Operate. The rate is per calendar hour. It DOES NOT INCLUDE command faults but DOES INCLUDE limit switch faults.
M6	<MV- FO>	Motor-Operated Valve - Fails to Open The data is from NUREG/CR 2770 (Reference 6.3.40, page 73), for Remote Operated Valves - Failure to Open, Close, or Operate. The rate is per calendar hour. It DOES NOT INCLUDE command faults but DOES INCLUDE limit switch faults.
M7	<MV- RC>	Motor-Operated Valve - Fails to Remain Closed The data is from NUREG/CR-2815 (Reference 6.3.27, Table C-1) for MOV's Catastrophic Internal Leakage. As such, the rate is NOT considered to include command faults. The "Minimum" and "Maximum" valves were interpreted as the 5% and 95% bounds. The EF = 84.
M8	<MV- RO>	Motor-Operated Valve - Transfer Closed, Fails to Remain Open The failure rate is from the Oconee PRA (Reference 6.3.1, Table B-1) for MOV Transfer Closed, but the reference note on this data indicates that the failure mode is actually MOV Fails to Remain Open. The value is based on WASH 1400 data with a wider spread imposed. The failure rate is NOT considered to include command faults. The Oconee analysts assume one demand every 45 days to arrive at an hourly rate.
N1	<NV- FC>	Manual Valve - Fails to close The data is from NUREG/CR-1363, Rev. 1 (Reference 6.3.3, page 454) for Manual Operated Valve, Fail to Operate, overall hour rate.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
N2	<NV- FO>	Manual Valve - Fails to Open The data is from NUREG/CR-1363, Rev. 1 (Reference 6.3.33, page 454) for Manual Operated Valve, Fail to Operate, overall hour rate.
N3	<NV- RC>	Manual Valve - Fails to Remain Closed Since this event represents internal rupture or disintegration of the valve it was judged to be the same as a MOV catastrophic internal leakage failure. The data is from NUREG/CR-2815, (Reference 6.3.27, Table C-1) for MOV's Catastrophic Internal Leakage. As such, the rate is NOT considered to include command faults. The "Minimum" and "Maximum" valves were interpreted as the 5% and 95% bounds. The EF = 84.
N4	<NV-RO>	Manual Valve - Fails to Remain Open Surveys of industry failure data disclose few documented manual valve "plugging" events and the valve population size and exposure history is uncertain. The mean failure rate is based on a consensus of several data sources. The NPRDS A02 and A03 Reports (Reference 6.3.47) recommend a failure rate of 2.2E-8/hr. while IPRDS (Reference 6.3.48, Table 9) recommends a value of 3.0E-8/hr. for PWR manual valves plugging. The Oconee PRA derived a mean "Transfer closed" rate of 3.4E-8/hr. (EF = 10) based on NUREG/CR-1363 manual valve "Leak Externally" data. A consensus fail to remain open rate of 3.0E-8/hr. with an EF of 10 was chosen for use in the PVNGS PRA.
P1	<PV- RO>	Pressure Regulating Valve - Fails to Remain Open Failures of concern actually include any regulator valve faults that result in flow conditions inadequate to meet fluid system success criteria. IEEE Standard 500, (Reference 6.3.36, page 1036) provides failure data for composite pressure/flow regulation valves, 1-6 in. size, ALL MODES of failure. The "recommended" failure rate is 3.2E-6/hr. Assuming, conservatively, that half of all these failure modes will fail the valve such that flow is inadequate, the median failure rate for PV-RO is estimated as 1.6E-6/hr. The IEEE Standard 500 "HIGH" and "LOW" valves imply an error factor of about 2, which was judged to be too low. Assuming an EF of 10, the mean "Fails to remain open" rate is estimated to be 4.2E-6/hr.
P2	<PXL EL>	Pipes - >3-in. diameter (per Section) - Leakage/Rupture The data is from WASH-1400 (Reference 6.3.15). Hourly failure rate is per pipe section.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
P3	<PXO PG>	Pipes - Flow orifice/reducer - Plugged The data is from IREP, (Reference 6.3.13, Table 5.1-1). The data is for Orifices, Failure to Remain Open (plug), which is from the WASH-1400 (Reference 6.3.15) data. The demand rate (3E-4/d) was converted to hourly rate (8.3E-7/hr.) by assuming a monthly test period.
P4	<PXS EL>	Pipes - <3-in. diameter (per Section) - Leakage/Rupture The data is from WASH-1400 (Reference 6.3.15). The hourly failure rate is per pipe section.
R1	<RV- RC>	Relief Valve (General) - Fails to Remain Closed The mean value was based on NUREG/CR 1363 (Reference 6.3.33, pages 468 and 480), PWR primary safety and BWR primary relief valves, "Premature Open", Overall rates. The higher of the two valves (3.9E-6/hr.) was rounded up to represent a somewhat higher premature open rate expected for "general" relief valves as compared to "primary" safety relief valves. This value agrees favorably with the values recommended in Reference 6.3.11 and 6.3.32. The failure rate is generally taken to represent premature opening while under design operating pressure. The 5th and 95th percentiles given in the source indicate an error factor of less than 3. An error factor of 5 is conservatively assumed for this derived mean.
R2	<NONE>	Safety Relief Valve - Fails to Open The mean value and error factor are "Recommended" values from EGG-SSRE-8875 (Reference 6.3.32) which compares data from several sources. The failure rate agrees with those given in the Oconee and Seabrook PRAs
R3	<NONE>	Safety Relief Valve - Fails to Remain Closed/Premature Opening The mean value was based on NUREG/CR-1363 (Reference 6.3.33, page 468), PWR primary safety valves, "Premature Open", overall rate. The value agrees well with the "Recommended" value of 3.E-6/hr. from Reference 6.3.29. The 5th and 95th percentiles given in NUREG/CR-1363 indicate an error factor of less than 3. An error factor of 5 is conservatively assumed based on examination of other sources.
R4	<NONE>	Safety Relief Valve - Fails to Reseat after Steam Relief. The Oconee PRA (Reference 6.3.1)indicates a mean of 4.9E-3/d with an assumed error factor of 3. Other sources range from 3.1E-3/d (NUREG/CR-1363, BWR safety relief values, no command faults) to 3.E-2/d (NUREG/CR-4550). The Oconee value was rounded up and an error factor of 5 chosen so as to more closely encompass the range of industry data.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
R5	<NONE>	Safety Relief Valve - Fails to Reseat after Water Relief This failure rate is used to represent the failure to reclose likelihood for a primary safety relief valve that is venting liquid. The mean value and error factor from the Oconee PRA (Reference 6.3.1) is considered applicable here. The data is based on an EPRI PWR Safety and Relief Valve Test Program that indicates a higher rate of reclose failures for valves that are venting liquid as compared to steam. The range factor of 10 was chosen to reflect a relatively high uncertainty in the data.
RX1	<RX- FT>	Relay - Failure to Transfer, Fails to Energize, Fails to De-energize (Includes Contacts FTC) The value is based on the Oconee PRA (Reference 6.3.1), which derives a relay "Fail to Energize" rate of 2.4E-4/d from WASH-1400. NUREG/CR-4126 (page 24) indicates 60% of the relays in its LER population are associated with valves stroked 12 times/year and 40% are associated with pumps demanded 4 times/year. This information was used to convert the Oconee demand rate to an hourly failure rate. An EF of 10 is conservatively assumed.
RX2	<RX- DE>	Relay - Spurious De-energize Data is taken from Oconee PRA (Reference 6.3.1, Table B-1), "Coil open". The Oconee source is WASH-1400 with a broader distribution imposed on the original data.
RX3	<RXS FT>	Bistable Relay - Fails to De-energize The data is from CE NPSD-227 (Reference 6.3.38, page 3-17), Bistable Relays. This demand rate was derived via Bayesian update of WASH-1400 relay "Coil short to power" failure rate. The prior distribution thus does not include contact pair faults. NPSD-277 implies that the operating experience used to update this rate does include contact pair faults. It is conservative to consider this bistable relay "fail to de-energize" rate as EXCLUDING contact pair faults. The stated 5th and 95th percentiles indicate an error factor of 3.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
S1	<SV- FC>	Solenoid Valve - Fails to Close The data is from NUREG/CR-4550 (Reference 6.3.37) and NUREG/CR-2728 (IREP, Reference 6.3.13) for solenoid operated valve "Failure to operate". The ASEP document indicates that 1E-4 of the total demand rate of 1E-3/d is due to "valve circuit command faults". Since a mechanical valve failure rate is desired here a value of 9.0E-4/d is appropriate. The demand rate is converted to an hourly failure rate assuming one actuation per quarter (2190 hrs.). The SOVs modeled in the PRA fault trees generally are actuated infrequently e.g., only during shutdown, so this assumption of one actuation per quarter results in a more realistic failure probability than the typical IREP monthly actuation assumption. The failure rate EXCLUDES command faults.
S2	<SV- FO>	Solenoid Valve - Fails to Open The same data/failure rate used for SOV - Fails to Close is used here. The data is from ASEP/IREP (Reference 6.3.13) for solenoid operated valve "Failure to operate" (See S1, SV - FC).
S3	<SV- RO>	Solenoid Valve - Fails to Remain Open The data is from IEEE Standard 500 (Reference 6.3.36, page 449) for a "Normally Open" solenoid valve operator "spurious closing". The "LOW", "RECOMMENDED", and "HIGH" values are taken as the 5th, median, and 95th percentiles of the distribution, respectively. It is judged that the value EXCLUDES command faults. Since this represents the valve fail-to-remain-open contribution from the operator only, it was increased by the manual valve fail to remain open value (3.0E-8/hr.). This later value is for mechanical faults within the valve body itself.
T1	<TK- EL>	Tank - Catastrophic Leakage/Rupture The data is from NEDM-14082 and is for rupture (large break) of a steam drum, protected water storage tank, or CST.
T2	<TPA FR>	Turbine-Driven Auxiliary Pump - Fails to Run Given Start The data is from NUREG/CR-2098, (Reference 6.3.39, page 94). The failure data is for turbine-driven PWR Auxiliary Feedwater Pumps, Failure to Operate Given a Start, INCLUDING the command faults. The point estimate is taken as the mean value. The lower and upper bounds are taken as the 5% and 95% confidence bounds. The failure rate is per critical hour.

Table 6.2-2 Derivation of PVNGS PRA Failure Rates (Continued)

Source Code	Type Code/ Failure Mode	Description/Data Source
T3	<TPA FS>	Turbine-Driven Auxiliary Pump - Fails to Start The data is from NUREG/CR-2098, (Reference 6.3.39, page 90). The failure data is for turbine-driven PWR Auxiliary Feedwater Pumps, Failure to Start INCLUDING the command faults. The point estimate is taken as the mean value. The lower and upper bounds are taken as the 5% and 95% confidence bounds. The failure rate is per critical hour.
V1	<VR- NO>	Voltage regulator - Fails to Provide Power The data is from the Oconee PRA (Reference 6.3.1, Table B-1) for voltage regulator, "Failure (open or shorted)" mode. Oconee derives the rate based on IEEE Standard 500 data.
X1	<XMD PW>	Transformer - Dry - Fails to Provide Power The data is from Oconee PRA (Reference 6.3.1, Table B-1) for a 4kV Dry Type Transformer. Base source is IEEE Standard 500 (1977) for 601V - 15kV dry type, three-phase transformers. Data INCLUDES faults of protective circuitry.
X2	<XML PW>	Transformer - Liquid - Fails to Provide Power The data is from Oconee PRA (Reference 6.3.1, Table B-1) for a 13.2kV liquid filled transformer. Base source is IEEE Standard 500 (1977) for 2 - 30kV liquid filled, three-phase transformers. Data INCLUDES faults of protective circuitry.
X3	<XMS PW>	Transformer - Startup - Fails to Provide Power The data is from Oconee PRA (Reference 6.3.1, Table B-1) for a 230kV liquid filled transformer. Base source is IEEE Standard 500 (1977) for 347 - 550kV liquid filled, three-phase transformers. Data INCLUDES faults of protective circuitry.

Table 6.2-3 Control Circuit Data Summary

Description	PVNGS Components	Type/ Failure Mode Code	Failure Rate
DC MOV Control Circuit (Subgroup 0) fails to open associated valve	AF-HV-32 AF-UV-37 AF-HV-33 AF-UV-36	CX0FO	2.9E-6/hr.
AC MOV Control Circuit (Subgroup 3) fails to open associated valve	NC-UV-105 NC-UV-607	CX3FO	7.9E-7/hr.
AC MOV Control Circuit (Subgroup 4) fails to open associated valve	SIA-UV-651, 653, 655 SIB-UV-654, 656, 652 (Shutdown Cooling Suction MOVs)	CX4FO	1.9E-6/hr.
AC MOV Control Circuit (Subgroup 5) fails to open associated valve	FW-HV-103 SG-HV-43 SG-HV-1143, 1145	CX5FO	1.0E-6/hr.
AOV Control Circuit (Subgroup 6) fails to open associated valve	SIA-UV-635, 645 SIB-UV-615, 625 (LPSI MOVs)	CX6FO	1.4E-6/hr.
Containment Sump Recirculation Valves (SIA-UV-673, 674; SIB-UV-675, 676) were assessed a failure probability of 4.1E-3/d. (Hourly failure rate not used because test periods were not uniform.)			
MOV Control Circuit (Subgroup 7) fails to open associated valve	SIA-UV-672, SIB-UV-671 (Containment Spray MOVs) CT-HV-1, 4 (AFNP01 Suction MOVs) SIA-UV-617, 627, 637, 647 SIB-UV-616, 626, 636, 646 (HPSI Injection MOVs)	CX7FO	1.0E-6/hr.
MOV Control Circuit (Subgroup 8) fails to open associated valve	SI-HV-604 SI-HV-609 (Hot-Leg Injection MOVs) SIA-HV-657, 685, 686 SIB-HV-658, 694, 696	CX8FO	1.3E-6/hr.
MOV Control Circuit (Subgroup 9) fails to open associated valve	AF-HV-30 AF-HV-31 AF-UV-34 AF-UV-35	CX9FO	1.8E-6/hr.
MOV Control Circuit (Subgroup 6) fails to close associated valve	SIA-HV-698, 306 SIB-HV-699, 307	CX6FC	1.4E-6/hr.
SOV Control Circuit (Subgroup 7) fails to close associated valve	ADV Solenoid Valves	CX7PC	5.2E-6/hr.
MDP Control Circuit (Subgroup -) fails to close associated motor breaker	CD-P01A, B, C (Condensate Pump Motors)	CX-FS	5.5E-7/hr.

Table 6.2-3 Control Circuit Data Summary (Continued)

Description	PVNGS Components	Type/ Failure Mode Code	Failure Rate
MDP Control Circuit (Subgroup 0) fails to close associated motor breaker	AFN-P01 (AF N Train Pump)	CX0FS	1.4E-6/hr.
MDP Control Circuit (Subgroup 6) fails to close associated Breaker	SIA-P01, P02, P03 SIB-P01, P02, P03 (ECCS Motor Driven Pump)	CX6FS	1.6E-6/hr.
MDP Control Circuit (Subgroup 5) fails to close associated Breaker	EWAP01, EWBP01, (Essential Cooling Water Pumps) SPAP01, SPBP01 (Spray Pond Pumps)	CX5FS	3.0E-6/hr.
Compressor Control Circuit (Subgroup 7) fails to close associated Breaker	IAN-C01A, B, C (Instrument Air Compressor)	CX7FS	1.0E-6/hr.
Chiller Control Circuit (Subgroup 8) fails to close associated Breaker	ECAE01 ECBE01 (Essential Chillers)	CX8FS	9.9E-6/hr.
MDP Control Circuit (Subgroup 9) fails to close associated Breaker	ECAP01, ECBP01 (Essential Chill Water Pumps)	CX9FS	2.3E-6/hr.
Circuit Breaker Control Fault (Subgroup -) causes spurious breaker trip	NHN-2806 NGNL06C4, L13E3 NGN L06D3, L02D3 NGN L25C3, L25C4 NGN L10D3, L10D4 PGBL32, 34 and 36 Supply Breakers PGAL31, 33 and 35 Supply Breakers	CX-ST	2.9E-6/hr.
Circuit Breaker Control Fault (Subgroup 0) causes spurious breaker trip	NGN-L13B2 NGN-L01B2, L25B2 NGN-L02B2, L08B2 PHAM31, 33 and 35 Battery Charger Supply Breaker PHBM32, 34 and 36 Battery Charger Supply Breakers NHN-M0317, M0802, M2118	CX0ST	7.1E-6/hr.
Circuit Breaker Control Fault (Subgroup 5) causes spurious breaker trip	PBA-S03L PBB-S04K	CX5ST	1.6E-6/hr.
Circuit Breaker Control Fault (Subgroup 6) causes spurious breaker trip	NANS01D, E, G NANS02E	CX6ST	1.1E-5/hr.
Circuit Breaker Control Fault (Subgroup 7) causes spurious breaker trip	NANS05A (NANS06H)	CX7ST	5.9E-6/hr.

Table 6.2-3 Control Circuit Data Summary (Continued)

Description	PVNGS Components	Type/ Failure Mode Code	Failure Rate
Circuit Breaker Control Fault (Subgroup 9) causes spurious breaker trip	NBN-S01A NBN-S02A PBAS03H, J, N PBBS04H, J, N	CX9ST	6.5E-6/hr.
Circuit Breaker Control Fault (Subgroup D) causes spurious breaker trip	NKNM4502 (Non-Class DC) PKA-M4102, PKC-M4302 PKB-M4202, PKD-M4402	CXDST	3.4E-7/hr.
Circuit Breaker Control Fault (Subgroup 8) causes spurious breaker trip)	NANS01N NANS02N NANS03A NANS04A	CX8ST	8.4E-6/hr.
AC MOV Control Circuit Fault (Subgroup 0) causes spurious valve closure	CD-HV-1, 2 CD-HV-31, 32, 33 SIA-UV-660 SIB-UV-659 (ECCS Mini-flow)	CX0RO	7.6E-6/hr.
AC MOV Control Circuit Fault (Subgroup 6) causes spurious valve closure	CH-HV-530, 531 (RWT Outlet MOVs) SPA-HV-49A SPB-HV-50A SIA-HV-306, 683, 678, 684, 687, 635, 645, 673, 674 SIB-HV-307, 692, 679, 689, 695, 615, 625, 675, 676	CX6RO	6E-7/hr.
AC MOV Control Circuit Fault (Subgroup 7) causes spurious valve closure	CD-UV-214A, B; 215A, B; 216 A, B Condensate System LP Heater Isolation MOVs SIA-UV-664, 669 SIB-UV-665, 668 (LPSI, CS, Mini-Flow)	CX7R0	3.6E-6/hr.

Table 6.2-4 Common Cause Events Data Summary

Identifier	Failure Description	Mean Probability	Comments/Source (All CCF Rates are Per Hour)
1AF-0123---MV-CC	Common Cause Failure (CCF) of AF Pump A discharge MOVs and AF Pump B discharge MOVs to open.	2.6E-5	Fail to open Common Cause Failure (CCF) rate estimated as 7.1E-8 (NUREG/CR-2770; R_4). Mean exposure time is 15 days.
1AF-ABN----MP-CC	CCF of all three AF pumps fail to start.	1.9E-5	Fail to start CCF rate is estimated as 1.6E-7/hr., based on review of nuclear power plant data (Appendix 6.A). Mean exposure period is five days.
1AF-BN----MP-CC	CCF of motor driven AF Motors to start/run.	4.5E-5	Appendix 6.A estimates the fail to start CCF rate as 1.7E-7/hr. and the fail to run CCF rate as 3.9E-7. The mean exposure period for fail to start faults is 8.7 days and 24 hrs. for fail to run.
1AFA48-----MV-CC	Both Steam Supply MOVs (UV-134 and UV-138) for turbine driven AF pump fail to open.	1.3E-3	The NUREG/CR-2770 CCF rate of 8.0E-8/hr. was Baysian updated to 3.5E-6/hr. based on PVNGS plant specific experience. Mean exposure time is 15 days.
1AFABV137-8CV-CC	AFA-P01 and AFB-P01 discharge check valves fail to open.	1.1E-6	The CCF rate is estimated as 10% of the random failure rate of 3E-8. Mean exposure time is 15 days.
1AFABV79-80CV-CC	AF A and B Train Steam Generator Supply check valves fail to open.	2.0E-5	The CCF rate is estimated as 10% of the random failure rate of 3E-8 from Table 6.2-1. Mean exposure time is 9 months.
1CHLT-226-227-CC	CCF of both VCT level instruments or associated signal conditioning circuits.	4.3E-5	The CCF rate for high output estimated as 3.0E-7/hr. from data in NUREG/CR-3289. Mean time to detect failure is estimated as 5 days.
1ECAB-E01--ARHCC	CCF of both Essential Chillers to start and/or run.	9.9E-5	Appendix 6.A estimates the fail to start CCF rate as 2.1E-7/hr. and the fail to run CCF rate as 9.3E-7. Mean exposure period is 15 days for fail to start and 24 hrs. fail to run.

Table 6.2-4 Common Cause Events Data Summary (Continued)

Identifier	Failure Description	Mean Probability	Comments/Source (All CCF Rates are Per Hour)
1ECAB-P01--MP-CC	CCF of both Essential Chill Water Pumps to start and/or run.	9.9E-5	Appendix 6.A estimates the fail to start CCF rate as 2.1E-7/hr. and the fail to run CCF rate as 9.3E-7. Mean exposure period is 15 days for fail to start, and 24 hrs. fail to run.
1EWAB-P01--MP-CC	CCF of both Essential Cooling Water Pumps to start and run.	9.9E-5	Appendix 6.A estimates the fail to start CCF rate as 2.1E-7/hr. and the fail to run CCF rate as 9.3E-7. Mean exposure period is 15 days for fail to start and 24 hrs. fail to run.
1PBAS03L-B-CXXCC	Control Circuit fault that trips A Train 4.16 KV bus normal supply breaker and prevents DG breaker from closing.	9.1E-5	Based on the failure rate of control circuit components common to both circuit breakers.
1PBBS04K-B-CXXCC	Control Circuit fault that trips B Train 4.16 KV bus normal supply breaker and prevents DG breaker from closing.	9.1E-5	Based on the failure rate of control circuit components common to both circuit breakers.
1PEABG012--DG-CC	Both Diesel Generators fail to start or run due to Common cause faults.	6.6E-4	From NUREG-2989 Table 9.8.26, page 363. Summation of DGCCF and DGHEC. (Common cause failures of DG support systems are considered with the respective support system.)
1PK-A-B----BX-CC	CCF of the PKA and PKB batteries to supply output.	3.6E-6	Single battery failure probability to provide output estimated as 9E-4 (NUREG-4550, Volume 2) Beta for exactly two batteries estimated as 4.0E-3 (NUREG-1150). Lethal faults included below.
1PK-ABC----BX-CC	CCF of all four class batteries.	3.6E-6	Lethal Common cause Beta estimated as 4.0E-3 (NUREG-1150). Single battery failure probability equal 9E-4 (NUREG-4550, Vol. 2).

Table 6.2-4 Common Cause Events Data Summary (Continued)

Identifier	Failure Description	Mean Probability	Comments/Source (All CCF Rates are Per Hour)
ISANT1113H0ITLCC ISANT1123H0ITLCC	CCF of three or more AFAS level transmitters in a single steam generator.	1.0E-4	CCF probability estimated as 1.0E-4 using data from NUREG/CR-3289.
ISA-AFAS12----CC	CCF of all AFAS level transmitters/ signal and conditioning on Steam Generators 1 and 2.	8.0E-5	CCF of six or more AFAS level transmitters in both steam generators. Conservatively estimated as 80% of the single SG common cause probability.
ISANLT203CCIB--CC	CCF of all four RAS bistables or associated signal conditioning, such that RAS does not occur on low RWT level.	6.0E-4	CCF probability estimated as 6.0E-4 from NUREG/CR-3289.
ISANLT203H0ITLCC	CCF of all four RWT level transmitters such that RAS signal does not occur on RWT low level.	1.9E-4	CCF probability estimated as 1.9E-4 using data from NUREG/CR-3289.
ISANPT102CCIB-CC	CCF of three or more RCS low pressure SIAS bistables such that SIAS signal does not occur on low RCS pressure.	4.6E-4	CCF probability estimated as 4.6E-4 using data from NUREG/CR-3289.
ISANPT102H0ITPCC	CCF of three or more RCS low pressure transmitters, such that SIAS signal does not occur on low RCS pressure.	1.0E-4	CCF probability estimated as 1.0E-4 using data from NUREG/CR-3289.
ISANPT352CCIB-CC	CCF of three or more containment pressure CSAS bistables, such that CSAS signal does not occur on high containment pressure.	6.0E-4	CCF probability estimated as 6.0E-4 using data from NUREG/CR-3289.

Table 6.2-4 Common Cause Events Data Summary (Continued)

Identifier	Failure Description	Mean Probability	Comments/Source (All CCF Rates are Per Hour)
ISANPT352LOITPCC	CCF of three or more containment pressure transmitters, such that CSAS signal does not occur on high containment pressure.	2.6E-4	CCF probability estimated as 2.6E-4 using data from NUREG/CR-3289.
ISG-2ADVS-SG2-CC	CCF of both ADVs on a single SG to open.	7.3E-4	The random independent failure probability for an ADV (8.1E-3) is multiplied by a Beta of 0.09 (NUREG/CR-4550).
ISI-HPSI4-6MV-CC	CCF to open of four or more of six intact RCS Loop HPSI Injection MOVs in trains A and B.	2.6E-5	The CCF rate was estimated as 7.1E-8 (NUREG/CR-2770). The mean exposure period is one half month.
ISI-HPSI8-8MV-CC	CCF to open of all eight HPSI Injection MOVs (both trains).	2.6E-5	The CCF rate was estimated as 7.1E-8 (NUREG/CR-2770). The mean exposure period is one half month.
ISIAB-CSS--MP-CC	CCF of both Containment Spray Pumps to start and/or run.	1.4E-4	Appendix 6.A estimates the following CCF rates: fail to run, 2.1E-7/hr.; fail to start, 9.3E-7/hr. The mean exposure period is 1.5 months for fail to start and 24 hrs. for fail to run.
ISIAB-CSS--MV-CC	CCF to open of the Containment Spray Injection MOVs in both trains.	3.0E-5	CCF rate estimated as 8.0E-8/hr. (NUREG/CR-2770). The mean exposure period is 1.5 month.
ISIAB-HPSI-MP-CC	CCF of both HPSI Pumps to start and/or run.	1.4E-4	Appendix 6.A estimates the following CCF rates: fail to run, 2.1E-7/hr.; fail to start, 9.3E-7/hr. The mean exposure period is 1.5 months for fail to start and 24 hrs. for fail to run.
ISIAB-LPSI-MP-CC	CCF of both LPSI pumps to start and/or run.	1.4E-4	Appendix 6.A estimates the following CCF rates: fail to run, 2.1E-7/hr.; fail to start, 9.3E-7/hr. The mean exposure period is 1.5 months for fail to start and 24 hrs. for fail to run.
ISIAB-LPSI3MV-CC	CCF to open of three or more of the four LPSI Injection MOVs.	3.9E-5	CCF rate estimated as 7.1E-8 (NUREG/CR-2770). The mean exposure period is assumed to be 0.75 month.

Table 6.2-4 Common Cause Events Data Summary (Continued)

Identifier	Failure Description	Mean Probability	Comments/Source (All CCF Rates are Per Hour)
1SISDCSUCTVAL-CC	CCF to open of Shutdown Cooling Suction MOVs in both Trains.	4.7E-4	CCF rate estimated as 7.1E-8 (NUREG/CR-2770). The mean exposure period is 9 months.
1SITCC-204-CV-CC	CCF of SIT Injection Check Valves to open in two or more of the three intact RCS loops.	2.0E-5	The CCF rate is estimated as 10% of the random independent faults or 3E-9/hr. The mean exposure period is 9 months.
4SR-AB-SUMP-MV-CC	CCF of at least one sump suction MOV in both recirculation lines.	3.87E-5	Appendix 6.A estimates the CCF rate as 7.1E-8/hr. The mean exposure period was assumed as 0.75 month.
1SPAB-P01--MP-CC	CCF of Spray Pond Pumps to start/ run.	6.1E-5	Appendix 6.A estimates the following CCF rates: fail to start, 2.1E-7/hr.; fail to run, 9.3E-7/hr. The mean exposure period is one fourth of a month for fail to start and 24 hrs. for fail to run.
1HJ-AB-F04-ARFCC	CCF of both Essential Control Room Fans to start.	3.5E-5	The CCF rates are estimated as 10% (NUREG/CR-4550) of the random failure rates of 1.13E-6 (CX4FS + ARFFS) fail to start and 6E-6 fail to run. The mean exposure period is one-fourth month for fail to start and 24 hrs. for fail to run.
1HJ-AB-Z34-ARFCC	CCF to start of all four Control Bldg. Essential Switchgear and ESF Equipment Fans to start.	5.75E-3	The CCF rates are estimated as 42% (based on NUREG/ CR-4550 data) of the two train CCF rates above (see 1HJ-AB-F04-ARFCC) or as 4.7E-8/hr. for fail to start and 2.6E-7/hr. for fail to run. The mean exposure periods are 1.5 months and 24 hrs. respectively.
1HANCOMPRES-ARSCC	CCF of both Standby Air Compressors fail to start on demand.	3.9E-3	The CCF rate is estimated as 6.7E-7 (NUREG/CR-2098). The mean exposure period is estimated as 4 months.
1RPSBKRS-----2OP	Reactor trip fails due to failure of two series RTBs to open (event probability is dominated by common cause).	5.0E-6	The CCF probability was estimated as 10% of the random independent failure probability of 5E-5 (from CEN-0327).

Table 6.2-5 Bayesian Update Analysis Summary

PRA Identifier	Description	Prior Distribution Failure Rates Mean	Prior Distribution Failure Rates E.F.	Plant Specific Experience	Updated Distribution Mean	Updated Distribution E.F.
1AFAP01----TPAFS	Turbine Driven AF Pump fails to start.	5.6E-5/hr.	8	Seven failures in 130,000 pump hrs.	5.5E-5	2
1AFAP01----TPAFR	Turbine Driven AF Pump fails to run.	4.9E-5/hr.	12	Two failures in 887 pump run hrs.	6.8E-4	3
1AFBP01----MPAFS 1AFNP01----MPAFS	Motor Driven AF Pumps fails to start (excludes command faults).	5.7E-6/hr.	2	Zero failures in 260,000 pump hrs.	4.7E-6	2
1AFBP01----CX5FS	Motor Driven AF (AFBP01) Control Circuit fails to close associated breaker.	1.3E-5/hr.	3	Zero failures in 260,000 pump hrs.	5.4E-6	3
1AFBP01----MPAFR	Motor Driven AF Pumps fails to run (includes command faults).	1.3E-5/hr.	10	Three failures in 11,000 pump run hrs.	1.3E-4	3
1PEAG01-DG---2FS 1PEBG01-DG---2FS	Diesel Generator fails to start (DG output breaker considered separately).	2.1E-2/d	3	Four failures in 646 demands.	7.9E-3/d	2
1PEAG01-DG---2FR 1PEBG01-DG---2FR	Diesel Generator Fails to run.	3E-3/hr.	3	Three failures in 1400 run hrs.	< 3E-3 (see note)	3

Note: For purposes of the PRA, a DG fail to run rate of 3.2E-3/hr. was utilized.

Table 6.2-6 Maintenance Unavailability Data

Basic Event Name/ Components Affected	Description	Maintenance Unavailability Probability	Comments
1AFAP01----TP6CM	Turbine Driven AF pump unavailable due to maintenance	3.9E-3	Based on plant specific experience: 73.5 unavailable hrs. in 18,700 Mode 1 hrs.
1AFBP01----MP6CM 1AFNP01----MP6CM	Motor Driven AF pump unavailable due to maintenance	2.5E-3	Based on plant specific experience: 94.0 unavailable hrs. in 37,300 Mode 1 pump hrs.
1CDNP01A---MP8CM 1CDNP01B---MP8CM 1CDNP01C---MP8CM	Condensate pump unavailable due to maintenance	2.1E-3	Based on plant specific experienced: 119 unavailable hrs. in 56,000 Mode 1 pump hrs.
1ECAP01----MP6CM 1ECBP01----MP6CM	Essential Chill Water pump unavailable due to maintenance	1.0E-3	Based on plant specific experience: 38 unavailable hrs. in 37,300 Mode 1 pump hrs.
1HJA-F04--AR6CM 1HJB-F04---AR6CM	Control Room Essential HVAC fans unavailable due to maintenance	4.0E-4	Maintenance Rate estimated as 1E-5/hr. (Appendix 6.C). MTTR estimated as 40 hrs. (Oconee PRA Table B-45B, 7 day LCO).
1HJAZ03---AR6CM 1HJB-Z03---AR6CM	Essential ESF Switchgear HVAC fan/ ACU unavailable due to maintenance	2.1E-4	Maintenance rate estimated as 1E-5/hr. (Appendix 6.C). MTTR estimated as 21 hrs.
1HJN-A01---AR8CM 1HJN-A02---AR8CM 1HJN-A03---AR8CM	Normal Control Bldg., normal Control Room, or normal ESF Switchgear Room fan/ACU units unavailable due to maintenance	1.3E-3	Maintenance rate estimated as 6.4E-5/hr. normally operating fan (Appendix 6.C). MTTR estimated as 20 hrs. since discussion with maintenance indicated that they receive high maintenance priority similar to if 72-hr. LCO applied.
1PEAG01----DG-CM 1PEBG02----DG-CM	Diesel Generator unavailable due to maintenance	6.0E-3	Maintenance unavailability from NUREG/CR-2989, page 28.
1SAALT203A-ITCM	One of four channels of RWT level instrumentation unavailable due to maintenance or test	2.0E-3	Only one channel may be placed in bypass. Level transmitter maintenance rate estimated as 4.4E-6/hr. (Oconee PRA page B-15). MTTR estimated as 116 hrs. (Oconee, page B-89).

Table 6.2-6 Maintenance Unavailability Data (Continued)

Basic Event Name/ Components Affected	Description	Maintenance Unavailability Probability	Comments
1SAAPT102A-IT2CM	One of four channels of RCS pressure transmitters (used for SIAS) unavailable due to maintenance	0.076 (.019 per channel)	Only one channel may be placed in bypass at a time. Pressure transmitter maintenance rate estimated as 2.9E-6/hr. (Oconee PRA, page B-15). MTTR conservatively estimated as 9 months (located inside containment).
1SAAT1113A-IT2CM 1SAAT1123A-IT2CM	One of four channels of SG low level transmitters on SG 1 (1113) or SG2 (1123) unavailable due to maintenance	0.116 (0.029 per channel)	Only one channel may be placed in maintenance at a time. Level transmitter maintenance rate estimated as 4.4E-6/hr. (Oconee PRA, B-15). MTTR conservatively estimated as 9 months (located inside containment).
1SAAPT352A-IT2CM	One of four channels of Containment Pressure Transmitters, unavailable due to maintenance	1.35E-3	Only one channel may be placed in bypass at a time. Transmitters are located outside containment. Maintenance rate estimated as 2.9E-6/hr. (Oconee PRA, page B-15). MTTR estimated as 116 hrs. (located outside containment, Oconee, page B-89).
1SIAP01----MP6CM 1SIBP01----MP6CM 1SIAP02----MP6CM 1SIBP02----MP6CM 4SIAP03----MP6CM 4SIBP03----MP6CM 1EWAP01----MP6CM 1EWBP01----MP6CM 1SPAP01----MP6CM 1SPBP01----MP6CM	ECCS pump (HPSI, LPSI or Containment pump), Essential Spray Pond pump, or Essential Cooling Water pump unavailable due to maintenance	1.3E-3	Estimated based on plant specific data (1988). Calculated number is generally consistent with NUREG-1150 (2E-3).

Table 6.2-6 Maintenance Unavailability Data (Continued)

Basic Event Name/ Components Affected	Description	Maintenance Unavailability Probability	Comments
Various SI & AF MOVs, SG ADVs, and Turbine driven AF stream supply MOVs (basic events ending with MV9CM or AV9CM).	Remotely operated valve unavailable due to maintenance	5.88E-4	Maintenance rate estimated as 2.75E-5/hr. (Oconee PRA, Table B-41). MTTR estimated as 21 hrs. (Oconee, Table B-44B). Review of plant specific data (1988) indicates that PVNGS MOV maintenance unavailability is consistent with or less than the unavailability calculated here.
Various HVAC dampers, assigned type code/failure mode DM9CM	Damper unavailable due to maintenance	5.88E-4	Estimated same as MOV maintenance unavailability above.
Various Critical Circuit Breakers-AF, EC, EW, SP, SI Pump Breakers, Essential Chiller Breakers, ESF Transformer Breakers, DG output Breakers, PBAS03 and PBBS04 Normal Supply Breakers, Battery Charger Supply Breakers, NNND11, NNND12 Voltage Regulator Breakers, NHNM71 Supply Breaker	Circuit Breaker unavailable due to maintenance	8.74E-5	The maintenance rate was estimated as 9.4E-6/hr. Catastrophic failure rate estimated as 2.85E-6 (PVNGS data table) x 3.3 to include incipient faults. MTTR estimated as 9.3 hrs. (IEEE-500, page 109).
1PKAM4102--CB0CM 1PKBM4202--CB0CM 1PKCM4302--CB0CM 1PKDM4402--CB0CM	Class Battery Output Circuit Breakers unavailable due to maintenance	1.9E-5	Maintenance rate estimated as 9.4E-6/hr. (see pump motor breakers above). MTTR estimated as 2 hrs. (2 hr. LCO).

Table 6.2-6 Maintenance Unavailability Data (Continued)

Basic Event Name/ Components Affected	Description	Maintenance Unavailability Probability	Comments
Various Non-class Circuit Breakers. Type code/failure mode is CB0CM. Includes NANS01,NANS02, NANS03B, NANS04B, NANS05B, NANS06H, NANS06K, NHM2118, NHNM0802, NHNM0317 and NKNM4502.	Non-class power circuit breaker unavailable due to maintenance	1.5E-4	Maintenance rate estimated as 9.4E-6/hr. (see pump motor/ breakers above). MTTR estimated as 16 hrs., based on the fact that although these circuit breakers are not covered by Technical Specification limits, they are important to the normal distribution of power and receive high maintenance priority.
Class Circuit Breaker, with 8 hr. technical specification LCO limit. Includes power distribution breakers on the following buses: PBAS03, PHAM31 PBBS04, PHAM33 PGAL31, PHAM35 PGAL33, PHAM37 PGAL35, PHBM32 PGBL32, PHBM34 PGBL34, PHBM36 PGBL36, PHBM38	Class power circuit breaker unavailable due to maintenance	6.58E-5	Maintenance rate estimated as 9.4E-6/hr (see pump motor breakers above). MTTR estimated as 7 hrs. (Technical Specification 3.8.3 limits outage time to 8 hrs).

Table 6.2-6 Maintenance Unavailability Data (Continued)

Basic Event Name/ Components Affected	Description	Maintenance Unavailability Probability	Comments
Non-class Electrical Bus unavailable. Includes the following buses: NANS03, NGNL06 NANS04, NGNL13 NANS05, NGNL25 NANS06, NHNM43 NGNL01, NHNM08 NGNL02, NHNM10 NHNM13, NHNM19 NHNM21, NHNM28 NHNM50, NHNM71 NKND41, NKND42	Non-class Electrical Bus unavailable due to maintenance	3.48E-5	The maintenance rate was estimated as 1.3E-6/hr. The catastrophic failure rate is 8.3E-7/hr (failure data table). This valve was multiplied by 1.5 to include incipient faults (IEEE-500, page 811). The MTTR was estimated as 26.8 hrs. (IEEE-500, page 810).
Class Electrical Bus unavailable (8 hr LCO). Includes the following buses: PBAS03, PBBS04 PGAL31, PGAL35 PGBL32, PGBL34 PGBL36, PHAM31 PHAM33, PHAM35 PHAM37, PHBM32 PHBM34, PHBM36 PHBM38, PGAL33	Class AC Electrical Bus unavailable due to maintenance	9.1E-6	The maintenance rate was estimated as 1.3E-6/hr. (see above). The MTTR was estimated as 7 hrs. (8 hr. LCO).

Table 6.2-6 Maintenance Unavailability Data (Continued)

Basic Event Name/ Components Affected	Description	Maintenance Unavailability Probability	Comments
1PKBH12----BX0CM 1PKBH16----BX0CM 1PKAH11----BX0CM 1PKAH15----BX0CM 1PKCH13----BX0CM 1PKDH14----BX0CM	Class Battery Charger unavailable due to maintenance	1.0E-4	Maintenance rate established as 9.2E-6/hr. (three times the random catastrophic rate of 3.1E-6/hr.). MTTR estimated as 11 hrs., (consistent with IEEE-500, given maintenance priority these components receive).
1PKAF11----BA0CM 1PKBF12----BA0CM 1PKCF13----BA0CM 1PKDF14----BA0CM	Class Battery unavailable due to maintenance	4.0E-6	Maintenance rate estimated as 2.0E-6/hr. (IEEE-500-1984, page 89). MTTR estimated as 2 hrs. (2 hr. LCO).
1PKCD23-125BS0CM 1PKCM43-125BS0CM 1PKDD24-125BS0CM 1PKDM44-125BS0CM	Class DC Bus or Distribution Panel unavailable due to maintenance	2.6E-6	Maintenance rate estimated as 1.3E-6/hr. (see non-class bus entry). MTTR estimated as 2 hrs. (2 hr. LCO).
1HJA-M23---DM9CM 1HJA-M51---DM9CM 1HJA-M62---DM9CM 1HJA-M66---DM9CM 1HJB-M31---DM9CM 1HJB-M58---DM9CM 1HJB-M66---DM9CM	Control Building HVAC Dampeners unavailable due to maintenance	5.9E-4	Maintenance rate estimated as 2.75E-5/hr. (Oconee PRA, Table B-41). MTTR estimated as 21 hrs. (Oconee, Table B44-B).
1IAN-C01B--AR7CM 1IAN-C01C--AR7CM	Instrument Air Compressors unavailable due to maintenance	1.5E-2	Maintenance rate estimated as 1.3E-4/hr. (Oconee, Table B-39). MTTR estimated as 116 hrs. (Oconee, Table B-46B).

Table 6.2-6 Maintenance Unavailability Data (Continued)

Basic Event Name/ Components Affected	Description	Maintenance Unavailability Probability	Comments
1ECAE01----AR7CM 1ECBE01----AR7CM	Essential Chiller unavailable due to maintenance	2.7E-3	Maintenance rate estimated as 1.3E-4/hr. (Oconee, Table B-39). MTTR estimated as 21 hrs. (Oconee, Table B-44B, 72 hr. LCO).
1PNAN11-125IN0CM 1PNBN12-125IN0CM 1PKCN43-125IN0CM 1PKDN44-125IN0CM	PNA or PNB Power supply inverter (125V DC to 120V AC) unavailable due to corrective maintenance. Shutdown cooling valve UV-653, UV-654 power supply inverters (125V DC to 120V AC) unavailable due to maintenance.	3.3E-3	Maintenance rate estimated as 3.0E-4/hr. (The inverter failure rate of 1.0E-4/hr. was multiplied by factor of 3 to account for incipient and degraded failures). MTTR was estimated as 11 hrs. (Oconee PRA, Reference 6.3.1, Table B-43B, 24 hr. LCO applies).
1PNAV25-480VR0CM 1PNBV26-480VR0CM	PNA or PNB Power Supply Voltage Regulator (Backup Power Supply for PNA/PNB) unavailable due to maintenance.	4.2E-4	Maintenance rate estimated as 9.2E-6/hr. (same as class battery changes above). MTTR was estimated as 48 hrs. (Although outage time is not limited by Technical Specification, these items receive sufficient priority that a MTTR slightly greater than what the Oconee PRA Table B-45B recommends for components with a week LCO was judged reasonable.)
1SIAE01----HX9CM 1SIBE01----HX9CM	Shutdown Heat Exchanger unavailable due to maintenance.	5.9E-4	Maintenance rate estimated as 2.8E-5/hr. (Appendix 6.C). MTTR was estimated as 21 hrs. (Oconee PRA, Table B-44B, 72 hr. LCO applies).

Table 6.2-7 Special Event Quantification

Identifier	Description	Probability	Comments
1MTC-UNFAV--TT-EE (ATWS event sequences with successful turbine trip, and success of at least one AF pump.	Reactor pressure exceeds 3200 psi following a loss of FW ATWS with turbine trip. If a loss of FW ATWS occurs early in life, but turbine trip does occur and MTC is less negative than -0.61×10^{-4} $\Delta\rho/°$ F, Accident Analysis (CENTS) has shown that 3200 psi would be exceeded.	0.032	A loss of FW event is limiting ATWS (CENPD-158), per CE analysis (CENTS). The percentage of time that MTC is less negative than $-0.61 \times 10^{-4} \Delta\rho/°$ F, was estimated as 3.3% from typical PVNGS core data (cycle dependant).
1MTC-UNFAV----EE (ATWS event sequences without turbine trip and success of at least one AF pump).	Reactor pressure exceeds 3200 psi following a loss of FW ATWS without turbine trip. If a loss of FW ATWS occurs early in the fuel cycle life with MTC less negative than $-0.77\Delta\rho/°$ F, accident analysis (CENTS) has shown that 3200 psi would be exceeded.	0.11	A loss of FW ATWS is the limiting ATWS event (CENPD-158). The percentage of time that MTC is less negative than $-0.77\Delta\rho/°$ F, was estimated as 11% (cycle dependant).
1RPSSIGNAL--2OP	RPS & SPS Reactor Trip Signals Fails	2.0E-8	The probability of failure of RPS Circuitry/ Sensors was estimated as 4.8E-6. The electrically diverse SPS circuitry was assessed a probability of failure of 1.0E-3. Common mode failure of the shunt trip coils and undervoltage trip coil, contributed an additional 1.5E-8.
1RPS-RODDROP-2OP	Failure of sufficient control rods to drop to prevent approaching ASME Class C limits, given a loss FW ATWS with unfavorable MTC and the CEDMs de-energized.	2.6E-6	Event probability was estimated as 2.6E-6. Consistent with CE NPSD-672 recommended value of 2.1E-6.
1PSRV-OPEN---2OP	The probability that one or more of the four PSVs fails to reclose following lifting (steam relief).	0.020	The probability that a single PSV fails to reseat following steam relief was estimated as 4.9E-3 (Table 6.2-1).

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
1PSRV-AL4OPN-20P	One or more of the four primary safety valves (PSVs) fails to open. Failure of one or more PSVs to open, was conservatively assumed to result in primary overpressurization.	1.2E-3	The probability that a single PSV fails to open is 3E-4 (Table 6.2-1).
1AFAP01-N0BAC-2OP	AF Pump AFAP01 (Turbine Driven AF Pump) fails to run 24 hrs. with no room HVAC available.	0.037	All Turbine driven AF components are heat resistent. The turbine driven pump is cooled by the water it pumps, and the turbine generator is qualified by test to 200° F. With no room cooling the analysis has shown that room temperatures approaching 190° F could occur <u>only</u> after 24 hrs. To account for the increased failure rate that may occur as temperature increases, the 95th percentile fail to run rate of 1.55E-3/hr. was utilized (from Table 6.2-5), resulting in failure probability of 3.7E-2.
1AFBP01-BAC--20P	AF Motor Driven Pump fails to run 24 hrs. given essential room cooling is unavailable but normal HVAC is supplied.	7.3E-3	Engineering evaluation indicates a 24-hr. room temperature of 165° F, a motor bearing temperature of 244° F, and a winding temperature of 145° C. Based on discussions with the motor manufacturer and pump evaluation, the motor driven pump would not be expected to fail at these temperatures. The probability of failure was estimated by doubling the base motor driven pump failure rate (1.3E-5/hr., Table 6.2-1) for every 18° F increase in room temperature (Arrhenius Equation) and consideration of increased winding failure rates.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
1AFBP01-NOBAC2OP	Motor Driven AF Pump AFBP01 fails to run 24 hrs. with no room HVAC.	0.5	Based on discussion with the motor manufacturer, significantly increased failure rates may occur if motor bearing temperature exceeds 250° F. For initial concrete temperatures of more than 85° F, analysis has shown that a motor bearing temperature of 250° F may be exceeded within 24 hrs. The event probability was conservatively estimated as 0.5, as during the summer months the initial concrete temperature can be greater than 85° F. For event sequences which contain this basic event, the pump is likely to run for the first 12 hrs., and was accounted for within the recovery analysis.
1EWAP01-BAC--2OP 1EWBP01-BAC--2OP	Essential Cooling Water Pump fails to run 24 hrs. A given essential room cooling is unavailable but the room door is open for 2 hrs. to provide some room cooling.	1.4E-2	Engineering evaluation indicates a 24-hr. room temperature of 168° F, a motor bearing temperature of 220° F, and a winding temperature of 144° C. Based on discussions with the motor manufacturer and pump evaluation, the motor driven pump would not be expected to fail at these temperatures. The probability of failure was estimated by doubling the base motor driven pump failure rate (2.1E-5/hr., Table 6.2-1) for every 18° F increase in room temperature (Arrhenius Equation) and consideration of increased winding failure rates.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
1EWAP01-NOBAC-2OP 1EWBP01-NOBAC-2OP	Essential Cooling Water Pump fails to run 24 hrs. given failure of essential cooling and backup cooling not supplied.	3.0E-2	Engineering evaluation indicates a 24-hr. temperature of 189° F, a motor bearing temperature of 241° F, and a winding temperature of 155° C. Based on discussion with the motor manufacturer the motor driven pump would not be expected to fail at these temperatures. The probability of failure was estimated by doubling the base motor driven pump failure rate (2.1E-5/hr., Table 6.2-1), for every 18° F increase in room temperature (Arrhenius Equation) and consideration of increased winding failure rates.
1SIAP02-BAC--2OP 1SIBP02-BAC--2OP	HPSI Pump fails to run 24 hrs. given essential room cooling is unavailable but the room door is open for 2 hrs.	1.7E-2	Engineering evaluation indicates a 24-hr. room temperature of 165° F, a motor bearing temperature of 197° F, and a winding temperature of 160° C. Based on discussions with the motor manufacturer and pump evaluation, the motor driven pump would not be expected to fail at these temperatures. The probability of failure was estimated by doubling the base motor driven pump failure rate (2.1E-5, Table 6.2-1), for every 18° F increase in room temperature (Arrhenius Equation) and consideration of increased winding failure rates.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
1SIAP02-NOBAC2OP 1SIBP02-NOBAC2OP	HPSI Pump fails to run 24 hrs. given essential room cooling is unavailable and backup cooling is not supplied.	5.3E-2	Engineering evaluation indicates a 24-hr. room temperature of 199° F, a motor bearing temperature of 239° F, and a winding temperature of 177° C. Based on discussions with the motor manufacturer and pump evaluation, the motor driven pump would not be expected to fail at these temperatures. The probability of failure was estimated by doubling the base motor driven pump failure rate (2.1E-5, Table 6.2-1), for every 18° F increase in room temperature (Arrhenius Equation) and consideration of increased winding failure rates.
1SIAP01-BAC--2OP 1SIBP01-BAC--2OP 1SIAP03-BAC-2OP 1SIBP03-BAC-2OP	LPSI or Containment Spray Pump fails to run 24 hrs. given essential room cooling is unavailable but the room door is opened at 2 hrs.	0.1	Engineering evaluation indicates a 24-hr. room temperature of 168° F, a motor bearing temperature (ball bearing design) of 262° F, and a winding temperature of 160° C. Based on Engineering evaluation, it is unlikely that the motor driven pump would fail at these temperatures. The probability of failure was set equal to 0.1 as a screening value.
1SIAP01-NOBAC2OP 1SIBP01-NOBAC2OP 1SIAP03-NOBAC2OP 1SIBP03-NOBAC2OP	LPSI of Containment Spray Pump fails to run 24 hrs. given essential room cooling is unavailable and backup cooling is not supplied.	1.0	Engineering evaluation indicates a 24-hr. room temperature of 189° F, a motor bearing temperature (ball bearing design) of 282° F, and a winding temperature of 172° C. The probability of failure was conservatively assumed equal to 1.0 since pump motor evaluation does not conclusively show that the motor bearing will continue to function at these temperatures.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
1LPA---LOP---2AT 1LPB---LOP---2AT	Sequencer Loss of Power/Load Shed (LOP/LS) Module fails to pass the DG start/DG Breaker close signal from the sequencer to K205 relay.	3.4E-6	LOP/LS solid state logic module failure rate was estimated as 8.0E-8/hr. (Table 6.2-1). Since only half the failures were assumed to prevent signal generation, the basic event failure rate was estimated as 4.0E-8/hr. The mean exposure period is 84 hrs. (weekly test).
1LPA---LOP---2SA 1LPB---LOP---2SA	Load Sequencer or LOP/LS Module causes a spurious LOP signal.	1.9E-6	The LOP/LS and load sequencer modules, were each estimated as having a failure rate of 8.0E-8/hr. (Table 6.2-1, solid state logic module). Since only half of the failures were assumed to result in spurious actuation, the failure rate was estimated as 8.0E-8/hr. Mean exposure period is 24 hrs.
1LSA--LDSHED-2SA 1LSB--LDSHED-2SA	Load sequencer or LOP/LS Module cause a spurious load shed signal.	1.9E-6	The LOP/LS and load sequencer modules, were each estimated as having a failure rate of 8.0E-8/hr. (Table 6.2-1, solid state logic module). Since only half of the failures were assumed to result in spurious actuation, the failure rate was estimated as 8.0E-8/hr. Mean exposure period is 24 hrs.
1LSA--LDSHED-2AT 1LSB--LDSHED-2AT	Load shed signal fails to clear due to sequencer or LOP/LS module fault.	6.7E-6	The LOP/LS and load sequencer modules, were each estimated as having a failure rate of 8.0E-8/hr. (Table 6.2-1, solid state logic module). Since only half of the failures were assumed to result in spurious actuation, the failure rate was estimated as 8E-8/hr. Mean exposure period is 84 hrs.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
ILPA-DETECT--2AT ILPB-DETECT-2AT	LOP/LS Module fails to provide DG start signal following a loss of power to the associated 4.16kV AC ESF bus.	3.4E-6	LOP/LS solid state logic module failure rate was estimated as 8.0E-8/hr. (Table 6.2-1). Since only half the failures were assumed to prevent signal generation the basic event failure rate was estimated as 4.0E-8/hr. Mean exposure period is 84 hrs. (weekly test).
ILPA1--LOP---2AT ILPB1--LOP---2AT ILPA2--LOP---2AT ILPB2--LOP---2AT	Load sequencer LOP Group 1 or Group 2 relay fails to de-energize given a LOP signal from LOP/LS module.	2.6E-3	Failure rate estimated as 4.0E-7/hr. (Table 6.2-1, RX-FT). Mean exposure period is 9 months.
ILSA1-LDSHED-2AT ILSB1-LDSHED-2AT ILSA2-LDSHED-2AT ILSB2-LDSHED-2AT	Load Sequencer Load Shed Group 1 or Group 2 relay (K202 or K204) fails to de-energize.	2.4E-4	Relay fail to transfer probability estimated as 2.4E-4 (WASH-1400). (Relay energizes on Load Shed and must subsequently de-energize).
ILSA1-LDSHED-2SA ILSB1-LDSHED-2SA ILSA2-LDSHED-2SA ILSB2-LDSHED-2SA	Spurious group Load Shed signal due to load shed relay (K202, K201) spurious energize.	1.0E-5	Relay spurious energize failure rate estimated as 4.3E-7/hr. (Table 6.2-1). Exposure period is 24 hrs.
ILSA-LDSHED-HISA ILSB-LDSHED-HISA	Spurious Load Shed occurs given cabinet cooling fans fail.	5.0E-1	PVNGS operating experience includes one instance where spurious load shed occurred due to insufficient BOP/ESFAS cabinet forced cooling flow. Loss of cabinet cooling was conservatively assumed to result in spurious Load Shed with a probability of 0.5.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
ISAA-LOADCHA-2AT ISAA-LOADCSI-2AT ISAA-LOADECA-2AT ISAA-LOADELI-2AT ISAA-LOADEWA-2AT ISAALOADHPI-2AT ISAA-LOADLPI-2AT ISAA-LOADSPA-2AT ISAB-LOADAFB-2AT ISAB-LOADCHB-2AT ISAB-LOADCS2-2AT ISAB-LOADECB-2AT ISAB-LOAD-EL2-2AT ISAB-LOADEWB-2AT ISAB-LOADHP2-2AT ISAB-LOADLP2-2AT ISAB-LOADLP2-2AT ISAB-LOADSPB-2AT	Load Sequencing Relays fail to de-energize (de-energize to actuate).	2.6E-3	Failure rate estimated as 4.0E-7/hr. (Relay fail to de-energize, from Table 6.2-1). Mean exposure period estimated as 9 months. (These relays are mechanically tested only during refueling outages).
SYFAULTSXM3--2PW SYFAULTSXM2--2PW	Faults in 525kV PVNGS switchyard, result in loss of the power supply feed from the aligned startup transformer.	4.4E-5	Based on PVNGS switchyard reliability study (1986).

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
ISAAAFS1A-K113FT ISAAAFS1A-K402FT ISAAAFS1A-K628FT ISAAAFS1A-K728FT ISAAAFS2A-K413FT ISAAAFS2A-K629FT ISAAAFS2A-K729FT ISAASIASA-K301FT ISAASIASA-K308FT ISAASIASA-K401FT ISAASIASA-K410FT ISAACSAA-K111FT ISABAFS1B-K402FT ISABAFS1B-K628FT ISABAFS1B-K728FT ISABAFS2B-K413FT ISABAFS2B-K629FT ISABAFS2B-K729FT ISABSIASB-K301FT ISABSIASB-K401FT ISABSIASB-K410FT ISABCSASB-K111FT	ESFAS (AFAS, SIAS, CSAS) Actuation Relays fail to de-energize. Relays are de-energized to actuate.	3.0E-4	Failure rate is 4.0E-7 from (Table 6.2-1). Mean exposure period is 31 days. Relays are tested every 62 days.
ISPURFWTRIP-2OP	All Main Feedwater Pumps trip within 30 min. of a reactor trip.	1.0E-1	Based on review of PVNGS plant trips and engineering judgement. Initiators which cause a FW trip take no credit for short term FW availability.
LOOP---------20P	Off-site power is lost following a reactor/ turbine trip.	2.7E-4	The probability that off-site power is lost within 24 hrs. of a reactor trip. (Reference 6.3.46).

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
ISAACSASA-K304FT ISAARASA--K312FT ISAARASA--K405FT ISAASIASA-K108FT ISAAAFSIA-K211FT ISAAAFS2A-K112FT ISABAFS1B-K211FT ISABAFS2B-K112FT ISABCSASB-K304FT ISABRASB--K312FT ISABRASB--K405FT ISABSIASB-K108FT	ESFAS Actuation Relay fails to transfer to de-energized state. Relays are de-energized to actuate.	2.6E-3	Failure rate is 4.0E-7/hr. from Table 6.2-1. Mean exposure period is 9 months.
LOOP-RECOVR1-2PW	This basic event represents the probability that off-site power is not restored within 60 min of a loss of off-site power event.	2.45E-1	From analysis of power recovery data (Appendix 6.B).
LOOP-RECOVR3-2PW	This basic event represents the probability that off-site power is not restored within 3 hrs of a loss of off-site power event.	6.15E-2	From analysis of power recovery data (Appendix 6.B).
LOOP-RECOVR7-2PW	This basic event represents the probability that off-site power is not restored within 7 hrs. of a loss of off-site power event.	1.0E-2	From analysis of power recovery data (Appendix 6.B).
LOOP-RECOVR12-2PW	This basic event represents the conditional probability of not restoring power within 12 hrs. given that power is not restored at 3 hrs.	3.0E-2	From analysis of power recovery data (Appendix 6.B). The probability of non-recovery is 6.15E-2 at 3 hrs. and 1.89E-3 at 12 hrs. Probability is calculated as 1.89E-3/ 6.15E-2.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
ISG-1-MSSVS--2OP ISG-2-MSSVS--2OP	Failure to open of all ten MSSVs on a single SG.	6.1E-6	From Table 6.2-1, single MSSV fail to open probability was estimated as 3E-4. Conservatively assuming a Common Cause Beta of 0.02 (from NUREG/CR-2770; page 73; remote/motor operated valves), a common mode failure probability of 6.1E-6 was estimated.
ISA-MSIS-----2SA	This basic event represents the probability that an MSIS occurs following a reactor trip.	5.0E-2	Probability was based on engineering judgement and a review of plant trip data.
IMSIV-1A---MV-FC IMSIV-2A-----MV-FC	MSIV fails to close.	2.2E-3	Based on NPRDS data on MSIV Reliability and PVNGS test frequencies.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
ISAALT203A-IB2FT ISABLT203B-IB2FT ISACLT203C-IB2FT ISADLT203D-IB2FT ISAAPT102A-IB2FT ISABPT102B-IB2FT ISACPT102C-IB2FT ISADPT102D-IB2FT ISAAT1113A-IB2FT ISABT1113B-IB2FT ISACT1113C-IB2FT ISADT1113D-IB2FT ISAAT1123A-IB2FT ISABT1123B-IB2FT ISACT1123C-IB2FT ISADT1123D-IB2FT ISAAPT352A-IB2FT ISABPT352B-IB2FT ISACPT352C-IB2FT ISADPT352D-IB2FT	ESFAS signal trip bistable fails to transfer.	1.1E-3	Failure rate estimated as 2.9E-6/hr. (Table 6.2-1). Mean exposure period is one half month.
ICEA-STUCK---2OP	Most reactive rod fails to insert into core following a steam line break given that CEDMs are de-energized.	3.04E-5	If most reactive rod fails to insert, HPSI (boration) may be required to prevent return to power. Review of industry data indicates a probability of 3.04E-5 (C-E System 80™ PRA, CE NPSD-672).
IHAAHVACAF--2OP IHABHVACAF--2OP	AF pump room HVAC fan fails to either start, or fails to run for 24 hrs.	2.7E-3	The probability that the AHU fan fails to start/run was estimated as 1.8E-3 (monthly test, control circuit is CX5FS). Other faults (Corrective Maintenance, Manual Valve Faults) add an additional 9E-4.

Table 6.2-7 Special Event Quantification (Continued)

Identifier	Description	Probability	Comments
HHAAHVACCSS--2OP HHABHVACCSS--2OP HHAAHVACHPS--2OP HHABHVACHPS--2OP HHAAHVACLPS--2OP HHABHVACLPS--SOP HHAAHVACEWS--2OP HHABHVACEWS--2OP	ECCS pumps (HPSI, LPSI and CS) or ECW pump room HVAC fan either fails to start or fails to run for 24 hrs.	3.4E-3	The probability that the AHU fan fails to start/ run was estimated as 2.5E-3 (quarterly test control circuit is (CX6FS). Other faults (Corrective Maintenance and Manual Valve Faults) adds on additional 9E-4.
IGANSYSTEM--2OP	Nitrogen System fails to provide Instrument Air pressure following an event which results in loss of the Instrument Air compressors.	1.0	Since the nitrogen supply does not have sufficient capacity to maintain instrument air pressure for more than several hours, the probability of failure was conservatively assumed equal to 1.0.

Table 6.2-8 PRA Event Naming Convention

The PVNGS PRA utilizes a 16-character basic event identifier to represent each of the fault tree basic events. Each basic event has the general form of:

IAFA COMPIDX TYPFM

where:

- The first character is a unit identifier and is normally a one, except for certain recirculation related events which were assigned the number four.
- The second and third characters are a system code. Commonly used codes include the following:

AF -	Auxiliary Feedwater System
CH -	Chemical and Volume Control System
EC -	Essential Chilled Water System
EW -	Essential Cooling Water System
GA -	Service Gas System (Nitrogen)
HA -	Auxiliary Building HVAC System
HJ -	Control Building HVAC System
NA -	Non-class 13.8kV Power System
PB -	Class 1E 4.16kV Power System
PH -	Class 1E 480V Power System
PE -	Class 1E Standby Power Generation System
PK -	Class 1E 125V DC Power System
PN -	Class 1E 120V AC Power System
NN -	Non-class 1E 120 V AC Power System
SA -	Engineered Safety Features Actuation System
SG -	Steam Generator/Main Steam Generation System
SI -	Safety Injection System
SP -	Spray Pond System

Table 6.2-8 PRA Event Naming Convention (Continued)

- The associated component train is designated by the fourth character. PVNGS Engineered Safeguards Systems normally have two trains (A and B), although certain systems such as PK and PN have four trains (A, B, C, and D). Non-class and non-safety related components are normally not train related, and are assigned an N as the fourth character.
- The fifth through eleventh characters (COMPIDX in the above example) designate the component identification. AF valve HV-30, for example, is assigned a code HV0030-.
- The twelfth and 13th characters are a component type code; the 14th character is a subgroup designator which is utilized when necessary. Commonly used codes include the following:

MV#	Motor Operated Valve (Subgroup #)
MP#	Motor Driven Pump (Subgroup #)
CB#	Circuit Breaker (Subgroup #)
DM#	HVAC Damper (Subgroup #)
CX#	Control Circuit (Subgroup #)
BS#	Electrical Bus (Subgroup #)
DG -	Diesel Generator
BA#	Battery Charger
BX -	Battery

- The last two characters (FM in the example above) are a failure mode code. Commonly used failure mode codes are:

FO:	Fails to Open
FC:	Fails to Close
FT:	Fails to Transfer
RO:	Fails to Remain Open
FS:	Fails to Start
FR:	Fails to Run
CC:	Common cause Failure Event
HR:	Operator Error Event (Remote Operation)
HL:	Operator Error Event (Local Operation)
CM:	Equipment Unavailable for Maintenance

Appendix 6.A

Common Cause Failure Probabilities

6.A.1 Introduction

This documentation provides the basis for the Common Cause Failure (CCF) modeling guidelines, the method of CCF quantification, and the selection of common cause (beta) factors.

6.A.2 Method and Data Sources

A review of the state-of-the-art literature on common cause failure modeling was performed to start this task. The Electric Power Research Institute (EPRI) work published in NUREG/CR-4780 was reviewed as a basis for the common cause failure analysis. NUREG/CR-4550, Volume 1, the methodology document, was also reviewed, as it is an acceptable basis for the PRA work. In addition, the CCF data documents published by EG&G, Inc. during the early 1980s were reviewed. Although these documents are principally data documents, they do contain information of CCF modeling methods.

In general, this evaluation found that methodology is secondary to availability and form of data. NUREG/CR-4780 confirms the secondary importance of method by concluding that within reason, any methodology, if executed properly, and judiciously, will give virtually the same qualitative answers, if the same input data is used, although the numerical answer might not be directly comparable. It was therefore not considered necessary to use the same calculational methods for all components, although the data manipulation and basic event modeling must be consistent throughout

Three constraints were encountered during this evaluation, which are unique to the PVNGS PRA:

1. The PVNGS PRA normally calculates failure probabilities as time dependent rather than using demand related failure probabilities for most components. This method requires knowledge of test intervals for all components. The CCF modeling is required to take this form.
2. The PVNGS PRA relies primarily on generic data. Most of the data is taken from the NUREG or Oconee PRA. In searching for the best CCF data, it was common to find that the CCF data for a given component was derived from a different source than the random independent data, and that the two data sources were not necessarily consistent with each other. This part of the task consisted of resolving inconsistencies between the CCF and the Random Independent Failure (RIF) data used for a given component.
3. The PVNGS PRA models command faults separately from component faults. In some cases, it is appropriate to model common cause command faults as well as component faults. It was therefore necessary to provide one CCF event that included all applicable faults. A further difficulty arose because some of the generic CCF data sources did not distinguish command faults.

The following documents were reviewed for this evaluation:

NUREG/CR-2770	Common Cause Failure Rates for Valves
NUREG/CR-2098	Common Cause Failure Rates for Pumps
NUREG/CR-3289	Common Cause Failure Rates for Instrumentation Assemblies
INPO 85-036	The Operational Performance of Auxiliary Feedwater Systems at US PWRs in 1980-1984.
CEN-0327	Combustion Engineering Generic PRA for C-E System 80™
NUREG/CR-4550	NUREG-1150 Methodology Document
NUREG/CR-4780	EPRI Methodology

6.A.2.1 Summary of Guidelines for Event Modeling

The documents listed above were reviewed for the availability of data to support common cause failure modeling. The existing common cause events in the PRA were also reviewed. The available data was compared with the events in the PRA and the guidelines in NUREG/CR-4780. The CCF modeling guidelines were then revised to be consistent and workable within the available data. The guidelines for the AF system components resulted from the plant specific evaluation of the AF system as discussed in Section 6.A.3.2 of this document. The guidelines are summarized below. They are discussed in more detail throughout the text.

1. Model CCF of all pump pairs. The probability of CCF for Fail to Start (FS) must include consideration of common cause contributions from those events representing command faults as well as the Motor Operated/Fail to Start (MP/

FS) event. CCF for Fail to Run (FR) should include command faults as well. Random independent command faults for FR are not modeled explicitly, but are generally included in the FR event. The CCF for FR can thus be related to only the random independent probability for FR.

2. Model CCF of the three AF pumps, but not the motors.
3. Model CCF of the B and the N AF pump motor, only.
4. Model CCF of all redundant, identical valve groups.
5. Model CCF of all redundant, identical check valve groups.
6. Do not model CCFs for any combinations of N-i components, where N is the minimum number of component failures needed to fail a function. Only model CCFs for the minimum number of components needed to fail the function.
7. Model CCF of instrumentation channels.
8. Model CCF of the 8/8 HPSI valves, the 4/4 LPSI valves, and the 2/2 CSS valves, but do not CCF any MOV combinations across these systems.
9. Model CCF of the check valve pairs in the discharge of the A and B AF pumps, but do not model combinations of these check valves with the ones in the downcomers or the main feedwater lines.

6.A.2.2 Rules for Data Selection

After the review of the data sources, a hierarchy of data usage was developed. These guidelines are intended to prioritize the data sources from good to bad.

1. No common cause factor will be greater than 0.1 unless convincing data exists to show otherwise. Common cause factor is intended to mean the ratio of the common cause failure probabilities to the total probability of all random independent failures applicable to a component.
2. For all systems, except auxiliary feedwater, the EG&G NUREG reports will be the preferred source of data for CCF factors, unless the EG&G data can be shown to be inapplicable or incorrect.
3. For components where the EG&G data is not acceptable, the beta factors from NUREG/CR-4550, Volume 1 will be the next preferred source of data.
4. Because the AF system at PVNGS possesses some true diversity between the A, B, and N pumps, a qualitative CCF analysis was performed for this system in accordance with guidelines in NUREG/CR-4780. This qualitative analysis defined to common cause failures which would be modeled, which in turn enables the data for them to be identified.

   For the AF components, the EG&G reports and the INPO report will be considered equal sources of data. The Institute of Nuclear Power Operations (INPO) report represents an accumulated exposure time equal to the EG&G pump reports of a newer vintage.
5. If all data sources were deemed inappropriate, or in some other way inapplicable, a beta factor of 0.1 was used. In no cases did this practice yield an unreasonable result.

6.A.2.3 Mathematical Calculation of CCF Probabilities

The three most common mathematical methods of common cause failure modeling are:

1. Beta factor method
2. Multiple Greek Letter method
3. Lethal shock/non-lethal shock

Detailed descriptions of these methods appear in the literature and will not be repeated here, other than a brief discussion to show how these relate to the PRA and how they relate to the data collection efforts.

The beta factor method was used in WASH-1400 study and has had considerable use since then. In this method, common cause failure probability is calculated to be a certain percentage of the random independent failure probability. Failure of successive components after the second is not considered. These components are considered to fail if the second one fails. When using this method, the random independent failure probability is not usually reduced by the beta factor.

The multiple Greek letter method is a natural enhancement of the beta factor method to account for failures of higher order components. In this method, the gamma, delta, and epsilon, (and so on) are used to account for the conditional probability of failure of the third, fourth, and fifth component, respectively. In this method, care is generally taken to distinguish between failure of exactly N components and failure of N or greater components. Naturally, this method provides more precise modeling of multiple failures, but also requires more data for accurate determination of each parameter. This method is the preferred method discussed in NUREG/CR-4780, but requires more extensive data collection and evaluation.

The lethal shock method is principally used in the EG&G NUREG reports published in the early 1980s. The data in these reports is not only correlated to fit the lethal shock method, but also correlated exclusively on a time dependent basis. The availability of hourly failure rates made these reports the most useful source of information to the Palo Verde PRA, although non-lethal shocks were not modeled.

Regardless of the modeling method chosen, a sanity check was made by comparing the common cause failure probability to the random independent failure probability to determine the magnitude of common cause failures.

The two most common calculational methods chosen for the PVNGS PRA were:

- To employ a simple beta factor for cases of two component failures
- To use a lethal shock number from an EG&G report for cases where more than two components had to fail.

6.A.2.3.1 CCF Events to be Modeled

The following common cause events were calculated to include contributions from the listed random independent failures.

Common Cause Event	Random Independent Events Included	
MP-CC	MP-FS	- fail to start, does not include command faults
	MP-FR	- fail to run including command faults
	CB-FT	- breaker fail to transfer
	CX-FT	- control circuit fail to function
MV-CC	MV-FO	- motor operated valve fails to open, does not include command faults
	CX-FT	- control circuit fail to function, included where data showed it to be important.
CV-CC	CV-FC	- check valve fails to open
ARF-CC	ARF-FS	- HVAC fails to start
	ARF-F	- HVAC fails to run
ARH-CC	ARH-FS	- chiller fails to start
	ARH-FR	- chiller fails to run

6.A.3 Development of Failure Rates for CCF

6.A.3.1 Summary of INPO AFW Study

The INPO study evaluated 48 auxiliary feedwater systems at nuclear plants over the years 1980 - 1984. The total exposure time was estimated at 48 systems *5 years * 8760hr./year = 2.1E+6/hr. A plant availability factor was not used in this calculation to be consistent with the exposure time calculation methods in the EG&G NUREGs.

The INPO report was written from an operation/availability perspective rather than from a PRA perspective. Thus, certain events that were considered failures in the INPO report would not necessarily be considered failures in the PRA sense. The INPO report lists 20 occurrences of unavailability of multiple pumps. These were categorized for retention as applicable to the PRA as follows:

- Five occurrences involving control failures were not retained because all the failures could have been mitigated by manual start of the pumps by the operator.
- Two occurrences of steam binding were considered applicable to the PRA.
- Three occurrences of undesired operator actions, which isolated steam or water valves were not retained for the PRA calculation. Pre-initiator restoration errors are modeled explicitly in the fault trees, where appropriate. Operator errors of commission during an accident are not included in PRA models.
- One control circuit design error was retained.
- One operator error was dismissed as highly recoverable.

- Three events involving instrument and control failures in the discharge valves were retained.
- Five other events involving instrument and control failures were retained.

There were no events where three AF pumps failed, but there were events where two motor driven pumps failed. The failures that were retained for possible application to PRA were further examined for their potential to cause a common cause failure of three or two pumps at Palo Verde. The failures were looked at in light of the design configuration of the AF system at Palo Verde:

- The steam binding failures were not considered applicable to Palo Verde because of the separation and isolation of the three pumps from each other.
- The control circuit design error was not considered applicable to Palo Verde because the N pump does not have auto actuation and the A and B pumps have different control circuits.
- The three instruments and control failures on the discharge valves were considered capable of causing failure of the Trains A/B, but not the Train N, because the Train N valves have diverse actuators and are manually actuated.
- The five other instrument and control failures involved pump start circuits. These are not considered capable of causing a failure of two or more pumps at Palo Verde because the N pump does not have any auto actuation and the A and B pumps have different control circuit types. Common cause failures of AFAS sensors and instrumentation is modeled explicitly in the fault trees.

Thus, all the events in the INPO study can be screened out as a potential common cause failure at Palo Verde. Although this leaves very little data upon which to calculate a CCF probability, it does provide affirmation that the AF configuration at Palo Verde does indeed provide substantial diversity.

6.A.3.2 Results of Plant Specific Evaluation of Auxiliary Feedwater

The supplies and sources of auxiliary feedwater at Palo Verde are unique when compared to a typical PWR. Although the PRA models auxiliary feedwater as on functional heading on the event tree, there is substantial diversity and redundancy in the components and systems that are capable of supplying feedwater after a reactor. Thus, it is important that the common cause failure modeling effort look closely at the components and systems included in the AF fault trees, and only model those components with true potential for common cause.

Auxiliary feedwater at Palo Verde can be supplied by

- Two safety class AF pumps of 500 gpm each. There is a turbine driven pump in the Train A and a motor driven pump in the Train B. These two pumps inject through two redundant parallel headers to the steam generators.
- One non-safety class motor driven pump of 500 gpm capacity. This pump is tested and maintained as a safety grade pump, but does not receive class 1E power directly. This pump has separate suction lines and injection lines

from the two safety grade pumps. This pump is called the N pump. Successful operation of the Train N requires non-safety grade air operated valves to open in the injection lines.

The common cause evaluation of the AF systems at Palo Verde found the following differences and similarities:

1. All three pumps (as distinguished from drivers) are of the same design and manufacture.
2. The driver for the B and N pumps are of the same design and manufacture, but the B pump driver is procured to safety quality standards while the N pump driver is not.
3. The N pump is located in a different building than the A and B pumps.
4. The N pump has entirely different suction lines from the Condensate Storage Tank (CST) than the safety grade pumps.
5. The N pump discharges through entirely separate lines to the steam generators than the A and B pumps. The discharge isolation valves on the N pump are of different design, manufacture, and motive supply than the discharge isolation valves on the A and B pumps. The A and B pumps discharge through 6 in. pipes all the way to the steam generator. The N pump discharge pipe is also 6 in., but expands to 8 in.
6. The N pump does not receive any automatic actuation signals. The A and B pumps receive SI and Auxiliary Feedwater Actuation Signal (AFAS) signals. The N pump is manually started under all conditions.
7. Due to complete piping separation in the suction and the discharge between the Trains A, B, and N, there is no potential for common steam binding of all three pumps. Additionally, since the A and B pump have:
   a) separate discharge headers,
   b) two closed isolation valves in the discharge headers, and
   c) separate suction lines back to the CST,

   there is no potential for common steam binding of the A and B pumps.

6.A.3.2.1 AF Common Cause Faults

After a review of the available data to support development of failure probabilities and consideration of the design features of the AF system listed above, the following guidelines were established for CCF modeling of the auxiliary feedwater systems:

1. The three AF pumps should have a common cause failure to include defects in manufacture, materials, maintenance, and design. There should not be any CCF due to air or steam binding, nor environmental effects.
2. The motor of the B and N pumps should have a common cause failure to include defects in manufacture, materials, maintenance, and design. There should not be any CCF for environmental effects, command faults or actuation faults.
3. There should not be any CCF actuation faults nor command faults of the A and B pump drivers. The drivers are diverse, the actuation is explicitly

modeled as AFAS, and the control circuits are diverse due to the diverse nature of the drivers.

4. There should be a common cause failure for 4/4 MOVs in the Train A and B discharge. It is not important if the globe valves or the gate valves are common cause failure. Any difference in valve failure probability between 4/4, 4/8, or 8/8 is beyond the scope of the present data base. The NUREG/CR-2770 data indicates that lethal shocks dominate common cause for MOVs. Thus, the failure probability for 4/8 is exceedingly low. In order to prevent double counting, only one term for 4/4 valves should be included. The success criteria requires four lines to fail to achieve complete system failure.
5. There should not be any common cause failures of the AOV discharge valves (1113 and 1123) with the MOV discharge valves in Trains A and B or CCF of valves 1113 and 1123 with HV-1143 and HV-1145. The reasons for these conditions are as follows:
   - FV-1113 and FV-1123 are of different size than the MOVs in A/B valves, (HV-1143 and HV-1145).
   - FV-1113 and FV-1123 have air actuators while UV 34-37, HV 30-33, and HV-1143/1145 have motor actuators.
   - FV-1123 and FV-1113 do not have control circuit faults whereas HV 30-33 and UV 34-37 have control circuit faults.
   - There are distinct differences between the valves which would rule out several causes of CCF. For example, HV-1143 and HV-1145 have different control circuits that HV 30-33, and are in different buildings.
   - The available data is not good enough to quantify those aspects of the valves that are subject to common cause failure.
   - If CCF of the six valves were postulated, failure of all AF would require two independent sets of common cause valve failures, which would likely be very much less than the CCF of all three pumps, which is explicitly modeled in the PRA.
6. There is no need to model CCF of the check valves in the downcomer lines because there is a single check valve failure which will fail the Train N.
7. There should be a term for common cause check valve failure in the Train A/B discharge, but not between the Trains A/B and N. There are three likely candidates for check valve failure in the Train A/B - V137/V138, V024/V016, V079/V080. If multiple check valve pairs are identified which require CCF analysis, then the mathematical problem of determining the difference between 2/2, 2/4, 4/6 and 2/6 must be addressed. Given the lack of data for check valves, it is recommended to model the check valve pair that has the longest test interval, and thus the highest failure probability.

6.A.3.3 Basis for Common Cause Failure Rates for Each Component

6.A.3.3.1 MOVs

Common cause failure rates for MOVs were developed form NUREG/CR-2770. Comparing the R2, R3, and R4 (Ri is the total probability of observing i component failures per unit time). This includes random independent failures, unsurvived non-lethal shocks, and lethal shocks. The Ri values are given for various total component numbers in the system. From the values for valve failures and command faults, on pages 72 and 73, it is apparent that:

a) lethal shocks dominate CCF for MOVs

b) command faults are very small contributors compared to valve faults. For greater than 3 valves, command faults are negligible.

c) the lethal shock rate is 7.1E-8/hr.

Thus the following rules for MOV CCFs were established:

1. Do not model N-i combinations of valves. Only model the worst (n/n) combination.
2. Use a lethal shock rate of 7.1E-8/hr. Note the test interval and the stagger if appropriate.

NUREG/CR-2770 specifies a random independent failure probability of 3.8E-6 for MOVs with command faults, 2.6E-6 without command faults, and a beta factor of 0.03.

The PRA uses 2.9E-6 for valve FO without command faults. Command faults including a circuit breaker and a control circuit for the typical MOV at PVNGS is about 2.9E-6 (NUREG/CR-1363). Thus, the use of a lethal shock rate of 7.1E-8/hr. gives a Palo Verde beta of about 0.025, which is comparable the NUREG/CR-2770 data.

6.A.3.3.2 Check Valves

Check valves are simple to evaluate because there are no command faults for check valves. The RIF data for check valves is 3E-8/hr. from NUREG/CR-1363. This data is used in the PRA. The CCF data from NUREG/CR-2770 specifies a lethal shock rate of 7E-8/hr. Obviously, these two data sources are inconsistent. The lethal shock rate calculated by NUREG/CR-2770 is driven by the limited population size and the absence of any common cause failure events.

This evaluation concluded that none of the sources reviewed have appropriate CCF data for check valves. Therefore, a simple beta factor of 0.1 will be applied to the PRA failure rate of 3E-8/hr., Thus, CCF is 3E-9/hr.

6.A.3.3.3 All Motor Driven Pumps Except AF pumps.

For random independent failure, the PRA uses data from NUREG/CR-1205, resulting in a rate of 2.1 E-5/hr. for failure to run with command faults and 1.0E-6/hr. for fail to start without command faults. The PRA explicitly models failure of command faults for fail to start, but does not explicitly model command faults for fail to run. Thus, the hourly rate for failure to run rightfully includes command faults.

In general, only one term for common cause failure of pumps is modeled in the PRA. It must therefore include appropriate contributions from command faults, fail to run faults, and fail to run command faults.

When comparing the suggested probabilities to NUREG/CR-1363 (i.e., the basis for the PRA) with the suggested probabilities in NUREG/CR-2098, several inconsistencies show up, even though the same component history was used for both studies. It appears that the data in 1363 was re-evaluated for 2098 by different rules and conventions.

Summary of guidelines for CCF of pumps:

a) RIF and CCF must compare such that the ratio CCF/RIF is less than 0.1, unless clear experience shows otherwise.

b) CCF shall include command faults for fail to start.

c) CCF shall include contribution for fail to run, including command faults.

d) If for some cases the RIF did not model command faults for pumps failing to run, the CCF for fail to run shall not include command faults.

e) As the same FS and FR rate is used for all pumps except AF, one CCF rate will be used for all pumps except AF.

The data in NUREG/CR-2098 for alternating and standby pumps were compared with each other and with the random independent failure data used in the PRA. The failure rate for 2/2 pumps CCF for FS was chosen as 2.1 E-7/hr., from NUREG/CR-2098, page 68, using the R2 value for alternating pumps, with command faults. The CCF rate for 4/4 pumps was similarly chosen as 7.5E-8, using the R4 value in NUREG/CR-2098. Random failure probabilities including the command faults, for pumps at Palo Verde, are about 1.2 E-6//hr. to 4.6E-6/hr., depending on the control circuit provided. Using a CCF of 2.1E-7/hr. provides a beta factor of 0175 to 0.046, which is reasonable. The alternating pump data was used instead of the standby pump data because the standby data of 6.7E-7/hr. would provide a beta of 0.56 to 0.15, which is significantly higher than those values generally found in the literature.

The CCF rate for 2/2 fail to run was taken to be 9.3E-7/hr from the same NUREG data. The CCF rate for 4/4 FR is 2.3E-7/hr.

6.A.3.3.4 Auxiliary Feedwater Pumps

After the qualitative analysis of the AF system was complete, it was obvious that special common cause failure rates would be needed for the AF pumps. Valves and check valves could use the CCF probabilities developed for the other components in the PRA.

The events that require special probabilities are:

- CCF of the two motor driven pump driver without command faults
- CCF of the three pumps (without drivers).

The first choice for AF pump data was NUREG/CR-2098. However, the numerical values in NUREG/CR-2098 are limited by the fact that there are no occurrences in the data base of failure for all AF pumps at a plant. There have been failures of two pumps and failures of one due to a potential common cause, but in the years surveyed for the NUREG, there were no occurrences of a complete AF failure due to a single cause. The NUREG method of calculation develops the lethal shock rate first and then fits the other parameters to be compatible with it. If there has never been a lethal shock, the value for omega is artificially high and all the other parameters are similarly biased by the lack of data.

The next choice of data was the INPO AFW report. The INPO report represents nearly as many plant years as the NUREG report. The INPO report is for the years 1980-1985, thus representing a newer population of plants with more current systems and operational conventions. NUREG/CR-2098 represents 2.3E+6 plant hrs. of operation. The INPO report represents 2.1E+6 plant hrs. of operation. The combined total of plant hrs. is 4.3E+6. The historical operating experience of no complete common cause feedwater system failures in this time provides a 50% Chi-squared estimate of 1.6E-7/hr.

For the 2/2 motor driven pump case, the data from NUREG/CR-2098 did not provide satisfactory rates for the AF circumstances. In fact, there was no satisfactory generic data base for the CCF of the B and N pumps. In order to find failure rates for the B and N pumps, a beta factor of 0.03 was subjectively chosen, based on the qualitative AF evaluation. The CCF for FS is 5.7E-6 * 0.03 = 1.7E-7/hr. and the CCF for FR is 1.3E-5 * 0.03 = 3.9E-7/hr. The 0.03 beta factor was subjectively chosen based on the lack of similarity in the two systems. Given that a 0.1 value for a beta factor is a generically acceptable screening value and these pumps have very little similarities, as discussed in Section 6.A.3.2, a value of 0.03 was considered adequate.

6.A.4 Results

6.A.4.1 CCF Rates

The following is a summary of CCF rates developed by this study.

Component	Number	Mode	Rate
MD PUMP, ARH	2/2	FS	2.1E-7
	2/2	FR	9.3E-7
	4/4	FS	7.5E-8
	4/4	FR	2.3E-7
MOV	2/2	FO	7.1E-8
	4/4	FO	7.1E-8
	6/6	FO	7.1E-8
	8/8	FO	7.1E-8
AF PUMPS	3/3	FS	1.6E-7
	B&N	FS	1.7E-7
	B&N	FR	3.9E-7
CHECK VALVES	X/X	FO	3E-9

Appendix 6.B

Statistical Analysis of NSAC-111 Data

One of the major recovery events considered in the PVNGS PRA is the probability of restoring the off-site power following a loss of off-site power (LOOP) event. For example, the study requires an estimate off-site power non-restoration probability at the PVNGS site, 1 hr. and 3 hrs. into a Station Blackout (SBO) Event.

The NSAC-111 report contains a list of 57 LOOP events which occurred at US nuclear power plants through 1986. Information presented in the report provides details on each incident, including the time that it took to restore off-site power.

Of the 57 LOOP events, seven of them describe conditions which are not likely to occur at the PVNGS, (e.g., ice, snow, and ocean salt spray). The remaining 50 events describe conditions which may also occur at the PVNGS.

Statistical analysis of the off-site power restoration data was carried out using W3, a three-parameter Weibull regression analysis computer program (Reference 6.3.50). A printout of the input data and analysis results are presented in Table 6.B-1. Although restoration times (Table 6.B-1) below 10 min. (data points I=1 to 11) were included in the calculation of the cumulative restoration probability, the regression analysis was limited to restoration times greater than 10 mins. This effectively limits the applicability of results to restoration times greater then 10 min.

The W3 program generated a Weibull distribution plot, the results of which are shown in Figure 6.B-1. Shaded triangles represent data points which are shifted in time by the Weibull parameter gamma; unshaded triangles, represent unshifted data points. The solid line drawn through the shaded triangles is the best-fit analytical equation of the time dependent off-site power restoration probability. The 5th and 95th percentile confidence levels bound the results.

From the above results, the analytical equation, e.g., correlation, which can be used to predict the off-site power non-restoration probability (P_{nr}) at the PVNGS site is,

$$P_{nr}(t) = \exp\{-[(t - 8.29)/28.4]^{0.57}\}$$

Restoration times within the correlation should be expressed in minutes. The correlation should not be used to calculate probabilities for power restoration times under 10 min.

Using the correlation to calculate non-restoration probability at 60 min. and 180 min. after LOOP, the probability of non-restoration of off-site power is estimated as 0.245 and 0.0615 respectively.

Table 6.B-1 Off-Site Power Restoration Printout of Input Data and Analysis Results

I	Input data: Time	Adjusted Time	Mean Rank	Best Fit
12	11.00	2.71	0.2353	0.2307
13	11.00	2.71	0.2549	0.2307
14	12.00	3.71	0.2745	0.2693
15	15.00	6.71	0.2941	0.3558
16	15.00	6.71	0.3137	0.3558
17	15.00	6.71	0.3333	0.3558
18	15.00	6.71	0.3529	0.3558
19	16.00	7.71	0.3725	0.3788
20	17.00	8.71	0.3922	0.3997
21	18.00	9.71	0.4118	0.4189
22	20.00	11.71	0.4314	0.4534
23	20.00	11.71	0.4510	0.4534
24	20.00	11.71	0.4706	0.4534
25	20.00	11.71	0.4902	0.4534
26	24.00	15.71	0.5098	0.5104
27	26.00	17.71	0.5294	0.5345
28	29.00	20.71	0.5490	0.5665
29	30.00	21.71	0.5686	0.5763
30	30.00	21.71	0.5882	0.5763
31	30.00	21.71	0.6078	0.5763
32	30.00	21.71	0.6275	0.5763
33	33.00	24.71	0.6471	0.6032
34	40.00	31.71	0.6667	0.6554
35	46.00	37.71	0.6863	0.6915
36	54.00	45.71	0.7059	0.7308
37	54.00	45.71	0.7255	0.7308
38	55.00	46.71	0.7451	0.7351
39	56.00	47.71	0.7647	0.7394
40	62.00	53.71	0.7843	0.7627

Table 6.B-1 Off-Site Power Restoration Printout of Input Data and Analysis Results (Continued)

Input data:		Adjusted		
I	Time	Time	Mean Rank	Best Fit
41	62.00	53.71	0.8039	0.7627
42	89.00	80.71	0.8235	0.8370
43	100.00	91.71	0.8431	0.8579
44	105.00	96.71	0.8627	0.8661
45	120.00	111.71	0.8824	0.8873
46	125.00	116.71	0.9020	0.8934
47	165.00	156.71	0.9216	0.9292
48	170.00	161.71	0.9412	0.9325
49	240.00	231.71	0.9608	0.9634
50	388.00	379.71	0.9804	0.9875
Results:				
Eta	Gamma	Beta	T-half	R2
2.84D+01	8.29D+00	5.70D-01	2.32D+01	9.88D-01

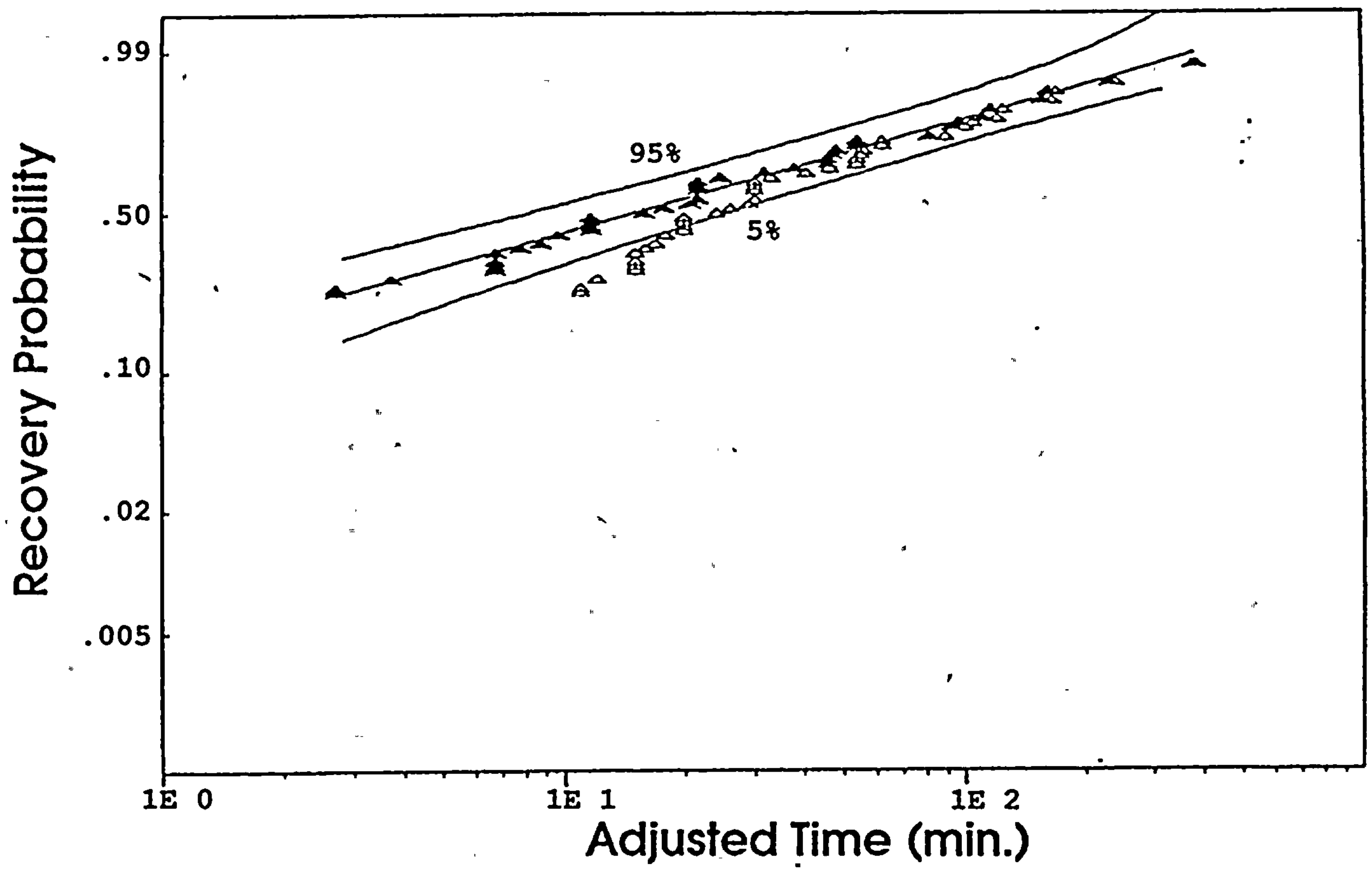

Figure 6.B-1

Off-site Power Recovery Probability as a Function of Time

Appendix 6.C

Unscheduled Maintenance Frequency Categories

6.C.1 Introduction

The PVNGS PRA probabilities for unscheduled maintenance unavailabilities are based upon the maintenance rates derived in the Oconee PRA (Reference 6.3.1). The maintenance rates utilized in the PVNGS PRA are summarized in Sections 6.C.2 through 6.C.4 below.

6.C.2 Standby Equipment with a Low Frequency of Maintenance

Distribution:	Standby Pumps Lognormal	Standby Fans Lognormal
5th percentile:	3.9×10^{-5} event/hr. (one event in 36 months)	4.7E-6/hr.
95th percentile:	1.5×10^{-4} event/hr. (one event in 9 months)	1.8E-5/hr.
Mean:	8.4×10^{-5} event/hr. (one event in 16.5 months)	1.0E-5/hr.
Variance:	1.4×10^{-9}	

Example PVNGS components:
Safety Injection Pumps (HPSI, LPSI, CS), AF Pumps, Standby Essential HVAC fans

Data Source:
Standby pump maintenance frequency was taken from Oconee PRA (Reference 6.3.1, Table B-40). The frequency of maintenance of standby fans was estimated as 12% of the standby pump rate. (A review of several failure data bases such as Seabrook PSS and the PVNGS failure data table indicates a standby fan failure rate of between 10 to 15% of the standby pump failure rate.)

These distributions generally apply to standby components that are tested regularly (usually monthly) and may be periodically removed from service for routine inspection and preventive maintenance (bearing inspection, lubrication repacking, motor checks, etc.).

6.C.3 Standby or Operating Equipment with Moderate Frequency of Maintenance

Distribution:	Lognormal
5th percentile:	5.8×10^{-5} event/hr. (one event in 24 months)
95th percentile:	2.3×10^{-4} event/hr. (one event in 6 months)
Mean:	1.3×10^{-4} event/hr. (one event in 11 months)
Variance:	3.1×10^{-9}

Example PVNGS components:
Charging Pumps, Instrument Air Compressors, Normal Chillers, Normal Chill Water Pumps.

Data Source:
Oconee PRA (Reference 6.3.1, Table B-39). This distribution generally applies to alternating service equipment. The frequency of maintenance for these components is higher than that for standby equipment because of the longer operating times, normal wear-out, more frequent minor repairs of leaks, vibration, etc., experienced with increased service.

6.C.4 Normal Operating Fans with High Frequency of Maintenance

Distribution:	Lognormal
5th percentile:	2.2×10^{-5} event/hr. (one event in 18 months)
95th percentile:	1.3×10^{-4} event/hr. (one event in 3 months)
Mean:	6.4×10^{-5} event/hr. (one event in 6.3 months)
Variance:	1.7×10^{-8}

Example PVNGS components:
Normally Operating HVAC Fans

Data Source:
The Oconee PRA (Reference 6.3.1, Table B-40) maintenance rate distribution for normally operating pumps was multiplied by a value of 0.29 to account for the relative frequency of fan maintenance versus pump maintenance. (From Table 6.2-1, the fan fail to run rate is approximately 29% of the motor driven pump fail to run rate.)

This distribution generally applies to normally operating equipment requiring relatively frequent routine maintenance. The nature of the equipment is such that unscheduled maintenance is required to repair coolant or lubrication leaks, adjust controls, and replace degraded subcomponents that contribute to impaired performance, but may not cause total component failure.

6.C.5 Power-Operated Valves, Standby-System Flow Paths

Distribution:	Lognormal
5th percentile:	1.9×10^{-5} event/hr. (one event in 6 years)
95th percentile:	3.8×10^{-5} event/hr. (one event in 3 years)
Mean:	2.8×10^{-5} event/hr. (one event in 4.2 years)
Variance:	3.4×10^{-11}

Example PVNGS components:
Shutdown Heat Exchangers, Motor Operated Valves

Data Source:
From Oconee PRA (Reference 6.3.1, Table B-41)

This distribution generally applies to components requiring relatively infrequent maintenance or components that can be maintained without functionally affecting system availability during non-cold shutdowns. Components included in this category are generally passive or require maintenance that can be performed with the system aligned normally or can be postponed until scheduled unit outages.
The decay-heat removal (DHR) heat exchangers generally require infrequent maintenance to repair minor leaks and inspect tubes. It is often preferable to perform this maintenance during unit operation because these heat exchangers are used only during cold shutdowns. Power-operated valves are removed from service periodically for minor packing adjustments or other repairs; however, most major valve maintenance is normally performed during scheduled shutdowns.

Appendix 6.D

PVNGS Data Base

The following table lists the failure events used within the PRA Model.

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1ADV-OPEN----2OP	ADV FAILS TO CLOSE AFTER DEMAND (STEAM RELIEF)		10.000	1.0E-003	D	Calculated	1.0E-003
1ADV-SGTR----2HR	OPERATOR FAILS TO USE ADVS TO REMOVE STEAM FROM RUPTURED SG		5.000	3.0E-001	D	Calculated	3.0E-001
1AF-0123---MV-CC	CCF TO OPEN OF 4/4 GLOBE DISCHARGE MOVS HV-30, 31, 32, 33		30.000	2.6E-005	D	Calculated	2.6E-005
1AF-ABN----MP-CC	COMMON CAUSE FAILURE TO START & RUN OF AFW PUMPS A, B, & N		11.000	1.9E-005	D	Calculated	1.9E-005
1AF-BN-----MP-CC	COMMON CAUSE FAILURE TO START & RUN OF AFW PUMPS B & N		11.000	4.5E-05	D	Calculated	4.5E-005
1AF-MAN-OPEN-2HR	OPERATOR FAILS TO MAN, LOCALLY OPEN PKC-POWERED VALVES ON LOSS OF PKC		10.000	7.0E-003	D	Calculated	7.0E-003
1AFA48-----MV-CC	BOTH STEAM SUPPLY MOV'S FAIL TO OPEN DUE TO COMMON CAUSE (UV-134 & UV-138)		4.000	1.3E-003	D	Calculated	1.3E-003
1AFABV137-8CV-CC	CHECK VALVES V137, V138 FAIL TO OPEN - COMMON CAUSE		5.000	1.1E-006	D	Calculated	1.1E-006
1AFABV79-80CV-CC	CHECK VALVES V079 & V080 FAIL TO OPEN - COMMON CAUSE		5.000	2.0E-005	D	Calculated	2.0E-005
1AFAHV0032-CX0FO	MOV HV-32 FAILS TO OPEN (CONTROL CIRCUIT FAULT)	2.9E-006	3.000	730.000	H	Test Period	1.1E-003
1AFAHV0032-MV-FO	MOV HV-32 FAILS TO OPEN (MECHANICAL FAULT)	2.9E-006	14.000	730.000	H	Test Period	1.1E-003
1AFAHV0032-MV9CM	MOV HV-32 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1AFAHV0054-MV-RO	MOV HV-54 FAILS TO REMAIN OPEN	2.3E-007	9.000	730.000	H	Test Period	8.4E-005
1AFAHV0054-MV9CM	MOV HV-54 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFAP01----TP6CM	AFW PUMP AFA-P01 UNAVAILABLE DUE TO MAINTENANCE		5.000	3.9E-003	D	Plant Specific	3.9E-003
1AFAP01----TPAFR	TURBINE DRIVEN AFW PUMP AFA-P01 FAILS TO RUN (24 HOURS)	4.9E-005	3.000	24.000	H	Mission Time	1.6E-002
1AFAP01----TPAFS	TURBINE PUMP AFAP01 FAILS TO START (LOCAL MECH OR CNTL FAULT)	5.6E-005	2.000	730.000	H	Test Period	2.0E-002
1AFAP01-2H-TPAFR	TURBINE DRIVEN AFW PUMP FAILS TO RUN (2 HOURS)	4.9E-005	3.000	2.000	H	Mission Time	1.4E-003
1AFAP01-NOBAC2OP	AFW A PUMP FAILS TO RUN 24HRS GIVEN FAILURE OF BOTH ESS AND NORMAL HVAC		10.000	3.7E-002	D	Calculated	3.7E-002
1AFAUV0037-CX0FO	MOV UV-37 CONTROL CIRCUIT FAULT (FAILS TO OPEN)	2.9E-006	3.000	1488.000	H	Test Period	2.2E-003
1AFAUV0037-MV-FO	MOV UV-37 FAILS TO OPEN LOCAL FAULT (MECHANICAL FAULT)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1AFAUV0037-MV9CM	MOV UV-37 UNAVAILABLE DUE TO MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFAV002---NV-RM	AFA-P01 TURBINE STEAM ISOL VLV SG-002 NOT RESTORED AFTER MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1AFAV002---NV-RO	AFA-P01 TURBINE STEAM ISOL VALVE SG-002 FAILS TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1AFAV006---NV-RM	L.O. VALVE V006 NOT RESTORED AFTER MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1AFAV006---NV-RO	L.O. MANUAL VALVE V006 FAILS TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1AFAV007---CV-FO	CHECK VALVE V007 FAILS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005
1AFAV015---CV-FO	AFW PUMP A DISCHARGE CHECK VALVE V015 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1AFAV016---NV-RM	AFW A PUMP MAN ISOL VALVE V016 NOT RESTORED AFTER MAINT		10.000	1.1E-004	D	Calculated	1.1E-004
1AFAV016---NV-RO	AFW A PUMP MAN ISOL VALVE V016 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1AFAV079---CV-FO	CHECK VALVE V079 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1AFAV137---CV-FO	AFW PUMP A DISCHARGE CHECK VALVE V137 FAILS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005
1AFAXFRRMWTTK-HL	OPERATOR CANNOT OR FAILS TO TRANS-FER TR A SUCTION TO RMWT		1.000	1.000	D	Screening Value	1.000
1AFBHV0030-CX9FO	MOV HV-30 CONTROL CIRCUIT FAULT (FAILS TO OPEN)	1.8E-006	3.000	1488.000	H	Test Period	1.7E-003
1AFBHV0030-MV-FO	MOV HV-30 FAILS TO OPEN (MECHANICAL FAULT)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1AFBHV0030-MV9CM	MOV HV-30 UNAVAILABLE DUE TO MAIN-TENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFBHV0031-CX9FO	MOV HV-31 FAILS TO OPEN CONTROL CIR-CUIT FAULTS	1.8E-006	3.000	1488.000	H	Test Period	1.7E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1AFBHV0031-MV-FO	MOV HV-31 FAILS TO OPEN LOCAL FAULT (MECHANICAL FAULT)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1AFBHV0031-MV9CM	MOV HV-31 UNAVAILABLE DUE TO MAIN-TENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFBP01----CB-FT	AFW TRAIN B PUMP CIRCUIT BREAKER FAILS TO CLOSE-LOCAL FAULT	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1AFBP01----CB0CM	AFW TRAIN B PUMP CKTBRK E-PBB-S04S UNAVAILABLE DUE TO UNSCHED MAIN-TENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1AFBP01----CX5FS	AFW B PUMP CONTROL CIRCUIT FAULT - FAIL TO START		3.000	2.0E-003	D	Calculated	2.0E-003
1AFBP01----MP6CM	AFW PUMP AFB-P01 UNAVAILABLE DUE TO MAINTENANCE		5.000	2.5E-003	D	Plant Spe-cific	2.5E-003
1AFBP01----MPAFR	AFW PUMP AFB-P01 FAILS TO RUN FOR 24 HOURS	1.3E-005	3.000	24.000	H	Mission Time	5.5E-004
1AFBP01----MPAFS	AFW MOTOR-DRIVEN PUMP AFB-P01 FAILS TO START	5.7E-006	2.000	730.000	H	Test Period	1.7E-003
1AFBP01-BAC--2OP	AFW B PUMP FAILS TO RUN 24HRS GIVEN NORMAL HVAC OK BUT ESS HVAC FAILED		10.000	7.3E-003	D	Calculated	7.3E-003
1AFBP01-NOBAC2OP	AFW B PUMP FAILS TO RUN 24HRS GIVEN FAILURE OF BOTH ESS AND NORMAL HVAC		10.000	5.0E-001	D	Calculated	5.0E-001
1AFBUV0034-CX9FO	MOV UV-34 CONTROL CIRCUIT FAULT (FAILS TO OPEN)	1.8E-006	3.000	1488.000	H	Test Period	1.7E-003
1AFBUV0034-MV-FO	MOV UV-34 FAILS TO OPEN (MECHANICAL FAULT)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1AFBUV0034-MV9CM	MOV UV-34 UNAVAILABLE DUE TO MAIN-TENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFBUV0035-CX9FO	MOV UV-35 FAILS TO OPEN CONTROL CIR-CUIT FAULT	1.8E-006	3.000	1488.000	H	Test Period	
1AFBUV0035-MV-FO	LOCAL FAULT MOV UV-35 FAILS TO OPEN (MECHANICAL FAULT)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1AFBUV0035-MV9CM	MOV UV-35 UNAVAILABLE DUE TO MAIN-TENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFBV021---NV-RM	CST TO AFW PUMP B MAN VALVE V021 NOT RESTORED AFTER MAINT		10.000	3.3E-006	D	Calculated	3.3E-006
1AFBV021---NV-RO	CST TO AFW PUMP B MAN VALVE V021 FAILS TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1AFBV022---CV-FO	CST TO AFW PUMP B CHECK VALVE V022 FAILS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005
1AFBV024---CV-FO	AFW PUMP B DISCHARGE CHECK VALVE V024 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1AFBV025---NV-RM	AFW PUMP B DISCHARGE MAN VALVE AF-025 NOT RESTORED AFTER MAINTE-NANCE		10.000	1.1E-004	D	Calculated	1.1E-004
1AFBV025---NV-RO	AFW PUMP B DISCHARGE MAN VALVE AF-025 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1AFBV080---CV-FO	CHECK VALVE V080 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1AFBV138---CV-FO	AFW PUMP B DISCHARGE CHECK VALVE V138 FAILS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005
1AFBXFRRMWTTK-HL	OPERATOR CANNOT OR FAILS TO TRANS-FER TR B SUCTION TO RMWT		1.000	1.000	D	Screening Value	1.000

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1AFCHV0033-CX0FO	MOV HV-33 CONTROL CIRCUIT FAULT (FAILS TO OPEN)	2.9E-006	3.000	730.000	H	Test Period	1.1E-003
1AFCHV0033-MV-FO	LOCAL FAULT HV-33 FAILS TO OPEN (MECHANICAL FAULT)	2.9E-006	14.000	730.000	H	Test Period	1.1E-003
1AFCHV0033-MV9CM	MOV HV-33 UNAVAILABLE DUE TO MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFCUV0036-CX0FO	MOV UV-36 CONTROL CIRC. FAULT (FAILS TO OPEN)	2.9E-006	3.000	1488.000	H	Test Period	2.2E-003
1AFCUV0036-MV-FO	MOV UV-36 FAILS TO OPEN (MECHANICAL FAULT)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1AFCUV0036-MV9CM	MOV UV-36 UNAVAILABLE DUE TO MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1AFN-CPWR-MFW-HL	OPER FAIL TO ALIGN BACKUP CNTRL POWER TO N PUMP WITHIN 2HRS (MFW AVAIL)		1.000	5.0E-003	D	Calculated	5.0E-003
1AFN-CPWR-----HL	OPERATOR FAILS TO ALIGN N PUMP TO BACKUP CONTROL POWER (MFW LOST) SYSTEMS		1.000	7.0E-002	D	Calculated	7.0E-002
1AFN-MSIS-----HR	OPERATOR FAILS TO OVERRIDE MSIS SIGNAL & REMOTELY ALIGN N TRAIN AFW		10.000	1.0E-002	D	Calculated	1.0E-002
1AFNP01----CB-FT	AFW TRAIN N PUMP CKTBRK FAILS TO CLOSE-LOCAL FAULT	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1AFNP01----CB0CM	AFW TRAIN N PUMP CKTBRK E-PBA-S03S UNAVAILABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1AFNP01----CX0FS	AFW N PUMP AFN-P01 CONTROL CIRC FAULT-FAIL TO START	1.4E-006	3.000	730.000	H	Test Period	5.1E-004
1AFNP01----MP6CM	PUMP AFN-P01 UNAVAILABLE DUE TO MAINTENANCE		5.000	2.5E-003	D	Plant Specific	2.5E-003
1AFNP01----MPAFR	AFW PUMP AFN-P01 FAILS TO RUN FOR 24 HOURS	1.3E-005	3.000	24.000	H	Mission Time	5.5E-004
1AFNP01----MPAFS	PUMP AFN-P01 FAILS TO START (LOCAL FAULT)	5.7E-006	2.000	730.000	H	Test Period	1.7E-003
1AFNV001---NV-RM	CST TO AFW N PUMP MAN SUCTION VALVE V001 NOT RESTORED AFTER MAINT		10.000	3.3E-006	D	Calculated	3.3E-006
1AFNV001---NV-RO	CST TO AFW N PUMP MAN SUCTION VALVE V001 FAILS TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1AFNV012---CV-FO	TRAIN N PUMP DISCHARGE CHECK VALVE AF-012 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1AFNV013---NV-RM	L.O. DISCHARGE MAN ISOL V-013 NOT RESTORED AFTER MAINTENANCE		10.000	1.1E-004	D	Calculated	1.1E-004
1AFNV013---NV-RO	L.O. DISCHARGE MAN ISOL VALVE AFV-013 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1AFW-MFW------HR	OPERATOR FAILS TO MAN ALIGN AFW FROM THE CNTL ROOM WITHIN 100 MIN (MFW AVAIL)		10.000	1.0E-003	D	Calculated	1.0E-003
1AFW-MFW-NOINDHR	OPER FAILS TO ALIGN AFW WITHIN 100 MINS. (INACURATE LEVEL IND) - MFW IS AVAIL		10.000	4.0E-003	D	Calculated	4.0E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1AFW-NOMFW----HR	OPERATOR FAILS TO MAN ALIGN AFW FROM THE CNTL ROOM WITHIN 40 MIN(NO MFW)		10.000	1.0E-002	D	Calculated	1.0E-002
1AFW-NOMFWIND-HR	OPER FAILS TO ALIGN AFW WITHIN 40 MINS. (INACURATE LEVEL IND) - NO MFW		5.000	3.0E-002	D	Calculated	3.0E-002
1ALFW-2HRS----HR	OPERATOR FAILS TO DEPRESS SG & SUPPLY ALT FW IN 2HR (30 MIN OF MFW AVAIL)		5.000	4.0E-002	D	Calculated	4.0E-002
1ALFW-60MINS--HR	OPERATOR FAILS TO DEPRESS SG & SUPPLY ALT FW IN 1HR (MFW NOT AVAIL)		3.000	1.2E-001	D	Calculated	1.2E-001
1BAM-CHGSUC--2OP	BAM TO CHARGING PUMP SUCTION LINE FAULTS		10.000	5.1E-002	D	Calculated	5.1E-002
1BAM-VCTLINE-2OP	BAM TO VCT/CHRG PUMP LINE FAULTS		10.000	2.2E-002	D	Calculated	2.2E-002
1BLOWDOWN----2HR	OPERATOR FAILS TO INITIATE BLOWDOWN		10.000	3.0E-003	D	Calculated	3.0E-003
1CDN-3PUMPS---CC	COMMON CAUSE FAIL-TO-RUN OF ALL 3 CONDENSATE PUMPS		30.000	1.5E-004	D	Calculated	1.5E-004
1CDNHCV154-NV-FO	MANUAL VALVE HCV-154 FAILS TO OPEN	2.9E-008	3.000	13140.000	H	Test Period	1.9E-004
1CDNHCV154-NV-RO	MANUAL VALVE HCV-154 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNHCV155-NV-FO	MANUAL VALVE HCV-155 FAILS TO OPEN	2.9E-008	3.000	13140.000	H	Test Period	1.9E-004
1CDNHCV155-NV-RO	MANUAL VALVE HCV-155 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNHCV3---NV-RO	CD PUMP A SUCT. MAN VALVE HCV3 FAILS TO REMAIN OPEN (NO FLOW FROM HOTWELLS 1 & 2	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CDNHCV4---NV-RO	CD PUMP C SUCT. MAN VALVE HCV4 FAILS TO REMAIN OPEN (NO FLOW FROM HOTWELLS 1 & 2	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNHV1----CX6RO	MOV HV-1 CONTROL CIRCUIT FAULTS - SPURIOUS CLOSE	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
1CDNHV1----MV-RO	MOV HV-1 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNHV2----CX6RO	MOV HV-2 CONTROL CIRCUIT FAULTS - SPURIOUS CLOSE	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
1CDNHV2----MV-RO	MOV HV-2 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNHV31---CX6RO	MOV HV-31 CONTROL CIRCUIT FAULTS - SPURIOUS CLOSE	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
1CDNHV31---MV-RO	MOV HV-31 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNHV32---CX6RO	MOV HV-32 CONTROL CIRCUIT FAULTS - SPURIOUS CLOSE	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
1CDNHV32---MV-RO	MOV HV-32 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNHV33---CX6RO	MOV HV-33 CONTROL CIRCUIT FAULTS - SPURIOUS CLOSE	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
1CDNHV33---MV-RO	MOV HV-33 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNLV81---AV-FO	AIR OPERATED VALVE LV-81 FAILS TO OPEN	4.1E-007	5.000	24.000	H	Mission Time	9.8E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CDNLV81---AV-RO	AIR OPERATED VALVE LV-81 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNLV82---AV-FO	AIR OPERATED VALVE LV-82 FAIL TO OPEN	4.1E-007	5.000	24.000	H	Mission Time	9.8E-006
1CDNLV82---AV-RO	AIR OPERATED VALVE LV-82 FAIL TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNP01A---MP-FR	CD PUMP A FAILS TO RUN 24 HRS	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1CDNP01A---MP8CM	CD PUMP A UNAVAIL DUE TO PERIOD OF UNSCHED MAINTENANCE		5.000	2.1E-003	D	Plant Specific	2.1E-003
1CDNP01B---MP-FR	CD PUMP B FAILS TO RUN 24 HRS	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1CDNP01B---MP8CM	CD PUMP B UNAVAIL DUE TO UNSCHEDULED MAINTENANCE	2.2E-004	5.000	0.002	H	Plant Specific	2.1E-003
1CDNP01C---MP-FR	CD PUMP C FAILS TO RUN 24 HRS	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1CDNP01C---MP8CM	CD PUMP C UNAVAIL DUE TO UNSCHED MAINTENANCE		5.000	1.2E-003	D	Plant Specific	1.2E-003
1CDNPCV9---PV-RO	PRESSURE REGULATING VALVE PCV9 FAILS TO REMAIN OPEN	4.2E-006	10.000	24.000	H	Mission Time	1.0E-004
1CDNPV200--AV-RO	AIR OPER VALVE PV200 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNPV200--ITPHO	PSESSURE TRANSMITTER PV-200 FAILS-HIGH OUTPUT	5.7E-007	8.000	24.000	H	Mission Time	1.4E-005
1CDNPV200--ITPNO	PRESSURE TRANSMITTER PV-200 FAILS-NO OUTPUT	2.1E-006	8.000	24.000	H	Mission Time	5.0E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CDNUV214A-CX8RO	MOV UV-214A CONTROL CIRCUIT FAULTS -SPURIOUS CLOSE	3.6E-006	10.000	24.000	H	Mission Time	8.6E-005
1CDNUV214A-MV-RO	MOV UV-214A FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNUV214B-CX8RO	MOV UV-214B CONTROL CIRCUIT FAULTS -SPURIOUS CLOSE	3.6E-006	10.000	24.000	H	Mission Time	8.6E-005
1CDNUV214B-MV-RO	MOV UV-214B FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNUV215A-CX8RO	MOV UV-215A CONTROL CIRCUIT FAULTS -SPURIOUS CLOSE	3.6E-006	10.000	24.000	H	Mission Time	8.6E-005
1CDNUV215A-MV-RO	MOV UV-215A FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNUV215B-CX8RO	MOV UV-215B CONTROL CIRCUIT FAULTS -SPURIOUS CLOSE	3.6E-006	10.000	24.000	H	Mission Time	8.6E-005
1CDNUV215B-MV-RO	MOV UV-215B FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNUV216A-CX8RO	MOV UV-216A CONTROL CIRCUIT FAULTS -SPURIOUS CLOSE	3.6E-006	10.000	24.000	H	Mission Time	8.6E-005
1CDNUV216A-MV-RO	MOV UV-216A FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNUV216B-CX8RO	MOV UV-216B CONTROL CIRCUIT FAULTS -SPURIOUS CLOSE	3.6E-006	10.000	24.000	H	Mission Time	8.6E-005
1CDNUV216B-MV-RO	MOV UV-216B FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1CDNV004---NV-RO	MANUAL VALVE V004 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CDNV005---NV-RO	MANUAL VALVE V005 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV007---NV-RO	MANUAL VALVE V007 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV008---NV-RO	MANUAL VALVE V008 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV052---NV-RO	MANUAL VALVE V052 IN COMMON CST SUCTION LINE FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV072---CV-FO	CHECK VALVE V072 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1CDNV074---CV-FO	CHECK VALVE V074 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1CDNV077---CV-FO	CHECK VALVE V077 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1CDNV084---NV-RO	MANUAL VALVE V084 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV085---NV-RO	MANUAL VALVE V085 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV086---NV-RO	MANUAL VALVE V086 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV087---NV-RO	MANUAL VALVE V087 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV088---NV-RO	MANUAL VALVE V088 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV089---NV-RO	MANUAL VALVE V089 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CDNV098---NV-RO	MANUAL VALVE V098 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV099---NV-RO	MANUAL VALVE V099 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV189---CV-FO	CHECK VALVE V189 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1CDNV268---NV-RO	MANUAL VALVE V268 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV269---NV-RO	MANUAL VALVE V269 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV323---NV-RO	MANUAL VALVE V323 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV325---NV-RO	MANUAL VALVE V325 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CDNV327---NV-RO	MANUAL VALVE V327 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1CH-HV203-205-CC	COMMON CAUSE FAILURES OF APS VALVES HV-203/205 FAIL TO OPEN		10.000	1.3E-004	D	Calculated	1.3E-004
1CH-RWTTEMP--2OP	RWT TEMPERATURE LESS THAN 70 DEG CAUSING SEAL INJ ISOLATION		10.000	3.0E-002	D	Calculated	3.0E-002
1CH-SEALINJ--2CM	SEAL INJECTION UNAVAILABLE DUE TO UNSCHEDULED MAINT.		10.000	1.5E-002	D	Plant Specific	1.5E-002
1CH-SEALINJ--2OP	SEAL INJECTION FAILS DUE TO LOCAL LINE FAULTS		10.000	1.1E-002	D	Calculated	1.1E-002
1CHAF20----FX-PG	RWT S.I. SUCTION STRAINER CHA-F20 PLUGS	3.0E-005	10.000	16.000	H	Mission Time	4.8E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CHAHV-205---2OP	APS VALVE CH-HV-205 FAILS TO OPEN (INCLUDES CONTROL FAULTS		10.000	4.53-003	D	Calculated	4.5E-003
1CHAHV0531-CX6RO	RWT OUTLET MOV HV-531 CONTROL CIRCUIT FAULT (SPURIOUS CLOSURE)	6.0E-007	10.000	16.000	H	Mission Time	9.6E-006
1CHAHV0531-MV-RO	RWT OUTLET MOV HV-531 LOCAL FAULT - FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1CHAL425---PXLEL	PIPE BREAK DOWN STREAM OF RWT IN SAFETY INJECTION SUCTION TRAIN A	8.5E-010	30.000	16.000	H	Mission Time	1.4E-008
1CHAP01-FR---2OP	CHARGING PUMP A FAILS TO RUN (INCLUDES LINE FAULTS)		10.000	2.8E-003	D	Calculated	2.8E-003
1CHAP01-FS---2OP	CHARGING PUMP A FAILS TO START (INCLUDES CONTROL FAULTS)		10.000	2.0E-002	D	Calculated	2.0E-002
1CHAV306---CV-FO	RWT OUTLET CHECK VALVE V-306 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1CHAV306---CV-RO	RWT OUTLET CHECK VALVE V-306 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1CHBF20----FX-PG	RWT S.I. SUCTION STRAINER CHB-F20 PLUGS	3.0E-005	10.000	16.000	H	Mission Time	4.8E-004
1CHBHV-203---2OP	APS VALVE HV-203 FAILS TO OPEN (INCLUDES CONTROL FAULTS)		3.000	4.5E-003	D	Calculated	4.5E-003
1CHBHV0530-CX6RO	RWT OUTLET MOV HV-530 CONTROL CIRCUIT FAULT (SPURIOUS CLOSURE)	6.0E-007	10.000	16.000	H	Mission Time	9.6E-006
1CHBHV0530-MV-RO	RWT OUTLET MOV HV-530 LOCAL FAULT - FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1CHBL425---PXLEL	PIPE BREAK DOWN STREAM OF RWT IN SAFETY INJECTION SUCTION TRAIN B	8.5E-010	30.000	16.000	H	Mission Time	1.4E-008

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CHBP01-FR---2OP	CHARGING PUMP B FAILS TO RUN/START (INCLUDES LINE AND CNTRL FAULTS		10.000	2.6E-002	D	Calculated	2.6E-002
1CHBV305---CV-FO	RWT OUTLET CHECK VALVE V-305 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1CHBV305---CV-RO	RWT OUTLET CHECK VALVE V-305 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1CHEHV-532-AV-RO	RWT ISO VALVE CHE-HV-532 FAILS TO REMAIN OPEN		9.000	3.4E-006	D	Calculated	3.4E-006
1CHEP01-FR---2OP	CHARGING PUMP E FAILS TO START/RUN (INCLUDES LINE AND CONTROL FAULTS		10.000	2.6E-002	D	Calculated	2.6E-002
1CHEP01EL-AB--HL	OPERATOR FAILS TO BACKUP CHE-P01 B POWER SUPPLY FROM LOAD GRP 1 (PGA-L35)		10.000	3.5E-002	D	Calculated	3.5E-002
1CHET01----TK-EL	RWT TANK CHE-T01 RUPTURE	1.0E-009	30.000	16.000	H	Mission Time	1.6E-008
1CHLT-226-227-CC	VCT AUTO MAKEUP FAILS DUE TO COM-MON CAUSE LT FAILURES		17.000	4.3E-005	D	Calculated	4.3E-005
1CHN-F03---PXOPG	BAM FILTER F03 FAILS TO ALLOW FLOW		3.000	9.2E-004	D	Calculated	9.2E-004
1CHNCC226227-2OP	VCT AUTO M/U FAILS DUE TO FAIL OF 226 AND 227 LTS AND OPER FAILS TO ALIGN		17.000	8.7E-005	D	Calculated	8.7E-005
1CHNP02A-----2OP	BAM PUMP-A FAILS TO OPERATE (INCLUDING LINE FAILURES)		10.000	6.5E-003	D	Calculated	6.5E-003
1CHNP02B-----2OP	BAM PUMP-B FAILS TO OPERATE (INCLUDES LINE FAILURES)		10.000	6.5E-003	D	Calculated	6.5E-003
1CR-ESSHVAC--2HR	OPER. FAILS TO INIT. CR HVAC INCL ESS COOL AFTER NORM HVAC TRIPS		10.000	7.0E-005	D	Calculated	7.0E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1CR-WC-UNISO--HR	OPER. FAILS TO UNIS CONTROL RM NORM HVAC (INCL NORM WC) UPON LOSS OF ESS HVAC		10.000	1.0E-003	D	Calculated	1.0E-003
1CRHVC-COOL12-HL	OPERATOR FAILS TO SHUT OFF 1 CR ESS. FAN AND OPEN DOOR WITHIN 12 HRS		10.000	2.0E-003	D	Calculated	2.0E-003
1CRHVC-COOL7--HL	OPERATOR FAILS TO SHUT OFF 1 CR ESS. FAN AND OPEN DOOR WITHIN 7 HRS		10.000	3.0E-003	D	Calculated	3.0E-003
1CRHVC-LOCA---HL	OPERATOR FAILS TO SHUT OFF CHILLER PUMPS ON LOSS OF ESS CHILL WTR		3.000	5.0E-001	D	Calculated	5.0E-001
1CTAHV001--CX7FO	AFN-P01 SUCTION MOV HV-1 CONTROL CIRCUIT FAULT	1.0E-006	3.000	730.000	H	Test Period	3.7E-004
1CTAHV001--MV-FO	AFN-P01 SUCTION MOV HV-1 FAILS TO OPEN	2.9E-006	14.000	730.000	H	Test Period	1.1E-003
1CTAHV004--CX7FO	AFN-P01 SUCTION MOV HV-4 CONTROL CIRCUIT FAULT	1.0E-006	3.000	730.000	H	Test Period	3.7E-004
1CTAHV004--MV-FO	AFN-P01 SUCTION MOV HV-4 FAILS TO OPEN	2.9E-006	14.000	730.000	H	Test Period	1.1E-003
1CTAV015---NV-RO	MANUAL VALVE V015 CST FAILS TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1CTBV014---NV-RO	CST MANUAL VALVE V014 FAILS TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1CTET01----TK-EL	CONDENSATE STORAGE TANK FAULTS (EXCESSIVE LEAKAGE)	1.0E-009	30.000	21.000	H	Mission Time	2.1E-008
1DCHVAC-BAKUP2HR	OPERATOR FAILS TO ESTABLISH BACKUP CLG TO DC EQUIP RMS FOLLOWING HI TEMP ALARM		10.000	6.7E-002	D	Calculated	6.7E-002

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1DEPRESSSGTR-2HR	OPERATOR FAILS TO DEPRESS RCS DURING SGTR TO STOP LEAK WITHIN 24 HOURS		10.000	9.0E-004	D	Calculated	9.0E-004
1EC-MANSTART-2HR	AFW A MANUAL STRT (NO AFAS SIG) & OPER FAILS TO STRT ESS. COOLING WTR SYS		5.000	3.OE-002	D	Calculated	3.0E-002
1ECAB-E01--ARHCC	COMMON CAUSE FAILURE OF BOTH ESSENTIAL CHILLERS (ECA-E01 AND ECB-E01)		17.000	9.9E-005	D	Calculated	9.9E-005
1ECAB-P01--MP-CC	COMMON CAUSE FAILURE OF BOTH TR A & B ESS CHILLED WTR PUMPS (ECA-P01 & ECB-P01)		30.000	9.99E-005	D	Calculated	9.9E-005
1ECAE01----AR7CM	TR A ESS. CHILLER ECA-E01 UNAVAILABLE DUE TO UNSCH ED. MAINT.	1.3E-004	5.000	21.000	H	MTTR	2.7E-003
1ECAE01----ARHFR	TRAIN A ESS. CHILLER ECA-E01 FAIL TO RUN (24 HRS)	6.0E-005	25.000	24.000	H	Mission Time	1.4E-003
1ECAE01----ARHFS	TRAIN A ESS. CHILLER ECA-E01 FAIL TO START	1.0E-006	5.000	730.000	H	Test Period	3.7E-004
1ECAE01----CB-FT	CHILLER ECA-E01 CIRCUIT BREAKER FAULT (FAIL TO CLOSE)	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1ECAE01----CB0CM	TRAIN A ESS. CHILLER ECA-E01 CIRCUIT BREAKER UNAVAIL. DUE TO UNSCHED. MAINT.	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1ECAE01----CX8FS	TR A ESS. CHILLER ECA-E01 CONTROL CIRCUIT FAULTS	9.9E-006	10.000	730.000	H	Test Period	3.6E-003
1ECAFSL533-1WFNO	ESS. CHILLED WATER FLOW SWITCH FSL-533 FAILS (NO OUTPUT)	1.6E-006	5.000	730.000	H	Test Period	5.8E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1ECAFT533--ITFNO	ESS. CHILLED WATER FLOW TRANSMITTER FT-533 FAILS (NO OUTPUT)	2.6E-006	6.000	730.000	H	Test Period	9.5E-004
1ECAP01----CB0CM	TRAIN A ESS. CHILLED WATER PUMP CIRCUIT BREAKER UNAVAIL. DUE MAI TO UNSCHED MAIN	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1ECAP01----CX9FS	TRAIN A ESS. CHILLED WATER PUMP ECA-P01 CONTROL CIRCUIT FAULTS	2.3E-006	10.000	730.000	H	Test Period	8.4E-004
1ECAP01----MP-FR	TR A ESS. CHILLED WTR PUMP (ECA-P01) FAILURE TO RUN GIVEN START	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1ECAP01----MP-FS	TR A ESS. CHILLED WTR PUMP (ECA-P01) FAILURE TO START	1.0E-006	2.000	730.000	H	Test Period	3.7E-004
1ECAP01----MP6CM	TRAIN A ESS. CHILLED WATER PUMP (ECA-P01) UNAVAIL. DURING UNSCHED. MAINT.		5.000	1.0E-003	D	Plant Specific	1.0E-003
1ECAV002---NV-RM	FAILURE TO RESTORE MANUAL VALVE V002 AFTER UNSCHED. MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1ECAV002---NV-RO	LOCAL FAULT MANUAL VALVE V002 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1ECAV011---NV-RM	FAILURE TO RESTORE MANUAL VALVE V011 AFTER UNSCHED. MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1ECAV011---NV-RO	LOCAL FAULT MANUAL VALVE V011 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1ECBE01----AR7CM	TR B ESS. CHILLER ECB-E01 UNAVAILABLE DUE TO UNSCH ED. MAINT.	1.3E-004	5.000	21.000	H	MTTR	2.7E-003
1ECBE01----ARHFR	TRAIN B ESS. CHILLER ECB-E01 FAIL TO RUN (24 HRS)	6.0E-005	25.000	24.000	H	Mission Time	1.4E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1ECBE01----ARHFS	TRAIN B ESS. CHILLER ECB-E01 FAIL TO START	1.0E-006	5.000	730.000	H	Test Period	3.7E-004
1ECBE01----CB-FT	CHILLER ECB-E01 CIRCUIT BREAKER FAULT (FAIL TO CLOSE)	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1ECBE01----CB0CM	TRAIN B ESS. CHILLER ECB-E01 CIRCUIT BREAKER UNAVAIL. DUE TO UNSCHED. MAINT.	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1ECBE01----CX8FS	TR B ESS. CHILLER ECB-E01 CONTROL CIRCUIT FAULTS	9.9E-006	10.000	730.000	H	Test Period	3.6E-003
1ECBFSL534-IWFNO	ESS. CHILLED WATER FLOW SWITCH FSL-534 FAILS (NO OUTPUT)	1.6E-006	5.000	730.000	H	Test Period	5.8E-004
1ECBFT534--ITFNO	ESS. CHILLED WATER FLOW TRANSMITTER FT-534 FAILS (NO OUTPUT)	2.6E-006	6.000	730.000	H	Test Period	9.5E-004
1ECBP01----CB0CM	TRAIN B ESS CHILLED WTR PUMP CIRCUIT BREAKER UNAVAIL DUE TO UNSCHED MAINT	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1ECBP01----CX9FS	TRAIN B ESS. CHILLED WATER PUMP ECB-P01 CONTROL CIRCUIT FAULTS	2.3E-006	10.000	730.000	H	Test Period	8.4E-004
1ECBP01----MP-FR	TR B ESS. CHILLED WTR PUMP (ECB-P01) FAILURE TO RUN GIVEN START	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1ECBP01----MP-FS	TR B ESS. CHILLED WTR PUMP (ECB-P01) FAILURE TO START	1.0E-006	2.000	730.000	H	Test Period	3.7E-004
1ECBP01----MP6CM	TRAIN B ESS. CHILLED WATER PUMP (ECB-P01) UNAVAIL. DURING UNSCHED. MAINT.		5.000	1.0E-003	D	Plant Specific	1.0E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1ECBV065---NV-RM	FAILURE TO RESTORE MANUAL VALVE V065 AFTER UNSCHED. MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1ECBV065---NV-RO	LOCAL FAULT MANUAL VALVE V065 FAIL-URE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1ECBV068---NV-RM	FAILURE TO RESTORE MANUAL VALVE V068 AFTER UNSCHED. MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1ECBV068---NV-RO	LOCAL FAULT MANUAL VALVE V068 FAIL-URE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1ESR-ESSHVAC-2HR	OPER FAILS TO INIT ESS SWGR RM HVAC INCL ESS COOL AFTER NORM HVAC TRIPS		10.000	1.0E-003	D	Calculated	1.0E-003
1ESR-WC-UNISO-HR	FAILURE TO UNISOLATE SWGR RM NOR-MAL HVAC (INCL NORM WC) UPON LOSS OF ESS HVAC		10.000	1.E-003	D	Calculated	1.0E-003
1EWA-UV065-CXXFO	ECW/NCW CROSSTIE MOV UV065 FAILS TO OPEN CONTROL CIRCUIT FAULT		10.000	1.4E-002	D	Calculated	1.4E-002
1EWA-UV065-MV-FO	ECW/NCW CROSSTIE MOV UV065 FAILS TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1EWA-UV145-CXXFO	ECW/NCW CROSSTIE MOV UV145 FAILS TO OPEN CONTROL CIRCUIT FAULT		10.000	1.4E-002	D	Calculated	1.4E-002
1EWA-UV145-MV-FO	ECW/NCW CROSSTIE MOV UV145 FAILS TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1EWA2MANVS-NV-RM	FAIL TO RESTORE 1 OF 2 MAN VLVS IN ESS COOL WATER LINES SERVICING SDHX A		10.000	3.7E-005	D	Calculated	3.7E-005
1EWA2MANVS-NV-RO	FTRO FAULT IN 1 OF 2 MAN. VALVES IN ESSEN COOL WATER LINES SERVICING SDHX A		84.000	2.5E-005	D	Calculated	2.5E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1EWAB-P01--MP-CC	COMMON CAUSE FAILURE OF BOTH ESS COOLING WATER PUMPS EWA-P01 & EWB-P01		30.000	9.9E-005	D	Calculated	9.9E-005
1EWAFSL151-IWFNO	ESS. COOLING WATER FLOW SWITCH FSL-151 FAILS (NO OUTPUT)	1.6E-006	5.000	730.000	H	Test Period	5.8E-004
1EWAFT151--ITFNO	ESS. COOLING WATER FLOW TRANSMITTER FT-151 FAILS (NO OUTPUT)	2.6E-006	6.000	730.000	H	Test Period	9.5E-004
1EWAHCV005-NV-RM	FAILURE TO RESTORE HCV-5 AFTER UNSCHED. MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1EWAHCV005-NV-RO	LOCAL FAULT MANUAL VALVE HCV-5 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWAHCV071-NV-RM	FAILURE TO RESTORE HCV-71 AFTER UNSCHED. MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1EWAHCV071-NV-RO	LOCAL FAULT MANUAL VALVE HCV-71 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWAHCV135-NV-RM	FAILURE TO RESTORE HCV-135 AFTER UNSCHED. MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1EWAHCV135-NV-RO	LOCAL FAULT MANUAL VALVE HCV-135 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWAP01----CB-FT	ESS. COOLING WATER TRAIN A PUMP EWA-P01 CKTBRK FAULT (FAIL TO CLOSE)	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1EWAP01----CB0CM	ESS. COOLING WATER TRAIN A EWA-P01 PUMP CKTBRK OUT FOR UNSCHED MAINT.	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1EWAP01----CX5FS	ESS. COOLING WATER TR A PUMP EWA-P01 CNTRL CIRC FAULTS (FAIL TO START)	3.0E-006	3.000	730.000	H	Test Period	1.1E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1EWAP01----MP-FR	ESS. COOLING WATER TRAIN A PUMP EWA-P01 FAILS TO RUN (24 HRS)	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1EWAP01----MP-FS	ESS. COOLING WATER TRAIN A PUMP EWA-P01 FAILS TO START	1.0E-006	2.000	730.000	H	Test Period	3.7E-004
1EWAP01----MP6CM	ESS. COOLING WTR TR A PUMP (EWA-P01) UNAVAIL. DURING UNSCHED MAINT		5.000	1.3E-003	D	Plant Specific	1.3E-003
1EWAP01-BAC--2OP	EW A PUMP FAILS TO RUN 24 HRS GIVEN NO ESS HVAC BUT WITH BACKUP COOLING		10.000	1.4E-002	D	Calculated	1.4E-002
1EWAP01-NOBAC2OP	EW A PUMP FAILS TO RUN 24 HRS GIVEN NO ESSENTIAL OR BACKUP ROOM COOLING		10.000	3.0E-002	D	Calculated	3.0E-002
1EWAV021---NV-RM	FAILURE TO RESTORE EWA MANUAL VALVE V021 AFTER UNSCHED. MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1EWAV021---NV-RO	LOCAL FAULT EWA MANUAL VALVE V021 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWAV022---NV-RM	FAILURE TO RESTORE EWA MANUAL VALVE V022 AFTER UNSCHED. MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1EWAV022---NV-RO	LOCAL FAULT EWA MANUAL VALVE V022 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWB2MANVS-NV-RM	FAIL TO RESTOR 1 OF 2 MAN VLVS IN ESS COOL WTR LINES SERVICING SDHX B		10.000	3.7E-005	D	Calculated	3.7E-005
1EWB2MANVS-NV-RO	FTRO FAULT IN 1 OF 2 MAN. VALVES IN ESSEN COOL WATER LINES SERVICING SDHX B		84.000	2.5E-005	D	Calculated	2.5E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1EWBFSL152-IWFNO	ESS. COOLING WATER FLOW SWITCH FSL-152 FAILS (NO OUTPUT)	1.6E-006	5.000	730.000	H	Test Period	5.8E-004
1EWBFT152--ITFNO	ESS. COOLING WATER FLOW TRANSMITTER FT-152 FAILS (NO OUTPUT)	2.6E-006	6.000	730.000	H	Test Period	9.5E-004
1EWBHCV006-NV-RM	FAILURE TO RESOTRE HCV-6 AFTER UNSCHED MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1EWBHCV006-NV-RO	LOCAL FAULT MANUAL VALVE HCV-6 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWBHCV072-NV-RM	FAILURE TO RESOTRE HCV-72 AFTER UNSCHED MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1EWBHCV072-NV-RO	LOCAL FAULT MANUAL VALVE HCV-72 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWBHCV136-NV-RM	FAILURE TO RESOTRE HCV-136 AFTER UNSCHED MAINTENANCE		10.000	3.3E-006	D	Calculated	3.3E-006
1EWBHCV136-NV-RO	LOCAL FAULT MANUAL VALVE HCV-136 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWBP01----CB-FT	EW PUMP EWB-P01 CKTBRK FAULT (FAIL TO CLOSE)	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1EWBP01----CB0CM	EW EWB-P01 PUMP CKTBRK UNAVAIL FOR UNSCHED MAINT	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1EWBP01----CX5FS	EW PUMP EWB-P01 CONTROL CIRCUIT FAULTS (FAIL TO START)	3.0E-006	3.000	730.000	H	Test Period	1.1E-003
1EWBP01----MP-FR	EW PUMP EWB-P01 FAIL TO RUN (24HRS)	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1EWBP01----MP-FS	EW EWB-P01 FAILS TO START	1.0E-006	2.000	730.000	H	Test Period	3.7E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1EWBP01----MP6CM	EW PUMP EWB-P01 UNAVAIL DURING UNSCHED MAINT		5.000	1.3E-003	H	Plant Specific	1.3E-003
1EWBP01-BAC--2OP	EW B PUMP FAILS TO RUN 24HRS GIVEN NO ESSENTIAL HVAC BUT WITH BACKUP COOLING		10.000	1.4E-002	D	Calculated	1.4E-002
1EWBP01-NOBAC2OP	EW B PUMP FAILS TO RUN 24 HRS GIVEN NO ESSENTIAL OR BACKUP ROOM COOLING		10.000	3.0E-002	D	Calculated	3.0E-002
1EWBV043---NV-RM	FAILURE TO RESTORE EWB MANUAL VALVE V043 AFTER UNSCHED. MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1EWBV043---NV-RO	LOCAL FAULT EWB MANUAL VALVE V043 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1EWBV044---NV-RM	FAILURE TO RESTORE EWB MANUAL VALVE V044 AFTER UNSCHED. MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1EWBV044---NV-RO	LOCAL FAULT EWB MANUAL VALVE V044 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1FP-ESR-AB-CO2SA	SPUR ACT OF CO2 FIRE PROTECTION - BOTH ESF SWGR ROOMS (SOLID STATE MASTER MOD)		30.000	9.6E-007	D	Calculated	9.6E-007
1FPA-ESRCO2--2SA	SPUR ACT OF TRAIN A ESF SWGR RM CO2 FIRE PROTECTION SYSTEM		10.000	4.9E-005	D	Calculated	4.9E-005
1FPB-ESRCO2--2SA	SPUR ACT OF TRAIN B ESF SWGR RM CO2 FIRE PROTECTION SYSTEM		10.000	4.9E-005	D	Calculated	4.9E-005
1FWNHV103--CX5FO	HP HEATER BYPASS MOV HV-103 FAILS TO OPEN -CONTROL CIRCUIT FAULT	1.0E-006	3.000	13140.000	H	Test Period	6.6E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1FWNHV103--MV-FO	HP HEATER BYPASS MOV HV-103 FAILS TO OPEN - MECHANICAL FAULT	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1FWNHV103--MV9CM	HP HEATER BYPASS MOV HV-103 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	116.000	H	Test Period	1.6E-003
1GAN2BACKUP--2HR	OPERATOR FAILS TO ISOLATE HP FROM LP NITROGEN		1.000	1.000	D	Screening value	1.000
1GANPSV029-RV-RC	SAFETY RELIEF VALVE PSV-29 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1GANPSV033-RV-RC	SAFETY RELIEF VALVE PSV-33 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1GANPSV036-RV-RC	SAFETY RELIEF VALVE PSV-36 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1GANPSV047-RV-RC	SAFETY RELIEF VALVE PSV-47 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1GANPSV051-RV-RC	SAFETY RELIEF VALVE PSV-51 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1GANPSV081-RV-RC	SAFETY RELIEF VALVE PSV-81 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1GANPV031--AV-RO	LOCAL FAULT AIR-OPERATED VALVE PV-31 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	2.8E-006
1GANPV038--AV-RO	LOCAL FAULT AIR-OPERATED VALVE PV-38 FAILS TO REMAIN OPEN	2.3E-007	9.000	168.000	H	Test Period	1.9E-005
1GANSYSTEM---2OP	FAILURE OF SERVICE GAS TO PROVIDE N2 TO INSTR. SYSTEM HEADER (LONG TERM)		1.000	1.000	D	Screening value	1.000
1GANV226---NV-RO	LOCAL FAULT MANUAL VALVE V226 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	3.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1GANV235---NV-RO	LOCAL FAULT MANUAL VALVE V235 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	3.6E-007
1GANV242---CV-RO	HP HEADER CHECK VALVE V242 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1GANV243---NV-RO	LOCAL FAULT MANUAL VALVE V243 FAILS TO REMAIN OPEN	3.0E-008	84.000	5840.000	H	Test Period	8.8E-005
1GANV244---NV-RO	LOCAL FAULT MANUAL VALVE V244 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	3.6E-007
1GANV247---NV-RO	LOCAL FAULT MANUAL VALVE V247 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	3.6E-007
1GANV248---NV-RO	LOCAL FAULT MANUAL VALVE V248 FAILS TO REMAIN OPEN	3.0E-008	84.000	5840.000	H	Test Period	8.8E-005
1HAAHVACAFW--2OP	AFA-P01 PUMP ROOM ESS HVAC AHU FAILS DUE TO LOCAL FAULTS		5.000	2.7E-003	D	Calculated	2.7E-003
1HAAHVACCSS--2OP	CONT. SPRAY TR. A PUMP ROOM COOLING UNIT FAILS DUE TO LOCAL FAULT		5.000	3.4E-003	D	Calculated	3.4E-003
1HAAHVACEWS--2OP	ESS. COOLING PWATER TRAIN A PUMP EWA-P01 ROOM COOLING LOCAL FAULTS		5.000	3.4E-003	D	Calculated	3.4E-003
1HAAHVACHPS--2OP	HPSI TR. A PUMP ROOM COOLING UNIT FAILS DUE TO LOCAL FAULT		5.000	3.4E-003	D	Calculated	3.4E-003
1HAAHVACLPS--2OP	LPSI TR. A PUMP ROOM COOLING UNIT FAILS DUE TO LOCAL FAULT		5.000	3.4E-003	D	Calculated	3.4E-003
1HABHVACAFW--2OP	AFB-P01 PUMP ROOM ESS HVAC AHU FAILS DUE TO LOCAL FAULTS		5.000	2.7E-003	D	Calculated	2.7E-003
1HABHVACCSS--2OP	CONT. SPRAY TR. B PUMP ROOM COOLING UNIT FAILS DUE TO LOCAL FAULT		5.000	3.4E-003	D	Calculated	3.4E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HABHVACEWS--2OP	EW PUMP EWB-P01 ROOM COOLING LOCAL FAULTS		5.000	3.4E-003	D	Calculated	3.4E-003
1HABHVACHPS--2OP	HPSI TR. B PUMP ROOM COOLING UNIT FAILS DUE TO LOCAL FAULT		5.000	3.4E-003	D	Calculated	3.4E-003
1HABHVACLPS--2OP	LPSI TR. B PUMP ROOM COOLING UNIT FAILS DUE TO LOCAL FAULT		5.000	3.4E-003	D	Calculated	3.4E-003
1HAN-AUXHVAC-2OP	NORM AUX BLDG HVAC FAILS DUE TO LOCAL FAULTS(2 FANS,2 BD DAMPERS,5 AIR-OP DAMPER		5.000	7.2E-004	D	Calculated	7.2E-004
1HJ-AB-F04-ARFCC	COMMON CAUSE FAIL TO START & RUN OF BOTH CR ESS HVAC AHUS		17.000	3.5E-005	D	Calculated	3.5E-005
1HJA-CRHVACA-2OP	ESS CR HVAC TR A UNIT (HJA-F04) FAILS TO OPERATE		10.000	1.1E-003	D	Calculated	1.1E-003
1HJA-F04---AR6CM	TR A ESS CR HVAC AHU (HJA-F04) UNAVAIL DUE TO MAINTENANCE		5.000	4.0E-004	D	Plant Specific	4.0E-004
1HJA-M01---DM-FO	NORM CONTROL RM HVAC AIR-OP ISOL DAMPER (HJA-M01) FAILS TO RE-OPEN	1.0E-006	16.000	730.000	H	Test Period	3.7E-004
1HJA-M01---DM-RO	CONTROL RM NORM AHU AIR-OP OUTLET DAMPER (HJA-M01) FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJA-M05---DMMRO	CR TR A ESS AHU DISCHARGE FIRE DAMPER HJA-M05 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005
1HJA-M06---DMMRO	CR TR A ESS AHU DISCHARGE FIRE DAMPER HJA-M06 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJA-M12---DMMRO	CR TR A ESS AHU INTAKE DAMPER HJA-M12 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005
1HJA-M13---DMMRO	CR TR A ESS AHU INTAKE FIRE DAMPER HJA-M13 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005
1HJA-M17---DMMFO	ESF SWITCHGEAR ROOM BACKDRAFT DAMPER HJA-M17 FAILS TO OPEN	1.1E-007	10.000	4380.000	H	Test Period	2.4E-004
1HJA-M18---DMMRO	ESF SWITCHGEAR RM FIRE DAMPER HJA-M18 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJA-M19---DMMRO	ESF SWITCHGEAR RM FIRE DAMPER HJA-M19 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJA-M33---DMMRO	ESF SWITCHGEAR ROOM FIRE DAMPER HJA-M33 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJA-M34---CXXRO	ESF SWITCHGEAR ROOM HVAC DAMPER HJA-M34 SOV CONTROL CIRCUIT FAULT		10.000	1.3E-005	D	Calculated	1.3E-005
1HJA-M34---DM-RO	ESF SWITCHGEAR ROOM HVAC DAMPER HJA-M34 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJA-M34---SV-RO	ESF SWITCHGEAR ROOM HVAC DAMPER SOLENOID VALVE FOR HJA-M34 FAILS TO REMAIN OPEN	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1HJA-M35---DMMRO	ESF SWITCHGEAR RM FIRE DAMPER HJA-M35 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJA-M37---DMMRO	ESF SWITCHGEAR ROOM FIRE DAMPER HJA-M37 FAILS TO REMAIN OPEN	2.5E-007	10.000	36.000	H	Mission Time / Detection Period	9.0E-006
1HJA-M38---DMMFO	ESF SWITCHGEAR ROOM BACKDRAFT DAMPER HJA-M38 FAILS TO OPEN	1.1E-007	10.000	4380	H	Test Period	2.4E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJA-M52---DM-FO	NORM CONRTOL RM HVAC AIR-OP ISOL DAMPER (HJA-M52) FAILS TO RE-OPEN	1.0E-006	16.000	730.000	H	Test Period	3.7E-004
1HJA-M52---DM-RO	CONTROL ROOM NORM AHU INTAKE AIR-OP DAMPER (HJA-M52) FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJA-M62---CXXFO	ESS DC EQUIP ROOM AIR-OP HVAC DAMPER HJA-M62 SOV CONTROL CIRCUIT FAULT		10.000	1.4E-004	D	Calculated	1.4E-004
1HJA-M62---DM-FO	ESS DC EQUIP ROOM AIR-OP HVAC DAMPER HJA-M62FAILS TO OPEN	1.0E-006	16.000	730.000	H	Test Period	3.7E-004
1HJA-M62---DM9CM	ESS DC EQUIP ROOM AIR-OP HVAC DAMPER HJA-M62 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1HJA-M62---SV-FO	ESS DC EQUIP ROOM AIR-OP DAMPER SOLENOID VALVE FOR HJA-M62 FAILS TO OPEN	9.1E-007	3.000	730.000	H	Test Period	3.0E-004
1HJA-M66---CXXFO	NORM ESF SWGR RM HVAC DAMPER HJA-M66 FAILS TO REOPEN -CONT CIRC FAULT		10.000	3.2E-004	D	Calculated	3.2E-004
1HJA-M66---CXXRO	NRM ESF SWGR RM HVAC DAMPER (HJA-M66) FAILS TO REMAIN OPEN -CONTROL CIRC FAULTS		10.000	1.4E-004	D	Calculated	1.4E-004
1HJA-M66---DM-FO	NORM ESF SWGR RM HVAC AIR-OP ISOL DAMPER (HJA-M66) FAILS TO REOPEN		16.000	3.0E-003	D	Calculated	3.0E-003
1HJA-M66---DM-RO	ESF SWITCHGEAR ROOM HVAC AIR-OP DAMPER HJA-M66 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJA-M66---DM9CM	NORM ESF SWGR RM HVAC AIR-OP DAMPER HJA-M66 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1HJA-M67---DMMRO	NORMAL/ESS. ESF DC EQUIP. RM FIRE DAMPER HJA-M67 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJA-M68---DMMRO	NORMAL/ESS. ESF DC EQUIP. RM FIRE DAMPER HJA-M68 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJA-M73---DMMRO	NORMAL/ESS. ESF DC EQUIP. RM FIRE DAMPER HJA-M73 FAILS TO REMAIN OPEN	2.5E-007	10.000	36.000	H	Mission Time / Detection Period	9.0E-006
1HJA-M76---DMMRO	CR TR A ESS AHU INTAKE MANUAL DAMPER HJA-M76 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005
1HJA-M77---DMMRO	CR TR A ESS AHU DISCHARGE MANUAL DAMPER HJA-M77 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005
1HJA-UY-7A-SV-FO	NORM CONTROL RM HVAC AIR-OP DAMPER (HJA-M01) SOV FAILS TO RE-OPEN	9.1E-007	3.000	730.000	H	Test Period	3.0E-004
1HJA-UY-7A-SV-RO	CONTROL RM NORM AHU AIR-OP DAMPER (HJA-M01) SOV FAILS TO REMAIN OPEN	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJA-UY-7B-SV-FO	NORM CONTROL RM HVAC AIR-OP DAMPER (HJA-M52) SOV FAILS TO RE-OPEN	9.1E-007	3.000	730.000	H	Test Period	3.0E-004
1HJA-UY-7B-SV-RO	CONTROL ROOM NORM AHU AIR-OP DAMPER (HJA-M52) SOV FAILS TO REMAIN OPEN	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1HJA-UY58C-SV-FO	NORM ESF SWGR RM HVAC AIR-OP DAMPER (HJA-M66) SOV FAILS TO REOPEN		3.000	1.0E-003	D	Calculated	1.0E-003
1HJA-UY58C-SV-RO	NORM ESF SWITCHGEAR RM HVAC AIR-OP DAMPER (HJA-M66) SOV FAILS TO REMAIN OPEN	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1HJA-Z03---AR6CM	ESS ESF SWGR RM HVAC TRAIN A AHU (HJA-Z03) UNAVAIL DUE TO MAINTE-NANCE		5.000	2.1E-004	D	Plant Spe-cific	2.1E-004
1HJAB-NORM-DM9CM	1 OF 4 NORM AHU IN OUT AIR-OP DMPRS UNAVAIL DUE TO MAINT (HJA/B M01,M52,M55) UNA	2.8E-005	3.000	100.000	H	MTTR	2.8E-003
1HJAHVACDCEQ-2OP	TR A ESS ESF EQUIP ROOM HVAC LOCAL UNIT (HJA-Z04) FAILS TO OPERATE		5.000	8.3E-003	D	Calculated	8.3E-003
1HJAHVACESGR-2OP	ESSENTIAL ESF SWITCHGEAR ROOM HVAC TRAIN A LOCAL UNIT FAILS TO OPERATE		5.000	1.7E-003	D	Calculated	1.7E-003
1HJAUY7A-7BCXXFO	NORM CR HVAC TR A DAMPERS (M01, M52) FTRO DUE TO COMMON CNTL CIRC FAULT		3.000	5.0E-004	D	Calculated	5.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJAUY7A-7BCXXRO	CR NORM AHU TR A DAMPERS (M01, M52) FTRO DUE TO COMMON SOV CNTL CIRC FAULT		3.000	3.6E-004	D	Calculated	3.6E-004
1HJB-CRHVACB-2OP	ESS CR HVAC TR B AHU (HJB-F04) FAILS TO OPERATE		10.000	1.1E-003	D	Calculated	1.1E-003
1HJB-F04---AR6CM	TR B ESS CR HVAC AHU (HJB-F04) UNAVAIL DUE TO MAINTENANCE		5.000	4.0E-004	D	Plant Specific	4.0E-004
1HJB-M01---DM-FO	NORM CR HVAC AIR-OP ISOL. DAMPER (HJB-M01) FAILS TO RE-OPEN	1.0E-006	16.000	730.000	H	Test Period	3.7E-004
1HJB-M01---DM-RO	CR NORM AHU AIR-OP OUTLET DAMPER (HJB-M01) FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJB-M06---DMMFO	CR TR B ESS AHU DISCHARGE BACK DRAFT DAMPER HJB-M06 FAILS TO OPEN	1.1E-007	10.000	730.000	H	Test Period	4.0E-005
1HJB-M07---DMMRO	CR AHU DISCHARGE FIRE DAMPER HJB-M07 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJB-M14---DMMRO	CR AHU DISCHARGE FIRE DAMPER HJB-M14 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJB-M25---DMMRO	CR AHU INTAKE FIRE DAMPER HJB-M25 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJB-M26---DMMRO	CR AHU INTAKE FIRE DAMPER HJB-M26 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJB-M27---DMMFO	CR TR B ESS AHU INTAKE BACKDRAFT DAMPER HJB-M27 FAILS TO REMAIN OPEN	1.1E-007	10.000	730.000	H	Test Period	4.0E-005
1HJB-M29---DMMRO	ESF SWITCHGEAR RM FIRE DAMPER HJB-M29 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJB-M30---DMMRO	ESF SWITCHGEAR RM FIRE DAMPER HJB-M30 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJB-M31---DM-FO	ESF SWITCHGEAR ROOM HVAC AIR-OP DAMPER HJB-M31 FAILS TO OPEN	1.0E-006	16.000	730.000	H	Test Period	7.3E-004
1HJB-M31---DM9CM	ESF SWITCHGEAR ROOM AIR-OP DAMPER HJB-M31 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1HJB-M31---SV-FO	ESF SWITCHGEAR ROOM HVAC DAMPER SOLENOID VALVE FOR HJB-M31 FAILS TO OPEN	9.1E-007	3.000	730.000	H	Test Period	6.0E-004
1HJB-M31M58CXXFO	CONTROL CIRC COMMON TO ESS DC EQ RM DAMPERS HJB-M31 & HJB-M58 FAIL TO OPEN		10.000	1.4E-004	D	Calculated	1.4E-004
1HJB-M39---DMMRO	ESF SWITCHGEAR ROOM FIRE DAMPER HJB-M39 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJB-M40---DMMRO	ESF SWITCHGEAR RM FIRE DAMPER HJB-M40 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJB-M41---DMMRO	ESF SWITCHGEAR ROOM FIRE DAMPER HJB-M41 FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJB-M42---DMMFO	ESF SWITCHGEAR ROOM BACKDRAFT DAMPER HJB-M42 FAILS TO OPEN	1.1E-007	10.000	4380	H	Test Period	2.4E-004
1HJB-M55---DM-FO	NORM CR HVAC AIR-OP ISOL DAMPER (HJB-M55) FAILS TO RE-OPEN	1.0E-006	16.000	730.000	H	Test Period	3.7E-004
1HJB-M55---DM-RO	CR NORM AHU INTAKE AIR-OP DAMPER (HJB-M55) FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJB-M58---DM-FO	ESS DC EQUIP ROOM AIR-OP HVAC DAMPER HJB-M58 FAILS TO OPEN	1.0E-006	16.000	730.000	H	Test Period	3.7E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJB-M58---DM9CM	ESS. DC EQUIP ROOM AIR-OP HVAC DAMPER HJB-M58 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1HJB-M58---SV-FO	ESS DC EQUIP ROOM AIR-OP HVAC DAMPER SOV FOR HJB-M58 FAILS TO OPEN	9.1E-007	3.000	730.000	H	Test Period	3.0E-004
1HJB-M66---CXXFO	NORM ESF SWGR RM HVAC DAMPER HJB-M66 FAILS TO REOPEN -CONT CIRC FAULT		3.000	3.2E-004	D	Calculated	3.2E-004
1HJB-M66---CXXRO	NRM ESF SWGR RM HVAC DAMPER (HJB-M66) FAILS TO REMAIN OPEN -CONTROL CIRC FAULTS		10.000	1.4E-004	D	Calculated	1.4E-004
1HJB-M66---DM-FO	NORM ESF SWGR RM HVAC AIR-OP ISOL DAMPER (HJB-M66) FAILS TO REOPEN		16.000	3.0E-003	D	Calculated	3.0E-003
1HJB-M66---DM-RO	ESF SWITCHGEAR ROOM HVAC AIR-OP DAMPER HJB-M66 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJB-M66---DM9CM	NORM ESF SWGR RM HVAC AIR-OP DAMPER HJB-M66 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1HJB-M68---DMMRO	NORMAL/ESS. ESF DC EQUIP. RM FIRE DAMPER HJB-M68 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJB-M69---DMMRO	NORMAL/ESS. ESF DC EQUIP. RM FIRE DAMPER HJB-M69 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJB-M72---DMMRO	NORMAL/ESS. ESF DC EQUIP. RM FIRE DAMPER HJB-M72 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJB-M75---DMMRO	ESSENTIAL DC EQUIP ROOM FIRE DAMPER FAILS TO REMAIN OPEN	2.5E-007	10.000	13140.000	H	Test Period	1.6E-003
1HJB-M78---DMMRO	CR TR B ESS AHU DISCHARGE MANUAL DAMPER HJB-M78 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005
1HJB-M79---DMMRO	CR TR B ESS AHU DISCHARGE MANUAL DAMPER HJB-M79 FAILS TO REMAIN OPEN	2.5E-007	10.000	730.000	H	Test Period	9.1E-005
1HJB-UY-8A-SV-FO	NORM CR HVAC AIR-OP DAMPER (HJB-M01) SOV FAILS TO RE-OPEN	9.1E-007	3.000	730.000	H	Test Period	3.0E-004
1HJB-UY-8A-SV-RO	CR NORM AHU AIR-OP DAMPER (HJB-M01) FAILS TO REMAIN OPEN	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1HJB-UY-8B-SV-FO	NORM CR HVAC AIR-OP DAMPER (HJB-M55) SOV FAILS TO RE-OPEN	9.1E-007	3.000	730.000	H	Test Period	3.0E-004
1HJB-UY-8B-SV-RO	CR NORM AHU AIR-OP DAMPER (HJB-M55) SOV FAILS TO REMAIN OPEN	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1HJB-UY62E-SV-FO	NORM ESF SWGR RM HVAC AIR-OP DAMPER (HJB-M66) SOV FAILS TO REOPEN		3.000	1.0E-003	D	Calculated	1.0E-003
1HJB-UY62E-SV-RO	NORM ESF SWITCHGEAR RM HVAC AIR-OP DAMPER (HJB-M66) SOV FAILS TO REMAIN OPEN	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJB-Z03---AR6CM	ESS ESF SWGR RM HVAC TRAIN B AHU (HJB-Z03) UNAVAIL DUE TO MAINTENANCE		3.000	2.1E-004	D	Plant Specific	2.1E-004
1HJBHVACDCEQ-2OP	ESSENTIAL ESF SWITCHGEAR ROOM HVAC LOCAL UNIT FAILS TO OPERATE		5.000	8.3E-003	D	Calculated	8.3E-003
1HJBHVACESGR-2OP	ESSENTIAL ESF SWITCHGEAR ROOM HVAC TRAIN B LOCAL UNIT FAILS TO OPERATE		5.000	1.7E-003	D	Calculated	1.7E-003
1HJBUY8A-8BCXXFO	NORM CR HVAC TR B DAMPERS (M01, M55) FAIL TO RE-OPEN DUE TO COMMON CNTL CIRC FAU		3.000	5.0E-004	D	Calculated	5.0E-004
1HJBUY8A-8BCXXRO	CR NORM AHU TR B DAMPERS (M01, M55) FTR OPEN DUE TO COMMON SOV CNTL CIRC FAULT		3.000	3.6E-004	D	Calculated	3.6E-004
1HJN-A02---AR8CM	NORMAL OPERATING CONTROL RM HVAC AHU HJN-A02 UNAVAILABLE DUE TO MAINTENANCE		5.000	1.3E-003	D	Plant Specific	1.3E-003
1HJN-A02---ARFFS	NORM CONTROL RM HVAC AHU (HJN-A02) FAILS TO RESTART AFTER TRIP		10.000	4.7E-005	D	Calculated	4.7E-005
1HJN-A02---CXXFS	NORM CONTROL RM HVAC AHU (HJN-A02) FAILS TO RESTART - CNTL CIRC FAULT		10.000	8.7E-004	D	Calculated	8.7E-004
1HJN-A03---AR8CM	NORMAL ESF SWGR RM HVAC AHU (HJN-A03) UNAVAILABLE DUE TO MAINTENANCE		5.000	1.3E-003	D	Plant Specific	1.3E-003
1HJN-A03---ARFFS	NORM ESF SWGR ROOM HVAC AHU (HJA-A03) FAILS TO RESTART AFTER TRIP		10.000	4.7E-005	D	Calculated	4.7E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJN-A03---CXXFS	NORM ESF SWGR ROOM HVAC AHU (HJN-A03) FAILS TO RESTART -CNTL CIRC FAULT		10.000	1.3E-003	D	Calculated	1.3E-003
1HJN-M107--DMMRO	ESF SWITCHGEAR ROOM FIRE DAMPER HJN-M107 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJN-M59---DMMRO	NORMAL ESF SWITCHGEAR RM FIRE DAMPER HJN-M59 FAILS TO REMAIN OPEN	2.5E-007	10.000	36.000	H	Mission Time / Detection Period	9.0E-006
1HJN-M60---DMMRO	NORMAL/ESS. ESF DC EQUIP. RM FIRE DAMPER HJN-M60 FAILS TO REMAIN OPEN	2.5E-007	10.000	24.000	H	Mission Time	6.0E-006
1HJN-M62---DMMRO	NORM ESF SWITCHGEAR ROOM FIRE DAMPER HJN-M62 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJN-M63---DMMRO	NORM ESF SWITCHGEAR ROOM FIRE DAMPER HJN-M63 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJN-M64---DMMRO	ESF SWITCHGEAR ROOM BACKDRAFT DAMPER HJN-M64 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1HJN-M65---DMMRO	NORM ESF SWGR ROOM BACKDRAFT DAMPER HJN-M65 FAILS TO REMAIN OPEN	2.5E-007	10.000	48.000	H	Mission Time / Detection Period	1.2E-005
1HJN-M99---DMMRO	NORMAL ESF SWITCHGEAR RM FIRE DAMPER HJN-M99 FAILS TO REMAIN OPEN	2.5E-007	10.000	36.000	H	Mission Time / Detection Period	9.0E-006
1HJNHVAC-CR--2OP	NORMAL OPERATING CR HVAC FAILS TO PROVIDE COOLING - LOCAL FAULTS		10.000	3.4E-004	D	Calculated	3.4E-004
1HJNHVACESGR-2OP	NORMALLY OPER ESF SWGR RM HVAC FAILS TO PROVIDE COOLING - LOCAL FAULTS		5.000	3.4E-004	D	Calculated	3.4E-004
1HLI-2HR-OP--2HR	OPERATOR FAILURE TO INITIATE HOT LEG INJ AT 2 HOURS		10.000	4.0E-004	D	Calculated	4.0E-004
1HLI2MV-CC-MV-CC	COMMON CAUSE FAILURE OF EITHER SET OF INJ MOV'S:2 OF 2 FAIL		30.000	1.1E-004	D	Calculated	1.1E-004
1HOTWELLFILL--HR	OPERATOR FAILS TO LINE-UP MANUAL HOTWELL FILL UPON LOW CONDENSER LEVEL		10.000	4.3E-003	D	Calculated	4.3E-003
1IAN-C01A--ARAFR	LOCAL FAULT AIR COMPRESSOR C01A FAILS TO RUN (24 HRS)	2.9E-004	25.000	24.000	H	Mission Time	7.0E-003
1IAN-C01A--ARAFS	LOCAL FAULT - AIR COMPRESSOR A FAILS TO START (AFTER RECOVERY OF OFFSITE POWER)	1.0E-006	5.000	5840.000	H	Test Period	2.9E-003
1IAN-C01A--CX7FS	CONTROL CIRCUIT FAILURE - COMPRESSOR A CIRCUIT BRKR FAIL TO CLOSE	1.0E-006	3.000	5840.000	H	Test Period	2.9E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1IAN-C01B--AR7CM	COMPRESSOR B UNAVAIL. DUE TO UNSCHEDULED MAINTENANCE	1.3E-004	5.000	116.000	H	MTTR	1.5E-002
1IAN-C01B--ARAFR	LOCAL FAULT AIR COMPRESSOR B (FAILS TO RUN)	2.9E-004	25.000	24.000	H	Mission Time	7.0E-003
1IAN-C01B--ARAFS	LOCAL FAULT AIR COMPRESSOR B (FAILS TO START)	1.0E-006	5.000	5840.000	H	Test Period	2.9E-003
1IAN-C01B--CX7FS	CONTROL CIRCUIT FAILURE -COMPRESSOR B CIRCUIT BREAKER FAIL TO CLOSE	1.0E-006	3.000	5840.000	H	Test Period	2.9E-003
1IAN-C01C--AR7CM	COMPRESSOR C UNAVAIL. DUE TO UNSCHEDULED MAINTENANCE	1.3E-004	5.000	116.000	H	MTTR	1.5E-002
1IAN-C01C--ARAFR	LOCAL FAULT AIR COMPRESSOR C (FAILS TO RUN)	2.9E-004	25.000	24.000	H	Mission Time	7.0E-003
1IAN-C01C--ARAFS	LOCAL FAULT AIR COMPRESSOR C (FAILS TO START)	1.0E-006	5.000	5840.000	H	Test Period	2.9E-003
1IAN-C01C--CX7FS	CONTROL CIRCUIT FAILURE -COMPRESSOR C CIRCUIT BREAKER FAIL TO CLOSE	1.0E-006	3.000	5840.000	H	Test Period	2.9E-003
1IAN-E01A--ARCIL	LOCAL FAULT OF AFTERCOOLER	3.0E-009	10.000	24.000	H	Mission Time	7.2E-008
1IAN-E01B--ARCIL	LOCAL FAULT OF AFTER COOLER B	3.0E-009	10.000	5840.000	H	Test Period	8.8E-006
1IAN-E01C--ARCIL	LOCAL FAULT OF AFTERCOOLER C	3.0E-009	10.000	5840.000	H	Test Period	8.8E-006
1IAN-F01A--FXAPG	COMPRESSOR A, INTAKE FILTER PLUGGED	6.8E-006	10.000	24.000	H	Mission Time	1.6E-004
1IAN-F01B--FXAPG	COMPRESSOR B, INTAKE FILTER PLUGGED	6.8E-006	10.000	24.000	H	Mission Time	1.6E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1IAN-F01C--FXAPG	COMPRESSOR C, INTAKE FILTER PLUGGED	6.8E-006	10.000	24.000	H	Mission Time	1.6E-004
1IAN-F02A--FXAPG	AIR FILTER IAN-F02A PLUGGED	6.8E-006	10.000	24.000	H	Mission Time	1.6E-004
1IAN-F03A--FXAPG	AIR FILTER IAN-F03A PLUGGED	6.8E-006	10.000	24.000	H	Mission Time	1.6E-004
1IAN-M01A--ARDPG	LOCAL FAULT OF AIR DRYER (IAN-M01A)	1.0E-005	10.000	24.000	H	Mission Time	2.4E-004
1IAN-X01A--TK-EL	EXCESSIVE LEAKAGE FROM AIR RECEIVER A	1.0E-009	30.000	24.000	H	Mission Time	2.4E-008
1IAN-X01B--TK-EL	EXCESSIVE LEAKAGE FROM AIR RECEIVER B	1.0E-009	30.000	5840.000	H	Test Period	2.9E-006
1IAN-X01C--TK-EL	EXCESSIVE LEAKAGE FROM AIR RECEIVER C	1.0E-009	30.000	5840.000	H	Test Period	2.9E-006
1IANCOMPRS-ARACC	COMMON CAUSE FAILURE OF ALL THREE COMPRESSORS - (FAI L TO OPERATE)		17.000	1.1E-005	D	Calculated	1.1E-005
1IANCOMPRS-ARSCC	COMMON CAUSE FAILURE OF COMPRES-SORS B AND C FAIL TO START		17.000	2.0E-003	D	Calculated	2.0E-003
1IANPIC-39-IWPNO	IA PRESS. INDICATING CONTROLLER (SWITCH) FAILS TO OPERATE (B & C COMP. ACT. FAIL	1.4E-006	14.000	5840.000	H	Test Period	4.1E-003
1IANPSV012-RV-RC	SAFETY RELIEF VALVE PSV-12 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1IANPSV013-RV-RC	SAFETY RELIEF VALVE PSV-13 FAILS TO REMAIN CLOSED	4.0E-006	5.000	5840.000	H	Test Period	1.2E-002

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1IANPSV014-RV-RC	SAFETY RELIEF VALVE PSV-14 FAILS TO REMAIN CLOSED	4.0E-006	5.000	5840.000	H	Test Period	1.2E-002
1IANPSV015-RV-RC	SAFETY RELIEF VALVE PSV-15 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1IANPSV016-RV-RC	SAFETY RELIEF VALVE PSV-16 FAILS TO REMAIN CLOSED	4.0E-006	5.000	5840.000	H	Test Period	1.2E-002
1IANPSV017-RV-RC	SAFETY RELIEF VALVE PSV-17 FAILS TO REMAIN CLOSED	4.0E-006	5.000	5840.000	H	Test Period	1.2E-002
1IANTRIPS-A--2ST	SPURIOUS TRIPS - COMPRESS A (AIR-OIL PRESS, TEMP.,ORVIBR)		10.000	1.0E-003	D	Calculated	1.0E-003
1IANTRIPS-B--2ST	SPURIOUS TRIPS - COMPRESS B (AIR-OIL PRESS, TEMP.,ORVIBR)		10.000	1.0E-003	D	Calculated	1.0E-003
1IANTRIPS-C--2ST	SPURIOUS TRIPS - COMPRESS C (AIR-OIL PRESS, TEMP.,ORVIBR)		10.000	1.0E-003	D	Calculated	1.0E-003
1IANV001---NV-RO	MANUAL VALVE V001 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1IANV005---CV-RO	CHECK VALVE V005 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1IANV006---NV-RO	MANUAL VALVE V006 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1IANV009---NV-RO	MANUAL VALVE V009 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1IANV010---NV-RO	MANUAL VALVE V010 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1IANV011---NV-RO	MANUAL VALVE V011 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1IANV016---NV-RO	MANUAL VALVE V016 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1IANV017---NV-RO	MANUAL VALVE V017 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1IANV023---NV-RM	FAILURE TO RESTORE V023 AFTER UNSCHEDULED MAINTENANCE		10.000	4.4E-005	D	Calculated	4.4E-005
1IANV023---NV-RO	MANUAL VALVE V023 FAILS TO REMAIN OPEN	3.0E-008	84.000	5840.000	H	Test Period	8.8E-005
1IANV024---CV-FO	CHECK VALVE V024 FAILS TO OPEN	3.0E-008	3.000	5840.000	H	Test Period	8.8E-005
1IANV025---NV-RM	FAILURE TO RESTORE V025 AFTER UNSCHEDULED MAINTENANCE		10.000	4.4E-005	D	Calculated	4.4E-005
1IANV025---NV-RO	MANUAL VALVE V025 FAILS TO REMAIN OPEN	3.0E-008	84.000	5840.000	H	Test Period	8.8E-005
1IANV029---NV-RM	FAILURE TO RESTORE V029 AFTER UNSCHEDULED MAINTENANCE		10.000	4.4E-005	D	Calculated	4.4E-005
1IANV029---NV-RO	MANUAL VALVE V029 FAILS TO REMAIN OPEN	3.0E-008	84.000	5840.000	H	Test Period	8.8E-005
1IANV032---CV-FO	CHECK VALVE V032 FAILS TO OPEN	3.0E-008	3.000	5840.000	H	Test Period	8.8E-005
1IANV033---NV-RM	FAILURE TO RESTORE V033 AFTER UNSCHEDULED MAINTENANCE		10.000	4.4E-005	D	Calculated	4.4E-005
1IANV033---NV-RO	MANUAL VALVE V033 FAILS TO REMAIN OPEN	3.0E-008	84.000	5840.000	H	Test Period	8.8E-005
1IANV050---CV-RO	CHECK VALVE V050 FAILS TO REMAIN OPEN	2.3E-007	3.000	24.000	H	Mission Time	5.5E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1IANV051---NV-RO	MANUAL VALVE V051 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1IANV057---NV-RO	MANUAL VALVE V057 (IA SYSTEM)"FAILS TO REMAIN OPEN	3.0E-008	84.000	2190.000	H	Test Period	3.3E-005
1LLOCA-RCS1A-3BK	PROBABILITY THAT LARGE LOCA BREAK OCCURED IN RCS LOOP 1A		1.000	2.5E-001	D	Calculated	2.5E-001
1LLOCA-RCS1B-3BK	PROBABILITY THAT LARGE LOCA BREAK OCCURED IN RCS LOOP 1B		1.000	2.5E-001	D	Calculated	2.5E-001
1LLOCA-RCS2A-3BK	PROBABILITY THAT LARGE LOCA BREAK OCCURED IN RCS LOOP 2A		1.000	2.5E-001	D	Calculated	2.5E-001
1LLOCA-RCS2B-3BK	PROBABILITY THAT LARGE LOCA BREAK OCCURED IN RCS LOOP 2B		1.000	2.5E-001	D	Calculated	2.5E-001
1LPA---LOP---2AT	LOP.LS MODULE FAILS TO PASS THE DG START/DG BRKR CLOSE SIGNAL FROM SEQ A TO K205		30.000	3.4E-006	D	Calculated	3.4E-006
1LPA---LOP---2SA	LOAD SEQ A OR LOP/LS MODULE A CAUSES A SPURIOUS TR A LOP SIGNAL		30.000	1.9E-006	D	Calculated	1.9E-006
1LPA-DETECT--2AT	LPA SEQUENCER A LOP/LS MODULE FAILS TO PROVIDE D.G. 1 START SIGNAL UPON LOP ON 4		30.000	3.4E-006	D	Calculated	3.4E-006
1LPA1--LOP---2AT	SEGR A LOP #1K203 RELAY FAILS TO DE-ENERGIZE ON LOP GRP 1 SIGNAL		10.000	2.6E-003	D	Calculated	2.6E-003
1LPA1--LOP-RX-DE	SEQR A LOP #1 K203 RELAY SPURIOUS DE-ENERGIZE	4.3E-006	91.000	24.000	H	Mission Time	1.0E-004
1LPA2--LOP---2AT	SEQR A LOP #2 K205 RELAY FAILS TO DE-ENER TO START DG1 & CLOSE BRKR		10.000	2.6E-003	D	Calculated	2.6E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1LPB---LOP---2AT	LOP.LS MODULE FAILS TO PASS THE DG START/DG BRKR CLOSE SIGNAL FROM SEQ B TO K205		30.000	3.4E-006	D	Calculated	3.4E-006
1LPB---LOP---2SA	LOAD SEQ B OR LOP/LS MODULE B CAUSES A SPURIOUS TR B LOP SIGNAL		30.000	1.9E-006	D	Calculated	1.9E-006
1LPB-DETECT--2AT	SEQR B LOP/LS MODULE FAILS TO SEND LOP SIGNAL AFTER LOP ON 4.16KV PBB-S04		30.000	3.4E-006	D	Calculated	3.4E-006
1LPB1--LOP---2AT	SEQR B LOP #1 K203 RELAY FAILS TO DE-ENERGIZE ON LOP GRP 1 SIGNAL		10.000	2.6E-003	D	Calculated	2.6E-003
1LPB1--LOP-RX-DE	SEQR B LOP #1 K203 RELAY SPURIOUS DE-ENERGIZES	4.3E-006	91.000	24.000	H	Mission Time	1.0E-004
1LPB2--LOP---2AT	SEQR B LOP #2 K206 RELAY FAILS TO DE-ENER TO START DG 2 & CLOSE		10.000	2.6E-003	D	Calculated	2.6E-003
1LSA--LDSHED-2AT	TR A LOAD SHED SIG. FAILS TO CLEAR DUE TO SEQUENCER OR LOP/LS MODULE FAULT		30.000	6.7E-006	D	Calculated	6.7E-006
1LSA--LDSHED-2SA	LOAD SEQUENCER A OR LOP/LS MODULE A CAUSED A SPURIOUS TRAIN A LOAD SHED SIGNAL		30.000	1.9E-006	D	Calculated	1.9E-006
1LSA-LDSHED-HISA	LOP/LS MODULE IN BOP ESFAS CABINET C02A GENERATES LOAD SHED DUE TO HI TEMP		10.000	5.0E-001	D	Calculated	5.0E-001
1LSA1-LDSHED-2AT	TR A, #1 LOAD SHED SIG. FAILS TO CLEAR DUE TO RELAY K202 FAULT (FAIL TO DE-ENER)		10.000	2.4E-004	D	Calculated	2.4E-004
1LSA1-LDSHED-2SA	SPURIOUS LOAD SHED TRAIN A, #1 ACTUATION SIGNAL (K202 RELAY SPUR ENER)		91.000	1.0E-005	D	Calculated	1.0E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1LSA2-LDSHED-2AT	TR. A, #2 LOAD SHED SIG. FAILS TO CLEAR RELAY K204 FAULT (FAIL TO DE-ENGER)		10.000	2.4E-004	D	Calculated	2.4E-004
1LSA2-LDSHED-2SA	K204 RELAY CAUSES A SPURIOUS TRAIN A, #2 LOAD SHED		91.000	1.0E-005	D	Calculated	1.0E-005
1LSB--LDSHED-2AT	TR B LOAD SHED SIG. FAILS TO CLEAR DUE TO SEQUENCER OR LOP/LS MODULE FAULT		30.000	6.7E-006	D	Calculated	6.7E-006
1LSB--LDSHED-2SA	LOAD SEQUENCER B OR LOP/LS MODULE B CAUSED A SPURIOUS TRAIN B LOAD SHED SIGNAL		30.000	1.9E-006	D	Calculated	1.9E-006
1LSB-LDSHED-HISA	LOP/LS MODULE IN BOP ESFAS CABINNET C02B GENERATES LOAD SHED DUE TO HI TEMP		10.000	5.0E-001	D	Calculated	5.0E-001
1LSB1-LDSHED-2AT	TR B, #1 LOAD SHED SIG. FAILS TO CLEAR DUE TO RELAY K202 FAULT (FAIL TO DE-ENER)		10.000	2.4E-004	D	Calculated	2.4E-004
1LSB1-LDSHED-2SA	SPURIOUS LOAD SHED TRAIN B, #1 ACT SIGNAL (K202 RELAY SPUR ENER)		91.000	1.0E-005	D	Calculated	1.0E-005
1LSB2-LDSHED-2AT	TR B, #2 LOAD SHED SIG. FAILS TO CLEAR RELAY K204 FAULT (FAIL TO DE-ENER)		10.000	2.4E-004	D	Calculated	2.4E-004
1LSB2-LDSHED-2SA	K304 RELAY CAUSES A SPURIOUS TRAIN B, #2 LOAD SHED		91.000	1.0E-005	D	Calculated	1.0E-005
1MSIV-1A---MV-FC	MSIV 1A FAILS TO CLOSE ON DEMAND		14.000	2.2E-003	D	Calculated	2.2E-003
1MSIV-2A---MV-FC	MSIV 2A FAILS TO CLOSE ON DEMAND		14.000	2.2E-003	D	Calculated	2.2E-003
1MSIV-CLOSE--2HR	OPERATOR FAILS TO CLOSE MSIV'S ON RUPTURED SG		10.000	5.0E-003	D	Calculated	5.0E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1MSIV-LEAK---2OP	FAILURE OF A MSIV TO CLOSE RESULTS IN CONTINUED STEAMING OF RUPTURED SG		1.000	1.000	D	Screening Value	1.000
1MSSV-OPEN---2OP	MSSV FAILS TO CLOSE AFTER DEMAND (STEAM RELIEF)		10.000	3.2E-002	D	Calculated	3.2E-002
1NANA03-138BS-PW	LOCAL FAULT 13.8 KV NON-SEGMENTED CROSS-TIE BUS E-NAN-A03	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NANA04-138BS-PW	LOCAL FAULT 13.8 KV NON-SEGMENTED CROSS-TIE BUS E-NAN-A04	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NANS01-138BS-PW	LOCAL FAULT 13.8 KV NON-CLASS BUS E-NAN-S01 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NANS01-UV---2SA	E-NAN-S01 BUS SPURIOUS UV TRIP OF ALL 13.8KV FEEDER BREAKERS		10.000	1.8E-004	D	Calculated	1.8E-004
1NANS01D---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S01D -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS01D---CB0CM	13.8 KV CKTBRK E-NAN-S01D UNAVAIL FOR PERIOD OF UNSCHED MAINTE-NANCE	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NANS01D---CX6ST	13.8 KV CKTBRK E-NAN-S01D CONTROL CIRC FAULTS -SPURIOUS TRIP	1.1E-005	10.000	24.000	H	Mission Time	2.6E-004
1NANS01E---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S01E -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS01E---CB0CM	13.8 KV CKTBRK E-NAN-S01E UNAVAIL FOR PERIOD OF UNSCHED MAINTE-NANCE	9.4E-006	10.000	16.000	H	MTTR	1.5E-004
1NANS01E---CX6ST	13.8 KV CKTBRK E-NAN-S01E CONTROL CIRC FAULTS -SPURIOUS TRIP	1.1E-005	10.000	24.000	H	Mission Time	2.6E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NANS01G---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S01G -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS01G---CB0CM	13.8 KV CKTBRK E-NAN-S01G UNAVAIL FOR PERIOD OF UNSCHED MAINTE-NANCE	9.4E-006	10.000	16.000	H	MTTR	1.5E-004
1NANS01G---CX6ST	13.8 KV CKTBRK E-NAN-S01G CONTROL CIRC FAULTS -SPURIOUS TRIP	1.1E-005	10.000	24.000	H	Mission Time	2.6E-004
1NANS01N---CB-ST	LOCAL FAULT OF 13.8KV CIRCUIT BREAKER E-NAN-S01N (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS01N---CX8ST	13.8KV CIRCUIT BREAKER E-NAN-S01N CONTROL CIRCUIT - SPURIOUS TRIP	8.4E-006	10.000	24.000	H	Mission Time	2.0E-004
1NANS02-138BS-PW	LOCAL FAULT 13.8 KV NON-CLASS BUS E-NAN-S02 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NANS02-UV---2SA	E-NAN-S02 BUS SPURIOUS UV TRIP OF ALL 13.8KV FEEDER BREAKERS		10.000	1.8E-004	D	Calculated	1.8E-004
1NANS02E---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S02E -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS02E---CB0CM	13.8 KV CKTBRK E-NAN-S02E UNAVAIL FOR PERIOD OF UNSCHED MAINTE-NANCE	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NANS02E---CX6ST	13.8 KV CKTBRK E-NAN-S02E CONTROL CIRC FAULTS -SPURIOUS TRIP	1.1E-005	10.000	24.000	H	Mission Time	2.6E-004
1NANS02N---CB-ST	LOCAL FAULT OF 13.8KV CIRCUIT BREAKER E-NAN-S02N (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NANS02N---CX8ST	13.8KV CIRCUIT BREAKER E-NAN-S02N CONTROL CIRCUIT - SPURIOUS TRIP	8.4E-006	10.000	24.000	H	Mission Time	2.0E-004
1NANS03-138BS-PW	LOCAL FAULT OF 13.8 KV BUS E-NAN-S03 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission. Time	2.0E-005
1NANS03-138BSOCM	13.8 KV BUS E-NAN-S03 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NANS03-138EXOPW	FAULT IN OVERHEAD 13.8 KV LINES BETWEEN E-NAN-S05 AND E-NAN-S03 BUSES	2.2E-006	5.000	24.000	H	Mission Time	5.3E-005
1NANS03A---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S03A -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS03A---CBOCM	13.8 KV CKTBRK E-NAN-S03A UNAVAIL-ABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1NANS03A---CX8ST	13.8 KV CKTBRK E-NAN-S03A CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)	8.4E-006	10.000	24.000	H	Mission Time	2.0E-004
1NANS03B---CBOCM	13.8 KV FAST-TRANS CKTBRK E-NAN-S03B UNAVAILABLE DUE TO UNSCHED MAIN-TENANCE	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NANS03B---CBOFT	LOCAL FAULT 13.8 KV FAST-TRANS CKT-BRK E-NAN-S03B - FAIL TO CLOSE	2.4E-006	10.000	4380.000	H	Test Period	5.3E-003
1NANS03B---CXXFT	13.8 KV FAST-TRANS CKTBRK E-NAN-S03B CONTROL CIRC FAULTS -FAIL TO CLOSE		10.000	7.6E-003	D	Calculated	7.6E-003
1NANS04-138BS-PW	LOCAL FAULT OF 13.8 KV BUS E-NAN-S04 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NANS04-138BSOCM	13.8 KV BUS E-NAN-S04 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NANS04-138EXOPW	FAULT IN OVERHEAD 13.8 KV LINES BETWEEN E-NAN-S06 AND E-NAN-S04 BUSES	2.2E-006	5.000	24.000	H	Mission Time	5.3E-005
1NANS04A---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S04A -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS04A---CB0CM	13.8 KV CKTBRK E-NAN-S04A UNAVAILABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1NANS04A---CX8ST	13.8 KV CKTBRK E-NAN-S04A CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)	8.4E-006	10.000	24.000	H	Mission Time	2.0E-004
1NANS04B---CB0CM	13.8 KV FAST-TRANS CKTBRK E-NAN-S04B UNAVAILABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NANS04B---CB0FT	LOCAL FAULT 13.8 KV FAST-TRANS CKTBRK E-NAN-S04B - FAIL TO CLOSE	2.4E-006	10.000	4380.000	H	Test Period	5.3E-003
1NANS04B---CXXFT	13.8 KV FAST-TRANS CKTBRK E-NAN-S04B CONTROL CIRC FAULTS -FAIL TO CLOSE		10.000	7.6E-003	D	Calculated	7.6E-003
1NANS05-138BS-PW	LOCAL FAULT 13.8 KV INTERMEDIATE BUS E-NAN-S05 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NANS05-138BS0CM	13.8 KV BUS E-NAN-S05 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NANS05A---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S05A -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS05A---CB0CM	13.8 KV CKTBRK E-NAN-S05A UNAVAILABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1NANS05A---CX7ST	13.8 KV CKTBRK E-NAN-S05A CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)	5.9E-006	10.000	24.000	H	Mission Time	1.4E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NANS05B---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S05B	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS05B---CX6ST	13.8 KV CKTBRK E-NAN-S05B CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)		10.000	2.9E-004	D	Calculated	2.9E-004
1NANS06-138BS-PW	LOCAL FAULT 13.8 KV INTERMEDIATE BUS E-NAN-S06 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NANS06-138BS0CM	13.8 KV BUS E-NAN-S06 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NANS06H---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S06H -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS06H---CX7ST	13.8 KV CKTBRK E-NAN-S06H CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)		10.000	2.9E-004	D	Calculated	2.9E-004
1NANS06K---CB-ST	LOCAL FAULT OF 13.8 KV CKTBRK E-NAN-S06K	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NANS06K---CB0CM	13.8 KV CKTBRK E-NAN-S06K UNAVAIL-ABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NANS06K---CX6ST	13.8 KV CKTBRK E-NAN-S06K CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)		10.000	1.4E-004	D	Calculated	1.4E-004
1NBNS01-416BS-PW	LOCAL FAULT OF BUS E-NBN-S01 (FAIL TO CARRY POWER)	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NBNS01-X-S02-EE	OPERATOR HAS NOT OR CAN NOT MANU-ALLY TRANSFER BUS TO ALT POWER SOURCE		1.000	1.000	D	Flag Event	1.000
1NBNS01A---CB-ST	LOCAL FAULT OF CIRCUIT BREAKER E-NBN-S01A (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NBNS01A---CX9ST	CIRCUIT BREAKER E-NBN-S01A CONTROL CIRUIT FAULT	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NBNS01C---CB-FT	CROSS-TIE CIRCUIT BREAKER E-NBN-S01C FAIL TO CLOSE	1.2E-006	5.000	13140.000	H	Test Period	7.9E-003
1NBNS01C---CXXFT	CROSS-TIE CIRCUIT BREAKER E-NBN-S01C CONTROL CIRCUIT FAULT		10.000	1.6E-002	D	Calculated	1.6E-002
1NBNS01UNAVAILEE	LOSS OF POWER AT NON-CLASS 4.16KV BUS E-NBN-S01		1.000	1.000		Flag Event	1.000
1NBNS02-416BS-PW	LOCAL FAULT OF BUS E-NBN-S02 (FAIL TO CARRY POWER)	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NBNS02A---CB-ST	LOCAL FAULT OF CIRCUIT BREAKER E-NBN-S02A (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NBNS02A---CX9ST	CIRCUIT BREAKER E-NBN-S02A CONTROL CIRCUIT SPURIOUS TRIP	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004
1NBNX02-138XMLPW	TRANSFORMER E-NBN-X02 FAILS TO PROVIDE POWER	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NBNX03-138EXOPW	FAULT IN OVERHEAD 13.8 KV LINES FROM E-NAN-S03 BUS TO NBNX03 TRANSFORMER	2.2E-006	5.000	24.000	H	Mission Time	5.3E-005
1NBNX03-138XMLPW	TRANSFORMER NBNX03 BETWEEN 13.8 & 4.16 KV BUSES FAILS	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NBNX04-138EXOPW	FAULT IN OVERHEAD 13.8 KV LINES FROM E-NAN-S04 BUS TO NBNX04 TRANSFORMER	2.2E-006	5.000	24.000	H	Mission Time	5.3E-005
1NBNX04-138XMLPW	TRANSFORMER NBNX04 BETWEEN 13.8 & 4.16 KV BUSES FAILS	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NC-FSL119-IWFNO	NCW TO WC CHILLER E01A FLOW SWITCH FAILS (NO OUTPUT)	1.6E-006	5.000	24.000	H	Mission Time	3.8E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NC-FSL120-1WFNO	NCW TO WC CHILLER E01B FLOW SWITCH CAILS (NO OUTPUT)	1.6E-006	5.000	24.000	H	Mission Time	3.8E-005
1NC-FSL121-1WFNO	NCW TO WC CHILLER E01C FLOW SWITCH FLS-121 FAILS (NO OUTPUT)	1.6E-006	5.000	8760.000	H	Test Period	7.0E-003
1NC-FSL606-1WFNO	NCW TO WC CHILLER E02 FLOW SWITCH FSL-606 FAILS (NO OUTPUT)	1.6E-006	5.000	8760.000	H	Test Period	7.0E-003
1NC-HCV019-NV-RO	NCW TO WC CHILLER E01A ISOLATION VALVE HCV FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1NC-HCV020-NV-RO	NCW TO WC CHILLER E01B ISOL. VALVE HCV-20 FAILS TO REMAIN OPEN.	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1NC-HCV021-NV-RO	NCW TO WC CHILLER E01C MAN ISOL VALVE HCV-121 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1NC-HCV612-NV-RO	NCW TO WC CHILLER E02 MANUAL ISOL VALVE HCV-612 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1NC-UV103--MV-RO	NCW TO WC CHILLER ISOLATION VALVE UV-103 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1NC-UV104--MV-RO	NCW TO WC CHILLER E01B ISOL. VALVE UV-104 FAILS TO REMAIN OPEN.	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1NC-UV105--CX3FO	NCW TO WC SHILLER E01C ISOL MOV UV-105 CONTROL CKT FAULT -FAIL TO OPEN	7.9E-007	3.000	8760.000	H	Test Period	3.5E-003
1NC-UV105--MV-FO	NCW TO WC CHILLER E01C ISOL MOV UV-105 FAILS TO OPEN ON WC PUMP P01C START	2.9E-006	14.000	8760.000	H	Test Period	1.3E-002
1NC-UV607--CX3FO	NCW TO WC CHILLER E02 ISOL MOV UV-067 CONTROL CIRCUIT FAULT - FAIL TO OPEN	7.9E-007	3.000	8760.000	H	Test Period	3.5E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NC-UV607--MV-FO	NCW TO WC CHILLER E02 ISOL MOV UV-607 FAILS TO OPEN ON WC PUMP P02 START	2.9E-006	14.000	8760.000	H	Test Period	1.3E-002
1NCW-ECW-OP--2HR	OPERATOR FAILS TO ALIGN ECW TO THE NCW SYSTEM WITHIN 10 MIN OF A LOSS OF NCW		3.000	4.0E-001	D	Calculated	4.0E-001
1NGNL01-138XMLPW	TRANSFORMER NGNL01 BETWEEN 13.8 KV AND 480 V LOAD CENTER FAILS	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NGNL01-480BS-PW	LOCAL FAULT OF LC E-NGN-L01 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NGNL01-480BSOCM	LC E-NGN-L01 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NGNL01B2--CB-ST	LOCAL FAULT OF 480V CB E-NGN-L01B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL01B2--CX0ST	CIRCUIT BREAKER E-NGN-L01B2 CONTROL CIRCUIT SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1NGNL01C3-CCB-FT	LOCAL FAULT -COMPRESSOR C CIRCUIT BREAKER FAIL TO CLOSE	1.2E-006	5.000	5840.000	H	Test Period	3.5E-003
1NGNL02-138XMLPW	TRANSFORMER NGNL02 BETWEEN 13.8 KV AND 480 V LOAD CENTER FAILS	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NGNL02-480BS-PW	LOCAL FAULT OF LC E-NGN-L02 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NGNL02-480BSOCM	LC E-NGN-L02 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NGNL02B2--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-NGN-LO2B2-FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NGNL02B2--CX0ST	CIRCUIT BREAKER E-NGN-L02B2 CONTROL CIRCUIT SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1NGNL02C3-BCB-FT	LOCAL FAULT -COMPRESSOR B CIRCUIT BREAKER FAIL TO CLOSE	1.2E-006	5.000	5840.000	H	Test Period	3.5E-003
1NGNL02D3--CB-ST	CIRCUIT BREAKER E-NGN-L02D3 FAILS TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL02D3--CX-ST	CIRCUIT BREAKER E-NGN-L02D3 CONTROL CIRCUIT SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1NGNL06-138XMLPW	TRANSFORMER NGNL06 BETWEEN 13.8 KV AND 480 V LOAD CENTER FAILS	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NGNL06-480BS-PW	LOCAL FAULT OF LC E-NGN-L06/FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NGNL06-480BS0CM	LC E-NGN-L06 UNAVAIL DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	27.000	H	MTTR	3.5E-005
1NGNL06C4--CB-ST	CIRCUIT BREAKER E-NGN-L06C4 FAILS TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL06C4--CX-ST	CIRCUIT BREAKER E-NGN-L06C4 CONTROL CIRCUIT SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1NGNL06C4--FU-OC	FAULT IN FUSE E-NGN-L06C4/ PREMATURE OPEN	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005
1NGNL06D3--CB-ST	CIRCUIT BREAKER E-NGN-L06D3 FAILS TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL06D3--CX-ST	CIRCUIT BREAKER E-NGN-L06D3 CONTROL CIRCUIT SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1NGNL06D3--FU-OC	FAULT IN FUSE E-NGN-L06D3/ PREMATURE OPEN	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NGNL10D3--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-NGN-L10D3 (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL10D3--CX-ST	CIRCUIT BREAKER E-NGN-L10D3 CONTROL CIRCUIT - SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1NGNL13-138XMLPW	TRANSFORMER NGNL13 BETWEEN 13.8 KV AND 480 V LOAD CENTER FAILS	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NGNL13-480BS-PW	LOCAL FAULT OF LC E-NGN-L13 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NGNL13-480BS0CM	LC E-NGN-L13 UNAVAILABLE FOR PERIOD OF UNSCHED. MAINTANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NGNL13B2--CB-ST	LOCAL FAULT OF 480V CKTBRK E-NGN-L13B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL13B2--CX0ST	CIRCUIT BREAKER E-NGN-L13B2 CONTROL CIRCUIT SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1NGNL13C3-ACB-FT	LOCAL FAULT - COMPRESSOR A CIRC BRKR FAIL TO CLOSE		5.000	3.5E-003	D	Calculated	3.5E-003
1NGNL13E3--CB-ST	LOCAL FAULT OF CIRCUIT BREAKER E-NGN-L13E3 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL13E3--CX-ST	CIRCUIT BREAKER E-NGN-L13E3 CONTROL CIRCUIT FAULT	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1NGNL13E3--FU-OC	FAULT IN FUSE E-NGN-L13E3 BETWEEN NHN-M21 & NGN-L13 (PREMATURE OPEN)	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005
1NGNL25-138XMLPW	TRANSFORMER NGNL25 BETWEEN 13.8 KV AND 480 V LOAD CENTER FAILS	7.3E-007	8.000	24.000	H	Mission Time	1.8E-005
1NGNL25-480BS-PW	LOCAL FAULT OF MCC E-NGN-L25 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NGNL25-480BS0CM	LC E-NGN-L25 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NGNL25B2--CB-ST	LOCAL FAULT OF 480V LC E-NGN-L25B2 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL25B2--CX0ST	CIRCUIT BREAKER E-NGN-L25B2 CONTROL CIRCUIT SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1NGNL25C3--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-NGN-L25C3 (FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL25C3--CX-ST	CIRCUIT BREAKER E-NGN-L25C3 CONTROL CIRCUIT -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1NGNL25C4--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-NGN-L25C4 (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NGNL25C4--CX-ST	CIRCUIT BREAKER E-NGN-L25C4 CONTROL CIRCUIT FAULT-SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1NHNM03-480BS-PW	LOCAL FAULT OF MCC E-NHN-M03(FAIL TO CARRY POWER)	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM03-480BS0CM	MCC E-NHN-M03 UNAVAIL FOR UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NHNM0317--CB-ST	LOCAL FAULT OF 480 V CIRC BREAKER E-NHN-M0317 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NHNM0317--CB0CM	480 V CIRC BREAKER E-NHN-M0317 UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NHNM0317--CX0ST	480 V CIRC BREAKER E-NHN-M0317 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1NHNM03C4--FU-OC	FAULT IN FUSE E-NGN-L25C4 BETWEEN NHN-M03 & NGN-L25 (PREMATURE OPEN)	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NHNM08----FU-OC	FAULT IN FUSE E-NGN-L02D3/ PREMATURE OPEN	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005
1NHNM08-480BS-PW	LOCAL FAULT OF MCC E-NHN-M08/FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM08-480BSOCM	MCC E-NHN-M08 UNAVAIL DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NHNM0802--CB-ST	LOCAL FAULT OF 480 V CIRC BREAKER E-NHN-M0802 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NHNM0802--CBOCM	480 V CIRC BREAKER E-NHN-M0802 UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NHNM0802--CX0ST	480 V CIRC BREAKER E-NHN-M0802 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1NHNM10----FU-OC	FAULT IN FUSE BETWEEN NHN-M10 AND NGN-L10 (PREMATURE OPEN)	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005
1NHNM10-480BS-PW	LOCAL FAULT OF MCC E-NHN-M10 (FAIL TO CARRY POWER)	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM10-480BSOCM	480V MCC E-NHN-M10 UNAVAIL FOR PERIOD OF UNSHCEDULED MAINT.	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NHNM1008--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-NHN-M1008 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NHNM13----FU-OC	FAULT IN FUSE BETWEEN NHN-M13 AND NGN-L25 (PREMATURE OPEN)	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005
1NHNM13-480BS-PW	LOCAL FAULT OF MCC E-NHN-M13 (FAIL TO CARRY POWER)	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM13-480BSOCM	480V MCC E-NHN-M13 UNAVAIL FOR PERIOD OF UNSCHEDULED MAINT.	1.3E-006	5.000	26.800	H	MTTR	3.5E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NHNM1315--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-NHN-M1315 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NHNM19-480BS-PW	LOCAL FAULT OF MCC E-NHN-M19 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM19-480BSOCM	MCC E-NHN-M19 UNAVAILABLE FOR UNSCHEDULED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NHNM21-480BS-PW	LOCAL FAULT OF 480V MCC E-NHN-M21 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM21-480BSOCM	480V MCC E-NHN-M21 UNAVAILABLE FOR PERIOD OF UNSCHEDULED MAINT.	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NHNM2118--CB-ST	LOCAL FAULT OF 480 V CIRC BREAKER E-NHN-M2118 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NHNM2118--CBOCM	480 V CIRC BREAKER E-NHN-M2118 UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NHNM2118--CX0ST	480 V CIRC BREAKER E-NHN-M2118 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1NHNM28----BSOCM	MCC E-NHN-M08 UNAVAIL DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NHNM28-480BS-PW	LOCAL FAULT OF MCC E-NHN-M28/FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM2806--CB-ST	480V CB NHN-M2806 FAILS TO CARRY POWER	2.3E-007	10.000	8.000	H	Mission Time	1.8E-006
1NHNM2806--CX-ST	480V CB NHN-M2806 SPURIOUS TRIP - CONTROL CIRCUIT FAULT	2.9E-006	10.000	8.000	H	Mission Time	2.3E-005
1NHNM50----BSOCM	MCC E-NHN-M50 UNAVAIL DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	26.800	H	MMTR	3.5E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NHNM50-480BS-PW	LOCAL FAULT OF MCC E-NHN-M50/FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM71-480BS-PW	LOCAL FAULT OF MCC E-NHN-M71 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NHNM71-480BS0CM	MCC E-NHN-M71 UNAVAILABLE FOR UNSCHEDULED MAINTENANCE	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NKND41-125BS0CM	125 V DC DIST. PANEL E-NKN-D41 UNAVAILBLE FOR PERIOD OF UNSCHED MAINT	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NKND41-125BSEPW	LOCAL FAULT OF DC DIST PANEL E-NKN-D41 -FAIL TO CARRY POWER	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1NKND42-125BS0CM	125 V DC DIST. PANEL E-NKN-D42 UNAVAILBLE FOR PERIOD OF UNSCHED MAINT	1.3E-006	5.000	26.800	H	MTTR	3.5E-005
1NKNF17----BA0CM	BATTERY 'E' (E-NKN-F17) UNAVAIL FOR PERIOD OF UNSCHED MAINT	2.0E-006	5.000	16.000	H	MTTR	3.2E-005
1NKNF17----BX-PW	LOCAL FAULT OF BATTERY 'E' (E-NKN-F17) -FAIL TO PROVIDE POWER	1.0E-006	3.000	2.000	H	Mission Time	2.0E-006
1NKNF17----BX-RM	FAILURE TO RESTORE BATTERY 'E' (E-NKN-F17) AFTER UNSCHED MAINT		10.000	1.1E-004	D	Calculated	1.1E-004
1NKNH17----BX0CM	BATTERY CHARGER 'E' (E-NKN-H17) UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.2E-006	5.000	16.000	H	MTTR	1.5E-004
1NKNH17----BXCNO	LOCAL FAULT OF BATTERY CHARGER 'E' (E-NKN-H17) -NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1NKNH20----BX0CM	BATT CHARGER 'E' (E-NKN-H20) UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.2E-006	5.000	16.000	H	MTTR	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NKNH20----BXCNO	LOCAL FAULT OF BATTERY CHARGER 'E' (E-NKN-H20) -NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1NKNH21----BX0CM	BATT CHARGER 'EF' (E-NKN-H21) UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.2E-006	5.000	16.000	H	MTTR	1.5E-004
1NKNH21----BXCNO	LOCAL FAULT OF BATTERY CHARGER 'EF' (E-NKN-H21) -NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1NKNM45-125BSEPW	LOCAL FAULT OF 125 V DC CONTROL CENTER E-NKN-M45 -FAIL TO CARRY POWER	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1NKNM4502--CB-ST	LOCAL FAULT OF 125 VDC CIRC BREAKER E-NKN-M4502 -FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1NKNM4502--CB0CM	125 VDC CIRC BREAKER E-NKN-M4502 UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.4E-006	5.000	16.000	H	MTTR	1.5E-004
1NKNM4502--CXDST	125 VDC CIRC BREAKER E-NKN-M4502 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	3.4E-007	3.000	2.000	H	Mission Time	6.8E-007
1NKNM4504--CB-ST	LOCAL FAULT OF 125VDC CIRC BREAKER E-NKN-M4504 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NKNM4505--CB-FT	MANUAL 125 V DC CIRCUIT BREAKER E-NKN-M4505 FAILS TO TRANSFER	1.2E-006	5.000	24.000	H	Mission Time	2.9E-005
1NKNM4505--CB-ST	LOCAL FAULT OF 25VDC CIRC BREAKER E-NKN-M4505 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NKNM4509--CB-ST	LOCAL FAULT OF CIRC BREAKER E-NKN-M4509 -FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NKNM4509--FU-OC	FAULT IN FUSE E-NKN-M4509 BETWEEN 125 V DC CONTROL CENTER AND DIST PNL	1.0E-006	10.000	2.000	H	Mission Time	2.0E-006
1NKNM4517--CB-ST	LOCAL FAULT OF 125VDC CIRC BREAKER E-NKN-M4517 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NNAV13-480VR-NO	VOLT REGULATOR (NNA-V13) BETWEEN 480V MCC PHA-M31 AND 120V PANEL FAILS	7.2E-006	50.000	24.000	H	Mission Time	1.7E-004
1NNAV13-480VROCM	VOLTAGE REG NNA-V13 FROM CLASS MCC PHA-M31 UNAVAIL DUE TO UNSCHED MAINT	9.2E-006	5.000	116.000	H	MTTR	1.1E-003
1NNBV14-480VR-NO	VOLT. REG. (NNB-V14) BETWEEN 480V MCC PHB-M32 AND 120V PANEL FAILS	7.2E-006	50.000	24.000	H	Mission Time	1.7E-004
1NNBV14-480VROCM	VOLT REG. NNB-V14 FROM CLASS MCC PHB-M32 UNAVAIL DUE TO UNSCHED MAINT	9.2E-006	5.000	116.000	H	MTTR	1.1E-003
1NNN52-D11-CB-ST	120V AC CIRCUIT BREAKER E-NNN-D11 FAILS -SPURIOUS TRIP	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NNN52-D12-CB-ST	120V AC CIRCUIT BREAKER E-NNN-D12 FAILS - SPURIOUS TRIP	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1NNND11-120BS-PW	LOCAL FAULT OF 120V AC DIST PANEL E-NNN-D11 -FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NNND12-120BS-PW	LOCAL FAULT OF AC DIST PANEL E-NNN-D12 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1NNNTS-11--CB-FT	AUTO/MANUAL TRANS SWITCH,TS-11,FAILS TO CLOSE	1.2E-006	5.000	13140.000	H	Test Period	7.9E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1NNNTS-11--CXXFT	AUTO/MANUAL TRANS SWITCH,TS-11,CONTROL CIRCUIT FAULT -FAIL TO TRANSFER		10.000	2.5E-002	D	Calculated	2.5E-002
1NNNTS-12--CB-FT	AUTO/MANUAL TRANS SWITCH, TS-12, FAILS TO TRANSFER ON LOSS OF POWER	1.2E-006	5.000	13140.000	H	Test Period	7.9E-003
1NNNTS-12--CXXFT	AUTO/ MANUAL TRANS SWITCH, TS-12, CNTRL CIRC FAULT - FAIL TO TRANSFER		10.000	2.5E-002	D	Calculated	2.5E-002
1NNNV11-480VR-NO	VOLTAGE REGULATOR, NNN-V11, BETWEEN 120V AND 480V DIST PANEL FAILS	7.2E-006	50.000	24.000	H	Mission Time	1.7E-004
1NNNV11-480VR0CM	VOLTAGE REGULATOR NNN-V11 UNAVAIL DUE TO UNSCHED MAINTENANCE	9.2E-006	5.000	116.000	H	MTTR	1.1E-003
1NNNV12-480VR-NO	VOLTAGE REULATOR NNN-V12, BETWEEN 120V AND 480V DIST PANEL FAILS	7.2E-006	50.000	24.000	H	Mission Time	1.7E-004
1NNNV12-480VR0CM	VOLTAGE REG. NNN-V12 UNAVAIL DUE TO UNSCHED. MAINTENANCE	9.2E-006	5.000	116.000	H	MTTR	1.1E-003
1PBAS03-416BS-PW	LOCAL FAULT OF 4160 V BUS E-PBA-S03 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1PBAS03-416BS0CM	4160 V BUS E-PBA-S03 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PBAS03B---CB-FT	EMERGENCY D.G. 1 CKTBRK E-PBA-S03B FAILS TO CLOSE	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1PBAS03B---CB0CM	EMERGENCY D.G. CKTBRK E-PBA-S03B UNAVAILABLE DUE TO UNSCHED MAIN-TENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PBAS03B---CXXFT	EMERGENCY D.G. 1 CKTBRK E-PBA-S03B CNTL CIRC FAULT -FAILS TO CLOSE		10.000	9.5E-003	D	Calculated	9.5E-003
1PBAS03H---CB-ST	LOCAL FAULT OF 4160 V CKTBRK E-PBA-S03H -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PBAS03H---CB0CM	4160 V CKTBRK E-PBA-S03H UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PBAS03H---CX9ST	4160 V CKTBRK E-PBA-S03H CONTROL CIRC FAULTS -SPURIOUS TRIP	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004
1PBAS03J---CB-ST	LOCAL FAULT OF 4160 V CKTBRK E-PBA-S03J -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PBAS03J---CB0CM	4160 V CKTBRK E-PBA-S03J UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PBAS03J---CX9ST	4160 V CKTBRK E-PBA-S03J CONTROL CIRC FAULTS -SPURIOUS TRIP	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004
1PBAS03L---CB-ST	LOCAL FAULT OF 4.16 KV CKTBRK E-PBA-S03L -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PBAS03L---CB0CM	4.16 KV CKTBRK E-PBA-S03L UNAVAIL-ABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PBAS03L---CX5ST	4.16 KV CKTBRK E-PBA-S03L CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)	1.6E-006	10.000	24.000	H	Mission Time	3.8E-005
1PBAS03L-B-CXXCC	COMMON CAUSE CONTROL CIRC TRIP OF CKTBRK S03L & DG CKTBRK S03B FAIL TO CLOSE		10.000	9.1E-005	D	Calculated	9.1E-005
1PBAS03N---CB-ST	LOCAL FAULT OF 4160 V CKTBRK E-PBA-S03N -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PBAS03N---CB0CM	4160 V CKTBRK E-PBA-S03N UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PBAS03N---CX9ST	4160 V CKTBRK E-PBA-S03N CONTROL CIRC FAULTS -SPURIOUS TRIP	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004
1PBBS04-416BS-PW	LOCAL FAULT OF 4160 V BUS E-PBB-S04 - FAIL TO CARRY POWER	8.3E-007	19.000	24.000	H	Mission Time	2.0E-005
1PBBS04-416BS0CM	4160 V BUS E-PBB-S04 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PBBS04B---CB-FT	EMERGENCY D.G. 2 CKTBRK E-PBB-S04B FAILS TO CLOSE	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1PBBS04B---CB0CM	EMERGENCY D.G. 2 CKTBRK E-PBB-S04B UNAVAILABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PBBS04B---CXXFT	EMERGENCY D.G. 2 CKTBRK E-PBB-S04B CNTL CIRC FAULT -FAILS TO CLOSE		10.000	9.5E-003	D	Calculated	9.5E-003
1PBBS04H---CB-ST	LOCAL FAULT OF 4160 V CKTBRK E-PBB-S04H -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PBBS04H---CB0CM	4160 V CKTBRK E-PBB-S04H UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PBBS04H---CX9ST	4160 V CKTBRK E-PBB-S04H CONTROL CIRC FAULTS -SPURIOUS TRIP	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004
1PBBS04J---CB-ST	LOCAL FAULT OF 4160 V CKTBRK E-PBB-S04J -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PBBS04J---CB0CM	4160 V CKTBRK E-PBB-S04J UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PBBS04J---CX9ST	4160 V CKTBRK E-PBB-S04J CONTROL CIRC FAULTS -SPURIOUS TRIP	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004
1PBBS04K---CB-ST	LOCAL FAULT OF 4.16 KV CKTBRK E-PBB-S04K -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PBBS04K---CB0CM	4.16 KV CKTBRK E-PBB-S04K UNAVAIL-ABLE DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PBBS04K---CX5ST	4.16 KV CKTBRK E-PBB-S04K CONTROL CIRCUIT FAULTS (SPURIOUS TRIP)	1.6E-006	10.000	24.000	H	Mission Time	3.8E-005
1PBBS04K-B-CXXCC	COMMON CAUSE CONTROL CIRC TRIP OF CKTBRK S04K & DG CKTBRK S04B FAIL TO CLOSE		10.000	9.1E-005	D	Calculated	9.1E-005
1PBBS04N---CB-ST	LOCAL FAULT OF 4160 V CKTBRK E-PBB-S04N -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PBBS04N---CB0CM	4160 V CKTBRK E-PBB-S04N UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PBBS04N---CX9ST	4160 V CKTBRK E-PBB-S04N CONTROL CIRC FAULTS -SPURIOUS TRIP	6.5E-006	10.000	24.000	H	Mission Time	1.6E-004
1PEABG012--DG-CC	COMMON CAUSE FAILURE OF 2-OUT-OF-2 EMERGENCY D.G.'S		10.000	6.6E-004	D	Calculated	6.6E-004
1PEAG01----DG-CM	EMERGENCY D.G. 1 (E-PEA-G01 UNAVAIL-ABLE DUE TO UNSCHEULED MAINT.		5.000	6.0E-003	D	Plant Spe-cific	6.0E-003
1PEAG01-DG---2FR	EMERGENCY D.G. 1 (E-PEA-G01) FAILS TO RUN (24 HOURS)		3.000	2.2E-002	D	Calculated	2.2E-002
1PEAG01-DG---2FS	EMERGENCY D.G. 1 (E-PEA-G01) FAILS TO START		2.000	7.9E-003	D	Calculated	7.9E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PEBG02----DG-CM	EMERGENCY D.G. 2 (E-PEB-G02 UNAVAILABLE DUE TO UNSCHEULED MAINT.		5.000	6.0E-003	D	Plant Specific	6.0E-003
1PEBG02-DG---2FR	EMERGENCY D.G. 2 (E-PEB-G02) FAILS TO RUN (24 HOURS)		3.000	2.2E-002	D	Calculated	2.2E-002
1PEBG02-DG---2FS	EMERGENCY D. G. 2 (E-PEB-G02) FAILS TO START		2.000	7.9E-003	D	Calculated	7.9E-003
1PGAL31-416XMDPW	TRANSFORMER PGAL31 BETWEEN 4160 V AND 480 V BUS FAILS	9.1E-007	10.000	24.000	H	Mission Time	2.2E-005
1PGAL31-480BS0CM	480 V LOAD CTR E-PGA-L31 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PGAL31-480BSEPW	LOCAL FAULT OF 480 V LOAD CTR E-PGA-L31 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PGAL31B2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGA-L31B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL31B2--CB0CM	480 V CKTBRK E-PGA-L31B2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGAL31B2--CX-ST	480 V CKTBRK E-PGA-L31B2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL31C2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGA-L31C2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL31C2--CB0CM	480 V CKTBRK E-PGA-L31C2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGAL31C2--CX-ST	480 V CKTBRK E-PGA-L31C2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL33-416XMDPW	TRANSFORMER PGAL33 BETWEEN 4160 V AND 480 V BUS FAILS	9.1E-007	10.000	24.000	H	Mission Time	2.2E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PGAL33-480BS0CM	480 V LOAD CTR E-PGA-L33 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PGAL33-480BSEPW	LOCAL FAULT OF 480 V LOAD CTR E-PGA-L33 - FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PGAL33B2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGA-L33B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL33B2--CB0CM	480 V CKTBRK E-PGA-L33B2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGAL33B2--CX-ST	480 V CKTBRK E-PGA-L33B2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL33B3--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-PGA-L33B3-FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL33B3--CB0CM	CIRCUIT BREAKER E-PGA-L33B3 UNAVAIL DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PGAL33B3--CX-ST	CIRCUIT BREAKER E-PGA-L33B3 CONTROL CIRCUIT FAULT (SPURIOUS TRIP)	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL33C2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGA-L33C2 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL33C2--CB0CM	480 V CKTBRK E-PGA-L33C2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGAL33C2--CX-ST	480 V CKTBRK E-PGA-L33C2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL33C3--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGA-L37C2 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL33C3--CB0CM	480 V CKTBRK E-PGA-L33C3 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PGAL33C3--CX-ST	480 V CKTBRK E-PGA-L33C3 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL35-416XMDPW	TRANSFORMER PGAL35 BETWEEN 4160 V AND 480 V BUS FAILS	9.1E-007	10.000	24.000	H	Mission Time	2.2E-005
1PGAL35-480BS0CM	480 V LOAD CTR E-PGA-L35 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PGAL35-480BSEPW	LOCAL FAULT OF 480 V LOAD CTR E-PGA-L35 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PGAL35B2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGA-L35B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL35B2--CB0CM	480 V CKTBRK E-PGA-L35B2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGAL35B2--CX-ST	480 V CKTBRK E-PGA-L35B2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL35C2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGA-L35C2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL35C2--CB0CM	480 V CKTBRK E-PGA-L35C2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGAL35C2--CX-ST	480 V CKTBRK E-PGA-L35C2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGAL35D2--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-PGA-L35D2-FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGAL35D2--CB0CM	CIRCUIT BREAKER E-PGA-L35D2 UNAVAIL DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PGAL35D2--CX-ST	CIRCUIT BREAKER E-PGA-L35D2 CONTROL CIRCUIT FAULT (SPURIOUS TRIP)	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PGBL32-416XMDPW	TRANSFORMER PGBL32 BETWEEN 4160 V AND 480 V BUS FAILS	9.1E-007	10.000	24.000	H	Mission Time	2.2E-005
1PGBL32-480BSOCM	480 V LOAD CTR E-PGB-L32 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PGBL32-480BSEPW	LOCAL FAULT OF 480 V LOAD CTR E-PGB-L32 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PGBL32B2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGB-L32B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGBL32B2--CB0CM	480 V CKTBRK E-PGB-L32B2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGBL32B2--CX-ST	480 V CKTBRK E-PGB-L32B2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGBL32C2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGB-L32C2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGBL32C2--CB0CM	480 V CKTBRK E-PGB-L32C2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGBL32C2--CX-ST	480 V CKTBRK E-PGB-L32C2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGBL32C3--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGB-L32C3 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGBL32C3--CB0CM	480 V CKTBRK E-PGB-L32C3 UNAVAIL FOR PERIOD OF UNSCHED. MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGBL32C3--CX-ST	480 V CKTBRK E-PGB-L32C3 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGBL34-416XMDPW	TRANSFORMER PGBL34 BETWEEN 4160 V AND 480 V BUS FAILS	9.1E-007	10.000	24.000	H	Mission Time	2.2E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PGBL34-480BSOCM	480 V LOAD CTR E-PGB-L34 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PGBL34-480BSEPW	LOCAL FAULT OF 480 V LOAD CTR E-PGB-L34 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PGBL34B2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGB-L34B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGBL34B2--CB0CM	480 V CKTBRK E-PGA-L34B2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGBL34B2--CX-ST	480 V CKTBRK E-PGA-L34B2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGBL34C2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGB-L34C2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGBL34C2--CB0CM	480 V CKTBRK E-PGB-L34C2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGBL34C2--CX-ST	480 V CKTBRK E-PGB-L34C2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGBL36-416XMDPW	TRANSFORMER PGBL36 BETWEEN 4160 V AND 480 V BUS FAILS	9.1E-007	10.000	24.000	H	Mission Time	2.2E-005
1PGBL36-480BSOCM	480 V LOAD CTR E-PGB-L36 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PGBL36-480BSEPW	LOCAL FAULT OF 480 V LOAD CTR E-PGB-L36 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PGBL36B2--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGB-L36B2 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGBL36B2--CB0CM	480 V CKTBRK E-PGB-L36B2 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PGBL36B2--CX-ST	480 V CKTBRK E-PGB-L36B2 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PGBL36C3--CB-ST	LOCAL FAULT OF 480 V CKTBRK E-PGB-L36C3 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PGBL36C3--CB0CM	480 V CKTBRK E-PGB-L36C3 UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	9.4E-006	5.000	7.000	H	MTTR	6.6E-005
1PGBL36C3--CX-ST	480 V CKTBRK E-PGB-L36C3 CONTROL CIRC FAULTS -SPURIOUS TRIP	2.9E-006	10.000	24.000	H	Mission Time	7.0E-005
1PHAM31-480BS0CM	MCC E-PHA-M31 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHAM31-480BSEPW	LOCAL FAULT OF MCC E-PHA-M31 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PHAM3107--CB-ST	LOCAL FAULT OF 480V CIRCUIT BRK E-PHA-M3107 (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHAM3107--CB0CM	480V CIRCUIT BRK E-PHA-M3107 UNAVAIL DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PHAM3107--CXXST	480V CIRCUIT BRK E-PHA-M3107 CONTROL CIRCUIT FAULT (SPURIOUS TRIP)		10.000	1.3E-005	D	Calculated	1.3E-005
1PHAM3108--CXXST	CNTRL CIRC FOR CNTCTS IN 480V FDR LINE FRM PHA-M31 FAULTS (SPUR TRIP)		10.000	1.6E-004	D	Calculated	1.6E-004
1PHAM3111--CB-ST	LOCAL FAULT OF 480 V CIRC BREAKER E-PHA-M3111 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHAM3111--CB0CM	480 V CIRC BREAKER E-PHA-M3111 UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.4E-006	5.000	9.300	H	MTTR	8.7E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PHAM3111--CX0ST	CONTROL CIRCUIT FOR CONTACTS IN 480V FEEDER LINE FROM E-PHA-M31 FAULTS - SPURIOU	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1PHAM3111--CXXFT	CONTACTS IN 480V FEEDER LINE FROM PHA-M31 FAIL TO RE-CLOSE DUE TO CONTROL CIRC F		10.000	2.4E-004	D	Calculated	2.4E-004
1PHAM33-480BS0CM	MCC E-PHA-M33 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHAM33-480BSEPW	LOCAL FAULT OF MCC E-PHA-M33 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PHAM3326--CB-ST	LOCAL FAULT OF 480 V CIRC BREAKER E-PHA-M3326 -FAIL TO.CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHAM3326--CB0CM	480 V CIRC BREAKER E-PHA-M3326 UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PHAM3326--CX0ST	480 V CIRC BREAKER E-PHA-M3326 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1PHAM3326--CXXFT	CNTCTS IN 480V FDR LINE FRM PHA-M33 FAIL TO RE-CLS DUE TO CNTRL CIRC FAULT		10.000	2.4E-004	D	Calculated	2.4E-004
1PHAM35-480BS0CM	MCC E-PHA-M35 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHAM35-480BSEPW	LOCAL FAULT OF MCC E-PHA-M35 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PHAM3523--CB-ST	LOCAL FAULT OF 480 V CIRC BREAKER E-PHA-M3523 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PHAM3523--CB0CM	480 V CIRC BREAKER E-PHA-M3523 UNAVAILALBE DUE TO UNSCHED MAINT	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PHAM3523--CX0ST	CONTROL CIRCUIT FAULT FOR CONTACTS IN 480 V FEEDER LINE FROM E-PHAM-M35 -SPURIOU	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1PHAM3523--CXXFT	CONTACTS IN 480V FEEDER LINE FROM PHA-M35 FAIL TO RE-CLOSE DUE TO CONTROL CIRC F		10.000	2.4E-004	D	Calculated	2.4E-004
1PHAM3529--CB-ST	LOCAL FAULT OF 480VAC CKTBRK PHA-M3529 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHAM3529--CB0CM	CKTBRK PHA-M3529 UNAVAIL DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	48.000	H	MTTR	4.5E-004
1PHAM3529--CXXFT	CONTACTS IN FEEDER LINE FROM PHAM35 FAIL TO RECLOSE DUE TO CNTRL CIRC FAULT		10.000	2.4E-004	D	Calculated	2.4E-004
1PHAM3529--CXXST	CNTRL CIRC FOR CONTACTS IN 480V FEEDER LINE FRM PHA-M35 FAULTS (SPURIOUS TRIP)		10.000	1.6E-004	D	Calculated	1.6E-004
1PHAM37-480BS0CM	MCC E-PHA-M37 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHAM37-480BSEPW	LOCAL FAULT OF MCC E-PHA-M37 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PHBM32-480BS0CM	MCC E-PHB-M32 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHBM32-480BSEPW	LOCAL FAULT OF MCC E-PHB-M32 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PHBM3208--CB-ST	LOCAL FAULT OF 480V CIRCUIT BRK E-PHB-M3208 (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHBM3208--CB0CM	480V CIRCUIT BRK E-PHB-M3208 UNAVAIL DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PHBM3208--CXXST	480V CIRCUIT BRK E-PHB-M3208 CONTROL CIRCUIT FAULT (SPURIOUS TRIP)		10.000	1.3E-005	D	Calculated	1.3E-005
1PHBM3209--CB-ST	LOCAL FAULT OF 480V CIRC BREAKER E-PHB-M3209 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHBM3209--CB0CM	480V CIRC BREAKER E-PHB-M3209 UNAVAIL DUE TO UNSCHED MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PHBM3209--CX0ST	480V CIRC BREAKER E-PHB-M3209 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1PHBM3209--CXXFT	CONTACTS IN 480V FDR LINE FROM PHB-M32 FAIL TO RECLOSE DUE TO CNTRL CIRC FAULT		10.000	2.4E-004	D	Calculated	2.4E-004
1PHBM3210--CXXST	CNTRL CIRC FOR CONTACTS IN 480V FEEDER LINE FROM PHB-M32 FAULTS (SPURIOUS TRIP).		10.000	1.6E-004	D	Calculated	1.6E-004
1PHBM34-480BS0CM	MCC E-PHB-M34 UNAVAILABLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHBM34-480BSEPW	LOCAL FAULT OF MCC E-PHB-M34 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PHBM3425--CB-ST	LOCAL FAULT OF 480V CIRCUIT BREAKER E-PHB-M3425 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PHBM3425--CB0CM	480V CIRC BREAKER E-PHB-M3425 UNAVAIL DUE TO UNSCHED MAINTE-NANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1PHBM3425--CX0ST	480V CIRC BREAKER CONTROL CIRCUIT FAULTS-SPURIOUS TRIP	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1PHBM3425--CXXFT	CONTACTS IN 480V FDR LINE FROM PHB-M34 FAIL TO RE-CLS OUT TO CNTRL CIRC FAULT		5.000	2.4E-004	D	Calculated	2.4E-004
1PHBM36-480BS0CM	MCC E-PHB-M36 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHBM36-480BSEPW	LOCAL FAULT OF MCC E-PHB-M36 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PHBM3626--CB-ST	LOCAL FAULT OF 480VAC CKTBRK PHB-M3626 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHBM3626--CB0CM	CKTBKR PHB-M3626 UNAVAILABLE DUE TO UNSCHEDLD MAINTENANCE	9.4E-006	5.000	48.000	H	MTTR	4.5E-004
1PHBM3626--CXXFT	CONTACTS IN FDR LINE FRM PHB-M36 FAIL TO RECLOSE DUE TO CNTRL CIRC FAULT		10.000	2.4E-004	D	Calculated	2.4E-004
1PHBM3626--CXXST	CNTRL CIRC FOR CONTACTS IN 480V FDR LINE FRM PHB-M36 FAULTS (SPURIOUS TRIP)		10.000	1.6E-004	D	Calculated	1.6E-004
1PHBM3627--CB-ST	LOCAL FAULT OF 480 V CIRCUIT BREAKER E-PHB-M3627 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PHBM3627--CB0CM	480 V CIRC BREAKER E-PHB-M3627 UNAVAIL DUE TO UNSCHEDULED MAIN-TENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PHBM3627--CX0ST	480 V CIRC BRKR E-PHB-M3627 CNTRL CIRC FAULTS -SPURIOUS TRIP-	7.1E-006	10.000	24.000	H	Mission Time	1.7E-004
1PHBM3627--CXXFT	CONTACTS IN 480V FDR LINE FROM PHB-M36 FAIL TO RECLOSE DUE TO CNTRL CIRC FAULT		10.000	2.4E-004	D	Calculated	2.4E-004
1PHBM38-480BS0CM	MCC E-PHB-M38 UNAVAILBLE FOR PERIOD OF UNSCHED. MAINTENANCE	1.3E-006	5.000	7.000	H	MTTR	9.1E-006
1PHBM38-480BSEPW	LOCAL FAULT OF MCC E-PHB-M38 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PK-A-B----BX-CC	COMMON CAUSE FAILURE OF 2-OUT-OF-2 CLASS 1E BATTERIES (BATTS A & B)		10.000	3.6E-006	D	Calculated	3.6E-006
1PK-ABC----BX-CC	COMMON CAUSE FAILURE OF 3-OUT-OF-3 CLASS 1E BATTERIES (BATTS A, B, & C)		10.000	3.6E-006	D	Calculated	3.6E-006
1PKAD21-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKA-D21 (SHORT TERM)	1.3E-007	5.000	2.000	H	Mission Time	2.6E-07
1PKAD2102--CB-ST	CIRCUIT BREAKER PKA-D2102 FAILS -SPURIOUS TRIP-	2.3E-007	10.000	20.000	H	Mission Time	4.6E-006
1PKAD2109--CB-ST	CIRCUIT BREAKER PKA-D2109 FAILS TO CARRY POWER		10.000	2.2E-003	D	Calculated	2.2E-003
1PKAD2121--CB-ST	CIRCUIT BREAKER PKA-D2121 FAILS -SPURIOUS TRIP-	2.3E-007	10.000	20.000	H	Mission Time	4.6E-006
1PKAF11----BA0CM	BATTERY 'A' (E-PKA-F11) UNAVAILABLE DUE TO UNSCHED MAINTENANCE	2.0E-006	5.000	2.000	H	MTTR	4.0E-006
1PKAF11----BX-PW	LOCAL FAULT OF BATTERY 'A' (E-PKA-F11) -FAIL TO PROVIDE POWER	1.0E-006	3.000	1138.000	H	Test Period	5.7E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKAF11----BX-RM	FAILURE TO RESTORE BATT 'A' (E-PKA-F11) AFTER 18 MONTH TEST OR UNSCHED MAINT		10.000	2.6E-005	D	Calculated	2.6E-005
1PKAH11----BX0CM	BATTERY CHARGER 'A' (E-PKA-H11) UNAVAILABLE DUE TO UNSCHED MAINTENANCE	9.2E-006	5.000	11.000	H	MTTR	1.0E-004
1PKAH11----BXCNO	LOCAL FAULT OF BATTERY CHARGER 'A' (E-PKA-H11) -NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1PKAH15----BX0CM	BACKUP BATT CHARGER 'AC' (E-PKA-H15) UNAVAIL DUE TO UNSCHEDULED MAINT.	9.2E-006	5.000	11.000	H	MTTR	1.0E-004
1PKAH15----BXCNO	BACK-UP BATT. CHARGER 'AC' (E-PKA-H15) FAILS TO OPERATE -NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1PKAM41-125BSEPW	LOCAL FAULT OF 125 V DC CONTROL CENTER E-PKA-M41 -FAIL TO CARRY POWER	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1PKAM41-BAKUP-EE	OPERATOR HAS NOT OR CANNOT USE BACKUP CHARGER 'AC' TO POWER PKA-M41 125V DC BUS		1.000	1.000	D	Flag Event	1.000
1PKAM4102--CB-ST	LOCAL FAULT OF 125 VDC CIRC BREAKER E-PKA-M4102 -FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1PKAM4102--CB0CM	125 VDC CIRC BREAKER E-PKA-M4102 UNAVAILABLE DUE TO UNSCHED MAINTENANCE POWER	9.4E-006	5.000	2.000	H	MTTR	1.9E-005
1PKAM4102--CXDST	125 VDC CIRC BREAKER E-PKA-M4102 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	3.4E-007	10.000	2.000	H	Mission Time	6.8E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKAM4104--CB-ST	LOCAL FAULT OF CIRC BREAKER E-PKA-M4104 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKAM4105--CB-FT	MANUAL CIRCUIT BREAKER E-PKA-M4105 FAILS TO TRANSFER		5.000	3.0E-003	D	Calculated	3.0E-003
1PKAM4105--CB-ST	LOCAL FAULT OF MANUAL CIRCUIT BRKR E-PKA-M4105 (FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKAM4106--CB-ST	LOCAL FAULT OF 125V DC CKTBRK PKA-M4106 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKAM4123--FU-OC	1 OF 2 FUSES FAIL (PKA-M4123) BETWEEN 125 VDC CNTRL CNTR AND DIST PNL	1.0E-006	10.000	4.000	H	Mission Time (2 fuses x 2 hours)	4.0E-006
1PKAM4140--FU-OC	FUSE BETWEEN BATT. CHARGER PKA-H11 AND N PUMP CNTRL CIRC FAILS (SPUR OPEN)	1.0E-006	10.000	4320.000	H	Test Period	2.2E-003
1PKAN10TS--CXXFT	XFMR SWITCH FAILS TO XFER CNTRL CIRC FAULT		10.000	1.0E-003	D	Calculated	1.0E-003
1PKAN10TS--IB-FT	XFRMR SWITCH FAILS TO XFER	2.9E-006	5.000	24.000	H	Mission Time	7.0E-005
1PKBD22-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKB-D22 POWER (SHORT TERM)	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1PKBD2202--CB-ST	CIRCUIT BREAKER PKB-D2202 FAILS - SPURIOUS TRIP-	2.3E-007	10.000	20.000	H	Mission Time / Detection Period	4.6E-006
1PKBD2209--CB-ST	CIRCUIT BKR PKB-D2209 FAILS TO CARRY POWER -SPURIOUS TRIP-		10.000	2.2E-003	D	Calculated	2.2E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKBD2214--CB-ST	CIRCUIT BREAKER PKB-D2214 FAILS -SPURIOUS TRIP-	2.3E-007	10.000	20.000	H	Mission Time / Detection Period	4.6E-006
1PKBD2221--CB-ST	CIRCUIT BREAKER PKB-D2221 FAILS -SPURIOUS TRIP-	2.3E-007	10.000	20.000	H	Mission Time / Detection Period	4.6E-006
1PKBF12----BA0CM	BATTERY 'B' (E-PKB-F12) UNAVAIL. DUE TO UNSCHDLED MAINTENANCE	2.0E-006	5.000	2.000	H	MTTR	4.0E-006
1PKBF12----BX-PW	LOCAL FAULT OF BATTERY 'B' (E-PKB-F12) -FAIL TO PROVIDE POWER-	1.0E-006	3.000	1138.000	H	Test Period	5.7E-004
1PKBF12----BX-RM	FAILURE TO RESTORE BATT 'B' (E-PKB-F12) AFTER 18 MO TESTING OR UNSCHED MAINT		10.000	2.6E-005	D	Calculated	2.6E-005
1PKBH12----BX0CM	BATTERY CHARGER 'B' (E-PKB-H12) UNAVAIL DUE TO UNSCHEDULED MAINTENANCE	9.2E-006	5.000	11.000	H	MTTR	1.0E-004
1PKBH12----BXCNO	LOCAL FAULT OF BATTERY CHARGER 'B' (E-PKB-H12) -NO OUTPUT -	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1PKBH16----BX0CM	BACKUP BATT CHARGER 'BD' UNAVAIL DUE TO UNSCHED MAINTENANCE	9.2E-006	5.000	11.000	H	MTTR	1.0E-004
1PKBH16----BXCNO	LOCAL FAULT OF BACKUP BATT CHARGER 'BD' (E-PKB-H16) -NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1PKBM42-125BSEPW	LOCAL FAULT OF 125V DC CNTL CNTR PKB-M42 (SHORT TERM)	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKBM42-BAKUP-EE	OPERATOR HAS NOT OR CAN'T USE BACKUP CHGR 'BD' TO POWER PKB-M42 125V DC BUS		1.000	1.000	D	Flag Event	1.000
1PKBM4202--CB-ST	LOCAL FAULT OF 125 V DC CIRC BREAKER PKB-M4202 -FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1PKBM4202--CB0CM	125 V DC CIRC BREAKER E-PKB-M4202 UNAVAIL DUE TO UNSCHED MAINTE-NANCE	9.4E-006	5.000	2.000	H	MTTR	1.9E-005
1PKBM4202--CXDST	125 V DC CIRC BRKR E-PKB-M4202 CNTRL CIRC FAULT -SPURIOUS TRIP-	3.4E-007	10.000	2.000	H	Mission Time	6.8E-007
1PKBM4204--CB-ST	LOCAL FAULT OF 480 V CIRCUIT BREAKER E-PHB-M3627- FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKBM4205--CB-FT	MANUAL CIRCUIT BREAKER E-PKB-M4205 FAILS TO TRANSFER		5.000	3.0E-003	D	Calculated	3.0E-003
1PKBM4205--CB-ST	LOCAL FAULT OF MANUAL CIRCUIT BRKR E-PKB-M4205 (FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKBM4206--CB-ST	LOCAL FAULT OF 125VDC MCC CKTBRK PKB-M4206 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKBM4210--FU-OC	1 OF 2 FUSES FAIL (PKB-M4210) BETWEEN CNTRL CNTR AND DIST PNL (SHORT TERM)	1.0E-006	10.000	4.000	H	Mission Time (2 fuses x 2 hours)	4.0E-006
1PKCD23-125BS0CM	125 V DC DIST. PANEL E-PKC-D23 UNAVAILBLE DUE TO UNSCHEDULED MAINTENANCE	1.3E-006	5.000	2.000	H	MTTR	2.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKCD23-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKC-D23 (SHORT TERM)	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1PKCF13----BA0CM	BATTERY 'C' (E-PKC-F13) UNAVAIL FOR PERIOD OF UNSCHED MAINT	2.0E-006	5.000	2.000	H	MTTR	4.0E-006
1PKCF13----BX-PW	LOCAL FAULT OF BATTERY 'C' (E-PKC-F13) -FAIL TO PROVIDE POWER	1.0E-006	3.000	1138.000	H	Test Period	5.7E-004
1PKCF13----BX-RM	FAILURE TO RESTORE BATTERY 'C' (E-PKC-F13) AFTER UNSCHED MAINT		10.000	2.6E-005	D	Calculated	2.6E-005
1PKCH13----BX0CM	BATTERY CHARGER 'C' (E-PKC-H13) UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.2E-006	5.000	11.000	H	MTTR	1.0E-004
1PKCH13----BXCNO	LOCAL FAULT OF BATTERY CHARGER 'C' (E-PKC-H13) -NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1PKCM43-125BS0CM	125 V DC CNTRL CNTR E-PKC-M43 UNAVAILBLE DUE TO UNSCHEDULED MAINTENANCE	1.3E-006	5.000	2.000	H	MTTR	2.6E-006
1PKCM43-125BSEPW	LOCAL FAULT OF 125 V DC CONTROL CENTER E-PKC-M43 (SHORT TERM)	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1PKCM43-BAKUP-EE	OPERATOR HAS NOT OR CAN'T USE BACKUP CHRGR 'AC' TO POWER PKC-M43 125V DC BUS		1.000	1.000	D	Flag Event	1.000
1PKCM4302--CB-ST	LOCAL FAULT OF 125 VDC CIRC BREAKER E-PKC-M4302 -FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1PKCM4302--CB0CM	125 VDC CIRC BREAKER E-PKC-M4302 UNAVAIL FOR PERIOD OF UNSCHED MAINT	9.4E-006	5.000	2.000	H	MTTR	1.9E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKCM4302--CXDST	125 VDC CIRC BREAKER E-PKC-M4302 CONTROL CIRCUIT FAULTS -SPURIOUS TRIP	3.4E-007	10.000	2.000	H	Mission Time	6.8E-007
1PKCM4304--CB-ST	LOCAL FAULT OF CIRC BREAKER E-PKC-M4304 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKCM4305--CB-FT	MANUAL CIRCUIT BRKR E-PKC-M4305 FAILS TO TRANSFER		5.000	3.0E-003	D	Calculated	3.0E-003
1PKCM4305--CB-ST	LOCAL FAULT OF MANUAL CIRCUIT BRKR E-PKC-M4305 (FAIL TO CARRY POWER)	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKCM4311--CB-ST	INVERTER SUPPLY CB PKCM4311 FAILS TO REMAIN CLOSED	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006
1PKCM4320--CB-ST	LOCAL FAULT OF CIRC BREAKER E-PKC-M4320 -FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1PKCN43-125IN-NO	125VDC/480VAC INVERTER BETWEEN PKC-M43 AND MOV UV-653 FAILS	1.0E-004	3.000	24.000	H	Mission Time	2.4E-003
1PKCN43-125IN0CM	125VDC/480VAC INVERTER TO UV-653 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	3.0E-004	5.000	11.000	H	MTTR	3.3E-003
1PKDD24-125BS0CM	125V DC DIST. PANEL E-PKD-D24 UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	1.3E-006	5.000	2.000	H	MTTR	2.6E-006
1PKDD24-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKD-D24 FAIL TO CARRY POWER	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1PKDF14----BA0CM	BATTERY 'D' (E-PKD-F14) UNAVAIL FOR PERIOD OF UNSCHED MAINTENANCE	2.0E-006	5.000	2.000	H	MTTR	4.0E-006
1PKDF14----BX-PW	LOCAL FAULT OF BATTERY 'D' (E-PKD-F14) -FAIL TO PROVIDE POWER	1.0E-006	3.000	1138.000	H	Test Period	5.7E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKDF14----BX-RM	FAIL TO RESTORE BATT 'D' (E-PKD-F14) AFTER 18 MON TESTING OR UNSCHED MAINT		10.000	2.6E-005	D	Calculated	2.6E-005
1PKDH14----BX0CM	BATTERY CHARGER 'D' (E-PKD-H14) UNAVAILABLE DUE TO UNSCHED MAIN-TENANCE	9.2E-006	5.000	11.000	H	MTTR	1.0E-004
1PKDH14----BXCNO	LOCAL FAULT OF BATTERY CHARGER 'D' (E-PKD-H14) - NO OUTPUT	3.1E-006	13.000	24.000	H	Mission Time	7.4E-005
1PKDM44-125BS0CM	125V DC CNTRL CNTR E-PKD-M44 UNAVAILALBE DUE TO UNSCHEDULED MAINTENANCE	1.3E-006	5.000	2.000	H	MTTR	2.6E-006
1PKDM44-125BSEPW	LOCAL FAULT OF 125V DC CONTROL CEN-TER E-PKD-M44 -FAIL TO CARRY POWER	1.3E-007	5.000	2.000	H	Mission Time	2.6E-007
1PKDM44-BAKUP-EE	OPERATOR HAS NOT OR CAN'T USE BACKUP CHRGR 'BD' TO PWR PKD-D24 125V DC BUS		1.000	1.000		Flag Event	1.000
1PKDM4402--CB-ST	LOCAL FAULT OF 125V DC CIRC BREAKER E-PKD-M4402 - FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1PKDM4402--CB0CM	125. DC CIRC BREAKER E-PKD-M4402 UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	9.4E-006	5.000	2.000	H	MTTR	1.9E-005
1PKDM4402--CXDST	125V DC CIRC BRK E-PKD-M4402 CON-TROL CIRCUIT FAULT S - SPURIOUS TRIP	3.4E-007	10.000	2.000	H	Mission Time	6.8E-007
1PKDM4404--CB-ST	LOCAL FAULT OF CIRC BREAKER E-PKD-M4404 -FAILS TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKDM4405--CB-FT	MANUAL CIRCUIT BRKR E-PKD-M4405 FAILS TO TRANSFER		5.000	3.0E-003	D	Calculated	3.0E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PKDM4405--CB-ST	LOCAL FAULT OF MANUAL CIRCUIT BRKR E-PKD-M4405 (FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PKDM4411--CB-ST	INVERTER SUPPLY CB PKDM4411 FAILS TO REMAIN CLOSED	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006
1PKDM4419--CB-ST	LOCAL FAULT OF CIRC BREAKER E-PKD-M4419 -FAIL TO CARRY POWER	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1PKDN44-125IN-NO	125VDC/480VAC INVERTER BETWEEN PKD-M44 AND MOV UV-654 FAILS	1.0E-004	3.000	24.000	H	Mission Time	2.4E-003
1PKDN44-125IN0CM	125VDC/480VAC INVERTER TO UV-654 UNAVAILABLE DUE TO UNSCHED MAINTENANCE	3.0E-004	5.000	11.000	H	MTTR	3.3E-003
1PNA52-D25-CB-ST	120V AC DIST PANEL CKTBRK PNA52 CONTROL CIRC FAILS - SPURIOUS TRIP	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PNAD25-120BSEPW	LOCAL FAULT OF 120V AC DIST PANEL PNA-D25 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PNAN11-125IN-NO	LOCAL FAULT OF 125VDC/120VAC (PNAN11) - FAIL TO OPERATE	1.0E-004	3.000	24.000	H	Mission Time	2.4E-003
1PNAN11-125IN0CM	INVERTER (PNAN11) UNAVAIL DUE TO UNSCHED MAINTENANCE	3.0E-004	5.000	11.000	H	MTTR	3.3E-003
1PNAN11CB1-CB-ST	LOCAL FAULT OF 125 V DC CKTBRK CB-1 ON INVERTER PNA-N11 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PNAN11CB2-CB-ST	LOCAL FAULT OF 125 V AC CKTBRK CB-2 ON INVERTER PNA-N11 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PNAN11TS--CXXFT	STATIC TRANS SWITCH PNAN11 CNTRL CIRC FAULT -FAIL TO TRANSFER		10.000	3.0E-003	D	Calculated	3.0E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PNAN11TS--IB-FT	STATIC TRANS SWITCH PNAN11 (SOLID STATE) FAILS TO TRANSFER ON LOP FROM PKAM41	2.9E-006	5.000	13140.000	H	Test Period	1.9E-002
1PNAV25-480VR-NO	VOLTAGE REG (PNA-V25) BETWEEN 480V MCC PHA-M35 & 120 V DIST PNL FAILS	7.2E-006	50.000	24.000	H	Mission Time	1.7E-004
1PNAV25-480VR0CM	VOLT REG. (PNA-V25) UNAVAIL DUE TO UNSCHED MAINTENANCE	9.2E-006	5.000	48.000	H	MTTR	4.4E-004
1PNB52-D26-CB-ST	120V AC DIST PANEL CKTBRK PNB52 CONTROL CIRC FAILS -SPURIOUS TRIP	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PNBD26-120BSEPW	LOCAL FAULT OF 120V AC DIST PANEL E-PNB-D26 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
1PNBN12-125IN-NO	LOCAL FAULT OF 125VDC/120VAC INVERTER (PNBN12) - FAIL TO OPERATE	1.0E-004	3.000	24.000	H	Mission Time	2.4E-003
1PNBN12-125IN0CM	INVERTER (PNBN12) UNAVAIL DUE TO UNSCHED MAINTENANCE	3.0E-004	5.000	11.000	H	MTTR	3.3E-003
1PNBN12CB1-CB-ST	LOCAL FAULT OF 125V DC CKTBRK CB-1 ON INVERTER PNB N12 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PNBN12CB2-CB-ST	LOCAL FAULT OF 120V AC CKTBRK CB-2 ON INVERTER PNB N12 - FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1PNBN12TS--CXXFT	STATIC TRANS SWITCH PNBN12 CONTROL CIRC FAULT - FAIL TO TRANSFER		10.000	3.0E-003	D	Calculated	3.0E-003
1PNBN12TS--IB-FT	STATIC TRANS SWITCH PNBN12 (SOLID STATE) FAILS TO TRNSFR ON LOP FROM PKB-M42	2.9E-006	5.000	13140.000	H	Test Period	1.9E-002

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1PNBV26-480VR-NO	VOLTAGE REGULATOR, PNB-V26, BETWEEN 480 V MCC PHB-M36 & 120V DIST PANEL FAILS	7.2E-006	50.000	48.000	H	Test Period	1.7E-004
1PNBV26-480VR0CM	VOLT REG (PNB-V26) UNAVAIL DUE TO UNSCHED MAINTENANCE	9.2E-006	5.000	48.000	H	MTTR	4.4E-004
1PNCD27-120--2PW	FAULTS OF 120V AC DIST PANEL PNC-D27 - FAIL TO CARRY POWER		10.000	8.6E-006	D	Calculated	8.6E-006
1PNCN13-INVT-2PW	FAULTS OF 125V DC INVERTER PNCN13 - FAIL TO CARRY POWER (INCLUDING MAINT.)		10.000	5.7E-003	D	Calculated	5.7E-003
1PNCV27-VREG-2PW	VOLT REG (PNC-V27) TRANSFER SWITCH OR CKTBRK FAULTS (INCL MAINT)		10.000	2.3E-003	D	Calculated	2.3E-002
1PND28-120---2PW	FAULTS OF 120V AC DIST PANEL PND-D28 - FAIL TO CARRY POWER		10.000	8.6E-006	D	Calculated	8.6E-006
1PNDN14-INVT-2PW	FAULTS OF 125VDC INVERTER PND-N13 - FAIL TO CARRY POWER (INCLUDES MAINT)		10.000	5.7E-003	D	Calculated	5.7E-003
1PNDV28-VREG-2PW	VOLT. REG. (PND-V28), TRANSFER SWITCH OR CKTBRK FLTS (INC MAINT)		10.000	2.3E-002	D	Calculated	2.3E-002
1PSRV-OPEN---2OP	PRIMARY SAFETY VALVE STICKS OPEN FOLLOWING A LIFT		10.000	2.0E-002	D	Calculated	2.0E-002
1PZRSPRAYLIN-2OP	CHARGING PUMP DISCHARGE LINE/ VALVE FAILURES		10.000	7.2E-004	D	Calculated	7.2E-004
1PZRVENTS-CC-3OP	COMMON CAUSE FAILURE TO OPEN 2-OUT-OF-2 COMBINATIONS OF PZR VENT VALVES		5.000	1.0E-003	D	Calculated	1.0E-003
1RC-OARCP5MN-2HR	OPER FAILS TO SECURE ALL RCPS WITHIN 5 MIN OF LOSS OF SEAL INJ AND CLG		5.000	4.0E-002	D	Calculated	4.0E-002

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1RCA-F03---PXOPG	FLOW ORIFICE RCA-F03 FOR PZR VENT BECOMES PLUGGED	8.3E-007	3.000	8.000	H	Mission Time	6.6E-006
1RCA-V090--NV-RO	MANUAL VALVE RCA-V090 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1RCAHV-103-CXXFO	PZR VENT VALVE HV-103 FAILS TO OPEN - CONTROL CIRCUIT FAULT		3.000	4.2E-003	D	Calculated	4.2E-003
1RCAHV-103-SV-FO	PZR VENT VALVE HV-103 FAILS TO OPEN	9.1E-007	3.000	13140.000	H	Test Period	5.4E-003
1RCAHV-106-CXXFO	PZR VENT VALVE HV-106 FAILS TO OPEN - CONTROL CIRCUIT FAULT		3.000	4.2E-003	D	Calculated	4.2E-003
1RCAHV-106-SV-FO	PZR VENT VALVE (SOV) HV-106 FAILS TO OPEN	9.1E-007	3.000	13140.000	H	Test Period	5.4E-003
1RCBHV-105-CXXFO	PZR VENT VALVE HV-105 FAILS TO OPEN - CONTROL CIRCUIT FAULT		3.000	4.2E-003	D	Calculated	4.2E-003
1RCBHV-105-SV-FO	PZR VENT VALVE (SOV) HV-105 FAILS TO OPEN	9.1E-007	3.000	13140.000	H	Test Period	5.4E-003
1RCBHV-108-CXXFO	PZR VENT VALVE HV-108 FAILS TO OPEN - CONTROL CIRCUIT FAULT		3.000	4.2E-003	D	Calculated	4.2E-003
1RCBHV-108-SV-FO	PZR VENT VALVE HV-108 FAILS TO OPEN	9.1E-007	3.000	13140.000	H	Test Period	5.4E-003
1RCBHV-109-CXXFO	PZR VENT VALVE HV-109 FAILS TO OPEN - CONTROL CIRCUIT FAULT		3.000	4.2E-003	D	Calculated	4.2E-003
1RCBHV-109-SV-FO	PZR VENT VALVE HV-109 FAILS TO OPEN	9.1E-007	3.000	13140.000	H	Test Period	5.4E-003
1RCP-SUBCOOL-2OP	RCS SUBCOOLING REQUIREMENTS FOR RUNNING RCPS IS LOST AND NOT REGAINED		1.000	1.000	D	Flag Event	1.000
1RCPSEALLEAK-2OP	RCP SEAL RUPTURE GIVEN LOSS OF ALL SEAL COOLING & SEAL INJ TO THE PUMP		10.000	8.0E-002	D	Calculated	8.0E-002

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1RCS-DEPRES--2HR	FAILURE OF THE OPERATOR TO INITIATE RCS DEPRESSURIZATION		3.000	2.7E-001	D	Calculated	2.7E-001
1RCS-HIPRES--3EE	RCS PRESSURE REMAINS ABOVE 200 PSIA (LPSI INJ PRESS) FOR > 20 MINUTES		1.000	1.000	D	Flag Event	1.000
1RWT-CHGLINE-2OP	RWT GRAVITY FEED FAILS DUE TO LINE FAULTS		10.000	4.7E-002	D	Calculated	4.7E-002
1RX-RUNBACK--2OP	REACTOR RUNBACK FAILS TO PREVENT A PSV LIFT		10.000	1.000	D	Flag Event	1.000
1SA-AFAS12----CC	COMMON CAUSE FAILURE OF AFAS-1 AND AFAS-2 (LEVEL INDICATION FAILS)		17.000	8.0E-005	D	Calculated	8.0E-005
1SA-MSIS-----2SA	MAIN STEAM ISOLATION SIGNAL GENERATED (DUE TO MISC REACTOR TRIPS)		10.000	5.0E-002	D	Calculated	5.0E-002
1SA-SIASENSR-3EE	SIAS A & B FAIL TO ACTUATE DUE TO COMMON CAUSE PRESS SENSING FAULTS		1.000	1.000	D	Flag Event	1.000
1SA0AF1OA-----HR	OPERATOR FAILS TO MANUALLY INITIATE AFAS ON DIVERSE INDICATON		1.000	1.000	D	Screening Value	1.000
1SA0AF2OA-----HR	OPERATOR FAILS TO MANUALLY INITIATE AFAS ON DIVERSE INDICATON		1.000	1.000	D	Screening Value	1.000
1SAA-ALARMS--2OP	CAB COOLING ALARMS FAIL (PWR SUPPLY, LOW FLOW, HI TEMP)		10.000	1.0E-003	D	Calculated	1.0E-003
1SAA-LOADCHA-2AT	LOAD SEQR. A SIG. FAILS TO START CH A PUMP DUE TO RELAY 231 FAULT		10.000	2.6E-003	D	Calculated	2.6E-003
1SAA-LOADCS1-2AT	LOAD SEQR. A SIG. FAILS TO START CS A PUMP (RELAY K223 FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAA-LOADECA-2AT	LOAD SEQR. A FAILS TO START CIRC. PUMP RELAY K227 FAULT (FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA-LOADEL1-2AT	LOAD SEQR. A SIGNAL FAILS TO LOAD VOLT REG (RELAY K232 FAULT)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAA-LOADEWA-2AT	LOAD SEQR A FAILS TO START EWA PUMP DUE TO RELAY K225 FAULT (FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAA-LOADHP1-2AT	LOAD SEQ A SIG FAIL TO START HPSI A PUMP RELAY K125 FAULT (FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAA-LOADLP1-2AT	LOAD SEQ A SIG FAILS TO START LPSI A DUE TO RELAY K126 FAULT (FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAA-LOADSEQ-2AT	LOAD SEQR. A FAILS TO S LOAD SIGNAL UPON RECEIVING ESFAS SIGNAL		30.000	3.4E-006	D	Calculated	3.4E-006
1SAA-LOADSEQA-CM	SEQR. A (INCLU. LOP/LS, DGSS MODULES) UNAVAIL DUE TO UNSCHED MAINT		5.000	1.1E-004	D	Plant Specific	1.1E-004
1SAA-LOADSPA-2AT	LOAD SEQR. A SIG. FAILS TO START ESS. SP B PUMP DUE TO RELAY K223 FAULT (FAIL TO		10.000	2.6E-003	D	Calculated	2.6E-003
1SAA2AB1---RX-FT	SIS MATRIX LOGIC RELAY 2AB-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AB2---RX-FT	SIS LOGIC MATRIX RELAY 2AB-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AB3---RX-FT	SIS LOGIC MATRIX RELAY 2AB-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AB4---RX-FT	SIS LOGIC MATRIX RELAY 2AB-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AC1---RX-FT	SIS MATRIX LOGIC RELAY 2AC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA2AC2---RX-FT	SIS LOGIC MATRIX RELAY 2AC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AC3---RX-FT	SIS LOGIC MATRIX RELAY 2AC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AC4---RX-FT	SIS LOGIC MATRIX RELAY 2AC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AD1---RX-FT	SIS MATRIX LOGIC RELAY 2AD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AD2---RX-FT	SIS LOGIC MATRIX RELAY 2AD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AD3---RX-FT	SIS LOGIC MATRIX RELAY 2AD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2AD4---RX-FT	SIS LOGIC MATRIX RELAY 2AD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2BC1---RX-FT	SIS MATRIX LOGIC RELAY 2BC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2BC2---RX-FT	SIS LOGIC MATRIX RELAY 2BC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2BC3---RX-FT	SIS LOGIC MATRIX RELAY 2BC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2BC4---RX-FT	SIS LOGIC MATRIX RELAY 2BC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2BD1---RX-FT	SIS MATRIX LOGIC RELAY 2BD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2BD2---RX-FT	SIS LOGIC MATRIX RELAY 2BD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA2BD3---RX-FT	SIS LOGIC MATRIX RELAY 2BD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2BD4---RX-FT	SIS LOGIC MATRIX RELAY 2BD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2CD1---RX-FT	SIS MATRIX LOGIC RELAY 2CD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2CD2---RX-FT	SIS LOGIC MATRIX RELAY 2CD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2CD3---RX-FT	SIS LOGIC MATRIX RELAY 2CD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA2CD4---RX-FT	SIS LOGIC MATRIX RELAY 2CD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AB1---RX-FT	CSS MATRIX LOGIC RELAY 4AB-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AB2---RX-FT	CSS LOGIC MATRIX RELAY 4AB-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AB3---RX-FT	CSS LOGIC MATRIX RELAY 4AB-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AB4---RX-FT	CSS LOGIC MATRIX RELAY 4AB-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AC1---RX-FT	CSS MATRIX LOGIC RELAY 4AC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AC2---RX-FT	CSS LOGIC MATRIX RELAY 4AC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AC3---RX-FT	CSS LOGIC MATRIX RELAY 4AC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA4AC4---RX-FT	CSS LOGIC MATRIX RELAY 4AC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AD1---RX-FT	CSS MATRIX LOGIC RELAY 4AD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AD2---RX-FT	CSS LOGIC MATRIX RELAY 4AD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AD3---RX-FT	CSS LOGIC MATRIX RELAY 4AD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4AD4---RX-FT	CSS LOGIC MATRIX RELAY 4AD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BC1---RX-FT	CSS MATRIX LOGIC RELAY 4BC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BC2---RX-FT	CSS LOGIC MATRIX RELAY 4BC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BC3---RX-FT	CSS LOGIC MATRIX RELAY 4BC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BC4---RX-FT	CSS LOGIC MATRIX RELAY 4BC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BD1---RX-FT	CSS MATRIX LOGIC RELAY 4BD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BD2---RX-FT	CSS LOGIC MATRIX RELAY 4BD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BD3---RX-FT	CSS LOGIC MATRIX RELAY 4BD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4BD4---RX-FT	CSS LOGIC MATRIX RELAY 4BD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA4CD1---RX-FT	CSS MATRIX LOGIC RELAY 4CD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4CD2---RX-FT	CSS LOGIC MATRIX RELAY 4CD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4CD3---RX-FT	CSS LOGIC MATRIX RELAY 4CD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA4CD4---RX-FT	CSS LOGIC MATRIX RELAY 4CD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AB1---RX-FT	RAS MATRIX LOGIC RELAY 5AB-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AB2---RX-FT	RAS LOGIC MATRIX RELAY 5AB-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AB3---RX-FT	RAS LOGIC MATRIX RELAY 5AB-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AB4---RX-FT	RAS LOGIC MATRIX RELAY 5AB-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AC1---RX-FT	RAS MATRIX LOGIC RELAY 5AC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AC2---RX-FT	RAS LOGIC MATRIX RELAY 5AC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AC3---RX-FT	RAS LOGIC MATRIX RELAY 5AC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AC4---RX-FT	RAS LOGIC MATRIX RELAY 5AC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AD1---RX-FT	RAS MATRIX LOGIC RELAY 5AD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA5AD2---RX-FT	RAS LOGIC MATRIX RELAY 5AD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AD3---RX-FT	RAS LOGIC MATRIX RELAY 5AD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5AD4---RX-FT	RAS LOGIC MATRIX RELAY 5AD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BC1---RX-FT	RAS MATRIX LOGIC RELAY 5BC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BC2---RX-FT	RAS LOGIC MATRIX RELAY 5BC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BC3---RX-FT	RAS LOGIC MATRIX RELAY 5BC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BC4---RX-FT	RAS LOGIC MATRIX RELAY 5BC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BD1---RX-FT	RAS MATRIX LOGIC RELAY 5BD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BD2---RX-FT	RAS LOGIC MATRIX RELAY 5BD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BD3---RX-FT	RAS LOGIC MATRIX RELAY 5BD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5BD4---RX-FT	RAS LOGIC MATRIX RELAY 5BD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5CD1---RX-FT	RAS MATRIX LOGIC RELAY 5CD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5CD2---RX-FT	RAS LOGIC MATRIX RELAY 5CD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA5CD3---RX-FT	RAS LOGIC MATRIX RELAY 5CD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA5CD4---RX-FT	RAS LOGIC MATRIX RELAY 5CD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AB1---RX-FT	AFAS-1 MATRIX LOGIC RELAY 6AB-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AB2---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AB-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AB3---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AB-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AB4---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AB-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AC1---RX-FT	AFAS-1 MATRIX LOGIC RELAY 6AC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AC2---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AC3---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AC4---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AD1---RX-FT	AFAS-1 MATRIX LOGIC RELAY 6AD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AD2---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6AD3---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA6AD4---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6AD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BC1---RX-FT	AFAS-1 MATRIX LOGIC RELAY 6BC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BC2---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6BC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BC3---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6BC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BC4---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6BC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BD1---RX-FT	AFAS-1 MATRIX LOGIC RELAY 6BD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BD2---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6BD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BD3---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6BD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6BD4---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6BD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6CD1---RX-FT	AFAS-1 MATRIX LOGIC RELAY 6CD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6CD2---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6CD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6CD3---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6CD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA6CD4---RX-FT	AFAS-1 LOGIC MATRIX RELAY 6CD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA7AB1---RX-FT	AFAS-2 MATRIX LOGIC RELAY 7AB-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AB2---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AB-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AB3---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AB-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AB4---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AB-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AC1---RX-FT	AFAS-2 MATRIX LOGIC RELAY 7AC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AC2---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AC3---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AC4---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AD1---RX-FT	AFAS-2 MATRIX LOGIC RELAY 7AD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AD2---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AD3---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7AD4---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7AD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7BC1---RX-FT	AFAS-2 MATRIX LOGIC RELAY 7BC-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAA7BC2---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7BC-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7BC3---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7BC-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7BC4---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7BC-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7BD1---RX-FT	AFAS-2 MATRIX LOGIC RELAY 7BD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7BD2---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7BD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7BD3---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7BD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7BD4---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7BD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7CD1---RX-FT	AFAS-2 MATRIX LOGIC RELAY 7CD-1 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7CD2---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7CD-2 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7CD3---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7CD-3 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAA7CD4---RX-FT	AFAS-2 LOGIC MATRIX RELAY 7CD-4 FAILS TO TRANSFER	4.0E-007	10.000	730.000	H	Test Period	1.5E-004
1SAAAF11A3ARX-CC	COMMON CAUSE FAILURE AFAS-1 RELAYS 1A AND 3A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAAAF12A4ARX-CC	COMMON CAUSE FAILURE AFAS-1 RELAYS 2A AND 4A		17.000	8.6E-007	D	Calculated	8.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAAAF1IC13RX-CC	COMMON CAUSE FAILURE AFAS-1 INITIATION RELAYS 1 AND 3		17.000	8.6E-007	D	Calculated	8.6E-007
1SAAAF1IC24RX-CC	COMMON CAUSE FAILURE AFAS-1 INITIATION RELAYS 2 AND 4		17.000	8.6E-007	D	Calculated	8.6E-007
1SAAAF1SSR1RXSFT	AFAS-1 INITIATION RELAY 1A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAAF1SSR2RXSFT	AFAS-1 INITIATION RELAY 2A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAAF1SSR3RXSFT	AFAS-1 INITIATION RELAY 3A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAAF1SSR4RXSFT	AFAS-1 INITIATION RELAY 4A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAAF21A3ARX-CC	COMMON CAUSE FAILURE AFAS-2 RELAYS 1A AND 3A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAAAF22A4ARX-CC	COMMON CAUSE FAILURE AFAS-2 RELAYS 2A AND 4A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAAAF2IC13RX-CC	COMMON CAUSE FAILURE AFAS-2 INITIATION RELAYS 1 AND 3		17.000	8.6E-007	D	Calculated	8.6E-007
1SAAAF2IC24RX-CC	COMMON CAUSE FAILURE AFAS-2 INITIATION RELAYS 2 AND 4		17.000	8.6E-007	D	Calculated	8.6E-007
1SAAAF2SSR1RXSFT	AFAS-2 INITIATION RELAY 1A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAAF2SSR2RXSFT	AFAS-2 INITIATION RELAY 2A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAAF2SSR3RXSFT	AFAS-2 INITIATION RELAY 3A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAAAF2SSR4RXSFT	AFAS-2 INITIATION RELAY 4A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAAFS1A---1CFT	RELAY AFAS-1C FAILS TO DE-ENERGIZE		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS1A-K113FT	AFAS-1 TR A RELAY K113 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS1A-K211FT	AFAS-1 TR A RELAY K211 FAILS TO DE-ENERG. UPON AFAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SAAAFS1A-K402FT	AFAS-1 TR A RELAY K402 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS1A-K628FT	AFAS-1 TR A RELAY K628 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS1A-K728FT	AFAS-1 TR A RELAY K728 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS2A---2CFT	RELAY AFAS-2C FAILS TO DE-ENERGIZE		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS2A-K112FT	AFAS-2 TR A RELAY K112 FAILS TO DE-ENERG. UPON AFAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SAAAFS2A-K413FT	AFAS-2 TR A RELAY K413 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS2A-K629FT	AFAS-2 TR A RELAY K629 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFS2A-K729FT	AFAS-2 TR A RELAY K729 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAAFSTRA--MCFT	RELAY AFAS-MC FAILS TO DE-ENERGIZE		10.000	3.0E-004	D	Calculated	3.0E-004
1SAAC02A---TC-OP	CABINET C02A TEMP THERMOCOUPLE FAILS TO INDICATE HI TEMP		10.000	5.5E-001	D	Calculated	5.5E-001

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAAC02A-COOL-HL	OPERATOR FAILS TO RESTORE FORCED AIR CABINET COOLING WITHIN 30 MINS		3.000	1.0E-001	D	Calculated	1.0E-001
1SAAC02A-FAN1-OP	BOP ESFAS CABINET C02A FAN 1 OR EITHER OF 2 FUSES FAIL		10.000	2.9E-003	D	Calculated	2.9E-003
1SAAC02A-FAN2-OP	BOP ESFAS CABINET C02A FAN 2 OR EITHER OF 2 FUSES FAIL		10.000	3.8E-004	D	Calculated	3.8E-004
1SAACIS1A3ARX-CC	COMMON CAUSE FAILURE CIAS RELAYS 1A AND 3A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACIS1B3BRX-CC	COMMON CAUSE FAILURE CIAS RELAYS 1B AND 3B		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACIS2A4ARX-CC	COMMON CAUSE FAILURE CIAS RELAYS 2A AND 4A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACIS2B4BRX-CC	COMMON CAUSE FAILURE CIAS RELAYS 2B AND 4B		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACISIC13RX-CC	COMMON CAUSE FAILURE INITIATION RELAYS 1 AND 3		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACISIC24RX-CC	COMMON CAUSE FAILURE INITIATION RELAYS 2 AND 4		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACISSSR1RXSFT	CIAS INITIATION RELAY 1A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAACISSSR2RXSFT	CIAS INITIATION RELAY 2A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAACISSSR3RXSFT	CIAS INITIATION RELAY 3A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAACISSSR4RXSFT	CIAS INITIATION RELAY 4A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAACSASA-K111FT	CSAS TRAIN A RELAY A-K111 FAILS TO DE-ENERGIZE UPON CSAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAACSASA-K304FT	CSAS TRAIN A RELAY A-K304 FAILS TO DE-ENERGIZE UPON CSAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SAACSS1A3ARX-CC	COMMON CAUSE FAILURE CSS RELAYS 1A AND 3A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACSS2A4ARX-CC	COMMON CAUSE FAILURE CSS RELAYS 2A AND 4A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACSSIC13RX-CC	CSS INITIATION RELAYS 1 AND 3 FAIL TO TRANSFER		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACSSIC24RX-CC	CSS INITIATION RELAYS 2 AND 4 FAIL TO TRANSFER		17.000	8.6E-007	D	Calculated	8.6E-007
1SAACSSSSR1RXSFT	CSS INITIATION RELAY 1A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAACSSSSR2RXSFT	CSS INITIATION RELAY 2A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAACSSSSR3RXSFT	CSS INITIATION RELAY 3A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAACSSSSR4RXSFT	CSS INITIATION RELAY 4A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAALT203A-IB2FT	RWT LT-203A BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SAALT203A-IT2CM	RWT LEVEL INSTRUMENT LT-203A BYPASSED		5.000	2.0E-003	D	Plant Specific	2.0E-003
1SAALT203A-ITLHO	RWT LEVEL INSTRUMENT LT-203A FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAAPT102A-IB2FT	RCS PT-102A BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SAAPT102A-IT2CM	RCS PRESSURE INSTRUMENT PT-102A BYPASSED		5.000	7.7E-002	D	Plant Specific	7.7E-002
1SAAPT102A-ITPHO	RCS PRESSURE INSTRUMENT PT-102A FAILS - HIGH OUTPUT	5.7E-007	8.000	24.000	H	Detection Period	6.8E-006
1SAAPT102A-ITPNO	RCS PRESSURE INSTRUMENT PT-102A FAILS - FAILURE	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005
1SAAPT352A-IB2FT	CONT. PT-352A BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SAAPT352A-IT2CM	CONT. PRESSURE INSTRUMENT PT-352A BYPASSED		5.000	1.4E-003	D	Plant Specific	1.4E-003
1SAAPT352A-ITPLO	CONT. PRESSURE INSTRUMENT PT-352A FAILS - LOW OUTPUT	2.7E-007	8.000	24.000	H	Detection Period	3.2E-006
1SAAPT352A-ITPNO	CONT. PRESSURE INSTRUMENT PT-352A FAILS - NO OUTPUT	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005
1SAARAS1A3ARX-CC	COMMON CAUSE FAILURE RAS RELAYS 1A AND 3A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAARAS2A4ARX-CC	COMMON CAUSE FAILURE RAS RELAYS 2A AND 4A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAARASA--K312FT	RAS TR A RELAY K312 FAILURE TO DE-ENERGIZE UPON RAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SAARASA--K405FT	RAS TRAIN A RELAY K405 FAILS TO DE-ENERG. UPON RAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SAARASIC13RX-CC	COMMON CAUSE FAILURE RAS INITIATION RELAY 1 AND 3		17.000	8.6E-007	D	Calculated	8.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAARASIC24RX-CC	COMMON CAUSE FAILURE RAS INITIATION RELAY 2 AND 4		17.000	8.6E-007	D	Calculated	8.6E-007
1SAARASK104RX-DE	RELAY RAS A K104 DE-ENERGIZES TO CAUSE SPURIOUS ACTUATION	4.3E-006	91.000	16.000	H	Mission Time	6.9E-005
1SAARASK309RX-DE	RELAY RAS A-K309 SPURIOUSLY DE-ENERGIZES TO CLOSE UV-664	4.3E-006	91.000	4.000	H	Mission Time	1.7E-005
1SAARASK405RX-DE	RELAY RAS A K405 SPURIOUSLY DE-ENERGIZES TO CLOSE UV-660.		91.000	3.4E-005	D	Calculated	3.4E-005
1SAARASSSR1RXSFT	RAS INITIATION RELAY 1A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAARASSSR2RXSFT	RAS INITIATION RELAY 2A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAARASSSR3RXSFT	RAS INITIATION RELAY 3A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAARASSSR4RXSFT	RAS INITIATION RELAY 4A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAASIAS101RX-DE	RELAY SIAS A K101 DE-ENERGIZES TO CAUSE SPURIOUS ACTUATION	4.3E-006	91.000	24.000	H	Mission Time	1.0E-004
1SAASIAS108RX-DE	SIAS RELAY A-K108 DE-ENERGIZES TO CAUSE SPURIOUS ACTUATION	4.3E-006	91.000	24.000	H	Mission Time	1.0E-004
1SAASIAS311RX-DE	RELAY SIAS A K311 DE-ENERGIZES TO CAUSE SPURIOUS ACTUATION	4.3E-006	91.000	24.000	H	Mission Time	1.0E-004
1SAASIASA-K108FT	SIAS TR A RELAY K108 FAILS TO DE-ENERGIZE		10.000	2.6E-003	D	Calculated	2.6E-003
1SAASIASA-K301FT	SIAS TR A RELAY K301 FAILS TO DE-ENERG UPON SIAS		10.000	3.0E-004	D	Calculated	3.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAASIASA-K308FT	SIAS TR A RELAY K308 FAILS TO DE-ENERG UPON SIAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAASIASA-K401FT	SIAS TRAIN A RELAY A-K401 FAILS TO DE-ENERGIZE UPON SIAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SAASIS1A3ARX-CC	COMMON CAUSE FAILURE SIS RELAYS 1A AND 3A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAASIS1B3BRX-CC	COMMON CAUSE FAILURE SIS RELAYS 1B AND 3B		17.000	8.6E-007	D	Calculated	8.6E-007
1SAASIS2A4ARX-CC	COMMON CAUSE FAILURE SIS RELAYS 2A AND 4A		17.000	8.6E-007	D	Calculated	8.6E-007
1SAASIS2B4BRX-CC	COMMON CAUSE FAILURE SIS RELAYS 2B AND 4B		17.000	8.6E-007	D	Calculated	8.6E-007
1SAASISIC13RX-CC	COMMON CAUSE FAILURE SIS INITIATION RELAYS 1 AND 3		17.000	8.6E-007	D	Calculated	8.6E-007
1SAASISIC24RX-CC	COMMON CAUSE FAILURE SIS INITIATION RELAYS 2 AND 4		17.000	8.6E-007	D	Calculated	8.6E-007
1SAASISSSR1RXSFT	SIS INITIATION RELAY 1A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAASISSSR2RXSFT	SIS INITIATION RELAY 2A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAASISSSR3RXSFT	SIS INITIATION RELAY 3A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAASISSSR4RXSFT	SIS INITIATION RELAY 4A FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SAAT1113A-IB2FT	SG LT-1113A BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAAT1113A-IT2CM	SG 1 LEVEL INSTRUMENT LT-1113A BYPASSED		5.000	1.2E-001	D	Plant Specific	1.2E-001
1SAAT1113A-ITLHO	SG 1 LEVEL INSTRUMENT LT-1113A FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SAAT1123A-IB2FT	SG LT-1123A BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SAAT1123A-IT2CM	SG 2 LEVEL INSTRUMENT LT-1123A BYPASSED		5.000	1.2E-001	D	Plant Specific	1.2E-001
1SAAT1123A-ITLHO	SG 2 LEVEL INSTRUMENT LT-1123A FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SAATEST2CDRX-TT	LOGIC MATRIX CD IN TEST		5.000	1.4E-003	D	Calculated	1.4E-003
1SAATEST4CDRX-TT	CSS LOGIC MATRIX CD IN TEST		5.000	1.4E-003	D	Calculated	1.4E-003
1SAATEST6CDRX-TT	LOGIC MATRIX CD IN TEST		5.000	1.4E-003	D	Calculated	1.4E-003
1SAATEST7CDRX-TT	AFAS-2 LOGIC MATRIX CD IN TEST		5.000	1.4E-003	D	Calculated	1.4E-003
1SAATESTCD-RX-TT	LOGIC MATRIX CD IN TEST		5.000	1.4E-003	D	Calculated	1.4E-003
1SAB-ALARMS--2OP	CAB COOLING ALARMS FAIL (PWR SUPPLY, LOW FLOW, HI TEMP)		10.000	1.0E-003	D	Calculated	1.0E-003
1SAB-LOADAFB-2AT	LOAD SEQUENCER B SIGNAL FAILS TO START AFW B PUMP DUE TO RELAY K222 FAULT (FAIL		10.000	2.6E-003	D	Calculated	2.6E-003
1SAB-LOADCHB-2AT	LOAD SEQR. B SIG. FAILS TO START CH B PUMP DUE TO RELAY 231 FAULT		10.000	2.6E-003	D	Calculated	2.6E-003
1SAB-LOADCS2-2AT	LOAD SEQR. B FAILS TO START CSSB PUMP DUE TO RELAY FAULT (FAIL TO DE-ENERG)		10.000	2.6E-003	D	Calculated	2.6E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SAB-LOADECB-2AT	LOAD SEQR. B SIG. FAILS TO START ESCHILB PUMP DUE TO RELAY K222 FAULT (FAIL TO D		10.000	2.6E-003	D	Calculated	2.6E-003
1SAB-LOADEL2-2AT	LOAD SEQ B SIGNAL FAILS TO RELOAD BATT. CHARGERS B, D, AND BD AND PNB-D26 DUE TO		10.000	2.6E-003	D	Calculated	2.6E-003
1SAB-LOADEWB-2AT	LOAD SEQR B FAILS TO STRT EWB PUMP DUE TO RELAY K225 FAULT (FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAB-LOADHP2-2AT	LOAD SEQR B SIG FAIL TO START HPSI B PUMP RELAY K125F AULT (FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAB-LOADLP2-2AT	LOAD SEQ B SIG FAILS TO START LPSI B DUE TO RELAY K126 FAULT (FAIL TO DE-ENER)		10.000	2.6E-003	D	Calculated	2.6E-003
1SAB-LOADSEQ-2AT	LOAD SEQR. B FAILS TO SEND LOAD SIGNAL UPON RECEIVING ESFAS SIGNAL		30.000	3.4E-006	D	Calculated	3.4E-006
1SAB-LOADSEQB-CM	SEQR B (INCLUDING LOP/LS, DGSS MODULES) UNAVAIL DUE TO UNSCHED MAINT		5.000	1.1E-004	D	Calculated	1.1E-004
1SAB-LOADSPB-2AT	LOAD SEQR. B SIG. FAILS TO START ESS. SP B PUMP DUE TO RELAY K223 FAULT (FAIL TO		10.000	2.6E-003	D	Calculated	2.6E-003
1SABAF11B3BRX-CC	COMMON CAUSE FAILURE AFAS-1 RELAYS 1B AND 3B		17.000	8.6E-007	D	Calculated	8.6E-007
1SABAF12B4BRX-CC	COMMON CAUSE FAILURE AFAS-1 RELAYS 2B AND 4B		17.000	8.6E-007	D	Calculated	8.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SABAF1SSR1RXSFT	AFAS-1 INITIATION RELAY 1B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAF1SSR2RXSFT	AFAS-1 INITIATION RELAY 2B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAF1SSR3RXSFT	AFAS-1 INITIATION RELAY 3B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAF1SSR4RXSFT	AFAS-1 INITIATION RELAY 4B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAF21B3BRX-CC	COMMON CAUSE FAILURE AFAS-2 RELAYS 1B AND 3B		17.000	8.6E-007	D	Calculated	8.6E-007
1SABAF22B4BRX-CC	COMMON CAUSE FAILURE AFAS-2 RELAYS 2B AND 4B		17.000	8.6E-007	D	Calculated	8.6E-007
1SABAF2SSR1RXSFT	AFAS-2 INITIATION RELAY 1B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAF2SSR2RXSFT	AFAS-2 INITIATION RELAY 2B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAF2SSR3RXSFT	AFAS-2 INITIATION RELAY 3B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAF2SSR4RXSFT	AFAS-2 INITIATION RELAY 4B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABAFS1B-K211FT	AFAS-1 TRAIN B RELAY K-211 FAILS TO DE-ENERG. UPON AFAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SABAFS1B-K402FT	AFAS-1 TR B RELAY K402 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABAFS1B-K628FT	AFAS-1 TR B RELAY K628 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SABAFS1B-K728FT	AFAS-1 TR B RELAY K728 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABAFS2B-K112FT	AFAS-2 TRAIN B RELAY K-112 FAILS TO DE-ENERG. UPON AFAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SABAFS2B-K413FT	AFAS-2 TR B RELAY K413 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABAFS2B-K629FT	AFAS-2 TR B RELAY K629 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABAFS2B-K729FT	AFAS-2 TR B RELAY K729 FAILS TO DE-ENERGIZE UPON AFAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABC02B---TC-OP	CABINET C02B TEMP THERMOCOUPLE FAILS TO INDICATE HI TEMP		3.000	5.5E-001	D	Calculated	5.5E-001
1SABC02B-COOL-HL	OPERATOR FAILS TO RESTORE FORCED AIR CABINET COOLING WITHIN 30 MINS		3.000	1.0E-001	D	Calculated	1.0E-001
1SABC02B-FAN1-OP	BOP ESFAS CABINET C02B FAN 1 OR EITHER OF 2 FUSES FAIL		10.000	2.9E-003	D	Calculated	2.9E-003
1SABC02B-FAN2-OP	BOP ESFAS CABINET C02B FAN 2 OR EITHER OF 2 FUSES FAIL		10.000	3.8E-004	D	Calculated	3.8E-004
1SABCISSSR1RXSFT	CIAS INITIATION RELAY 1B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABCISSSR2RXSFT	CIAS INITIATION RELAY 2B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABCISSSR3RXSFT	CIAS INITIATION RELAY 3B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABCISSSR4RXSFT	CIAS INITIATION RELAY 4B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SABCSASB-K111FT	CSAS TRAIN B RELAY B-K111 FAILS TO DE-ENERGIZE UPON CSAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABCSASB-K304FT	CSAS TRAIN B RELAY B-K304 FAILS TO DE-ENERGIZE UPON CSAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SABCSS1B3BRX-CC	COMMON CAUSE FAILURE CSS RELAYS 1B AND 3B		17.000	8.6E-007	D	Calculated	8.6E-007
1SABCSS2B4BRX-CC	COMMON CAUSE FAILURE CSS RELAYS 2B AND 4B		17.000	8.6E-007	D	Calculated	8.6E-007
1SABCSSSSR1RXSFT	CSS INITIATION RELAY 1B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABCSSSSR2RXSFT	CSS INITIATION RELAY 2B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABCSSSSR3RXSFT	CSS INITIATION RELAY 3B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABCSSSSR4RXSFT	CSS INITIATION RELAY 4B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABLT203B-IB2FT	RWT LT-203B BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SABLT203B-ITLHO	RWT LEVEL INSTRUMENT LT-203B FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SABPT102B-IB2FT	RCS PT-102B BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SABPT102B-ITPHO	RCS PRESSURE INSTRUMENT PT-102B FAILS - HIGH OUTPUT	5.7E-007	8.000	24.000	H	Detection Period	6.8E-006
1SABPT102B-ITPNO	RCS PRESSURE INSTRUMENT PT-102B FAILS - FAILURE	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SABPT352B-IB2FT	CONT. PT-352B BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SABPT352B-ITPLO	CONT. PRESSURE INSTRUMENT PT-352B FAILS - LOW OUTPUT	2.7E-007	8.000	24.000	H	Detection Period	3.2E-006
1SABPT352B-ITPNO	CONT. PRESSURE INSTRUMENT PT-352B FAILS - NO OUTPUT	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005
1SABRAS1B3BRX-CC	COMMON CAUSE FAILURE RAS RELAYS 1B AND 3B		17.000	8.6E-007	D	Calculated	8.6E-007
1SABRAS2B4BRX-CC	COMMON CAUSE FAILURE RAS RELAYS 2B AND 4B		17.000	8.6E-007	D	Calculated	8.6E-007
1SABRASB--K312FT	RAS TR B RELAY K312 FAILURE TO DE-ENERGIZE UPON RAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SABRASB--K405FT	RAS TRAIN B RELAY K405 FAILS TO DE-ENERG. UPON RAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SABRASK104RX-DE	RELAY RAS B K104 DE-ENERGIZES TO CAUSE SPURIOUS ACTUATION	4.3E-006	91.000	16.000	H	Mission Time	6.9E-005
1SABRASK309RX-DE	RELAY RAS B-K309 SPURIOUSLY DE-ENERGIZES TO CLOSE UV-665	4.3E-006	91.000	4.000	H	Mission Time	1.7E-005
1SABRASK405RX-DE	RELAY RAS B K405 SPURIOUSLY DE-ENERGIZES TO CLOSE UV-659		91.000	3.4E-005	D	Calculated	3.4E-005
1SABRASSSR1RXSFT	RAS INITIATION RELAY 1B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABRASSSR2RXSFT	RAS INITIATION RELAY 2B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABRASSSR3RXSFT	RAS INITIATION RELAY 3B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SABRASSSR4RXSFT	RAS INITIATION RELAY 4B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABSIAS311RX-DE	RELAY SIAS B K311 DE-ENERGIZES TO CAUSE SPURIOUS ACTUATION	4.3E-006	91.000	24.000	H	Mission Time	1.0E-004
1SABSIASB-K108FT	SIAS TR B RELAY K108 FAILS TO DE-ENERG. UPON SIAS		10.000	2.6E-003	D	Calculated	2.6E-003
1SABSIASB-K301FT	SIAS TRAIN B RELAY B-K301 FAILS TO DE-ENERGIZE UPON SIAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABSIASB-K401FT	SIAS TR B RELAY K401 FAILS TO DE-ENERG UPON SIAS		10.000	3.0E-004	D	Calculated	3.0E-004
1SABSISSSR1RXSFT	SIS INITIATION RELAY 1B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABSISSSR2RXSFT	SIS INITIATION RELAY 2B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABSISSSR3RXSFT	SIS INITIATION RELAY 3B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABSISSSR4RXSFT	SIS INITIATION RELAY 4B FAILS TO TRANSFER		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SABT1113B-IB2FT	SG LT-1113B BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SABT1113B-ITLHO	SG LEVEL INSTRUMENT LT-1113B FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SABT1123B-IB2FT	SG LT-1123B BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SABT1123B-ITLHO	SG 2 LEVEL INSTRUMENT LT-1123B FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SACLT203C-IB2FT	RWT LT-203C BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SACLT203C-ITLHO	RWT LEVEL INSTRUMENT LT-203C FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SACPT102C-IB2FT	RCS PT-102C BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SACPT102C-ITPHO	RCS PRESSURE INSTRUMENT PT-102C FAILS - HIGH OUTPUT	5.7E-007	8.000	24.000	H	Detection Period	6.8E-006
1SACPT102C-ITPNO	RCS PRESSURE INSTRUMENT PT-102C FAILS - FAILURE	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005
1SACPT352C-IB2FT	CONT. PT-352C BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SACPT352C-ITPLO	CONT. PRESSURE INSTRUMENT PT-352C FAILS - LOW OUTPUT	2.7E-007	8.000	24.000	H	Detection Period	3.2E-006
1SACPT352C-ITPNO	CONT. PRESSURE INSTRUMENT PT-352C FAILS - NO OUTPUT	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005
1SACT1113C-IB2FT	SG LT-1113C BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SACT1113C-ITLHO	SG LEVEL INSTRUMENT LT-1113C FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SACT1123C-IB2FT	SG LT-1123C BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SACT1123C-ITLHO	SG 2 LEVEL INSTRUMENT LT-1123C FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SADLT203D-IB2FT	RWT LT-203D BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SADLT203D-ITLHO	RWT LEVEL INSTRUMENT LT-203D FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SADPT102D-IB2FT	RCS PT-102D BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SADPT102D-ITPHO	RCS PRESSURE INSTRUMENT PT-102D FAILS - HIGH OUTPUT	5.7E-007	8.000	24.000	H	Detection Period	6.8E-006
1SADPT102D-ITPNO	RCS PRESSURE INSTRUMENT PT-102D FAILS - FAILURE	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005
1SADPT352D-IB2FT	CONT. PT-352D BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SADPT352D-ITPLO	CONT. PRESSURE INSTRUMENT PT-352D FAILS - LOW OUTPUT	2.7E-007	8.000	24.000	H	Detection Period	3.2E-006
1SADPT352D-ITPNO	CONT. PRESSURE INSTRUMENT PT-352D FAILS - NO OUTPUT	2.1E-006	8.000	24.000	H	Detection Period	2.5E-005
1SADT1113D-IB2FT	SG 1 LEVEL BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D.	Calculated	1.1E-003
1SADT1113D-ITLHO	SG 1 LEVEL INSTRUMENT LT-1113D FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SADT1123D-IB2FT	SG LT-1123D BISTABLE FAILS TO TRANSFER		5.000	1.1E-003	D	Calculated	1.1E-003
1SADT1123D-ITLHO	SG 2 LEVEL INSTRUMENT LT-1123D FAILS - HIGH OUTPUT	5.1E-007	8.000	24.000	H	Detection Period	6.1E-006
1SANLT203CC--2SA	SPURIOUS RAS ACT. DUE TO COMMON CAUSE FAILURE OF LT-203 INST. OR BISTABLES		17.000	2.0E-006	D	Calculated	2.0E-006
1SANLT203CCIB-CC	COMMON CAUSE FAILURE OF LT-203 BISTABLES (RWT LEVEL)		17.000	6E-004	D.	Calculated	6.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SANLT203HOITLCC	COMMON CAUSE FAILURE OF LT-203 RWT LEVEL INSTRUMENTS		17.000	1.9E-004	D	Calculated	1.9E-004
1SANPT102CC--2SA	SPUR SIAS A & B ACT DUE TO COMMON CAUSE FAILURE OF PT102 INSTRMNTS OR BISTBLS		17.000	1.2E-005	D	Calculated	1.2E-005
1SANPT102CCIB-CC	COMMON CAUSE FAILURE OF PT-102 BISTABLES (PRESSURIZER)		17.000	4.6E-004	D	Calculated	4.6E-004
1SANPT102HOITPCC	COMMON CAUSE FAILURE OF PT-102 RCS PRESSURE INSTRUMENTS (PRESSURIZER)		17.000	1.0E-004	D	Calculated	1.0E-004
1SANPT351CC--2SA	SPUR SIAS A & B ACT DUE TO COMMON CAUSE FAILURE OF PT351 INSTRMNTS OR BISTBLS		17.000	1.2E-005	D	Calculated	1.2E-005
1SANPT351CCIB-CC	COMMON CAUSE FAILURE OF PT-351 BISTABLES		17.000	6.0E-004	D	Calculated	6.0E-004
1SANPT351LOITPCC	COMMON CAUSE FAILURE OF PT-351 CONT. PRESSURE INSTRUMENTS		17.000	2.6E-004	D	Calculated	2.6E-004
1SANPT352CCIB-CC	COMMON CAUSE FAILURE OF PT-352 BISTABLES (CONTAINMENT PRESS)		17.000	6.0E-004	D	Calculated	6.0E-004
1SANPT352LOITPCC	COMMON CAUSE FAILURE OF PT-352 CONT. PRESSURE INSTRUMENTS		17.000	2.6E-004	D	Calculated	2.6E-004
1SANT1113CCIB-CC	COMMON CAUSE FAILURE OF LT-1113 BISTABLES		17.000	4.6E-004	D	Calculated	4.6E-004
1SANT1113HOITLCC	COMMON CAUSE FAILURE OF LT-1113 SG LEVEL INSTRUMENTS		17.000	1.0E-004	D	Calculated	1.0E-004
1SANT1123CCIB-CC	COMMON CAUSE FAILURE OF LT-1123 BISTABLES		17.000	4.6E-004	D	Calculated	4.6E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SANT1123HOITLCC	COMMON CAUSE FAILURE OF LT-1123 SG 2 LEVEL INSTRUMENTS		17.000	1.0E-004	D	Calculated	1.0E-004
1SBALT203A1RXSFT	RWT LT-203A RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBALT203A2RXSFT	RWT LT-203A RELAY 2 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBALT203A3RXSFT	RWT LT-203A RELAY 3 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAPT102A1RXSFT	RCS PT-102A RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAPT102A2RXSFT	RCS PT-102A RELAY 2 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAPT102A3RXSFT	RCS PT-102A RELAY 3 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAPT352A1RXSFT	CONT. PT-352A RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAPT352A2RXSFT	CONT. PT-352A RELAY 2 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAPT352A3RXSFT	CONT. PT-352A RELAY 3 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAT1113A1RXSFT	SG LT-1113A RELAY 1 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAT1113A2RXSFT	SG LT-1113A RELAY 2 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAT1113A3RXSFT	SG LT-1113A RELAY 3 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SBAT1123A1RXSFT	SG LT-1123A RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAT1123A2RXSFT	SG LT-1123A RELAY 2 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBAT1123A3RXSFT	SG LT-1123A RELAY 3 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBLT203B1RXSFT	RWT LT-203B RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBLT203B2RXSFT	RWT LT-203B RELAY 2 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBLT203B3RXSFT	RWT LT-203B RELAY 3 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBPT102B1RXSFT	RCS PT-102B RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBPT102B2RXSFT	RCS PT-102B RELAY 2 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBPT102B3RXSFT	RCS PT-102B RELAY 3 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBPT352B1RXSFT	CONT. PT-352B RELAY 1 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBPT352B2RXSFT	CONT. PT-352B RELAY 2 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBPT352B3RXSFT	CONT. PT-352B RELAY 3 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBT1113B1RXSFT	SG LT-1113B RELAY 1 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SBBT1113B2RXSFT	SG LT-1113B RELAY 2 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBT1113B3RXSFT	SG LT-1113B RELAY 3 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBT1123B1RXSFT	SG LT-1123B RELAY 1 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBT1123B2RXSFT	SG LT-1123B RELAY 2 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBBT1123B3RXSFT	SG LT-1123B RELAY 3 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCLT203C1RXSFT	RWT LT-203C RELAY 1 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCLT203C2RXSFT	RWT LT-203C RELAY 2 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCLT203C3RXSFT	RWT LT-203C RELAY 3 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCPT102C1RXSFT	RCS PT-102C RELAY 1 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCPT102C2RXSFT	RCS PT-102C RELAY 2 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCPT102C3RXSFT	RCS PT-102C RELAY 3 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCPT352C1RXSFT	CONT. PT-352C RELAY 1 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCPT352C2RXSFT	CONT. PT-352C RELAY 2 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SBCPT352C3RXSFT	CONT. PT-352C RELAY 3 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCT1113C1RXSFT	SG LT-1113C RELAY 1 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCT1113C2RXSFT	SG LT-1113C RELAY 2 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCT1113C3RXSFT	SG LT-1113C RELAY 3 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCT1123C1RXSFT	SG LT-1123C RELAY 1 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCT1123C2RXSFT	SG LT-1123C RELAY 2 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBCT1123C3RXSFT	SG LT-1123C RELAY 3 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDLT203D1RXSFT	RWT LT-203D RELAY 1 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDLT203D2RXSFT	RWT LT-203D RELAY 2 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDLT203D3RXSFT	RWT LT-203D RELAY 3 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDPT102D1RXSFT	RCS PT-102D RELAY 1 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDPT102D2RXSFT	RCS PT-102D RELAY 2 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDPT102D3RXSFT	RCS PT-102D RELAY 3 FAILS TO TRANS-FER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SBDPT352D1RXSFT	CONT. PT-352D RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDPT352D2RXSFT	CONT. PT-352D RELAY 2 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDPT352D3RXSFT	CONT. PT-352D RELAY 3 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDT1113D1RXSFT	SG LT-1113D RELAY 1 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDT1113D2RXSFT	SG LT-1113D RELAY 2 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDT1113D3RXSFT	SG LT-1113D RELAY 3 FAILS TO TRANSFER/ DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDT1123D1RXSFT	SG LT-1123D RELAY 1 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDT1123D2RXSFT	SG LT-1123D RELAY 2 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SBDT1123D3RXSFT	SG LT-1123D RELAY 3 FAILS TO TRANSFER/DEENERGIZE		3.000	8.6E-006	D	Demand Probability	8.6E-006
1SCHV-1A---AV-RO	BLOWDOWN AIR-OP VALVE SC-HV-1A FAILS TO REMAIN OPEN (LOCAL FAULTS)	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
1SCHV-1C---AV-FO	BLOWDOWN AIR-OPERATED VALVE HV-1C FAILS TO OPEN	4.1E-007	5.000	13140.000	H	Test Period	2.7E-003
1SCHV-1C---MV9CM	BLOWDOWN VALVE HV-1C UNAVAIL DUE TO UNSCHEDULED MAINTAINANCE	2.8E-005	3.000	116.000	H	MTTR	3.3E-003
1SCHY-1A---SV-RO	BLOWDOWN VALVE SC-HV-1A SOLENOID FAILS TO REMAIN ENERGIZED	9.0E-007	3.000	8.000	H	Mission Time	7.2E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SCHY-1C---SV-FO	BLOWDOWN VALVE SC-HV-1C SOLENOID FAILS TO OPERATE	9.1E-007	3.000	13140.000	H	Test Period	5.4E-003
1SCV-001---NV-RO	MANUAL VALVE V-001 FAILS TO REMAIN OPEN	3.0E-008	84.000	8.000	H	Mission Time	2.4E-007
1SCV-002---NV-RO	MANUAL VALVE V 002 FAILS TO REMAIN OPEN	3.0E-008	84.000	8.000	H	Mission Time	2.4E-007
1SCV-109---NV-RO	MANUAL VALVE V-109 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SCV-110---NV-RO	MANAUL VALVE V-110 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SDCPROC-OP--2HR	OPERATORS FAIL TO ALIGN LPSI PUMPS FOR SHUTDOWN COOLING		10.000	1.5E-003	D	Calculated	1.5E-003
1SG-1-MSSVS--2OP	ALL MSSVS ON STEAM GENERATOR 1 FAIL TO OPEN (COMMON CAUSE)		30.000	6.1E-006	D	Calculated	6.1E-006
1SG-2-MSSVS--2OP	ALL MSSVS ON STEAM GENERATOR 2 FAIL TO OPEN (COMMON CAUSE)		30.000	6.1E-006	D	Calculated	6.1E-006
1SG-2ADVS-SG1-CC	2 OF 2 ADVS ON SG1 FAIL DUE TO COMMON CAUSE AND ADVS ON SG2 ARE UNAFFECTED		12.000	7.3E-004	D	Calculated	7.3E-004
1SG-2ADVS-SG2-CC	2 OF 2 ADVS ON SG2 FAIL DUE TO COMMON CAUSE AND ADVS ON SG1 ARE UNAFFECTED		12.000	7.3E-004	D	Calculated	7.3E-004
1SG-2MSIV--AV2FC	FAILURE OF 1 OR MORE MSIV'S ON EACH STEAM GENERATOR TO CLOSE ON A SLB		5.000	7.4E-004	D	Calculated	7.4E-004
1SG-4ADVS-----CC	COMMON CAUSE FAILURE OF ALL 4 ADVS		30.000	6.5E-005	D	Calculated	6.5E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SG-BAD-ISO---HR	OP ISOLATES BAD SG DURING A SGTR EVEN THOUGH COOLING VIA OTHER SG HAS FAILED		3.000	1.6E-001	D	Calculated	1.6E-001
1SGA72D2102CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2102"(SPURIOUS OPEN)	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006
1SGA72D2114CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2114 "(SPURIOUS OPEN)	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006
1SGAHV0179-AV-FO	LOCAL FAULT OF ADV HV-179	4.1E-007	5.000	2190.000	H	Test Period	4.5E-004
1SGAHV0179-AV9CM	HV-179 UNAVAILABLE FOR PERIOD OF UNSCHEDULED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SGAHV0184-AV-FO	LOCAL FAULT OF ADV HV-184 (AIR OPERATED VALVE)	4.1E-007	5.000	2190.000	H	Test Period	4.5E-004
1SGAHV0184-AV9CM	HV-184 UNAVAILABLE FOR PERIOD OF UNSCHEDULED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SGAHY0179ASV-FC	LOCAL FAULT SOLENOID VALVE HY-179A (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAHY0179CIMCNO	LOCAL FAULT OF I/P CONTROL UNIT HY-179C	1.1E-006	33.000	2190.000	H	Test Period	1.2E-003
1SGAHY0179RSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-179R (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAHY0184ASV-FC	LOCAL FAULT SOLENOID VALVE HY-184A(FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAHY0184CIMCNO	LOCAL FAULT OF I/P CONTROL UNIT HY-184C	1.1E-006	33.000	2190.000	H	Test Period	1.2E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGAHY0184RSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-184R (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAHY79AR-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET A (HY-179)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGAHY84AR-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET A (HY-184)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGAPCV0303PV-RO	REGULATOR PCV-303 FAILS CLOSED	4.2E-006	10.000	2190.000	H	Test Period	4.6E-003
1SGAPCV0310PV-RO	REGULATOR PCV-310 FAILS TO REMAIN OPEN	4.2E-006	10.000	2190.000	H	Test Period	4.6E-003
1SGAPCV0317PV-RO	REGULATOR PCV-317 FAILS CLOSED	4.2E-006	10.000	2190.000	H	Test Period	4.6E-003
1SGAPCV0323PV-RO	REGULATOR PCV-323 FAILS CLOSED	4.2E-006	10.000	2190.000	H	Test Period	4.6E-003
1SGAPSL0306IWPNO	LOCAL FAULT PRESSURE SWITCH PSL-306 FAILS (NO OUTPUT)	1.4E-006	14.000	2190.000	H	Test Period	1.5E-003
1SGAPSL0313IWPNO	LOCAL FAULT PRESSURE SWITCH PSL-313 "FAILS (NO OUTPUT)	1.4E-006	14.000	2190.000	H	Test Period	1.5E-003
1SGAPSV0302RV-RC	SRV PSV-302 FAILS OPEN	4.0E-006	5.000	10.500	H	Mission Time	4.2E-005
1SGAPSV0305RV-RC	SRV PSV-305 FAILS OPEN (PREMATURE)	4.0E-006	5.000	2190.000	H	Test Period	4.4E-003
1SGAPSV0309RV-RC	SRV PSV-309 FAILS OPEN	4.0E-006	5.000	10.500	H	Mission Time	4.2E-005
1SGAPSV0312RV-RC	SRV PSV-312 FAILS OPEN (PREMATURE)	4.0E-006	5.000	2190.000	H	Test Period	4.4E-003
1SGAPSV0316RV-RC	SRV PSV-316 FAILS OPEN	4.0E-006	5.000	10.500	H	Mission Time	4.2E-005
1SGAPSV0319RV-RC	SRV PSV-319 FAILS OPEN (PREMATURE)	4.0E-006	5.000	2190.000	H	Test Period	4.4E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGAPSV0322RV-RC	SRV PSV-322 FAILS OPEN	4.0E-006	5.000	10.500	H	Mission Time	4.2E-005
1SGAPSV0325RV-RC	SRV PSV-325 FAILS OPEN (PREMATURE)	4.0E-006	5.000	2190.000	H	Test Period	4.4E-003
1SGAPT0306-ITPNO	LOCAL FAULT PRESSURE TRANSMITTER PT-306	2.1E-006	8.000	2190.000	H	Test Period	2.3E-003
1SGAPT0313-ITPNO	LOCAL FAULT PRESSURE TRANSMITTER PT-313	2.1E-006	8.000	2190.000	H	Test Period	2.3E-003
1SGAPV0306ASV-FO	SOLENOID VALVE PV-306A FAILS TO OPEN	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAPV0306BSV-FO	SOLENOID VALVE PV-306B FAILS TO OPEN	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAPV0313ASV-FO	SOLENOID VALVE PV-313A FAILS TO OPEN	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAPV0313BSV-FO	SOLENOID VALVE PV-313B FAILS TO OPEN	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGAUV0134-CX-FO	MOV UV-134 FAILS TO OPEN CONTROL CIRCUIT FAULT	2.2E-006	10.000	730.000	H	Test Period	3.3E-003
1SGAUV0134-MV-FO	MOV UV-134 LOCAL FAULT FAILS TO OPEN		3.000	3.9E-003	D	Calculated	3.9E-003
1SGAUV0134-MV-RO	STEAM SUPPLY MOV UV-134 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGAUV0134-MV9CM	MOV UV-134 UNAVAILABLE DUE TO ACTUATOR MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SGAUV0134ACXXFO	SOV UV-134A FAILS TO OPEN CONTROL CIRCUIT FAULT		10.000	1.2E-003	D	Calculated	1.2E-003
1SGAUV0134ASV-FO	SOV UV-134A LOCAL FAULT FAILS TO OPEN	9.1E-007	3.000	1488.000	H	Test Period	6.1E-004
1SGAUV0138-CX-FO	MOV UV-138 FAILS TO OPEN CONTROL CIRCUIT FAULT	2.2E-006	3.000	730.000	H	Test Period	3.3E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGAUV0138-MV-FO	MOV UV-138 LOCAL FAULT FAILS TO OPEN		3.000	3.9E-003	D	Calculated	3.9E-003
1SGAUV0138-MV-RO	STEAM SUPPLY MOV UV-138 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGAUV0138-MV9CM	MOV UV-138 UNAVAILABLE DUE TO ACTUATOR MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SGAUV0172-AV-RO	UV-172 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGAUV0175-AV-RO	AOV UV-175 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGAUV172P-AV-RO	AOV PILOT VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGAUV175P-AV-RO	AOV PILOT VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGAUY0172-CXXRO	SOLENOID VALVE CIRCUIT FAULTS - SPURIOUS TRIP		10.000	2.4E-005	D	Calculated	2.4E-005
1SGAUY0172-SV-RO	SOLENOID VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1SGAUY0175-CXXRO	SOLENOID VALVE UY-175 CIRCUIT FAULT - SPURIOUS TRIP		10.000	2.4E-005	D	Calculated	2.4E-005
1SGAUY0175-SV-RO	SOLENOID VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1SGAV043---CV-FO	CHECK VALVE V043 FAILS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005
1SGAV044---CV-FO	CHECK VALVE V044 FAILS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGB72D2202CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2202	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006
1SGB72D2214CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2214 (SPURIOUS OPEN)	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006
1SGBHV0178-AV-FO	LOCAL FAULT OF ADV HV-178	4.1E-007	5.000	2190.000	H	Test Period	4.5E-004
1SGBHV0178-AV9CM	HV-178 UNAVAILABLE FOR PERIOD OF UNSCHEDULED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SGBHV0185-AV-FO	LOCAL FAULT OF ADV HV-185	4.1E-007	5.000	2190.000	H	Test Period	4.5E-004
1SGBHV0185-AV9CM	HV-184 UNAVAILABLE FOR PERIOD OF UNSCHEDULED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SGBHY0178ASV-FC	LOCAL FAULT SOLENOID VALVE HY-178A (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGBHY0178CIMCNO	LOCAL FAULT OF I/P CONTROL UNIT HY-178C	1.1E-006	33.000	2190.000	H	Test Period	1.2E-003
1SGBHY0178RSV-FC	LOCAL FAULT SOLENOID VALVE HY-178R (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGBHY0185ASV-FC	LOCAL FAULT OF SOLENOID VALVE HY-185A (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGBHY0185CIMCNO	LOCAL FAULT OF I/P CONTROL UNIT HY-185	1.1E-006	33.000	2190.000	H	Test Period	1.2E-003
1SGBHY0185RSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-185R (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGBHY78AR-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET A (HY-178)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGBHY85AR-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET A (HY-185)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGBUV0130-AV-RO	UV-130 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGBUV0135-AV-RO	AOV UV-135 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGBUV130P-AV-RO	AOV PILOT VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGBUV135P-AV-RO	AOV PILOT VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGBUY0130-CXXRO	SOLENOID VALVE CIRCUIT FAULTS - SPURIOUS TRIP		10.000	2.4E-005	D	Calculated	2.4E-005
1SGBUY0130-SV-RO	SOLENOID VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1SGBUY0135-CXXRO	SOLENOID VALVE CIRCUIT FAULTS - SPURIOUS TRIP		10.000	2.4E-005	D	Calculated	2.4E-005
1SGBUY0135-SV-RO	SOLENOID VALVE FAILS TO REMAIN OPEN - LOCAL FAULTS	9.0E-007	3.000	24.000	H	Mission Time	2.2E-005
1SGC72D2305CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2305 (SPURIOUS OPEN)	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006
1SGC72D2306CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2306 (SPURIOUS OPEN	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGCHY0179BSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-179B (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGCHY0179SSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-179S (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGCHY0184BSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-184B (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGCHY0184SSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-184S (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGCHY79BS-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET B (HY-179)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGCHY84BS-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET B (HY-184)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGD72D2405CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2405 (SPURIOUS OPEN)	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006
1SGD72D2406CBDST	LOCAL FAULT OF CIRCUIT BRKR 72-D2406 (SPURIOUS OPEN)	2.3E-007	10.000	26.000	H	Mission Time / Detection Period	6.0E-006
1SGDHY0178BSV-FC	LOCAL FAULT SOLENOID VALVE HY-178B(FAILS TO CLOSE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGDHY0178SSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-178S(FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGDHY0185BSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-185B (FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004
1SGDHY0185SSV-FC	LOCAL FAULT OF SOLENOID VALVE HY-185S(FAIL TO OPERATE)	9.1E-007	3.000	2190.000	H	Test Period	9.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGDHY78BS-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET B (HY-178)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGDHY85BS-CX7FC	CONTROL CIRCUIT FAULT SOLENOID SET B (HY-185)	5.2E-006	10.000	2190.000	H	Test Period	1.5E-003
1SGEHV-41--MV-RO	BLOWDOWN VALVE HV-41 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
1SGEHV-43--CX5FO	BLOWDOWN VALVE HV-43 FAILS TO OPEN -CONTROL CIRCUIT FAULTS-	1.0E-006	3.000	13140.000	H	Test Period	6.6E-003
1SGEHV-43--MV-FO	BLOWDOWN VALVE HV-43 FAILS TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SGEV334---CV-FO	CHECK VALVE V334 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGEV337---NV-RO	MANUAL VALVE V337 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SGEV339---CV-FO	CHECK VALVE V339 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGEV342---NV-RO	MANUAL VALVE V342 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SGEV346---CV-FO	CHECK VALVE V346 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGEV348---CV-FO	CHECK VALVE V348 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGEV350---CV-FO	CHECK VALVE V350 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGEV354---NV-RO	MANUAL VALVE V354 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SGEV357---CV-FO	CHECK VALVE V357 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGEV358---CV-FO	CHECK VALVE V358 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGEV360---CV-FO	CHECK VALVE V360 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGEV363---NV-RO	MANUAL VALVE V363 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SGEV642---CV-FO	CHECK VALVE AF-642 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1SGEV652---CV-FO	CHECK VALVE AF-652 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1SGEV653---CV-FO	CHECK VALVE 653 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1SGEV693---CV-FO	CHECK VALVE AF-693 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1SGEV885---NV-RO	START-UP LINE MAN ISOL VALVE V885/ V886 FAILS TO REMAIN OPEN	3.0E-008	84.000	1488.000	H	Test Period	2.2E-005
1SGEV887---CV-FO	START-UP SPRING LOADED CHECK V887 FAILS TO OPEN	3.0E-008	3.000	1488.000	H	Test Period	2.2E-005
1SGEV889---NV-RM	MANUAL VALVE V889 NOT RESTORED AFTER MAINTENANCE		11.000	7.5E-005	D	Calculated	7.5E-005
1SGEV889---NV-RO	MANUAL VALVE V889 FAILS TO REMAIN OPEN	3.0E-008	84.000	1488.000	H	Test Period	2.2E-005
1SGEV963---NV-RO	MANUAL VALVE V963 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SGEV964---NV-RO	MANUAL VALVE V964 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SGEV965---NV-RO	MANUAL VALVE V965 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SGEV966---NV-RO	MANUAL VALVE V966 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGN-BYPASSMV2HR	OPERATOR FAILS TO OPEN DOWNCOMER BYPASS MOV HV-1143/1145		5.000	6.7E-002	D	Calculated	6.7E-002
1SGN-F02A--FXAPG	FILTER SGN-F02A PLUGGED	6.8E-006	10.000	2.000	H	Mission Time	1.4E-005
1SGN-F03A--FXAPG	FILTER SGN-F03A PLUGGED	6.8E-006	10.000	2.000	H	Mission Time	1.4E-005
1SGNFV1113-AV-FO	AOV FV-1113 FAILS TO OPEN		5.000	3.0E-003	D	Calculated	3.0E-003
1SGNFV1113-AV-RO	AOV FV-1113 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGNFV1123-AV-FO	FV-1123 FAILS TO OPEN		5.000	3.0E-003	D	Calculated	3.0E-003
1SGNFV1123-AV-RO	FV-1123 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGNHV1143-CX5FO	MOV HV-1143 CONTROL CIRCUIT FAULT (FAILS TO OPEN)	1.0E-006	3.000	13140.000	H	Test Period	6.6E-003
1SGNHV1143-MV-FO	DOWNCOMER BYPASS MOV HV-1143 FAILS TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SGNHV1145-CX5FO	MOV HV-1145 CONTROL CIRCUIT FAULT (FAILS TO OPEN)	1.0E-006	3.000	13140.000	H	Test Period	6.6E-003
1SGNHV1145-MV-FO	DOWNCOMER BYPASS MOV HV-1145 FAILS TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SGNPSL1128IWPNO	PRESSURE SWITCH 1128 FAILS TO TRANS-FER/NO OUTPUT	1.4E-006	14.000	13140.000	H	Test Period	9.2E-003
1SGNPV1128-SV-FO	SOV PV-1128 FAILS TO OPEN	9.1E-007	3.000	13140.000	H	Test Period	5.4E-003
1SGNV002---CV-FO	AFW TRAIN N SG 1 DISCHARGE CHECK VALVE SG-002 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGNV008---CV-FO	TRAIN N SG 2 DISCHARGE CHECK VALVE V008 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SGNV435---NV-RO	MANUAL VALVE V435 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1SGNV437---NV-RO	MANUAL VALVE V437 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1SGNV440---CV-RO	CHECK VALVE V440 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGNV441---CV-FO	CHECK VALVE V441 FAILS TO OPEN	3.0E-008	3.000	24.000	H	Mission Time	7.2E-007
1SGNV959---CV-RO	CHECK VALVE V959 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SGNX02-ACUM-2OP	FAILURE TO SUPPLY N2 FROM DEDICATED ACCUMULATOR, SGN-X02 (LONG TERM)		1.000	1.000	D	Screening Value	1.000
1SGPCV1130-PV-RO	PRESSURE CONTROL VALVE PCV-1130 FAILS TO REMAIN OPEN	4.2E-006	10.000	13140.000	H	Test Period	2.8E-002
1SGPCV1147-PV-RO	PRESSURE REGULATING VALVE PC1147 FAILS TO REMAIN OPEN	4.2E-006	10.000	24.000	H	Mission Time	1.0E-004
1SGPSV1131-RV-RC	SAFETY RELIEF VALVE PSV-1131 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1SGPSV1147-RV-RC	RELIEF VALVE PSV1147 FAILS TO REMAIN CLOSED	4.0E-006	5.000	24.000	H	Mission Time	9.6E-005
1SGUV-500P-AV-FO	BLOWDOWN VALVE SG-UV-500P FAILS TO OPEN		5.000	9.0E-004	D	Calculated	9.0E-004
1SGUV-500Q-AV-FO	BLOWDOWN ISO VALVE UV-500Q FAILS TO OPEN		5.000	9.0E-004	D	Calculated	9.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SGUY-500P-SV-FO	BLOWDOWN VALVE SG-UV-500P SOLENOID VALVE FAILS		3.000	1.3E-005	D	Calculated	1.3E-005
1SGUY-500Q-SV-FO	BLOWDOWN VALVE SG-UV-500Q SOLENOID VALVE FAILS		3.000	1.3E-005	D	Calculated	1.3E-005
1SGV-289---NV-RO	MANUAL VALVE SG-V289 FAILS TO REMAIN OPEN	3.0E-008	84.000	8.000	H	Mission Time	2.4E-007
1SI-BAC-RMCOOLHL	OPERATOR FAILS TO PROVIDE BACKUP ROOM COOLING TO SI PUMP ROOMS		3.000	2.0E-001	D	Calculated	2.0E-001
1SI-HPSI4-6MV-CC	COMMON CAUSE FAILURE OF 4-OUT-OF-6 HPSI INJECTION MOVS IN AVAILABLE LINES		30.000	2.6E-005	D	Calculated	2.6E-005
1SI-HPSI8-8MV-CC	COMMON CAUSE FAILURE OF 8-OUT-OF-8 HPSI INJECTION MOVS IN 4 AVAILABLE LINES		30.000	2.6E-005	D	Calculated	2.6E-005
1SI-P01----CXXFS	LPSI PUMP FAILS TO RESTART AFTER CONTROL CIRCUIT TRIP		3.000	1.3E-003	D	Calculated	1.3E-003
1SI-P01----MPRFS	LPSI PUMP FAILS TO RESTART AFTER TRIP		2.000	3.0E-003	D	Calculated	3.0E-003
1SI-P03-1H-MP2HR	OPERATOR FAILS TO SHUT OFF CONT. SPRAY TR A PUMP WITHIN 1 HR OF SIAS		10.000	2.2E-003	D	Calculated	2.2E-003
1SI-P03-20MMP2HR	OPERATOR FAILS TO SHUT OFF CONT. SPRAY TR A PUMP WITHIN 20 MINS OF SIAS		3.000	2.7E-001	D	Calculated	2.7E-001
1SI-SDCBRKR--2HL	OPERATOR FAILS TO CLOSE MOV UV-653/ 654 CIRCUIT BREAKERS		10.000	3.0E-004	D	Calculated	3.0E-004
1SIA-LPSIA-MV-CC	COMMON CAUSE FAILURE OF 2-OUT-OF-2 LPSI TRAIN A INJ. MOV'S		30.000	9.9E-006	D	Calculated	9.9E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIA3-SDCILOK-OP	RCS PRES INTERLOCK PERMISSIVE FAILS (PRES TRANSMITTER PT-103 & BISTABLES)		10.000	2.7E-002	D	Calculated	2.7E-002
1SIA5-SDCILOK-OP	RCS PRES INTERLOCK PERMISSIVE FAILS (PRES TRANSMITTER PT-105 & BISTABLES)		10.000	2.7E-002	D	Calculated	2.7E-002
1SIAB-CSS--MP-CC	COMMON CAUSE FAILURE OF TRAIN A & B CONTAINMENT SPRAY PUMPS		30.000	3.7E-004	D	Calculated	3.7E-004
1SIAB-CSS--MV-CC	COMMON CAUSE FAILURE OF TRAIN A & B CONTAINMENT SPRAY INJECTION MOV'S		30.000	3.0E-005	D	Calculated	3.0E-005
1SIAB-HPSI-MP-CC	COMMON CAUSE FAILURE OF 2-OUT-OF-2 HPSI PUMPS		30.000	1.4E-004	D	Calculated	1.4E-004
1SIAB-LPSI-MP-CC	COMMON CAUSE FAILURE OF 2-OUT-OF-2 LPSI PUMPS		30.000	1.4E-004	D	Calculated	1.4E-004
1SIAB-LPSI-MV-CC	COMMON CAUSE FAILURE OF 4-OUT-OF-4 LPSI INJECTION MOV'S		30.000	3.9E-005	D	Calculated	3.9E-005
1SIAB-LPSI3MV-CC	COMMON CAUSE FAILURE OF 3-OUT-OF-3 LPSI INJ MOVS FOR INTACT RCS LOOP S.I.		30.000	3.9E-005	D	Calculated	3.9E-005
1SIACSSA-TEST-TT	CONTAINMENT SPRAY TRAIN A UNAVAILABLE DUE TO TEST		5.000	9.1E-004	D	Calculated	9.1E-004
1SIAE01----HX-PG	LOCAL FAULT CAUSING BLOCKAGE OF FLOW IN TRAIN A SDHX (SIA-E01)		10.000	6.5E-005	D	Calculated	6.5E-005
1SIAE01----HX9CM	SDHX SIA-E01 UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAF0390--PXOPG	TRAIN A HOT LEG INJECTION FLOW ORIFICE PLUGS	8.3E-007	3.000	22.000	H	Mission Time	1.8E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAFO0019-PXOPG	LPSI TRAIN A MINIMUM FLOW LINE FLOW ORIFICE FO-19 PLUGGED	8.3E-007	3.000	16.000	H	Mission Time	1.3E-005
1SIAFO0021-PXOPG	CONT. SPRAY TRAIN A MIN. FLOW RECIRC LINE FLOW ORIFICE FO-21 PLUGGED	8.3E-007	3.000	2190.000	H	Test Period	9.1E-004
1SIAFO43---PXOPG	LOOP 1B HPSI HDR 1 FLOW OROFICE FO43 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIAFO47---PXOPG	LOOP 2B HPSI HDR 1 FLOW OROFICE FO47 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIAFO49---PXOPG	LOOP 2A HPSI HDR 1 FLOW OROFICE FO49 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIAFO717--PXOPG	LOOP 2A HPSI HDR 1 FLOW OROFICE FO717 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIAFO727--PXOPG	LOOP 2B HPSI HDR 1 FLOW OROFICE FO727 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIAFO747--PXOPG	LOOP 1B HPSI HDR 1 FLOW OROFICE FO747 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIAHPSI3-3MV-CC	COMMON CAUSE FAILURE OF 3 OUT OF 3 INJECT MOVS IN THE HPSI TRAIN A HEADER		30.000	7.4E-007	D	Calculated	7.4E-007
1SIAHV0306-CX6RO	LPSI TR. A FLOW CONTROL MOV HV-306 CNTL CIRC FAULTS -SPURIOUS CLOSE	6.0E-007	10.000	16.000	H	Mission Time	9.6E-006
1SIAHV0306-MV-RO	LPSI TR. A FLOW CONTROL MOV HV-306 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1SIAHV0604-CB-ST	TRAIN A HOT LEG MOV HV-604 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIAHV0604-CX8FO	TRAIN A HLI MOV HV-604 CONTROL CIRCUIT FAULT-FAIL TO OPEN	1.3E-006	10.000	13140.000	H	Test Period	8.5E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAHV0604-MV-FO	LOCAL FAULT TRAIN A HOT LEG MOV HV-604 FAILS TO OPEN	2.9E-006	10.000	13140.000	H	Test Period	1.9E-002
1SIAHV0604-MV-RO	LOCAL FAULT TRAIN A HOT LEG MOV HV604 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SIAHV0604-MV9CM	MOV HV-604 UNAVAILABLE DUE TO UNSCHEDULED MAINTAINANCE		3.000	5.9E-004	D	Plant Specific	5.9E-004
1SIAHV0683-CX6RO	LPSI TR. A PUMP SUCTION MOV HV-683 CNTL CIRC FAULTS -SPURIOUS CLOSE	6.0E-007	10.000	16.000	H	Mission Time	9.6E-006
1SIAHV0683-MV-RO	LPSI TR. A PUMP SUCTION MOV HV-683 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1SIAHV0683-MV9CM	LPSI TR. A PUMP SUCTION MOV HV-683 UNAVAIL FOR PERIOD OF UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAHV0691-MV-RC	SDC LOOP A WARM-UP BYPASS MOTOR OPER VALVE FAILS TO REMAIN CLOSED	1.0E-007	84.000	13140.000	H	Test Period	6.6E-004
1SIAHV0698-CX6FC	LOCAL FAULT TR A COLD LEG INJ ORIFICE BYPASS VALVE FAILS TO CLOSE (CNTRL CKT FAU	1.4E-006	3.000	13140.000	H	Test Period	9.2E-003
1SIAHV0698-MV-FC	LOCAL FAULT TR A COLD LEG INJ ORIFICE BYPASS VALVE FAILS TO CLOSE	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIAHV0698-MV-RC	LOCAL FAULT TR A COLD LEG INJ ORIFICE BYPASS VALVE FAILS TO REMAIN CLOSED	1.0E-007	84.000	22.000	H	Mission Time	2.2E-006
1SIAHV0698-MV-RO	HPSI TR. A FLOW CONTROL MOV HV-698 FAILS TO REMAIN OPEN	2.3E-007	9.000	13140.000	H	Test Period	1.5E-003
1SIALPSI-TEST-TT	LPSI TRAIN A IN TEST		5.000	9.1E-004	D	Calculated	9.1E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAP01----CB-FT	LPSI TRAIN A PUMP (SIA-P01) CIRCUIT BREAKER FAULT -FAIL TO CLOSE	1.2E-006	5.000	2190.000	H	Test Period	1.3E-003
1SIAP01----CB0CM	LPSI TRAIN A PUMP (SIA-P01) CIRCUIT BREAKER OUT FOR UNSCHED. MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SIAP01----CX6FS	LPSI TRAIN A PUMP (SIA-P01) CONTROL CIRCUIT FAULT -FAIL TO START	1.6E-006	3.000	2190.000	H	Test Period	1.8E-003
1SIAP01----MP-FR	LPSI TRAIN A PUMP (SIA-P01) FAIL TO RUN AFTER START	2.1E-005	2.000	16.000	H	Mission Time	3.4E-004
1SIAP01----MP-FS	LPSI TRAIN A PUMP (SIA-P01) FAIL TO START (LOCAL FAULT)	1.0E-006	2.000	2190.000	H	Test Period	1.1E-003
1SIAP01----MP6CM	LPSI TR. A PUMP SIA-P01 UNAVAILABLE FOR PERIOD OF UNSCHED MAINTENANCE		5.000	1.3E-003	D	Plant Specific	1.3E-003
1SIAP01-BAC--2OP	LPSI PUMP A FAILS TO RUN 24HRS GIVEN NO ESS HVAC BUT WITH B/U ROOM COOLING		10.000	1.0E-001	D	Calculated	1.0E-001
1SIAP01-NOBAC2OP	LPSI PUMP A FAILS TO RUN 24HRS GIVEN NO ESS OR BACKUP ROOM COOLING		10.000	1.000	D	Screening Value	1.000
1SIAP02----CB-FT	LOCAL FAULT -HPSI TR. A PUMP CIRCUIT BREAKER FAILS TO CLOSE	1.2E-006	5.000	2190.000	H	Test Period	1.3E-003
1SIAP02----CB0CM	HPSI TR. A PUMP CIRCUIT BREAKER OUT FOR UNSCHEDULED MAINT.	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SIAP02----CX6FS	HPSI TR. A PUMP CONTROL CIRCUIT FAULT -FAILS TO START	1.6E-006	3.000	2190.000	H	Test Period	1.8E-003
1SIAP02----MP-FR	HPSI TR. A MOTOR-DRIVEN PUMP SIAP02 FAILS TO RUN	2.1E-005	2.000	16.000	H	Mission Time	3.4E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAP02----MP-FS	HPSI TR. A MOTOR-DRIVEN PUMP SIAP02 FAILS TO START	1.0E-006	2.000	2190.000	H	Test Period	1.1E-003
1SIAP02----MP6CM	HPSI TR. A MOTOR-DRIVEN PUMP OUT FOR UNSCHEDULED MAINT.		5.000	1.3E-003	D	Plant Specific	1.3E-003
1SIAP02-BAC--2OP	HPSI A PUMP FAILS TO RUN 24 HRS GIVEN NO ESS HVAC BUT WITH BACKUP ROOM COOLING		10.000	1.7E-002	D	Calculated	1.7E-002
1SIAP02-NOBAC2OP	HPSI TRAIN A PUMP FAILS TO RUN 24HRS GIVEN NO ESS OR BACKUP ROOM COOLING		10.000	5.3E-002	D	Calculated	5.3E-002
1SIAP03----CB0CM	CONT. SPRAY TRAIN A PUMP CIRCUIT BREAKER UNAVAIL. DUE TO UNSCHED. MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SIAP03----MP2OP	PUMP OVERHEAT DUE TO RUN ON RECIRC. LINE FOR MORE THAN 1 HR		10.000	1.0E-001	D	Calculated	1.0E-001
1SIAP03-BAC--2OP	CS A PUMP FAILS TO RUN 24HRS GIVEN NO ESS HVAC BUT WITH BACKUP ROOM COOLING		10.000	1.0E-001	D	Calculated	1.0E-001
1SIAP03-NOBAC2OP	CS A PUMP FAILS TO RUN 24HRS GIVEN NO ESS HVAC OR BACKUP ROOM COOLING		10.000	1.000	D	Screening Value	1.000
1SIAPSV0468RV-RC	TRAIN A HOT LEG RELIEF VALVE PSV-468 FAILS TO REMAIN CLOSED	4.0E-006	5.000	22.000	H	Mission Time	8.8E-005
1SIAPSV417-RV-RC	HPSI TR. A PRESS. RELIEF VALVE PSV-417 FAILS TO REMAIN CLOSED	4.0E-006	5.000	16.000	H	Mission Time	6.4E-005
1SIAUV0617-CB-ST	HPSI 2A HDR INJ. MOV UV-617 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAUV0617-CX7FO	HPSI 2A HDR INJ. MOV UV-617 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004
1SIAUV0617-MV-FO	LOCAL FAULT HPSI 2A HDR INJECTION MOV UV-617 FAILS TO OPEN	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1SIAUV0617-MV9CM	HPSI 2A HDR INJ. MOV UV-617 OUT FOR UNSCHEDULED MAINT.	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0627-CB-ST	HPSI 2B HDR INJ. MOV UV-627 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIAUV0627-CX7FO	HPSI 2B HDR INJ. MOV UV-627 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004
1SIAUV0627-MV-FO	LOCAL FAULT HPSI 2B HDR INJECTION MOV UV-627 FAILS TO OPEN	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1SIAUV0627-MV9CM	HPSI 2B HDR INJ. MOV UV-627 OUT FOR UNSCHEDULED MAINT.	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0635-CB-ST	LPSI 1A HDR INJ. MOV UV-635 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIAUV0635-CX6FO	LPSI 1A HDR INJ. MOV UV-635 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.4E-006	3.000	1488.000	H	Test Period	1.0E-003
1SIAUV0635-MV-FO	LPSI 1A HDR INJ. MOV UV-635 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
1SIAUV0635-MV9CM	LPSI 1A HDR INJ. MOV UV-635 UNAVAIL-ABLE DURING UNSCHED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0644-MV-RO	SIT 1B ISOLATION VALVE 1SIAUV0644 FAILS TO REMAIN OPEN	2.3E-007	9.000	13140.000	H	Test Period	1.5E-003
1SIAUV0645-CB-ST	LPSI 1B HDR INJ. MOV UV-645 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAUV0645-CX6FO	LPSI 1B HDR INJ. MOV UV-645 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.4E-006	3.000	1488.000	H	Test Period	1.0E-003
1SIAUV0645-MV-FO	LPSI 1B HDR INJ. MOV UV-645 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
1SIAUV0645-MV9CM	LPSI 1B HDR INJ. MOV UV-645 UNAVAILABLE DURING UNSCHED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0647-CB-ST	HPSI 1B HDR INJ. MOV UV-647 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIAUV0647-CX7FO	HPSI 1B HDR INJ. MOV UV-647 CONTROL CIRCUIT FAULT -FAILS TO OPEN	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004
1SIAUV0647-MV-FO	LOCAL FAULT HPSI 1B HDR INJECTION MOV UV-647 FAILS TO OPEN	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1SIAUV0647-MV9CM	HPSI 1B HDR INJ. MOV UV-647 OUT FOR UNSCHEDULED MAINT.	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0651-CB-ST	480V AC CIRCUIT BREAKER M3507A FAULT/FAIL TO CARRY POWER	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006
1SIAUV0651-CX4FO	RCS ISOLATION MOTOR OPER VALVE UV651 CONTROL CIRCUIT FAULT (FAIL TO OPEN)	1.9E-006	3.000	13140.000	H	Test Period	1.3E-002
1SIAUV0651-MV-FO	RCS ISOLATION MOTOR OPER VALVE UV651 LOCAL FAULT (FAIL TO OPEN)	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIAUV0651BCB-ST	480V AC BACKUP CB M3503 FAULT/FAIL TO CARRY POWER	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006
1SIAUV0655-CB-ST	480V AC CIRCUIT BREAKER E-PHA-M3504 FAILS TO CARRY POWER	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006
1SIAUV0655-CX4FO	UV655 CONTROL CIRCUIT FAULT	1.9E-006	3.000	13140.000	H	Test Period	1.3E-002

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAUV0655-MV-FO	CONTAINMENT ISOLATION MOV UV655 LOCAL FAULT(FAIL TO OPEN)	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIAUV0655-MV9CM	MOV UV655 UNAVAIL DUE TO UNSCHED-ULED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0660-CX0RO	TR A COMMON S.I. MIN FLOW LINE SOV UV-660 CNTL CIRC FAULT -SPURIOUS CLOSE	7.6E-006	10.000	16.000	H	Mission Time	1.2E-004
1SIAUV0660-SV-RO	TR A COMMON S.I. MIN FLOW LINE UV-660 LOCAL FAULT -FAIL TO REMAIN OPEN	9.0E-007	3.000	2190.000	H	Test Period	9.9E-004
1SIAUV0660-SV9CM	TR A COMMON S.I. MINI FLOW LINE SOV UV-660 UNAVAIL DURING UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0660-SV9CM	TR A COMMON S.I. MINI FLOW LINE SOV UV-660 UNAVAIL DURING UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0664-CX7RO	CS A MIN. FLOW RECIRC MOV UV-664 CONTROL CIRCUIT SPURIOUS CLOSE	1.0E-006	10.000	16.000	H	Mission Time	1.6E-005
1SIAUV0664-MV-RO	CS A MIN. FLOW RECIRC MOV UV-664 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1SIAUV0664-MV9CM	CS A MIN. FLOW RECIRC MOV UV-664 UNAVAIL DUE TO UNSCHED. MAINTE-NANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAUV0669-CX7RO	LPSI TRAIN A MINIMUM FLOW MOV UV-669 ACTUATION FAULT -SPURIOUS CLOSE	1.0E-006	10.000	16.000	H	Mission Time	1.6E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAUV0669-MV-RO	LPSI TRAIN A MINIMUM FLOW MOV UV-669 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1SIAUV0669-MV9CM	LPSI TRAIN A MINIMUM FLOW MOV UV-669 UNAVAILABLE DURING UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIAV201---CV-FO	LPSI TR. A PUMP SUCTION CHECK VALVE V-201 FAIL TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIAV201---CV-RO	LPSI TR. A PUMP SUCTION CHECK VALVE V-201 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIAV404---CV-FO	HPSI PUMP A DISCHARGE CHECK VALVE V404 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIAV404---CV-RO	HPSI PUMP A DISCHARGE CHECK VALVE V404 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIAV434---CV-FO	LPSI TRAIN A PUMP DISCHARGE CHECK VALVE V-434 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIAV434---CV-RO	LPSI TRAIN A PUMP DISCHARGE CHECK VALVE V-434 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIAV435---NV-RM	LPSI PUMP 1 DISCH. MAN. ISOL. VLV V435 FAIL TO RESTORE AFTER MAINTENANCE		10.000	3.3E-004	D	Calculated	3.3E-004
1SIAV435---NV-RO	LPSI PUMP 1 DISCH. MAN. ISOL. VALVE V435 FAILS TO REMAIN OPEN	3.0E-008	84.000	2190.000	H	Test Period	3.3E-005
1SIAV451---CV-FO	LPSI TRAIN A MINIMUM FLOW LINE CHECK VALVE V-451 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIAV470---NV-RM	PUMP A SUCTION MAN ISOL VLV V470 FAIL TO RESTORE AFTER MAINT		10.000	9.9E-006	D	Calculated	9.9E-006
1SIAV470---NV-RO	HPSI PUMP A SUCTION MAN. ISOL. VALVE V470 FAIL TO REMAIN OPEN	3.0E-008	84.000	2190.000	H	Test Period	3.3E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIAV476---NV-RM	PUMP A DISCH. MAN. ISOL. VLV V476 FAIL TO RESTORE AFTER MAINT		10.000	2.0E-003	D	Calculated	2.0E-003
1SIAV476---NV-RO	HPSI PUMP A DISCH. MAN. ISOL. VALVE V476 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SIAV486---CV-FO	CS A MIN. FLOW RECIRC CHECK VALVE V-486 FAIL TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIAV522---CV-FO	TRAIN A HOT LEG INJ CHECK VALVE V522 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIAV522---CV-RO	TRAIN A HOT LEG INJ CHECK VALVE V522 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SIAV523---CV-FO	TRAIN A HOT LEG INJ CHECK VALVE V523 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIAV523---CV-RO	TRAIN A HOT LEG INJ CHECK VALVE V523 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SIAV957---NV-RM	TRAIN A HOT LEG ISOLATION MANUAL VALVE V957 FAILS TO RESTORE AFTER MAINT		10.000	4.0E-005	D	Calculated	4.0E-005
1SIAV957---NV-RO	TRAIN A HOT LEG ISOLATION MANUAL VALVE V957 FAILS TO OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SIB-LPSIB-MV-CC	COMMON CAUSE FAILURE OF 2-OUT-OF-2 LPSI TRAIN B INJ. MOV'S		30.000	9.9E-006	D	Calculated	9.9E-006
1SIB4-ILOKOVR-HL	OPERATOR FAILS TO OVERRIDE INTER-LOCK PERMISSIVE LOCALLY		1.000	1.000	D	Screening Value	1.000
1SIB4-SDCILOK-OP	RCS PRES INTERLOCK PERMISSIVE FAILS (PRES TRANSMITTER PT-104 & BISTABLES)		10.000	2.7E-002	D	Calculated	2.7E-002

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIB6-SDCILOK-OP	RCS PRES INTERLOCK PERMISSIVE FAILS (PRES TRANSMITTER PT-106 & BISTABLES)		10.000	2.7E-002	D	Calculated	2.7E-002
1SIBCSSB-TEST-TT	CONTAINMENT SPRAY TRAIN B UNAVAILABLE DUE TO TEST		5.000	9.1E-004	D	Calculated	9.1E-004
1SIBE01----HX-PG	LOCAL FAULT CAUSING BLOCKAGE OF FLOW IN TRAIN B SDHX (SIB-E01)		10.000	6.5E-005	D	Calculated	6.5E-005
1SIBE01----HX9CM	SDHX SIB-E01 UNAVAILABLE DURING UNSCHEDULED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBF0391--PXOPG	TRAIN B HOT LEG INJECTION FLOW ORIFICE PLUGS	8.3E-007	3.000	22.000	H	Mission Time	1.8E-005
1SIBFO0020-PXOPG	LPSI TRAIN B MINIMUM FLOW LINE FLOW ORIFICE FO-20 PLUGGED	8.3E-007	3.000	16.000	H	Mission Time	1.3E-005
1SIBFO0022-PXOPG	CONT. SPRAY TRAIN B MIN. FLOW RECIRC LINE FLOW ORIFICE FO-21 PLUGGED	8.3E-007	3.000	2190.000	H	Test Period	9.1E-004
1SIBFO44---PXOPG	LOOP 1B HPSI HDR 2 FLOW OROFICE FO44 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIBFO48---PXOPG	LOOP 2B HPSI HDR 2 FLOW OROFICE FO48 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIBFO50---PXOPG	LOOP 2A HPSI HDR 2 FLOW OROFICE FO50 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIBFO716--PXOPG	LOOP 2A HPSI HDR 2 FLOW OROFICE FO716 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIBFO726--PXOPG	LOOP 2B HPSI HDR 2 FLOW OROFICE FO726 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005
1SIBFO746--PXOPG	LOOP 1B HPSI HDR 2 FLOW OROFICE FO746 PLUGS	8.3E-007	3.000	24.000	H	Mission Time	2.0E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBHPSI3-3MV-CC	COMMON CAUSE FAILURE OF 3 OUT OF 3 INJECT MOVS IN THE HPSI TRAIN B HEADER		30.000	7.4E-007	D	Calculated	7.4E-007
1SIBHV0307-CX6RO	LPSI TR. B FLOW CONTROL MOV HV-307 CNTL CIRC FAULTS -SPURIOUS CLOSE	6.0E-007	10.000	16.000	H	Mission Time	9.6E-006
1SIBHV0307-MV-RO	LPSI TR. B FLOW CONTROL MOV HV-307 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1SIBHV0609-CB-ST	TRAIN B HOT LEG MOV HV-609 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIBHV0609-CX8FO	TRAIN B HLI MOV HV-609 CONTROL CIRCUIT FAULT-FAIL TO OPEN	1.3E-006	10.000	13140.000	H	Test Period	8.5E-003
1SIBHV0609-MV-FO	LOCAL FAULT TRAIN B HOT LEG MOV HV-609 FAILS.TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIBHV0609-MV-RO	LOCAL FAULT TRAIN B HOT LEG MOV HV609 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SIBHV0609-MV9CM	MOV HV-609 UNAVAILABLE DUE TO UNSCHEDULED MAINTAINANCE		3.000	5.9E-004	D	Plant Specific	5.9E-004
1SIBHV0690-MV-RC	SDC LOOP B WARM-UP BYPASS MOV HV-690 FAILS TO REMAIN CLOSED	1.0E-007	84.000	13140.000	H	Test Period	6.6E-004
1SIBHV0692-CX6RO	LPSI TRAIN B PUMP SUCTION MOV HV-692 CNTL CIRCUIT FAULTS -SPURIOUS CLOSE	6.0E-007	10.000	16.000	H	Mission Time	9.6E-006
1SIBHV0692-MV-RO	LPSI TR. B PUMP SUCTION MOV HV-692 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1SIBHV0692-MV9CM	LPSI TR. B PUMP SUCTION MOV HV-692 UNAVAILABLE DUE TO UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBHV0699-CX6FC	LOCAL FAULT TR B COLD LEG INJ ORIFICE BYPASS VALVE FAILS TO CLOSE (CNTRL CKT FAU	1.4E-006	3.000	13140.000	H	Test Period	9.2E-003
1SIBHV0699-MV-FC	LOCAL FAULT TR B COLD LEG INJ ORIFICE BYPASS VALVE FAILS TO CLOSE	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIBHV0699-MV-RC	LOCAL FAULT TR B COLD LEG INJ ORIFICE BYPASS VALVE FAILS TO REMAIN CLOSED	1.0E-007	84.000	22.000	H	Mission Time	2.2E-006
1SIBHV0699-MV-RO	HPSI TR. B FLOW CONTROL MOV HV-699 FAILS TO REMAIN OPEN	2.3E-007	9.000	13140.000	H	Test Period	1.5E-003
1SIBLPSI-TEST-TT	LPSI TRAIN B IN TEST		5.000	9.1E-004	D	Calculated	9.1E-004
1SIBP01----CB-FT	LPSI TRAIN B PUMP (SIB-P01) CIRCUIT BREAKER LOCAL FAULT -FAIL TO CLOSE	1.2E-006	5.000	2190.000	H	Test Period	1.3E-003
1SIBP01----CBOCM	LPSI TRAIN B PUMP (SIB-P01) CIRCUIT BREAKER OUT FOR UNSCHED. MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SIBP01----CX6FS	LPSI TRAIN B PUMP (SIB-P01) CONTROL CIRCUIT FAULT -FAIL TO START	1.6E-006	5.000	2190.000	H	Test Period	1.8E-003
1SIBP01----MP-FR	LPSI TRAIN B PUMP (SIB-P01) FAIL TO RUN AFTER START (16 HRS)	2.1E-005	2.000	16.000	H	Mission Time	3.4E-004
1SIBP01----MP-FS	LPSI TRAIN B PUMP (SIB-P01) -FAIL TO START (LOCAL FAULT)	1.0E-006	2.000	2190.000	H	Test Period	1.1E-003
1SIBP01----MP6CM	LPSI TR. B PUMP SIB-P01 UNAVAILABLE FOR PERIOD OF UNSCHED MAINTENANCE		5.000	1.3E-003	D	Plant Specific	1.3E-003
1SIBP01-BAC--2OP	LPSI PUMP B FAILS TO RUN 24HRS GIVEN NO ESS OR BACKUP ROOM COOLING		10.000	1.0E-001	D	Calculated	1.0E-001

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBP01-NOBAC2OP	LPSI PUMP B FAILS TO RUN 24HRS GIVEN NO ESS HVAC BUT WITH B/U ROOM CLG		10.000	1.000	D	Screening Value	1.000
1SIBP02----CB-FT	LOCAL FAULT -HPSI TR. B PUMP CIRCUIT BREAKER FAILS TO CLOSE	1.2E-006	5.000	2190.000	H	Test Period	1.3E-003
1SIBP02----CB0CM	HPSI TR. B PUMP CIRCUIT BREAKER OUT FOR UNSCHEDULED MAINT.	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SIBP02----CX6FS	HPSI TR. B PUMP CONTROL CIRCUIT FAULT -FAILS TO START	1.6E-006	3.000	2190.000	H	Test Period	1.8E-003
1SIBP02----MP-FR	HPSI TR. B MOTOR-DRIVEN PUMP (SIB-P02) FAILS TO RUN	2.1E-005	2.000	16.000	H	Mission Time	3.4E-004
1SIBP02----MP-FS	HPSI TR. B MOTOR-DRIVEN PUMP (SIB-P02) FAILS TO START	1.0E-006	2.000	2190.000	H	Test Period	1.1E-003
1SIBP02----MP6CM	HPSI TR. B MOTOR-DRIVEN PUMP OUT FOR UNSCHEDULED MAINT.		5.000	1.3E-003	D	Plant Specific	1.3E-003
1SIBP02-BAC--2OP	HPSI B PUMP FAILS TO RUN 24 HRS GIVEN NO ESS HVAC BUT WITH BACKUP ROOM COOLING		10.000	1.7E-002	D	Calculated	1.7E-002
1SIBP02-NOBAC2OP	HPSI B PUMP FAILS TO RUN 24HRS GIVEN NO ESS OR BACKUP ROOM COOLING		10.000	5.3E-002	D	Calculated	5.3E-002
1SIBP03----CB0CM	CONT. SPRAY TRAIN B PUMP CIRCUIT BREAKER UNAVAIL. DUE TO UNSCHED. MAINTENANCE	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SIBP03----MP2OP	PUMP OVERHEAT DUE TO RUN ON RECIRC. LINE FOR MORE THAN 1 HR		3.000	1.0E-001	D	Calculated	1.0E-001
1SIBP03-BAC--2OP	CS B PUMP FAILS TO RUN 24HRS GIVEN NO ESS HVAC BUT WITH BACKUP ROOM COOLING		10.000	1.0E-001	D	Calculated	1.0E-001

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBP03-NOBAC2OP	CS B PUMP FAILS TO RUN 24HRS GIVEN NO ESS OR BACKUP ROOM COOLING		10.000	1.000	D	Screening Value	1.000
1SIBPSV0166RV-RC	TRAIN B HOT LEG RELIEF VALVE PSV-166 FAILS TO REMAIN CLOSED	4.0E-006	5.000	22.000	H	Mission Time	8.8E-005
1SIBPSV409-RV-RC	HPSI TR. B PRESS. RELIEF VALVE PSV-409 FAILS TO REMAIN CLOSED	4.0E-006	5.000	16.000	H	Mission Time	6.4E-005
1SIBUV0614-MV-RO	SIT 2A ISOLATION VALVE 1SIBUV0614 FAILS TO REMAIN OPEN	2.3E-007	9.000	13140.000	H	Test Period	1.5E-003
1SIBUV0615-CB-ST	LPSI 2A HDR INJ. MOV UV-615 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIBUV0615-CX6FO	LPSI 2A HDR INJ. MOV UV-615 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.4E-006	3.000	1488.000	H	Test Period	1.0E-003
1SIBUV0615-MV-FO	LPSI 2A HDR INJ. MOV UV-615 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
1SIBUV0615-MV9CM	LPSI 2A HDR INJ. MOV UV-615 UNAVAIL-ABLE DURING UNSCHED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBUV0616-CB-ST	HPSI 2A HDR INJ. MOV UV-616 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIBUV0616-CX7FO	HPSI 2A HDR INJ. MOV UV-616 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004
1SIBUV0616-MV-FO	LOCAL FAULT HPSI 2A HDR INJECTION MOV UV-616 FAILS TO OPEN	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1SIBUV0616-MV9CM	HPSI 2A HDR INJ. MOV UV-616 OUT FOR UNSCHEDULED MAINT.	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBUV0624-MV-RO	SIT 2B ISOLATION VALVE 1SIBUV0624 FAILS TO REMAIN OPEN	2.3E-007	9.000	13140.000	H	Test Period	1.5E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBUV0625-CB-ST	LPSI 2B HDR INJ. MOV UV-625 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIBUV0625-CX6FO	LPSI 2B HDR INJ. MOV UV-625 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.4E-006	3.000	1488.000	H	Test Period	1.0E-003
1SIBUV0625-MV-FO	LPSI 2B HDR INJ. MOV UV-625 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
1SIBUV0625-MV9CM	LPSI 2B HDR INJ. MOV UV-625 UNAVAIL-ABLE DURING UNSCHED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBUV0626-CB-ST	HPSI 2B HDR INJ. MOV UV-626 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIBUV0626-CX7FO	HPSI 2B HDR INJ. MOV UV-626 CONTROL CIRCUIT FAULT -FAIL TO OPEN	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004
1SIBUV0626-MV-FO	LOCAL FAULT HPSI 2B HDR INJECTION MOV UV-626 FAILS TO OPEN	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1SIBUV0626-MV9CM	HPSI 2B HDR INJ. MOV UV-626 OUT FOR UNSCHEDULED MAINT.	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBUV0646-CB-ST	HPSI 1B HDR INJ. MOV UV-646 CIRCUIT BREAKER SPURIOUS OPEN	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIBUV0646-CX7FO	HPSI 1B HDR INJ. MOV UV-646 CONTROL CIRCUIT FAULT -FAILS TO OPEN	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004
1SIBUV0646-MV-FO	LOCAL FAULT HPSI 1B HDR INJECTION MOV UV-646 FAILS TO OPEN	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
1SIBUV0646-MV9CM	HPSI 1B HDR INJ. MOV UV-646 OUT FOR UNSCHEDULED MAINT.	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBUV0652-CB-ST	480V AC CIRCUIT BREAKER E-PHB-M3604A FAILS TO CARRY POWER	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBUV0652-CX4FO	MOTOR OPER VALVE UV652 CONTROL CIRCUIT FAULT	1.9E-006	3.000	13140.000	H	Test Period	1.3E-002
1SIBUV0652-MV-FO	MOV UV652 LOCAL FAULT(FAIL TO OPEN)	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIBUV0652BCB-ST	480V AC CB M3604 FAILS TO CARRY POWER	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006
1SIBUV0656-CB-ST	480V AC CIRCUIT BREAKER E-PHB-M3605	2.3E-007	10.000	16.000	H	Mission Time	3.7E-006
1SIBUV0656-CX4FO	MOTOR OPER VALVE UV656 CONTROL CIRCUIT FAULTS	1.9E-006	3.000	13140.000	H	Test Period	1.3E-002
1SIBUV0656-MV-FO	MOTOR OPER VALVE UV656 LOCAL FAULT (FAIL TO OPEN)	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIBUV0656-MV9CM	MOTOR OPER VALVE UV656 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBUV0659-CX0RO	TR B COMMON S.I. MIN FLOW LINE UV-659 CNTL CIRC FAULT -SPURIOUS CLOSE	7.6E-006	10.000	16.000	H	Mission Time	1.2E-004
1SIBUV0659-SV-RO	TR B COMMON S.I. MIN FLOW LINE UV-659 LOCAL FAULT: FAIL TO REMAIN OPEN	9.0E-007	3.000	2190.000	H	Test Period	9.9E-004
1SIBUV0659-SV9CM	TR B COMMON S.I. MIN FLOW LINE SOV UV-659 UNAVAIL DURING UNSCHED MAINTENANCE	2.8E-005	2.000	21.000	H	MTTR	5.9E-004
1SIBUV0665-CX7RO	CS B MIN. FLOW RECIRC MOV UV-665 CONTROL CIRC FAULT - SPURIOUS CLOSE	1.0E-006	10.000	16.000	H	Mission Time	1.6E-005
1SIBUV0665-MV-RO	CS B MIN. FLOW RECIRC MOV UV-665 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBUV0665-MV9CM	CS B MIN FLOW RECIRC MOV UV-665 UNAVAIL DUE TO UNSCHED MAINT.	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBUV0668-CX7RO	LPSI TRAIN B MINIMUM FLOW MOV UV-668 ACTUATION FAULT -SPURIOUS CLOSE	1.0E-006	10.000	16.000	H	Mission Time	1.6E-005
1SIBUV0668-MV-RO	LPSI TRAIN B MINIMUM FLOW MOV UV-668 LOCAL FAULT -FAIL TO REMAIN OPEN	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
1SIBUV0668-MV9CM	LPSI TRAIN B MINIMUM FLOW MOV UV-668 UNAVAILABLE DURING UNSCHED MAINT	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SIBV200---CV-FO	LPSI TR. B PUMP SUCTION CHECK VALVE V-200 FAIL TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIBV200---CV-RO	LPSI TR. B PUMP SUCTION CHECK VALVE V-200 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIBV402---NV-RM	PUMP B SUCTION MAN ISOL VLV V402 FAIL TO RESTORE AFTER MAINT		10.000	9.9E-006	D	Calculated	9.9E-006
1SIBV402---NV-RO	HPSI PUMP B SUCTION MAN. ISOL. VALVE V402 FAIL TO REMAIN OPEN	3.0E-008	84.000	2190.000	H	Test Period	3.3E-005
1SIBV405---CV-FO	HPSI PUMP B DISCHARGE CHECK VALVE V405 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIBV405---CV-RO	HPSI PUMP B DISCHARGE CHECK VALVE V405 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIBV446---CV-FO	LPSI TRAIN B PUMP DISCHARGE CHECK VALVE V-446 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIBV446---CV-RO	LPSI TRAIN B PUMP DISCHARGE CHECK VALVE V-446 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIBV447---NV-RM	LPSI PUMP 2 DISCH. MAN. ISOL. VLV V447 FAIL TO RESTORE AFTER MAINTENANCE		10.000	3.3E-004	D	Calculated	3.3E-004
1SIBV447---NV-RO	LPSI PUMP 2 DISCH. MAN. ISOL. VALVE V447 FAILS TO REMAIN OPEN	3.0E-008	84.000	2190.000	H	Test Period	3.3E-005
1SIBV448---CV-FO	LPSI TRAIN B MINIMUM FLOW LINE CHECK VALVE V-448 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIBV478---NV-RM	PUMP B DISCH. MAN. ISOL. VLV V478 FAIL TO RESTORE AFTER MAINT		10.000	2.0E-004	D	Calculated	2.0E-004
1SIBV478---NV-RO	HPSI PUMP B DISCH. MAN. ISOL. VALVE V478 FAILS TO REMAIN OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SIBV487---CV-FO	CS B MIN. FLOW RECIRC CHECK VALVE V-487 FAIL TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
1SIBV532---CV-FO	TRAIN A HOT LEG INJ CHECK VALVE V532 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIBV532---CV-RO	TRAIN A HOT LEG INJ CHECK VALVE V532 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SIBV533---CV-FO	TRAIN B HOT LEG INJ CHECK VALVE V533 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIBV533---CV-RO	TRAIN A HOT LEG INJ CHECK VALVE V533 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SIBV958---NV-RM	TRAIN B HOT LEG ISOLATION MANUAL VALVE V958 FAILS TO RESTORE AFTER MAINT		10.000	4.0E-005	D	Calculated	4.0E-005
1SIBV958---NV-RO	TRAIN B HOT LEG ISOLATION MANUAL VALVE V958 FAILS TO OPEN	3.0E-008	84.000	13140.000	H	Test Period	2.0E-004
1SICHV0321-CB-ST	TRAIN A HOT LEG MOV HV-321 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SICHV0321-CX0FO	TRAIN A HLI MOV HV-321 CONTROL CIRCUIT FAULT-FAIL TO OPEN		3.000	1.3E-002	D	Calculated	1.3E-002
1SICHV0321-MV-FO	LOCAL FAULT TRAIN A HOT LEG MOV HV-321 FAILS TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SICHV0321-MV-RO	LOCAL FAULT TRAIN A HOT LEG MOV HV321 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SICHV0321-MV9CM	MOV HV-321 UNAVAILABLE DUE TO UNSCHEDULED MAINTAINANCE		3.000	5.9E-004	D	Plant Specific	5.9E-004
1SICUV0653-CB-FT	MOV UV-653 480V AC CIRCUIT BREAKER E-PKC-B43 FAILS TO CLOSE	1.2E-006	10.000	16.000	H	Mission Time	1.9E-005
1SICUV0653-CX4FO	RCS ISOLATION MOTOR OPER VALVE SIC-UV653 CONTROL CIRCUIT FAULT	1.9E-006	3.000	13140.000	H	Test Period	1.3E-002
1SICUV0653-MV-FO	RCS ISOLATION MOTOR OPER VALVE SIC-UV653 LOCAL FAULT (FAIL TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIDHV0331-CB-ST	TRAIN B HOT LEG MOV HV-331 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
1SIDHV0331-CX0FO	TRAIN B HLI MOV HV-331 CONTROL CIRCUIT FAULT-FAIL TO OPEN		3.000	1.3E-002	D	Calculated	1.3E-002
1SIDHV0331-MV-FO	LOCAL FAULT TRAIN B HOT LEG MOV HV-331 FAILS TO OPEN	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIDHV0331-MV-RO	LOCAL FAULT TRAIN B HOT LEG MOV HV331 FAILS TO REMAIN OPEN	2.3E-007	9.000	22.000	H	Mission Time	5.1E-006
1SIDHV0331-MV9CM	MOV HV-331 UNAVAILABLE DUE TO UNSCHEDULED MAINTAINANCE		3.000	5.9E-004	D	Plant Specific	5.9E-004
1SIDUV0654-CB-FT	480V AC CIRCUIT BREAKER E-PKD-B44 FAIL TO CLOSE	1.2E-006	5.000	16.000	H	Mission Time	1.9E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIDUV0654-CX4FO	MOTOR OPER VALVE UV654 CONTROL CIRCUIT FAULT	1.9E-006	3.000	13140.000	H	Test Period	1.3E-002
1SIDUV0654-MV-FO	MOTOR OPER VALVE UV654 LOCAL FAULT (FAIL TO OPEN)	2.9E-006	14.000	13140.000	H	Test Period	1.9E-002
1SIEV113---CV-FO	CHECK VALVE V113 IN HPSI 2A HEADER FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV113---CV-RO	CHECK VALVE V113 IN HPSI 2A HEADER FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV114---CV-FC	CHECK VALVE V114 IN LPSI 2A HEADER FAILS TO CLOSE		10.000	3.0E-003	D	Calculated	3.0E-003
1SIEV114---CV-FO	LPSI 2B HEADER CHECK VALVE V-114 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV114---CV-RC	CHECK VLV V114 IN LPSI 2A HDR WAS SHUT BUT DEVELOPED INTERNAL LEAKAGE	4.0E-009	15.000	13140.000	H	Test Period	2.6E-005
1SIEV114---CV-RO	LPSI 2B HEADER CHECK VALVE V-114 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV123---CV-FO	CHECK VALVE V123 IN HPSI 2B HEADER FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV123---CV-RO	CHECK VALVE V123 IN HPSI 2B HEADER FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV124---CV-FC	CHECK VALVE V124 IN LPSI 2B HEADER FAILS TO CLOSE		10.000	3.0E-003	D	Calculated	3.0E-003
1SIEV124---CV-FO	LPSI 2B HEADER CHECK VALVE V-124 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV124---CV-RC	CHECK VLV V124 IN LPSI 2B HDR WAS SHUT BUT DEVELOPED INTERNAL LEAKAGE	4.0E-009	15.000	13140.000	H	Test Period	2.6E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIEV124---CV-RO	LPSI 2B HEADER CHECK VALVE V-124 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV134---CV-FO	LPSI 1A HEADER CHECK VALVE V-134 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV134---CV-RO	LPSI 1A HEADER CHECK VALVE V-134 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV143---CV-FO	CHECK VALVE V143 IN HPSI 1B HEADER FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV143---CV-RO	CHECK VALVE V143 IN HPSI 1B HEADER FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV144---CV-FC	CHECK VALVE V144 IN LPSI 1B HEADER FAILS TO CLOSE		10.000	3.0E-003	D	Calculated	3.0E-003
1SIEV144---CV-FO	LPSI 1B HEADER CHECK VALVE V-144 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV144---CV-RC	CHECK VLV V144 IN LPSI 1B HDR WAS SHUT BUT DEVELOPED INTERNAL LEAKAGE	4.0E-009	15.000	13140.000	H	Test Period	2.6E-005
1SIEV144---CV-RO	LPSI 1B HEADER CHECK VALVE V-144 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV215---CV-FO	SIT 2A CV 1SIEV215 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV215---CV-RC	CHECK VALVE V215 IN SIT 2A LINE FAILS TO REMAIN CLOSED	4.0E-009	15.000	13140.000	H	Test Period	2.6E-005
1SIEV217---CV-FO	SAFETY INJECTION HEADER 2A CHECK VALVE V217 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV217---CV-FO	SAFETY INJECTION HEADER 2A CHECK VALVE V217 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIEV217---CV-RO	SAFETY INJECTION HEADER 2A CHECK VALVE V217 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV225---CV-FO	SIT 2B CV 1SIEV225 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV225---CV-RC	CHECK VALVE V225 IN SIT 2B LINE FAILS TO REMAIN CLOSED	4.0E-009	15.000	13140.000	H	Test Period	2.6E-005
1SIEV227---CV-FO	SAFETY INJECTION HEADER 2B CHECK VALVE V227 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV227---CV-RO	SAFETY INJECTION HEADER 2B CHECK VALVE V227 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV237---CV-FO	SAFETY INJECTION HEADER 1A CHECK VALVE V237 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV237---CV-RO	SAFETY INJECTION HEADER 1A CHECK VALVE V237 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV245---CV-FO	SIT 1B CV 1SIEV245 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV245---CV-RC	CHECK VALVE V245 IN SIT 1B LINE FAILS TO REMAIN CLOSED	4.0E-009	9.000	13140.000	H	Test Period	2.6E-005
1SIEV247---CV-FO	SAFETY INJECTION HEADER 1B CHECK VALVE V247 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV247---CV-FO	SAFETY INJECTION HEADER 1B CHECK VALVE V247 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV247---CV-RO	SAFETY INJECTION HEADER 1B CHECK VALVE V247 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV540---CV-FO	SAFETY INJECTION HEADER 2A CHECK VALVE V540 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV540---CV-RO	SAFETY INJECTION HEADER 2A CHECK VALVE V540 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SIEV541---CV-FO	SAFETY INJECTION HEADER 2B CHECK VALVE V541 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV541---CV-RO	SAFETY INJECTION HEADER 2B CHECK VALVE V541 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV542---CV-FO	SAFETY INJECTION HEADER 1A CHECK VALVE V542 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV542---CV-RO	SAFETY INJECTION HEADER 1A CHECK VALVE V542 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SIEV543---CV-FO	SAFETY INJECTION HEADER 1B CHECK VALVE V543 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
1SIEV543---CV-RO	SAFETY INJECTION HEADER 1B CHECK VALVE V543 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
1SILI1BLINE--3OK	LPSI 1B INJECTION HEADER IS AVAILABLE		1.000	1.000	D	Flag Event	1.000
1SILI2ALINE--3OK	LPSI 2A INJECTION HEADER IS AVAILABLE		1.000	1.000	D	Flag Event	1.000
1SILI2BLINE--3OK	LPSI 2B INJECTION HEADER IS AVAILABLE		1.000	1.000	D	Flag Event	1.000
1SISDCSUCTVAL-CC	SDC SUCTION LINE MOV'S FAIL COMMON CAUSE (BOTH LINES FAIL)		30.000	4.7E-004	D	Calculated	4.7E-004
1SISIT1BLINE-3OK	INJECTION LINE FROM SIT 1B IS AVAILABLE		1.000	1.000	D	Flag Event	1.000
1SISIT2ALINE-3OK	INJECTION LINE FROM SIT 2A IS AVAILABLE		1.000	1.000	D	Flag Event	1.000
1SISIT2BLINE-3OK	INJECTION LINE FROM SIT 2B IS AVAILABLE		1.000	1.000	D	Flag Event	1.000

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SITCC-2O4-CV-CC	COMMON CAUSE FAILURE OF 2/4 SIT CHECK VALVES		5.000	4.7E-006	D	Calculated	4.7E-006
1SPA4MANVS-NV-RM	FAIL TO RESTORE 1 OF 4 ESP TR A MAN VALVES AFTER UNSCHED MAINT ON 1 OF 2 DG COOL		10.000	1.5E-004	D	Calculated	1.5E-004
1SPA4MANVS-NV-RO	ESS. SPRAY POND TR A MAN VALVE FTRO (1 OF 4 VALVES SERVING CRITDG COMPS)	3.0E-008	84.000	2920.000	H	Test Period	4.4E-005
1SPAB-P01--MP-CC	COMMON CAUSE FAILURE OF SPA-P01 AND SPB-P01		30.000	6.1E-005	D	Calculated	6.1E-005
1SPAHCV045-NV-RM	FAILURE TO RESTORE HCV-45 AFTER UNSCHED. MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1SPAHCV045-NV-RO	LOCAL FAULT MANUAL VALVE HCV-45 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1SPAHCV047-NV-RM	FAILURE TO RESTORE HCV-47 AFTER UNSCHED. MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1SPAHCV047-NV-RO	LOCAL FAULT MANUAL VALVE HCV-47 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1SPAHV049A-CX6RO	MOV HV-49A CONTROL CIRC. FAULT (SPURIOUS CLOSURE)	6.0E-007	10.000	730.000	H	Test Period	2.2E-004
1SPAHV049A-MV-RO	MOV HV-49A LOCAL FAULT (FAILURE TO REMAIN OPEN)	2.3E-007	9.000	730.000	H	Test Period	8.4E-005
1SPAHV049A-MV9CM	MOV HV-49A UNAVAIL. DURING UNSCHED. MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SPAP01----CB-FT	TRAIN A SPRAY POND PUMP SPA-P01 CIRC. BKR. FAULT (FAIL TO CLOSE)	1.2E-006	5.000	730.000	H	Test Period	4.4E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SPAP01----CB0CM	TRAIN A SPRAY POND PUMP SPA-P01 CIRCUIT BREAKER OUT FOR UNSCHED. MIANT.	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SPAP01----CX5FS	TRAIN A SPRAY POND PUMP SPA-P01 CONTROL CIRCUIT FAULTS	3.0E-006	3.000	730.000	H	Test Period	1.1E-003
1SPAP01----MP-FR	TRAIN A SPRAY POND PUMP SPA-P01 FAILS TO RUN (24 HRS)	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1SPAP01----MP-FS	TRAIN A SPRAY POND PUMP SPA-P01 FAILS TO START	1.0E-006	2.000	730.000	H	Test Period	3.7E-004
1SPAP01----MP6CM	TRAIN A SPRAY POND PUMP SPA-P01 UNAVAIL. DURING UNSCHED. MAINT.		3.000	1.3E-003	D	Plant Specific	1.3E-003
1SPAV041---CV-FO	CHECK VALVE V-041 FIALS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005
1SPAV041---CV-RO	CHECK VALVE V-041 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SPB4MANVS-NV-RM	FAIL TO RESTORE 1 OF 4 ESP TR B MAN VALVES AFTER UNSCHED MAINT ON 1 OF 2 DG COOL		10.000	1.5E-004	D	Calculated	1.5E-004
1SPB4MANVS-NV-RO	ESS. SPRAY POND TR B MAN VALVE FTRO (1 OF 4 VALVES SERVING CRIT DG COMPS)	3.0E-008	84.000	2920.000	H	Test Period	4.4E-005
1SPBHCV046-NV-RM	FAILURE TO RESTORE HCV-46 AFTER UNSCHED MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1SPBHCV046-NV-RO	LOCAL FAULT HCV-46 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005
1SPBHCV048-NV-RM	FAILURE TO RESTORE HCV-48 AFTER UNSCHED MAINTENANCE		10.000	3.7E-005	D	Calculated	3.7E-005
1SPBHCV048-NV-RO	LOCAL FAULT HCV-48 FAILURE TO REMAIN OPEN	3.0E-008	84.000	730.000	H	Test Period	1.1E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SPBHV050A-CX6RO	MOV HV-50A CONTROL CIRC. FAULT (SPURIOUS CLOSURE)	6.0E-007	10.000	730.000	H	Test Period	2.2E-004
1SPBHV050A-MV-RO	MOV HV-50A LOCAL FAULT (FAILURE TO REMAIN OPEN)	2.3E-007	9.000	730.000	H	Test Period	8.4E-005
1SPBHV050A-MV9CM	MOV HV-50A UNAVAIL. DURING UNSCHED. MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
1SPBP01----CB-FT	TRAIN B SPRAY POND PUMP SPB-P01 CIRC. BKR. FAULT (FAULT TO CLOSE	1.2E-006	5.000	730.000	H	Test Period	4.4E-004
1SPBP01----CB0CM	TRAIN B SPRAY POND PUMP SPB-P01 CIRC. BKR. OUT FOR UNSCHED. MAINT.	9.4E-006	5.000	9.300	H	MTTR	8.7E-005
1SPBP01----CX5FS	TRAIN B SPRAY POND PUMP SPB-P01 CONTROL CIRCUIT FAULTS	3.0E-006	3.000	730.000	H	Test Period	1.1E-003
1SPBP01----MP-FR	TR B SPRAY POND PUMP SPB-P01 FAILURE TO RUN GIVEN START	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1SPBP01----MP-FS	TRAIN B SPRAY POND PUMP SPB-P01 FAILS TO START	1.0E-006	2.000	730.000	H	Test Period	3.7E-004
1SPBP01----MP6CM	TRAIN B SPRAY POND PUMP SPB-P01 UNAVAIL. DURING UNSCHED. MAINT.		5.000	1.3E-003	D	Plant Specific	1.3E-003
1SPBV012---CV-FO	CHECK VALVE V-012 FAILS TO OPEN	3.0E-008	3.000	730.000	H	Test Period	1.1E-005
1SPBV012---CV-RO	CKECK VALVE V-012 FAILURE TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1SPUR-SIAS---3EE	SPUR. ACT. OF SIAS A&B DUE TO ESF SWGR HVAC INDUCED FAILURE OF TWO CLASS 120V		1.000	1.000	D	Flag Event	1.000

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1SPUR-SIAS-AB3EE	SPURIOUS ACT OF TR A & B SIAS UPON LOSS OF TWO CLASS 120VAC BUSES DUE TO ESF SWG		1.000	1.000	D	Flag Event	1.000
1SPURMFWTRIP-2OP	MAIN FW PUMPS SPURIOUS TRIP FOL-LOWING REACTOR TRIP		3.000	1.0E-001	D	Calculated	1.0E-001
1TBV-QOPEN---2OP	TURBINE BYPASS VALVES FAIL TO QUICK OPEN ON A TURBINE TRIP		7.000	3.5E-003	D	Calculated	3.5E-003
1TBV-SYSTEM--2OP	TBVS FAIL TO OPEN - MECHANICAL & CONTROL SYSTEM FAULS		10.000	2.0E-002	D	Calculated	2.0E-002
1TCPCOOL-A---2OP	FAILURE OF TURBINE COOLING WATER SPECIFIC TO COMPRESSOR A		10.000	1.0E-004	D	Calculated	1.0E-004
1TCPCOOL-B---2OP	FAILURE OF TURBINE COOLING WATER SPECIFIC TO COMPRESSOR B		10.000	1.0E-004	D	Calculated	1.0E-004
1TCPCOOL-C---2OP	FAILURE OF TURBINE COOLING WATER SPECIFIC TO COMPRESSOR C		10.000	1.0E-004	D	Calculated	1.0E-004
1WC-2-2FTR-ARHCC	COMMON CAUSE FAILURE TO RUN OF 2/2 NORMALLY OPERATING WC CHILLERS.		17.000	2.2E-005	D	Calculated	2.2E-005
1WC-2-2FTR-MP-CC	COMMON CAUSE FAILURE TO RUN OF 2/2 NORMALLY OPERATING WC CHILLER PUMPS.		30.000	2.2E-005	D	Calculated	2.2E-005
1WC-2-2FTS-ARHCC	COMMON CAUSE FAIL TO START OF 2/2 STANDBY WC CHILLERS.		17.000	4.6E-004	D	Calculated	4.6E-004
1WC-2-2FTS-MP-CC	COMMON CAUSE FAILURE TO START OF 2/ 2 STANDBY WC CHILLER PUMPS		30.000	4.6E-004	D	Calculated	4.6E-004
1WC-E01A---ARHFR	WC CHILLER E01A FAILS TO RUN 24 HOURS	6.0E-005	25.000	24.000	H	Mission Time	1.4E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1WC-E01B---ARHFR	WC CHILLER E01B FAILS TO RUN 24 HRS	6.0E-005	25.000	24.000	H	Mission Time	1.4E-003
1WC-E01C---ARHFR	WC CHILLER E01C FAILS TO RUN 24 HRS	6.0E-005	25.000	24.000	H	Mission. Time	1.4E-003
1WC-E01C---ARHFS	WC SCHILLER E01C FAILS TO START	1.0E-006	5.000	8760.000	H	Test Period	4.4E-003
1WC-E01C---CXXFS	WC CHILLER E01C FAILS TO START DUE TO CONT CKT FAULT		3.000	2.7E-002	D	Calculated	2.7E-002
1WC-E02----AR7CM	WC CHILLER E02 UNAVAILABLE DUE TO UNSCHEDULED MAINT	1.3E-004	5.000	116.000	H	MTTR	1.5E-002
1WC-E02----ARHFR	WC CHILLER E02 FAILS TO RUN 24 HOURS	6.0E-005	25.000	24.000	H	Mission Time	1.4E-003
1WC-E02----ARHFS	WC CHILLER E02 FAILS TO START	1.0E-006	5.000	8760.000	H	Test Period	4.4E-003
1WC-E02----CXXFS	WC CHILLER E02 FAILS TO START DUE TO CONTROL CIRCUIT FAULT		3.000	2.7E-002	D	Calculated	2.7E-002
1WC-EO1C---AR7CM	CHILLER E01 C UNAVAILABLE DUE TO CORRECTIVE MAINTENANCE	1.3E-004	5.000	116.000	H	MTTR	1.5E-002
1WC-FSL137-IWFNO	WC FLOW SWITCH FS-137 FAILS (NO OUTPUT)	1.6E-006	5.000	8760.000	H	Test Period	7.0E-003
1WC-FSL517-IWFNO	WC FLOW SWITCH FS-517 FAILS (NO OUTPUT)	1.6E-006	5.000	24.000	H	Mission Time	3.8E-005
1WC-FSL617-IWFNO	WC FLOW SWITCH FS-617 FAILS (NO OUTPUT)	1.6E-006	5.000	24.000	H	Mission Time	3.8E-005
1WC-FSL717-IWFNO	WC FLOW SWITCH FL-717 FAILS (NO OUTPUT)	1.6E-006	5.000	8760.000	H	Test Period	7.0E-003
1WC-P01A---MP-FR	WC CHILLER PUMP P01A FAILS TO RUN 24 HRS	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1WC-P01B---MP-FR	WC CHILLER PUMP P01B FAILS TO RUN 24 HRS	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1WC-P01C---CB-ST	WC CHILLER PUMP P01C CIRCUIT BREAKER SPURIOUS TRIP (NO CR INDICATION)	2.3E-007	10.000	8760.000	H	Test Period	1.0E-003
1WC-P01C---CXXFS	WC CHILLER PUMP P01C FAILS TO START DUE TO CONTROL CKT FAULT		3.000	2.0E-002	D	Calculated	2.0E-002
1WC-P01C---MP-FR	WC CHILLER PUMP P01C FAILS TO RUN 24 HRS	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1WC-P01C---MP-FS	WC CHILLER PUMP P01C FAILS TO START	1.0E-006	2.000	8760.000	H	Test Period	4.4E-003
1WC-P01C---MP7CM	WC CHILLER PUMP P01C UNAVAILABLE DUE TO CORRECTIVE MAINT	1.3E-004	5.000	116.000	H	MTTR	1.5E-002
1WC-P02----CB-ST	WC CHILLER PUMP P02 CKT BRKR SPURIOUS TRIP (NO CR INDICATION)	2.3E-007	10.000	8760.000	H	Test Period	1.0E-003
1WC-P02----CXXFS	WC CHILLER PUMP P02 FAILS TO START DUE TO CONTROL CIRCUIT FAULTS		3.000	2.0E-002	D	Calculated	2.0E-002
1WC-P02----MP-FR	WC CHILLER PUMP P02 FAILS TO RUN 24 HOURS	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
1WC-P02----MP-FS	WC CHILLER PUMP P02 FAILS TO START	1.0E-006	2.000	8760.000	H	Test Period	4.4E-003
1WC-P02----MP7CM	WC CHILLER PUMP P02 UNAVAILABLE DUE TO UNSCHEDULED MAINTENANCE	1.3E-004	5.000	116.000	H	MTTR	1.5E-002
1WC-SV070--CXXRO	NORMAL CHILLED WATER SUPPLY VALVE UV-70 SOV CNTRL CIRCUIT SPURIOUS CLOSE		10.000	1.1E-004	D	Calculated	1.1E-004
1WC-SV070--SV-RO	NORMAL CHILLED WATER SUPPLY VALVE UV-70 SOV CONTROLLER FAILS TO REMAIN OPEN	9.0E-007	10.000	24.000	H	Mission Time	2.2E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1WC-UV070--AV-RO	NORMAL CHILLED WATER SUPPLY VALVE UV-70 FAILS TO REMAIN OPEN	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
1WC-UV070--AV9CM	NORMAL CHILLED WATER SUPPLY VALVE UV-70 UNAVAIL DUE TO UNSCHED MAINT	2.8E-005	3.000	25.000	H	MTTR	7.0E-004
1WC-V002---NV-RO	EC CHILLER PUMP P02 INLET ISOLATION VALVE V-002 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1WC-V015---NV-RO	WC CHILLER P01C INLET ISOLATION VALVE V-015 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1WC-V016---NV-RO	WC CHILLER PUPMP P01B INLET ISOLATION VALVE V016 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1WC-V025---CV-RO	WC CHILLER INLET E01A INLET CHECK VALVE FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1WC-V029---CV-RO	WC CHILLER PUMP P01B INLET CHECK VALVE V029 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1WC-V030---CV-FO	WC CHILLER E02 ISOLATION INLET CHECK VALVE V-030 FAILS TO OPEN	3.0E-008	3.000	8760.000	H	Test Period	1.3E-004
1WC-V088---NV-RO	WC CHILLER E01A ISOLATION VALVE V-88 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1WC-V089---NV-RO	WC CHILLER E01B ISOLATION VALVE V089 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1WC-V090---NV-RO	NORMAL CHILLED WATER ISOL VALVE V-090 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1WC-V114---NV-RO	WC CHILLER E01A ISOLATION VALVE V-114 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007
1WC-V115---NV-RO	WC CHILLER E01B ISOLATION VALVE V-115 FAILS TO REMAIN OPEN	3.0E-008	84.000	24.000	H	Mission Time	7.2E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
1WC-V116---NV-RO	WC CHILLER E02 MANUAL ISOLATION VALVE V-116 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1WC-V152---CV-RO	NORMAL CHILLED WATER RETURN CV (V152) FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
1WC-V581---NV-RO	WC CHILLER PUMP P02 INLET ISOLATION VALVE V-581 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1WC-V582---CV-FO	WC CHILLER E02 ISOLATION INLET CHECK VALVE V-582 RAILS TO OPEN	3.0E-008	3.000	8760.000	H	Test Period	1.3E-004
1WC-V583---NV-RO	WC CHILLER E02 MANUAL ISOLATION VALVE V-583 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1WC-V584---NV-RO	NORMAL CHILLED WATER ISO VALVE V-584 FAILS TO REMAIN OPEN	3.0E-008	84.000	8760.000	H	Test Period	1.3E-004
1ZAACO4E2--RX-FT	CONTROL CIRCUIT RELAY FAILURE	4.0E-007	10.000	13140.000	H	Test Period	2.6E-003
1ZABCO4E2--RX-FT	CONTROL CIRCUIT RELAY FAILURE	4.0E-007	10.000	13140.000	H	Test Period	2.6E-003
4CRHVC-LDSHD-LHL	OPERATOR FAILS TO TERMINATE SPUR LOAD SHED BEFORE CLASS BATT. DEPLETION		3.000	1.0E-001	D	Calculated	1.0E-001
4DCEQ-AC-COOLEHL	OPERATOR FAILS TO TAKE ACTION TO PREVENT TEMP RISE IN DC EQUIP RMS A & C		10.000	1.0E-003	D	Calculated	1.0E-003
4DCEQ-BD-COOLEHL	OPERATOR FAILS TO TAKE ACTION TO PREVENT TEMP RISE IN DC EQUIP RMS B & D		10.000	1.0E-003	D	Calculated	1.0E-003
4NKND41-125BSEPW	LOCAL FAULT OF DC DIST PANEL E-NKN-D41 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
4NKND42-125BSEPW	LOCAL FAULT OF DC DIST PANEL E-NKN-D42 -FAIL TO CARRY POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4NKNM45-125BSEPW	125V DC CONTROL CENTER E-NKN-M45 - FAILS TO PROVIDE POWER	1.3E-007	5.000	24.000	H	Mission Time	3.1E-006
4NKNM45-2HLOP-HR	OPER FAILS TO ALIGN SWING CHGR " (E-NKN-H21) TO DC CNTRL CNTR E-NKN-M45		5.000	2.9E-002	D	Calculated	2.9E-002
4NKNM4509--CB-ST	LOCAL FAULT OF CIRC BREAKER E-NKN-M4509 -FAILT TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
4NKNM4509--FU-OC	FAULT IN FUSE E-NKN-M4509 BETWEEN 125V DC CONTROL CNTR AND DIST PNL	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005
4NKNM4510--CB-ST	LOCAL FAULT OF CIRC BREAKER E-NKN-M4510 -FAIL TO CARRY POWER	2.3E-007	10.000	24.000	H	Mission Time	5.5E-006
4NKNM4510--FU-OC	FAULT IN FUSE E-NKN-M4510 BETWEEN 125 V DC CONTROL CNTR AND DIST PNL	1.0E-006	10.000	24.000	H	Mission Time	2.4E-005
4PKA41-2HROP--HR	OPERATOR FAILS TO ALIGN BACKUP CHARGER TO E-PKA-M41 IN 2 HRS		10.000	1.0E-002	D	Calculated	1.0E-002
4PKAD21-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKA-D21 (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006
4PKAM41-125BSEPW	LOCAL FAULT OF 125V DC CONTROL CENTER E-PKA-M41 (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006
4PKAM4123--FU-OC	1 OF 2 FUSES FAIL (PKA-M4123) BETWEEN CNTL CNTR & DIST PANEL (LONG TERM)	1.0E-006	10.000	44.000	H	Mission Time (2 fuses x 22 hours)	4.4E-005
4PKB42-2HROP--HR	OPERATOR FAILS TO ALIGN BACKUP CHARGER TO E-PKB-M42 IN 2 HRS		10.000	1.0E-002	D	Calculated	1.0E-002
4PKBD22-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKB-D22 (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4PKBM42-125BSEPW	LOCAL FAULT OF 125V DC CNTL CNTR PKB-M42 -FAIL TO CARRY POWER (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006
4PKBM4210--FU-OC	1 OF 2 FUSES FAIL (PKB-M4210) BETWEEN CNTL CNTR & DIST PANEL (LONG TERM)	1.0E-006	10.000	44.000	H	Mission Time (2 fuses x 24 hours)	4.4E-005
4PKC43-2HROP--HR	OPERATOR FAILS TO ALIGH BACKUP CHARGER TO 4-PKC-M43 IN 2 HRS		10.000	1.0E-002	D	Calculated	1.0E-002
4PKCD23-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKC-D23 (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006
4PKCM43-125BSEPW	LOCAL FAULT OF 125 V DC CONTROL CENTER E-PKC-M43 (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006
4PKCM4320--CB-ST	LOCAL FAULT OF CIRC BREAKER E-PKC-M4320 -FAIL TO CARRY POWER (LONG TERM)		10.000	5.1E-006	D	Calculated	5.1E-006
4PKD44-2HROP--HR	OPERATOR FAILS TO ALIGN BACKUP CHARGER 'BD'TO E-PKD-M44 IN 2 HRS		10.000	1.0E-002	D	Calculated	1.0E-002
4PKDD24-125BSEPW	LOCAL FAULT OF 125V DC DIST PANEL E-PKD-D24 (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006
4PKDM44-125BSEPW	LOCAL FAULT OF 125V DC CONTROL CENTER E-PKD-M44 (LONG TERM)	1.3E-007	5.000	22.000	H	Mission Time	2.9E-006
4PKDM4419--CB-ST	LOCAL FAULT OF CIRC BREAKER E-PKD-M4419 -FAIL TO CARRY POWER (LONG TERM)		10.000	5.1E-006	D	Calculated	5.1E-006
4SI-LPSRPUMP-2HR.	OPERATOR FAILS TO RESTART LPSI PUMPS AFTER RAS SIGNAL IS RECEIVED		3.000	1.0E-001	D	Calculated	1.0E-001
4SIAHS0672-CX7FO	MOV UV-672 CONTROL CICUIT FAULTS	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIAHS0678-CX6RO	MOV HV-678 CONTROL CIRC. FAULT(SPURIOUS CLOSURE)	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
4SIAHS0684-CX6RO	MOV HV-684 CONTROL CIRC. FAULT(SPURIOUS CLOSURE)	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
4SIAHS0687-CX6RO	MOV HV-687 CONTROL CIRC. FAULT(SPURIOUS CLOSURE)	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
4SIAHV0306-CX6FC	CONTROL CIRC FAULT LPSR TRAIN A FLOW CONTROL MOV HV-306 -FAILS TO CLOSE	1.4E-006	3.000	2190.000	H	Test Period	1.5E-003
4SIAHV0306-MV-FC	LOCAL FAULT LPSR TRAIN A FLOW CONTROL MOV HV-306 -FAILS TO CLOSE	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SIAHV0306-MV9CM	UNSCHEDULED MAINTENANCE ON LPSR TRAIN A FLOW CONTROL MOV HV-306	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIAHV0657-CX8FO	CONTROL CIRCUIT FAULT SDCHX/LPSR A CROSS-CONNECT MOV HV-657 -FAILS TO OPEN	1.3E-006	10.000	2190.000	H	Test Period	1.4E-003
4SIAHV0657-MV-FO	SDCHX/LPSR A CROSS-CONNECT MOV HV-657 FAILS TO OPEN (LOCAL FAULT)	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SIAHV0678-MV-RO	MOV HV-678 LOCAL FAULT(FAILURE TO REMAIN OPEN)	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
4SIAHV0684-MV-RO	MOV HV-684 LOCAL FAULT(FAILURE TO REMAIN OPEN)	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
4SIAHV0685-CX8FO	CONTROL CIRC FAULT LPSR/SDHX A CROSS- CONNECT MOV HV-685 -FAILS TO OPEN	1.3E-006	10.000	2190.000	H	Test Period	1.4E-003
4SIAHV0685-MV-FO	LOCAL FAULT LPSR/ SDHX A CROSS- CONNECT MOV HV-685 -FAILS TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIAHV0685-MV9CM	UNSCHEDULED MAINT. ON LPSR/SDHX A CROSS-CONNECT MOV HV-685	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIAHV0686-CX8FO	CONTROL CIRC FAULT SDHX/LPSR A CROSS- CONNECT MOV HV-686 -FAILS TO OPEN	1.3E-006	10.000	2190.000	H	Test Period	1.4E-003
4SIAHV0686-MV-FO	LOCAL FAULT SDHX/LPSR A CROSS -CON-NECT MOV HV-686 -FAILS TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SIAHV0686-MV9CM	UNSCHEDULED MAINT. ON SDHX/LPSR A CROSS-CONNECT MOV HV-686	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIAHV0687-MV-RO	MOV HV-687 LOCAL FAULT(FAILURE TO REMAIN OPEN)	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
4SIAHV0687-MV9CM	MOV HV-687 UNAVAIL. DURING UNSCHED. MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIAP02----CB-ST	HPSR TRAIN A PUMP ELECTRIC POWER CIRCUIT BRKR FAILS TO REMAIN CLOSED	2.3E-007	10.000	8.000	H	Mission Time	1.8E-006
4SIAP02----MP-FR	HPSR TR. A MOTOR-DRIVEN PUMP SIAP02 FAILS TO RUN DURING RECIRC	2.1E-005	2.000	8.000	H	Mission Time	1.7E-004
4SIAP03----CB-FT	CONT. SPRAY TRAIN A PUMP CIRCUIT BKR. FAULT -FAIL TO CLOSE	1.2E-006	5.000	2190.000	H	Test Period	1.3E-003
4SIAP03----CX6FS	CONT. SPRAY TRAIN A PUMP CONTROL CIRCUIT FAULT -FAILS TO START	1.6E-006	3.000	2190.000	H	Test Period	1.8E-003
4SIAP03----MP-FR	CONT. SPRAY TRAIN A PUMP (SIA-P03) FAILS TO RUN GIVEN START (RECIRC)	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
4SIAP03----MP-FS	CONT. SPRAY TRAIN A PUMP (SIA-P03) FAILS TO START (RECIRC.)	1.0E-006	2.000	2190.000	H	Test Period	1.1E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIAP03----MP6CM	CONT. SPRAY TRAIN A PUMP (SIA-P03) UNAVAIL. DUE TO UNSCHED. MAINTENANCE		5.000	1.3E-003	H	Plant Specific	1.3E-003
4SIAPSV417-RV-RC	HPSR TR. A PRESS. RELIEF VALVE PSV-417 FAILS TO REMAIN CLOSED	4.0E-006	5.000	8.000	H	Mission Time	3.2E-005
4SIAUV0651-MV-RO	RCS ISOLATION MOTOR OPER VALVE SIA-UV651 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
4SIAUV0655-MV-RO	MOV UV655 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
4SIAUV0672-MV-FO	MOV UV-672 LOCAL FAULT(FAILURE TO OPEN)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
4SIAUV0672-MV9CM	MOV UV-672 UNAVAIL. DURING UNSCHED. MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIAV105---NV-RM	CONT. SPRAY PUMP A SUCTION MANUAL VALVE V-105 FAIL TO RESTORE AFTER MAINT		10.000	9.9E-006	D	Calculated	9.9E-006
4SIAV105---NV-RO	CONT. SPRAY TRAIN A PUMP SUCTION MANUAL VALVE V-105 FAILS TO REMAIN OPEN	3.0E-008	84.000	2190.000	H	Test Period	3.3E-005
4SIAV157---CV-FO	CONT. SPRAY TRAIN A PUMP SUCTION CHECK VALVE V-157 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
4SIAV157---CV-RO	CONT. SPRAY TRAIN A PUMP SUCTION CHECK VALVE V-157 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
4SIAV164---CV-FO	CONT. SPRAY TRAIN A HEADER CHECK VALVE V-164 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
4SIAV404---CV-RO	HPSR PUMP A DISCHARGE CHECK VALVE V404 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIAV485---CV-FO	CONT. SPRAY TRAIN A PUMP DISCHARGE CHECK VALVE V-485 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
4SIAV485---CV-RO	CONT. SPRAY TRAIN A PUMP DISCHARGE CHECK VALVE V-485 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
4SIBHS0671-CX7FO	MOV UV-671 CONTROL CICUIT FAULTS	1.0E-006	3.000	1488.000	H	Test Period	7.4E-004
4SIBHS0679-CX6RO	MOV HV-679 CONTROL CIRC. FAULT(SPURIOUS CLOSURE)	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
4SIBHS0689-CX6RO	MOV HV-689 CONTROL CIRC. FAULT(SPURIOUS CLOSURE)	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
4SIBHS0695-CX6RO	MOV HV-695 CONTROL CIRC. FAULT(SPURIOUS CLOSURE)	6.0E-007	10.000	24.000	H	Mission Time	1.4E-005
4SIBHV0307-CX6FC	CONTROL CIRC FAULT LPSR TRAIN B FLOW CONTROL MOV HV-307 -FAILS TO CLOSE	1.4E-006	3.000	2190.000	H	Test Period	1.5E-003
4SIBHV0307-MV-FC	LOCAL FAULT LPSR TRAIN B FLOW CONTROL MOV HV-307 -FAILS TO CLOSE	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SIBHV0307-MV9CM	UNSCHEDULED MAINT. ON LPSR TRAIN B FLOW CONTROL MOV HV-307	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIBHV0658-CX8FO	CONTROL CIRCUIT FAULT SDCHX/LPSR B CROSS-CONNECT MOV HV-658 -FAILS TO OPEN	1.3E-006	10.000	2208.000	H	Test Period	1.4E-003
4SIBHV0658-MV-FO	SDCHX/LPSR B CROSS-CONNECT MOV HV-658 FAILS TO OPEN (LOCAL FAULT)	2.9E-006	14.000	2208.000	H	Test Period	3.2E-003
4SIBHV0679-MV-RO	MOV HV-679 LOCAL FAULT(FAILURE TO REMAIN OPEN)	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIBHV0689-MV-RO	MOV HV-689 LOCAL FAULT(FAILURE TO REMAIN OPEN)	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
4SIBHV0694-CX8FO	CONTROL CIRC FAULT LPSR/SDHX B CROSS- CONNECT MOV HV-694 -FAILS TO OPEN	1.3E-006	10.000	2190.000	H	Test Period	1.4E-003
4SIBHV0694-MV-FO	LOCAL FAULT LPSR/SDHX B CROSS- CONNECT MOV HV-694 -FAILS TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SIBHV0694-MV9CM	UNSCHEDULED MAINT. ON LPSR/SDHX B CROSS-CONNECT MOV HV-694	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIBHV0695-MV-RO	MOV HV-695 LOCAL FAULT(FAILURE TO REMAIN OPEN)	2.3E-007	9.000	2190.000	H	Test Period	2.5E-004
4SIBHV0695-MV9CM	MOV HV-695 UNAVAIL. DURING UNSCHED. MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIBHV0696-CX8FO	CONTROL CIRC FAULT SDHX/LPSR B CROSS- CONNECT MOV HV-696 -FAILS TO OPEN	1.3E-006	10.000	2190.000	H	Test Period	1.4E-003
4SIBHV0696-MV-FO	LOCAL FAULT SDHX/LPSR B CROSS- CONNECT MOV HV-696 -FAILS TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SIBHV0696-MV9CM	UNSCHEDULED MAINT. ON SDHX/LPSR B CROSS-CONNECT MOV HV-696	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIBP02----CB-ST	HPSR TRAIN B PUMP ELECTRIC POWER CIRCUIT BRKR FAILS TO REMAIN CLOSED	2.3E-007	10.000	8.000	H	Mission Time	1.8E-006
4SIBP02----MP-FR	HPSR TR. B MOTOR-DRIVEN PUMP SIBP02 FAILS TO RUN DURING RECIRC	2.1E-005	2.000	8.000	H	Mission Time	1.7E-004
4SIBP03----CB-FT	CONT. SPRAY TRAIN B PUMP CIRCUIT BKR. FAULT -FAIL TO CLOSE	1.2E-006	5.000	2190.000	H	Test Period	1.3E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIBP03----CX6FS	CONT. SPRAY TRAIN B PUMP CONTROL CIRCUIT FAULT -FAILS TO START	1.6E-006	3.000	2190.000	H	Test Period	1.8E-003
4SIBP03----MP-FR	CONT. SPRAY TRAIN B PUMP (SIB-P03) FAILS TO RUN GIVEN START (RECIRC)	2.1E-005	2.000	24.000	H	Mission Time	5.0E-004
4SIBP03----MP-FS	CONT. SPRAY TRAIN B PUMP (SIB-P03) FAILS TO START (RECIRC.)	1.0E-006	2.000	2190.000	H	Test Period	1.1E-003
4SIBP03----MP6CM	CONT. SPRAY TRAIN B PUMP (SIB-P03) UNAVAIL. DUE TO UNSCHED. MAINTENANCE		3.000	0.001	D	Plant Specific	1.3E-003
4SIBPSV409-RV-RC	HPSR TR. B PRESS. RELIEF VALVE PSV-409 FAILS TO REMAIN CLOSED	4.0E-006	5.000	8.000	H	Mission Time	3.2E-005
4SIBUV0652-MV-RO	MOTOR OPER VALVE UV652 FAIL TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
4SIBUV0656-MV-RO	MOTOR OPER VALVE UV656 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
4SIBUV0671-MV-FO	MOV UV-671 LOCAL FAULT(FAILURE TO OPEN)	2.9E-006	14.000	1488.000	H	Test Period	2.2E-003
4SIBUV0671-MV9CM	MOV UV-671 UNAVAIL. DURING UNSCHED. MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SIBV104---NV-RM	CONT. SPRAY PUMP B SUCTION MANUAL VALVE V-104 FAIL TO RESTORE AFTER MAINT.		10.000	9.9E-006	D	Calculated	9.9E-006
4SIBV104---NV-RO	CONT. SPRAY TRAIN B PUMP SUCTION MANUAL VALVE V-104 FAILS TO REMAIN OPEN	3.0E-008	84.000	2190.000	H	Test Period	3.3E-005
4SIBV158---CV-FO	CONT. SPRAY TRAIN B PUMP SUCTION CHECK VALVE V-158 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIBV158---CV-RO	CONT. SPRAY TRAIN B PUMP SUCTION CHECK VALVE V-158 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
4SIBV165---CV-FO	CONT. SPRAY TRAIN B HEADER CHECK VALVE V-165 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
4SIBV405---CV-RO	HPSR PUMP B DISCHARGE CHECK VALVE V405 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIBV484---CV-FO	CONT. SPRAY TRAIN B PUMP DISCHARGE CHECK VALVE V-484 FAILS TO OPEN	3.0E-008	3.000	2190.000	H	Test Period	3.3E-005
4SIBV484---CV-RO	CONT. SPRAY TRAIN B PUMP DISCHARGE CHECK VALVE V-484 FAILS TO REMAIN OPEN	2.3E-007	9.000	24.000	H	Mission Time	5.5E-006
4SICUV0653-MV-RO	RCS ISOLATION MOTOR OPER VALVE UV653 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
4SIDUV0654-MV-RO	MOTOR OPER VALVE UV654 FAILS TO REMAIN OPEN	2.3E-007	9.000	16.000	H	Mission Time	3.7E-006
4SIEV113---CV-RO	CHECK VALVE V113 IN HPSR 2A HEADER FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIEV123---CV-RO	CHECK VALVE V123 IN HPSR 2B HEADER FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIEV143---CV-RO	CHECK VALVE V143 IN HPSR 1B HEADER FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIEV217---CV-RO	SAFETY INJECTION HEADER 1A CHECK VALVE V217 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIEV227---CV-RO	SAFETY INJECTION HEADER 2B CHECK VALVE V227 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SIEV247---CV-RO	S.I. HEADER 1B CHECK VALVE V247 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIEV540---CV-RO	SAFETY INJECTION HEADER 2A CHECK VALVE V540 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIEV541---CV-RO	SAFETY INJECTION HEADER 2B CHECK VALVE V541 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SIEV543---CV-RO	S.I. HEADER 1B CHECK VALVE V543 FAILS TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SR-ABSUMP-MV-CC	COMMON CAUSE FAILURE TO OPEN OF AT LEAST ONE SUMP SUCTION MOV IN EACH TRAIN		30.000	3.9E-005	D	Calculated	3.9E-005
4SRA0FO4---FX-PG	TRAIN A SUMP SUCTION SCREEN (SRA-F04) PLUGS	3.0E-005	10.000	8.000	H	Mission Time	2.4E-004
4SRAUV0673-CB-ST	TRAIN A SUMP SUCTION MOV UV-673 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
4SRAUV0673-CX6FO	TRAIN A SUMP SUCTION MOV UV-673 CONTROL CIRCUIT FAULT -FAIL TO OPEN		3.000	4.1E-003	D	Calculated	4.1E-003
4SRAUV0673-CX6RO	TRAIN A SUMP SUCTION MOV UV-673 CONTROL CIRC FAULT -SPURIOUS CLOSE DURING RECIRC	6.0E-007	10.000	8.000	H	Mission Time	4.8E-006
4SRAUV0673-MV-FO	TRAIN A SUMP SUCTION MOV UV-673 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SRAUV0673-MV-RO	TR. A SUMP SUCTION UV-673 LOCAL FAULT -FAIL TO REMAIN OPEN DURING RECIRC	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SRAUV0674-CB-ST	TRAIN A SUMP SUCTION MOV UV-674 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SRAUV0674-CX6FO	TRAIN A SUMP SUCTION MOV UV-674 CONTROL CIRCUIT FAULT -FAIL TO OPEN		3.000	4.1E-003	D	Calculated	4.1E-003
4SRAUV0674-CX6RO	TRAIN A SUMP SUCTION MOV UV-674 CONTROL CIRC FAULT -SPURIOUS CLOSE DURING RECIRC	6.0E-007	10.000	8.000	H	Mission Time	4.8E-006
4SRAUV0674-MV-FO	TRAIN A SUMP SUCTION MOV UV-674 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SRAUV0674-MV-RO	TR. A SUMP SUCTION UV-674 LOCAL FAULT -FAIL TO REMAIN OPEN DURING RECIRC	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SRAUV0674-MV9CM	TRAIN A SUMP SUCTION MOV UV-674 UNAVAILABLE DURING UNSCHED. MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SRAV205---CV-FO	TRAIN A SUMP SUCTION CHECK VALVE CV-205 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
4SRAV205---CV-RO	TRAIN A SUMP SUCTION CHECK VALVE CV-205 FAIL TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SRB0FO4---FX-PG	TRAIN B SUMP SUCTION SCREEN (SRB-F04) PLUGS	3.0E-005	10.000	8.000	H	Mission Time	2.4E-004
4SRBUV0675-CB-ST	TRAIN B SUMP SUCTION MOV UV-675 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
4SRBUV0675-CX6FO	TRAIN B SUMP SUCTION MOV UV-675 CONTROL CIRCUIT FAULT -FAIL TO OPEN		3.000	4.1E-003	D	Calculated	4.1E-003
4SRBUV0675-CX6RO	TRAIN B SUMP SUCTION MOV UV-675 CONTROL CIRC FAULT -SPURIOUS CLOSE DURING RECIRC	6.0E-007	10.000	8.000	H	Mission Time	4.8E-006
4SRBUV0675-MV-FO	TRAIN B SUMP SUCTION MOV UV-675 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
4SRBUV0675-MV-RO	TR. B SUMP SUCTION UV-675 LOCAL FAULT -FAIL TO REMAIN OPEN DURING RECIRC	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SRBUV0676-CB-ST	TRAIN B SUMP SUCTION MOV UV-676 CIRCUIT BREAKER SPURIOUS TRIP	2.3E-007	10.000	2.000	H	Mission Time	4.6E-007
4SRBUV0676-CX6FO	TRAIN B SUMP SUCTION MOV UV-676 CONTROL CIRCUIT FAULT -FAIL TO OPEN		3.000	4.1E-003	D	Calculated	4.1E-003
4SRBUV0676-CX6RO	TRAIN B SUMP SUCTION MOV UV-676 CONTROL CIRC FAULT -SPURIOUS CLOSE DURING RECIRC	6.0E-007	10.000	8.000	H	Mission Time	4.8E-006
4SRBUV0676-MV-FO	TRAIN B SUMP SUCTION UV-676 LOCAL FAULT -FAIL TO OPEN	2.9E-006	14.000	2190.000	H	Test Period	3.2E-003
4SRBUV0676-MV-RO	TR. B SUMP SUCTION UV-676 LOCAL FAULT -FAIL TO REMAIN OPEN DURING RECIRC	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SRBUV0676-MV9CM	TRAIN B SUMP SUCTION MOV UV-676 UNAVAILABLE DURING UNSCHED MAINTENANCE	2.8E-005	3.000	21.000	H	MTTR	5.9E-004
4SRBV206---CV-FO	TRAIN B SUMP SUCTION CHECK VALVE CV-206 FAILS TO OPEN	3.0E-008	3.000	13140.000	H	Test Period	2.0E-004
4SRBV206---CV-RO	TRAIN B SUMP SUCTION CHECK VALVE CV-206 FAIL TO REMAIN OPEN	2.3E-007	9.000	8.000	H	Mission Time	1.8E-006
4SREL180---PXLEL	PIPE RUPTURE IN TRAIN B SUMP SUCTION LINE	8.5E-010	30.000	13140.000	H	Test Period	5.6E-006
4SREL181---PXLEL	PIPE RUPTURE IN TRAIN A SUMP SUCTION LINE	8.5E-010	30.000	13140.000	H	Test Period	5.6E-006
ANANX02-SU-XMSPW	STARTUP TRANSFORMER #2 (A-E-NAN-X02) FAILS	1.7E-006	5.000	24.000	H	Mission Time	4.1E-005

Event Name	Description	Fail Rate	Error Factor	Factor	Units	Factor Type	Probability
ANANX03-SU-XMSPW	STARTUP TRANSFORMER #3 (A-E-NAN-X03) FAILS	1.7E-006	5.000	24.000	H	Mission Time	4.1E-005
LOOP---------2PW	LOSS OF OFFSITE POWER TO 525 KV PVNGS SWITCHYARD (AFTER PLANT TRIP)		10.000	2.7E-004	D	Calculated	2.7E-004
LOOP-RECOVR1-2PW	OFFSITE POWER (VIA SWITCHYARD) NON-RECOVERY WITHIN 1 HOUR		3.000	2.5E-001	D	Calculated	2.5E-001
LOOP-RECOVR3-2PW	NON-RECOVERY OF OFFSITE POWER (VIA SWITCHYARD) WITHIN 3 HOURS OF SBO		5.000	6.2E-002	D	Calculated	6.2E-002
SPUR-RAS-DCR-3EE	SPURIOUS RAS ACT. (BOTH TRAINS) DUE TO LOSS OF PNA AND PNC OR PNB AND PND			1.000	D	Flag Event	1.000
SYFAULTSXM2--2PW	525 KV PVNGS SWITCHYARD FAILS TO PROVIDE POWER TO S.U. TRANSFORMER #2		0.000	4.4E-005	D	Calculated	4.4E-005
SYFAULTSXM3--2PW	525 KV PVNGS SWITCHYARD FAILS TO PROVIDE POWER TO S.U. TRANSFORMER #3		0.000	4.4E-005	D	Calculated	4.4E-005