SYSTEM 80+

SHUTDOWN RISK EVALUATION REPORT

DCTR 10

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ABB-COMBUSTION ENGINEERING
NUCLEAR POWER SYSTEMS
WINDSOR, CONNECTICUT

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ABSTRACT

In engineering the System 80+ Standard Plant Design, ABB-Combustion Engineering recognized the significance of addressing safety during shutdown operations. System 80+ is engineered with features that enhance shutdown safety: 1) by deliberate system engineering, equipment specification and plant arrangements for shutdown operation, 2) by mode dependent control logic that assists and limits operations, 3) by instrumentation, displays and alarms that clearly portray plant status in each mode and 4) by thorough procedural guidance and Technical Specifications that address important shutdown evolutions. This report presents these features and evaluates them in the context of the specific shutdown issues identified by the NRC. The report fulfills the ABB-Combustion Engineering commitments to the NRC to 1) provide shutdown information in support of the System 80+ Design Certification and 2) provide responses to specific RAI's on shutdown operations.

DEFINITIONS

The following definitions of terms are employed throughout this report.

DEFINITIONS

AVAILABLE (AVAILABILITY): The status of a system, structure or component that is in service or can be placed in service in a FUNCTIONAL or OPERABLE state by immediate manual or automatic actuation.

CONTAINMENT CLOSURE: The action to secure primary (PWR) or secondary (BWR) containment and its associated structures, systems, and components as a FUNCTIONAL barrier to fission product release under existing plant conditions.

CONTINGENCY PLAN: An approved plan of compensatory actions:

- o To maintain DEFENSE IN DEPTH by alternate means when pre-outage planning reveals that specified systems, structures or components will be unavailable;
- o To restore DEFENSE IN DEPTH when system AVAILABILITY drops below the planned DEFENSE IN DEPTH during the outage;
- o To minimize likelihood of a loss of KEY SAFETY FUNCTIONS during HIGHER RISK EVOLUTIONS.

DECAY HEAT REMOVAL CAPABILITY: The ability to maintain reactor coolant system (RCS) temperature and pressure, and spent fuel pool (SFP) temperature below specified limits following a shutdown.

DEFENSE IN DEPTH: For the purpose of managing risk during shutdown, defense in depth is the concept of.

- o Providing systems, structures and components to ensure backup of KEY SAFETY FUNCTIONS using redundant, alternate or diverse methods;
- o Planning and scheduling outage activities in a manner that optimizes safety system AVAILABILITY;
- o Providing administrative controls that support and/or supplement the above elements.

DEFUELED: All fuel assemblies have been removed from the reactor vessel and placed in the spent fuel pool or other storage facility.

DIVISION: One or more trains that share a common component, e.g. AC power. Divisions are the highest level of separation and independence.

ESTIMATED CRITICAL POSITION (ECP): A calculated set of reactor conditions and/or parameters that define a critical reactor state. (Keff = 1.0)

FUNCTIONAL (FUNCTIONALITY): The ability of a system or component to perform its intended service with considerations that applicable technical specification requirements or licensing/design basis assumptions may not be maintained.

HIGHER RISK EVOLUTIONS: Outage activities, plant configurations or conditions during shutdown where the plant is more susceptible to an event causing the loss of a key safety function.

INVENTORY CONTROL: Measures established to ensure that irradiated fuel remains covered with coolant to maintain heat transfer and shielding requirements.

KEY SAFETY FUNCTIONS: During shutdown, they are decay heat removal, inventory control, power availability, reactivity control, and containment.

MID-LOOP: PWR condition with fuel in the reactor vessel and level below the top of the hot legs at their junction to the reactor vessel.

MODE: The reactor operating state defined by reactivity, power level and coolant temperature, as follows:

<u>MODES</u>

MODE	REACTIVITY CONDITION, K_{eff}	% RATED THERMAL POWER	COOLANT TEMPERATURE, °F
1	$\geq$ 0.99	> 5	$\geq$ 350
2	$\geq$ 0.99	$\leq$ 5	$\geq$ 350
3	< 0.99	NA	$\geq$ 350
4	< 0.99	NA	350 > T_{ave} > 210
5	< 0.99	NA	$\leq$ 210
6*	$\leq$ 0.95	NA	$\leq$ 135

* Fuel in the reactor vessel with one or more of the vessel head closure studs less than fully tensioned or with the head removed.

OPERABLE: The ability of a system to perform its specified function with all applicable technical specifications requirements satisfied.

REACTIVITY CONTROL: Measures established to precluded inadvertent dilutions, criticalities, power excursions or losses of shutdown margin, and to predict and monitor core behavior.

REDUCED INVENTORY: PWR condition with fuel in the reactor vessel and level lower than three feet below the reactor vessel flange.

RISK MANAGEMENT: Integrated process of assessing and reducing the likelihood and/or consequences of an adverse event.

SHUTDOWN: Plant status when the reactor core is subcritical and a startup is not in progress.

STARTUP: Plant status commencing with activities to heatup the RCS above 200 degrees F and to bring the reactor core to a critical condition and up to 5% of rated thermal power.

TRAIN: A set of safety related components that perform a safety function. Trains performing redundant functions are physically, electrically, and mechanically separated to the extent necessary to insure independent performance of its safety function.

LIST OF ACRONYMS

ACC	-	Advanced Control Complex
ACC	-	Advanced Control Complex
ADV	-	Atmosphere Dump Valve
ALWR	-	Advanced Light Water Reactor
ARO	-	All Rods Out
BAST	-	Boric Acid Storage Tank
CC	-	Component Cooling
CCW	-	Component Cooling Water System
CD	-	Condensate
CDF	-	Core Damage Frequency
CEA	-	Control Element Assembly
CET	-	Core Exit Thermocouple
CI	-	Containment Isolation
CPC	-	Core Protection Calculator
CRO	-	Control Room Operator
CS	-	Containment Spray
CSAS	-	Containment Spray Actuation Signal
CSS	-	Containment Spray System
CVCS	-	Chemcial and Volume Control System
CW	-	Circulating Water
DG	-	Diesel Generator
DBA	-	Design Basis Accident
DBE	-	Design Basis Event
DEHLS	-	Double Ended Hot Leg Slot
DESLS	-	Double Ended Suction Leg Slot
DF	-	Decontainment Factor
DHR	-	Decay Heat Removal
DIAS	-	Discrete Indication Alarm System
DLS	-	Diesel Load Sequence
dP	-	Pressure Differential
DVI	-	Direct Vessel Injection
EAB	-	Exclusion Area Boundary
ECCS	-	Emergency Core Cooling System
EDS	-	Electrical Distribution System
EF	-	Emergency Feedwater
EFAS	-	Emergency Feedwater Actuation Signal
EFW	-	Emergency Feedwater
EPRI	-	Electric Power Research Institute
FW	-	Feed Water
GIS	-	Generated Iodine Spike
HACT	-	Head Area Cable Tray Assembly
HCR	-	Human Congnitive Reliability
HJTC	-	Heated Junction Thermocouple
HPSI	-	High Pressure Safety Injection
HVT	-	Holdup Volume Tank
I&C	-	Instrumentation & Control
IA	-	Instrument Air
IBD	-	Inadvertent Boron dilution
ICI	-	In-Core Instrument

INPO	-	Institute for Nuclear Power Operations
IPSO	-	Integrated Process Status Overview
IRWST	-	In-containment Refueling Water Storage Tank
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
LOCA	-	Loss of Coolant Accidents
LOCV	-	Loss of Condeser Vacuum
LOP	-	Loss of Offsite Power
LTOP	-	Low Temperature Overpressure Protection
MFW	-	Main Feedwater
MMI	-	Man-Machine Interface
MPC	-	Maximum Permissible Concentration
MSIV	-	Main Steam Isolation Valve
NPSH	-	Net Positive Suction Head
NPSHA	-	Net Positive Suction Head Available
OSI	-	Operational Support Information
P&ID	-	Piping and Instrumentation Diagram
PCT	-	Peak Clad Temperature
PNS-Bus	-	Normal Permanent Non-Safety Bus
RAI	-	Requests for Additional Information
RC	-	Reactor Coolant
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
REM	-	Realistic Evaluation Model
RHR	-	Residual Heat Removal
RTD	-	Hot Leg Resistance Temperature Detector
SC	-	Shutdown Cooling
SCS	-	Shutdown Cooling System
SD	-	Safety Depressurization
SDS	-	Safety Depressurization System
SG	-	Steam Generator
SGTR	-	Steam Generator Tube Rupture
SI	-	Safety Injection
SIS	-	Safety Injection System
SIT	-	Safety Injection Tank
SRP	-	Standard Review Plan
SUFW	-	Start Up Feedwater
SW	-	Service Water
TB	-	Turbine Bypass
TS	-	Technical Specification
URD	-	Utility Requirements Document

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1.0 INTRODUCTION

1.1 PURPOSE

This report presents features of the System 80+ design which address the issues of shutdown risk. It further evaluates these features with respect to their ability to reduce and/or mitigate the consequences of this risk. It fulfills the commitment made to the NRC by ABB-Combustion Engineering (ABB-CE) in Reference 1 to submit shutdown risk information in support of the System 80+ Design Certification.

1.2 SCOPE

Sections 2.1 through 2.13 present detailed discussions on the specific shutdown issues. Following the detailed discussions of these shutdown risk issues, the report provides a probabilistic risk assessment in Section 3.0. This is followed in Sections 4.0, 5.0 and 6.0 by an evaluation of the applicability of the analyses in CESSAR-DC Chapters 6 and 15 to LOCA and accident events that are initiated from shutdown modes. Section 7.0 evaluates the features of System 80+ that simplify shutdown operations and thereby reduce the potential for initiating shutdown events. Conclusions of this report are provided in Section 8.0. The scope of the information presented was discussed with the NRC at a presentation by ABB-CE in Rockville, Maryland on December 18, 1991 and is outlined by the ABB-CE slides enclosed with the NRC minutes of the meeting in Reference 2.

The report also addresses the RAI's from the NRC staff on CESSAR-DC that pertain to shutdown risk. Appendix A of this report lists the RAI's and provides either the response or a referral to sections of the report which encompass the response to each RAI.

1.3 BACKGROUND

In Generic Letter No. 88-17 (Reference 4) the NRC issued recommendations to all holders of licenses for PWR's to implement certain "expeditious actions" before operating their plants in a reduced inventory condition and to implement, as soon as practical, "program enhancements" concerning operations during shutdown cooling. The objective was to prevent the reoccurrence of events that had occurred and that had the potential for core damage and/or release of radiation. In NUREG-1449, NRC staff evaluations of shutdown operations indicate that recommendations have been implemented and/or are underway at operating plants.

1.4 SYSTEM 80+ FEATURES

In this section, a comparison is made between the characteristics of past events and the System 80+ design features. The categories of shutdown events at operating plants are those used by the NRC in Chapter 2 of NUREG-1449 with little modification. These categories are mostly the same as the issues identified by Secy-91-283 and presented by ABB-CE at the December 18, 1991 meeting with the NRC (Reference 2). Each category encompasses a group of similar events that have in common the type of event initiator. Ultimately, if left unmitigated by automatic or manual actions, all events might eventually lead to over heating and/or physical damage to fuel with consequent radiation release, but each scenario sequence may differ. Depending upon the importance placed on each step in a sequence, the same events could be grouped differently. For example, the NUREG-1449 category, "Loss of Shutdown Cooling", includes the issues listed in Reference 2 as 1) Mid-Loop Operation, 2) Loss of Decay Heat Removal Capability and 3) Effect of PWR Upper Internals.

The categories employed in this section to group past events encompass (and for some categories are identical to) the issues which are listed by Reference 2 and which are presented in detail in this report with a few exceptions. The exceptions apply to postulated LOCA events initiated at high pressure and other significant events initiated at high pressure for which we do not have actual experience because they have not occurred in operating plants. They exist only as analyses for use as guidance to avoid the physical event and therefore are not included in the categories of past events.

Past events are grouped into the following ten categories:

- Loss of shutdown cooling
- Loss of electrical power
- Loss of reactor coolant
- Containment integrity
- Overpressurization
- Flooding and spills
- Boron and reactivity events
- Fire protection
- Heavy loads and fuel handling
- Mode change events

For each past event placed into a category an initiator is identified. The plant design objective is to prevent the occurrence of the event initiator, but realistically, absolute prevention is impracticable and may be impossible. A combination of prevention and mitigatic is employed in the System 80+ design.

Table 1-1 provides an overview of the System 80+ features that avoid core damage during shutdown operating modes. It lists the ten shutdown event categories and for each category it lists event initiators for past events. These initiators are presented in a generic fashion; each initiator representing many specific events that have occurred. For each initiator, the features of the System 80+ design that are available to prevent occurrence of an initiator and/or to mitigate the consequences of an initiator are listed.

Table 1-2 provides a list of specific past events initiated from shutdown modes. Events were selected to include all ten event categories and all types of event initiators, but not all similar significant events that have occurred. Several information sources were utilized to compile this list. They include events listed in NUREG-1449 which were taken from the 1990 AEOD report (Reference 5) and which occurred mostly between January 1988 and July 1990 with some additional events. For events since July 1990, ABB-CE searched the INPO database for LER's using a selection of keywords pertinent to the ten event categories and to shutdown operation. Various other INPO and NSAC documents were also reviewed for significant event reports dating from 1976 to 1990.

Events in Table 1-2 are grouped into the ten categories given above. For each specific event, the features of the System 80+ design that apply to prevent and mitigate the event are indicated. A review of this table serves as a design review of the System 80+ capabilities to avoid core damage and/or significant radiation release during shutdown modes. The design features are discussed in more detail in the following Sections of this report.

TABLE 1-1

SHUTDOWN EVENT CATEGORIES AND SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION

EVENT CATEGORY	EVENT INITIATOR	SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION
1.) Loss of Shutdown Cooling	SCS flow loss by pump suction vortex.	A) Mid-loop level maximized by locating SCS suction piping at the bottom of the hot leg.
		B) Hard piped venting for SCS pumps relieves gas binding more quickly and conveniently. There are loop seals in the suction lines.
		C) One SCS suction line from each hot leg provides SCS redundancy with separation of pump suction sources.
		D) Containment spray pumps interchangeable with SCS pumps provide redundant capacity and may take suction from IRWST to refill RCS and to mitigate gas binding.
	Inaccurate mid-loop level leading to suction vortex.	E) With head on, reactor vessel level monitoring system level indications from vessel head to a level below that required for SCS operation. Level indication is accurate for intended use.
		F) Core exit thermocouples monitor coolant temperature down to 100°F prior to withdrawal of CEIs prior to fuel shuffling. The RTDs and SCS temperatures are accurate during SCS operation.
		G) With head off, level indication near hot leg elevation is provided by high resolution instruments.
		H) SCS performance monitored on each of 2 SCS pumps by pump motor current, flow rate, discharge pressure and suction pressure. Possible SCS flow variance with decay heat to minimize potential for vortexing during mid-loop.
	Loss of flow while head off, upper internals in vessel and cavity flooded leads to core heatup.	I) Internals design limits coolant flow from cavity to core, however, high availability of SCS system and/or backups assures forced convection.
	Various low level and loss of RHR events.	J) Non-shared SCS system allows SCS maintenance and testing during Modes 1-4 prior to cold shutdown, increasing availability in Modes 5 and 6.
		K) All SCS valves are motor operated, preventing failures on loss of air if electro-pneumatic operators were used.

TABLE 1-1 (Continued)

SHUTDOWN EVENT CATEGORIES AND SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION

	EVENT CATEGORY	EVENT INITIATOR		SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION
1.)	Loss of Shutdown Cooling (Continued)		L)	Shutdown specific control room displays, tech specs, and procedural guidance reduces likelihood of personnel errors.
			M)	Inadvertent errors are reduced and early operator evaluation of failures is improved by 1.) IPSO overview display with critical function and system status specific to shutdown modes, 2.) CRT displays with system lineups and component status and 3.) alarms that are dependent on plant mode and equipment status.
			N)	Prevention of inappropriate automatic actions from personnel errors by shutdown specific control logic (e.g., remove autoclosure interlocks from SCS suction valves.)
			O)	CCW availability is increased by 2 redundant Divisions, each with two pumps and heat exchangers.
			P)	Service water availability is increased by 2 Redundant Divisions, each with two pumps.
			Q)	Each SCS Division has four potential sources of AC power for increased availability.
2.)	Loss of Electric Power	Equipment failure and/or inadvertent personnel error leading to loss of power and shutdown cooling	A)	Alternate AC gas turbine provides third on-site power source.
			B)	Two switchyard interfaces provide flexibility.
			C)	Shutdown specific tech specs and procedural guidance reduce likelihood of personnel errors.
			D)	A reserve transformer provides an alternate supply to the safety bus if the normal source (unit auxiliary transformer) is de-energized.
			E)	Each safety division has a dedicated diesel generator.
			F)	No equipment is shared between diesels.
			G)	No equipment is shared with another unit.

TABLE 1-1 (Continued)

SHUTDOWN EVENT CATEGORIES AND SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION

	EVENT CATEGORY	EVENT INITIATOR		SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION
3.)	Loss of Reactor Coolant	From shutdown mode, equipment failure and/or personnel error leads to loss of coolant, usually through systems connected to RCS.	A)	Inadvertent errors are reduced and early operator evaluation of failures is improved by 1.) IPSO overview display with critical function and system status specific to shutdown modes 2.) CRT displays with system lineups and component status and 3.) alarms that are dependent on plant mode and equipment status.
		Inadvertent RPV pressurization while connected systems are open causing coolant level drop in vessel.	B)	Removal of repressurizer manway will not allow significant RV head pressurization. Thus, instruments are not affected.
			C)	In-core instrument seal table evolutions are prohibited by procedural guidance while vessel head is on and mid-loop evolutions are in progress, preventing seal leaks.
			D)	Coolant loss via RCP during seal maintenance reduced by pump impeller weight creating seal.
		Cavity draining exposes fuel being transferred.	E)	Cavity draining limited by reinforced pool seal between vessel flange and cavity floor.
			F)	Containment layout prevents total draining if seal fails.
4.)	Containment Integrity	Loss of shutdown cooling and/or loss of reactor coolant results in core boiling requiring rapid containment closure to prevent radiological release.	A)	Tech spec requires hatch and all penetrations closed during mid-loop evolutions. Containment configuration and size allow more outage activities within containment, resulting in less time without containment integrity.
			B)	Redundancy in SCS system, electric power supply and support systems together with increased instrumentation reduce likelihood of an initiating event progressing to boiling.
		Personnel errors result in opening pathways from containment to atmosphere during shutdown evolutions.	C)	Shutdown specific control room displays, tech specs, and procedural guidance reduce likelihood of personnel errors.
5.)	Overpressurization	Inadvertent high pressure safety injection acturtion at low temperature pressurizes RCS and SCS system.	A)	SCS system relief valves sized for maximum safety injection liquid flow.
5.)	Overpressurization (Continued)		B)	RCS is vented through the pressurizer manway.

TABLE 1-1 (Continued)

SHUTDOWN EVENT CATEGORIES AND SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION

EVENT CATEGORY	EVENT INITIATOR	SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION
		C) Ring forged reactor vessel beltline and vessel material provide additional margin to pressurized thermal shock.
6.) Flooding and Spills	Uncontrolled coolant flow from opened systems, typically combined with other inadvertent and/or poorly planned evolutions, floods essential equipment.	A) Inadvertent errors are reduced and early operator evaluation of failures is improved by 1.) IPSO overview display with critical function and system status specific to shutdown modes 2.) CRT displays with system lineups and component status and 3.) alarms that are dependent on plant mode and equipment status.
		B) Shutdown specific control room displays, tech specs, and procedural guidance reduce likelihood of personnel errors.
		C) Plant layout, including separation of redundant divisions, limits damage that may occur to affected division. No communication between divisions, including piping, electrical, HVAC, floor drains, etc.
7.) Boron and Reactivity Events	Various CVCS misoperations and uncalibrated source range neutron monitors cause approach to criticality.	A) Shutdown specific control room displays, tech specs, and procedural guidance reduce likelihood of improper operation.
	CVCS misoperation causes boron dilution or potential boron precipitation.	B) Precipitation prevented by design that limits boron concentration to below cold precipitation concentration in most borated coolant lines, eliminating need for most heat tracing.
		C) Boron dilution alarm provides advanced warning.
8.) Fire Protection	During shutdown evolutions, use of combustible materials plus ignition sources such as temporary power lines increases potential for fire damage to essential systems.	A) Plant layout and fire barriers separate redundant divisions and systems to limit potential fire damage.
		B) Combustible materials are limited in specific fire control areas.
9.) Heavy Loads and Fuel Handling	Inadequate design and/or surveillance of lifting devices causes potential damage to fuel or essential equipment.	A) Shutdown specific guidance limits pathways for heavy lifts.

TABLE 1-1 (Continued)

SHUTDOWN EVENT CATEGORIES AND SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION

EVENT CATEGORY	EVENT INITIATOR	SYSTEM 80+ FEATURES FOR PREVENTION, DETECTION AND MITIGATION
		B) Plant arrangement minimizes potential for damaging drops.
		C) Proven design for fuel, core arrangement and fuel handling machine minimizes potential fuel drop.
10.) Mode Change Events	Operator and/or procedural errors allow mode changes without satisfying entry requirements.	A) Shutdown specific control room displays, tech specs, and procedural guidance reduce likelihood of personnel errors.
		B) Inadvertent errors are reduced and early operator evaluation of failures is improved by 1.) IPSO overview display with critical function and system status specific to shutdown modes 2.) CRT displays with system lineups and component status and 3.) alarms that are dependent on plant mode and equipment status.

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATING FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
NOTE (1)	MILLSTONE 2	LOSS OF SHUTDOWN COOLING	12/07/81	IN MODE 5, SDC PUMP TRIPPED DUE TO TESTING AND RCS TEMPERATURE ROSE 110 DEG F TO 200 DEG F IN ABOUT 20 MINUTES. HEATUP AND COOLDOWN LIMITS WERE EXCEEDED. MODE 4 WAS ENTERED WITHOUT SATISFYING MODE 4 LCO'S.	1H, 1J, 1M
NOTE (1)	SALEM 1	LOSS OF SHUTDOWN COOLING	03/16/82	IN MODE 5, VITAL BUS WAS DE-ENERGIZED CAUSING LOSS OF POWER TO 1 CCW PUMP AND 2 SERVICE WATER PUMPS. THE OTHER CCS AND SERVICE WATER PUMPS WERE OUT OF SERVICE FOR MAINTENANCE. THUS, A COMPLETE LOSS OF CCW AND SERVICE WATER RESULTED. THE IMMEDIATE EFFECT WAS TO CAUSE ALL CHARGING PUMPS, BORON INJECTION PATHS, RHR TRAINS, AND D/G'S TO BE INOPERABLE. VITAL BUS WAS RESTORED WITHIN 1 HR RESTORING SW. CCW RESTORED 2 HRS LATER.	1M, 1O, 1P, 1Q, 2R
395/82004	V.C. SUMMER	LOSS OF SHUTDOWN COOLING	09/15/82	DURING COLD SHUTDOWN WHILE TESTING OVERPRESSURE PROTECTION SYSTEMS FOR RHR PROTECTION, THE INTERLOCKS CAUSED THE RHR SUCTION ISOLATION VALVE TO INADVERTENTLY CLOSE BECAUSE OF INADEQUATE TEST PROCEDURE, RESULTING IN LOSS OF RHR FLOW.	1C, 1N
334/83020	BEAVER VALLEY 1	LOSS OF SHUTDOWN COOLING	06/29/83	INADEQUATE COMMUNICATION AND WORK PROCEDURES DURING REFUELING OUTAGE CAUSED LOSS OF ELECTRICAL POWER TO THE RUNNING RHR PUMP.	1L, 1M, 1Q
NOTE (1)	PALISADES	LOSS OF SHUTDOWN COOLING	01/08/84	DE-FUELED. WITH BOTH THE MAIN TRANSFORMER AND ONE OF TWO D/G'S OUT OF SERVICE, A PROBLEM DEVELOPED ON AN INCOMING ELECTRICAL FEEDER. SINCE ONE D/G WAS OUT OF SERVICE, THE PLANT SHOULD NOT HAVE DISCONNECTED FROM THE PROBLEM FEEDER. HOWEVER, THE DISCONNECT WAS MADE AND THE PLANT WAS POWERED BY ONE D/G. WHEN THIS WAS DONE, ALL SW WAS LOST BECASUE ONE SW PUMP WAS OUT OF SERIVCE AND THE OTHER 2 SW PUMPS WERE POWERED BY THE INOPERABLE D/G. LACK OF SW CAUSED LOSS OF RUNNING D/G AND LOSS OF ALL AC.	1M, 2A, 2B, 2D, 2E
316/84014	D.C. COOK 2	LOSS OF SHUTDOWN COOLING	05/21/84	INADEQUATE PROCEDURE ALLOWED STARTING SECOND RHR PUMP BEFORE STOPPING THE RUNNING PUMP, LEADING TO VORTEXING AND AIR BINDING OF RHR PUMPS.	1A, 1B, 1C, 1D, 1H, 1M
295/84031	ZION 1	LOSS OF SHUTDOWN COOLING	09/14/84	LOSS OF RHR OCCURRENCE WHILE WATER LEVEL WAS BEING LOWERED. PERSONNEL ERROR WITH NITROGEN PURGE GAS VALVE CAUSED INACCURATE LEVEL INDICATION LEADING	1A, 1B, 1C, 1D, 1E, 1H, 1M

(1) NO LICENSEE EVENT REPORT (LER) NUMBER AVAILABLE. THIS EVENT SUMMARY WAS OBTAINED FROM ANOTHER SOURCE OF INFORMATION.

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
				TO CAVITATION IN RHR PUMP.	
413/85029	CATAWBA 1	LOSS OF SHUTDOWN COOLING	04/22/85	INACCURATE LEVEL INDICATION DURING DRAINING IN MODE 5 CAUSED LOSS OF RHR PUMP SUCTION. PERSONNEL ERROR ALLOWED SECOND RHR TRAIN TO BE DOWN FOR MAINTENANCE WHILE DRAINING WAS IN PROGRESS. CHARGING RESTORED LEVEL. THE OPERABLE PUMP WAS VENTED AND RHR RESTORED.	1A, 1B, 1C, 1D, 1E, 1H, 1M
304/85028	ZION 2	LOSS OF SHUTDOWN COOLING	12/14/85	SHUTDOWN COOLING WAS LOST WHILE THE PLANT WAS IN COLD SHUTDOWN. IT WAS ATTRIBUTED TO VORTEXING. THE CAUSE OF THE EVENT WAS IDENTIFIED TO BE INADEQUATE PROCEDURE COUPLED WITH LEVEL MEASUREMENT AND THE LACK OF KNOWLEDGE ABOUT WHAT CONDITIONS, OR AT WHAT POINT, VORTEXING CAN OCCUR.	1A, 1B, 1C, 1D, 1E, 1G, 1H, 1M
302/86003	CRYSTAL RIVER 3	LOSS OF SHUTDOWN COOLING	02/02/86	AT MID-LOOP, RHR PUMP SHAFT BROKE AFTER CONTINUOUS OPERATION FOR ABOUT 30 DAYS. PLACING SECOND RHR PUMP IN OPERATION WAS DELAYED BECAUSE A TRIPPED BREAKER WAS POWERING THE SUCTION VALVE. TEMPERATURE ROSE 33 DEG F TO 131 DEG F.	1C, 1D, 1H, 1M
NOTE (1)	WATERFORD	LOSS OF SHUTDOWN COOLING	07/14/86	NEAR MID-LOOP, A DRAIN PATH WAS NOT CLOSED AND LEVEL DROPPED. OPERATING RHR PUMP BEGAN TO CAVITATE AND WAS SHUTDOWN. RHR LOST SEVERAL TIMES OVER A 3 AND 1/2 HOUR PERIOD. RCS TEMPERATURE ROSE 94 DEG F TO 232 DEG F.	1A, 1B, 1C, 1D, 1E, 1G, 1H, 1M
323/87005	DIABLO CANYON 2	LOSS OF SHUTDOWN COOLING	04/10/87	AT MID-LOOP, 7 DAYS AFTER SHUTDOWN WITH HEAD VENTED, A LEAK CAUSED LOSS IN RCS LEVEL AND THE RHR PUMP BECAME AIR BOUND. RHR WAS LOST FOR 1 HOUR, 28 MINUTES; RCS TEMPERATURE ROSE 87 DEG F TO 220 DEG F AND PRESSURE INCREASED TO 10 PSIG.	1A, 1B, 1C, 1D, 1E, 1H, 1M
287/88005	OCONEE 3	LOSS OF SHUTDOWN COOLING	09/11/88	LOSS OF SHUTDOWN COOLING OCCURRED WHILE IN MODE 5 WHEN NON-LICENSED OPERATOR BECAME CONFUSED WHILE RACKING BREAKERS THEREBY RESULTING IN A LOSS OF POWER TO THE LOW PRESSURE INJECTION PUMPS. COOLANT TEMPERATURE INCREASED 15 DEGREES.	1D, 1J, 1L, 2M
454/88007	BYRON 1	LOSS OF SHUTDOWN COOLING	09/19/88	SHUTDOWN COOLING WAS LOST WHILE THE PLANT WAS IN THE REFUELING MODE. IT WAS ATTRIBUTED TO RHR PUMP CAVITATION CAUSED BY ENTRAINMENT OF AIR IN THE PUMP SUCTION DUE TO VORTEXING WHICH ADMITTED AIR WHEN THE REACTOR VESSEL WATER LEVEL LOWERED BELOW THE TOP OF THE REACTOR COOLANT HOT LEGS. WATER	1A, 1B, 1C, 1D, 1G, 1H, 1M

(1) NO LICENSEE EVENT REPORT (LER) NUMBER AVAILABLE. THIS EVENT SUMMARY WAS OBTAINED FROM ANOTHER SOURCE OF INFORMATION.

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
				LEVEL WAS MONITORED BY VISUALLY OBSERVING LEVEL IN REFUELING CAVITY, WHICH WAS 4 INCHES ABOVE THE FLANGE WITH THE UPPER INTERNALS IN PLACE WHEN CAVITATION OCCURRED.	
313/88014	ARKANSAS NUC ONE 1	LOSS OF SHUTDOWN COOLING	10/26/88	PERSONNEL ERROR CAUSED LOSS OF POWER TO THE DECAY HEAT REMOVAL COOLER OUTLET VALVES RESULTING IN LOSS OF SHUTDOWN COOLING. WITH LOSS OF POWER, THE VALVES, WHICH WERE DESIGNED TO "FAIL OPEN", WENT TO THE CLOSED POSITION. INVESTIGATION REVEALED THAT THE VALVES' ELECTRIC PNEUMATIC POSITIONER OUTPUT LINES HAD BEEN REVERSED CAUSING THE VALVES TO "FAIL CLOSED" ON LOSS OF POWER. COOLANT TEMPERATURE INCREASED 18 DEGREES.	1C, 1M
369/88049	MCGUIRE 1	LOSS OF SHUTDOWN COOLING	11/23/88	IN MODE 6, RHR PUMP LOST ITS SUCTION PRESSURE BECAUSE IT BECAME AIR BOUND WHILE STROKE TESTING VALVE IN SPRAY SYSTEM AT SUMP SUCTION, ALLOWING AIR TRAPPED IN INADEQUATELY VENTED HORIZONTAL PIPING TO BE FORCED INTO RHR SYSTEM. THE PUMP WAS MANUALLY STOPPED CAUSING A LOSS OF RHR. THE REACTOR COOLANT SYSTEM TEMP INCREASED FROM 90 DEG F TO 116 DEG F IN 39 MINUTES.	1B, 1C, 1D, 1H, 1J, 1F, 1N
313/88024	ARKANSAS 1	LOSS OF SHUTDOWN COOLING	12/19/88	RELAY PROBLEM CAUSED RHR SUCTION VALVE IN SINGLE SUCTION LINE TO CLOSE. RHR LOST FOR 12 MINUTES; RCS TEMPERATURE ROSE 12 DEG F TO 147 DEG F.	1B, 1C, 1D, 1H, 1M
457/89001	BRAIDWOOD 2	LOSS OF SHUTDOWN COOLING	02/23/89	DURING AN ESF RESPONSE TIME SURVEILLANCE, INADEQUATE PROCEDURE CAUSED THE RHR PUMP ISOLATION VALVE TO INADVERTENTLY CLOSE RESULTING IN LOSS OF RHR.	1C, 1D, 1H, 1M, 1N
317/89007	CALVERT CLIFFS 1	LOSS OF SHUTDOWN COOLING	03/17/89	DAMAGE TO SCS PIPING AND SUPPORTS RESULTING FROM THE SLAMMING SHUT OF CHECK VALVES WHEN ONE SCS/LPSI PUMP IS STOPPED WHILE ANOTHER IS RUNNING. SUPPORTS WERE STIFFENED. IT IS NOT CERTAIN IF THIS OCCURRENCE IS UNIQUE TO MODES 2,3,4,5,&6; IT COULD BE DUE TO LOWER PRESSURES.	1C, 1J
328/90013	SEQUOYAH 2	LOSS OF SHUTDOWN COOLING	09/11/90	LOSS OF SHUTDOWN COOLING OCCURRED, WHILE IN MODE 5, WHEN A SUCTION ISOLATION VALVE WAS INADVERTENTLY CLOSED WHEN POWER WAS REMOVED FROM AN AUTOCLOSURE INTERLOCK. THE OPERATOR FAILED TO IDENTIFY THE EFFECTS OF REMOVING RPS RACKS FROM SERVICE.	1H, 1M, 1N

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
275-91002	DIABLO CANYON 1	LOSS OF SHUTDOWN COOLING	02/07/91	PERSONNEL ERROR ALLOWED TRIP OF RHR PUMPS DURING CAVITY FILL AND SUBSEQUENT FAILURE TO COMMUNICATE OPEN SHIFT TURNOVER.	1L, 1M
295/91005	ZION 1	LOSS OF SHUTDOWN COOLING	04/21/91	LOSS OF INSTRUMENT INVERTER OUTPUT POWER CAUSES MOMENTARY HIGH RCS PRESSUE SIGNAL THAT INITIATES CLOSE OF RHR SUCTION VALVE RESULTING IN LOSS OF RESIDUAL HEAT REMOVAL SYSTEM DURING COLD SHUTDOWN (MODE 5).	1H, 1M, 1N
456/91006	BRAIDWOOD 1	LOSS OF SHUTDOWN COOLING	04/27/91	PLANT WAS ENTERING MODE 4 FROM MODE 5. SDC TRAIN 1A WAS OPERATING, BUT THE PUMP STOPPED AS A RESULT OF A MULTITUDE OF MANUAL AND AUTOMATIC ACTIONS AND REACTIONS IN THE ELECTRICAL POWER SUPPLY DURING SURVEILLANCE TESTING. SDC WAS RESTORED USING TRAIN 1B.	1H, 1M, 1J
382/91005	WATERFORD 3	LOSS OF SHUTDOWN COOLING	05/05/91	THE PLANT WAS IN MODE 5. SHUTDOWN COOLING TRAIN B WAS OPERATING WHEN THE PUMP BECAME AIRBOUND. SDC WAS RESTORED USING TRAIN A. THE PUMP LOST SUCTION AS A RESULT OF MAINTENANCE ON A HPSI CHECK VALVE IN A BRANCH LINE.	1C, 1D, 1H, 1M
251-91003	TURKEY POINT 4	LOSS OF SHUTDOWN COOLING	06/26/91	INADEQUATE PROCEDURE CONTROLS LED TO LOSS OF POWER TO COMPONENT COOLING WATER PUMPS AND LOSS OF SPENT FUEL POOL COOLING WHILE CORE WAS OFFLOADED.	1M, 1O
NOTE (1)	TROJAN 1	LOSS OF SHUTDOWN COOLING	07/23/91	IMPROPERLY ADJUSTED RELIEF VALVES IN THE COMPONENT COOLING WATER SYSTEM OPENED UPON A PRESSURE SPIKE CAUSED BY STARTUP OF A SECOND CCW PUMP AND SUBSEQUENTLY FAILED TO RESEAT RESULTING IN LEAKAGE OF CCW INVENTORY AND POTENTIAL LOSS OF RHR.	1M
250-91005	TURKEY POINT 3	LOSS OF SHUTDOWN COOLING	08/30/91	PERSONNEL ERROR CAUSED CAVITATION IN COMPONENT COOLING WATER PUMPS WITH POTENTIAL LOSS OF RHR DURING MODE 6.	1M, 1O
424/91-009	VOGTLE 1	LOSS OF SHUTDOWN COOLING	10/26/91	INADEQUATE PRESSURIZER VENT CAUSED INACCURATE RCS LEVEL INDICATION WHILE DRAINING REFUELING CAVITY BELOW FLANGE LEVEL LEADING TO VORTEXING AND LOSS OF RHR PUMPED FLOW.	1A, 1B, 1C, 1D, 1G, 1H, 1M, 5B

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TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
NOTE (1)	INDIAN POINT 2	LOSS OF ELECTRICAL POWER	11/16/84	WHILE IN COLD SHUTDOWN FOR MORE THAN 1 MONTH, LOSS OF OFFSITE POWER OCCURRED DUE TO SHEET METAL BLOWING ACROSS PHASES OF BUSWORK. 1 D/G OUT OF SERVICE, OTHER 2 D/G'S STARTED BUT AN OUTPUT BREAKER TO ONE VITAL BUS DID NOT CLOSE BECAUSE THE BREAKER FOR NORMAL OFFSITE POWER HAD NOT OPENED. OTHER ATTEMPTS TO ENERGIZE THAT BUS FAILED DUE TO CONTROL POWER FUSES BEING BLOWN.	2A, 2B, 2D, 2E, 2F
285/87008	FORT CALHOUN	LOSS OF ELECTRICAL POWER	07/21/87	DUE TO PERSONNEL ERROR, ALL AC OFFSITE ELECTRICAL POWER WAS LOST FOR 40 MINUTES AND THE ONE OPERABLE DIESEL GENERATOR DID NOT START BECAUSE CONTROL SWITCH WAS IN "OFF" POSITION DUE TO ERECTION OF SCAFFOLDING AROUND DIESEL. THE DIESEL WAS MANUALLY STARTED AND SHUTDOWN COOLING WAS THEN RESTORED AFTER 5 MINUTES.	2A, 2B, 2C, 2D, 2E, 2F
NOTE (1)	MCGUIRE 1	LOSS OF ELECTRICAL POWER	09/08/87	AT MID-LOOP, VALVE BETWEEN DIESEL FUEL STORAGE TANK AND DAY TANK FOR ONE DIESEL CLOSED IN ERROR. OTHER D/G WAS INOPERABLE. DIESEL WOULD HAVE TRIPPED HAD OPERATORS NOT FOUND PROBLEM. DAY TANK WAS AVAILABLE.	2A, 2C, 2F
400/87059	HARRIS	LOSS OF ELECTRICAL POWER	10/11/87	ONE INCOMING LINE TO ONE OF THE SAFETY BUSES WAS OUT OF SERVICE FOR MODIFICATION. THE ONE REMAINING INCOMING LINE BREAKER TRIPPED DUE TO ACCIDENTAL JARRING OF PROTECTION RELAYS. THE DIESEL GENERATOR ON THIS BUS STARTED AND LOADED APPROPRIATELY.	2A, 2B, 2D, 2E, 2F
NOTE (1)	WOLF CREEK	LOSS OF ELECTRICAL POWER	10/15/87	A SERIES OF ENGINEERED SAFETY FEATURE ACTUATIONS OCCURRED DUE TO REDUCED BATTERY VOLTAGE. THE 480 VOLT AC BUS WHICH POWERS THE BATTERY CHARGERS WAS REMOVED FROM SERVICE FOR MAINTENANCE. AT THE ONSET OF THE WORK, A BATTERY LIFE TIME ESTIMATE WAS MADE. HOWEVER, THIS TIME WAS EXCEEDED AND THE 125 VOLT DC SOURCE WAS LOST.	2C, 2D
302/87025	CRYSTAL RIVER 3	LOSS OF ELECTRICAL POWER	10/16/87	WHILE SHUTDOWN FOR REFUELING, THE STARTUP TRANSFORMER WAS ACCIDENTALLY SHORTED IN PREPARATION FOR MAINTENANCE. ONE OF TWO VITAL BUSES LOST POWER. AN ESF ACTUATION COMPLICATED POWER RESTORATION. POWER TO THE CONTROL ROOM ANNUNCIATORS AND EVENT RECORDER WAS LOST. AN ALERT WAS DECLARED.	2A, 2B, 2C, 2D

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TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 90+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 90+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
247/87013	INDIAN POINT 2	LOSS OF ELECTRICAL POWER	11/05/87	WHILE IN COLD SHUTDOWN, WITH ALL 3 DIESEL GENERATORS DOWN FOR MAINTENANCE AND ALMOST ALL ESF TAGGED OUT OF OPERATION, A TECHNICIAN INITIATED A PARTIAL SIS CAUSING LOSS OF 480V VITAL POWER BECAUSE THE DIESELS WERE TAGGED OUT. ADDITIONAL BATTERY CABLE WORK CAUSED LOSS OF INSTRUMENT BUSES WHICH COMPLICATED EVENT. NORMAL OFFSITE POWER WAS RESTROED WITHIN 3 MINUTES.	2A, 2B, 2C, 2D
336/88005	MILLSTONE 2	LOSS OF ELECTRICAL POWER	02/04/88	IN PREPARATION FOR A TEST, THE AUXILIARY CONTACT OF A BREAKER WAS ENERGIZED CAUSING LOSS OF ONE TRAIN ON VITAL 4160 V AC. THE OTHER TRAIN WAS OUT OF SERVICE FOR MAINTENANCE. THE DIESEL GENERATOR STARTED BUT BECAUSE OF A SEQUENCER FAILURE DID NOT LOAD. OPERATOR ACTION WAS REQUIRED TO RE-ENERGIZE THE BUS AND REESTABLISH SHUTDOWN COOLING.	2A, 2B, 2C, 2D
029/88010	YANKEE ROWE	LOSS OF ELECTRICAL POWER	11/16/88	PLANT WAS IN MODE 5 WITH GENERATOR CIRCUIT TESTING IN PROGRESS. DUE TO A MAINTENANCE ERROR, POWER WAS LOST TO TWO EMERGENCY 480 VOLT BUSES. ONE SOURCE OF OFFSITE POWER AND ONE DIESEL GENERATOR WERE UNAVAILABLE DUE TO MAINTENANCE. THE PLANT HAS THREEE DIESEL GENERATORS. A TIE BREAKER PROBLEM DELAYED RESTORING POWER TO ONE OF THE BUSES.	2A, 2B, 2C, 2D
313/89040	ARKANSAS NUC ONE 1	LOSS OF ELECTRICAL POWER	12/05/89	PERSONNEL ERROR CAUSED LOSS OF POWER RESULTING IN AUTOMATIC ACTUATION OF AN EMERGENCY DIESEL GENERATOR AND THE LOSS OF RHR FOR APPROXIMATELY 9 MINUTES DURING WHICH TIME THE REACTOR COOLANT SYSTEM TEMPERATURE INCREASED 17 DEGREES.	2B, 2C, 2D
285/90006	FORT CALHOUN 1	LOSS OF ELECTRICAL POWER	02/26/90	ONE OF TWO DIESEL GENERATORS AND ONE OF TWO SOURCES OF OFFSITE POWER WERE OUT OF SERVICE. THE CONTAINMENT EQUIPMENT HATCH WAS OPEN. POWER TO 4160 SAFETY BUSES WAS LOST WHEN A TRIP CIRCUIT BREAKER OPENED FOR UNKNOWN REASONS. THE OPERABLE DIESEL GENERATOR STARTED. BECAUSE OF A DESIGN FEATURE WOULD NOT LOAD ON THE BUS UNTIL THE RHR PUMP MOTOR CONNECTED TO THE BUS WAS TRIPPED. THE PUMP MOTOR BREAKER WAS OPENED AND THE BUS WAS RE-ENERGIZED. A 2 DEG F RCS TEMPERATURE INCREASE OCCURRED.	2A, 2B, 2D, 2E, 2F
424/90006	VOGTLE 1	LOSS OF ELECTRICAL POWER	03/20/90	AT MID-LOOP, A LOSS OF OFFSITE POWER TO OPERATING	2A, 2B, 2D, 2E

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TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
				RHR PUMP AND THE FAILURE OF DIESEL GENERATOR TO CONTINUE TO RUN OCCURRED. RHR RESTORED AFTER 41 MINUTES; RCS TEMPERATURE ROSE 46 DEG F TO 136 DEG F.	
336/90016	MILLSTONE 2	LOSS OF ELECTRICAL POWER	10/09/90	LOSS OF POWER TO THE CONTAINMENT RADIATION MONITOR CAUSES INADVERTENT ESAS ACTUATION OF CONTAINMENT PURGE ISOLATION SYSTEM DURING REFUELING.	2C
275-91004	DIABLO CANYON 1	LOSS OF ELECTRICAL POWER	03/07/91	PERSONNEL ERROR OUTSIDE CONTAINMENT SHORTED OFFSITE POWER LINE CAUSING POTENTIAL FOR LOSS OF RHR.	2A, 2B, 2C, 2D, 2E, 2F, 2G
251-91001	TURKEY POINT 4	LOSS OF ELECTRICAL POWER	03/13/91	POOR HOUSEKEEPING WHILE CORE OFF LOADED CAUSED WASTE MATERIAL TO SHORT OUT POWER SUPPLY WITH CONSEQUENT LOSS OF SPENT FUEL POOL COOLING AND 3 DEGREE TEMPERATURE RISE.	2A, 2B, 2C, 2E
247-91006	INDIAN POINT 2	LOSS OF ELECTRICAL POWER	03/20/91	LOSS OF NORMAL OFF-SITE POWER WHILE 2 OF 3 DIESELS OUT OF SERVICE WITH CONSEQUENT LOSS OF ONE DC BUS, WHILE CORE OFF LOADED. LOSS OF COMPONENT COOLING WATER PUMPS, BUT SPENT FUEL POOL COOLING CONTINUED FROM AN ALTERNATE OFF-SITE SOURCE.	2A, 2B, 2C
456-91006	BRAIDWOOD 1	LOSS OF ELECTRICAL POWER	04/27/91	WHILE IN MODE 5, DURING RELAY REPAIR, RHR AND COMPONENT COOLING PUMP POWER WAS LOST.	2A, 2B, 2C, 2E, 10
247-91010	INDIAN POINT 2	LOSS OF ELECTRICAL POWER	06/22/91	DIESEL TRIP WHILE OFFSITE BREAKER OPEN FOR TEST DURING COLD SHUTDOWN RESULTED IN LOSS OF SPENT FUEL POOL COOLING FOR 36 MINUTES.	2A, 2B, 2C, 2D, 2E, 2F

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM RHR
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM RHR PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
364/87008	FARLEY 2	LOSS OF REACTOR COOLANT	11/27/87	DURING A REFUELING OUTAGE, NEGLECT BY PERSONNEL TO REFILL A SECTION OF PIPE BETWEEN THE CONTAINMENT SUMP SUCTION ISOLATION VALVES AFTER DRAINING RESULTED IN A PRESSURE PULSE THAT OPENED A RHR LOOP SUCTION PRESSURE RELIEF VALVE DURING STROKING OF CONTAINMENT SUMP SUCTION VALVES THEREBY CAUSING A DECREASE IN THE REACTOR COOLANT SYSTEM PRESSURE AND PRESSURIZER LEVEL.	3A
327/88021	SEQUOYAH 1	LOSS OF REACTOR COOLANT	05/23/88	IN COLD SHUTDOWN WITH THE RCS PARTIALLY DRAINED, IMPROPER VALVE ALIGNMENT CAUSED BY POOR COMMUNICATIONS RESULTED IN A LOSS OF REACTOR COOLANT WATER INVENTORY, RHR PUMP CAVITATION, AND LOSS OF RHR COOLING. RHR RECOVERED AFTER [illegible] FILLING FROM RWST.	1B, 1C, 1D, 1M
NOTE (1)	SURRY 1	LOSS OF REACTOR COOLANT	05/27/88	ABOUT 25,800 GALLONS OF REACTOR COOLANT WERE DRAINED FROM THE REACTOR CAVITY DUE TO LEAKING REACTOR CAVITY RING DUE TO ISOLATION OF THE INSTRUMENT AIR FOR MAINTENANCE.	1C, 1D, 1M
361/88012	SAN ONOFRE 2	LOSS OF REACTOR COOLANT	06/22/88	FAILURE TO IMPLEMENT UPDATED FINAL SAFETY ANALYSIS REPORT (UFSAR) COMMITMENT RESULTS IN DRAINING OF APPROXIMATELY 9000 GALLONS FROM THE SPENT FUEL POOL INTO THE REACTOR CAVITY. UFSAR REQUIRES THAT ALL CONNECTIONS TO THE SPENT FUEL STORAGE POOL ARE MADE SO AS TO PRECLUDE THE POSSIBILITY OF SIPHON DRAINING OF THE POOL.	3A, 3B
255/89033	PALISADES	LOSS OF REACTOR COOLANT	11/21/89	DUE TO PRESSURIZER PORV DESIGN CHARACTERISTICS, WHEN THE PORV BLOCK VALVE OPENED, THE PORV ALSO OPENED AND RCS PRESSURE DROPPED FROM 2134 TO 1365 PSI.	3A
456/89016	BRAIDWOOD 1	LOSS OF REACTOR COOLANT	12/01/89	AT 350 PSIG, APPROX 67,000 GALLONS OF REACTOR COOLANT WAS LOST WHEN A RHR PUMP SUCTION RELIEF VALVE LIFTED. ABOUT 2 AND 1/2 HOURS WAS REQUIRED TO ISOLATE THE LEAK.	6A, 6C
457/90002	BRAIDWOOD 2	LOSS OF REACTOR COOLANT	03/18/90	FROM SHUTDOWN AT 350 PSIG, RHR SUCTION VALVE WAS OPENED BEFORE CLOSING THE RHR PUMP DISCHARGE VALVE TO THE RWST WHICH HAD BEEN PREVIOUSLY OPENED ON RECIRCULATION FOR BORON SAMPLING. WITH THE RHR PUMP OFF, COOLANT DRAINED FROM THE PRESSURIZED RCS TO THE RWST.	3A

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TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
029/79-007	YANKEE I	LOSS OF REACTOR COOLANT	09/27/79	FAILURE OF SEAL IN AN INCORE INSTR[illegible]ON TUBE AT THE SEAL TABLE RESULTS IN PRESSU[illegible]NDARY LEAKAGE AND POTENTIAL FOR CORE UNCOVERY.	3C

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
NOTE (1)	SALEM 2	CONTAINMENT INTEGRITY	05/25/83	IN REFUELING, CONTAINMENT INTEGRITY COULD NOT BE ESTABLISHED WITHIN THE REQUIRED 8 HOURS WITH THE ELECTRICAL POWER AVAILABLE. CONDITION LASTED ABOUT 9 HOURS.	4A, 4B, 4C, 2A, 2B
NOTE (1)	SAN ONOFRE 1	CONTAINMENT INTEGRITY	02/13/85	IN MODE 3, A SECURITY OFFICER REQUIRED TO UNLOCK BOTH NORMAL AND EMERGENCY HATCHES, MANIPULATED THE EMERGENCY HATCH SO THAT BOTH DOORS WERE OPEN. CONDITION EXISTED ABOUT 21 HOURS.	4C
NOTE (1)	FARLEY 1	CONTAINMENT INTEGRITY	04/15/85	DURING REFUELING, BOTH DOORS OF PERSONNEL AIR LOCK WERE INADVERTENTLY LEFT OPEN FOR ABOUT 4 HOURS.	4C
NOTE (1)	MCGUIRE 1	CONTAINMENT INTEGRITY	05/25/85	IN REFUELING, DURING CORE ALTERATIONS, CONTAINMENT VENTILATION COOLING WATER SYSTEM VENT VALVE WAS FOUND LOCKED OPEN. THIS CONFIGURATION CREATED A PATH FROM THE UPPER CONTAINMENT TO THE AUXILIARY BUILDING THROUGH THE OPEN VALVE INSIDE CONTAINMENT.	4A
NOTE (1)	FARLEY 1	CONTAINMENT INTEGRITY	09/30/89	ON TWO SEPARATE OCCASIONS CORE ALTERATIONS WERE PERFORMED WITHOUT CONTAINMENT INTEGRITY REQUIRED BY TECHNICAL SPECIFICATIONS. A PATHWAY EXISTED FROM THE STEAM GENERATOR SECONDARY SIDE MANWAY IN CONTAINMENT THROUGH THE STEAM GENERATOR ATMOSPHERIC RELIEF VALVE.	4A
266/90011	POINT BEACH 1	CONTAINMENT INTEGRITY	08/29/90	ENGINEERING EVALUATION INDICATES THAT THE RHR PUMPS MAY NOT PROVIDE ADEQUATE NPSH TO THE CONTAINMENT SPRAY PUMPS WHEN THE ECCS IS IN THE RECIRCULATION MODE. CORRECTIVE ACTIONS INCLUDE PROCEDURAL CHANGES.	1J
412/90013	BEAVER VALLEY 2	CONTAINMENT INTEGRITY	09/15/90	WATER TURBULENCE DURING THE REACTOR CAVITY FILL OPERATION CAUSES AN INCREASE IN CONTAINMENT AIRBORNE ACTIVITY RESULTING IN AUTOMATIC CONTAINMENT PURGE ISOLATION.	--
336-90018	MILLSTONE 2	CONTAINMENT INTEGRITY	10/02/90	PERSONNEL ERROR WHILE DRAINING STEAM GENERATOR DURING REFUELING OUTAGE CAUSED OPEN PATHWAY FROM CONTAINMENT THROUGH MANWAY AND ADV TO THE OUTSIDE ATMOSPHERE.	4A, 4C
336-990161	MILLSTONE 2	CONTAINMENT INTEGRITY	10/09/90	DURING MODE 6 CORE ALTERATIONS, MAINTENANCE PERSONNEL ERROR RESULTED IN UNAVAILABILITY OF	4A, 4C

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TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
				CONTAINMENT PURGE VALVE AUTOMATIC ISOLATION CAPABILITY.	
309/19009	MAINE YANKEE 1	CONTAINMENT INTEGRITY	10/20/90	A DESIGN DEFICIENCY IN THE CONTAINMENT ISOLATION VALVE POSITION INDICATION SYSTEM CAUSED IMPROPER ILLUMINATION OF SEVERAL ISOLATION VALVE POSITION INDICATOR LIGHTS DURING HOT SHUTDOWN.	--
213/90024	CONNECTICUT YANKEE 1	CONTAINMENT INTEGRITY	10/31/90	DURING SURVEILLANCE TESTING WITH PLANT IN COLD SHUTDOWN (MODE 5) A DESIGN DEFICIENCY IN THE CONTAINMENT ISOLATION VALVE WHICH SUPPLIES COMPONENT COOLING WATER TO THE NEUTRON SHIELD TANK COOLER CAUSED THE VALVE TO BE INOPERABLE.	1D
255/91004	PALISADES 1	CONTAINMENT INTEGRITY	01/05/91	INADEQUATE PREVENTATIVE MAINTENANCE PROCEDURES RESULTS IN EXCESSIVE LEAKAGE THROUGH VIEWING PORT GASKET ON INNER DOOR OF CONTAINMENT EMERGENCY AIRLOCK. LEAKAGE WAS DETERMINED DURING COLD SHUTDOWN MODE WITH REACTOR COMPLETELY DEFUELED.	4C
413/91003	CATAWBA 1	CONTAINMENT INTEGRITY	01/10/91	EQUIPMENT FAILURE-MALFUNCTION RESULTS IN UNLATCHING OF EMERGENCY PERSONNEL HATCH DURING HOT STANDBY (MODE 3).	--
338/19005	NORTH ANNA 1	CONTAINMENT INTEGRITY	02/05/91	INADEQUATE PROCEDURES RESULTED IN BREACH OF CONTAINMENT BUILDING PENETRATIONS DURING REFUELING.	4A, 4C
272/91006	SALEM 1	CONTAINMENT INTEGRITY	02/27/91	EVENT OCCURRED ON 2/16, 2/20, AND 2/27. INADEQUATE ADMINISTRATIVE CONTROLS PLUS EQUIPMENT FAILURE OF THE RADIATION MONITORING SYTEM RESULTS IN ACTUATION OF ESF SIGNALS (CONTAINMENT PURGE - PRESSURE - VACUUM RELIEF) FOR THE CONTAINMENT VENT ISOLATION SYSTEM DURING COLD SHUTDOWN (MODE 5) AND [illegible] (MODE 6).	4C
213/91006	CONNECTICUT YANKEE 1	CONTAINMENT INTEGRITY	03/05/91	DURING COLD SHUTDOWN (MODE 5), AN ENGINEERING EVALUATION OF CONTAINMENT INSTRUMENTATION PENETRATIONS REVEALED THAT INADEQUATE PROCEDURES PERTINENT TO CALIBRATION OF PRESSURE TRANSMIETTERS RESULTED IN A VIOLATION OF CONTAINMENT INTEGRITY. CORRECTIVE ACTION CONSISTED OF REVISING THE PERTINENT PROCEDURES.	4C
213/91010	CONNECTICUT YANKEE 1	CONTAINMENT INTEGRITY	03/15/91	PERSONNEL ERROR CAUSED A MANUAL CONTAINMENT ISOLATION VALVE TO REMAIN OPEN DURING HOT STANDBY	4C

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
				(MODE 3) PROVIDING A BREACH OF CONTAINMENT INTEGRITY.	
275/91006	DIABLO CANYON 1	CONTAINMENT INTEGRITY	03/26/91	SAMPLE PUMP OF RADIATION MONITORING SYSTEM SEIZED, RESULTING IN ACTUATION OF ESF SIGNAL FOR THE CONTAINMENT VENT ISOLATION SYSTEM DURING COLD SHUTDOWN.	---
266/91004	POINT BEACH 1	CONTAINMENT INTEGRITY	05/10/91	DURING STEAM GENERATOR CREVICE FLUSHING, THE PRIMARY SYSTEM TEMPERATURE EXCEEDED 200 DEG F FOR APPROX. 10 MINUTES BEFORE BEING COOLED TO LESS THAN 200 DEG F USING THE RHR SYSTEM.	4C
369-91012	MCGUIRE 1	CONTAINMENT INTEGRITY	09/21/91	INADEQUATE PROCEDURES ALLOWED A PRESSUE BOUNDARY DOOR TO THE ANNULUS VENTILATION SYSTEM TO REMAIN OPEN DURING MODES 1, 2, 3, AND 4.	4C
301-91003	POINT BEACH 2	CONTAINMENT INTEGRITY	10/10/91	PERSONNEL ERROR ALLOWED OPEN CONTAINMENT HATCH DURING REFUELING SHUTDOWN.	4A, 4C
335/91008	ST. LUCIE 1	CONTAINMENT INTEGRITY	11/10/91	FAILURE OF MAINTENANCE PERSONNEL TO FOLLOW APPROVED PROCEDURE RESULTED IN IMPROPER MANIPULATION OF RELIEF AND DRAIN VALVES WHICH CREATED A DIRECT FLOW PATH FROM CONTAINMENT TO THE REACTOR AUXILIARY BUILDING THEREBY COMPROMISING CONTAINMENT INTEGRITY DURING REFUELING.	4C
213/91025	CONNECTICUT YANKEE 1	CONTAINMENT INTEGRITY	11/14/91	INADEQUATE PROCEDURES RESULTED IN IMPROPER ALIGNMENT OF ALL CONTAINMENT PENETRATIONS DURING REFUELING.	4A, 4C
529/91007	PALO VERDE 2	CONTAINMENT INTEGRITY	12/05/91	INADEQUATE PROCEDURES RESULTS IN OPEN CONTAINMENT ISOLATION VALVE DURING CORE ALTERATIONS WHICH IS CONTRARY TO TECH SPEC REQUIREMENTS THAT EACH PENETRATION PROVIDING DIRECT ACCESS FROM THE CONTAINMENT ATMOSPHERE TO THE OUTSIDE ATMOSPHERE SHALL BE CLOSED BY AN ISOLATION VALVE.	4A, 4C

TABLE 1-7

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
423/88005	MILLSTONE 3	OVERPRESSURIZATION	01/19/88	FAILURE OF THE LOW TEMPERATURE OVERPRESSURE PROTECTION SYSTEM TO OPERATE. THE EVENT WAS MITIGATED BY OPERATOR ACTION. ISOLATION OF THE RHR LETDOWN PATH CAUSED A PRESSURE EXCURSION. THE PEAK RCS PRESSURE REACHED WAS 526 PSIA. THE LOW TEMPERATURE OVERPRESSURE PROTECTION SYSTEM DID NOT WORK BECAUSE A POWER SUPPLY WHICH WAS REQUIRED FOR SYSTEM OPERATION HAD ITS FUSES REMOVED WITHOUT KNOWING WHAT EFFECT THIS REMOVAL WOULD HAVE ON THE SYSTEM.	5A, 1M
NOTE (1)	SURRY 1	OVERPRESSURIZATION	04/15/88	BOTH PRESSURIZER PORV'S FAILED TO OPEN MANUALLY. TORQUE VALUES FOR DIAPHRAGM HOLD DOWN BOLTS WERE NOT SPECIFIED AND ACTUATOR OPERATION WAS INTERMITTENT. REQUIRED TO BE OPERABLE FOR LTOP.	5A, 5C
311/89021	SALEM	OVERPRESSURIZATIONS	10/27/89	ONE TRAIN THE RHR SUCTION PIPING WAS PRESSURIZED TO 600 PSIG (150 PSIG ABOVE THE DESIGN). THE EVENT OCCURRED BECAUSE THE RHR COLD LEG INJECTION VALVE DID NOT SEAT PROPERLY AND ALLOWED RCS COOLANT TO PRESSURIZE THE LINE.	5A, 5C, 1M
255/90017	PALISADES 1	OVERPRESSURIZATION	09/26/90	PALISADES HAS BOTH SPRING-LOADED SAFETY VALVES AND POWER-OPERATED RELIEF VALVES (PORV) WHICH ARE PARALLEL. THE PORV IS SET AT A LOWER PRESSURE THAN THE SAFETY VALVE. THERE ARE BLOCK VALVES UPSTREAM OF THE PORV'S. THE PORV'S WERE NOT OPERABLE IN COLD SHUTDOWN AND ON SHUTDOWN COOLING AS IS REQUIRED WITH RCS TEMPERATURE LESS THAT 430 DEG F. THE PORV'S WOULD NOT OPEN WITH A FAILURE OF THE TEMPERATURE INPUT RESULTING IN LOSS OF LOW TEMPERATURE OVERPRESSURE PROTECTION FOR THE RCS.	5A, 5C

(1) NO LICENSEE EVENT REPORT (LER) NUMBER AVAILABLE. THIS EVENT SUMMARY WAS OBTAINED FROM ANOTHER SOURCE OF INFORMATION.

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
287/76018	OCONEE 1	FLOODING AND SPILLS	10/09/76	WHILE IN COLD SHUTDOWN, WITH THE CONDENSER WATERBOX MANWAYS OPEN FOR MAINTENANCE, VALVE FAILURES ALLOWED LAKE WATER TO FLOW BY GRAVITY OUT THE OPEN MANWAYS, FLOODING THE TURBINE BUILDING TO A DEPTH OF 24 INCHES AND THREATENING THE AUXILIARY BUILDING CONTAINING SAFETY RELATED EQUIPMENT.	6A, 6B, 6C
247/84011	INDIAN POINT 2	FLOODING AND SPILLS	08/13/84	DURING MAINTENANCE, A VALVE HAD BEEN REMOVED FROM ONE SERVICE WATER TRAIN LEAVING AN OPEN PIPE, LOCATED IN THE COMPONENT COOLING WATER PUMP ROOM. SUBSEQUENTLY, ANOTHER OPERATOR CLOSED VALVES WHICH DIVERTED WATER THROUGH A PARTIALLY OPEN CROSS-CONNECT VALVE BETWEEN THE OPERATING TRAIN AND THE OUT-OF-SERVICE TRAIN. LEAKAGE FROM THE OPEN PIPE FLOODED THE ROOM, COVERING ALL THREE CCW PUMP MOTORS CAUSING LOSS OF ALL CCW FLOW.	6A, 6B, 6C
213/84013	CONNECTICUT YANKEE	FLOODING AND SPILLS	08/21/84	THE REFUELING CAVITY SEAL FAILED AND ABOUT 200,000 GALLONS OF REACTOR COOLANT SPILLED INTO THE CONTAINMENT IN ABOUT 20 MINUTES. CONTAINMENT SUMP OVERFLOWED AND LEVEL IN CONTAINMENT REACHED ABOUT 18 INCHES. IT WAS POSTULATED THAT FOR A WORST CASE SCENARIO, THAT THE FUEL POOL COULD HAVE BEEN DRAINED. THE FUEL TRANSFER CAN WAS NOT IN USE AND THE FUEL POOL WAS ISOLATED FROM THE CAVITY AT TIME OF THE EVENT. NRC BULLETIN 84-03 WAS ISSUED.	3E, 3F, 6C
NOTE (1)	SALEM 1	FLOODING AND SPILLS	12/22/87	IN MODE 5 FOR REFUEL OUTAGE, WITH TWO BLANK FLANGES INSTALLED ON SERVICE WATER PIPING - ONE WHERE A VALVE WAS REMOVED AND ONE AT ANOTHER LOCATION, A LEAK OCCURRED. FLANGES HAD BEEN LOOSENED AFTER ORIGINAL INSTALLATION TO PROVIDE A NECESSARY LEAK PATH. DUE TO VALVE FAILURE AND FLANGES BEING LOOSE, A LARGE AMOUT OF SERVICE WATER (ABOUT 144,000 GAL) ENTERED ONE SERVICE WATER BAY. THE WATER LEVEL WAS ABOVE THE SERVICE WATER PUMP MOTORS IN THE BAY. SOME ELECTRICAL EQUIPMENT AND THE CARDOX ROOM OUTSIDE THE BAY WERE WETTED.	6A, 6B, 6C
370/88010	MCGUIRE 2	FLOODING AND SPILLS	09/05/87	ABOUT 10,000 GALLONS OF WATER ENTERED THE AUXILIARY BUILDING WHEN ONE TRAIN OF CONTAINMENT SPRAY WAS OVERPRESSURIZED AND THE BOTTOM FLANGE GASKET OF A HEAT EXCHANGER FAILED.	6A, 6B, 6C

TABLE 3-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
NOTE (1)	SOUTH TEXAS	FLOODING AND SPILLS	04/09/90	WHILE THE REACTOR CAVITY WAS BEING FILLED, ONE OF TWO REQUIRED SPOOL PIECES HAD NOT BEEN INSTALLED. THIS CREATED A DRAIN PATH FROM THE LOWER EQUIPMENT STORAGE AREA TO THE CONTAINMENT AND 17,000 GAL OF WATER ENTERED CONTAINMENT.	6A, 6B
348/91004	FARLEY 1	FLOODING AND SPILLS	04/23/91	PERSONNEL ERROR CAUSED 5000 GALLONS OF WATER TO DRAIN FROM RWST TO CONTAINMENT FLOOR WHEN FIVE VALVES WERE IMPROPERLY OPENED IN CONTAINMENT SPRAY SYSTEM DURING VALVE TESTING.	6A, 6B

(1) NO LICENSEE EVENT REPORT (LER) NUMBER AVAILABLE. THIS EVENT SUMMARY WAS OBTAINED FROM ANOTHER SOURCE OF INFORMATION.

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 8b*
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 8b* PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
NOTE (1)	SAN ONOFRE 2	BORON AND REACTIVITY EVENTS	03/14/82	IMPROPER VALVE ALIGNMENT DURING NITROGEN BACKFLUSHING IN CVCS RESULTED IN THE LPSI PUMPS BECOMING GAS BOUND. RHR WAS REESTABLISHED IN ABOUT 90 MINUTES. DURING THE RESTORATION, LPSI SUCTION WAS ALIGNED TO THE RWST. DUE TO BORON STRATIFICATION IN THE RWST, MEASURED BORON CONCENTRATION IN THE TANK WAS HIGHER THAN THAT PUMPED INTO THE RCS. THUS, THE ADDITION RESULTED IN DILUTION TO LESS THAN 2000 PPM	7A, 7C
NOTE (1)	SALEM 1	BORON AND REACTIVITY EVENTS	07/16/84	0% POWER, ONE CHARGING PUMP SEIZED. METAL FILINGS AND RESIN PARTICLES WERE FOUND IN THE PUMP. SIMILAR MATERIAL WAS FOUND IN THE SUCTION LINES TO ALL CHARGING PUMPS. POTENTIAL EXISTED TO CAUSE LOSS OF ALL CENTRIFUGAL CHARGING PUMPS.	7A
NOTE (1)	CALLAWAY 1	BORON AND REACTIVITY EVENTS	07/19/84	INADEQUATE SURVEILLANCE PROCEDURES MADE BOTH TRAINS OF THE SRM DOUBLING CIRCUIT INOPERABLE FOR ABOUT 5 HOURS IN MODE 5. THE SRM TRIP AND HIGH FLUX ALARMS WERE STILL OPERATIONAL.	7A, 7C
250/87017	TURKEY POINT 3	BORON AND REACTIVITY EVENTS	05/29/87	NITROGEN GAS BINDING OF ALL BORIC ACID TRANSFER PUMPS, CAUSED BY FAILURE OF MECHANICAL SEAL, RESULTED IN LOSS OF THE NORMAL AND EMERGENCY BORIC ACID FLOW PATHS TO THE VOLUME CONTROL TANKS. CROSS TIE BETWEEN TURKEY POINT 3 AND 4 ALLOWED GAS LEAK FROM SEAL FAILURE ON UNIT 4 TO DISABLE PUMP ON UNIT 3.	2C
NOTE (1)	VOGTLE 1	BORON AND REACTIVITY EVENTS	06/06/87	DURING STARTUP, DUE TO ERROR IN THE ESTIMATED CRITICAL POSITION, REACTOR BECAME CRITICAL BEFORE EXPECTED. TRAINEE WAS PERFORMING STARTUP AND SRO WAS INATTENTIVE. PROCEDURE FAILED TO ADEQUATELY TREAT MODERATOR TEMPRATURE'S EFFECT ON BORON WORTH. REACTOR TRIP OCCURRED DUE TO HIGH SOURCE RANGE FLUX.	7A
368/88008	ARKANSAS NUC ONE 2	BORON AND REACTIVITY EVENTS	05/04/88	DURING HOT STANDBY, GAS BINDING OF CHARGING PUMPS CAUSED BY INADVERTENT EMPTYING OF VCT, DUE TO ERRONEOUS VCT LEVEL INDICATION, RESULTED IN LOSS OF RCS NORMAL MAKEUP/EMERGENCY BORATION CAPABILITY. ERRONEOUS LEVEL INDICATION WAS CAUSED BY LEAK ON THREADED FITTING OF LEVEL TRANSMITTER.	---
482/88025	WOLF CREEK 1	BORON AND REACTIVITY EVENTS	11/25/88	DIESEL GENERATOR ON ONE TRAIN OF EMERGENCY	7A, 2A

(1) NO LICENSEE EVENT REPORT (LER) NUMBER AVAILABLE. THIS EVENT SUMMARY WAS OBTAINED FROM ANOTHER SOURCE OF INFORMATION.

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
				CHARGING AND BORATION WAS REMOVED FROM SERVICE WHILE CHARGING PUMP IN THE REDUNDANT TRAIN WAS INOPERABLE RESULTING IN NO OPERABLE BORON INJECTION FLOW PATH DURING CORE ALTERATIONS.	
206/89002	SAN ONOFRE 1	BORON AND REACTIVITY EVENTS	[illegible]/89	FOLLOWING REFUELING, PERSONNEL ERROR RESULTED IN DECONTAMINATION OF REACTOR REFUELING CAVITY WITH APPROXIMATELY 440 GALLONS OF UNBORATED WATER WHICH REDUCED THE BORON CONCENTRATION OF THE REACTOR COOLANT BY 37 PPM. THE MINIMUM SHUTDOWN MARGIN OF 5% (1900 PPM BORON CONCENTRATION) WAS NOT APPROACHED. EVENT OCCURRED WHILE SOURCE RANGE MONITORS WERE INOPERABLE.	7A, 7C
250/89040	TURKEY POINT 3	BORON AND REACTIVITY EVENTS	03/20/89	WITH TURKEY POINT 4 IN MODE 3 AND TURKEY POINT 3 AT POWER, HEAT TRACED SUCTION LINES OF BORIC ACID TRANSFER PUMPS SHARED BY THE TWO UNITS WERE INOPERABLE BECAUSE OF LOW TEMPERATURE, JEOPARDIZING BORATION CAPABILITY.	7B
280/89016	SURRY 1	BORON AND REACTIVITY EVENTS	04/14/89	DURING COLD SHUTDOWN, A LEAK IN THE RCS STANDPIPE MAKEUP VALVE CAUSED AN INCREASE IN RCS INVENTORY RESULTING IN A DESCREASE IN RCS BORON CONCENTRATION. BORON CONCENTRATION WAS REDUCED BY LESS THAN 80 PPM OVER A PERIOD OF NINE DAYS. VALVE LEAKAGE WAS CAUSED BY IMPROPER ADJUSTMENT OF OPERATOR TRAVEL STOPS DURING MAINTENANCE.	7A, 7C
281/89015	SURRY 2	BORON AND REACTIVITY EVENTS	10/25/89	DUE TO PROBLEMS WITH THE BORIC ACID BLENDER IN THE CVCS, THE MODE OF OPERATION FOR THE BLENDER WAS CHANGED TO MANUAL. RCS FILLING WAS IN PROGRESS AND THE FLOWS WERE INCREASED TO EXPEDITE FILLING OF THE RCS. THIS RESULTED IN DECREASED BORON CONCENTRATION. ADJUSTMENT CAUSED THE BORON CONCENTRATION TO DECREASE BELOW THE REQUIRED 2000 PPM.	7A, 7C
414/90009	CATAWBA 2	BORON AND REACTIVITY EVENTS	07/23/90	CORE ALTERATIONS WERE IN PROGRESS WITHOUT AUDIBLE COUNT RATE INDICATION IN CONTROL ROOM OR CONTAINMENT FROM SOURCE RANGE NEUTRON FLUX MONITORS. ATTRIBUTED TO OPERATOR ERROR.	7A

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
368/90017	ARKANSAS NUC. ONE 2	FIRE PROTECTION	07/10/90	PERSONNEL ERROR RESULTS IN AN INOPERABLE FIRE BARRIER PENETRATION SEAL.	8A, 8B
261-91005	ROBINSON 2	FIRE PROTECTION	02/14/91	OVERLOADED ELECTRIC EXTENSION CORDS IGNITED COMBUSTIBLE MATERIALS DURING REFUELING OUTAGE. NO SAFETY RELATED EQUIPMENT IN FIRE AREA.	8A, 8B
368-91007	ARKANSAS NUC ONE 2	FIRE PROTECTION	02/23/91	FIRE IN EMERGENCY SAFETY FEATURES MOTOR CONTROL CENTER DURING HOT STANDBY DISABLED EQUIPMENT IN ONE ESF TRAIN. REDUNDANT SAFETY RELATED EQUIPMENT MAINTAINED SAFE SHUTDOWN CONDITION.	8A
344-91021	TROJAN 1	FIRE PROTECTION	05/24/91	UNABLE TO VERIFY THAT PLANT COULD BE PLACED INTO RHR CONDITION FOLLOWING WORST CASE FIRE BECAUSE NECESSARY DEPRESSURIZATION CONTROL SYSTEMS COULD NOT BE CREDITED.	8A
269-91008	OCONEE 1	FIRE PROTECTION	06/12/91	FOLLOWING CRAFT WORK AREA, FIRE BARRIER DOORS WERE LEFT OPEN, IN VIOLATION OF PROCEDURE.	8A
266-91007	POINT BEACH 1	FIRE PROTECTION	06/26/91	FOLLOWING WORK IN AREA, FIRE BARRIER SEALS IN EMERGENCY SAFETY FEATURES ROOMS WERE NOT SECURE IN VIOLATION OF PROCEDURE. POTENTIAL FOR LOSS OF ESF.	8A
423-91029	MILLSTONE 3	FIRE PROTECTION	11/21/91	INADEQUATE PROCEDURES DURING CONSTRUCTION RESULTED IN UNSEALED FIRE PORTECTION BARRIER BETWEEN RHR AND CONTAINMENT RECIRCULATION SPRAY CUBICLES IN ENGINEERED SAFETY FEATURES BUILDING.	8A

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 1-1)
286-90008	INDIAN POINT 3	HEAVY LOADS AND FUEL HANDLING	/ /	PRIOR DAMAGE TO INTERNALS WHILE LIFTING LED TO STUCK FUEL ASSEMBLIES DURING REFUELING AND POTENTIAL RADIOACTIVE RELEASE DURING CONSEQUENT RETRIEVAL HANDLING.	I
369-91016	MCGUIRE 1	HEAVY LOADS AND FUEL HANDLING	/ /	INADEQUATE PROCEDURE ALLOWED MISPLACEMENT OF SPENT FUEL CAUSING POTENTIAL FOR LOCAL OVERHEATING IN SPENT FUEL POOL.	10A
455-90008	BYRON 2	HEAVY LOADS AND FUEL HANDLING	09/29/90	INADEQUATE PROCEDURES LED TO A FUEL ASSEMBLY DROP ONTO TOP OF FUEL RACK IN SPENT FUEL POOL.	9C
316-90010	COOK 2	HEAVY LOADS AND FUEL HANDLING	10/05/90	DESIGN ERROR IN POLAR CRANE COULD LEAD TO FAILURE AT MUCH LOWER LOADS THAN SPECIFIED DESIGN.	9A, 9B
313-90015	ARKANSAS NUC. ONE 1	HEAVY LOADS AND FUEL HANDLING	10/26/90	INADEQUATE PROCEDURE LED TO LACK OF SURVEILLANCE FOR SPENT FUEL BUILDING VENTILATION SYSTEM AND POTENTIAL FOR RADIATION RELEASE SHOULD EVENT OCCUR.	10A
247/91004	INDIAN POINT 2	HEAVY LOADS AND FUEL HANDLING	02/12/91	SINGLE OVERLOAD EVENT OR CORROSION FATIGUE/STRESS CORROSION CRACKING CAUSES FAILURE OF HOLD DOWN BOLTS FOR POLAR CRANE RAIL. SUFFICIENT MARGIN EXISTED TO ACCEPT REDUCED BOLT CONFIGURATION.	9A, 9B
275/91014	DIABLO CANYON 1	HEAVY LOADS AND FUEL HANDLING	02/13/91	INADEQUATE PROCEDURE ALLOWED MOVEMENT OF HEAVY LOADS OVER FUEL STORAGE POOL WHILE ALL THREE DIESELS WERE INOPERABLE CAUSING POTENTIAL FOR RADIATION RELEASE UPON DROP EVENT WHEN VENTILATION UNAVAILABLE.	9A, 9B
498-91005	SOUTH TEXAS 1	HEAVY LOADS AND FUEL HANDLING	02/18/91	INADEQUATE PROCEDURE CONTROLS ALLOWED OPEN DOOR IN FUEL HANDLING BUILDING DURING FUEL MOVEMENT PROVIDING POTENTIAL FOR RADIATION RELEASE.	9A, 9B, 9C
382-91004	WATERFORD 3	HEAVY LOADS AND FUEL HANDLING	04/04/91	PERSONNEL ERROR OMITTED REQUIRED SURVEILLANCE OF FUEL HANDLING MACHINE PRIOR TO USE DURING REFUELING.	9C
NOTE (1)	PALISADES	HEAVY LOADS AND FUEL HANDLING	02/29/72	DURING REFUELING, WHILE LIFTING THE UPPER GUIDE STRUCTURE, A FUEL ASSEMBLY STUCK TO THE BOTTOM OF THE GUIDE STRUCTURE AND WAS SUSPENDED ABOVE THE CORE. CONTAINMENT INTEGRITY WAS VERIFIED AND NON-ESSENTIAL PERSONNEL WERE EVACUATED.	9C

(1) NO LICENSEE EVENT REPORT (LER) NUMBER AVAILABLE. THIS EVENT SUMMARY WAS OBTAINED FROM ANOTHER SOURCE OF INFORMATION.

TABLE 1-2

SHUTDOWN EVENTS AND SYSTEM 80+
PREVENTION, DETECTION, AND MITIGATION FEATURES

LER. NO.	PLANT NAME	EVENT CATEGORY	DATE	EVENT SUMMARY	SYSTEM 80+ PREVENTION, DETECTION, AND MITIGATING FEATURES (SEE TABLE 3-1)
NOTE (1)	TROJAN	MODE CHANGE EVENTS	08/18/82	BOTH TRAINS OF SI WERE BLOCKED FOR ABOUT 43 HOURS WHILE IN MODES 3 AND 4. WHILE IN MODE 5, BOTH TRAINS WERE BLOCKED DUE TO TESTING. THE PLANT STATUS PANEL INDICATED THIS CONDITION, HOWEVER, IT WAS NOT LOGGED AND PROPER PROCEDURES WERE NOT FOLLOWED FOR REMOVAL OF THE SYSTEM FROM SERVICE.	1M, 10A, 10B
NOTE (1)	NORTH ANNA 1	MODE CHANGE EVENTS	12/06/82	AN INADVERTENT AUTOMATIC SI OCCURRED WHICH BLOCKED ADDITIONAL SI ACTUATIONS UNTIL RESET BY CLOSING THE REACTOR TRIP BREAKERS. THE PROCEDURE USED TO RECOVER FROM THE SI ACTUATION, IMPLIED IT WAS ACCEPTABLE TO LEAVE THE SI BLOCKED FOR UP TO 36 HOURS WHICH IS NOT CORRECT. THE SI WAS UNBLOCKED ABOUT 22 HOURS LATER.	1M, 10A, 10B
NOTE (1)	OCONEE 2	MODE CHANGE EVENTS	04/10/87	HEATING UP, BREAKERS FOR HPI SUCTION VALVES FROM BWST WERE LEFT TAGGED OUT. THIS IS A TECHNICAL SPECIFICATION VIOLATION BECAUSE TWO FLOW PATHS TO HPI ARE REQUIRED. CAUSE WAS FAILURE TO REVIEW TAGOUT LOGBOOK AND POOR COMMUNICATION BETWEEN OPERATIONS STAFF AND SUPPORT.	1M, 10A, 10B
454/91005	BYRON 1	MODE CHANGE EVENTS	10/27/91	PERSONNEL ERROR RESULTS IN PLANT ENTERING HOT SHUTDOWN (MODE 4) FROM COLD SHUTDOWN (MODE 5) WITH INOPERABLE CONTAINMENT SPRAY SYSTEM AND ECCS.	10A, 10B

(1) NO LICENSEE EVENT REPORT (LER) NUMBER AVAILABLE. THIS EVENT SUMMARY WAS OBTAINED FROM ANOTHER SOURCE OF INFORMATION.

2.0 SHUTDOWN RISK ISSUES

Sections 2.1 through 2.13 present detailed evaluations of specific shutdown issues that were identified at the December 18, 1991 meeting with the NRC and that are listed in Reference 2. Each section is subdivided into four subsections. The first subsection states the issue consistent with the interpretation and evaluation in NUREG-1449 and the appropriate RAIs. The second subsection lists the acceptance criteria that are employed to evaluate the System 80+ design to prevent and/or mitigate unacceptable consequences related to each shutdown issue. The third subsection discusses the postulated plant scenarios, the analyses and the evaluations considered by to assure that the shutdown issue is adequately addressed. Finally, the fourth subsection states how the issue is resolved by the System 80+ design. Depending upon each issue and its significance in evaluating System 80+, the content of these subsections varies. Where appropriate, reference is made to RAI's on the issue, both outstanding and previously submitted. Appendix A contains the responses to all the RAI's.

2.1 PROCEDURES

2.1.1 ISSUE

The operational guidance provided by the plant designer to the owner/operator might not be sufficient to insure that procedures to avoid, detect, mitigate, and/or recover from abnormal events initiated from shutdown operations can be developed by the plant owner/operator.

2.1.2 ACCEPTANCE CRITERIA

The operational guidance provided by the plant designer to the owner/operator shall be sufficient to properly utilize design features that are available to detect, mitigate and assist recovery from abnormal events initiated during shutdown operations.

2.1.3 DISCUSSION

The System 80+ design incorporates advanced features which promote safer and simpler plant operation. The features include redundancy and diversity of components and systems, dedicated and/or permanently aligned systems, and an advanced information system which better informs the operations staff of plant status, potential adverse system interactions, and available recovery paths if an abnormal event occurs. These features also contribute to improved operability and maintainability that should significantly reduce the initiating situations that have contributed to increased shutdown risk.

The plant owner/operator is responsible for preparing detailed procedures for normal, abnormal, and emergency operations using guidance developed by the plant designer and plant site specific information. The plant designer's guidance generally is in the form of suggested operational sequences that preserve the safety bases of the design. Since shutdown operations must be intimately connected to an outage strategy, specific procedures cannot be imposed by the plant designer to cover the array of possible shutdown events. However, the plant designer can provide guides which instruct the plant owner/operator in the use of design features which can detect, mitigate, and assist recovery from abnormal events that can occur during shutdown operations.

The operational guidance contained in this report will be provided to the plant owner/operator through the plant designer's Operational Support Information (OSI) program. The intent of the OSI program is to insure that features of the System 80+ design are effectively utilized in the operation of the plant as specified in the plant owner/operator's operations program. The OSI program also provides a formal means to transfer design related bases for operations, regulatory operational commitments and related information that is typically provided to and required by a plant license applicant. The OSI program is staged to develop more detailed information as the plant design matures and is expected to be completed during the construction and pre-operational phases of a plant project. The OSI program integrates information from various interrelated areas, e.g., the Maintenance Plan, the Reliability Assurance Program and as-procured equipment characteristics, to insure the owner/operator can efficiently operate the plant within the design bases.

A summary of general operational guidance related to shutdown operations is provided in Table 2.1-1. Specific details are contained in the appropriate sections of this report.

An outline of the operational guidance developed to support RCS reduced inventory operations is provided in Appendix C. This guidance together with supporting information from this report is sufficient for a plant owner/operator to develop an operational guideline for reduced RCS inventory operations. The development of a detailed procedure by the plant owner/operator would require specific equipment characteristics of procured components and results of the pre-operational testing (CESSAR DC Chapter 14) to determine system performance values. As an example to support mid-loop operation, the shutdown coolant system flows, suction line vortexing characteristics, level instrumentation calibration, among others, would be measured during plant startup. This data would be used to verify performance as well as to provide operational data. Specific testing requirements for shutdown oriented instrumentation will be added to CESSAR DC Chapter 14 in an update amendment.

2.1.4 RESOLUTION

The issue of procedures for shutdown operation is resolved for System 80+ by providing operational guidance to address use of advanced design features to detect, mitigate, and assist recovery from abnormal events initiated from shutdown operations.

TABLE 2.1-1

SUMMARY OF PROCEDURAL GUIDANCE RELATED TO SHUTDOWN OPERATIONS

TOPIC	PROCEDURAL GUIDANCE	REFERENCE TO REPORT SECTION
Unplanned Draining of the Reactor Coolant	Prevention	2.12.1, 2.12.2.1(3), 2.12.3, 2.12.3.2.1, 2.12.4
	Administratively Control Major Potential Draindown Paths Identified for Shutdown Modes	
	Identification	
	Monitor Instrumentation for RCS Level, Inventory and Temperature Controls a. Refueling pool level. b. Containment and subsphere sump levels. c. Level indicators and alarms: EDT, RDT, IRWST, HVT, VCT. d. RCS operational leakage (Tech. Spec. Surveillance). e. RCS level indicators and alarms. 1) Pressurizer level 2) RV Delta-P level instruments f. Pressurizer pressure	2.3.3.1, 2.12.4, 2.8 Table 2.8-1

TABLE 2.1-1

SUMMARY OF PROCEDURAL GUIDANCE RELATED TO SHUTDOWN OPERATIONS

TOPIC	PROCEDURAL GUIDANCE	REFERENCE TO REPORT SECTION
Unplanned Draining of the Reactor Coolant	Prevention	2.12.1, 2.12.2.1(3), 2.12.3, 2.12.3.2.1, 2.12.4
	Administratively Control Major Potential Draindown Paths Identified for Shutdown Modes	
	Identification	
	Monitor Instrumentation for RCS Level, Inventory and Temperature Controls a. Refueling pool level. b. Containment and subsphere sump levels. c. Level indicators and alarms: EDT, RDT, IRWST, HVT, VCT. d. RCS operational leakage (Tech. Spec. Surveillance). e. RCS level indicators and alarms. 1) Pressurizer level 2) RV Delta-P level instruments f. Pressurizer pressure	2.3.3.1, 2.12.4, 2.8 Table 2.8-1

information that is typically provided to and required by a plant license applicant. The OSI program is staged to develop more detailed information as the plant design matures and is expected to be completed during the construction and pre-operational phases of a plant project. The OSI program integrates information from various interrelated areas, e.g., the Maintenance Plan, the Reliability Assurance Program and as-procured equipment characteristics, to insure the owner/operator can efficiently operate the plant within the design bases.

A summary of general operational guidance related to shutdown operations is provided in Table 2.1-1. Specific details are contained in the appropriate sections of this report.

An outline of the operational guidance developed to support RCS reduced inventory operations is provided in Appendix C. This guidance together with supporting information from this report is sufficient for a plant owner/operator to develop an operational guideline for reduced RCS inventory operations. The development of a detailed procedure by the plant owner/operator would require specific equipment characteristics of procured components and results of the pre-operational testing (CESSAR DC Chapter 14) to determine system performance values. As an example to support mid-loop operation, the shutdown coolant system flows, suction line vortexing characteristics, level instrumentation calibration, among others, would be measured during plant startup. This data would be used to verify performance as well as to provide operational data. Specific testing requirements for shutdown oriented instrumentation will be added to CESSAR DC Chapter 14 in an update amendment.

2.1.4 RESOLUTION

The issue of procedures for shutdown operation is resolved for System 80+ by providing operational guidance to address use of advanced design features to detect, mitigate, and assist recovery from abnormal events initiated from shutdown operations.

TABLE 2.1-1 (Cont'd)

SUMMARY OF PROCEDURAL GUIDANCE RELATED TO SHUTDOWN OPERATIONS

TOPIC	PROCEDURAL GUIDANCE	REFERENCE TO REPORT SECTION
	g. RCS temperature 1) Core Exit Thermocouples 2) Resistance Temperature Detectors 3) Shutdown Cooling a) SG Parameters b) Shutdown Cooling System	2.8, 2.3.3.1
	MITIGATION (Immediate Operator Action) Identify leakage path. Isolate leakage path. Make up losses. a. Safety Injection b. SDC via IRWST c. Containment spray from IRWST via SDC lines d. Charging pumps e. BAST f. Safety Injection Tanks	2.3.3.4, 2.12.3, 2.12.4, 2.12.2.3(2) Appendix C

TABLE 2.1-1 (Cont'd)

SUMMARY OF PROCEDURAL GUIDANCE RELATED TO SHUTDOWN OPERATIONS

TOPIC	PROCEDURAL GUIDANCE	REFERENCE TO REPORT SECTION
Heavy Loads	Restrictions specified for:	2.11.3
1) Drop of transported equipment. 2) Drop of fuel bundle 3) Refueling pool seal integrity. 4) Loads over ICI table.	a. Lift Height b. Travel Directions c. Systems Lineup (Specified in CESSAR DC, Chapter 9 and Plant Designer's "Heavy Load Guides")	
Outage Maintenance	Strategy for Shutdown Operations	2.4.3.2.2
	a. Define operating and operational divisions. b. Limit maintenance activities to components and systems not included in a).	Appendix C

TABLE 2.1-1 (Cont'd)

SUMMARY OF PROCEDURAL GUIDANCE RELATED TO SHUTDOWN OPERATIONS

TOPIC	PROCEDURAL GUIDANCE	REFERENCE TO REPORT SECTION
Fire Protection	Administratively require fire protection systems to remain operable in shutdown modes.	2.7.3.2, and 2.7.3.3
	Procedurally Control: a. Combustible materials b. Housekeeping c. Hot work	
	Pre-Fire Plan a. Outline fire fighting strategies b. Monitor status of fire barriers	2.7.3.2

TABLE 2.1-1 (Cont'd)

SUMMARY OF PROCEDURAL GUIDANCE RELATED TO SHUTDOWN OPERATIONS

TOPIC	PROCEDURAL GUIDANCE	REFERENCE TO REPORT SECTION
RCS Cooling Using Feed and Bleed (other systems not available)	RCS Pressurized	
	1. Start SI pump.	2.4.3.1.3.1.1
	2. Reduce pressure through Safety Depressurization System (SDS) venting to IRWST. (Maintain subcooled temperatures in RCS).	2.4.3.1.3.2.1
	3. Secure operating RCPs (if applicable)	
	4. Cycle SI feed and SDS bleed to reduce RCS pressure and temperature.	
	5. When depressurized, open SDS and Run SI continuously.	
	6. Align SDC heat exchanger for IRWST cooling.	
	7. Restore Normal SDC systems.	

TABLE 2.1-1 (Cont'd)

SUMMARY OF PROCEDURAL GUIDANCE RELATED TO SHUTDOWN OPERATIONS

TOPIC	PROCEDURAL GUIDANCE	REFERENCE TO REPORT SECTION
	RCS Depressurized 1. Start SI 2. Open SDS 3. Secure RCP's (if RCS not vented) 4. Align SDC heat exchanger for IRWST Cooling. 5. Restore normal SDC Systems	
SG Tube Rupture	Include in Emergency Procedure Guides a requirement to maintain a positive primary to secondary pressure differential.	Table 2.6-1 Section C(a)
Lockout of main feedwater pumps in shutdown modes with RTCBs closed.	Administratively lockout main feedwater pumps if subcritical.	4.1.1 and 4.1.2

2.2 TECHNICAL SPECIFICATION IMPROVEMENTS

2.2.1 ISSUE

When a plant is operated within the limiting conditions for operation provided by the technical specifications, the consequences of design basis events should be bounded by the results of the safety analyses. However, limiting conditions for operation developed for power operation might not be sufficient to insure that the consequences of events initiated from shutdown modes are bounded by the analyses. Technical specification should include the necessary limiting conditions for operation that are applicable to shutdown modes.

2.2.2 ACCEPTANCE CRITERIA

Technical specification shall insure that when the plant is operated within the limiting conditions for operation applicable to the mode of operation, consequences of design basis events shall be bounded by the results of safety analyses for that mode.

2.2.3 DISCUSSION

The System 80+ design incorporates advanced features which promote safer operation and greater margins to operating limits. The features include redundancy and diversity of components and systems and an advanced information system which better informs the operations staff of plant status, potential adverse system interactions, and the recovery paths if an abnormal event occurs. These features also contribute to improved operability and maintainability that should significantly reduce the initiating situations that have contributed to increased shutdown risk.

One objective of the plant designer is to reduce the operational constraints that limit the plant owner's flexibility to operate the plant as efficiently as possible. Another objective is to formally impose the operational constraints required to insure the plant remains within analyzed bounds for operation through the initial set of technical specifications. Overly restrictive technical specifications especially for shutdown modes may unnecessarily complicate operations and may increase risks by prolonging the shutdown period and adding to staff stress. The objective of this assessment of shutdown risk for the System 80+ relative to technical specifications is to modify existing technical specifications to the extent necessary to address event initiators not fully covered by analysis of the traditional design basis events.

A summary of the proposed technical specification modifications is provided in Table 2.2-1, with a markup of the LCO and APPLICABILITY sections of the present technical specifications, as applicable, in

Appendix D. In addition, a new technical specification section applicable to reduced RCS inventory operations in Modes 5 and 6 (with fuel in the core) is presented in Appendix E.

The technical specification modifications and additions reflect:

a. the added redundancy and diversity of the System 80+ design that allows these modifications without affecting operational flexibility;

b. analysis of events initiated during shutdown operations;

c. assessment of the risk of operating in these plant configurations for extended periods, e.g., refueling, unplanned maintenance.

The rationale for the technical specification modifications is contained in the appropriate sections of this report.

2.2.4 RESOLUTION

The issue of shutdown specific technical specifications is resolved for System 80+ by modifications and additions to the technical specifications based upon safety analyses performed for Modes 2 through 6. These modifications and additions provide additional ensurance that the consequences of transients and accidents which might occur during shut down modes of operation are less limiting than those given in Chapter 6 and 15 of CESSAR-DC. The proposed technical specification modifications and additions will be reviewed against the shutdown PRA findings and a change package will be proposed for a future CESSAR-DC amendment.

TABLE 2.2-1

SYSTEM 80+ TECHNICAL SPECIFICATIONS MODIFICATIONS

RELATED TO IMPROVED SHUTDOWN OPERATIONS

Item	Tech Spec	Number and Title	Type of Change	LCO	Bases
1.	3.1.1	Shutdown Margin (SDM) >210°F	Revision	Change mode applicability ≤500°F	Extended applicability.
2.	3.1.2	SDM ≤ 210°F	Replace	Add Kn-1 and ECP requirements.	Provide protection for ejected CEA and CEA group withdrawl in shutdown modes.
3.	3.1.10	SDM Test Exemption for CEDMs Testing	New	Allow CEDMs Testing in Modes 4 and 5	Provide exceptions to Test Operability of CEDMs. Movement of only one CEA at a time is allowed.
4.	3.3.1	RPS Instrumentation	Revision	Specify the modes of applicability in Table 3.3.1-1. Extend SG Pressure-Low to Mode 3 and RC Flow-Low to Modes 3, 4, and 5 when the CEAs can be moved.	Provide Reactor Trip function for Steam Line Break (SLB) in Shutdown Modes.
5.	3.3.5	Core Protection Calculators	Revision	Extend Operability to Modes 3, 4, and 5 when CEAs can be moved.	Provides Reactor Trip Function for unplanned CEA Group withdrawal.

TABLE 2.2-1 (Cont'd)

SYSTEM 80+ TECHNICAL SPECIFICATIONS MODIFICATIONS

RELATED TO IMPROVED SHUTDOWN OPERATIONS

Item	Tech Spec	Number and Title	Type of Change	LCO	Bases
6.	3.3.10	ESFAS Instrumentation-Automatic Actuation	Revision	Add Mode 4 to CSAS Mode applicability in Table 3.3.12-1	Insures availability of automatic CSAS for mitigation of LOCA event in Shutdown Mode 4.
7.	3.4.11	RCS P/T Limits	Revision	Add minimum Pressure Restriction RCS Temperatures between 483°F and 543°F.	Provide a SIAS for SLB and other increased heat removal events initiated in this temperature regime.
8.	3.5.3	LTOP	Revision	Change restriction on number of SI pumps operable to 2.	Two SI divisions required operable in applicable modes.
9.	3.5.4	Safety Injection System	Revision	Extend requirements for 2 SI divisions to all of Modes 4, 5, and 6.	Required for RCS inventory makeup for LOCA events in lower operating modes.
10.	3.5.4	IRWST	Revision	a. Extend operability requirements to Modes 5 and 6. b. Specify maximum water temperature at 110°F.	a. For compatibility with 3.5.3. b. Presently stated in Bases.

TABLE 2.2-1 (Cont'd)

SYSTEM 80+ TECHNICAL SPECIFICATIONS MODIFICATIONS

RELATED TO IMPROVED SHUTDOWN OPERATIONS

Item	Tech Spec	Number and Title	Type of Change	LCO	Bases
11.	3.8.2	AC Sources (Shutdown)	Revision	Require 1 circuit between the offsite transmission network to each onsite Class 1E distribution system in Modes 5 and 6.	Provide additional backup AC power source.
12.	3.3.15	Boron Dilution Alarm	New	Both boron dilution alarms shall be operable in Modes 3, 4, 5, and 6.	Provide additional protection for prevention of an inadvertent boron dilution of the RCS.
13.	3.3.14	Accident Monitoring Instrumentation (AMI)		Add Radiation Monitoring Instrumentation for a. SG Liquid Blowdown b. Steam Line c. Air Ejectors d. Stack to Table 3.3.14-1	Required for SG tube rupture detection in shutdown modes.
14.	3.1.6	Shutdown CEA Insertion Limits		Add special test exceptions and applicability to only critical conditions.	Clarify applicability and STE's.

TABLE 2.2-1 (Cont'd)

SYSTEM 80+ TECHNICAL SPECIFICATIONS MODIFICATIONS

RELATED TO IMPROVED SHUTDOWN OPERATIONS

Item	Tech Spec	Number and Title	Type of Change	LCO	Bases
15.	3.1.7	Regulating CEA Insertion Limits		Same as Item 14.	Sames as Item 14.
16.	3.3.12	ESFAS Instrumentation Manual Actuation		Add Mode 4 to CSAS Mode Applicability in Table 3.3.12-1	Insures availability of manual CSAS for mitigation of LOCA event in shutdown mode 4.
17.	3.4.11	LTOP		Delete requirement for SI pumps.	2 required for Shutdown, see LCO 3.5.3. LTOP sizing increased to avoid PTS.
18.	3.8.5	DC Sources (Shutdown)		Clarify LCO to provide most reliable line up.	Prevents loss of operable D/G due to maintenance.
19.	3.8.8	Distribution Systems (Shutdown)		Clarify LCO to provide most reliable line up.	Prevents loss of operable D/G due to maintenance.
20.	3.9.4	Shutdown Cooling (Refueling Operations)		Require Additional SDC division to be operable.	Allows increased reliability for decay heat removal.

2.3 REDUCED INVENTORY OPERATION AND GL 88-17 FIXES

2.3.1 ISSUE

The NRC has voiced increasing concern over the safety of operations during plant shutdowns. Plant events which have occurred in the industry have highlighted the need for a close examination of operations during reduced inventory conditions in the reactor coolant system. Following the Diablo Canyon incident, the NRC published Generic Letter 88-17, which required that holders of operating licenses or construction permits address a number of deficiencies in order to enhance the safety of shutdown operations and reduce the risk to the public. Specific areas of concern include:

1. instrumentation which would greatly improve the operator's monitoring capability during reduced inventory operations,
2. the availability of existing equipment for use in mitigating a loss of SCS or loss of RCS inventory,
3. nozzle dam installation procedures which would ensure a vent pathway is available so that RCS pressurization can be minimized if shutdown cooling is lost.
4. alternate ways to add inventory to keep the core covered should SCS be lost,
5. administrative procedures that would avoid RCS perturbations during reduced inventory operations, and
6. containment closure issues.

The NRC has specified that programmed enhancements should accomplish a comprehensive improvement in the plant's ability to cope with shutdown operations. The NRC asserted that plants are not well designed for reduced inventory operations, that procedures are incomplete for shutdown cooling recovery or alternate actions and that mitigating features may not be available under shutdown conditions. Therefore, the NRC has recommended that licensees implement means to prevent accident initiation, to monitor a progression that may lead to core damage and to evaluate consequences and, where needed, to provide mitigation.

2.3.2 ACCEPTANCE CRITERIA

The System 80+ design shall reflect a comprehensive consideration of shutdown and lower power risk, by adequately addressing all GL 88-17 recommendations and other issues relevant to reduced inventory, especially in the areas of instrumentation, technical specifications, procedures, equipment availability and analyses.

2.3.3 DISCUSSION

During plant shutdowns, certain maintenance and testing activities require a draindown of the RCS to a partially filled condition. Normal maintenance activities include the replacement of RCP seals and journal bearings. A testing activity requiring RCS draindown is the Technical Specification for inservice inspection of the steam generator tubes. The use of nozzle dams during maintenance and testing activities minimizes the time during which the RCS must be operated in a partially filled condition. To minimize operating time at mid-loop level, nozzle dams are installed on the steam generators and the RCS is reflooded to continue maintenance and testing.

While the RCS coolant level is lowered to within the hot leg, the risk of loosing shutdown cooling is increased due to the possibility of vortexing at the SCS suction line interface with the hot leg. In the worst scenario, subsequent to vortexing in the SCS suction line, a large percentage of air is entrained into the SCS suction piping and the SCS pump performance is degraded or interrupted. If SCS operation is not reestablished, core boiling and pressurization can produce very rapid core uncovery, sometimes in as little as 15 to 20 minutes. This phenomenon, and the high probability of it occurring, prompted the NRC to issue the recommendations of GL 88-17.

System 80+ design features result in practical and significant benefits during reduced inventory operations. These design features are outlined in Sections 2.3.3.1 through 2.3.3.5 which follow. Details of the capabilities of these System 80+ design features to enhance safety during reduced inventory conditions and of the analytical bases for changes to Technical Specifications and procedure guidance to the owner/operator are presented in other sections of this report.

2.3.3.1 Instrumentation for Shutdown Operations

Diverse, accurate, and redundant instrumentation (including control room CRT displays) give continuous system status and provide the operations staff with precise information to monitor reduced inventory operations and to respond to loss of shutdown cooling events, should they occur. Detailed information on reduced inventory instrumentation is included in Section 2.8 of this Report.

Analyses form the basis for instrument design and calibration so as to assure correct instrument operability during reduced inventory states. Phenomena which can affect instrumentation operation are considered in the recommended use of instrument types for various scenarios. Instrumentation availability during reduced inventory is assured via the plant Technical Specifications that are provided in Section 2.2 of this report.

A general description of the types of instrumentation which are used for reduced inventory is outlined below.

1. Redundant and independent wide and narrow range level sensors are provided for continuous monitoring of RCS level during draindown operations. The level indicators provide monitoring capability from the pre-drain down normal level in the pressurizer to a point lower than that required for SCS operation. The level indicators are calibrated for low temperature operation and they provide a high degree of accuracy. Indication in the main control room and low-low, low, high and high-high level alarms are provided.

   The wide range level instruments cover draining from the pressurizer to below the bottom of the hot leg and are available with the head on and off the vessel. The narrow range level instruments cover reduced inventory operations, and are also available with head on and off the vessel. The narrow range instruments are accurate for measuring level within the hot leg. During a draindown, level monitoring would be transitioned from the wide range level instruments to the narrow range instruments when the greatest degree of accuracy is required during operations with level within the hot leg region.

2. Several independent diverse temperature measurements representative of core exit temperature are provided during reduced inventory operations. Temperature indication is available when the head is located both on and off the vessel. Since temperature is valuable in guiding SCS restoration actions and in monitoring the success of recovery actions, alarm setpoints are based on integrated response times necessary to support SCS recovery, event mitigation, time to boil, and containment closure.

3. SCS operation monitoring instrumentation is provided that assures precise knowledge of the status of the operating SCS loop; including pressure, temperature, flow and pump performance indicators.

2.3.3.2 SCS Design

The functional design of the Shutdown Cooling System (SCS) is substantially complete for System 80+. Design features that improve SCS performance during shutdown operation are detailed below.

1. The System 80+ SCS suction lines do not contain any loop seals. An improved suction piping layout allows self venting.

Entrained air travels back up to the hot leg without the possibility of being trapped anywhere in the SCS suction line. This feature allows the SCS pumps to be restarted without requiring complicated venting procedures, assuring an expedited reflood of the shutdown cooling pump suction.

2. The two SCS suction lines are independent and redundant to each other. Problems associated with a specific suction line would not limit the other shutdown cooling train from being operated, after level recovery (if necessary), for continued decay heat removal.

3. The two containment spray system pumps are interchangeable with the SCS pumps and are designed to back up the SCS pumps in the event of a non-electrical pump failure. Thus, there are four pumps available for shutdown cooling, provided support systems are available. Plant Technical Specifications will assure pump availability during shutdown operations.

4. There are no interlocks on the shutdown cooling suction piping which have the potential for disturbing shutdown cooling. Although previous designs (e.g., System 80) included interlocks to isolate the SCS in the event of an unanticipated RCS pressurization during shutdown cooling, this interlock has been deleted from the System 80+ design per the EPRI ALWR Utility Requirements Document. This reasonably reduces the likelihood of losses of SCS.

2.3.3.3 Steam Generator Nozzle Dam Integrity

The System 80+ design addresses the NRC concern for preventing significant pressurization in the upper plenum of the reactor vessel during core boiling scenarios. System 80+ procedural guidance recommend, a nozzle dam installation and removal sequence by which the nozzle dams are installed in the cold legs first. After the cold leg nozzle dams are installed, the hot leg nozzle dams can be installed. Likewise, when removing the nozzle dams, the hot leg nozzle dams are removed first, subsequently cold leg nozzle dams can be removed. This installation and removal procedure will maximize the time that the steam generators are available for reflux boiling in the case of a loss of decay heat removal, and minimize the time that both hot legs are simultaneously blocked by nozzle dams. This installation procedure requires that the pressurizer manway is opened so that a hot side vent pathway exists prior to blocking both RCS hot legs with nozzle dams.

In the System 80+ design, the ability of the RCS to withstand pressurization during reduced inventory operations with the nozzle dams installed is limited by the design pressure of the steam generator hot and cold leg nozzle dams. Based on field hydrostatic tests performed on nozzle dams, a conservative value of 40 psia is assumed for this pressure limit. In order to assure that the nozzle dam design pressure is not exceeded during reduced inventory operations with boiling conditions in the reactor vessel, the System 80+ design includes a requirement will be imposed to establish a mid loop vent pathway via the pressurizer manway before operating in reduced inventory. When the manway is opened to the containment atmosphere, it provides sufficient venting capacity to prevent RCS pressurization and subsequent nozzle dam failure. The pressurizer manway vent pathway is of sufficient capacity to prevent core uncovery due solely to pressurization of the hot side resulting from boiling in the core coolant.

The pressurizer manway will be closed except during normal RCS draindown activities (see Section 2.1). During a normal draindown to reduced inventory operations, when pressurizer level decreases to a preestablished setpoint, the RCS vent pathway will be aligned by opening the pressurizer manway. Following refueling operations, RCS integrity will not be reestablished until the RCS coolant level reaches the pressurizer. Only at that point will the manway be reinstalled. This mid loop vent alignment allows sufficient venting of the RCS to the pressurizer cubicle should SCS be lost, resulting in onset of core boiling.

Analyses have indicated that the pressurizer manway opened and relieving to the pressurizer cubicle will be sufficient for venting the RCS during RCS boiling and preventing steam generator nozzle dam failure. An acceptable, conservative RCS equilibrium pressure which is below the assumed steam generator nozzle dam design pressure has been calculated to occur 4 days post shutdown. Therefore, the earliest time after shutdown (from full power) for operating at mid loop level is recommended as 4 days. Based on industry operational data, a reasonable minimum RCS cooldown from Mode 1, followed by a draindown from normal RCS level to mid loop, can be performed in approximately 4.5 days. Therefore, the 4 day requirement does not impact the achievable start time for nozzle dam installation. Additionally, it provides the necessary degree of protection required for loss of decay heat removal scenarios. This data is to be incorporated into guidance for the owner/operator to employ when planning outage evolutions. Additionally, procedural guidance regarding the earliest time after shutdown for entry to reduced inventory operations is provided in Section 2.2 of this report. Such restrictions are implemented to minimize the consequences of a loss of shutdown cooling event during reduced inventory operations.

The specified time after shutdown is based on the following analytical results:

- decay heat vs. time after shutdown

- the resultant RCS heat up rate assuming a total loss of decay heat removal
- the consequential maximum RCS steam pressure for Mode 5, reached by boiling RCS inventory.

Power history (unit specific, cycle specific) decay heat loads vs. time plots could be used to calculate lower decay heat loads at 4 days, thus allowing entry into mid loop operation and nozzle dam installation earlier during shutdown. In fact, the use of the pressurizer manway as the vent pathway yields an acceptable equilibrium pressure (below steam generator nozzle dam design pressure) at 2 days post shutdown. This capability would be further supported by higher nozzle dam pressure limits than assumed in the analysis. Although this meets EPRI ALWR requirements for refueling scheduling, it is not recommended that the plant enter mid loop level operations before 4 days. Complying with procedural guidance which requires mid loop operation <u>no earlier</u> than 4 days adds margin to the relationship between RCS pressure and nozzle dam design pressure. Furthermore, the entry time for mid loop level reasonably limits the makeup flow required to match boil-off to within several makeup schemes available in the System 80+ design (see Section 2.3.3.4). It fixes the time to boil (assuming an initial RCS temperature of 150 deg F) to greater than 15 minutes, which lengthens the time available for loss of shutdown cooling system (SCS) mitigation actions.

2.3.3.4 Alternate Inventory Additions and DHR Methods

The effective management of time and efforts is crucial to coping with a loss of shutdown cooling. Awareness of time constraints provides information that is useful in deciding how to allocate effort. If shutdown cooling cannot be restored within the time to core uncovery, getting a source of water lined up to keep the core covered becomes a first priority. Inventory makeup directly extends the margin of safety prior to uncovering the core.

Successful coping with a loss of shutdown cooling would include performing the steps outlined in Section 2.4 of this report. One of the last measures specified in that section includes adding makeup to the RCS to replenish boil off. This is thought of as a last resort measure in the System 80+ design due to the multiple success paths available to restore decay heat removal, and the time available to take corrective actions.

However, as required by Generic Letter 88-17, sufficient existing equipment should be maintained in an operable or available status so as to mitigate a loss of RCS inventory should core boiling or an uncontrolled and significant inventory loss occur. Generic Letter 88-17 also recommends that the water addition rate capable of being provided by each of the means should be at least sufficient to keep the core covered. Finally, Generic Letter 88-17 states that the path of water addition must assure that makeup flow does not bypass the reactor vessel before exiting any opening in RCS.

For the System 80+ design, at least 2 available means of adding inventory to the RCS will be available whenever the RCS is in a reduced inventory condition. Operating guidance is provided to specify the source of makeup water, the means of providing makeup to the RCS, and the recommended implementation strategy. The guidance will designate makeup pathways that ensure that makeup water does not bypass the reactor vessel.

The water addition rate capable of being provided should be at least sufficient to makeup for the boil off rate. This keeps the core covered and provides an adequate degree of protection for loss of decay heat removal scenarios. With the earliest nozzle dam installation occurring at 4 days post trip, the decay heat present would require approximately 135 gpm of makeup flow to compensate for boil off. This value is based on the pressurizer manway being opened, venting steam to the pressurizer cubicle. The steaming rate, and therefore, the required makeup rate, will reduce beyond 4 days post trip. The exact makeup rate may require adjustment based on actual, as-built conditions.

For Mode 5, reduced inventory operations, a shutdown cooling pump, the containment spray pumps, or safety injection pumps will be utilized as described in Section 2.4 to provide pumped makeup (for boil off) should SCS be lost. Procedural guidance will caution operators on using a containment spray pump in the same loop as the affected shutdown cooling pump, especially if the shutdown cooling pump has been lost due to air entrainment/pump cavitation. The makeup pump (shutdown cooling, containment spray or safety injection) will be aligned to the in-containment refueling water storage tank (IRWST) as the preferred source for makeup. An alternate source for borated water is the boric acid storage tank (BAST).

For Modes 5 and 6 the charging system via a charging pump (or alternatively, a boric acid makeup pump) will be utilized to provide pumped makeup should all methods of decay heat and inventory replenishment delineated above be lost. The pump chosen will be aligned to the BAST.

If no method of pumped inventory addition is available, a source for gravity feed inventory addition is via the safety injection tanks (SITs). This is applicable in Modes 5 and 6, and is considered only as a last resort. This method of gravity feed will only be implemented if SCS is lost along with all other means of supplying water to the RCS, and RCS boiling is occurring. If at least 2 tanks available provides assurance that over 20,000 gallons of water are available for discharge. Inventory addition from 2

SITs would assure approximately a 5 1/2 ft. rise in RCS water level and would make up for approximately 3 hours of core boil off.

Use of the shutdown cooling pumps, containment spray pumps, or safety injection pumps ensures that makeup flow will not bypass the core regardless of postulated openings in the RCS. Flow delivery will be through the direct vessel injection (DVI) nozzles. Even in the case of a DVI line break, sufficient inventory will be added to make up for core boil off. Use of the charging pump or boric acid makeup pump also ensures that makeup flow will not bypass the core, since it will be injected via the cold leg and enter the core via the normal charging path.

2.3.3.5 Operations

Procedures and Technical Specifications necessary to support the program are identified and will be implemented into the plant design. Procedural guidance for the conduct of mid-loop draindowns is provided to assure that no testing or maintenance activity adversely affects the NSSS during mid-loop operations. Guidance will be provided that assures that testing and maintenance activities performed during reduced inventory avoid operations that deliberately lead to perturbations in the RCS and all supporting systems necessary to maintain the RCS in a stable condition. These operations include (but are not limited to):

- RCS drain operations
- shutdown cooling testing and maintainance activities
- reactor coolant gas vent system testing and maintenance
- component cooling water testing and maintenance
- withdrawal of the incore instrumentation for refueling
- safety injection system testing and maintenance
- personnel communications system perturbations
- in-core instrument seal table evolutions while the reactor vessel head is on and mid loop operations are in progress.

Avoiding RCS and support system perturbations assures that adequate operating, operable, and/or available equipment of high reliability is provided for cooling the RCS and for avoiding a loss of RCS cooling. These actions also maintain sufficient existing equipment in an operable or available status so as to mitigate a loss of SCS or a loss of RCS inventory, should either occur. Adequate communications are essential to activities related to the RCS or systems necessary to maintain the RCS in a stable, controlled condition.

Due to the Diablo Canyon incident and other industry events, the requirements for evacuating personnel from the containment building, closing of the containment building e[illegible]ment hatch and containment air lock doors, and isolation of p[illegible]ations leading outside containment were evaluated based on ti[illegible] boil and time to core uncovery criteria. A description of the containment closure conditions referred to, along with a description of containment closure design features, is contained in Section 6.0 of this report.

2.3.4 RESOLUTION

The resolution of the reduced inventory issue on System 80+ is complete. Resolution is comprised of the results of the analyses outlined above, related evaluations in Section 2.4 on availability of decay heat removal, Technical Specifications in Section 2.2 and procedural guidance in Section 2.1.

The System 80+ design reflects a comprehensive consideration of shutdown and low power risk by adequately addressing all Generic Letter 88-17 recommendations and other issues relevant to reduced inventory.

2.4 LOSS OF DECAY HEAT REMOVAL CAPABILITY

2.4.1 ISSUE

Events that have occurred at operating plants demonstrate the vulnerability during shutdown Modes to loss of decay heat removal. The variety of maintenance activities taking place at shutdown combined with the possible system and equipment interactions that may occur lead to many conceivable scenarios for experiencing a loss of decay heat removal. Three dominant design objectives have evolved from the emphasis placed on prevention of shutdown events:

1. Provide redundant Shutdown Cooling System capacity and identify alternate decay heat removal capability.

2. Provide instrumentation to effectively monitor shutdown operations, including critical plant configurations such as mid-loop.

3. Provide flexible redundancy in AC power.

The System 80+ features that address these issues are presented below in the context of demonstrating an integrated design capable of avoiding unacceptable consequences from the entire spectrum of potential event scenarios.

2.4.2 ACCEPTANCE CRITERIA

All event scenarios may be characterized by initiation, detection, mitigation and consequence. To measure the success of the integrated response of System 80+ to events initiated from Modes 2 through 6, two criteria related to the potential for radiological release are adopted here. Significant release can only occur from fuel cladding rupture resulting from heatup after the coolant level drops below the top of the active core. Therefore, the first acceptance criterion is that there shall be no fuel cladding failure resulting from postulated events, excluding LOCA, initiated from Modes 2 through 6. The second criterion is that the radiological exposure of the public to events resulting in the loss of decay heat removal shall be limited to a fraction of the 10CFR100 limits that is specified in sections of this report where applicable.

2.4.3 DISCUSSION

In this section, an evaluation is presented of the System 80+ features that are designed to prevent violation of the above criterion. Section 2.4.3.1 examines events and event initiators which potentially result in the loss of shutdown cooling leading to boiling. Causes of past events considered include mid-loop operation, power failure and operator error. Appropriate Technical

Specification limitations and procedural guidance are identified by the analyses and are provided in Sections 2.1 and 2.2.

Section 2.4.3.2 presents the features of System 80+ which help prevent a loss of decay heat removal due to the loss of AC power. This is one of the specific concerns identified in NUREG-1410. The discussion in this section is directly related to the means of coping with a loss of decay heat removal. This concern is also identified in NUREG-1410 and evaluated in Section 2.4.3.1.

Section 2.4.3.3 presents the features of System 80+ that help assure the availability of the diesel generator. This issue was also identified in NUREG-1410. Availability of the diesel generator has been a significant factor in numerous past events.

Taken together, these sections demonstrate the integrated capability of the System 80+ to prevent and mitigate a loss of decay heat removal to ensure that the acceptance criteria are not violated.

2.4.3.1 Shutdown Event Initiation and Analyses

2.4.3.1.1 Introduction

This section examines events which could result in a loss of the Shutdown Cooling System (SCS) due to various initiators (events which challenge the SCS, such as a loss of power, inadvertent closure of a valve in the pump suction line and air ingestion in the pump suction) under various plant configurations and modes of operation and the ways these events can be prevented, detected and mitigated.

The discussion is structured into three parts. The first part focuses on design features which improve the SCS's resistance to initiators. The emphasis here is on hardware design. The second part assumes a loss of the SCS, regardless of the initiator, and discusses the ability of System 80+ to recover from the event. Here too, the emphasis is primarily on hardware design. The third part recognizes the limitations of hardware design as a response to initiators and the need to demonstrate that adequate redundancy is provided to cover all possible plant configurations. This will include the plant's ability to cope with a loss of DHR. The emphasis here is on operator actions, operating procedures and technical specifications in the context of the various plant configurations which can exist in Modes 4, 5 and 6.

2.4.3.1.2 Resistance to Initiators

Design improvements have been made to the System 80+ SCS that reduce the likelihood for a loss of DHR. This is, in part, the result of applying a "beyond single failure criteria" design philosophy to improve the SCS's ability to withstand a wide range of initiators, including a loss of power, equipment failure, control system failure and operator error. The major design features attributed to the SCS's increased resistance are summarized in Table 2.4-1. The SCS Piping and Instrumentation Diagrams are shown in Figure 2.4-2 through 2.4-4.

TABLE 2.4-1

SUMMARY OF SYSTEM 80+ SCS DESIGN FEATURES THAT INCREASE RESISTANCE AGAINST INITIATORS

SCS Nozzle at bottom of hot leg.
Dedicated DHR function.
Independent suction lines for each train.
Elimination of auto-closure interlocks in suction valves.
Elimination of cross train communication.
Increased system design pressure.
Improved flow control.
Improved protection against pump excessive flow conditions.
Flexibility to reduce flowrates to maximize NPSHA.
Improved RCS level instrumentation at mid-loop.
Instrumentation to indicate incipient pump cavitation.
Elimination of loop seals in suction lines.
Improved AC power reliability.

The most important feature that was added for the System 80+ SCS is its dedication to the DHR function. No portions of the SCS are included in the Emergency Core Cooling System (ECCS) as has been done with past designs. This means the SCS components do not double for components credited in other safety systems during Modes 1 through 4. This single design change allows various SCS improvements and simplifications including the ability to perform routine maintenance outside of shutdown cooling modes (5 and 6).

The system is comprised of two identical, redundant, and totally separate trains each capable of performing the required DHR function. Dedicated heat exchangers have been provided in each SCS train. Previous designs used a single heat exchanger for both the SCS and the containment spray system (CSS), and as a result this required system realignment as the plant moved through modes 4 to 5. However, the System 80+ design eliminates these manual actions which decrease the potential for operator error during Modes 5 and 6.

Each SCS train has independent suction lines from the RCS hot-legs. There are no cross-connections between SCS trains. Direct vessel injection (DVI) introduced for System 80+ and the dedicated DHR function of the SCS have enabled each train to be separate. This allowed simplifications in the arrangements resulting in greater protection for each pump from suction line failures due to air ingestion and discharge line failures resulting from pump to pump interaction.

Interlocks are provided on the SCS suction isolation valves to prevent these valves from being opened when RCS pressure is above the SCS entry pressure. These interlocks are enabled when RCS pressure is slightly above the shutdown cooling initiation pressure. All interlocks to close these valves, such as closure on high pressure, have been eliminated. During an overpressurization transient, the SCS will be maintained active to continue DHR. The SCS is designed to mitigate these events with low temperature overpressure protection (LTOP) using spring-loaded relief valves and by an increased SCS design pressure.

System flow control and protection from pump overspeed has been improved. System flow control is accomplished using valving and fixed resistance orifices in each train (orifices are not shown in Figure 2.4-1). The orifices are sized to limit the maximum flowrate from the SCS pumps and adjustments to shutdown cooling flowrate to match decay heat levels is accomplished by modulating valves. This design philosophy not only minimizes seat wear due to high fluid velocities resulting from throttling, but also prevents pump excessive flow conditions.

Operating procedures for the SCS during reduced inventory operation provide minimum flowrates necessary to perform DHR as a function of time after shutdown. SCS flowrate will be decreased as the cooling requirements decrease from lower decay heat levels. The lower shutdown cooling flowrate increases the net positive suction head available (NPSHA) to the SCS pumps. This provides greater operational margin for the RCS during midloop when SCS NPSHA is at a minimum and the potential for cavitation is at a maximum.

The ability to accurately measure and provide the RCS fluid levels has been the cause of many incidents resulting in the loss of DHR. System 80+ has made many improvements in the instrumentation for measuring the liquid level in the RCS and data display to the operator in the control room. Further discussion on this topic appears in sections 2.3 and 2.8 of this report.

Improvements have been made in the instrumentation of the SCS to provide the operator with more information about critical points in the system. The intent is to provide the operator with detailed system parameters so appropriate actions can be taken before the loss of DHR occurs. If a loss of the SCS does occur these parameters will aid in the correct and timely evaluation of the initiator thus decreasing SCS recovery time. Major new instruments which have been included in the System 80+ design are suction and discharge pressure indicators and SCS pump motor current indication. These instruments are all indicated in the main control room.

Suction piping arrangements have been simplified and improved. Several incidents have been attributed to the presence of loop seals in the suction lines that allow air to collect and lead to the reduction of NPSHA and air binding. System 80+ arrangements for the suction lines do not have loop seals and thereby enhance the ability of the pumps to survive low NPSHA conditions.

Improvements in AC power reliability are discussed in sub-section 2.4.3.2.

The System 80+ SCS design features presented above, and summarized in Table 2.4-1, provide a way to minimize a loss of the SCS. These design features also address initiators which are known to have defeated DHR systems in currently operating plants. A summary of these initiators and corresponding SCS deign features are provided in Tables 1-1 and 1-2.

2.4.3.1.3 Recovery from Initiators

Recognizing that some initiators may defeat the SCS, the System 80+ design will require that both SCS trains and one division of AC power be operable during Modes 5 and 6. This allows safety injection and containment spray equipment in the redundant division to undergo maintenance activities as necessary.

Table 1-2 provides a detailed listing of events that have resulted in the loss of shutdown cooling. Table 1-1 summarizes design features incorporated into System 80+ to prevent, detect and mitigate the effects of the events listed in Table 1-2. Consequently, a detailed listing of all potential initiators will not be provided in this section. Instead, initiators that result in the loss of DHR are categorized into four groups. This categorization is structured primarily to simplify the discussion but may also aid in constructing diagnostic loss of SCS procedures. These groups relate the initiator to a location in the system with respect to the SC pump. The instrumentation provided for monitoring the pump's performance identify whether the failure is in the suction line, discharge line, the pump itself, or a power failure. With proper diagnostic information from these groups, the operator can perform appropriate recovery actions to restore DHR. Table 2.4-2 identifies the groups, some representative initiators in each group, a brief description of the event and the instrumentation available to detect the event. The discussion that follows examines how DHR can be recovered using this information assuming a loss of a SCS train.

2.4.3.1.3.1 Group I Initiators

Group I initiators include a failure in the suction side of the SC pump. Suction line initiators are the most common during the midloop operation. These would include air ingestion, inadvertent closure of a valve in the suction line, failure of a relief valve to close, leakage from the system and procedural errors. The result of any of these initiators is to reduce the NPSHA for the SC pump.

Information provided to the operator in the control room for detecting and diagnosing these events include various alarms and indicators. The SCS includes an alarm for a low flow condition during shutdown cooling. This will be the initial indication of a possible suction line initiator since its set point is above the onset of cavitation. The typical alarm used for SCS flow is set to indicate a drop in flow from the design value of 5000 gpm to approximately 3000 gpm. This, in conjunction with a low suction pressure, fluctuating motor current and near normal discharge pressure (during the onset of cavitation), will confirm a Group I initiator (SC pump suction).

2.4.3.1.3.1.1 Recovery During Mode 5

The equipment available to recover from this initiator depends on the mode of operation and includes the redundant SCS train, one of two containment spray (CS) and two of four safety injection (SI) pumps. (Technical Specifications will require that two AC sources will be available to each division of class 1E AC power during reduced inventory operations in Modes 5 and 6. See section 2.2 of this report.) The CS pumps are identical to the SC pumps and provide a redundant source for DHR flow during Modes 5 and 6. The SI pumps provide a viable source of DHR flow in Mode 5 as their capacity will match the reduced decay heat generation rate.

If the redundant SCS train cannot be used to recover from a Group I initiator during Mode 5, the CS pumps can be used to re-establish inventory control and DHR. The CS pumps can be aligned to take suction from either the RCS hot-legs or the In-containment Refueling Water Storage Tank (IRWST). During a Group I initiator, however, the CS pumps, which are normally aligned to the IRWST, can be used to re-establish inventory control by injecting IRWST water into the reactor vessel through the DVI nozzles (see Figure 2.4-1). This alignment can also provide DHR using the SCS heat exchanger. This response requires operator action to open an SDS valve RCS to allow water to circulate through the RCS to effect DHR (by opening a Safety Depressurization System (SDS) valve), the manual opening of one (normally locked closed) cross-connect valve and the actuation of the CS pump from the control room. Once the event is terminated, either the original SCS train or the redundant train can be activated to resume DHR. If a group I initiator produces a loss of coolant accident outside of containment, the operator has over 24 hours to identify and mitigate the event based on CS pump flow to match boiloff rate assuming the source of water is the IRWST.

If the CS pump is not functional, the SI pumps can be used to re-establish inventory control by injecting IRWST water into the reactor vessel. DHR would then be performed by either the redundant SCS train after RCS level is recovered, by "break" flow, if the initiator provided an opening in the system, or by feed-and-bleed by opening a SDS valve. In the extreme, a single SI pump can provide sufficient flow to match boil-off thereby extending operator response time to identify the initiator and terminate the event.

2.4.3.1.3.1.2 Recovery During Mode 6

The equipment available to recover from this initiator during Mode 6 includes the redundant SCS train and possibly the opposite division's CS pump.

In this mode, the primary recovery system will be the redundant SCS train. However, if it is not available, then a CS pump may be aligned to take suction from the RCS hot-leg and discharge into the DVI nozzles. The success of this action is dependant on the particular Group I initiator since the operable CS pump must use the same RCS suction as the defeated SCS train (see Figure 2.4-1) and the opposite division's CS pump may be inoperable due to maintenance.

2.4.3.1.3.2 Group II Initiators

Group II initiators include a failure in the discharge side of the SC pump. Discharge line initiators include inadvertent closure or opening of a valve and the inadvertent actuation or leakage from a relief valve. The result of Group II initiators is to change the SCS system resistance curve. The pump will respond in accordance with its characteristic curve. Specifically, for the closure of a valve in the discharge line, the system resistance will increase resulting in a decrease in DHR flow and power consumption with a concurrent increase in discharge head. Pump by-pass lines prevent pump operation at shutoff. For the inadvertent opening of a valve, there will be a reduction in system resistance which will produce an increase in flow and a decrease in power consumption at a lower pump head.

Information provided to the operator in the control room to detect and diagnose these events include the same alarms and indicators discussed in connection with Group I initiators (sub-section 2.4.3.1.3.1). The instrumentation critical to identifying a Group II initiator includes the SC pump discharge pressure, flowrate and motor current indication (see Table 2.4-2).

2.4.3.1.3.2.1 Recovery During Mode 5

The equipment available to recover from this initiator during Mode 5 include the redundant SCS train, one CS pump and two SI pumps.

In this mode, the primary recovery system will be the redundant SCS train as the potential to lose the other SCS pump is unlikely. For the low probability case where the redundant SCS train cannot be used, the CS pump may be used to re-establish inventory control and DHR. If the CS pump is not functional, the SI pumps can be used to re-establish inventory control. DHR then would be performed by either the redundant SCS train after RCS level has been recovered, by break flow or by feed-and-bleed.

2.4.3.1.3.2.2 Recovery During Mode 6

The equipment available to recover from this initiator during Mode 6 include the redundant SCS train and possibly the CS pump. The success of using the CS pump is dependent on the specific Group II initiator since the CS pump shares injection lines with the defeated SCS train.

2.4.3.1.3.3 Group III Initiators

Group III initiators include a mechanical failure of the SC pump. Table 2.4-2 shows some examples. Recovery from Group III initiators include activating the redundant SCS train or aligning the CS pump.

2.4.3.1.3.4 Group IV Initiators

Group IV initiators are due to a loss of AC power. Recovery from Group IV initiators include automatic actuation of battery power, actuation of the combustion turbine or, if the loss of power is local to the train, activating the redundant SCS train or CS pump. System 80+ AC power availability is discussed in section 2.4.3.2.

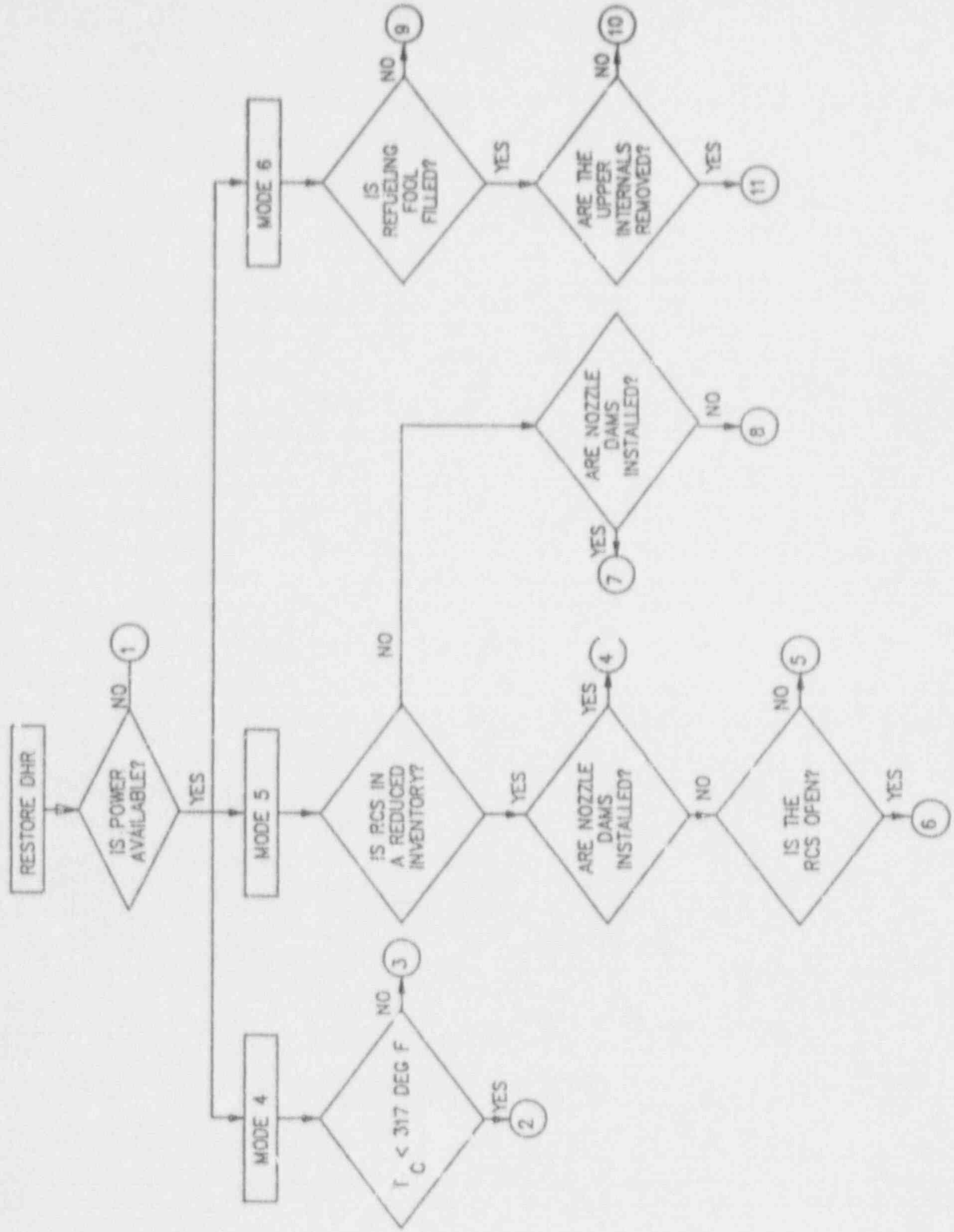
2.4.3.1.4 Recovery Based on Plant Configuration

Section 2.4.3.1.3 provided a general discussion regarding the recovery from initiators. This section examines the recovery from initiators for several specific plant configurations and modes. This analysis illustrates the capability of System 80+ to recover from losses of DHR and identifies new procedural requirements and technical specifications to minimize such losses and facilitate mitigative actions.

Figure 2.4-1 facilitates the identification of several major plant configurations of interest for shutdown risk. The termination points shown in the figure relate to Table 2.4-3 which provides an analysis of the configuration identifying possible initiators, current applicable technical specifications, new technical specifications, additional procedural requirements, alternative support equipment and systems available to mitigate losses of DHR and recovery actions from initiators.

2.4.3.1.5 Conclusions

The System 80+ SCS design features provide the necessary redundancy, flexibility, and diversity to reduce the likelihood of losing decay heat removal due to a loss of the SCS. The features of the design, the Technical Specifications, and the procedure guidance allow shutdown activities within certain limits and provide operational guidance for system flexibility and assurance that a loss of decay heat removal is unlikely.



SYSTEM 80+™	PLANT STATES AND TERMINATION POINTS FOR RESTORATION OF DHR	Figure 2.4-1

TABLE 2.4-2

SCS INSTRUMENTATION

INITIATOR	ITEM	RESULT	INDICATORS/ALARMS	
I - FAILURE IN THE SUCTION LINE				
INADVERTENT SIGNAL CLOSES MOTOR OPERATED VALVE	SI-651, 6533, 655 OR SI-652, 654, 666	LOSS OF COOLING FLOW	LOW FLOW ALARM FLUCTUATING DISCHARGE PRESSURE CURRENT FLUCTUATIONS LOW SUCTION PRESSURE POSITION INDICATION ON VALVE OPERATORS	FI-302 & FI-305
OPERATOR ERROR IN CLOSING SCS SUCTION ISOLATION VALVE	SI-106 & SI-107	LOSS OF COOLING FLOW	LOW FLOW ARM FLUCTUATING DISCHARGE PRESSURE CURRENT FLUCTUATIONS LOW SUCTION PRESSURE POSITION INDICATION ON VALVE OPERATORS	FI-302 & FI-305 P-302 & P-305 I-306 & I-307 P-300 & P-301
LOW RCS LEVEL RESULTING IN VORTEX FORMATION AND AIR ENTRAINMENT		PUMPS WILL CAVITATE RESULTING IN LOSS OF COOLING FLOW	LOW FLOW ARM FLUCTUATING DISCHARGE PRESSURE CURRENT FLUCTUATIONS LOW SUCTION PRESSURE RCS LEVEL	
II - FAILURE IN THE DISCHARGE LINE				
INADVERTENT SIGNAL CLOSES MOTOR OPERATED VALVE	SI-310 & 312, 601 OR SI-311 & 313, 600	SYSTEM RESISTANCE INCREASES CAUSING THE PUMP TO OPERATE NEAR SHUTOFF	LOW FLOW ARM FLUCTUATING DISCHARGE PRESSURE CURRENT FLUCTUATIONS LOW SUCTION PRESSURE RCS LEVEL	FI-302 & FI-305 P-302 & P-305 P-300 & P-301 I-306 & I-307
OPERATOR ERROR IN CLOSING SCS DISCHARGE ISOLATION VALVE	SI-579, 578	SYSTEM RESISTANCE INCREASES CAUSING THE PUMP TO OPERATE NEAR SHUTOFF	LOW FLOW ARM FLUCTUATING DISCHARGE PRESSURE CURRENT FLUCTUATIONS LOW SUCTION PRESSURE RCS LEVEL	FI-302 & FI-305 P-302 & P-305 P-300 & P-301 I-306 & I-307

TABLE 2.4-2

SCS INSTRUMENTATION

INITIATOR	ITEM	RESULT	INDICATORS/ALARMS	
II - FAILURE IN THE DISCHARGE LINE (CONT)				
INADVERTENT SIGNAL OPENS MOTOR OPERATED VALVE	SI-690, 691	SYSTEM RESISTANCE DECREASES CAUSING PUMP TO EXCEED ITS RUNOUT FLOW. ALSO, FLOW SPLIT MAY CAUSE RCS TO HEAT UP AS LESS FLOW WILL BE DELIVERED.	LOW FLOW INDICATION	FI-302 & FI-305
			LOW DISCHARGE PRESSURE	P-302 & P-305
			SUCTION PRESSURE DECREASES	P-300 & P-301
			INCREASED POWER CONSUMPTION	I-306 & I-307
			POSITION INDICATION ON VALVE OPERATORS	
VALVES IN THE IRWST TEST PATH NOT CLOSED FOLLOWING COMPLETION OF SC FULL FLOW TEST	SI-315,693 & 301 OR SI-304,686 & 300	PUMPS WILL DRAIN THE RCS INVENTORY INTO THE IRWST THROUGH THE TEST PATH THEN LOSE SUCTION AS THE FLUID IN THE HOT LEG DROPS	LIQUID LEVEL INSTR FOR MIDLOOP OPERATION	SEE SECTION 2.3
			RAPID DECREASE IN RCS PRESSURE	
			RAPID DECREASE IN RCS LEVEL	
			LIQUID LEVEL ALARMS IN THE IRWST	L-350, L-351
			TEMP INDICATION IN THE IRWST	T-350, T-351
			AFTER LEVEL DECREASES BELOW MIDLOOP	
			LOW FLOW ALARM	FI-302 & FI-305
			NORMAL DISCHARGE PRESSURE	P-302 & P-305
			CURRENT FLUCTUATIONS	I-306 & I-307
			LOW SUCTION PRESSURE	P-300 & P-301
SCS ACTIVE TRAIN IS USED TO FILL REFUELING POOL	SI-450 & 458 SI-454 & 455	THE SCS HAS BEEN DESIGNED TO SUPPORT EPRI REQUIREMENT 4.3.1.2 FOR REFUELING POOL (RFP) FILL. IF THE RFP IS FILLED USING THE TRAIN PERFORMING SC, THEN THE RCS INVENTORY COULD BE TRANSFERED TO THE RFP.	NO DETECTION UNTIL RCS INVENTORY DECREASES DECREASES BELOW THE MIDLOOP.	
			LOW FLOW ALARM	FI-302 & FI-305
			NORMAL DISCHARGE PRESSURE	P-302 & P-305
			CURRENT FLUCTUATIONS	P-300 & P-301
			LOW SUCTION PRESSURE	I-306 & I-307
INADVERTENT CROSS CONNECT TO THE CONTAINMENT SPRAY SYSTEM	SI-430, 431	LOSS OF COOLANT FLOW	LOW RCS LEVEL	

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TABLE 2.4-2

SCS INSTRUMENTATION

INITIATOR	ITEM	RESULT	INDICATORS/ALARMS	
III - FAILED PUMP				
SHAFT FAILURE		LOSS OF COOLANT FLOW	LOW FLOW ARM	FI-302 & FI-305
			NO DISCHARGE PRESSURE	P-305 & P-306
			NO SUCTION PRESSURE	P-300 & P-301

TABLE 2.4-3

TERMINATION POINT 1

Plant Configuration	Modes 4, 5 or 6
Initiators	Loss of power
Current Applicable Technical Specifications	LCO 3.8.1 - 3.8.8
New Technical Specification Requirements	See section 2.2
New Procedural Requirements	See section 2.1
Recovery From Initiators	See section 2.4.3.2 and 2.4.3.3.

TABLE 2.4-3

TERMINATION POINT 2

Plant Configuration	Mode 4. RCS cold leg temperature less then 317°F. IRWST Full.
Initiators	Group I-IV. RCS line break.
Current Applicable Technical Specifications	LCO 3.4.6 Two RCS loops or two SCS trains or any combination of these to be operable. One RCS loop or SCS train to be in operation. LCO 3.5.1 Four SIT's operable when pressurizer pressure is greater than 900 psia. LCO 3.5.4 IRWST operable. LCO 3.6.6 Two CSS trains operable. LCO 3.8.2 AC Power (Shutdown)
New Technical Specification Requirements	Two SI pumps operable.
New Procedural Requirements	None
Alternative Support Equipment/Systems	None required.
Recovery From Initiators	DHR will be provided by sources other than the SCS when the RCS pressure is above [500] psig. During these conditions, the ECCS will be operable. The SIS will be available by automatic actuation down to RCS pressures of 400 psig (SIAS cutout pressure) and manually to 317° F. The CSS is operable through out Mode 4. Below [500] psig Group I - IV initiators can be mitigated per section 2.4.3.1.

TABLE 2.4-3

TERMINATION POINT 3

Plant Configuration	Mode 4. RCS temperature greater than 317°F. IRWST full.
Initiators	Group I - III (for RCS pressure less then [500] psig) Group IV RCS line break.
Current Applicable Technical Specifications	LCO 3.4.6 Two RCS loops or two SCS trains or any combination of these to be operable. One RCS loop or SCS train to be in operation. LCO 3.5.1 Four SIT's operable when pressurizer pressure is greater than 900 psia. LCO 3.5.3 Two SIS trains operable. LCO 3.5.4 IRWST operable. LCO 3.6.6 Two CSS trains operable.
New Technical Specification Requirements	None
New Procedural Requirements	None
Alternative Support Equipment/Systems	None required.
Recovery From Initiators	DHR will be provided by sources other than the SCS when the RCS pressure is above [500] psig. During these conditions, the ECCS will be operable. The SIS will be available by automatic actuation down to RCS pressures of 400 psig (SIAS cutout pressure) and manually to 317° F. The CSS is operable through out Mode 4. Below [500] psig Group I - IV initiators can be mitigated per section 2.4.3.1.

TABLE 2.4-3

TERMINATION POINT 4

Plant Configuration	Mode 5 RCS in reduced inventory. Nozzle dams installed. IRWST full.
Initiators	Group I-IV. RCS line break.
Current Applicable Technical Specifications	LCO 3.4.8 Two SCS trains operable. One SCS train operating. LCO 3.4.11 LTOP operable with a maximum of two SIS train operable. LCO 3.8.2 AC Power (Shutdown)
New Technical Specification Requirements	One CS pump operable. Two SI pumps operable. Midloop vent operable.
New Procedural Requirements	Maintain shutdown cooling (SC) flow rate near the minimum required for DHR.
Alternative Support Equipment/Systems	Pumps... Charging pump. Boric Acid Make-up pump. Tanks... Safety Injection Tanks (SIT) Boric Acid Storage Tank (BAST)
Recovery From Initiators	Regain inventory control... SC, CS or SI pumps can be used to inject IRWST water into the RCS to regain water level. If these pumps are not functional inventory control can be established using a charging pump or boric acid make-up pump by injecting BAST water into the RCS. Regain DHR capability... DHR can be regained by using the redundant SCS train once level is recovered. If the redundant SC pump is not functional DHR can be established using the CS pump. If the CS pump is not functional, DHR can be established by feed and bleed using SI pumps and opening the SDS valves.
Time To Boil	Approximately 10-15 minutes.

TABLE 2.4-3

TERMINATION POINT 5

Plant Configuration	Mode 5. RCS in reduced inventory. Nozzle dams not installed. RCS closed (mid loop vent or RCP seals). IRWST full.
Initiators	Group I-IV. RCS line break.
Current Applicable Technical Specifications	LCO 3.4.8 Two SCS trains operable. One SCS train operating. LCO 3.4.11 LTOP operable with a maximum of one SIS train operable.
New Technical Specification Requirements	One CS pump operable. Two SI pumps operable. Midloop vent operable.
New Procedural Requirements	Maintain shutdown cooling (SC) flow rate near the minimum required for DHR.
Alternative Support Equipment/Systems	Pumps... Charging pump. Boric Acid Make-up pump. Tanks... Safety Injection Tanks (SIT) Boric Acid Storage Tank (BAST) Steam Generators
Recovery From Initiators	Regain inventory control... SC, CS or SI pumps can be used to inject IRWST water into the RCS to regain water level. If these pumps are not functional inventory control can be established using charging pump or boric acid make-up pump by injecting BAST water into the RCS. Regain DHR capability... DHR can be regained by using the redundant SCS train. If the redundant SC pump is not operable DHR can be regained using the CS pump. If the CS pump is not functional DHR can be established initially by reflux boiling, then by feed and bleed using SI pumps and opening the SDS valves.

TABLE 2.4-3

TERMINATION POINT 6

Plant Configuration	Mode 5. RCS in reduced inventory. Nozzle dams not installed. RCS open (manway) IRWST full.
Initiators	Group I-IV. RCS line break.
Current Applicable Technical Specifications	LCO 3.4.8 Two SCS trains operable. One SCS train operating. LCO 3.4.11 LTOP operable with a maximum of two SIS trains operable. LCO 3.8.2 AC Power (Shutdown)
New Technical Specification Requirements	One CS pump operable. Two SI pumps operable. Midloop vent operable.
New Procedural Requirements	Maintain shutdown cooling (SC) flow rate near the minimum required for DHR.
Alternative Support Equipment/Systems	Pumps... Charging pump. Boric Acid Make-up pump. Tanks... Safety Injection Tanks (SIT) Boric Acid Storage Tank (BAST) Steam Generators
Recovery From Initiators	Regain inventory control... SC, CS, SC or SI pumps can be used to inject IRWST water into the RCS to regain water level. If these pumps are not functional inventory control can be established using charging pump or boric acid make-up pump by injecting BAST water into the RCS. SITs can also be used. Regain DHR capability... DHR can be regained by using the redundant SCS train. If the redundant SC pump is not operable DHR can be regained using the CS pump. IF the CS pump is not functional, DHR can be established by reflux boiling, or feed and bleed using CS or SI pumps and utilizing the open pressurizer manway.

TABLE 2.4-3

TERMINATION POINT 7

Plant Configuration	Mode 5. RCS not in reduced inventory. Nozzle dams installed. IRWST full.
Initiators	Group I-IV. RCS line break.
Current Applicable Technical Specifications	LCO 3.4.8 Two SCS trains operable. One SCS train operating. LCO 3.4.11 LTOP operable with a maximum of one SIS train operable.
New Technical Specification Requirements	Two SI pumps operable.
New Procedural Requirements	One CS pump available. Midloop vent operable.
Alternative Support Equipment/Systems	Pumps... CS pump. SI pump. Charging pump. Boric Acid Make-up pump. Tanks... Safety Injection Tanks (SIT) Boric Acid Storage Tank (BAST)
Recovery From Initiators	Regain DHR capability... DHR can be regained by using the redundant SCS train. If the redundant SC pump is not functional DHR can be regained using the CS pump. If the CS pump is not functional, DHR can be established by feed and bleed using SI pumps or utilizing the open pressurizer manway.

TABLE 2.4-3

TERMINATION POINT 8

Plant Configuration	Mode 5. RCS water level above reduced inventory. Nozzle dams not installed. IRWST full.
Initiators	Group I-IV. RCS line break.
Current Applicable Technical Specifications	LCO 3.4.8 Two SCS trains operable. One SCS train operating. LCO 3.4.11 LTOP operable with a maximum of one SIS train operable.
New Technical Specification Requirements	Two SI Pumps operable.
New Procedural Requirements	One CS pump available.
Alternative Support Equipment/Systems	Pumps... CS pump. SI pump. Charging pump. Boric Acid Make-up pump. Tanks... Safety Injection Tanks (SIT) Boric Acid Storage Tank (BAST) Steam Generators
Recovery From Initiators	Regain DHR capability... DHR can be regained by using the redundant SCS train. If the redundant SC pump is not functional, DHR can be regained using the CS pump. If the CS pump is not functional, DHR can be established by reflux boiling, or feed and bleed using SI pumps and opening the SDS valves.

TABLE 2.4-3

TERMINATION POINT 9

Plant Configuration	Mode 6 Refueling pool empty IRWST Full
Initiators	Group 1-IV LOCA
Current Applicable Technical Specifications	LCO 3.9.5 Two SCS trains operable. One SCS train operating.
New Technical Specification Requirements	Two SI pumps operable.
New Procedural Requirements	None.
Alternative Support Equipment/Systems	One CS pump available.
Recovery From Initiators	Regain DHR capability... DHR can be regained using the redundant SCS train. If the SCS pump is not functional, DHR can be regained using the CS pump and SCS heat exchanger. If the CS pump is not functional, DHR can be established using feed and bleed since the IRWST is not fully drained.

TABLE 2.4-3

TERMINATION POINT 10

Plant Configuration	Mode 6. Refueling pool filled. Reactor vessel head off. Upper internals in place. IRWST empty.
Initiators	Group I-IV RCS line break.
Current Applicable Technical Specifications	LCO 3.9.4 For high water level, one SCS train operable and in operation. LCO 3.9.5 For low water level, two SCS trains operable and one in operation.
New Technical Specification Requirements	Two SCS pumps operable.
New Procedural Requirements	One CS pump available.
Alternative Support Equipment/Systems	Instrumentation... Refueling Pool water level indication in addition to high and low level alarm. Pumps... Charging pumps. Boric acid make-up pumps. Tanks... Boric Acid Storage Tank (BAST)
Recovery From Initiators	Regain DHR capability... DHR can be regained by using the redundant SCS train. If the redundant SCS pump is not functional, DHR can be established by either passive or active means as described in section 2.10.3. If DHR has been defeated due to an inter-system LOCA, DHR can be regained by matching boil-off using the charging pumps or boric acid make-up pumps injecting BAST water.

TABLE 2.4-3

TERMINATION POINT 11

Plant Configuration	Mode 6. Refueling pool filled. Reactor vessel head off. Upper internals removed. IRWST empty.
Initiators	Group I-IV RCS line break.
Current Applicable Technical Specifications	LCO 3.9.4 For high water level, one SCS train operable and in operation. LCO 3.9.5 For low water level, two SCS trains operable and one in operation.
New Technical Specification Requirements	Two SCS pumps operable.
New Procedural Requirements	One CS pump available.
Alternative Support Equipment/Systems	Instrumentation... Refueling Pool water level indication in addition to high and low level alarm. Pumps... Charging pumps. Boric acid make-up pumps. Tanks... Boric Acid Storage Tank (BAST)
Recovery From Initiators	Regain DHR capability... DHR can be regained by using the redundant SCS train. If the redundant SCS pump is not functional, DHR can be established by feed and bleed. If DHR has been defeated due to an inter-system LOCA, DHR can be regained by matching boil-off using the charging pumps or boric acid make-up pumps injecting BAST water.

2.4.3.2 System 80+ AC Power Reliability

2.4.3.2.1 Introduction

This section presents the System 80+ features that increase the availability of electrical power to supply the Class 1E buses and the capability to restore power if the electrical source is interrupted. The electrical distribution system provides redundant and diverse sources of power to the Class 1E buses during shutdown modes and reduced inventory in the reactor coolant system and provides redundancy and flexibility to insure re-energizing the Class 1E buses is possible if power is interrupted.

2.4.3.2.2 Discussion

Electrical power sources need to be carefully managed during shutdown operations to maintain a desired level of safety. This is especially true during reduced inventory operations. Reduced inventory requires heightened awareness to manage the risks of maintaining an electrical source to the Class 1E buses and of insuring an alternate source is available. The potential for a complete loss of decay heat removal due to the loss of electrical power is lowered when the electrical supply requirements for shutdown modes and reduced inventory are managed properly.

The management and operation of these electrical sources will be guided by Technical Specifications for shutdown operations and reduced inventory. Technical Specifications will be written to identify the minimum acceptable electrical distribution system alignments for operating in shutdown modes and reduced inventory. The operation of the electrical distribution system during shutdown modes and reduced inventory can be guided by procedures for normal alignments and for aligning alternate electrical sources if normal sources are interrupted.

The electrical distribution system design will provide flexibility and redundancy to allow for the management of competing priorities during shutdown. These competing priorities include the need to perform maintenance on electrical system equipment versus the need to have electrical sources available to provide power to the Class 1E buses.

The System 80+ electrical system design (see Figure 2.4-5) provides the redundancy and flexibility to insure the risks associated with shutdown modes and reduced inventory operations are lowered to acceptable levels. This is accomplished by providing two independent divisions of AC Electrical Power. Each division has two 4.16 KV Safety Buses with three sources of electrical power.

These three sources are:

1. Normal-Permanent Non-Safety Bus (PNS-Bus),
2. Alternate-Reserve Transformer and
3. Emergency-Diesel Generator.

The normal source (PNS-Bus) of power to the Safety Bus has three sources of electrical power. The three sources are: (1) Normal - The division related Unit Auxiliary Transformer (UAT) being powered from Switchyard Interface I through the Unit Main Transformer (UMT), (2) Alternate - The division related Reserve Transformer being served from Switchyard Interface II, and (3) Backup - the Combustion Turbine.

Therefore, the Class 1E Safety Buses have the potential to be fed from four different ultimate sources during shutdown modes and reduced inventory operations. These sources are:

1. Switchyard Interface I,
2. Switchyard Interface II,
3. Diesel Generator, and
4. Combustion Turbine.

This distribution system provides the shutdown management team with the flexibility to perform shutdown activities on one source of power to a division 4.16 KV Safety Bus and still maintain other diverse sources of reliable electrical power to the 4.16 KV Safety Bus.

Along with the electrical system design features, the System 80+ Technical Specifications include shutdown modes and reduced inventory operation Limiting Conditions for Operations (LCOs). The LCOs provide minimum acceptable electrical distribution alignments. Guidance is also provided by procedure to the operation staff to insure available source alignments are identified whenever shutdown activities are in progress. Additional procedural guidance is provided for aligning any available source(s) to the Safety Bus(es) if power to the bus(es) is interrupted. The procedure guidance and Technical Specifications are provided in Sections 2.1 and 2.2 of this report.

2.4.3.2.3 Conclusion

The System 80+ electrical distribution system design features provide the necessary redundancy, flexibility, and diversity to reduce the likelihood of losing decay heat removal due to a loss of electrical power. The features of the design, the Technical Specifications, and the procedure guidance allow shutdown activities within certain limits and provide operational guidance for system flexibility and assurance that a loss of the decay heat removal is extremely unlikely.

2.4.3.3 System 80+ Diesel Generator Availability

2.4.3.3.1 Introduction

The availability of the Diesel Generator and the Diesel Loading Sequencer to automatically start and load during shutdown modes of operation is one of the issues identified in NUREG-1410. The availability of the Diesel Generator instrumentation and control system to provide reliable indications and automatic trip signals for Diesel Generator protection during emergency operation (e.g. automatic start while in shutdown modes); and the availability of adequate information and indications to identify, diagnose, and correct Diesel Generator operational problems are significant to the overall maintenance of decay heat removal as presented in Section 2.4.3.1.

The Diesel Generator (DG) and Diesel Load Sequencer (DLS) provide emergency power to the Class 1E buses during shutdown modes of operation with the same methods used during power modes of operation. The Instrumentation and Control (I&C) system for the DG provides signals to start the diesel for emergency operation, applicable protective trips to prevent or limit damage to the DG at all times and DG status to the Control Room and to the local control panel. This status includes trip signals (alarms, indications and recordings), parameter indications, and alarms for abnormal parameters. Also, controls for starting, stopping, synchronizing, and loading the DG are provided in the Control Room and at the local control panel.

2.4.3.3.2 Discussion

The Diesel Generator (DG) and Diesel Load Sequencer (DLS) need to maintain a consistent means of operation independent of the plant operation condition. This ensures the operating staff is not required to learn different operating schemes and therefore reduces potential human error.

The System 80+ DG and DLS provides this simplicity of operation. The DG is the emergency source of power to the Class 1E bus. The DG and the DLS are available for operation during shutdown conditions unless undergoing maintenance. The Class 1E buses are monitored for undervoltage and degraded voltage conditions. If either condition is sensed, the DG is started and the DLS is initiated (see Figure 2.4-6 copied from CESSAR-DC Figure 7.3-5). For a loss of power to the Class 1E bus, the response of the DG and DLS is not dependent on plant operational modes. Therefore, the response of the System 80+ equipment provides the operator with the same parameters and indication to be monitored whether shutdown or operated at power. This design characteristic provides a basis for consistency in operating procedures and operator training. This eliminates the necessity of two sets of procedures dependent on plant operating conditions. It also eliminates extra required training for the operation staff. (Detail on the Emergency Diesel Generators can be found in CESSAR-DC Section 8.3.1.1.4).

The DG I&C system needs to ensure the diesel is protected during all modes of operation. However, certain protective trips need to be bypassed during emergency operation.

The System 80+ Diesel Generator protection system provides automatic trips to prevent or limit damage to the DG. The protection trips provided during emergency operation are:

1. Engine Overspeed,
2. Generator Differential Protection,
3. Low-Low Lube Oil Pressure, and
4. Generator Voltage - Controlled Overcurrent.

These trips are provided in accordance with Reg. Guide 1.9 Position 7. All other trips are bypassed during emergency operation. (See CESSAR-DC Section 8.3.1.1.4.4 for a complete description of trips bypassed during emergency operation). The protection circuitry is dependent on the initiating signal and not dependent on plant operational modes. The sensing of an undervoltage or degraded voltage condition during shutdown causes an automatic DG start, activates the protective circuitry, and bypasses all non-emergency trips. This circuitry allows for consistency in the operational response to an emergency start of the DG independent of plant operating mode.

The I&C system needs to ensure the operator is informed of the DG's operational status. This status includes parameter indications and alarms. The I&C systems need to provide controls to allow the operator to start and load the diesel to provide power to the Class 1E buses. This status and control scheme needs to be provided locally and in the control room.

The System 80+ control room is designated as the Nuplex 80+ Advanced Control Complex (ACC). The Nuplex 80+ ACC presents the operator with the information and controls necessary to complete any tasks identified in a task analysis process. The task analysis for DG operation identifies the parameters, alarms, and controls required to operate the DG from the Nuplex 80+ ACC. This identified status and control scheme is presented to the Control Room Operator on the Electrical Distribution Auxiliary Console. The presentation of this information is accomplished in accordance with a structural and hierarchial format discussed in CESSAR-DC Section 18.7.1. This formatting provides the operator with parameter displays, alarm status, alarm categorization, and alarm priority. This method of information presentation provides the Control Room Operator (CRO) with the tools necessary to monitor and/or diagnose DG status.

The System 80+ local control panels for the DG provides the Plant Equipment Operator with the same information and controls as is available to the CRO. The DG status information and control scheme on the local control panel utilizes the same Man-Machine Interface (MMI) features used in the Nuplex 80+ ACC. These features meet the System 80+ human factors standards and guidelines.

2.4.3.3.3 Conclusion

The System 80+ Diesel Generator instrumentation and control systems design features provide starting signals for the DG and DLS initiation and protective trip signals for DG emergency operation and provide DG status information to the control room and local control panel which allows the operator to operate, monitor, and diagnose DG and DLS operation. These features of the System 80+ design enhance the operator's interface with the emergency equipment and reduces the potential of human error.

2.4.4 RESOLUTION

The issue regarding vulnerability during shutdown modes to a loss of decay heat removal (DHR) is resolved for System 80+ by the design features for the Shutdown Cooling System (SCS), instrumentation and controls, electrical power distribution system, new technical specifications and procedure guidance described in this and other sections of this report. These features demonstrate the reduced potential for significant radiological releases from fuel cladding failure due to postulated events and radiological releases from a loss of DHR due to loss of SCS events. In particular, features of the SCS and electrical distribution system provide the necessary redundancy, flexibility and diversity to significantly reduce the likelihood of losing DHR.

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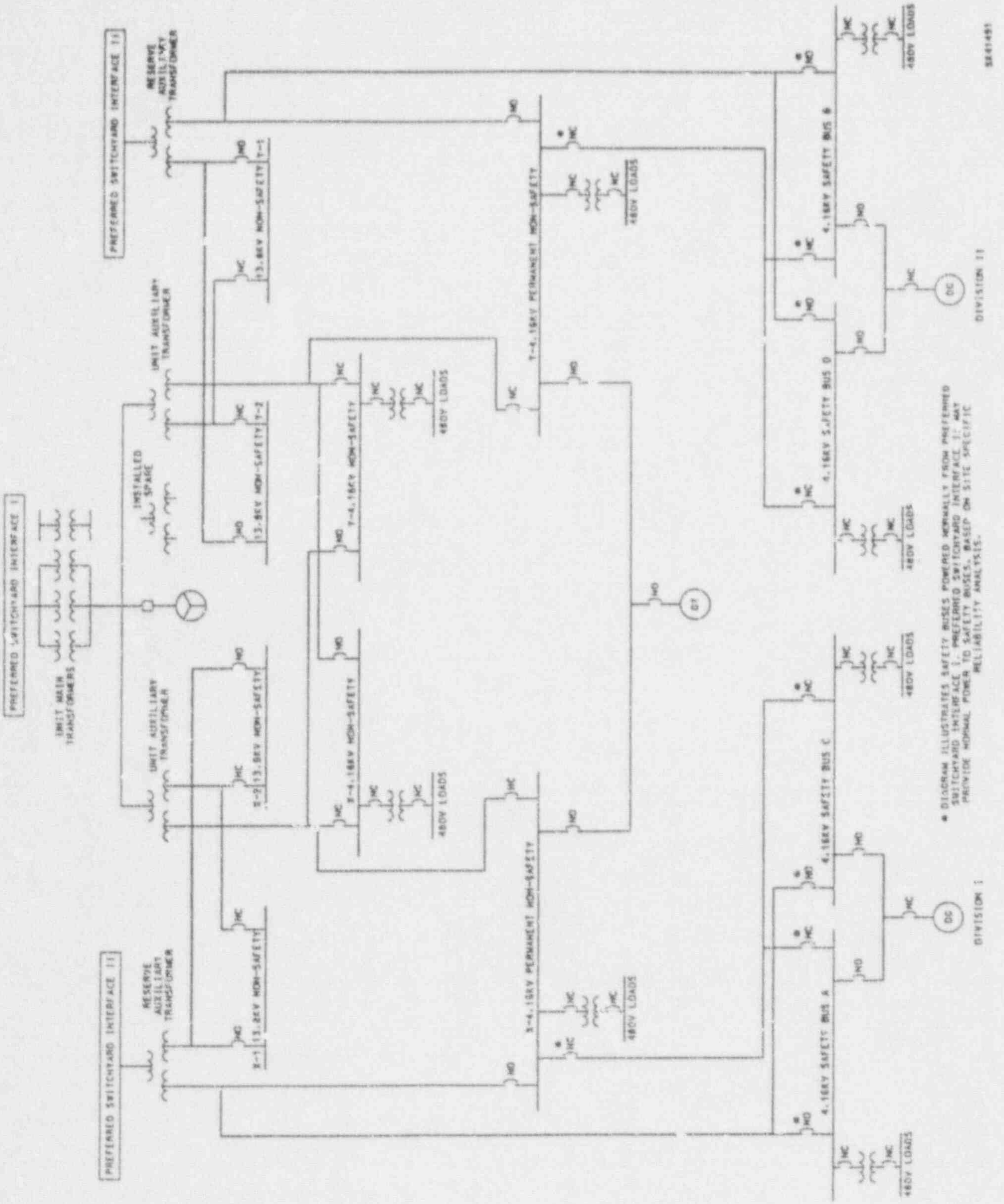

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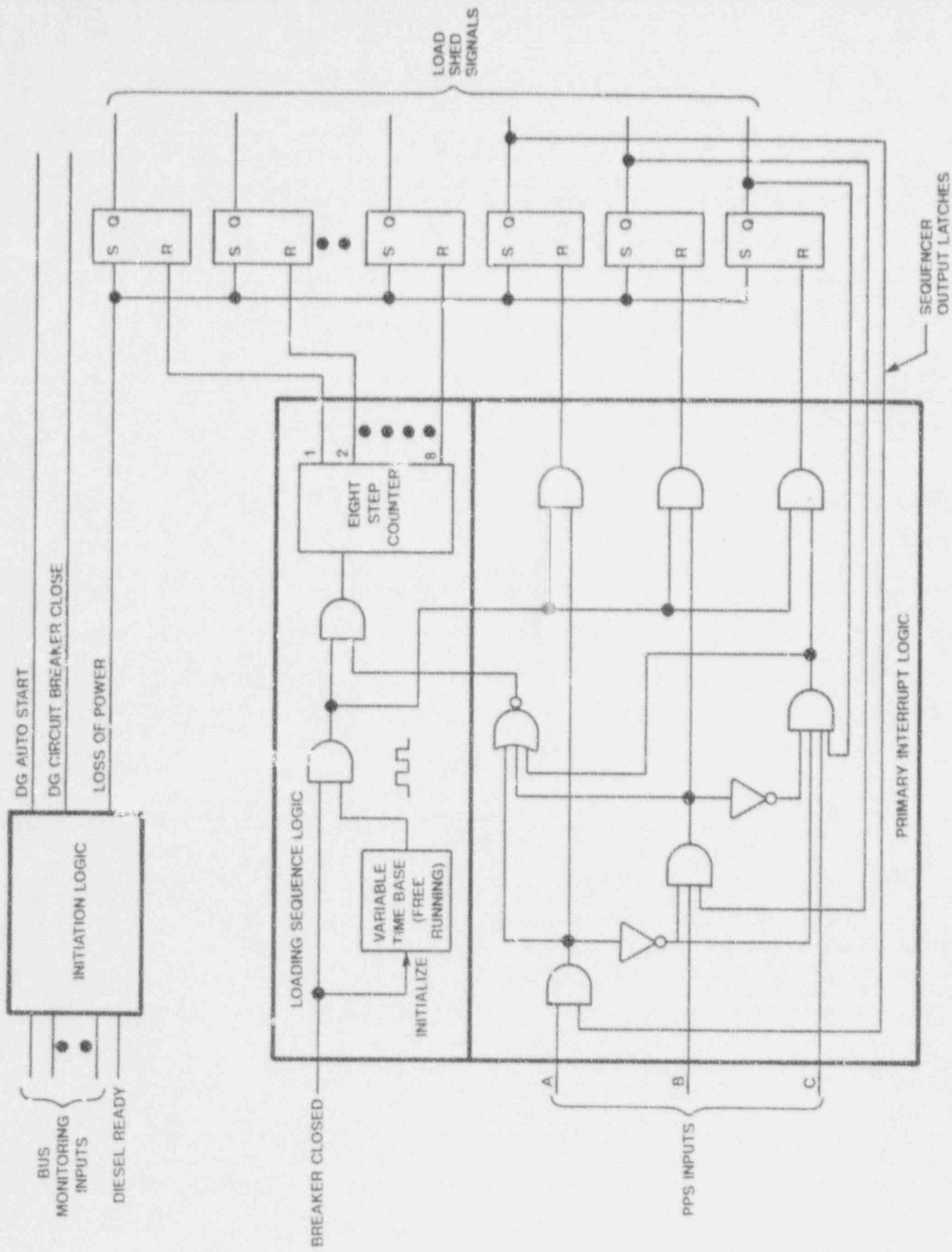
Figure

2.4-5



SYSTEM 80+™	DIESEL LOAD SEQUENCE SIMPLIFIED LOGIC DIAGRAM	Figure 2.4-6

2.5 PRIMARY/SECONDARY CONTAINMENT CAPABILITY AND SOURCE TERM

2.5.1 ISSUE

This section addresses the ability of the containment to protect the public from the consequences of a release of radiation during the time the containment is open.

This issue is related to events initiated in Mode 5 or 6 which have the potential for radiological release. The events which will be considered are the loss of decay heat removal capability initiated by either a loss of shutdown cooling or by a loss of coolant caused by either operator error or a pipe break.

Following a loss of decay heat removal not the result of a pipe break, a radiological release from an open containment can occur when the time for the core to reach saturation is less than the time to restore RCS cooling and, failing this, the additional time to evacuate, close and isolate the containment. The time for the coolant to reach saturation is a function of plant conditions at the time the event is initiated.

Time to restore includes the time to detect that decay heat removal has been lost plus the time to restore either shutdown cooling or initiate alternate means of cooling. Time to detect depends on the instrumentation available to detect that Primary System cooling has been lost. The time to restore decay heat removal depends on the available systems and procedures.

Once Primary System cooling has been lost measures must be taken to evacuate and seal the containment before the system begins to boil. The time to close and isolate the containment depends on:

Design, operation, condition and status of equipment to close penetrations, equipment hatches and personnel air-locks,

Procedures for routing material and lines through these openings,

Training of personnel

Conditions of pressure, temperature and radiation within the containment as the core uncovers.

2.5.2 ACCEPTANCE CRITERIA

The following acceptance criteria apply to the issue addressed in this section:

1. Radiological exposure of the public to any event resulting in a loss of decay heat removal shall be limited to a small fraction of the limits stated in 10CFR100.

2. Radiological exposure to the public to any event resulting in a pipe break shall be limited to the limit stated in 10CFR100.

2.5.3 DISCUSSION

2.5.3.1 Problem Formulation

At issue is the radiological exposure of the public,for events leading to a release of radiation, while the containment is open. The release will depend on the events considered, the containment integrity; e.g. access areas open, and technical specifications and procedures for closing the containment.

Conservative assumptions are made in the analysis that leads to the time in which the containment must be closed such that radiation levels for personnel inside the containment and at the site boundaries are within limits of applicable acceptance criteria. Containment closure depends on conditions of pressure and temperature within the containment following the start of the event. These will influence the time to achieve containment closure: pressure through the dose release rate outside containment, and temperature through the limits on work time within the containment.

The results are used to support recommended changes to technical specifications and/or procedures.

2.5.3.2 Containment Integrity

The integrity of the containment vessel is to ensure that the release of any radioactivity does not exceed the limits established in 10CFR100. Containment integrity is maintained in accordance with Technical Specifications (TS) in Modes 1, 2 , 3, 4 and 5, with reduced inventory, and Mode 6, with reduced inventory or core alterations.

In Modes 1, 2, 3 and 4 the containment is required to be operable per TS 3.6.1 (Containment). Integrity exists when the items defined in the Definitions Section of the Technical Specification are satisfied. Additional Technical Specifications for containment personnel locks and containment isolation valves provide specific actions and surveillance requirements to ensure containment integrity is not compromised.

In Mode 5, with the Reactor Coolant System (RCS) in reduced inventory, and Mode 6 during core alteration, or reduced inventory, containment integrity is maintained in accordance with TS 3.9.3 and 3.10.5 (Containment Penetrations).

2.5.3.2.1 Integrity Requirements

2.5.3.2.1.1 Modes 1-4

Maintaining containment integrity in Modes 1-4 is accomplished by ensuring compliance with Technical Specifications. Prior to entry into Mode 4 from Mode 5, all surveillance requirements of TS 3.6.1 (Containment), TS 3.6.2 (Containment Personnel Locks) and TS 3.6.3 (Containment Isolation Valves) are verified complete, in accordance with the applicable procedures.

2.5.3.2.1.2 Mode 5

Mode 5 is divided into two operational conditions:

1. RCS Level above reduced inventory

2. RCS Level below reduced inventory

Entry into or out of these operational conditions is controlled by procedures and Technical Specifications and require verification by the Senior Reactor Operator.

2.5.3.2.1.2.1 RCS Level Above Reduced Inventory

There are no Technical Specification requirements on containment integrity in Mode 5 when not in reduced inventory. Therefore proceeding from Mode 4 to Mode 5 does not require compliance with Technical Specifications dealing with containment integrity. It is during this mode of operation that equipment for maintenance and refueling outages, and support personnel, are moved into and out of containment through the one equipment hatch and two personnel locks. Also during this mode the surveillance testing of containment penetrations is completed and verified in accordance with site specific procedures.

2.5.3.2.1.2.2 RCS Level Below Reduced Inventory

In Mode 5 the RCS may be drained to facilitate installation of the steam generator nozzle dams as well as other maintenance. Draining the RCS to a reduced inventory level (>3 feet below the reactor flange) requires (through the Containment Penetrations Technical Specifications) monitoring for any leakage of radiation through the penetrations. To maintain containment integrity, the equipment hatch and one of the two doors on each of the personnel locks must be closed during core alterations.

2.5.3.2.1.3 Mode 6

The potential for fuel handling accidents in Mode 6 establish the requirement that containment integrity be maintained. Thus the equipment hatch and one of the two doors on each of the personnel locks must be closed during core alterations.

Entry from Mode 5 to Mode 6 may require verification of containment penetration status. Since Mode 5 has two possible operational states, containment configuration must be satisfied and verified by the Senior Reactor Operator. Entry into Mode 6 from Mode 5 reduced inventory operation requires monitoring of containment penetrations for radiation leakage. Entry into Mode 6 from Mode 5, not at reduced inventory,requires verification of penetration status.

2.5.3.2.2 System 80+ Containment Features

2.5.3.2.2.1 Building Arrangement and Ventilation

The containment openings are surrounded by the Nuclear Annex Building. Therefore, there are no direct openings to the outside environment, and all leakage and air flow from containment openings (personnel locks, equipment hatch, open penetrations) is exhausted into the Nuclear Annex.

The Nuclear Annex Ventilation System (a non-safety grade system) draws air from various points in the Nuclear Annex and exhausts to the unit vent. If high radiation levels are detected by the system radiation monitor, the exhaust flow automatically aligns to a filter train. The filter train consists of particulate filters and carbon absorbers to remove radioactive material prior to exhausting into the unit vent.

2.5.3.2.2.2 Personnel Locks

The personnel locks allow passage of the work force into and out of the containment during all modes of operation. System 80+ has two personnel locks; one at elevation 115+6 (Figure 2.5-1A), one at elevation 146.

Each personnel lock is a right circular cylinder approximately 10 feet in diameter with a door at both ends. The locks form part of the containment pressure boundary. Therefore, closure and sealing of the locks prevents leakage of radioactive material.

The design and testing of the personnel locks ensures its ability to withstand pressures in excess of the maximum pressure following containment DBA. Closure of a single door assures containment integrity.

Each of the doors contains double seals and local leakage rate testing capability to provide pressure integrity. To effect a leak tight seal, the personnel lock design uses pressure seated doors. Any leakage passes into the Nuclear Annex.

Each personnel lock is provided with limit switches on both doors that provide control room indication of door position. The doors are interlocked, to prevent simultaneous opening thus compromising containment integrity during Modes 1-4.

The normal alignment of the personnel locks during the various modes of operation is listed in Table 2.5-1.

In Mode 5 with inventory greater than the reduced level (<3 feet below the flange) both personnel locks can be only opened during an outage when it is necessary to transfer equipment into and out of containment. Closure can be initiated by dispatching personnel from the control room if containment integrity needs to be restored. Closure of both doors can be accomplished within 10 minutes.

2.5.3.2.2.3 Equipment Hatch

The containment equipment hatch provides a means for moving large equipment and components into and out of containment. On System 80+ the hatch is 22 feet in diameter and located on the 146 elevation (Figure 2.5.-1B). Normal alignment of the equipment hatch during the modes of operation is listed in Table 2.5-1.

The hatch, when closed, is part of the containment pressure boundary. Sealing is by means of a double seal which is Type B leak rate tested in accordance with 10CFR50, Appendix J, prior to entry into Mode 4.

The equipment hatch is removed following cleanup of containment atmosphere and entry into Mode 5, at full inventory. The hatch moves horizontally on a rail system. This design allows the hatch to be moved, allowing equipment to be transferred in and out of containment without interference. The rail system is designed to minimize hatch movement thus reduce closure time.

The rail system utilizes a AC powered trolley. This AC power is from a 1E bus which is normally supplied from offsite power through the Unit Auxiliary Transformers. On loss of offsite power, power can be supplied from the Reserve Transformer, Emergency Diesel Generator, or the Combustion Turbine. In the event of the failure of all power sources the trolley system is designed to be operated manually.

Before proceeding to Mode 5, at reduced inventory, or Mode 6, reduced inventory, or core alterations, the equipment hatch must be closed. With or without AC power closure time is less than one hour.

After being set in place, the hatch is bolted. Technical Specifications require that in Modes 1-4 all bolts be in place and tightened. In Mode 5, with reduced inventory, and Mode 6, Tech Specs require that [four] bolts be in place and tightened. This minimum number of bolts is sufficient to secure the hatch so that no visible gap can be seen between the seals and sealing surface.

The hatch is designed to be pressure seated. Thus any increase in pressure inside the containment will act to seal the hatch. In addition any radiation leakage will be into the Nuclear Annex.

2.5.3.2.2.4 Penetrations

There are [100] fluid system penetrations in the containment vessel. Each penetration is provided with a means of isolation by the Containment Isolation System (CESSAR-DC, Section 6.2.4).

Procedures, to meet Technical Specification surveillance requirements, are provided for maintaining proper valve alignment to ensure containment integrity, prior to entry into Mode 4, Mode 5 (at reduced inventory) or Mode 6, reduced inventory of core alterations. In Mode 5, with the RCS level greater than reduced inventory, these penetrations are leak tested in accordance with 10CFR50, Appendix J. Mis-alignment of the valves can result in leakage paths limited by size of these normally small diameter (<.75 inches) valves.

2.5.3.3 <u>Events Analyzed</u>

The radiological release is a function of the mass of coolant entering the containment either as subcooled liquid or steam. In mode 5 this release can be the result of either a loss of shutdown cooling (Section 2.4) or a LOCA (Section 5.0).

The release of radiation in Mode 5, at reduced inventory, can be the result of the events discussed in Section 2.4 leading to a loss of shutdown cooling. The most conservative assumption is events in which the system is in a reduced inventory condition resulting in the minimum time for the coolant to reach saturation. Per EPRI ALWR outage guidelines, the earliest a plant will enter Mode 5, at reduced inventory, is 50 hours after shutdown. For events leading to loss of shutdown cooling the minimum time to reach saturation was 10.5 minutes. Core uncovery was reached 55 minutes after saturation. The mass-energy releases for this event are listed in Table 2.5-2.

For the LOCAs initiated from full inventory, discussed in Section 5.3.5.1, a break in the DVI line of 0.4 ft^2 or less results in a time to reach saturation of 1.7 minutes, a time to the initiate core uncovery of 7.17 minutes and an additional time of 16 minutes for the peak clad temperature to reach 2200°F. The mass-energy releases are listed in Table 2.5-3.

Mode 6 events are all assumed to result from loss of shutdown cooling and subsequent heating of the coolant to saturation. Per the EPRI guidelines for ALWR outages the earliest a plant will start refueling is 86 hours after shutdown. Decay heat consistent with this time was assumed in calculating mass-energy releases in Mode 6 (Table 2.5-4). The time to reach saturation, assuming an initial temperature of 135°F, with this decay heat rate is 14.6 minutes with an additional 125 minutes to core uncovery.

2.5.3.4 <u>Acceptance Criteria</u>

Per Section 2.5.2 Acceptance Criteria are based on limits to radiological exposure to the public stated in 10CFR100. However, radiation exposure and containment temperature will affect the ability of utility personnel to close containment within an acceptable time. Acceptance criteria are stated to meet site boundary limits of 10CFR100 and for utility personnel, based on utility guidelines.

2.5.3.4.1 Radiation Limits

Two limits on radiation levels will be considered;limits on exposure to utility personnel working in the containment and site boundary limits for release from the containment. These limits are used to establish the time at which the containment must be closed to prevent exceeding either the off-site or in-containment acceptance limits.

2.5.3.4.1.1 Loss of Shutdown Cooling; Site Boundary Limits

The acceptance criteria in Section 2.5.2 for Loss of Shutdown Cooling refer to limits based on a fraction of the whole body dose (25 rem) and thyroid dose (300 rem) mandated in 10CFR100. The fraction selected is related to the event probability per reactor year, or the event frequency.

The fraction is taken as 10% of the integrated whole body and thyroid doses stated in 10CFR100 for two hour exposure;

Whole Body dose < .10 (25 rem) = 2.5 rem

Thyroid dose < .10 (300 rem) = 30 rem

2.5.3.4.1.2 Loss of Coolant Accidents; Site Boundary Limits

Per the acceptance criteria in Section 2.5.2 exposure to the public to any event resulting in a pipe break are the limits stated in 10CFR100;

Whole Body dose < 25 rem

Thyroid dose < 300 rem

2.5.3.4.1.3 Limits on Utility Personnel

Routine containment closure does not require special precautions outside of routine radiation work permits which provides workers with instructions on clothing required and the radiation exposure of the work areas. In addition the atmosphere both inside and outside containment is continually monitored for radiation levels. Maximum levels are established to limit exposure to workers both inside and outside containment and yet permit work to continue to mitigate the effects of any accident and close the containment.

2.5.3.4.1.3.1 Air Borne Radiation

Equipment hatch installation during an accident situation requires added precautions to protect workers from both internal and external exposure while work is being performed and the containment is being closed. Workers are protected from external contamination by being required to wear anti-contamination clothing. If airborne radiation levels in the work area reach or exceed .25 MPC workers are required to don one of the following types of breathing apparatus; forced flow respirator supplied from a breathing air system, self-contained breathing apparatus, full face cartridge respirator.

Work times for workers varies, depending on prior exposure history. Quarterly exposure of 520 MPCs have been established as the limit at which a worker will be required to exit containment. Each type of self contained breathing unit has associated with it a protection factor which reduces internal exposure, per the following relationship;

Received MPC * Hour = (Measured MPC*time)/Protection Factor

Protection factors and the equivalent measured MPCs used for determining the maximum time for utility personnel in containment are listed in Table 2.5-5.

Radiation levels are measured locally. Thus times at which exposure reaches unacceptable limits will vary with location within containment. The acceptance limit serves as an indication of the time limits based on radiation exposure.

2.5.3.4.1.3.2 Whole Body Radiation

Areas outside and inside containment are continually monitored for radiation. Maximum whole body dose of 2.5 rems, 10% the 10CFR100 limits, is permitted to allow work to continue to mitigate consequences of the accident.

2.5.3.4.2 Temperature Limits

A combination of environmental (temperature, relative humidity), and work related (type of clothing, type of work) factors influence the work time duration within containment, in addition to radiation exposure. The temperature, as radiation exposure, varies with location in containment. Thus, work times based on temperature limits will also vary. The acceptance criteria is not absolute but serves as an indicator of the work time based on average containment conditions.

Work times will also be influenced by the type of protective clothing. NUREG 1449 notes an upper limit on temperature of 160°F to avoid burning the lungs. However, a self contained breathing pack will provide air at a breathable temperature for a longer period of time.

Guidelines for the limits on the time in which work can be performed in high temperature humid environments are established in EPRI-NP4453 LRI. These "Stay Times" are based on an average, or global, wet bulb temperature, adjusted for type of clothing (work clothing without or with vapor barrier) and type of work (light, moderate or heavy). At the containment initial conditions of 100°F and 50% relative humidity, assuming no protective clothing, maximum work times for moderate work is longer than two hours. Whereas with protective clothing the time is reduced to about 60 minutes.

Acceptance limits on temperature will be assumed based on the maximum times needed to closed containment in each of the modes and events considered;

For Mode 5 loss of shutdown cooling at reduced inventory, and Mode 6 with loss of inventory due to boil-off, a minimum time needed to close the personnel hatches of 10 minutes of moderate work is assumed.

For Mode 5 LOCA, a minimum time of 60 minutes of moderate work is assumed.

2.5.3.5 Analysis

Calculations were done to predict pressure, temperature and activity within the containment for the Mode 5 and 6 events discussed above. These calculations were done in two steps.

2.5.3.5.1 Thermodynamic Conditions

A lumped parameter nodal model is used to predict pressure, temperature versus time for a given rate of mass and energy flow into the containment. The model includes provisions for varying, as a function of time, flow areas open to the ambient.

Mass and energy are conserved in the vapor space for both condensible and non-condensibles components. The vapor space model assumes:

1. Complete and instantaneous mixing of the flows,
2. Quasi-static equilibrium for temperature,
3. All constituents are uniformly distributed,
4. Dalton's law applicable to find total pressure; containment pressures is the sum of the partial pressures of the non-condensibles and vapor pressure of the steam,
5. Ideal Gas law applicable for determining partial pressures of the non-condensibles (air),
6. Steam partial pressures determined from steam tables, for both saturated and superheated conditions.

The code models a sump for the accumulation of condensed water, allowing for flashing of the water based on the temperature of the water exceeding the saturation temperature, based on containment pressure.

Heat losses to passive (walls) and active (fan-coolers) heat sinks are included as options.

The method has been validated by comparison with the more detailed, multi-node code, CONTRANS used for the detailed containment analysis shown in CESSAR-DC Chapter 6. The main limitation, as compared to CONTRANS, is in the representation of passive heat sinks by a slab geometry, rather than the more representative, multi-node model. This results in an over-prediction of heat removal resulting in lower containment temperatures. However, the present analysis assumes no passive or active heat sinks, resulting in the maximum values and rates of change of temperature and pressure with time inside the containment.

The following nominal initial conditions are assumed in the calculations;

Containment volume = 3,377,000 ft^3

Pressure = 14.7 psia

Temperature = 100°F

Relative humidity = 50%

Based on values for the open areas, the analysis predicts thermodynamic conditions inside the containment versus time for the mass flow rate and enthalpy release for the Modes 5 and 6 events (Section 2.5.3.3). The calculation starts (calculation time =0) at the time at which the coolant reaches saturation.

2.5.3.5.2 Radiation Release

The amounts of activity inside and leaving the containment as a function of time are computed using results of the analysis for the thermodynamic variables in the containment; e.g., containment steam mass, pressure, temperature, integrated mass flow into the containment and integrated steam and air flow leaving the containment. The procedure calculates, for a given RCS activity:

1. Curies present in the containment,
2. Curies input to the containment,
3. Integrated Curies into the containment,
4. Curies discharged out of the containment,
5. Integrated Curies discharged out of the containment.

The model assumes perfect mixing in the containment of the incoming RCS activity without assuming any benefit from decontamination factors (DF=1). The amount of exiting activity is based on the volumetric discharge of the air-steam mixture.

The assumption of no heat removal in the thermodynamic calculation results in high values of pressure versus time, resulting in a conservatively high mass rate of flow though the open areas.

In determining atmospheric concentrations a two hour EAB dispersion factor of 4.97×10^{-4} was used (CESSAR-DC). Atmospheric releases were calculated assuming no mitigating effect of the filters in the Annex building surrounding the containment.

In calculating radiation limits for utility personnel a maximum control room atmospheric dispersion factor of 2.0×10^{-4} was used (CESSAR-DC).

RCS specific activity for the events analyzed were taken as the Technical Specification limits of a gross activity of (100/E) microcurie/gram and a dose equivalent I-131 specific activity of 1 microcurie/gram.

2.5.3.5.3 Results

The calculation for activity, pressure and temperature starts at the time the coolant reaches saturation and continues, assuming no recovery, through core uncovery.

The time limit of when containment must be closed is a function of when acceptance criteria for radiation exposure to the public are met.

The time available for closing the containment (closure window) is the difference between the acceptance criteria time limit and the time when the event is detected.

The earliest time for detection (see Section 2.8 for detection methods), resulting in the maximum closure window, is at the initiation of the event (Figure 2.5-2). The latest time the event will be detected is assumed to be when the coolant reaches saturation. This results in the minimum closure window for closing the containment. Closure times herein are conservatively based on the minimum closure window.

The dose rates and containment temperature are functions of the open area of the equipment and personnel penetrations and how long they are open. Per Section 2.5.3.2, in Mode 5, with a full inventory, both equipment and personnel penetrations are open, while in Mode 5, with reduced inventory, and for Mode 6 reduced inventory or core alterations, one door in each of the two personnel locks must be closed but not sealed.

For Mode 5 analysis for the LOCA, assumes full inventory,thus equipment hatches (380 ft^2) and personnel locks (60 ft^2) are assumed open,to maximize release to ambient.

Mode 5, Loss of Shutdown Cooling, at reduced inventory fluid level is at the mid-plane of the hot legs. For Mode 6 the fluid level is assumed at the level of the upper flange. This analysis conservatively assumes that both personnel locks (60 ft^2) are open.

The thermodynamic and radiation analyses were done assuming that the equipment hatch and personnel lock areas remain open throughout the calculation.

Times at which the open areas must be closed, based on the exposure limits in Sections 2.5.3.4.1.1 and 2.5.3.4.1.2, are shown schematically in Figure 2.5-3:

1. For LOCA,limiting site boundary doses to; < 25 rem whole body, < 300 rem thyroid for a two hour period following start of the release.

2. For loss shutdown cooling, limiting site boundary doses to; < 2.5 rem whole body, < 30 rem thyroid for a two hour period following the release.

The time available for utility personnel to complete containment closure are based on the limits in Sections 2.5.3.4.1.3 and 2.5.3.4.2;

1. Limiting dose to utility personnel within containment of 520 MPCs,

2. Limiting utility personnel to a whole body dose < 2.5 rems,

3. Temperature limits inside containment based on minimum work time of 10 minutes of moderate work for Loss of Shutdown Cooling events and 60 minutes of moderate work for LOCA,

2.5.3.5.3.1 Mode 5: Loss-of-Shutdown Cooling at Reduced Inventory

The mass-energy release for this case is listed in Table 2.5-2 (Mode 5, Loss of Shutdown Cooling). Results are shown in Figure 2.5-4.

2.5.3.5.3.1.1 Site Boundaries

The integrated two hour doses for both whole body and tyroid exposures are below the acceptance levels;

Whole Body(rem) = .216 < 2.5   Thyroid (rem) = 4.54 < 30

Thus the minimum closure window based on protection to the public is over two hours.

2.5.3.5.3.1.2 Utility Personnel

The MPC level at which breathing protection must be used is reached almost immediately. The minimum closure window, based on the time equivalent MPC level for full face cartridge protection, is about 89 minutes. With the next level of protection (forced air) the MPC level after two hours is, Maximum MPC after two hours =15.85 < 520

The whole body rem levels after two hours,for utility personnel, are below the acceptance levels.

Whole Body Dose (rems) = .087 < 2.5

Containment temperature after about two hours is about 180°F. However at the ten minute limit needed to close the personnel locks the temperature is 109°F. This temperature is lower than the EPRI temperature and humidity (120°F, 50% RH) limit needed for 10 minutes of moderate work, providing work time of about 30 minutes in which to close the personnel hatches.

2.5.3.5.3.2 Mode 5: LOCA

The mass-energy release for this case is listed in Table 2.5-3 (Mode 5, LOCA). Results are shown in Figures 2.5-5.

2.5.3.5.3.2.1 Site Boundaries

The whole body and tyroid integrated doses after two hours are both below the acceptance limits for a LOCA;

Whole Body(rem) = 1.35 < 25 Thyroid(rem) = 97.8 < 300

The minimum closure window, based on site boundary limits is greater than two hours.

2.5.3.5.3.2.2 Utility Personnel

The lower equivalent MPC level for full face cartridge is reached almost immediately. However the maximum MPC levels with either air supplied or self-contained unit are not attained during the two hour period. Thus the minimum closure time window is greater than two hours.

Maximum MPC after 2 hours = 173.5 < 520

The rem levels for utility personnel are below the acceptance levels.

Maximum whole Body Dose after 2 hours = .54 < 2.5 rems

Containment temperature within the first 10 minutes of the LOCA rises to about 170°F and then, due to the decrease in mass flow from the break and increased flow out of containment, decreases to an equilibrium value of 130°F. Based on the EPRI guidelines minimum closure time window to close the containment would be less than the time of one hour to close the equipment hatch.

2.5.3.5.3.3 Mode 6: Refueling; Inventory Boil-Off

The mass-energy releases for this case is listed in and Table 2.5-4 (Mode 6, Boil Off of Inventory). Results are shown in Figure 2.5-6.

2.5.3.5.3.3.1 Site Boundary Limits

The two hour integrated release is below the acceptance limits for both whole body and thyroid exposures.

Whole Body(rem) = .227 < 2.5   Thyroid(rem) = 4.8 < 30

Thus the minimum closure window based on exposure to the public is in excess of two hours.

2.5.3.5.3.3.2 Utility Personnel

The MPC level at which breathing protection must be used is reached almost immediately. The minimum closure window, based on the lowest level of protection (face cartridge), is reached in about 86 minutes. The exposure limit with the next level of protection (Forced Flow) is, after two hours,

Maximum MPC after two hours = 16.3 < 520

The whole body levels for utility personnel are below the acceptance level.

Maximum whole body dose after two hours = .091 < 2.5 rems

At the 10 minute point, the time set to close the personnel hatches, containment temperature is about 110°F. The EPRI guidelines allows for 30 minutes of moderate work at this temperature.

2.5.4 RESOLUTION

At issue is release of radiation to the public during the time the containment is open in Modes 5 and 6.

Events in Mode 5 or 6 considered in which radiation may be released include loss of shutdown cooling or loss of coolant.

The time in which the containment closure must be completed is based on dose limits set by 10CFR100 and the rate of release for the events considered.

The time to close the containment depends on: design, operation, condition and status of equipment; procedures and training of personnel in closing the containment. Conditions of pressure, temperature and radiation within the containment influence the time available for utility personnel to close the containment.

2.5.4.1 Mode 5; Reduced Inventory (Loss of Shutdown Cooling)

Results of the analysis show that the integrated two hour whole body and thyroid doses are below the acceptance limits of 2.5 rem (whole body) and 30 rem (thyroid).

Radiation and temperature within the containment are within limits to provide a 10 minute closure window needed by utility personnel to close the containment.

2.5.4.2 Mode 5; Full Inventory (LOCA)

The analysis indicates that the integrated two hour whole body and thyroid doses are below the acceptance limits of 25 rem (whole body) and 300 rem (thyroid).

Internal radiation levels for utility personnel are within acceptable limits provided either air supplied or self-contained breathing units are used. Whole body dose is also within acceptance limits.

Temperature within the containment are at levels that could limit the time available for utility personnel to close the containment within one hour. The use of multiple crews would help but the temperature levels could permit only short work intervals per crew.

The following should be considered to either decrease the time needed to close and seal the equipment hatch and/or lengthen the work time within containment:

1. The use of fan coolers to decrease the maximum temperatures thus permitting longer work periods,

2. Improved design of the equipment hatch to reduce the time needed to close the containment,

3. A review of procedures and training with the objective of reducing the time needed to close the containment following a LOCA.

2.5.4.3 Mode 6: Refueling Configuration (Inventory Boil Off)

Results of the analysis show that the integrated two hour whole body and thyroid doses are below the acceptance limits of 2.5 rem (whole body) and 30 rem (thyroid).

Radiation and temperature within the containment are within the limits necessary for the 10 minutes needed by utility personnel to close the personnel hatches in the containment.

TABLE 2.5-1

CONTAINMENT OPENINGS

Opening	Area	Normal Status			
	ft^2	Modes 1-4	Mode 5 >Reduced Inventory	Mode 5 <Reduced Inventory	Mode 6
Equipment Hatch	380	Closed	Open	Closed	Closed
Personnel Locks (2)	30/Lock	Closed	Open	1 door closed per lock	1 door close per lock

TABLE 2.5-2

MASS-ENERGY RELEASE FOR MODE 5 LOSS OF SHUTDOWN COOLING

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0	0	0
.025	13.8	1162.8
1000	13.8	1162.8
3000	13.8	1162.8
3300	Time to reach core uncovery	
10,000	13.8	1162.8

TABLE 2.5-3

MASS-ENERGY RELEASE FOR MODE 5 LOCA

Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0	0	0
6.2	2128.8	267.9
100.1	1896.8	278.5
200.1	1383.5	292.3
300.1	1284.3	294.4
400.1	841.3	308.9
430	Time to reach core uncovery	
500.1	151.2	551.6
600.1	119.9	639.6
700.1	96.5	707.8
1100.2	98.4	430.4
1190	Time for Fuel to Exceed 2200 F	
1500.2	129.3	380.5
1900	134	383.4
2300	133.9	385.6
2500	133.4	386.2
3000	132	386.1
3500	131	384.1
4000	130.5	381
10,000	130.5	381

TABLE 2.5-4

MASS-ENERGY RELEASE FOR MODE 6 INVENTORY BOIL-OFF

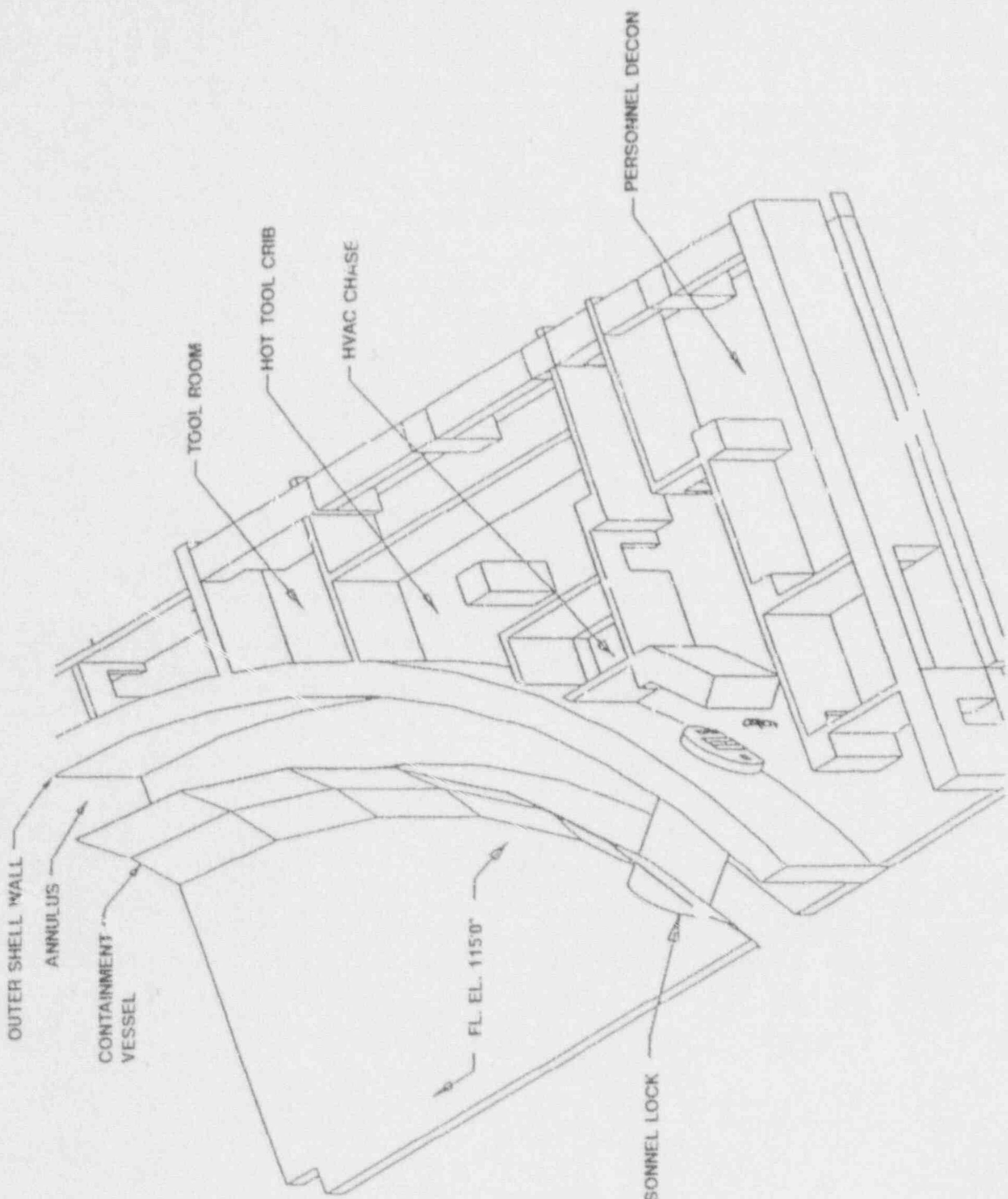
Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0	0	0
1000	14.39	1150.5
4000	14.39	1150.5
6000	14.39	1150.5
7500	Time to reach core uncovery	
10,000	14.39	1150.5

TABLE 2.5-5

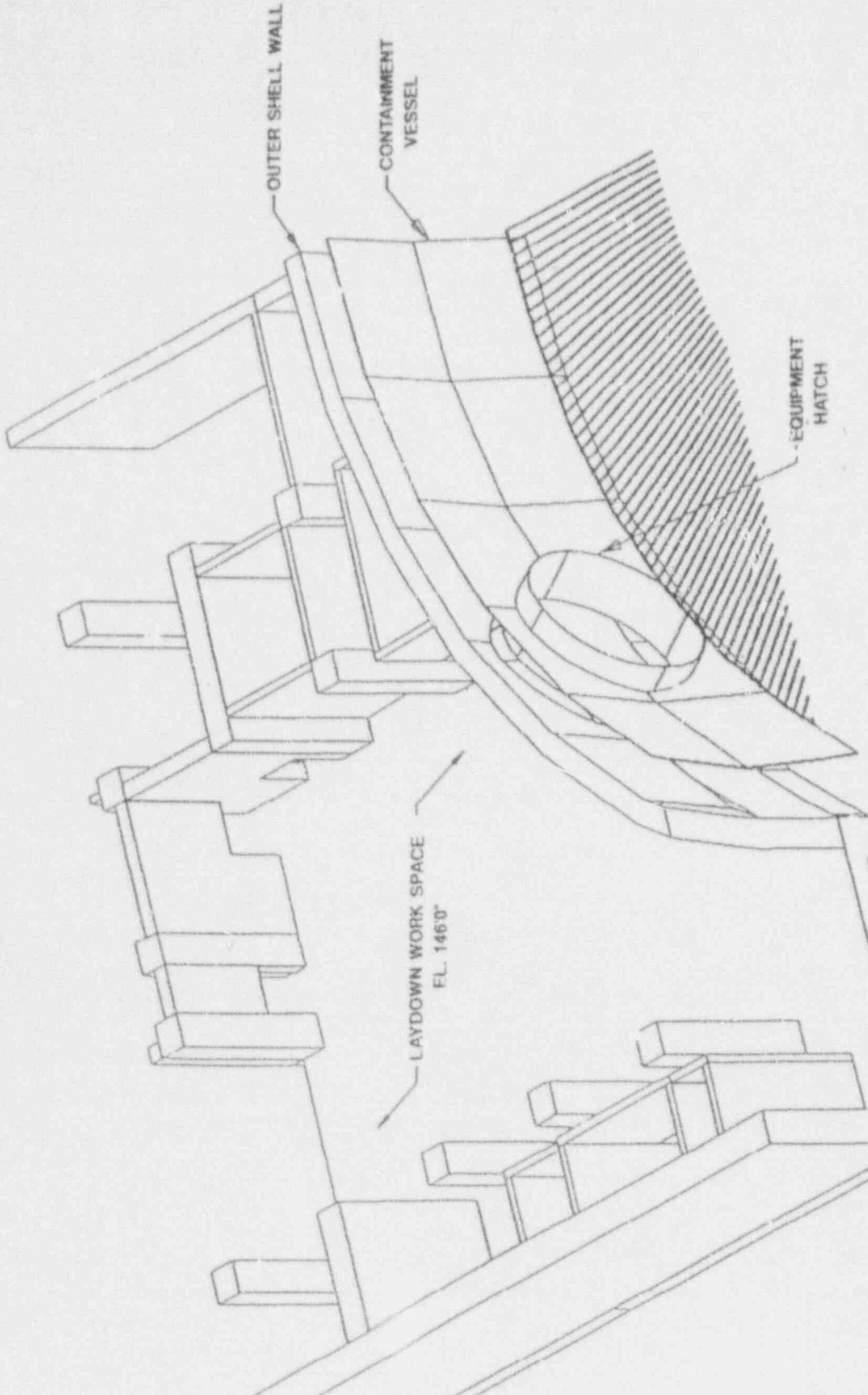
PROTECTION FACTORS AND EQUIVALENT MPC

Type of Breathing Unit	Protection Factor	Equiv. MPC*
Full Face Cartridge	50	2.6 x 10^4
Air Supplied Forced Flow	2000	1.04 x 10^6
Self-Contained Breathing	10,000	5.2 x 10^6

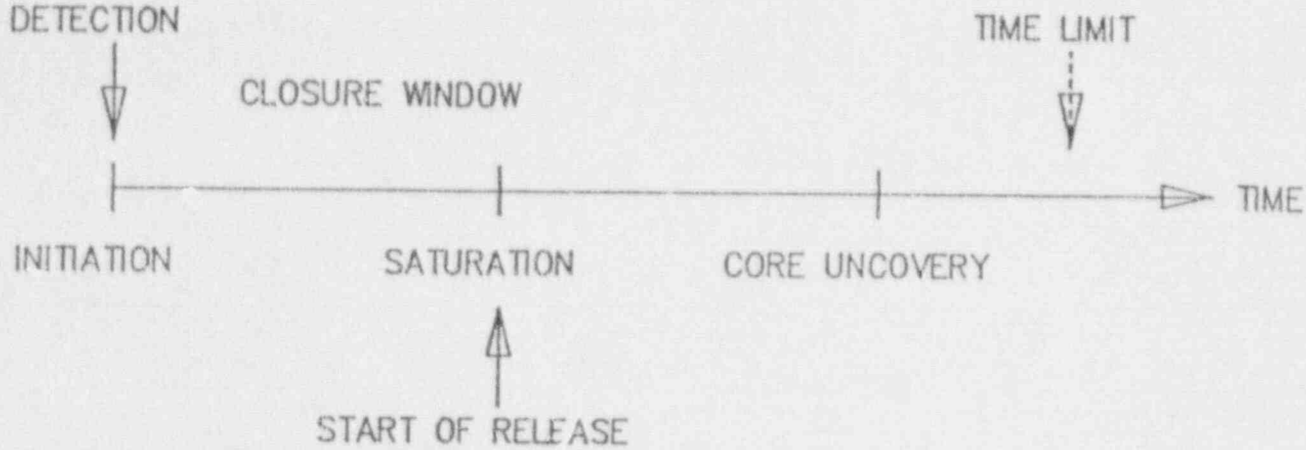
* Based exposure limit of 520 MPC



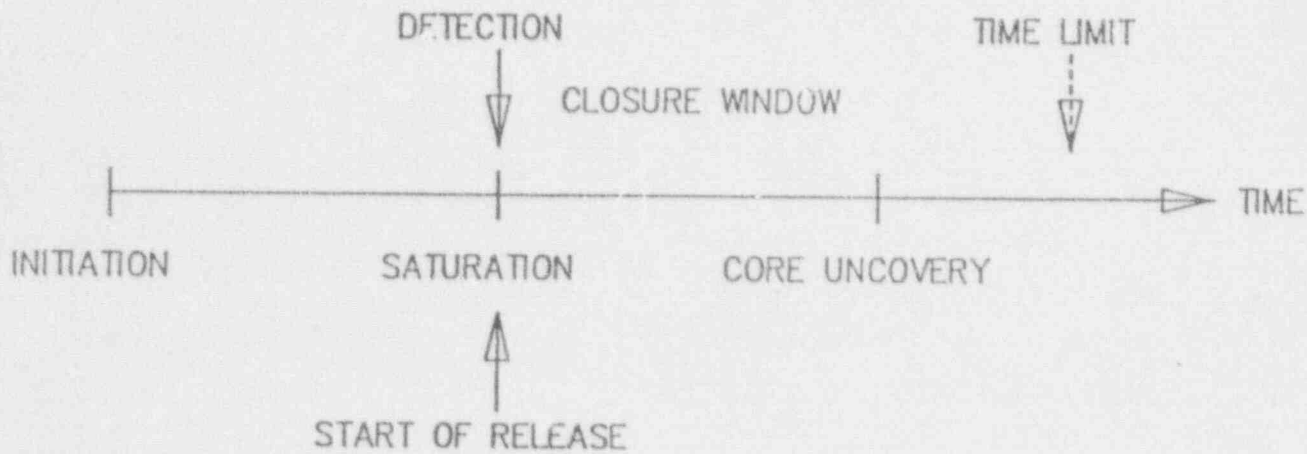
SYSTEM 80+™	PERSONNEL LOCK LEVEL 115	Figure 2.5-1A



SYSTEM 80+™	EQUIPMENT HATCH LEVEL 146	Figure 2.5-1B

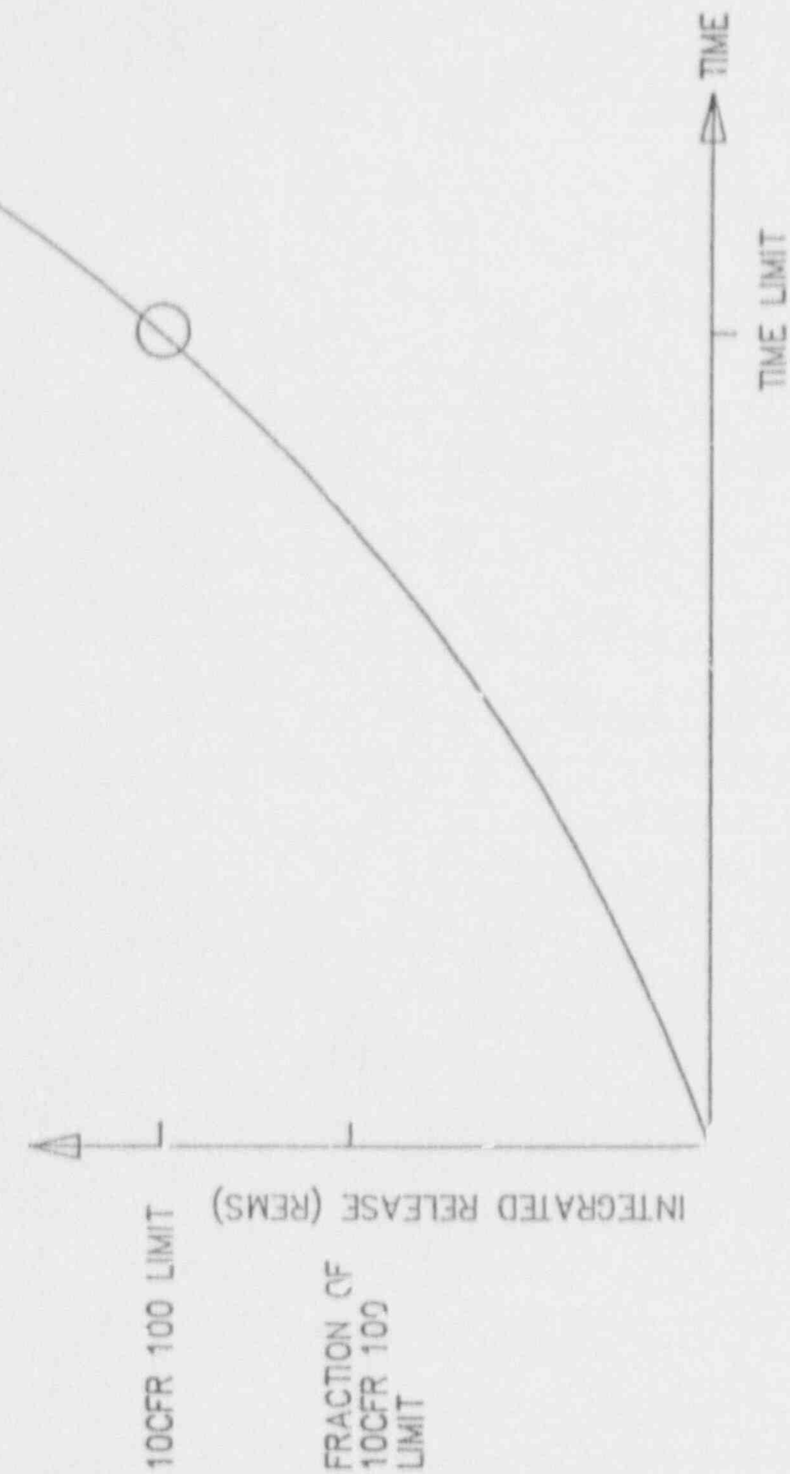


A. MAXIMUM CONTAINMENT CLOSURE WINDOW

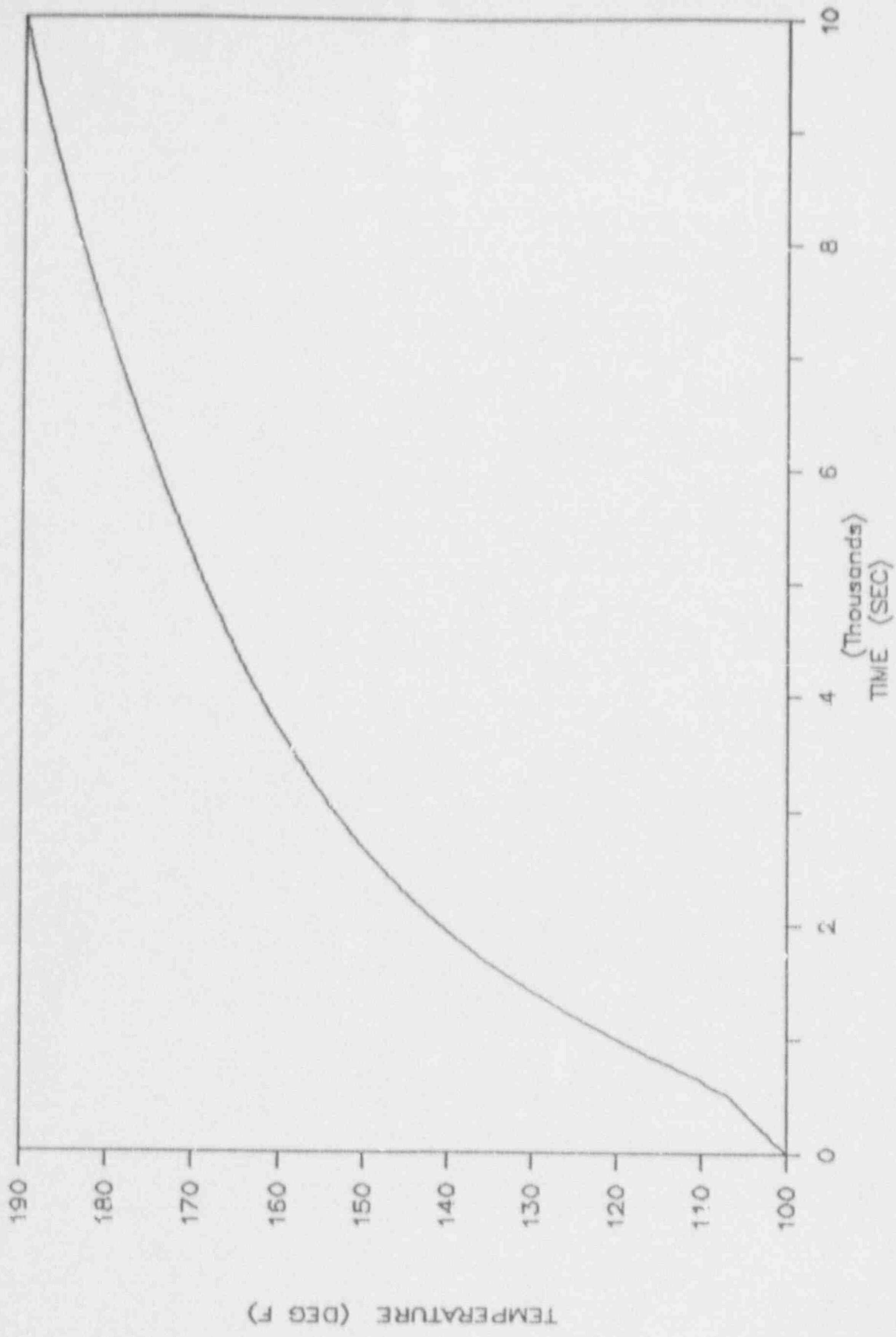


B. MINIMUM CONTAINMENT CLOSURE WINDOW

SYSTEM 80+™	EVENT TIMES FOR CONTAINMENT CLOSURE	Figure 2.5-2



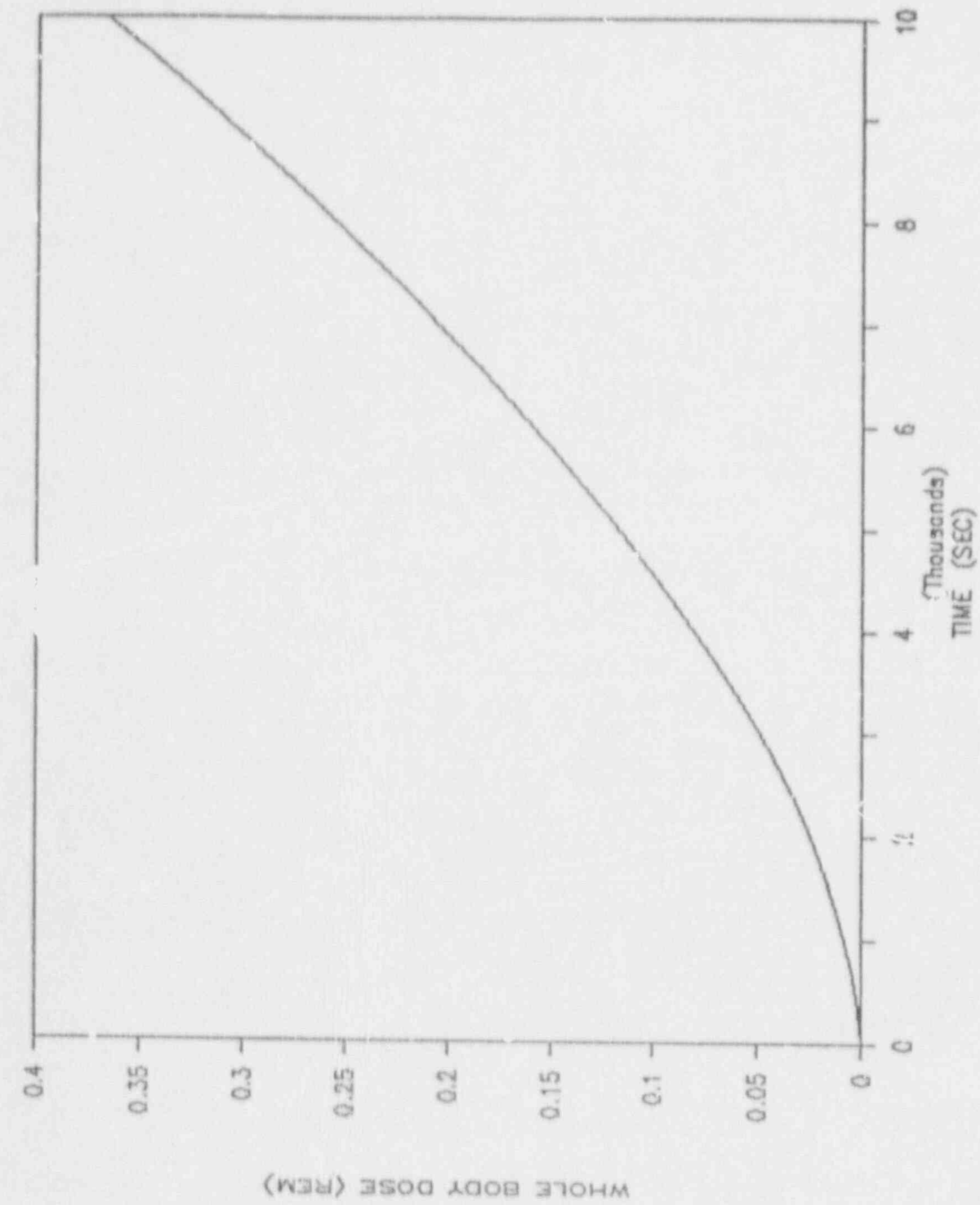
SYSTEM 80+™	LIMITS OF CONTAINMENT CLOSURE TIME	Figure 2.5-3



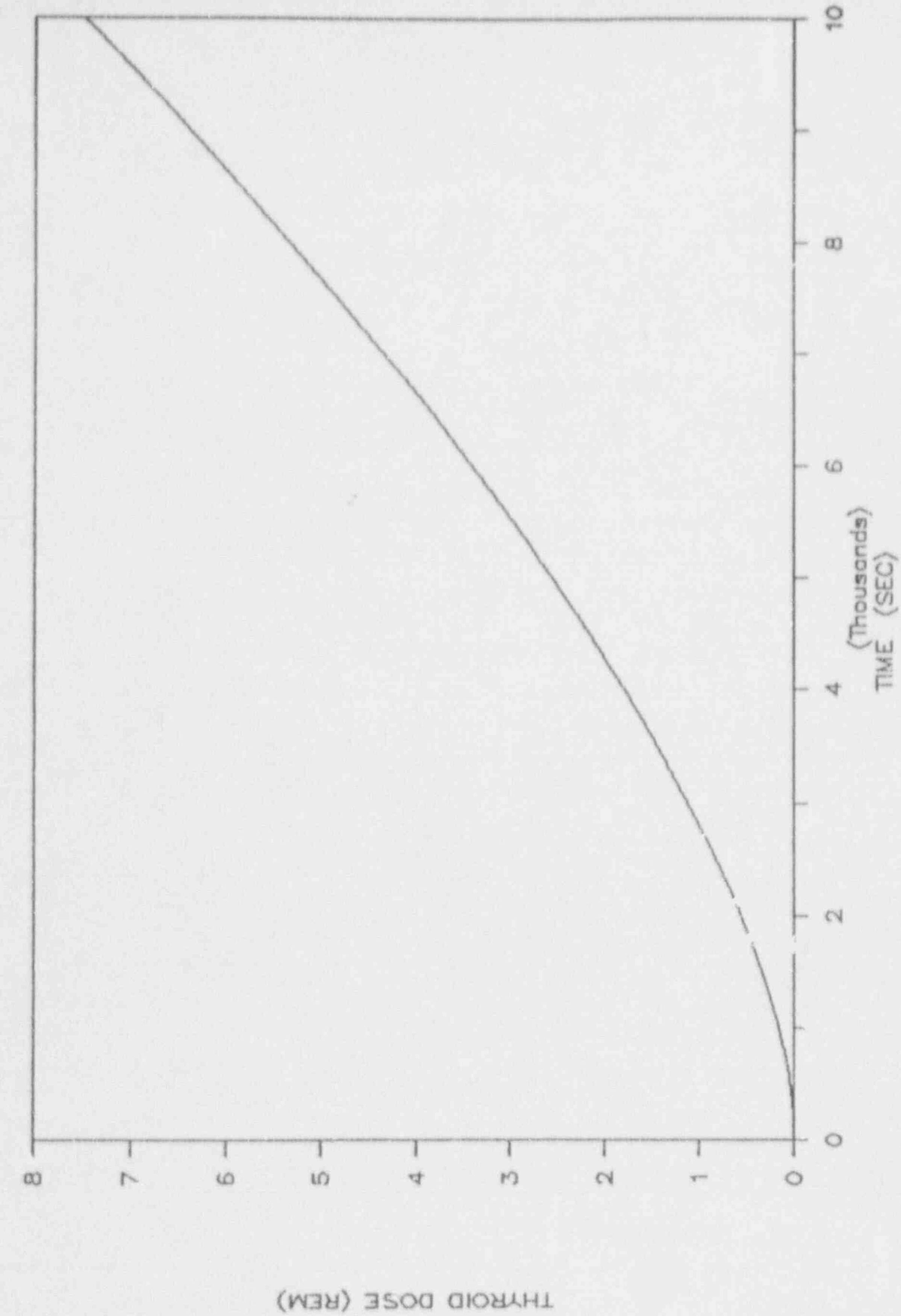
SYSTEM 80+™

MODE 5 SDC
CONTAINMENT TEMPERATURE vs TIME

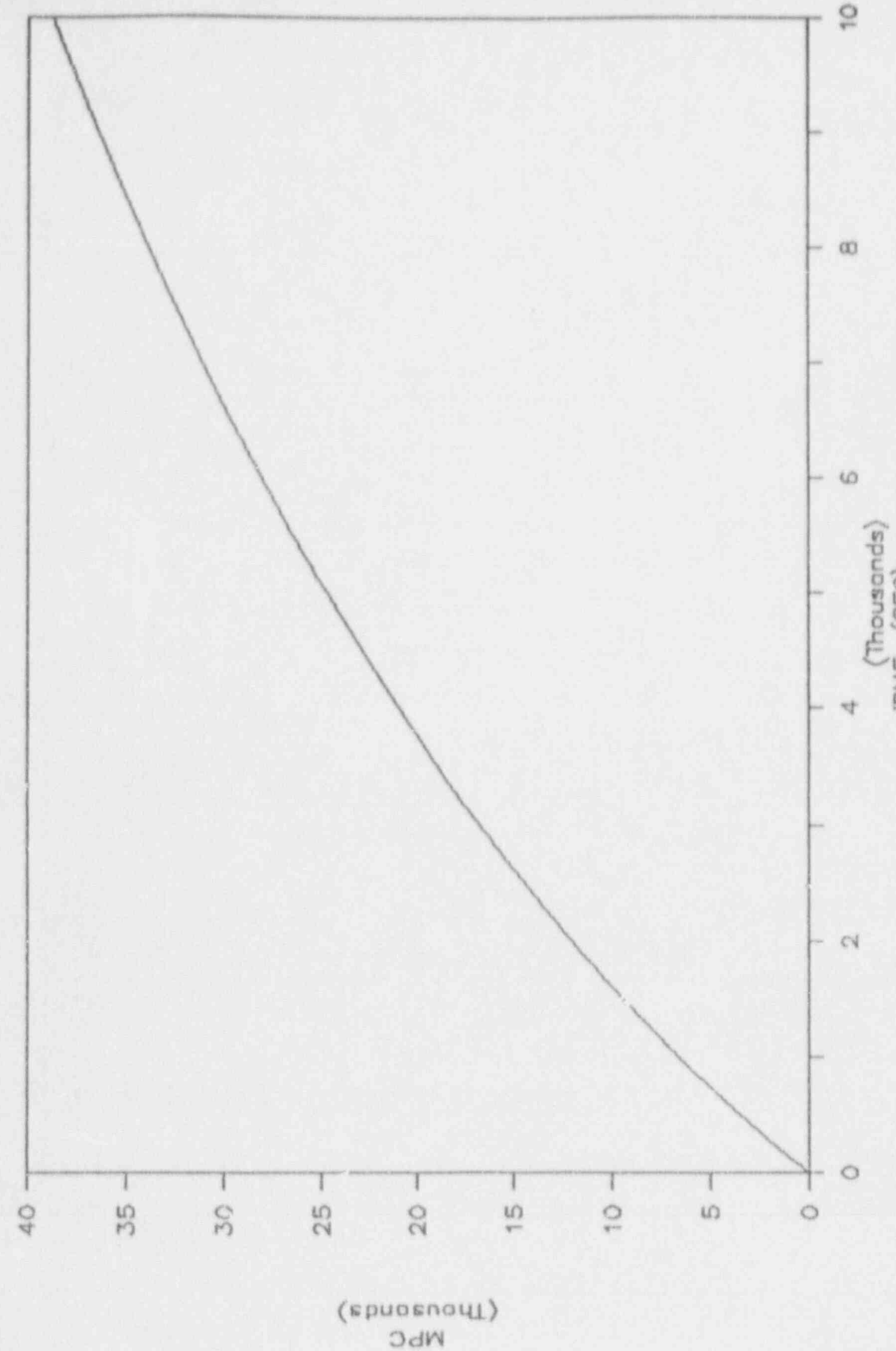
Figure 2.5-4A



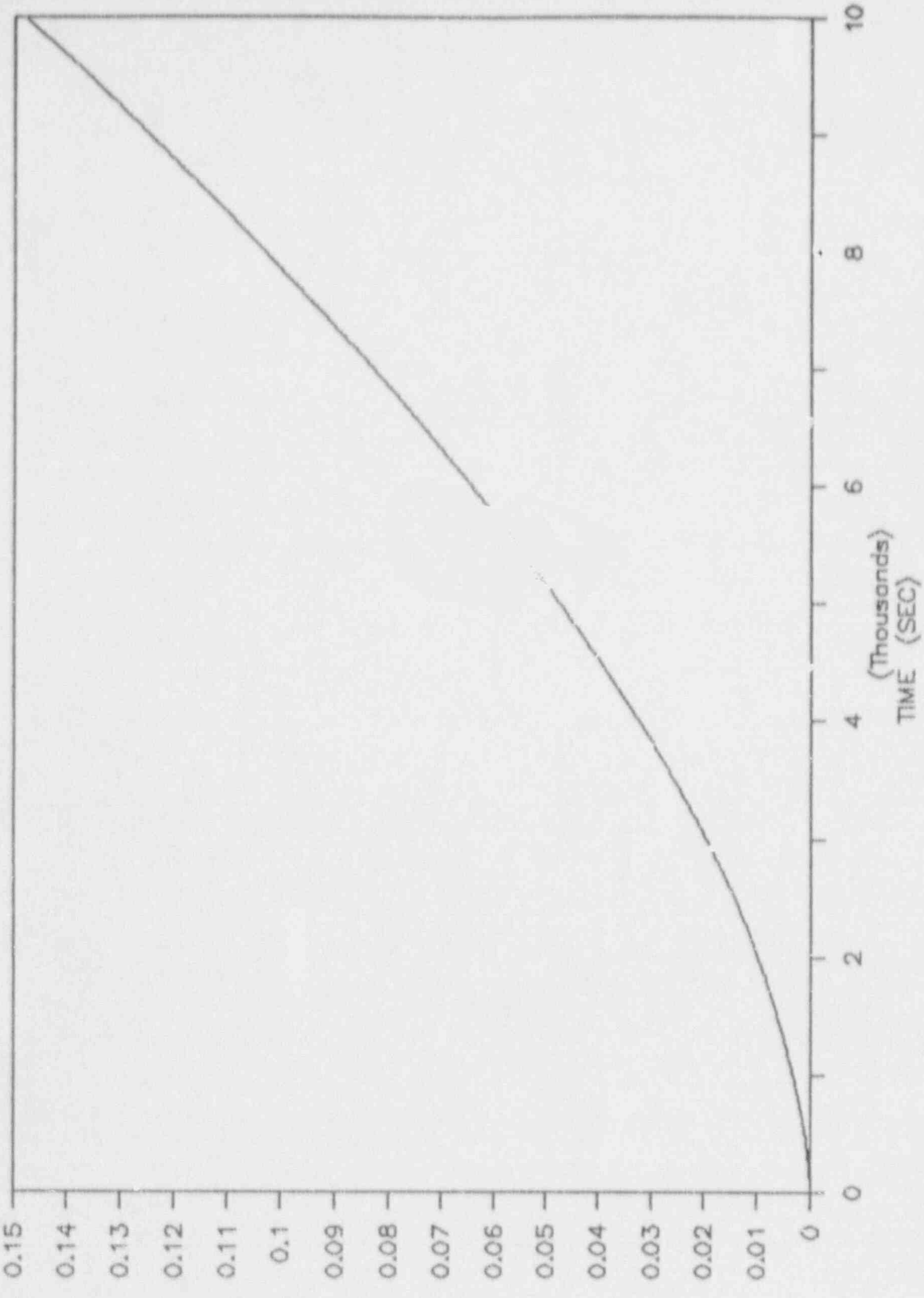
SYSTEM 80+™	MODE 5 SDC WHOLE BODY DOSE vs TIME	Figure 2.5-[illegible]9



SYSTEM 80+™	MODE 5 SDC THYROID DOSE vs TIME	Figure 2.5-4C



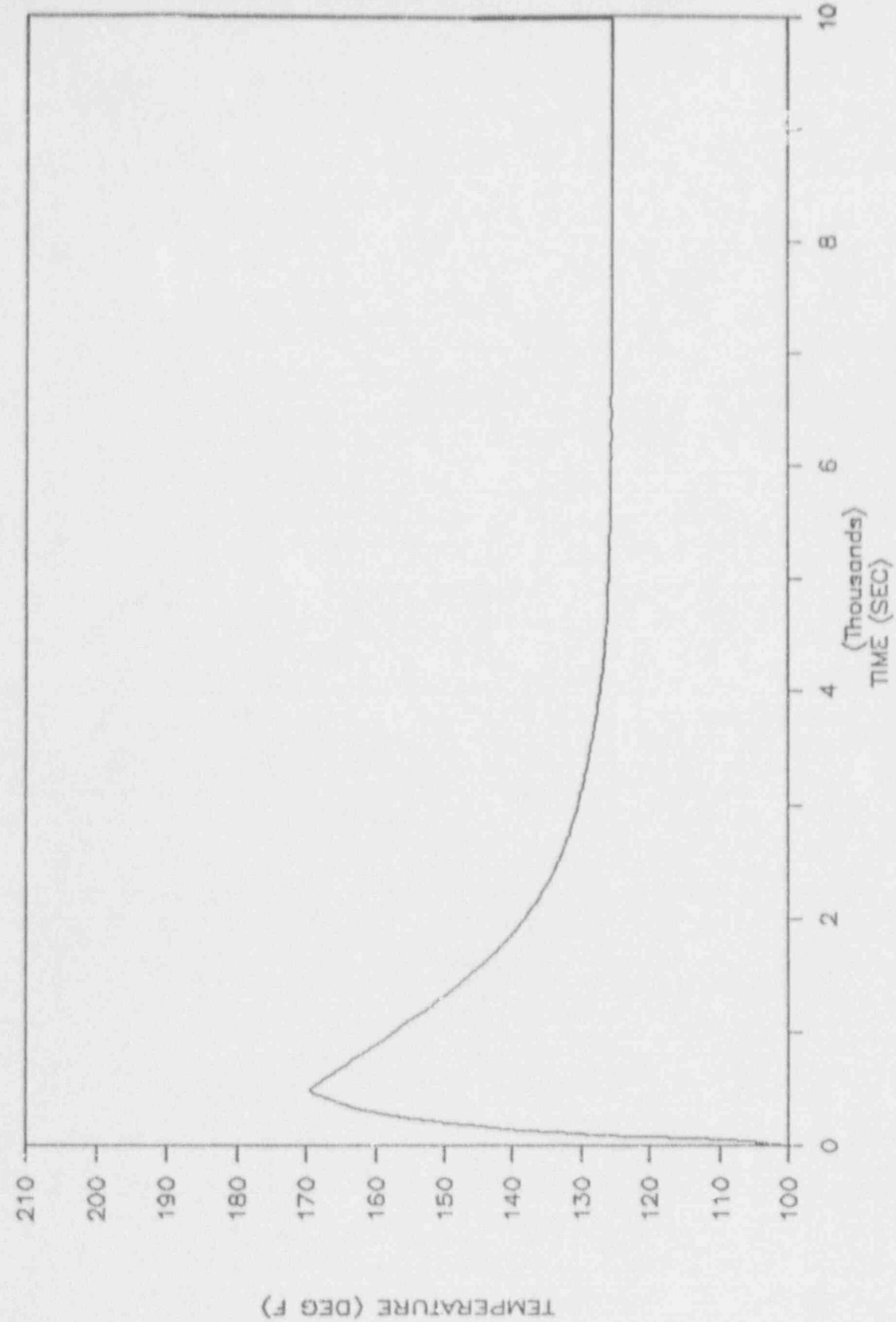
SYSTEM 80+™	MODE 5 SDC MPC vs TIME	Figure 2.5-4D



SYSTEM 80+™

MODE 5 SDC
UTILITY PERSONNEL WHOLE BODY DOSE vs TIME

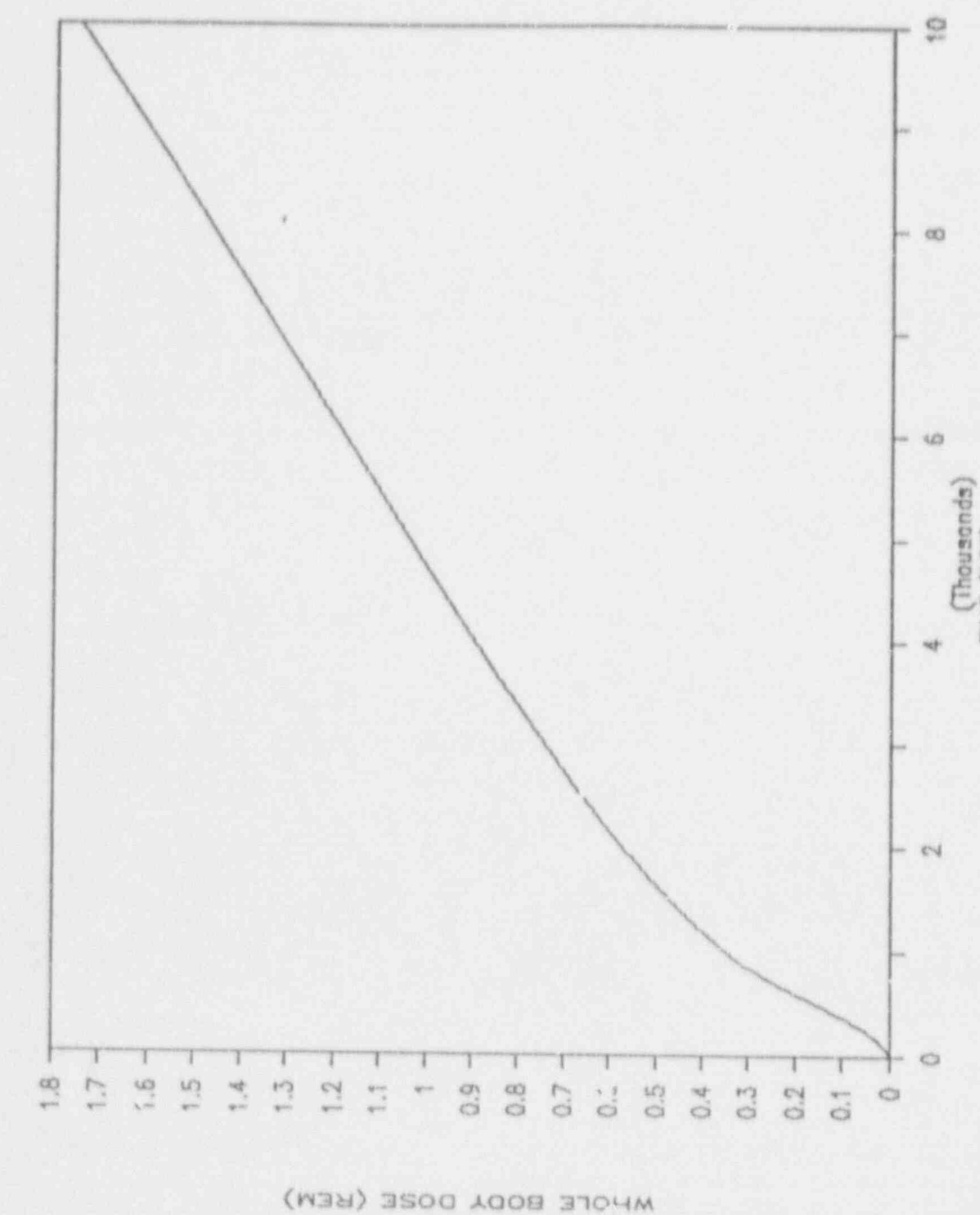
Figure 2.5-4E



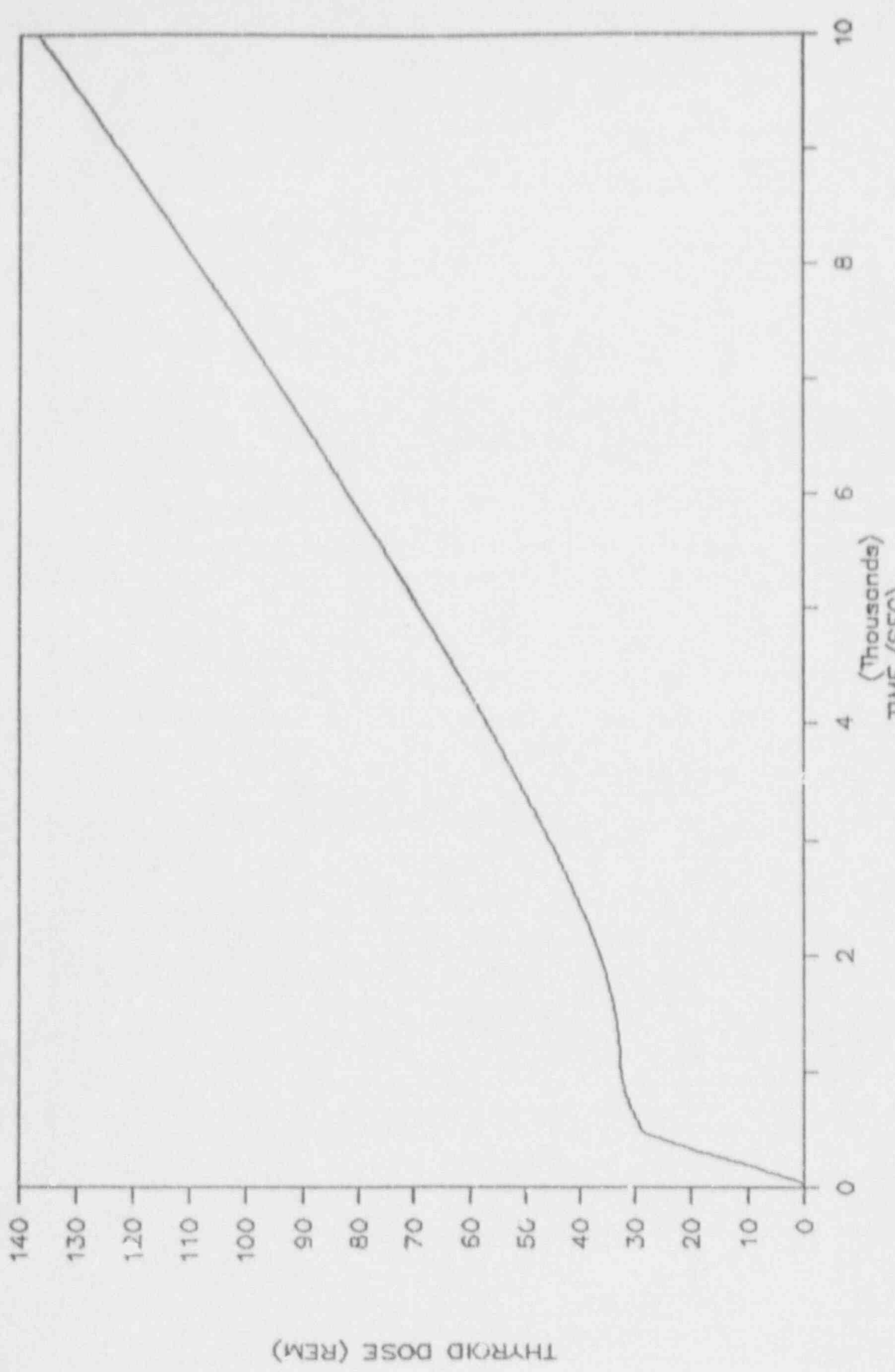
SYSTEM 80+™

MODE 5 LOCA
CONTAINMENT TEMPERATURE vs TIME

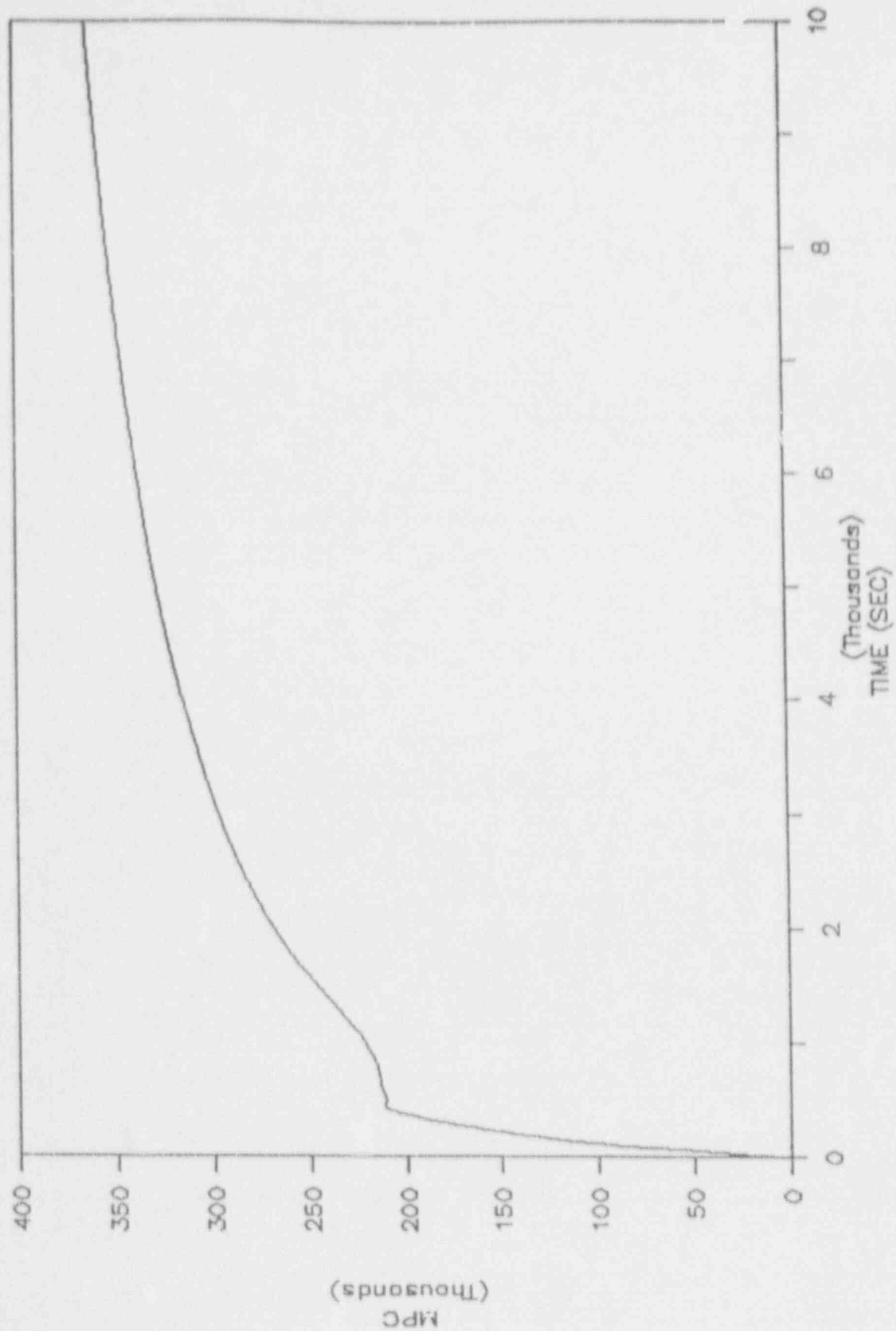
Figure 2.5-5A



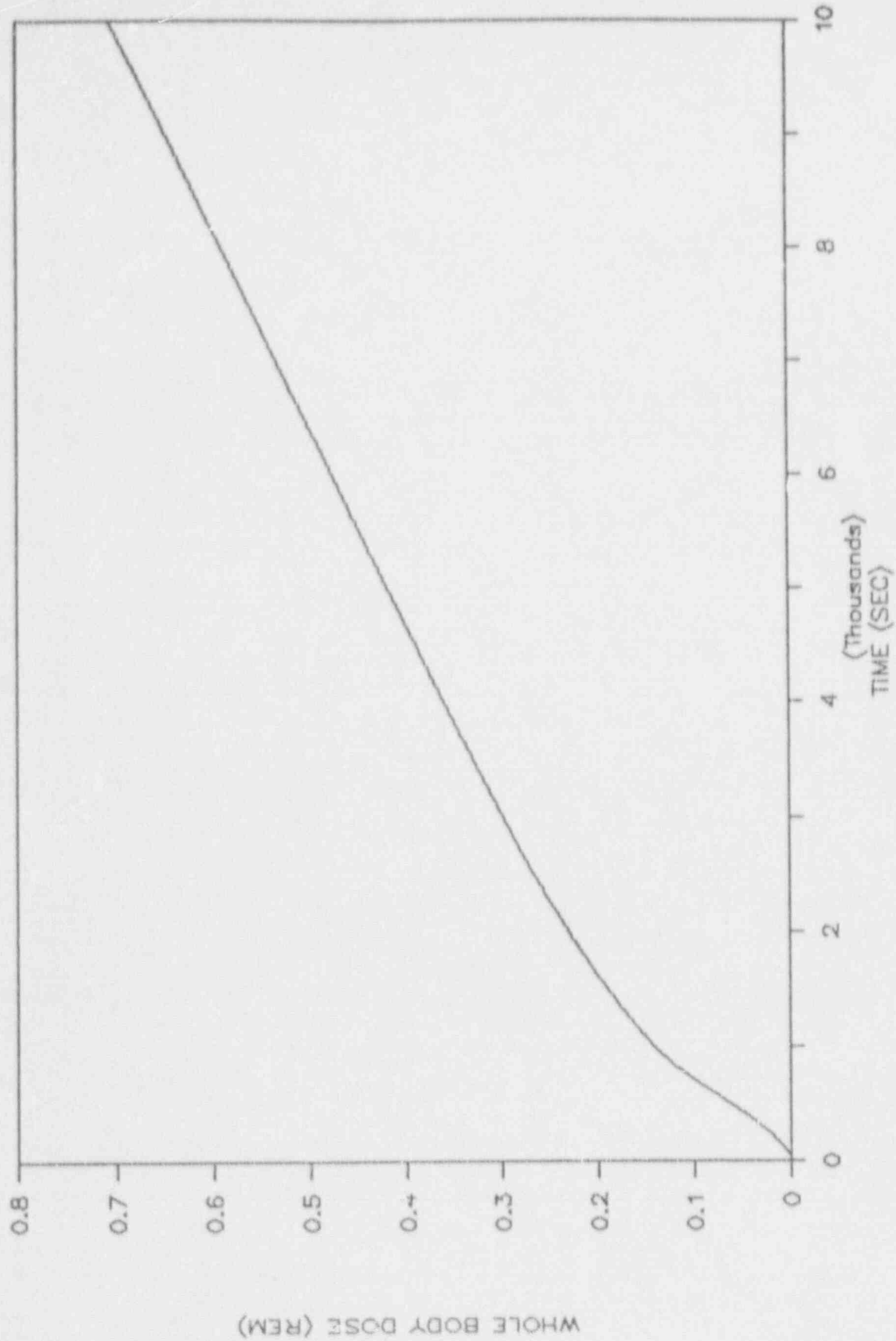
SYSTEM 80+™	MODE 5 LOCA WHOLE BODY DOSE vs TIME	Figure 2.5-5B



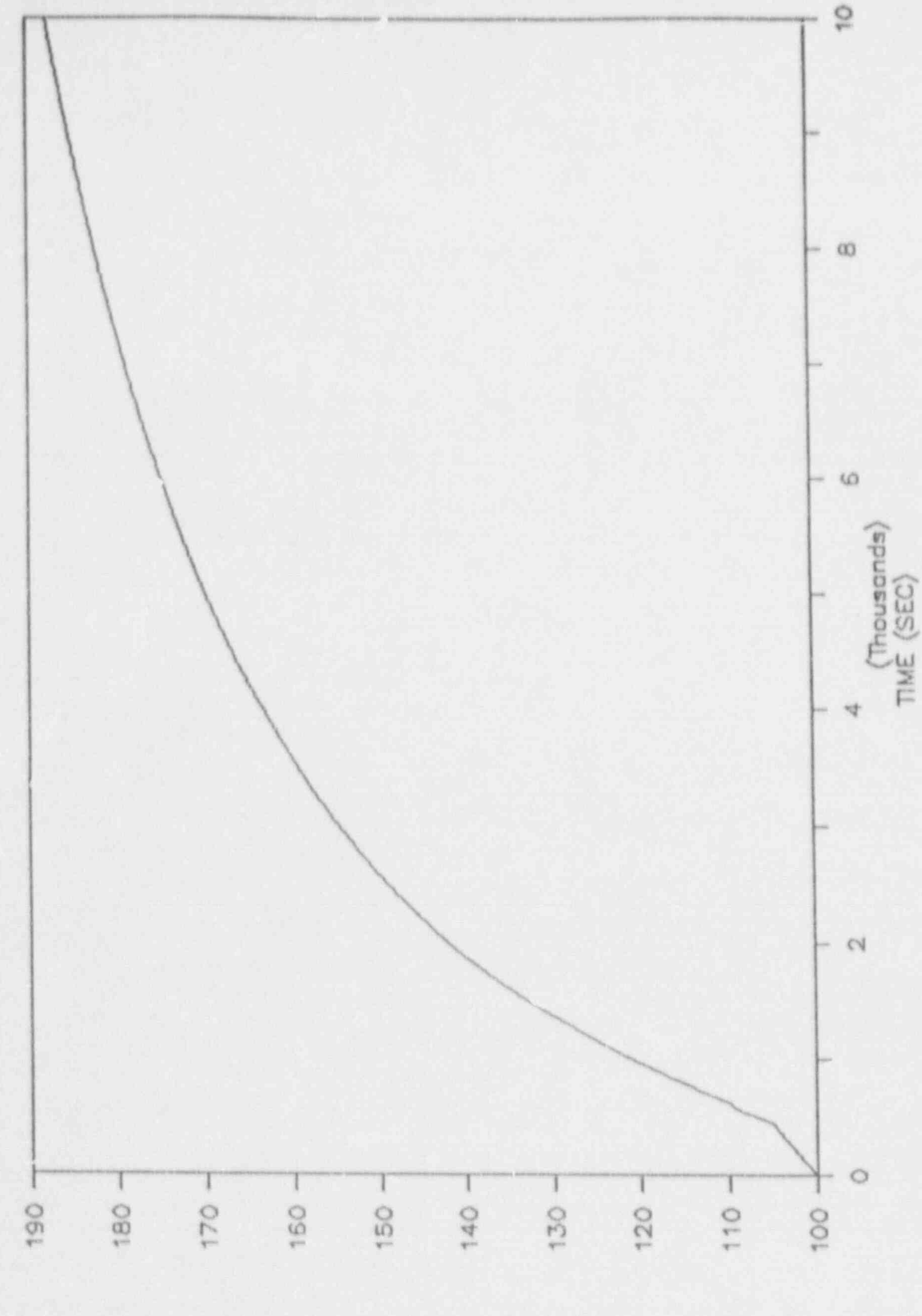
SYSTEM 80+™	MODE 5 LOCA THYROID DOSE vs TIME	Figure 2.5-5C



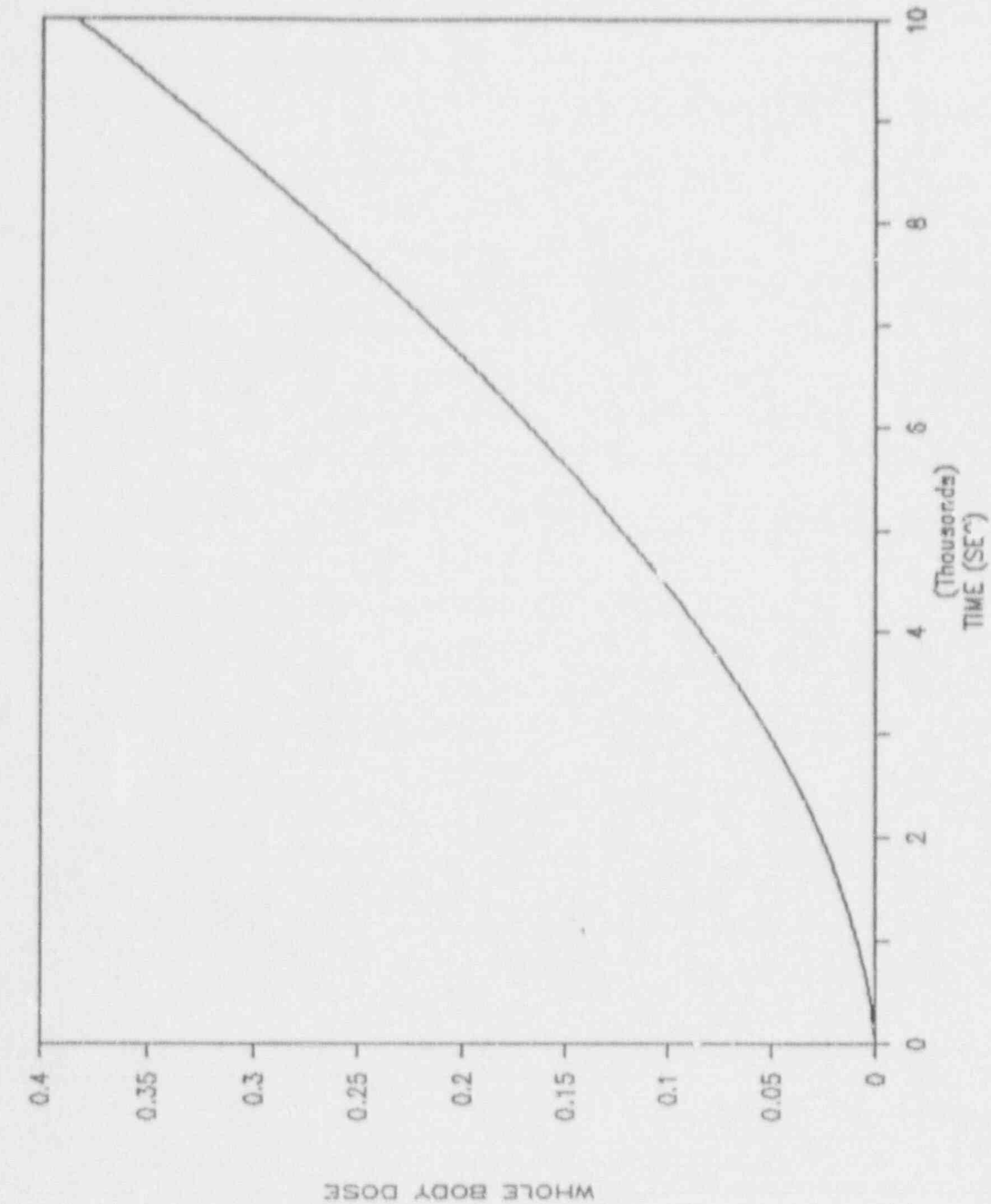
SYSTEM 80+™	MODE 5 LOCA MPC vs TIME	Figure 2.5-5D



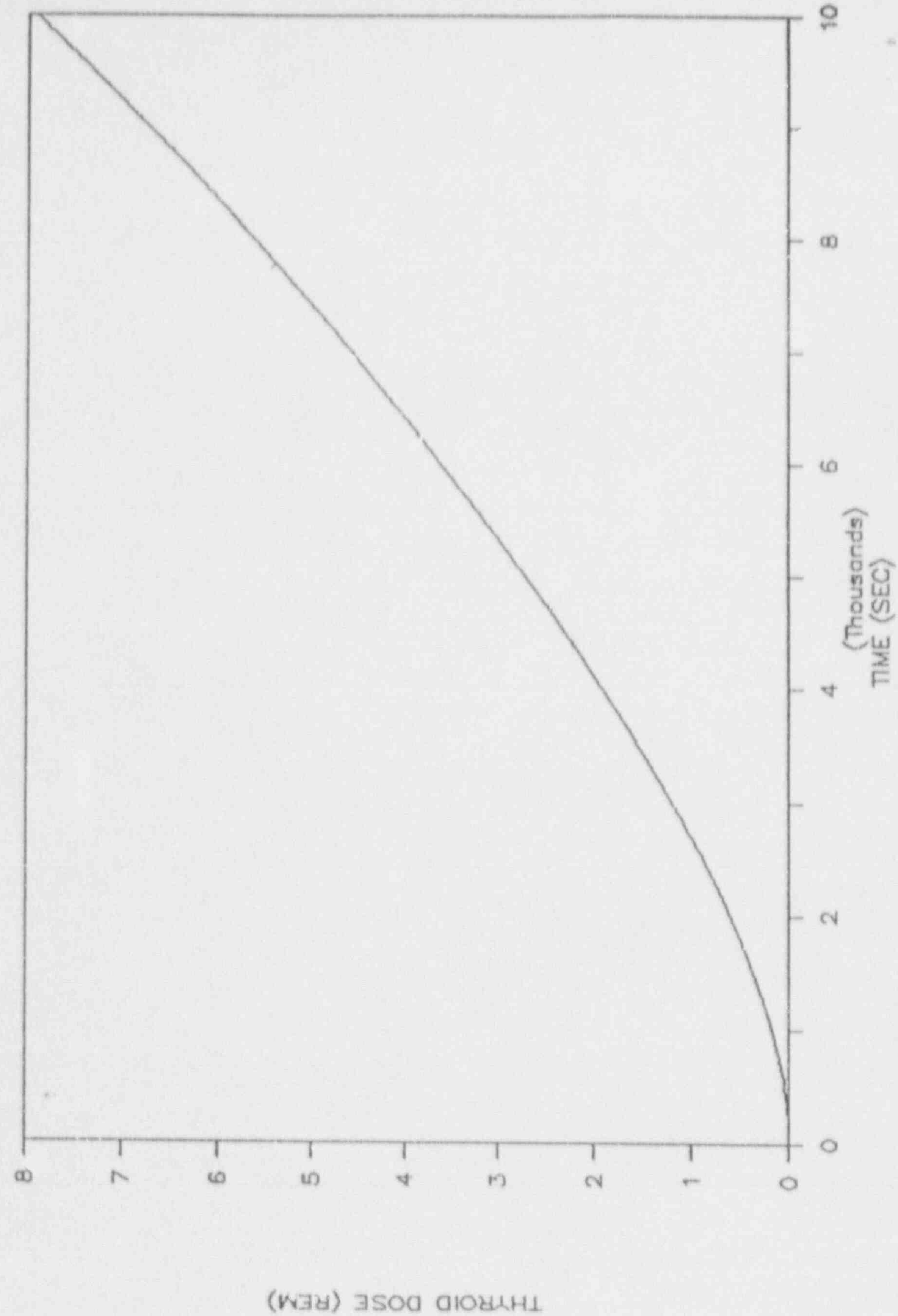
SYSTEM 80+™	MODE 5 LOCA UTILITY PERSONNEL WHOLE BODY DOSE vs TIME	Figure 2.5-5E



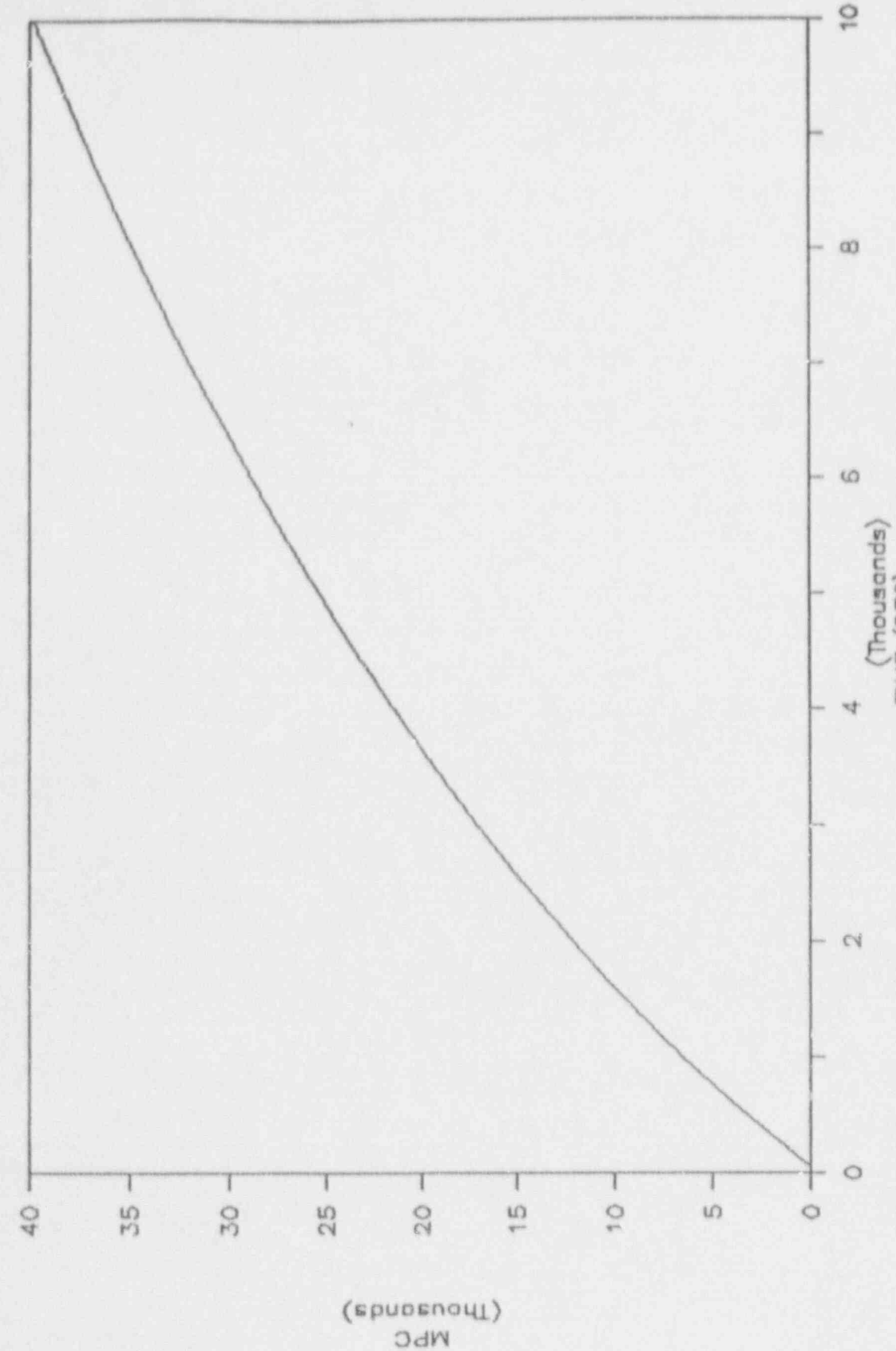
SYSTEM 80+™	MODE 6 BOIL-OFF CONTAINMENT TEMPERATURE vs TIME	Figure 2.5-6A



SYSTEM 80+™	MODE 6 BOIL-OFF WHOLE BODY DOSE vs TIME	Figure 2.5-6B



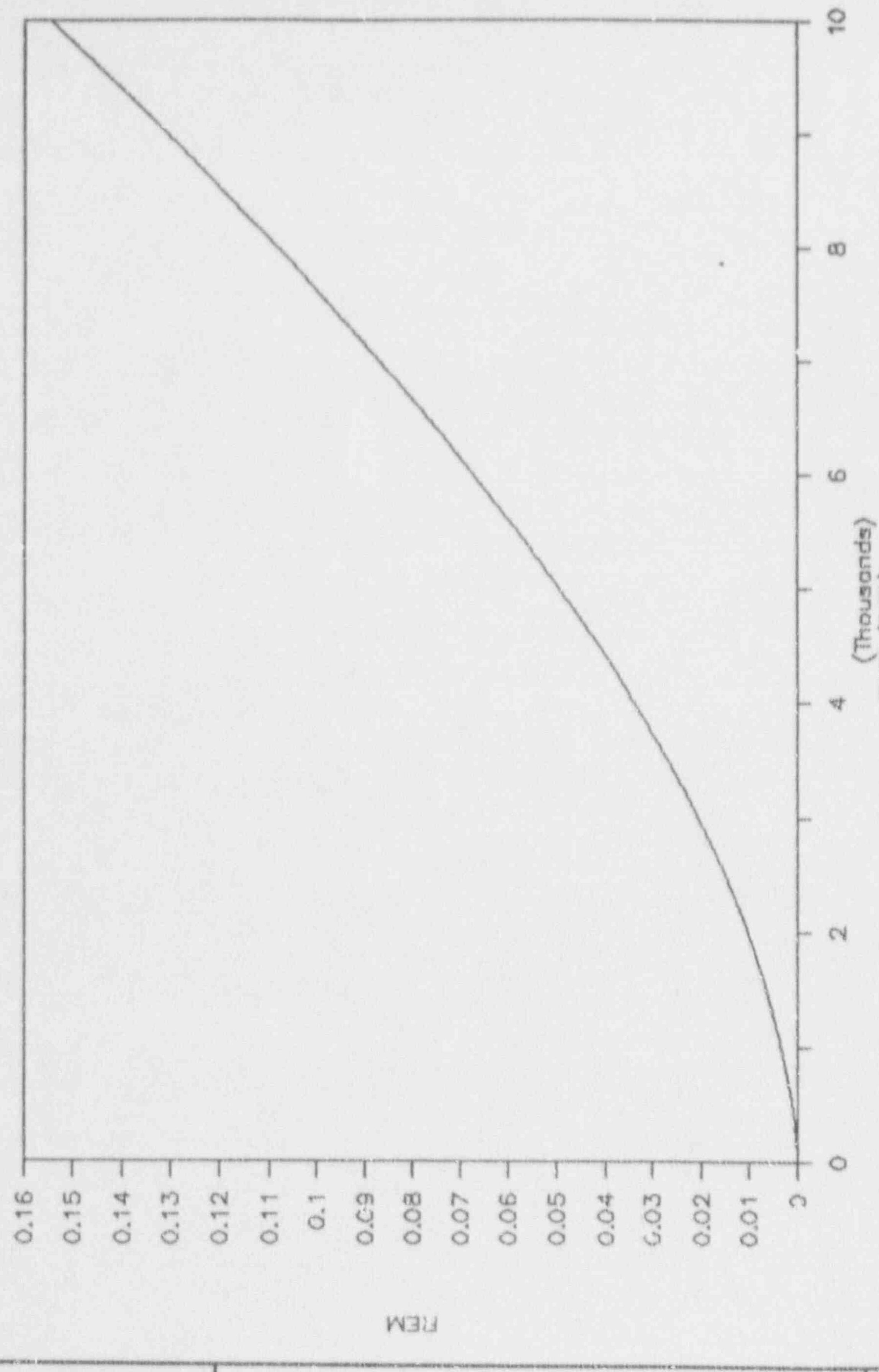
SYSTEM 80+™	MODE 6 BOIL-OFF THYROID DOSE vs TIME	Figure 2.5-6C



SYSTEM 80+™

MODE 6 BOIL-OFF
MPC vs TIME

Figure
2.5-6D



MODE 6 BOIL-OFF
UTILITY PERSONNEL WHOLE BODY DOSE vs TIME

Figure 2.5-6E

2.6 RAPID BORON DILUTION

2.6.1 ISSUE

The issues of the rapid boron dilution can be broken down into three categories as follows:

1. The introduction of deborated water into the RCS via Shutdown Cooling System (SCS), which flows into the RCS through the Direct Vessel Injection (DVI) lines, during maintenance of inline components.

2. Introduction of a water slug into the RCS during startup or refueling operations, including a specific example from NUREG-1449 (Reference 3). In that example, a loss of offsite power has occurred and the charging pumps are returned on line, powered by the Emergency Diesel Generators. If the plant were in startup mode - i.e., deboration in progress - the charging pumps could continue to operate causing a "slug" of unborated water to collect in the lower plenum of the reactor vessel. If it is then assumed that offsite power is restored and the RCP's are restarted, then a water slug of deborated water can be injected into the core.

3. A potential boron dilution resulting from inleakage from the secondary side of a steam generator during a SGTR event.

All the above issues will be addressed in the discussion and resolution sections of this report.

2.6.2 ACCEPTANCE CRITERIA

The acceptance criteria for the rapid boron dilution event should be consistent with the acceptance criteria that are necessary to meet the relevant requirements of GDC 10, 15 and 26. Specifically, these criteria are as follows:

1. Pressure in the reactor coolant and main steam systems should be maintained below the RCS P/T limits (see Figure 3.4.3-1 of Technical Specification 3.4.3) or below 110% of the design value, whichever is less.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for PWRs and CPR remains above the MCPR safety limit for BWRs based on acceptable correlations (see SRP Section 4.4).

3. An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

4. An incident of moderate frequency in combination with any single active component failure, or single operator error, shall be considered and is an event for which an estimate of the number of potential fuel failures shall be provided for radiological dose calculations. For such accidents, the number of fuel failures must be assumed for all rods for which the DNBR or CPR falls below those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model (see SRP Section 4.2), that fewer failures occur. There shall be no loss of function of any fission product barrier other than the fuel cladding.

The above criteria are the same requirements as the acceptance criteria for the Inadvertent Boron Dilution (IBD) event as stated in NUREG-0800 Section 15.4.6, Reference 6, with the exception of Item 5. This criteria states that the available operator action time be 30 minutes for an IBD event during refueling conditions and 15 minutes for startup, cold shutdown and power operation. This requirement is not applicable to a "rapid" boron dilution event.

2.6.3 DISCUSSION

2.6.3.1 Identification of Dilution Sources

A study was performed to identify possible flow paths of non-borated water which could potentially result in a water slug being injected into the RCS which subsequently finds its way into the core. The results of this study are presented in Table 2.6-1. The study concluded that considering restrictions on operations (see Section 2.1), the only source of non-borated water is the DVI lines. The maximum slug volume was determined to be 60 FT^3. The study also considered the issues identified in Section 2.6.1. The conclusion as shown in the resolutions of Table 2.6-1 is that for the System 80+ design, the scenarios defined by these issues do not result in a potential source of a non-borated water slug.

2.6.3.2 Event Analyzed

As mentioned in Section 2.6.3.1, the only credible source of an unborated water slug is the DVI lines, the volume of which is a maximum of $60ft^3$. This event was thus analyzed to determine the impact on the core and reactor coolant system. Table 2.6-2 list the assumptions and initial conditions used in the analysis.

The water slug was assumed to be injected into the reactor vessel via the DVI lines at the maximum flowrate of the 4 high pressure safety injection (HPSI) pumps. After the water slug was injected, a reactor coolant pump was assumed to start in order to instantaneously flush the water slug through the reactor vessel system and into the core.

Two cases were analyzed. The first case assumed the plant to be in Mode 5 reduced inventory with a boron concentration resulting in a K-effective of 0.99 with all rods out (ARO) of the core. This configuration results in the least amount of water with the highest boron concentration prior to the injection of the water slug. The second case likewise assumed reduced inventory, and a boron concentration associated with ARO conditions. However, Mode 3 conditions were used. This resulted in a reduced fluid density and increased boron concentration. The purpose of the second case was to bound conditions in Mode 3, 4 and 6 (without reduced inventory) by maximizing the change in reactivity resulting from a larger differential in temperature and boron levels between the DVI injection water and the RCS water. The change in the boron concentration, and RCS temperature, resulting from an unborated cold water slug being injected into ARO boron conditions was quantified in terms of reactivity units and compared with the margin to criticality available. In Modes 3, 4, and 5 this value will be equivalent to the required shutdown margin, since the reactor trip breakers will be open. This is required per the technical specification associated with the low flow trip, which requires at least two reactor coolant pumps be in operation if the reactor trip breakers are closed.

The above two cases bound the consequences in Modes 3 through 5, since reduced inventory conditions were assumed, boron concentrations much higher than would be expected to occur with 6.5% $\Delta k/k$ shutdown margin were used to conservatively calculate changes in boron concentration; in addition, saturated RCS conditions were also used, thus resulting in the minimum initial RCS fluid mass. Although the Mode 6 boron concentrations would be larger than those utilized in the analyses, the slug which reaches the core will have a higher boron concentration than that which resulted from the mode 3 analysis due to the higher initial RCS boron concentration. Since the minimum value of the boron concentration for the Mode 3 case was considerably higher than the critical boron concentration with all rods out in Mode 6, the result of the Mode 3 analysis verifies the acceptability of the Mode 6 case.

2.6.3.3 Mathematical Model

The above scenarios were modeled utilizing a Computational Fluid Dynamics (CFD) software package utilizing a 2-D model.

2.6.3.4 Results

The results of the above analysis demonstrated that with a rapid injection of an unborated water slug of 60 FT^3 into the reactor coolant system, in conjunction with the operational constraints as stated in the Technical Specification identified in section 2.6.3.2

that the maximum positive reactivity addition for both cases 1 and 2 is less than 2%. This is significantly less than the available shutdown margin of greater than or equal to 6.5%. For Mode 6 the maximum positive reactivity insertion will result in a K-effective from criticality.

2.6.3.5 Conclusion

The analysis confirmed that the Acceptance Criteria, as stated in Section 2.6.2 has been met. The core remained substantially subcritical, thus RCS pressure and DNBR Limits were not violated.

2.6.4 RESOLUTION

The design of the System 80+ plant minimizes the possibility of a Rapid Boron Dilution event. Analyses have shown that the core remains subcritical when the maximum credible water slug is "flushed" through the RCS. The concern of a slug being produced by the charging pumps following a loss of offsite power is not credible in the System 80+ design. The issue of a slug forming as a result of a SGTR event will be prohibited by the Emergency Procedure Guides.

In summary, the issue of a rapid boron dilution event for System 80+ can be considered resolved.

TABLE 2.6-1

POSSIBLE FLOW PATHS OF NON-BORATED WATER

SYSTEM		FLOW PATH		RESOLUTION
A. SAFETY INJECTION SYSTEM				
1. STANDBY	a.	RCS LEAKAGE THROUGH 1st ISOLATION CHECK VALVE (SI-217,-227,-237,-247) REF: PFS-91-044	a.	RESULTS IN A DILUTED SLUG OF WATER (ASSUMED 0 ppm BORON) WITH A VOLUME OF 15 CU. FT. PER DVI LINE (60 CU. FT. TOTAL)
	b.	LEAKAGE THROUGH SIS HOT LEG INJECTION ISOLATION VALVE (SI-522,-532) DILUTES SIS HOT LEG INJECTION LINE	b.	PRESSURE INSTRUMENTATION PROVIDED IN LINE TO DETECT LEAKAGE... OPERATOR ACTION PREVENTS INJECTION OF SLUG BY DIVERTING FLOW THROUGH SIT FILL AND DRAIN LINE
	c.	INADVERTENT REFILL OF SIS SECTIONS WITH NON-BORATED WATER POST-MAINTENANCE	c.	OWNER/OPERATOR PROCEDURES MUST [illegible]RE THAT NO NON-BORATED SOURCES OF WAT[illegible] USED TO REFILL THE SIS...(NO [illegible]ACTICAL [illegible]URCES EXIST IN THE SYS 80+ DESIGN)
2. SIS OPERATION		NONE		SIS PUMPS TAKE SUCTION FROM BORATED IRWST
B. SHUTDOWN COOLING SYSTEM				
1. STANDBY (ISOLATED)	a.	LEAKAGE OF RCS FLUID THROUGH 1st ISOLATION VALVE (SI-651,-652)	a.	- LEAKAGE IS INTO A BORATED SCS, WILL NOT RESULT IN A SLUG OF PURE WATER - OPERATOR IS REQUIRED TO WARM UP SCS AND CHECK BORON CONC. BEFORE INJECTING INTO RCS PER OPERATIONAL PROCEDURES
	b.	LEAKAGE OF COMPONENT COOLING WATER THROUGH A RUPTURED SCHX TUBE	b.	- LEAKAGE IS INTO A BORATED SCS - DILUTION WOULD BE BOUNDED BY CHECK VALVES AND NORMALLY CLOSED GATE AND GLOBE VALVES - MAXIMUM dP IS 150 PSIG, PRESSURE WOULD QUICKLY STABILIZE BEFORE SIGNIFICANT DILUTION RESULTS - APPROXIMATE DILUTION OF 1 GALLON - OPERATOR CHECKS BORON CONCENTRATION UPON SCS HEATUP, WILL DETECT DILUTION AND CORRECT BEFORE INJECTION

TABLE 2.6-1 (Continued)

POSSIBLE FLOW PATHS OF NON-BORATED WATER

SYSTEM	FLOW PATH	RESOLUTION
	c. INADVERTENT REFILL OF SCS SECTIONS WITH NON-BORATED WATER POST-MAINTENANCE	c. OWNER/OPERATOR PROCEDURES MUST REQUIRE THAT NO NON-BORATED SOURCES OF WATER ARE USED TO REFILL THE SCS...(NO PRACTICAL SOURCES EXIST IN THE SYS. 80+ DESIGN)
2. SCS OPERATION (NON-ISOLATED)	a. LEAKAGE OF CCW THROUGH RUPTURED SCHX TUBE	a. - IF CCWS PRESSURE > SCS PRESSURE, CCW INFLOW WILL MIX WITH FLOW FROM HOT LEG, BORON CONC. >0 ppm - PRESSURE FROM OPERATING SCS PUMP IS LIKELY TO CREATE A dP SUCH THAT CCW INFLOW IS PRECLUDED - LOSS OF CCW INVENTORY INTO SCS WILL EVENTUALLY BE DETECTED BY CCW SURGE TANK LOW LEVEL ALARMS - POSSIBLE VOLUME OF LEAKAGE AND RESULTING BORON CONC. IS SMALL COMPARED TO THE CESSAR-DC CHP. 15 ANALYSIS, INADVERT. BORON DILUTION EVENT - THIS EVENT IS NOT COINCIDENT WITH THE CHARGING PUMP EVENT OF CESSAR-DC CHAPTER 15, SECTION 15.4.6
	b. INJECTION OF PURE WATER THROUGH CVCS PURIFICATION LINE INTO SCS	b. ONLY SOURCE OF NON-BORATED WATER IN CVCS IS THE RMWST...DESIGN OF CVCS PREVENTS THIS SITUATION (I.E., MULTIPLE FAILURES ARE NECESSARY FOR THIS TO OCCUR)
C. REACTOR COOLANT SYSTEM		
STEAM GENERATORS	a. STEAM GENERATOR TUBE RUPTURE RESULTING IN SECONDARY FLOW TO RCS	a. PROCEDURES WILL REQUIRE THAT A POSITIVE dP EXIST BETWEEN PRIMARY AND SECONDARY SIDES OF S.G. REF: RAI 440.109
	b. LEAKAGE OF SECONDARY FLUID THROUGH RUPTURED TUBE DURING HYDROSTATIC TEST WITH FUEL IN CORE, dP OF 800 PSIG (AFTER MAJOR STEAM GENERATOR MAINTENANCE)	b. OPERATOR WILL DETECT PRESSURE CHANGE AND CORRECT BEFORE STARTING RCPs VERY UNLIKELY THAT FUEL WILL BE IN CORE DURING THIS TEST

TABLE 2.6-1 (Continued)

POSSIBLE FLOW PATHS OF NON-BORATED WATER

	SYSTEM		FLOW PATH		RESOLUTION
D.	CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)	a.	UPON STARTUP FROM MODE 6, POWER IS LOST...RCPs AND CHARGING PUMPS SHUT OFF, DIESELS POWER UP AND CHARGING PUMPS CONTINUE TO PROVIDE FLOW TO VESSEL (PURE WATER). RCPs START ONCE OFFSITE POWER IS RESTORED AND PUMP SLUG OF DILUTED WATER INTO CORE REF: NRC INFO. NOTICE 91-54	a.	CHARGING PUMPS ARE POWERED OFF AAC SOURCE (GAS TURBINE), PUMPS MUST BE MANUALLY ALIGNED TO AAC BUS BY OPERATOR, PROCEDURES DICTATE OPERATOR ACTION
		b.	UNABLE TO BORATE VCT DUE TO NITROGEN GAS BINDING OF BAMPs	b.	BASTs ARE NOT PRESSURIZED BY ANY GAS, VENTED TO GWMS..PRECLUDES GAS BINDING OF BAMPs
		c.	INJECTION OF PURE WATER INTO RCS FROM THE RMWST	c.	DESIGN OF CVCS PREVENTS THIS SITUATION (I.E., MULTIPLE FAILURES ARE NECESSARY FOR THIS TO OCCUR) HOWEVER, CONSIDERED IN THE CESSAR-DC CHAPTER 15 ANALYSIS

Table 2.6-2

Rapid Boron Dilutions Analysis-Assumptions and Initial Conditions

	Parameters	Conditions	
		Case 1	Case 2
1.	RCS Liquid Volume	Mode 5, Reduced Inventory (mid-loop)	Mode 3, Reduced Inventory (mid-loop)
2.	RCS Temperature	210°F	572°F
3.	RCS Pressure	atmospheric	1250 psia
4.	CEA Configuration	N-1	N-1
5.	RCS Boron Concentration	1% subcritical assuming ARO	1% subcritical assuming ARO
6.	Available Shutdown Margin	7/6.5% $\Delta K/K$	7/6.5% $\Delta K/K$
7.	Water Slug Volume, Boron Concentration	60 FT^3, 0 ppm	60 FT^3, 0 ppm
8.	Water Slug Injection Method	4 HPSI Pumps, Maximum Flow	4 HPSI Pumps, Maximum Flow
9.	Water Slug Temperature	40°F	40°F
10.	Single Failure	*	*

*No single failure will impact the event consequences.

2.7 FIRE PROTECTION

2.7.1 ISSUE

The risk of fire during shutdown operations is higher than when the plant is in power operation. This increase in risk is due to the presence of transient combustibles and ignition sources such as welding, grinding, and cutting operations necessary to support shutdown maintenance activities. Another risk is the reduced level of fire protection for systems such as the shutdown cooling and fuel pool cooling systems when the plant is in a shutdown mode, resulting in a higher susceptibility of failure due to fire.

2.7.2 ACCEPTANCE CRITERIA

A defense in depth philosophy shall be employed in the design of the fire protection system in order to reduce the overall shutdown risk due to fire. The elements in this defense in depth philosophy are:

1. Prevent a fire from occurring,
2. Promptly detect and suppress a fire,
3. Mitigate the consequences of a fire.

The fire protection features shall be independent from other features or systems which are routinely taken out of service during shutdown modes of operation.

2.7.3 DISCUSSION

For clarity the three elements of the defense in depth philosophy outlined above will be discussed in reverse order. Only Division 1 of a system is discussed; Division 2 is identical to Division 1.

2.7.3.1 Mitigation of Fire Consequences

DIVISIONAL SEPARATION

Shutdown Cooling System components for each division are completely separated from each other with 3-hour rated fire barriers with no communicating openings (see CESSAR-DC Figure 9.5.1-2 reproduced here as Figure 2.7-1). All penetrations within these barriers are sealed with assemblies that are qualified to maintain the integrity of the 3-hour rating. This assures that a fire involving one division of Shutdown Cooling System components will not affect the redundant division.

INTERDIVISIONAL SEPARATION

Within each division, the containment spray pump and the shutdown cooling pump can be interchanged with each other. These pumps can be used interchangeably with valve manipulations guided by approved procedures. For each division, the shutdown cooling pump is separated from the containment spray pump with 3-hour rated fire barriers and 3-hour rated fire doors for openings. The valve which allows switchover from one pump to the other is located in a separate fire area. This will enable operators to make the switchover without being exposed to a fire involving either the Containment Spray or Shutdown Cooling Systems. Finally, the containment spray pump is powered from a safety bus separate from the shutdown cooling pump. The safety buses are separated from each other with 3-hour rated fire walls. For example, the Division 1 Safety Bus A is located in Fire Area 65 and the Division 1 Safety Bus C is located in Fire Area 70 (see CESSAR-DC Figure 9.5.1-3 reproduced here as Figure 2.7-2).

This interdivisional mechanical and electrical separation assures the operating of shutdown cooling can be maintained if a fire occurs concurrent with the redundant division being out of service.

2.7.3.2 Detection and Suppression of Fires

DETECTION

Fire Area 38 contains the Division 1 containment spray pump and heat exchanger and Fire Area 41 contains the shutdown cooling pump and heat exchanger. These areas were evaluated during the recently completed System 80+ Fire Hazards Assessment. This assessment considered the fixed and transient combustible loads in these areas and the importance of the components to plant shutdown. Both areas will be equipped with full area coverage ceiling mounted ionization smoke detectors. These detectors provide an early warning alarm at the central fire alarm console in the event of a fire. Detector location and spacing is based on engineering analysis to optimize detector effectiveness. This analysis will be referenced in the System 80+ Fire Hazards Analysis to be completed later in the design process.

The detection system is highly reliable and will be kept in service at all times, even during shutdown modes of operation.

SUPPRESSION

The System 80+ Fire Hazards Assessment concludes that a fixed automatic suppression in the form of automatic sprinklers is not warranted. This is due to the minimal combustible loadings in these areas. This will be verified later by engineering analysis, which is similar to the analysis for detector layout and location, and will be referenced in the System 80+ Fire Hazards Analysis to be completed by the plant designer before operations.

Portable fire extinguishers and fixed manual fire hose stations provide manual fire fighting capability. The fire hoses are supplied from a dedicated fire protection water supply. Because of the fire barrier arrangement discussed previously, manual fire fighting activities can be accomplished without exposing either the redundant division equipment or interdivisional equipment to the effects of smoke or hot gases from a fire.

MANUAL FIRE FIGHTING

A fully trained and equipped on-site fire brigade would provide fire fighting activities for the System 80+. (See CESSAR-DC Section 9.5.1.9.3.) The brigade would be thoroughly familiar with the plant layout and will conduct sufficient fire drills and fire pre-planning to effectively control and suppress any credible fire. A documented pre-fire plan which outlines the necessary fire fighting strategies, will be prepared prior to plant start-up.

MAINTAINED LEVEL OF FIRE PROTECTION

The System 80+ fire protection system is not degraded or reduced during plant shutdown. There will be no reason to breach the fire boundaries, interrupt the detection system, or impair the fire hose (standpipe) system. All of these features are provided specifically for fire protection and are not shared with or dependent on any other systems or features.

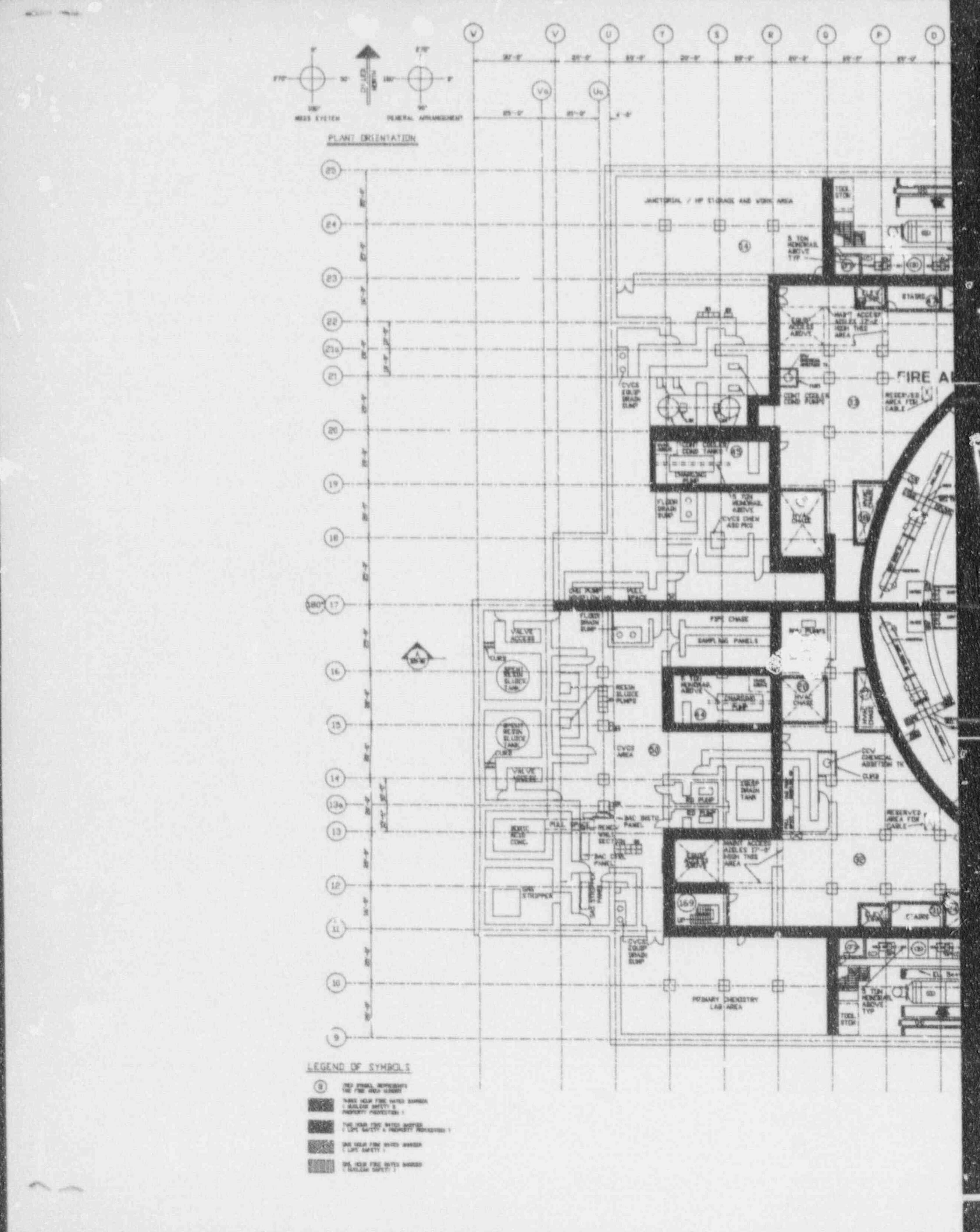
2.7.3.3 <u>Prevention of Fires</u>

Prevention is the most important element in the defense in depth philosophy. When this element is successful there is no need to employ the other elements. To facilitate the implementation of this element, work place procedures and guidelines will be established by the owner-operator based on guidance provided by the plant designer. Procedural guidance would include control of combustibles, housekeeping, and control of hotwork. The preparation of these procedures will consider those areas in which a fire during shutdown modes of operation could pose a risk. The procedures will include requirements to reduce the risk of fire ignition during shutdown. For example, the control of combustibles procedure may establish a maximum amount and configuration of combustible materials that may be left unattended in any of these areas. This will not be based solely on an arbitrary "good engineering practice" approach, but will consider the amount of combustibles necessary to result in a fire that could cause unacceptable damage. The control of hotwork and housekeeping procedures will be developed by the owner-operat and implemented so as to not place unnecessary restrictions on shutdown maintenance activities, yet will provide a high level of fire prevention.

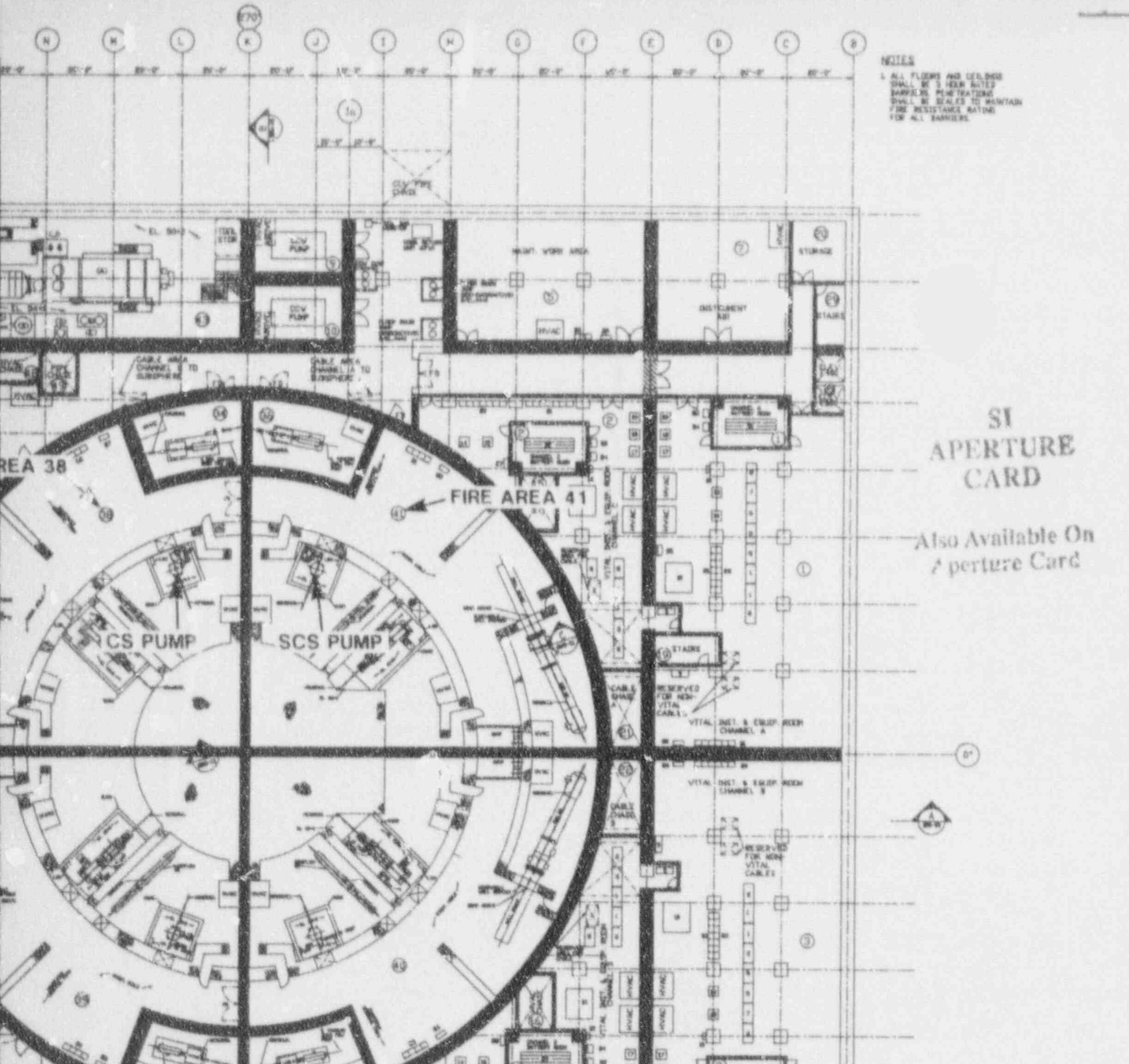
2.7.4 RESOLUTION

The fire protection features provided by the System 80+ design are consistent with the acceptance criteria outlined in Section 2.7.2. These features will significantly reduce the risk due to fire during shutdown operation to an acceptable level. The combination of fire protection features resulting from employing the defense in depth philosophy will minimize the potential for fire damage to systems required for shutdown operations.

This issue has been resolved by the design features of System 80+.



PLANT ORIENTATION
JANITORIAL / HP STORAGE AND WORK AREA
FIRE A
PIPE CHASE
SAMPLING PANELS
VALVE ACCESS
CVCS AREA
GAS STRIPPER
PRIMARY CHEMISTRY LAB AREA
LEGEND OF SYMBOLS

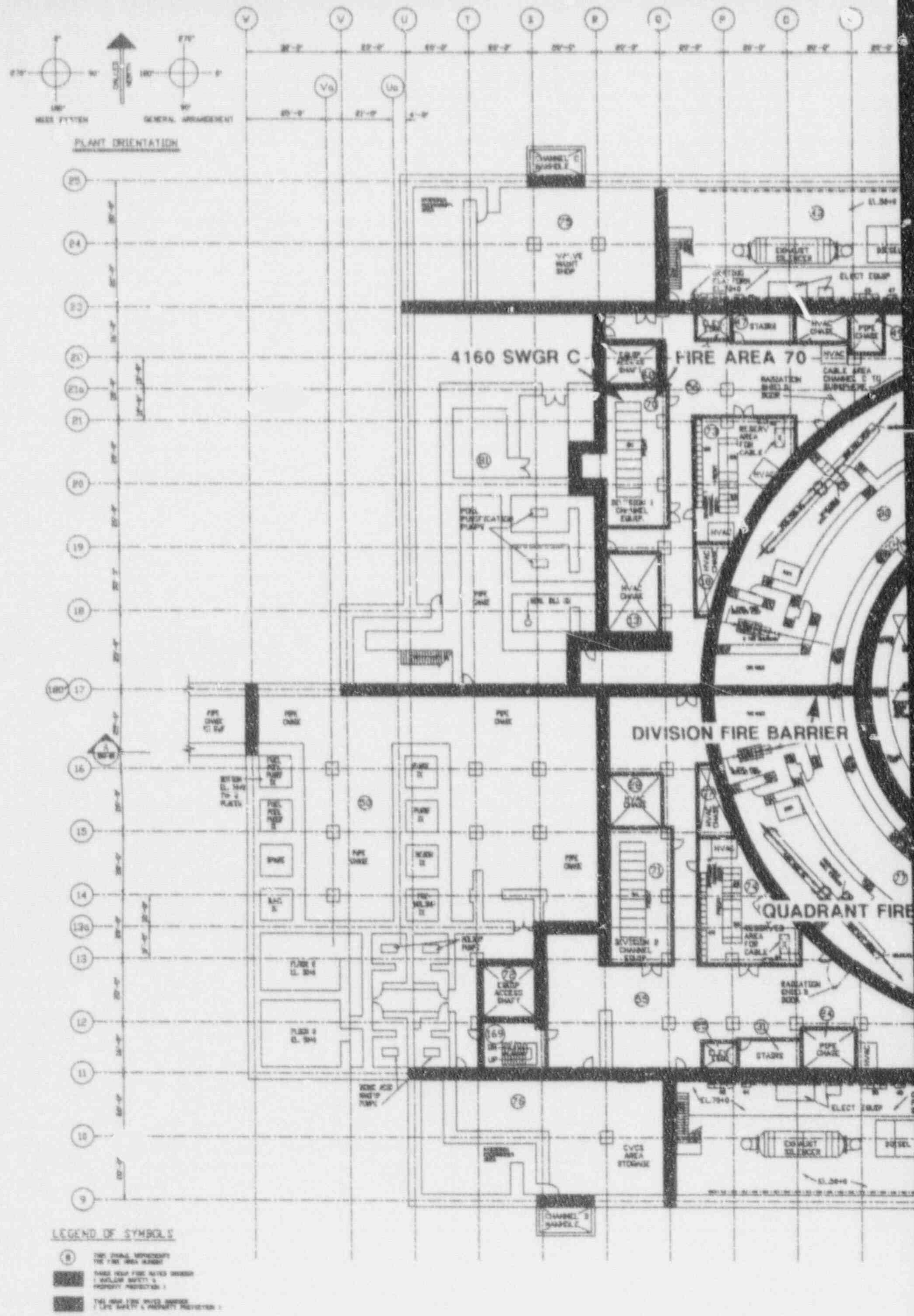


SI
APERTURE
CARD

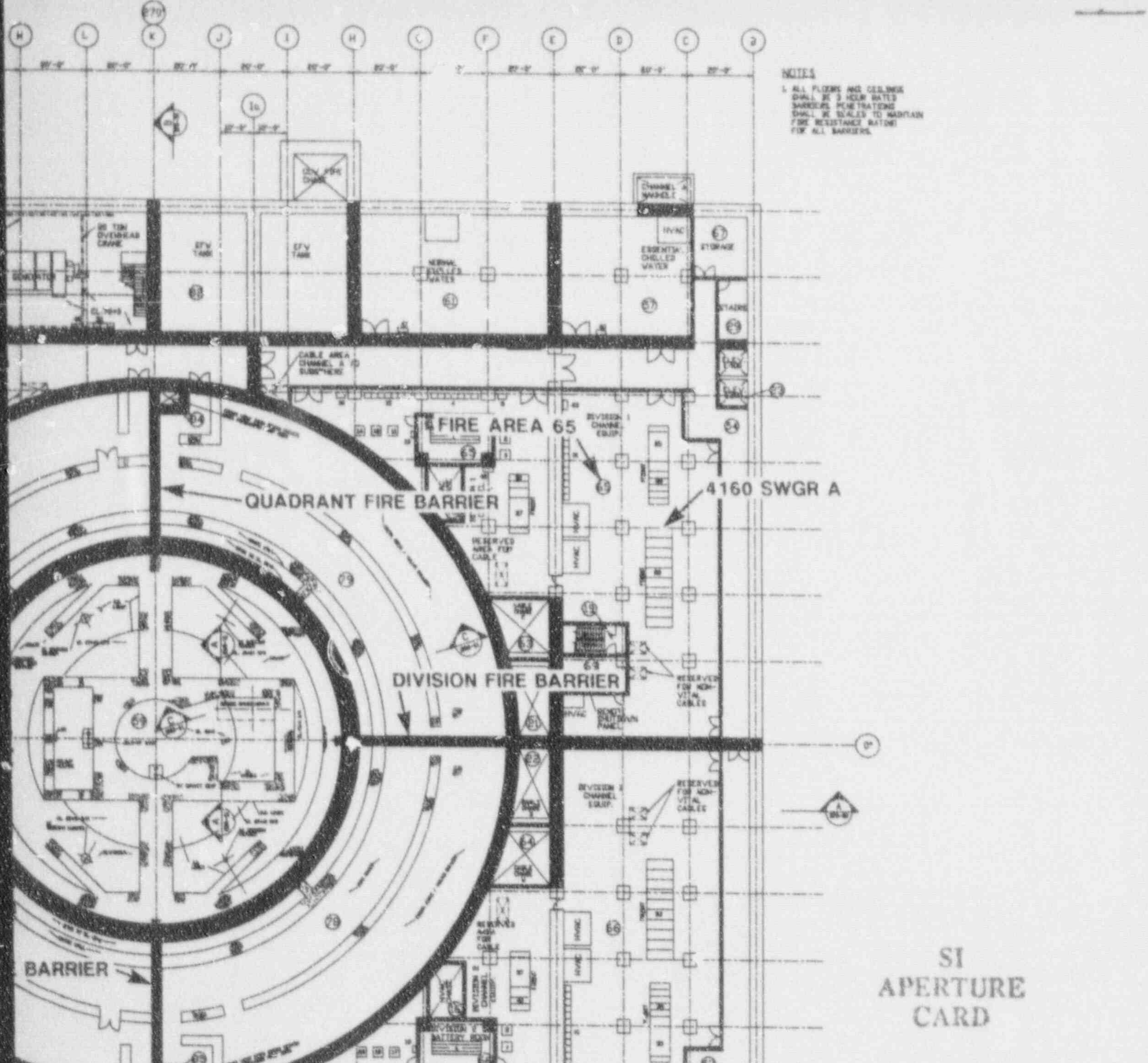
Also Available On
Aperture Card

SYSTEM 80+™	NUCLEAR ISLAND FIRE BARRIER LOCATIONS PLAN AT ELEVATION 50+0	Figure 2.7-1

9208070093-04



PLANT ORIENTATION
GENERAL ARRANGEMENT
4160 SWGR C
FIRE AREA 70
DIVISION FIRE BARRIER
QUADRANT FIRE
STAIRS
HVAC CHASE
PIPE CHASE
ELECT EQUIP
EXHAUST SILENCER
CVCS AREA STORAGE
EQUIP ACCESS SHAFT
LEGEND OF SYMBOLS



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Also Available On
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SYSTEM 80+ ™	NUCLEAR ISLAND FIRE BARRIER LOCATIONS PLAN AT ELEVATION 70+0	Figure 2.7-2

9208070093-05

2.8 INSTRUMENTATION

2.8.1 ISSUE

Over the past several years, industry and regulatory concern with a loss of shutdown cooling has increased. Despite an emphasis on improved shutdown procedures, the frequency of some incidents has not been reduced, particularly for losses of shutdown cooling during mid-loop operations. Furthermore, the effects of a loss of shutdown cooling are more serious than originally realized. The Nuclear Regulatory Commission (NRC) has requested responses to several design issues related to Nuclear Steam Supply Systems (NSSS) operations while on shutdown cooling; specifically during reduced inventory operations.

Operators have, in many cases, had difficulty in determining plant parameters and equipment status during depressurized, shutdown conditions. This is due to the amount and quality of information available being marginally adequate or inadequate for prevention, recognition and mitigation of abnormal conditions in a timely manner. In particular, this information includes the reactor coolant system water level, reactor core exit temperature, and performance of decay heat removal systems.

Losses of shutdown cooling can be partially attributed to misleading, inaccurate, or erroneous vessel level indication, particularly when vessel coolant level is lowered to within the hot leg between the level required for steam generator nozzle dam installation and the level required to prevent vortexing in the shutdown cooling suction line. Refer to Figure 2.8-1. Providing an adequate fluid level in the hot leg above the level at which vortexing occurs will ensure that the shutdown cooling fluid will not entrain air. This scenario has been a contributor to the loss of shutdown cooling due to pump cavitation.

The NRC has recommended that advanced reactor designs include an enhanced instrumentation package which assures:

1. that reduced inventory operations can be accurately and continuously measured. For example, accurate instrumentation can establish reactor coolant level anytime during the draindown process. Accurate level measurement can assist in differentiating between the anticipated dynamic effects of the draindown process and additional, unintended inventory losses; and

2. that a loss of decay heat removal event during reduced inventory operations can be readily detected. This ensures a timely response to a loss of shutdown cooling event. The instrumentation should "provide reliable indication of parameters that describe the state of the Reactor Coolant

System (RCS) and the performance of systems normally used to cool the RCS for both normal and accident conditions" (Reference 4).

The NRC has specified that instrumentation for reduced inventory conditions should provide both visible and audible indications of abnormal conditions in reactor vessel temperature and level, and decay heat removal system performance.

2.8.2 ACCEPTANCE CRITERIA

The instrumentation provided for reduced inventory operations in the System 80+ design will reduce the safety risks associated with shutdown modes of operation. Instrumentation will be provided to avoid causing or contributing to a loss of shutdown cooling at reduced inventory conditions, and to aid in correctly interpreting a loss of shutdown cooling, should one occur.

The following recommendations are taken from Enclosure 2 to Reference 4:

"At a minimum, provide the following in the Control Room (CR):

1. two independent RCS level indications when the reactor vessel (RV) head is on the vessel

2. at least two independent temperature measurements representative of the core exit whenever the RV head is located on the top of the RV (we [NRC] suggest that temperature indications be provided at all times)

3. the capability of continuously monitoring decay heat removal (DHR) system performance whenever a DHR system is being used for cooling the RCS

4. visible and audible indications of abnormal conditions in temperature, level and DHR system performance."

Also, Enclosure 2 of Reference 4 includes NRC concerns and suggestions on meeting these recommendations. These include, for example:

"1. We suggest that licensees investigate ways to provide [accurate] temperature [measurements] even if the head is removed, particularly if a lowered RCS inventory condition exists.

2. We expect sufficient information [be provided] to the operators that an approaching [DHR system] malfunction is clearly indicated.

3. We expect both audible alarms and a panel indication when conditions exist which jeopardize continued operation of a DHR system, as well as when DHR is lost.

4. The low limit of level indication must be below the level necessary for operation of the DHR system. Level information is necessary under loss of DHR conditions since it provides an indication of core coverage and ... of the time to core uncovery. It is also useful in mitigating the loss of DHR accident."

Section 2.8.3.2 of this report contains the description of the System 80+ instrumentation package for reduced inventory operations, including:

- the monitored parameters,
- instrumentation ranges and accuracies,
- alarm setpoints,
- instrument availability,
- display and monitoring capability, and
- quality assurance.

A summary of the System 80+ design features which meet each of the above mentioned NRC recommendations for instrumentation are provided in the following.

2.8.3 DISCUSSION

2.8.3.1 <u>Instrumentation Design Basis</u>

To effectively monitor the draindown process to mid-loop via System 80+ enhanced instrumentation, information obtained from plant analyses forms the basis for the instrument's design requirements.

Instrumentation specified for reduced inventory operations is based on analyses in the following areas:

- operations from a solid plant to mid-loop conditions (which define dynamic draindown characteristics);
- instrumentation features which will reduce the likelihood of operator error during shutdown operation;
- possible ways in which shutdown cooling can be lost while the plant is in a reduced inventory condition;

- flow dynamics of the shutdown cooling system (SCS), including those which contribute to vortexing;

- the plant response to losses of shutdown cooling, due to various initiators, including RCS thermal hydraulic effects and manometric effects; and

- mitigation planning aimed at the reinitiation of shutdown cooling, delaying the onset of boiling, and delaying core uncovery.

The design goals of the instrumentation package are to provide:

prevention - enhanced monitoring capabilities for prevention of a complete loss of SCS operation, and

mitigation - the timely response to a loss of SCS.

These goals have been achieved with the design features of the System 80+ instrumentation described in the following.

2.8.3.2 Instrumentation Description

Table 2.8-1 describes the instrumentation package for reduced inventory operations included in the System 80+ design. Additional details are provided below.

2.8.3.2.1 Level

Four unique sets of instruments are provided for the measurement of level during RCS draindown and reduced inventory operations. These instruments make up the refueling water level indication system.

The first set of instruments is a pair of wide-range, dP-based level sensors. These sensors are provided to measure level between the pressurizer and the junction of each SCS suction line with the RCS during draindown operations. Another pair of dP-based level sensors is utilized to determine RCS water level once it is within the reactor vessel. These narrow-range level sensors function to measure level between the direct vessel injection (DVI) nozzle and the junction of the SCS suction lines with the RCS.

One wide-range and one narrow-range dP instrument are connected to each SCS suction line. Separate lower level taps are provided for each instrument. See Figure 2.8-2. Because of the location of the upper level taps, each of these dP instruments will operate with, or without, the reactor vessel head in place.

In addition to the dP-based instruments described above, two heated-junction thermocouple (HJTC) systems will also be available for reactor vessel level measurement during Mode 5 reduced inventory operations. The first system displays the output from the two inadequate core cooling probes which are located inside the reactor vessel. The range of these probes extends from the reactor vessel head to the fuel alignment plate (See Figure 2.8-3). The measurement of RCS water level via these probes is limited only to those periods when the reactor vessel head is installed.

A second HJTC system provides narrow-range level indication for mid-loop operations via measurement of reactor vessel water level in the hot leg region. This system displays the output from two HJTC probes specifically designed with thermocouples clustered in the hot leg region (see Figure 2.8-4). The benefit of this design is that it permits very accurate measurement when the reactor vessel is in the hot legs.

The HJTC systems compensate for the flow gradient across the core associated with the operation of only one SCS suction line. The HJTC instruments are located in areas of the core which minimize the effect of the core outlet nozzles. The HJTC sensors have an accuracy and response time consistent with the maximum draindown rate of the RCS. The HJTCs are designed so that instrument signal and power are transmitted on individual electrical conductors. Failure of one HJTC sensor will not result in a loss of signal from the remaining sensors. The measurement of RCS water level via these probes is limited to those periods when the reactor vessel head is installed.

The use of both wide-range and narrow-range dP instruments, and two pairs of HJTC probes for refueling water level monitoring provides highly reliable, redundant, and independent indication of reactor vessel water level. Overlapping instrument ranges provide continuous draindown measurement from the pressurizer to a level below that necessary for SCS operation. Since this level instrumentation is independent, common mode misoperation, or failures due to dynamic effects, will not be masked.

Each independent level instrument provides a suitable measurement, and is accurate, for its intended range of use. For mid-loop operations, the narrow-range HJTC probes provide accurate level measurement to within one inch of vessel level. This is critical since there is a very narrow margin between the RCS water level necessary for nozzle dam installation, and that required to prevent SCS pump cavitation. The refueling water level instrumentation is displayed and alarmed in the control room because of its importance to plant safety.

2.8.3.2.2 Temperature

Several instruments are available for continuous temperature measurements during reduced inventory operations with the reactor vessel head on. These include:

- core exit thermocouples (CETs),
- shutdown cooling heat exchanger inlet and return line temperature sensors,
- hot leg resistance temperature detectors (RTDs), and
- refueling water level instruments temperature sensor (HJTC probe only).

All provide representative indications of the core exit temperature when the shutdown cooling system is operational. If the shutdown cooling system is lost, the CETs, hot leg RTDs, and refueling water level instruments temperature sensors (HJTC) input are available to track the response to the loss of shutdown cooling or the approach to boiling.

Per Enclosure 2 to Reference 4, temperature measurement is provided with the reactor vessel head off. The temperature instruments operable during this mode are the hot leg resistance temperature detectors and, prior to fuel shuffle, the CETs. Core exit fluid temperature can be measured through the use of hot leg RTDs as long as the SCS is operable. Each RCS hot leg has a total of five RTDs which are located in the hot leg at the junction of the SCS suction nozzle. In relation to the hot leg horizontal centerline, two RTDs are located above the centerline, one is at the centerline, and two are below the centerline. Only the lowermost two in each hot leg will provide input to the temperature reading for mid-loop operations, since they will be the only ones in full contact with reactor coolant. The lowest probes penetrate the internal diameter of the hot leg pipe at approximately 10" below the midloop fluid level, thus assuring accurate readings are provided.

All temperature sensors will have associated alarms in the control room to be used as aids in determining the response to a loss of shutdown cooling and tracking the approach to boiling. Awareness of time constraints operator via training provides information that is useful for deciding how to allocate effort.

2.8.3.2.3 Shutdown Cooling System Performance

As stated in Enclosure 2 to Reference 4, sufficient information will be available to the control room operator to indicate an approaching shutdown cooling system malfunction. Indications of sufficient pump suction pressure and possible vortexing include unsteady pump current (as indicated by SCS/containment spray system (CSS) pump motor current), loss or reduction in shutdown cooling flow (as indicated by the shutdown cooling system flowrate), insufficient pump NPSH (as indicated by the pump suction pressure sensor), or indication of rising RCS level (as water is displaced by the air and vapor in the shutdown cooling system). If a pump gives indications of air ingestion or cavitation, alarms will prompt the operator to stop the pump immediately. As detailed in Section 2.8.3.2.5, shutdown cooling panel displays will include valve lineup information for critical shutdown cooling flowpaths.

2.8.3.2.4 Quality Assurance

The following instruments are designated as safety related and therefore within the scope of environmental qualification and quality assurance.

- core exit thermocouples
- hot leg resistance temperature detectors
- refueling water level temperature sensor (unheated thermocouple)
- refueling water level instrument (ICCI heated junction thermocouple based design)
- shutdown cooling flowmeter
- shutdown cooling heat exchanger inlet and return line temperature sensors
- shutdown cooling valve position indicators

The safety related designation of these instruments is a consequence of their required functions in other plant modes of operation, including for some, inadequate core cooling. The CENP Quality Assurance Program designates items which are safety-related as Quality Class 1 equipment, and therefore, are subject to the highest level of quality activity.

Enclosure 2 to Reference 4 states: "...we will accept the following for resolving the items identified in the letter: ..... (2) reliable equipment in lieu of the comparable safety grade classification ...." The CENP Quality Assurance Program designates items which are not safety-related but nevertheless require a high level of quality activity, as Quality Class 2 equipment. In this case, where reliable and accurate instrumentation is required for reduced RCS inventory conditions, designating the instrument as Quality Class 2 requires that a quality program be implemented that assures that quality is commensurate with intended use. In the procurement of the instrumentation, appropriate technical requirements and quality requirements are specified in the purchase order to this end. The following list of Quality Class 2 instruments identified on Table 2.8-1 are classified as non safety-related:

- refueling water level indicator (wide and narrow range dP design),
- refueling water level indicator (clustered HJTC design),
- shutdown cooling pump suction and discharge pressure sensors, and
- SCS pump/CS pump ammeter.

2.8.3.2.5 Display and Monitoring Capability

Details of the NUPLEX 80+ Advanced Control Complex Information presentation and panel layout evaluation are described in CESSAR-DC Section 18.7. In addition to the following summary, refer to Section 18.7 for detailed or supplementary explanation of control room information presentation.

The operator obtains plant information from a number of sources in the NUPLEX 80+ control room, which include:

1. A large plant overview status board known as the Integrated Process Status Overview (IPSO),
2. Alarm tiles and associated alarm messages,
3. Discrete indicators which provide frequently used and important information,
4. CRT display formats containing essentially all power plant information, and
5. Component and process control indicators.

There are a number of NUPLEX 80+ design features in 1 through 5 above that specifically implement indications, alarms, and displays applicable to depressurized, shutdown conditions. They are described in the following sections.

2.8.3.2.5.1 Integrated Process Status Overview (IPSO)

IPSO is used for quickly assessing overall plant status, organizing operational concerns, and establishing priorities for operator action. Information provided on the IPSO display includes:

1. Major system and component statuses shown on an overview schematic which are representative of the current operating heat transport systems,

2. Alarms to aid the operator in quickly identifying the location of important status information,

3. Deviations from control setpoints and identification of improving or degrading trends to improve the operator's awareness of plant conditions, and

4. Key representative parameters (e.g., RCS temperature and reactor vessel level).

Alarm windows are provided for plant critical functions:

- Reactivity Control
- Core Heat Removal
- RCS Heat Removal
- RCS Inventory Cont.
- RCS Pressure Cont.
- Steam/Feedwater Conversion*
- Electrical Generation*
- Heat Rejection*
- Containment Environment Control
- Containment Isolation
- Radiological Emissions Control

*For power production only

Nuplex 80+ alarms are mode-dependent and equipment dependent to ensure their validity for different operational conditions. For all modes, including shutdown and refueling conditions, individual sensed process parameter values and alarm states are used to determine critical function alarms, either directly or as processed by an algorithm that uses more than one (1) process parameter input. In either case, the operator quickly is made aware of the affected critical function(s). For example, a high core exit temperature alarm state would be used as an input to the Core Heat Removal critical safety function alarm during a loss of shutdown cooling.

The systems represented on IPSO are the major heat transport pathways and systems that are required to support the heat transport process. These systems include those that require availability monitoring per Regulatory Guide 1.47, and all major success paths that support the Plant Critical Functions.

The following systems have dynamic operating status representations on IPSO. Their identifying descriptors on the IPSO display are shown below:

CC - Component cooling water
CD - Condensate
CI - Containment isolation
CS - Containment spray

CW - Circulating water
EF - Emergency feedwater
FW - Feedwater
IA - Instrument air
SC - Shutdown cooling
RC - Reactor coolant
SI - Safety injection
SW - Service water
TB - Turbine bypass
SD - Safety Depressurization

System information presented on IPSO includes system operational status, any change in operational status (i.e., active to inactive, or inactive to active) and the existence of alarms associated with the system. Alarm information on systems helps to directly inform an operator about possible underlying causes of critical function alarms. The IPSO display, as well as all display pages, is also available at any data processing system CRT, which includes control room panels, the control room supervisor's desk, assistant operator workstations, and the technical support station.

2.8.3.2.5.2 Alarm Tiles and Associated Alarm Messages

Alarm tiles are displayed on electroluminescent flat panel displays in the Discrete Indication Alarm System (DIAS). These tiles are functionally grouped and located on the appropriate control room panel. Shutdown cooling system alarm tiles are located on the Engineered Safety Features panel. This panel includes the controls for Safety Injection, the Safety Injection Tanks, Shutdown Cooling, Reactor Cavity Flood, Safety Depressurization, Emergency Feedwater, Containment Spray, IRWST, and Containment Isolation. Individual alarm inputs to the shutdown cooling alarm tiles include (for each train):

- low shutdown cooling pump header pressure
- low shutdown cooling flow
- high shutdown cooling heat exchanger outlet temperature
- shutdown cooling pump motor current deviation

In addition, this panel will have a tile for RCS conditions, with individual inputs for shutdown, depressurized conditions:

- low RCS water level
- high core exit temperature
- low refueling cavity level

To ensure alarm validity, all NUPLEX 80+ alarms are mode and equipment status dependent, and signal validation of inputs is done where multiple signals of the same process parameter exist. These features eliminate nuisance alarms and help ensure a true "dark board" when alarms do not exist. These features enhance operator diagnosis of alarms when they do exist.

When alarm tiles in DIAS are acknowledged, the operator is presented with a DIAS display with alarm messages showing which of the alarm tile inputs caused the alarm.

2.8.3.2.5.3 Discrete Indicators

Discrete indicators are provided on the NUPLEX 80+ control room workstations to provide the operator with information that (1) is frequently used to assess system level performance, and (2) allows continued operation if the Data Processing System should become unavailable. Discrete indicators use validated process parameter inputs where multiple process parameter measurements exist, and include trend information for routine monitoring, and diagnosis of abnormal conditions. Where analog data is composed of different ranges of information, DIAS automatically shifts to the appropriate range, and indicates to the operator that a range change has occurred.

Discrete Indicator displays to support shutdown cooling for key parameters are on the Engineered Safety Features panel. These include:

<u>Shutdown Cooling System (per train)</u>

- inlet temperature
- outlet temperature
- pump header pressure
- flow
- heat exchanger inlet temperature
- heat exchanger outlet temperature
- pump motor current

<u>Reactor Coolant System</u>

- pressurizer level
- reactor coolant system level

- pressure
- core exit temperature
- refueling cavity level

2.8.3.2.5.4 CRT Display Pages

CRT display pages contain, in a structured hierarchy, all the System 80+ plant information that is available to the operator. The CRT pages are useful for information presentation because they allow graphic layouts of plant processes in formats that are consistent with the operator's visualization of the plant. In addition, CRT formats are designed to aid operational activities of the plant by providing trends, categorized listings, messages, operational prompts, as well as alert the operator to abnormal processes.

The IPSO display page forms the apex of the NUPLEX 80+ CRT display page hierarchy. Three levels exist below IPSO: general monitoring, system/component control, detail/diagnostic. Each level of the hierarchy provides an information content designed to satisfy particular operational needs.

The CRT displays are provided by the Data Processing System (DPS). Any display page is available at any CRT. Operator acknowledgement of CRT alarms also acknowledges the same alarm in DIAS (and vice versa). The CRT alarm actuation message indicates the cause of the alarm, similar to DIAS.

The shutdown cooling system will be shown on a Level 2 display, with more detailed information on two Level 3 displays, one per shutdown cooling train. These displays will include all necessary information to clearly describe the status and performance of the system. This includes system mimic, component activity (e.g., on/off or open/closed) component controllability (e.g., key valves locked open or closed), system parameters (e.g., temperature, level), and system/component alarms. The Level 2 display will include reactor coolant system level and core exit temperature to integrate the shutdown cooling and RCS status for this display. The RCS is also presented on a separate Level 2 display.

2.8.3.2.5.5 Component and Process Control Indicators

NUPLEX 80+ component control features (e.g., actuation/switches/ controls) provide the primary method by which the operator actuates equipment and systems. The shutdown cooling system controls are functionally grouped within a system mimic on the Engineered Safety Features panel. At that panel, shutdown cooling system control is integrated with DIAS alarm tiles important to shutdown cooling and with CRT display of the shutdown cooling system. Controls, alarms and CRT displays for other systems applicable to shutdown operations, such as component cooling water and safety injection, are available at that panel as well.

2.8.3.2.5.6 NUPLEX 80+ Alarm Characteristics

There are a number of special features in the design of the NUPLEX 80+ alarm system that support operator diagnosis of alarm conditions and that would be particularly supportive of depressurized, shutdown operations. These are:

1. Mode and Equipment Status Dependency

2. Audible Alarm Information

3. Stop Flash Feature

4. Operator Established Alarms

5. Operator Aids

In addition, the categorization of all alarms is considered in the bases for alarm display location. For instance, alarms that indicate approach to potential equipment damage, but do not affect critical function or success path status, are presented only on alarm tiles. These would not be included as input to alarms shown on IPSC.

A key feature to aid operator navigation in the CRT display page hierarchy also includes alarm categorization to assist the operator. This feature, the "display page menu", is on each CRT display page. The menu indicates alarms exist in various sectors of the hierarchy, and depending on the sector, the operator can distinguish between lower level alarms that are critical function or success path related, and those that are not (e.g., personnel hazard, or equipment damage).

By displaying critical function alarms, success path alarms, personnel hazard alarms and equipment damage alarms on unique display locations, the operator can rapidly determine the type and relative significance of alarms. For example, an Inventory Control critical function alarm, without a concurrent Volume Control success path performance alarm immediately suggests that inventory may be decreasing due to a non-success-path cause, such as a coolant leak, in which case indication for IRWST level, and containment temperature, pressure and humidity would be immediately checked by the operator. Similar distinctions can be made by the operator for single or multiple alarm conditions to assist the operator in quickly establishing needs and priorities for operator action.

2.8.4 RESOLUTION

The issue of instrumentation for shutdown operation is resolved on System 80+ by the instrumentation and control room displays described in the previous sections of this report. This instrumentation will meet or exceed the recommendations of Generic Letter 88-17, and will significantly reduce risk associated with operations during shutdown, particularly when the reactor is in a reduced inventory condition, as long as prior to the start of draining the reduced inventory instrumentation is placed into operation.

The NUPLEX 80+ Advanced Control Room Complex provides an overview display, indicators, CRT displays, and alarms that meet the acceptance criteria in Section 2.8.2. Indication and alarms are provided on discrete indicators, alarm tile windows and CRTs for RCS level and temperature. In addition, shutdown cooling system status and performance is monitored on CRTs. Shutdown cooling system performance is alarmed on IPSO, alarm tile windows and on CRTs. Also, all alarms are processed for their individual effect on plant critical functions such as reactivity control, core heat removal and RCS heat removal.

TABLE 2.8-1

REDUCED INVENTORY INSTRUMENTATION PACKAGE

Monitored Parameter	Instrument Type	Instrument Function	Range	Indication and Alarm Location	Comments
RCS Water level	Refueling Water Level Indication System (dP based design)	Continuous, redundant wide range RCS water level indication during draindown operations.	Wide Range: two instruments, each with a tap at hot leg/ SCS suction line interface, reference leg at top of pressurizer.	Control Room, with low and low-low level alarms.	Highly reliable. Meets NRC requirement for water level measurement to a point lower than that required for SCS operation.
RCS Water Level	Refueling Water Level Indication System (ICCI HJTC system)	Independent continuous level indication in the reactor vessel.	Top of the vessel down to the fuel alignment plate.	Control Room, with low and low-low level alarms.	Redundant axial strings of thermocouples from the vessel head to the fuel alignment plate. System provides excellent accuracy and continuous measurement.
RCS Water Level	Refueling Water Level Indicating System (clustered HJTC design)	Independent, continuous, narrow-range level indication in the reactor vessel.	Top of the vessel down to the fuel alignment plate.	Control Room, with low-low, low, high and high-high level alarms.	Redundant axial strings of thermocouples from the vessel head to the fuel alignment plate. This instrument is different from the ICCI HJTC system discussed above in that thermocouples are clustered in the hot leg region to provide greater instrument accuracy (<1").
RCS Water Level	Refueling Water Level Indication (dP based design)	Continuous, redundant narrow range level indication during reduced inventory operations.	Narrow range: two instruments, each with a tap at SCS suction line/ hot leg interface, reference leg at DVI nozzle.	Control Room, with low and low-low level alarms.	Highly reliable for mid loop operations. Meets NRC requirement for water level measurement to a point lower than required for SCS operation.

TABLE 2.8-1 (Continued)

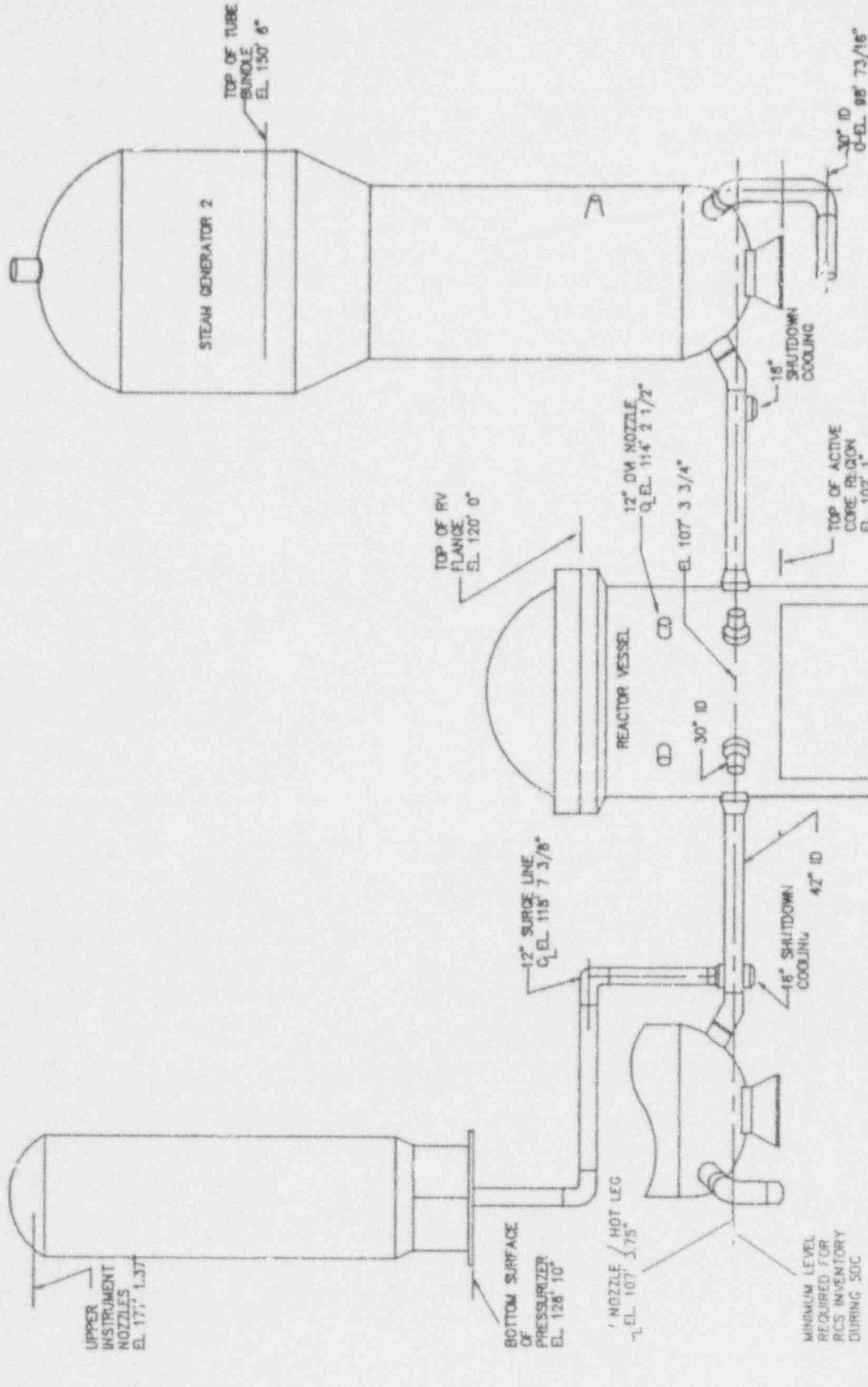
REDUCED INVENTORY
INSTRUMENTATION PACKAGE

Monitored Parameter	Instrument Type	Instrument Function	Range	Indication and Alarm Location	Comments
RCS Temperature	CETs (thermocouple design)	Measures temperature of coolant exiting core.	Optimized for SCS and refueling modes. Will measure boiling. Approximate range 50-250 deg F.	Control Room, with alarms at high and high-high temperature.	Tracks approach to boiling. Temperature indication provided even when head is off vessel. Not available during fuel shuffling. Availability will be maximized.
RCS Temperature	Refueling water level probe (heated junction thermocouple based design)	Continuous, independent temperature measurement inside the vessel.	Optimized for SCS and refueling modes. Will measure boiling. Approximate range 100 - 250 deg F.	Control Room with alarms at high and high-high temperatures.	Indicates actual vessel water temperature. Tracks approach to boiling.
Hot Leg Temperature	Resistance Temperature Detectors (RTDs)	Measures core exit temperature in the hot leg at both SCS suction line regions. Redundant RTDs provided in each hot leg.	Optimized for shutdown operations. Approximate range 50 - 250 deg F.	Control Room, alarms at high temperature.	Temperature indication is affected by loss of shutdown cooling flow, since flow by the RTDs will not occur.
SCS Flowrate	Flowmeter	Decay heat removal system performance.	Bounds SCS pump flow range.	Control Room, includes low flow alarm.	One located in each SCS return line to the RCS. Can be used to measure CSP flow if CSPs are used for SCS.
SCS Pump/CS Pump Discharge Pressure	Pressure sensor	Measures individual pump discharge pressures.	0 to system design pressure.	Control Room with low pressure alarm.	One instrument located at the discharge to each pump. Identifies individual pump status.
SCS Pump/CS Pump Motor Current	Ammeter	Measure current drawn by pump motor. Fluctuations show air entrainment.	0 to system design pressure	Control Room, alarms with preset drop in current.	Confirms pump status (individual pump air entrainment) independent of pressure and flow indicators.

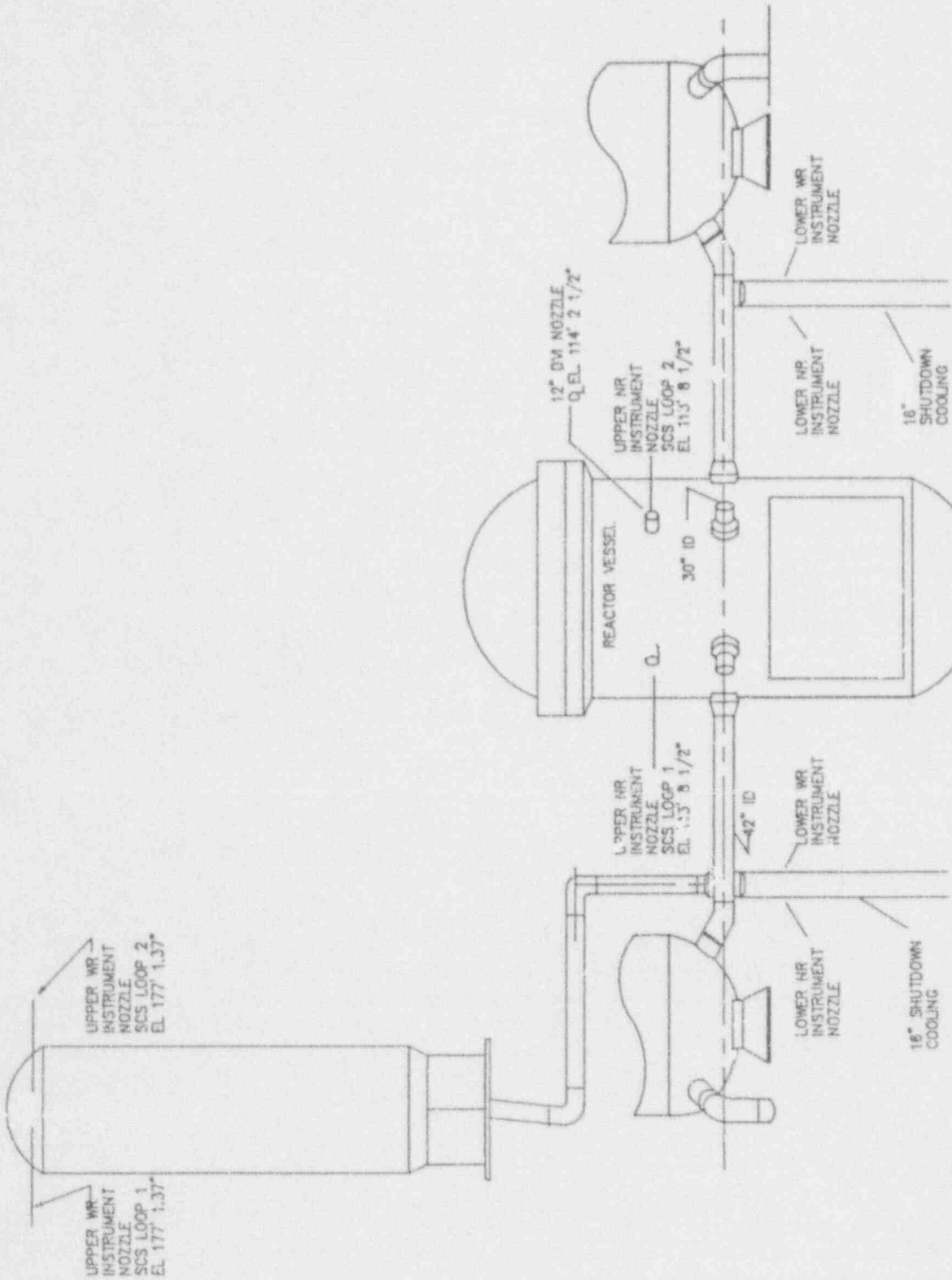
TABLE 2.8-1 (Continued)

REDUCED INVENTORY
INSTRUMENTATION PACKAGE

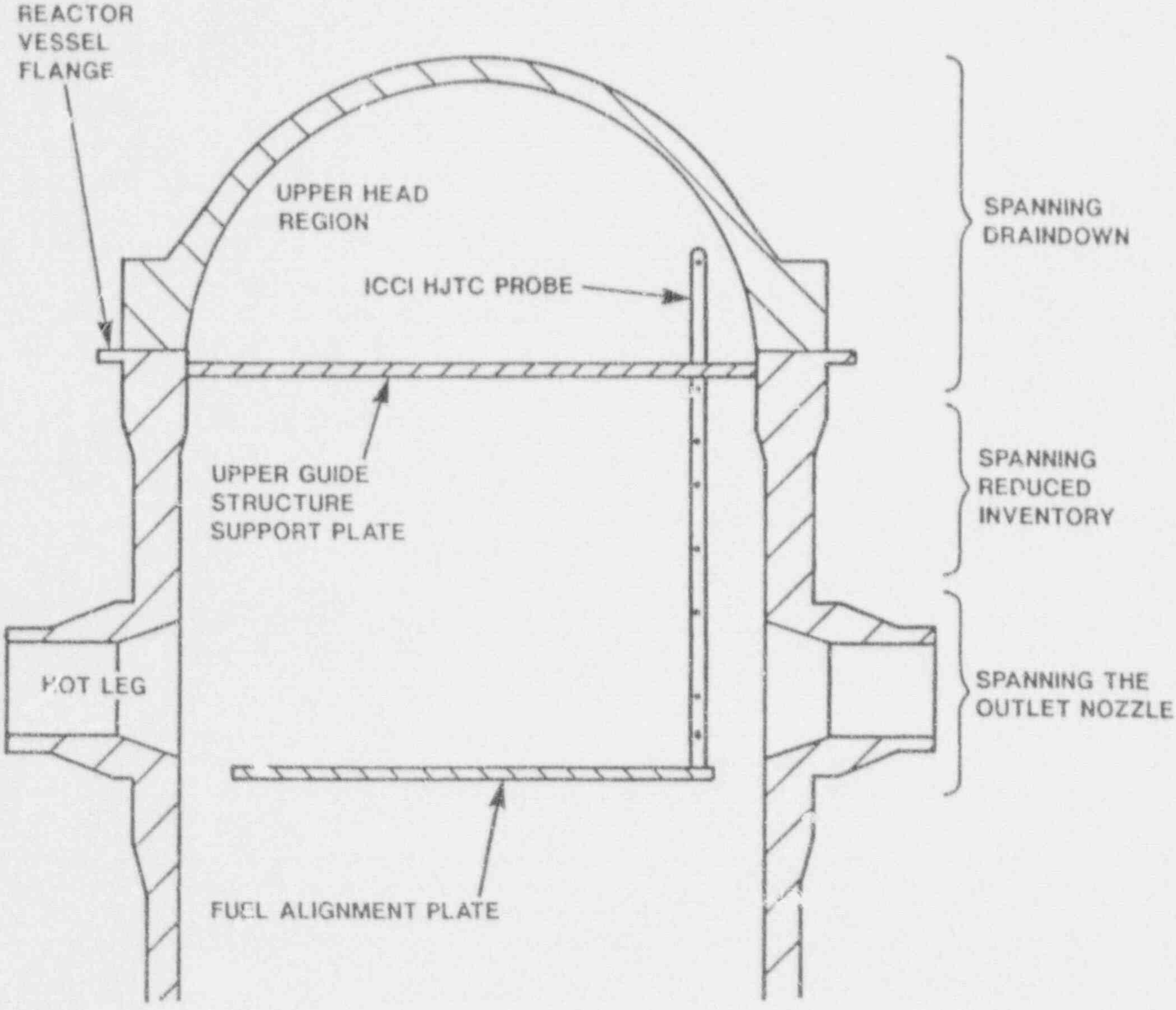
Monitored Parameter	Instrument Type	Instrument Function	Range	Indication and Alarm Location	Comments
SCS Pump/CS Pump suction pressure	Pressure sensor	Measure pump suction pressure in each pump.	0 to system design pressure.	Control Room with low pressure alarm.	One instrument located at the suction of each pump. Identifies individual pump status.
SCHX Inlet and Return Line Temperature	Temperature sensor	Measures temperature in the suction and discharge lines of the shutdown cooling heat exchanger.	40 - 392 deg. F.	Control Room alarms at high temperature.	Temperature indication only available when SCS is operational.
SCS Valve Position Indication	Valve position indication open/closed or throttled.	Status of valve positions in the SCS.	Open/closed/throttled position indication.	Control Room	Will provide information of system lineup status and available flowpaths.



SYSTEM 80+™	REACTOR COOLANT SYSTEM ELEVATIONS RELATED TO SHUTDOWN COOLING OPERATIONS	Figure 2.8-1

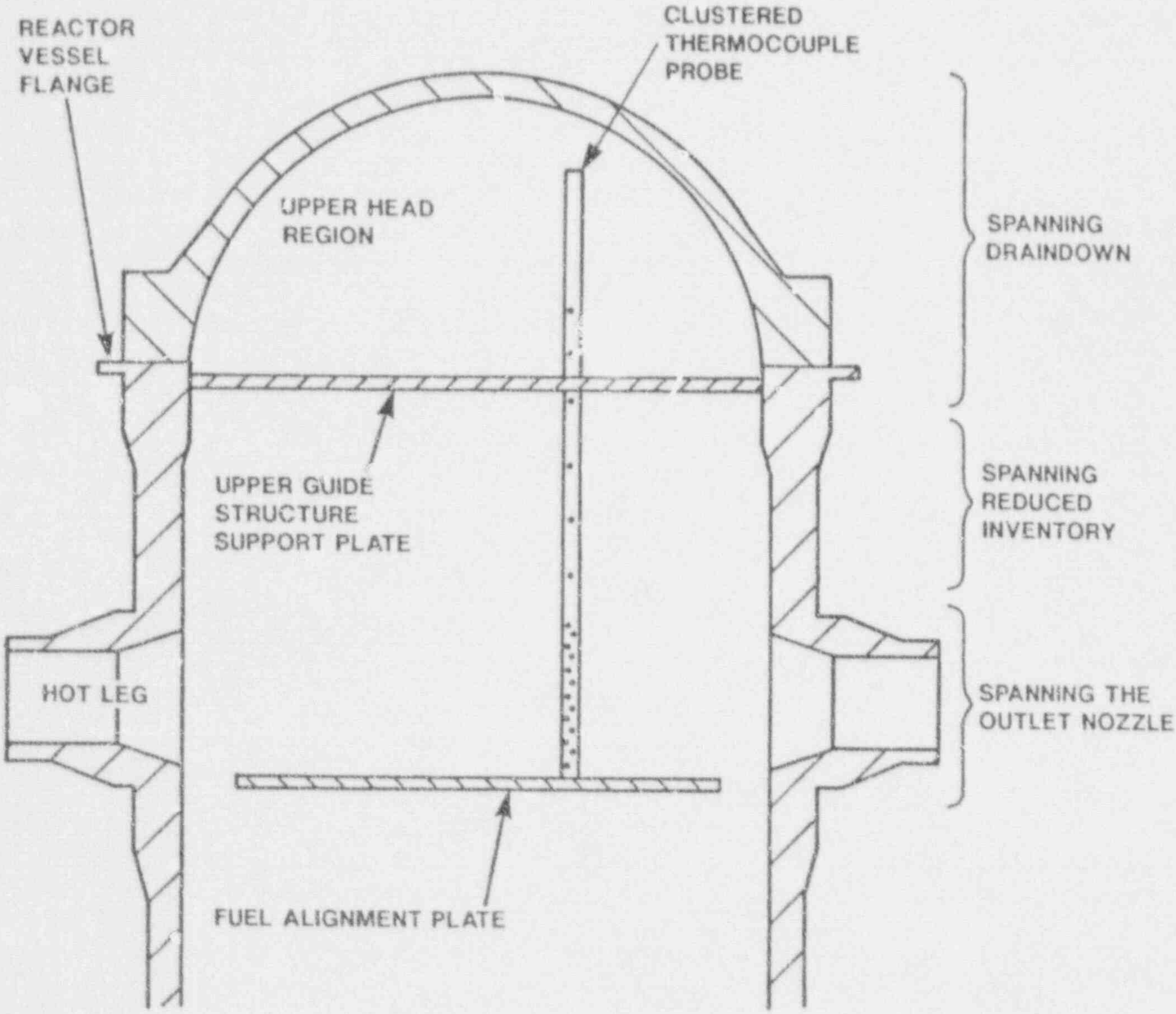


SYSTEM 80+™	DIFFERENTIAL PRESSURE INSTRUMENT TAP LOCATIONS SCHEMATIC	Figure 2.8-2



NOT TO SCALE
(ONE OF TWO PROBES SHOWN)

SYSTEM 80+™	SCHEMATIC REPRESENTATION OF THE INADEQUATE CORE COOLING HJTC PROBES	Figure 2.8-3



*EXAMPLE OF SENSOR POSITIONING. NOT INTENDED TO BE TO SCALE
(ONE OF TWO INSTRUMENT PROBES SHOWN)

SYSTEM 80+™	SCHEMATIC REPRESENTATION OF THE NARROW-RANGE HEATED JUNCTION THERMOCOUPLE PROBES	Figure 2.8-4

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2.9 ECCS RECIRCULATION CAPABILITY

2.9.1 ISSUE

The issue is the potential for loss of flow to the Containment Spray (CS) and Safety Injection (SI) pumps during accident conditions. System flow could be inhibited by a number of factors. These factors include:

1. Hydraulic effects, such as air ingestion and vortex formation.
2. Debris in the IRWST resulting from maintenance activities or deterioration of insulation from actuation of containment sprays or from LOCA consequences, or
3. The combined effects of items (1) and (2).

2.9.2 ACCEPTANCE CRITERIA

The design of the System 80+ Incontainment Refueling Water Storage Tank (IRWST) and Holdup Volume Tank (HVT) and their associated debris-blocking devices shall comply with the requirements of General Design Criterion 35 of Title 10, Code of Federal Regulations, Part 50, Appendix A. Design Criterion 35 requires that "...suitable containment capabilities shall be provided to assure that ... the system's safety function can be accomplished." To satisfy this requirement, the IRWST and HVT are designed to provide a clean and reliable source of water to the SI pumps for long-term recirculation. The containment is designed to direct containment spray water and emergency core cooling water to the HVT and then to the IRWST.

The SIS shall meet the acceptance criteria specified in USNRC Standard Review Plan section 6.3, Emergency Core Cooling System, Revision 2. In particular, Section 6.3 of the SRP addresses the availability of an adequate source of water for the SIS. Acceptance criteria pertaining to the design of the containment emergency sumps are provided in SRP section 6.2.2, Containment Heat Removal Systems, Revision 4. These criteria address the drainage of containment spray water and emergency core cooling water to the recirculation suction points (sumps) and the screen assemblies surrounding these suction points. Regulatory Guide 1.82. Water Sources for Long-term Recirculation Cooling Following a Loss-of-Coolant Accident, Rev. 1, provides the guidelines for the design of the IRWST and the HVT, and the design of the screens associated with these tanks. Technical considerations related to this issue are detailed in NUREG-0897, Containment Emergency Sump Performance, Revision 1.

2.9.3 DISCUSSION

Water introduced into the System 80+ containment from a RCS break or from containment sprays drains into the Holdup Volume Tank (HVT). This tank serves the purpose of the "containment sump." The Holdup Volume Tank is therefore the low collection point in containment. The contents of this tank are directed to the IRWST through the two IRWST spillways (see Figure 2.9-3). The IRWST serves as the single water source of long-term recirculation for emergency core cooling and containment heat removal.

With the System 80+ design, it should be noted that the IRWST does not serve as the containment sump; this tank specifically serves as a storage tank for refueling water, a clean and reliable source of water for Safety Injection, and a heat sink for condensing steam discharged from the pressurizer.

The arrangement of the IRWST within containment meets the multi-sump requirement of Reg. Guide 1.82, Water Sources for Long-term Recirculation Cooling Following a LOCA. The general plant arrangement separates redundant trains of the SIS and the CSS. The divisional boundary provides complete separation between divisions and effectively creates two identical support buildings. The result is a plant arrangement with two SI pumps and one CS pump in each division. Within each division, the two SI trains (and each CS train) are separated by a quadrant wall to isolate the trains from each other to the maximum extent practical. Each of the four SI pumps has its own suction connection to the IRWST (see Figure 2.9-1) and each of the two CS pumps shares one of these four connections.

Following an accident, water introduced into containment drains to the Holdup Volume Tank. Debris that may exist in containment may be transported to the HVT with this fluid. Debris greater than 1.5 inches diameter is prevented from entering the HVT by a vertical trash rack, which is located at the entrance to the HVT (see Figure 2.9-3). The vertical trash rack is greater than six feet high and more than forty feet long. A debris curb exists at the base of this trash rack to prevent high density debris that may be swept along the floor by fluid flow toward the HVT from reaching the trash rack. The vertical orientation of the trash rack will help impede the deposition of debris buildup on the screen surface. Particles that are smaller than the trash rack mesh will enter the Holdup Volume Tank.

The Holdup Volume Tank is designed to function as a solids trap to help prevent debris from entering the IRWST. High density debris that makes its way through the trash rack will accumulate in the bottom of this tank. The IRWST spillways are located at a high enough elevation to assure that much of the higher-density debris (and debris that tends to sink slowly) will settle to the bottom of the HVT before spilling over into the IRWST. Debris that remains in suspension will make its way to the IRWST spillways. The spillways are shown in Figure 2.9-3. Screens are not present in these spillways to assure uninterrupted flow to the IRWST.

The fine debris that is introduced into the IRWST is prevented from entering the SIS suction piping by a debris screen. These screens are located at each end of the four wing walls that serve as supports for the reactor coolant pumps (see Figures 2.9-1 and 2.9-2). These wing wall assemblies extend from the IRWST floor to the maximum IRWST water level, assuring that all debris will be filtered before reaching the SIS suction lines. The screen assemblies completely enclose the suction lines by running from the end of each wing wall to the side walls of the Holdup Volume Tank or the primary shield walls, as applicable. The wing-wall screens have the capability of removing particles greater than 0.09 inches diameter This screen size is consistent with the screens used on currently operating units. The wing-wall screens are the final barrier to debris before the SIS suction lines.

Blockage of the debris screens is a major concern with respect to recirculation. The System 80+ screens have a vertical orientation to prevent debris from settling on the screen surfaces. This helps in keeping the screens clear. The design considered the types and quantities of insulation used for the System 80+ components, since post-LOCA deterioration of this insulation is the major potential source of debris in containment. The location of insulation with respect to the HVT and IRWST as well as the possible location of breaks have also been considered. The effective areas of the screens have been determined according to the guidelines provided in Appendix A to Regulatory Guide 1.82, Guidelines for Review of Sump Design and Water Source for Emergency Core Cooling.

The debris screens have been designed to withstand the vibratory motion of a seismic event without loss of structural integrity. Each screen is capable of withstanding loads imposed by postulated missiles as well as loads due to pressure head differentials.

Consideration has also been given to the materials used for the debris screens. Materials have been selected to avoid degradation during periods of inactivity (i.e., no submergence), and during periods in which the screens are partially or fully submerged.

Each screen used in the System 80+ design is provided with an access opening to allow for inspection of the racks or screens. The screens will be visually examined periodically to detect any corrosion or structural degradation during refueling outage periods. As seen in figure 2.9-1, the suction lines are located within the confines of the wing wall away from the IRWST spargers. This wall design helps isolate the suction lines from the open sections of the IRWST, where most of the maintenance activities will be performed. The fine wing-wall screen will filter any trash generated from this type of activity. In the event that maintenance is needed within the wing walls and near the ECCS suction inlets, permanent box-like screens over the suction piping will protect these lines.

Long-term return of spray water from upper level elevations is not dependent on individual piping runs or spillways. Multiple passive spillways are provided to route water back to the Holdup Volume Tank. Major openings such as hatches and stairwells are also available to return water to the screened entrance to the HVT.

Protection against air ingestion by SIS pumps is also a major concern with respect to recirculation and has been considered in the System 80+ design. The location and size of the suction lines in the IRWST have been chosen such that air entrainment is minimized. Pump air ingestion analysis is based on minimum submergence, maximum Froude number, and maximum pipe velocities. The available surface area used in determining the design coolant velocity has been calculated conservatively to account for blockage that may result as per Reg. Guide 1.82, Appendix A, Guidelines for Review of Sump Design and Water Sources for Emergency Core Cooling. The minimum water level in the IRWST has been conservatively calculated to be 75+6 (elevation). This water level allows for sufficient NPSH for the Containment Spray pumps and Safety Injection pumps operating at runout flow. A conservative margin has been provided between the elevation of the suction piping opening and this minimum water level to minimize the possibility of air ingestion. Applying the parameters of the IRWST to the equations in Reg. Guide 1.82, Appendix A, yields zero air ingestion at normal pump flowrates and less than 2% air ingestion at pump runout flowrates. The IRWST suction lines are also provided with vortex suppressors to aid in minimizing air ingestion by the SIS pumps. The guidelines in Appendix A of Reg. Guide 1.82 regarding the design of these vortex suppressors have been considered.

During normal full power operation, it is possible to perform a full flow test of the SIS and CSS pumps while taking suction from the IRWST and returning to the IRWST via a recirculation line (see SIS P&IDs in CESSAR-DC, Figures 6.3.2-1 A, B, C). This testing can verify the satisfactory hydraulic performance of the IRWST by running the pumps at runout flow.

2.9.4 RESOLUTION

The design of the System 80+ IRWST and HVT assures that a clean and reliable source of borated water is available for ECCS recirculation. The arrangement of the IRWST within the System 80+ containment offers advantages over conventional sumps. Like sumps, the tank serves as the single source of water for SIS and CSS pump recirculation, but the protection afforded the SIS pumps against debris ingestion or blockage is significantly greater than in current designs. First, water in containment draining back to the IRWST must pass through a large trash rack before entering the HVT. The HVT serves as an effective solids trap for high density debris. Lower density debris that makes its way into the IRWST via the IRWST spillways encounters debris screens that filter fine particles from the SIS suction inlets. Each of the four SIS pumps have separate IRWST suction lines and each of the two CSS pumps takes suction from one of these four lines. Box screens at all four suction lines provide a final trap.

Multiple spillways are available to return water from the upper containment elevations to the IRWST. The drain pathways are fully redundant to assure recirculation capability. The location of the suction inlets within the IRWST provide additional protection against suction inlet damage and/or blockage.

Consideration has been given to IRWST hydraulic performance, the generation of potential debris and associated effects (including debris screen blockage), and the preservation of SIS pump NPSH during post-LOCA conditions in the overall design. The performance of the design is deemed acceptable with respect to these considerations.

This issue has been resolved by design features of System 80+.

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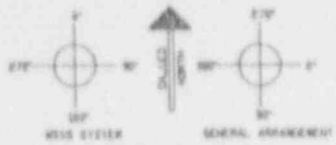
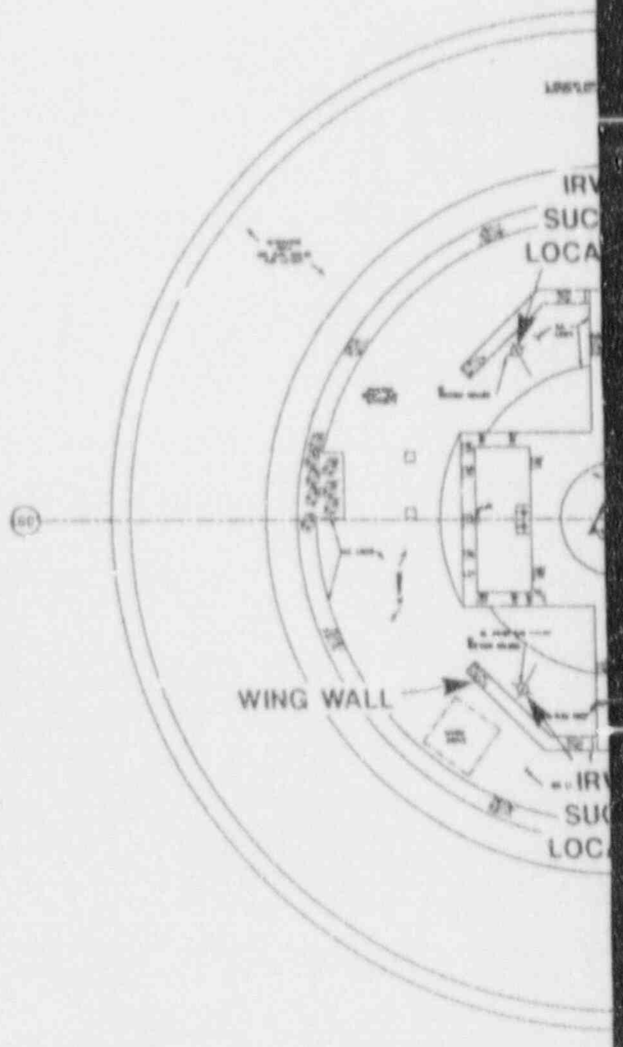
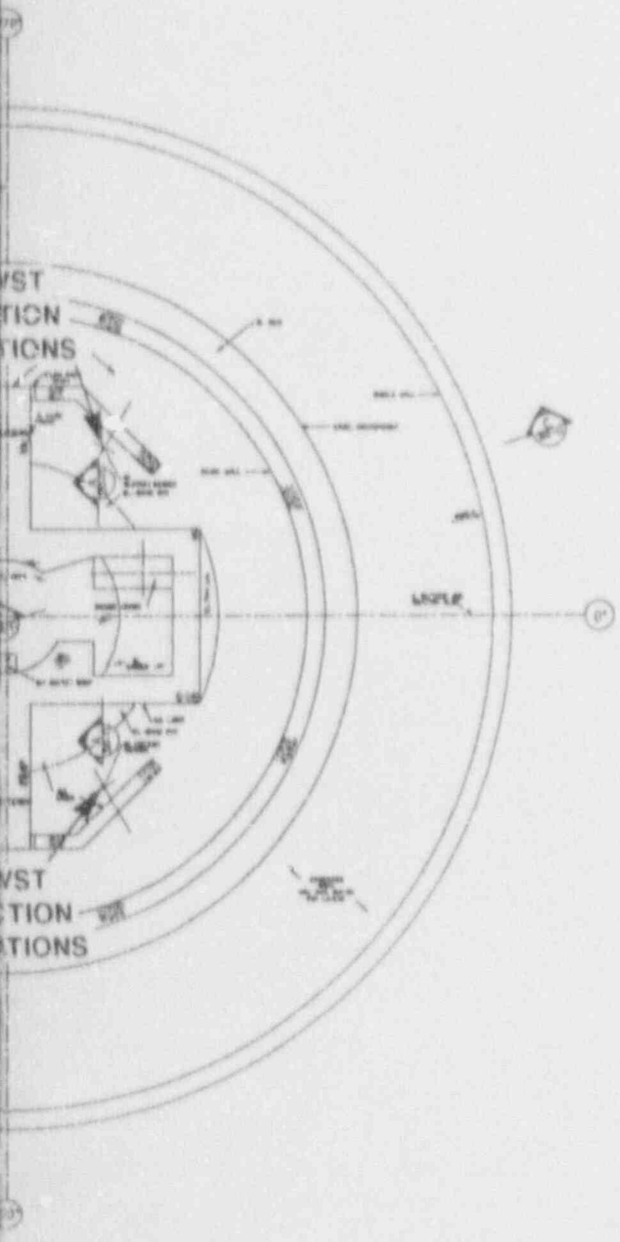


PLANT ORIENTATION





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SYSTEM 80+™	LOCATIONS OF SAFETY INJECTION SYSTEM SUCTION IN IRWST	Figure 2.9-1

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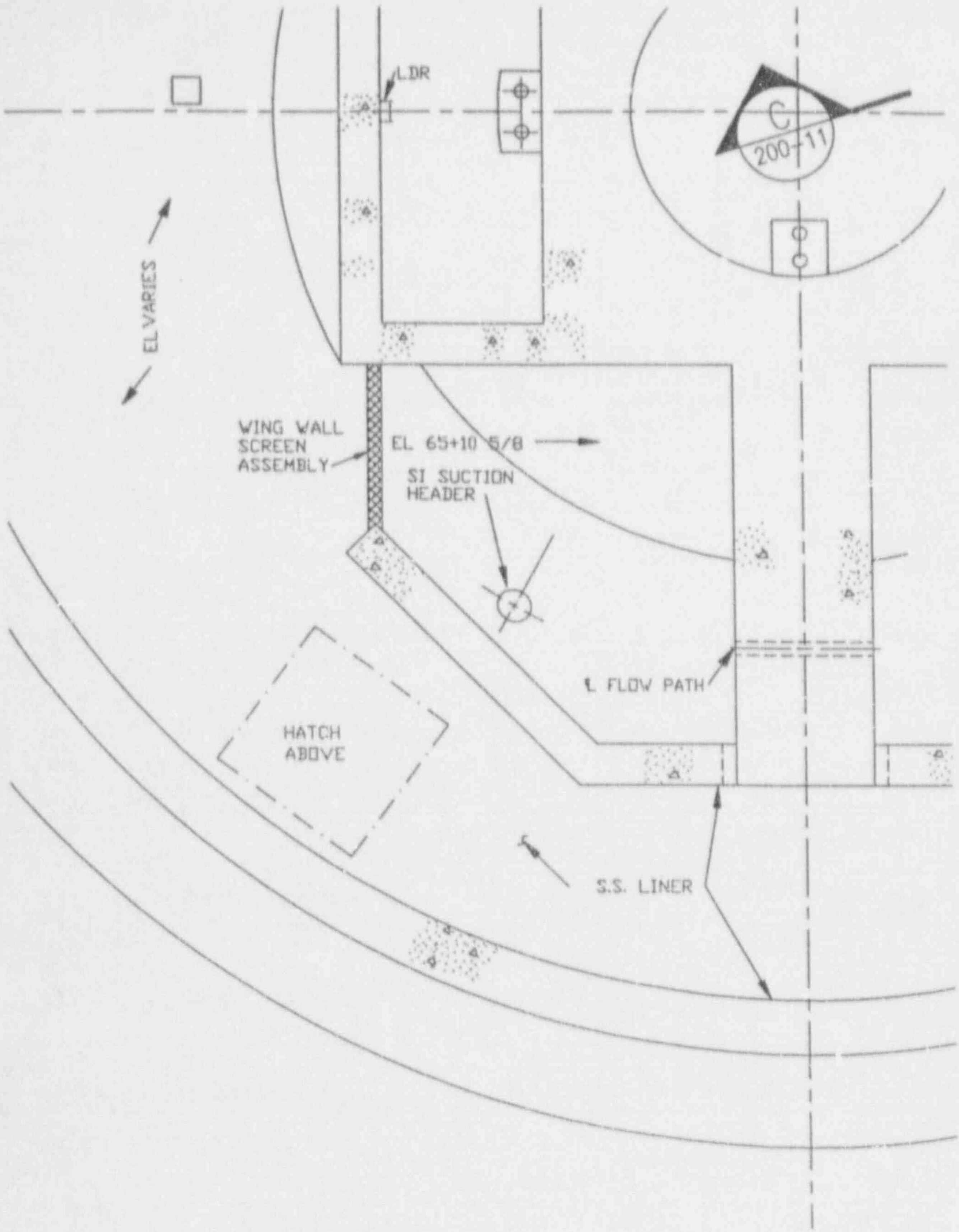
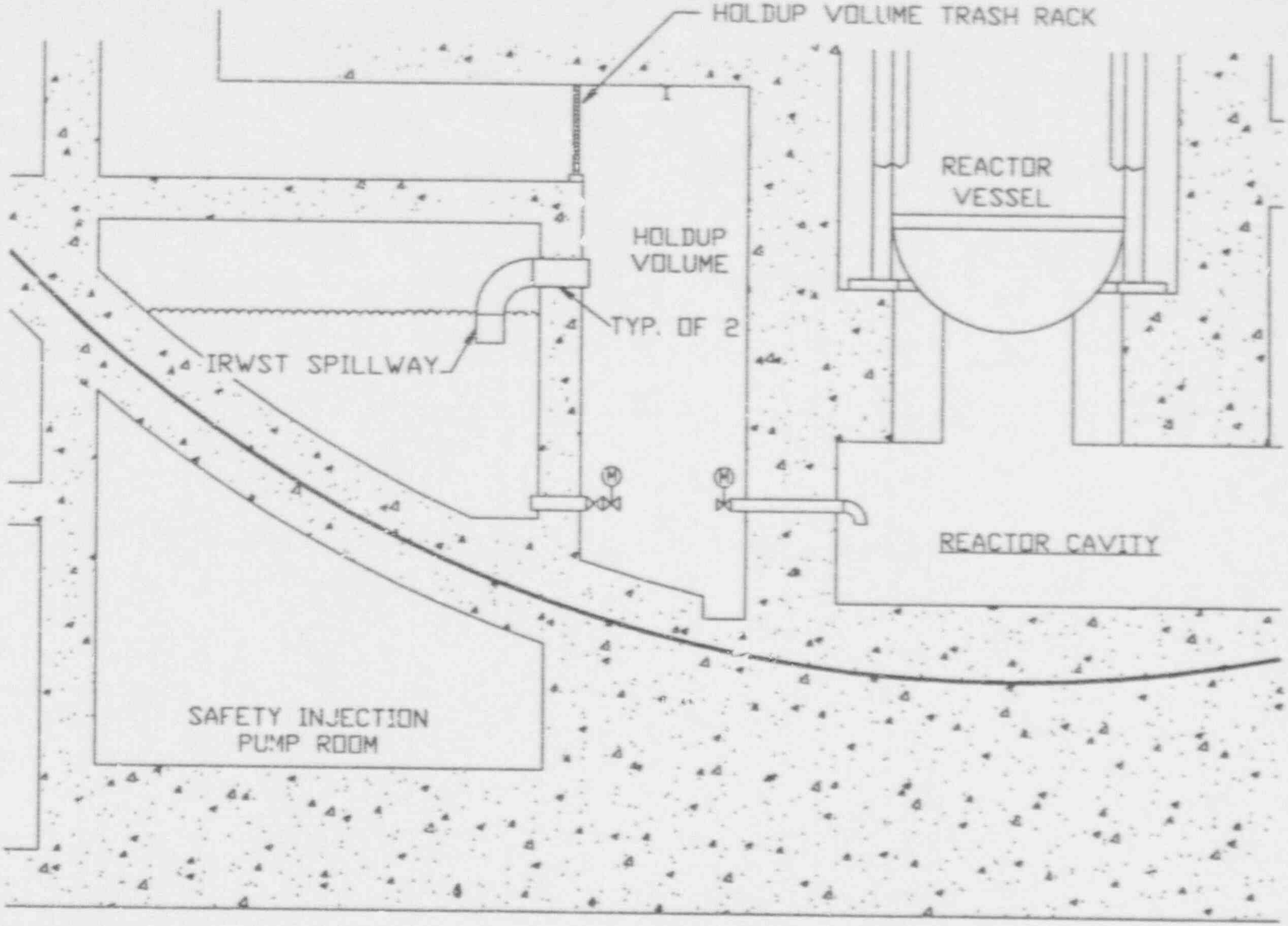


SYSTEM 80+™	LOCATION OF WING WALL DEBRIS SCREEN ASSEMBLIES	Figure 2.9-2



LOCATIONS OF TRASH RACK AND SPILLWAY FOR IRWST AND HVT

Figure 2.9-3

2.10 EFFECTS OF PWR UPPER INTERNALS

2.10.1 ISSUE

Events with the potential for loss of Decay Heat Removal (DHR) have initiated from plant configurations with the reactor vessel head removed, the refueling pool filled with water and the reactor upper internals still in place. Under these conditions, the reactor vessel upper internals may provide sufficient hydraulic resistance to natural circulation flow between the refueling pool and the reactor core to inhibit, or even prevent, the refueling pool water from cooling the core under circumstances wher forced convection DHR has been lost.

2.10.2 ACCEPTANCE CRITERIA

When the reactor vessel head is off and the core and upper internals are in the vessel, any one or more of the following conditions shall be satisfied:

1. Demonstration by analysis that the time to boil exceeds the time required to evacuate and establish containment integrity; and/or

2. Demonstration by analysis that either a natural or forced circulation flow path, with or without heat exchangers, can be established to perform DHR for a sufficiently long period of time to allow plant operators to terminate the event.

2.10.3 DISCUSSION

In mode 6 configurations with the vessel head removed, loss of shutdown cooling events could be of concern if the upper internals inhibit natural circulation cooling of the core via the heat sink in the upper refueling pool. An analysis to predict the extent of natural circulation flow through the Upper Guide Structure (UGS) is described below. Resolution of this issue is based on the results of that analysis.

Hydraulic flow resistance data are provided in Table 2.10-1. These were utilized in an analysis to ascertain the possibility of natural circulation flow communication through the upper internals between the core and refueling pool for a Mode 6 configuration with the vessel head removed.

The entry flow path through access holes in the core support barrel flange to the upper downcomer from the refueling pool was shown to admit negligible flow in view of its high hydraulic resistance. Equal flow areas for the down-flow and up-flow were assumed through the core and upper internals with turnaround at the base of the active core. An iterative algorithm, based on the principles of conservation of mass, momentum and energy, was used to determine the transient natural circulation flow, after loss of shutdown cooling, and the time to saturation at the core outlet. Sensitivity of the results to magnitude of the upper internals flow resistance was also determined.

Several key assumptions made in the analysis include one-dimensional flow with no transverse momentum and energy exchange, no conduction loss through the vessel, no convection from the surface of the refueling pool and no heat storage within the bounds of the upper internals. The decay heat generation was conservatively assumed constant, characteristic of two days after shutdown, with an additional 10 percent uncertainty. No credit was taken for the available need developed at the core exit due to the forty foot elevation difference. Other simplifications included a uniform refueling pool temperature together with equal metal and fluid temperatures in each core flow zone that actually exhibit a linear variation axially.

This analysis indicates that natural circulation flow makes the water in the upper refueling pool available for cooling the core and significantly extends the time required for the core outlet temperature to reach saturation under these circumstances. Fluid temperature versus time variation results as a function of initial coolant temperature are shown in Figure 2.10-1. The curves in the figure for the maximum Mode 6 initial coolant temperature of 135°F indicate that the core outlet temperature would not reach saturation until 35 minutes after the loss of decay heat removal. The calculated natural circulation flow rate increases throughout this time period with a value of about one percent of the rated design core flow rate at one minute after loss of DHR rising to 1.5 percent where the outlet temperature reaches saturation at 35.5 minutes. For an initial coolant temperature of 100°F, the time to saturation increases significantly to 125.5 minutes.

A sensitivity evaluation shows that it would take only a few minutes to reach saturation at the core outlet in the complete absence of flow communication with the refueling pool. Another analysis indicates an additional time period of at least one hour to core uncovery after saturation is reached throughout the entire core volume in addition to the core outlet.

These results make it possible to conclude that the presence of the upper internals does not prevent natural circulation communication with the refueling pool. Depending upon the initial fluid temperature, the time to boil will exceed 35 minutes and may be several hours in duration. Ample time, therefore, exists for the implementation of operating procedures to deal with the restoration of forced circulation decay heat removal and/or to begin the process of containment closure, which requires 10 minutes when in Mode 6 configurations.

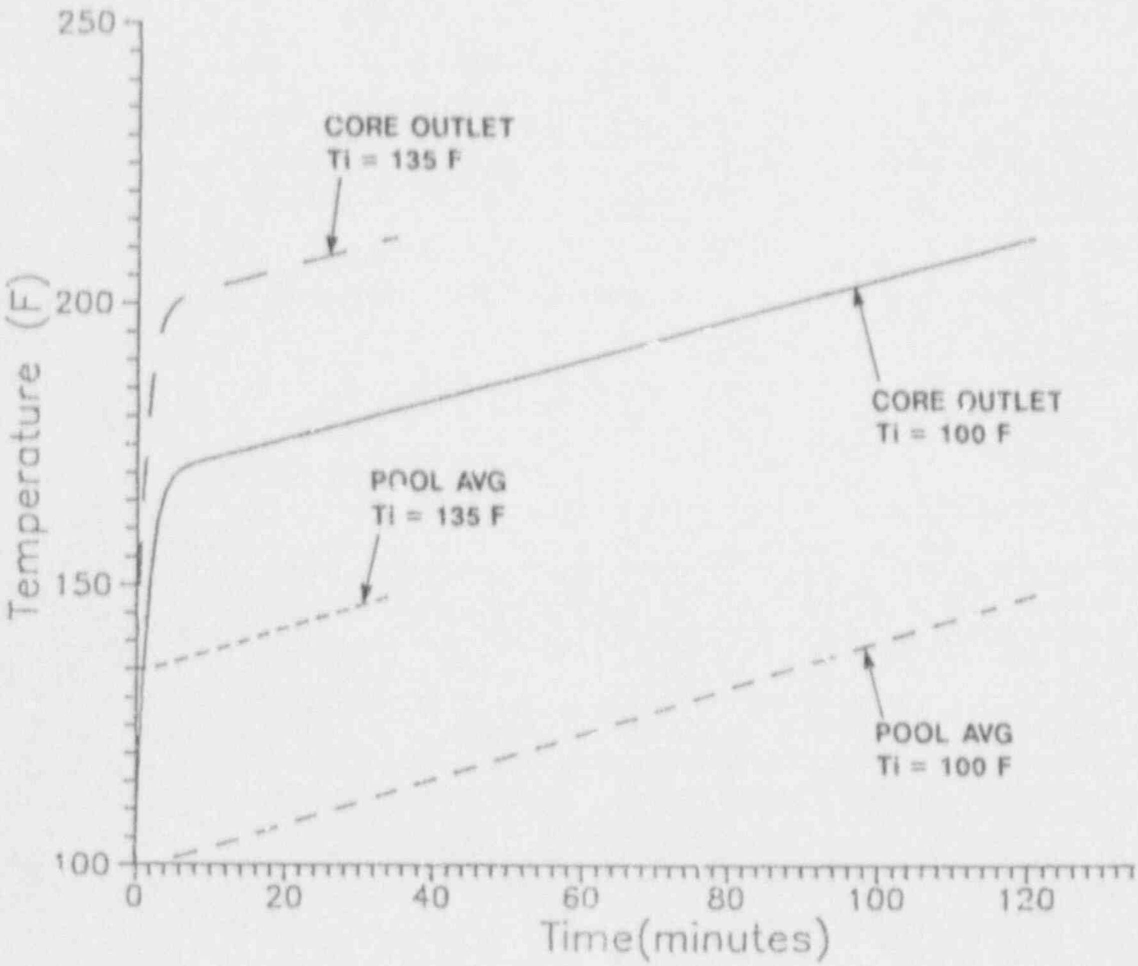
TABLE 2.10-1

HYDRAULIC FLOW RESISTANCE DATA FOR SYSTEM 80+

Region	Dimensionless Flow Resistance K	Cross-sectional Flow Area - Ft^2
Core Support Barrel Flange Entry	1823.0	2.949
Upper Downcomer	0.17	40.53
Lower Downcomer	2.644	33.53
Inlet Plenum	14.0	115.6
Core	12.77	60.8
Fuel Alignment Plate	0.69	20.6
Upper Guide Structure	1.246	3.34

2.10.4 RESOLUTION

The results discussed above indicate the availability of a natural circulation flow path through the upper internals in the vessel in the event of a loss of both SCS trains during Mode 6 when the refueling pool is full. The heat removal effected by transference of core-generated decay heat to the upper refueling pool would allow plant operators a minimum time period of at least 35 minutes to terminate the event before the core outlet temperature reached saturation. Substantially more time would be available before possible uncovery of the core. This time period is of sufficient duration that the issue can be considered resolved on the basis of both of the previously stated acceptance criteria. It is clearly longer than the minimum Mode 6 containment closure time of 10 minutes and sufficiently long enough to allow plant operators to restore shutdown cooling.



SYSTEM 80+™	RESULTS OF MODE 6 NATURAL CIRCULATION ANALYSIS OF SYSTEM 80+ TEMPERATURE vs TIME	Figure 2.10-1

2.11 FUEL HANDLING AND HEAVY LOADS

2.11.1 ISSUE

Questions have been raised regarding the potential for damage to fuel and safety related equipment due to dropping of heavy loads during plant shutdown. Related issues involve the transport of heavy loads within the reactor containment building and the spent fuel building. These include dropping the reactor vessel closure head and internals, dropping the head area cable trays [HACTS], accidental release of a fuel assembly, and movement of the spent fuel storage cask. Drop accidents involving primary NSSS piping are not considered, since by design piping is routed beneath the reactor refueling pool.

2.11.2 ACCEPTANCE CRITERIA

Fuel and safety related equipment shall not be subject to damage that may adversely effect public health. Also, fuel assemblies located within the reactor or within storage racks shall remain subcritical during and following postulated load drop accidents.

2.11.3 DISCUSSION

The transport of heavy loads within the containment building and the spent fuel building is controlled by integrating relevant design characteristics for the building and the handling equipment. Plant layout, equipment design and handling procedures are chosen to insure that heavy loads are restricted to preassigned travel zones. Equipment interlocks and procedures are also used to insure that load transport is accomplished in a predictable manner.

Specific issues associated with the transport of heavy loads within the containment building include movement of th reactor vessel closure head, the reactor internals, the HACTS, and individual fuel assemblies. Special measures are taken to safeguard these operations and mitigate the consequences of postulated load drop accidents.

Procedural guidance for raising the reactor closure head, as provided in CESSAR-DC Section 9.1.4.2.3.3, specifies that the fuel transfer tube valve be closed and that the pool water level follow the vertical movement of the closure head as it is raised from the reactor. This insures that the containment building remains isolated from the spent fuel pool building during transport of the closure head. Also, by isolating the containment building from the spent fuel building the spent fuel pool is protected against drain down that might occur as a result of a postulated drop accident.

Evaluations have been performed which demonstrate that a postulated head drop, from its specified maximum lift height, onto the reactor vessel will not result in a significant risk to public safety. Though the reactor vessel and internals may sustain damage, the reactor vessel will remain filled and the fuel will remain covered and in a subcritical configuration. Evaluations of the reactor internals demonstrate that a drop accident involving the internals would be less severe than the postulated head drop accident.

Travel paths for the closure head and the internals, leading from the reactor vessel to the respective storage stands, are arranged so that the transported loads do not pass directly over the ICI seal table (Refer to Figure 2.11-1). If it is postulated that portions of these structures do impact the seal table, seal housings and guide tubing above the seal table, the resulting damage would be localized to these components. Under these conditions, the water level within the vessel will remain at the flange level. In addition should the reactor cavity pool seal be damaged to the extent that there will be significant pool drainage, the reactor vessel will remain filled.

The refueling machine is structurally designed to withstand the effects of design basis seismic motions. In addition, this machine is provided with interlocks which restrict machine movements to permissible zones as well as lock the fuel grapple in place. The refueling machine is designed to transport one fuel assembly at a time between the reactor core and the fuel transfer system. It is also designed to transport CEA rod and ICI disposal containers between an intermediate storage rack and the fuel transfer system. The grapple for the disposal containers is the same design as the one used for fuel assemblies.

The refueling machine is designed so that it can not pass over the top of the ICI seal table. This precludes the possibility of load drop accident involving a fuel assembly falling onto the ICI seal table. Also, during normal refueling operations the travel path is restricted so that it passes over the reactor cavity pool seal at predetermined locations. As a minimum, the pool seal is designed so that it will withstand without leakage a postulated fuel drop accident in these zones. If, for other postulated reasons, there is significant drainage of the pool, it is possible to rapidly lower a fuel assembly on the refueling machine grapple to an elevation which insures that it remains submersed in water. The assembly may be inserted into the reactor vessel or lowered into the deep end of the refueling pool, adjacent to the fuel transfer system.

The head area cable tray assembly (HACTS), which is used to route power and signal lines away from the reactor vessel closure head, is designed to be handled by the auxiliary hoist on the polar crane. The cable trays are ra[illegible] vertically by this hoist from the installed position over the reactor vessel and moved to a storage position on top of either of the two steam generator walls. The trays are handled by four separate slings that are fastened to specially designed lift fixtures on the structural frame of the HACTS. All lifting components are designed in accordance with the criteria of NUREG-0612, Control of Heavy Loads at Nuclear Power plants. Prior to movement of the cable trays, the reactor must be in the shutdown mode and depressurized.

During a postulated load drop accident involving the impact of the HACTS onto the reactor vessel, the maximum impact energy is estimated to be about twenty percent of that associated with the reactor vessel closure head drop.

Though the reactor vessel may be damaged, the level of damage to the vessel and its support would be less severe than that associated with dropping the reactor vessel head. Furthermore, since the cable tray assembly is not a rigid structure, an appreciable fraction of the impact energy would be dissipated during plastic deformation of the HACTS itself.

For the postulated dropped cable tray accident, it is most probable that the HACTS would impact the closure head lift rig and the CEDM pressure housings. These structures are likely to be permanently deformed by bending and/or buckling. In some instances the pressure housings may also leak. The extent of damage, however, would not be sufficient to cause the reactor vessel to drain down, nor to adversely affect core criticality.

As with the containment building, special consideration is given to the transport of heavy loads and fuel assemblies in the fuel building. Also restrictions regarding the transport of heavy loads over fuel storage racks, and movement of the fuel shipping cask apply (Refer to Figure 2.11-2).

Transport of the fuel shipping cask within the spent fuel building is accomplished using a special high capacity hoist. The cask is transported using a staggered lift from the wash down area to the laydown area, where fuel loading takes place. This is done to limit the maximum drop height for the respective regions. In each case the floors and walls have been designed to withstand a postulated cask drop accident.

The spent fuel pool is connected to the cask laydown area by a gate, which will be closed to isolate the two zones during cask movement. The elevation of the gate is specified so that fuel located in the spent fuel storage racks would remain submerged following a postulated pool drain down through the gate.

The hoist used for transport of the fuel shipping cask is mechanically interlocked to prevent travel over the spent fuel pool. This interlock prevents the possibility of inadvertent movement of heavy loads over the spent fuel storage racks.

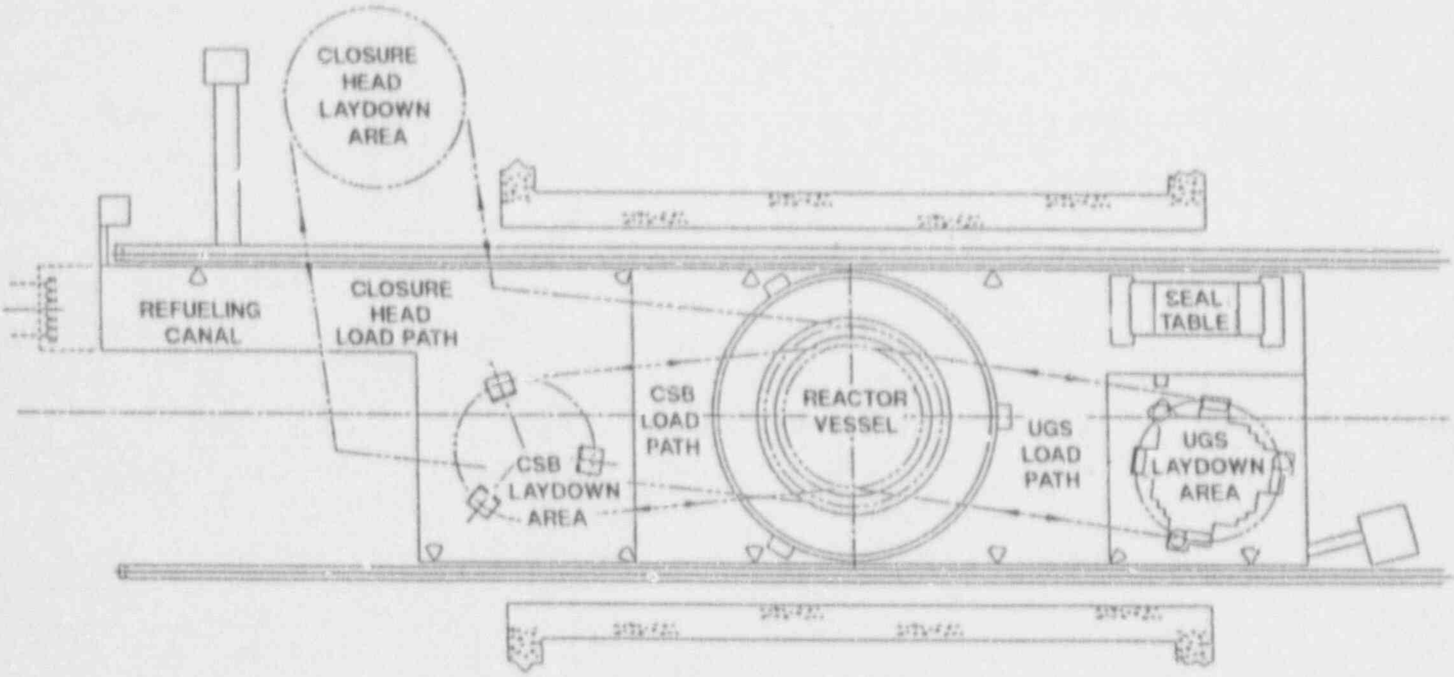
New fuel enters the fuel building through a designated unloading area. It is handled and transported to new fuel storage racks by an intermediate capacity hoist. The lift height of the hoist is restricted to limit the maximum drop height of the fuel and tool onto the new fuel storage racks. Like the fuel storage cask hoist, this hoist is also mechanically interlocked to prevent travel over the spent fuel pool.

The fuel handling machine used in the fuel building is similar in design to the refueling machine. It is structurally designed to withstand seismic excitations. Also, it is provided with interlocks to control the movement of fuel within the pool.

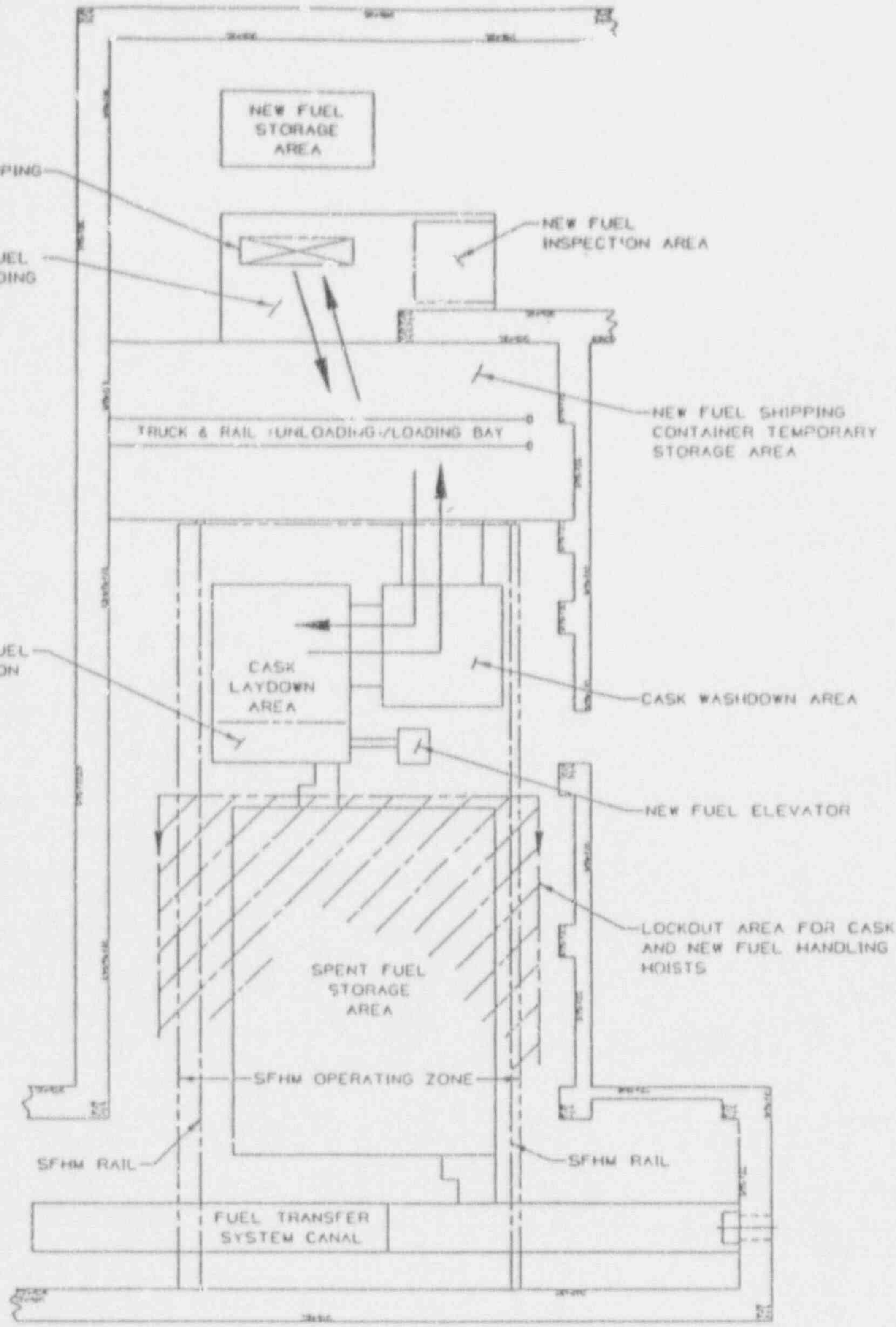
Both the new fuel and spent fuel storage racks are designed to withstand impact energies associated with postulated fuel drop accidents. They are designed to limit damage to the stored fuel and to maintain it in a subcritical configuration. Plant operating procedures also restrict the transport of loads over the fuel storage areas so that they do not exceed the design requirements for the storage racks. The consequences of dropping a spent fuel assembly in the spent fuel pool have been evaluated and the results presented in CESSAR-DC, Section 15.7.4. It has been shown that a postulated accident of this type would not present a risk to public health.

2.11.4 RESOLUTION

The issue of fuel handling and heavy loads is resolved for System 80+ by the equipment design and building layout which satisfy applicable criteria and provide physical limitations to movement and by administrative limitations in Chapter 9 of CESSAR-DC. The design and layout of the System 80+ plant incorporates features that have proven to be successful on other plants. Appropriate improvements have been introduced which provide an additional margin of safety during handling operations.



SYSTEM 80+™	CONTAINMENT BUILDING LOAD HANDLING PATHS	Figure 2.11-1



SYSTEM 80+™	FUEL HANDLING BUILDING LOAD HANDLING PATHS	Figure 2.11-2

2.12 POTENTIAL FOR DRAINING THE REACTOR COOLANT SYSTEM

2.12.1 ISSUE

The issue is the risk of losing primary coolant from the reactor coolant system during Modes 2 through 6 (shutdown, hot standby, hot shutdown, cold shutdown, and refueling). The safety significance of draining the coolant from the reactor coolant system during shutdown is that such an event can directly lead to voiding in the core and eventual core damage. The draining of the reactor coolant system may also lead to a loss of decay heat removal cooling capability which in turn could lead to core uncovery.

2.12.2 ACCEPTANCE CRITERIA

The criteria utilized to evaluate the adequacy of the System 80+ design with respect to the potential for draining the RCS are prevention, detection and mitigation. Prevention is the preferred criteria but in some instances detection and mitigation are to be provided.

2.12.2.1 Prevention Criteria

1. The design shall prevent or inhibit the draining through the use of isolation valves, interlocks, and system alignment restrictions during the various modes of plant operation.

2. The design shall minimize the potential for component failure, inadvertent action, or human/operator error to result in the rapid draining of the reactor vessel. Redundant components shall be provided as appropriate. The design shall provide instrumentation, overview displays, and alarms to clearly supply the operator with equipment status specific to shutdown modes.

3. Technical specifications and procedural guidance shall be provided to the plant owner/operator to assist in identifying plant conditions and configurations in Modes 2-6 that could result in a potential primary coolant drainage event.

2.12.2.2 Detection Criteria

The design shall have the capability to detect and monitor a drainage event. Drainage pathways that could lead to a loss of decay heat removal or core uncovery shall be considered. Appropriate instrumentation, displays and alarms shall be provided. The adequacy of System 80+ instrumentation to detect drainage events shall be confirmed and additional instrumentation shall be provided as necessary.

2.12.2.3 Mitigation Criteria

1. The design shall have the capability to mitigate the loss of primary coolant from the reactor including isolation of a drain path and the ability to provide a source and path for sufficient make-up.

2. Technical specifications and procedural guidance shall be provided to identify potential make-up water injection sources and paths in the event a drainage path does occur. Recovery actions shall be specified.

2.12.3 DISCUSSION

Primary coolant can drain from the reactor vessel due to a path directly from the Reactor Coolant System (RCS) or by way of paths through systems interfacing with the RCS. Plant modes of operation characterize the potential for draining the reactor coolant system (the alignments and conditions, such as pressure, temperature and flow which can exist within and between the RCS and interfacing systems) and the rate at which such draining can occur.

The causes of RCS draining (initiators) can be categorized into two groups. The first group includes components and equipment that fail to operate as intended. This could, for example, result from equipment malfunction (e.g., stuck open relief valve). The second group includes operator error such as misoperation of valves or pumps.

There are several key factors that affect the probability and the consequence (i.e., the risk) associated with an initiator. Consideration of these factors can aid in the development of procedures for prevention, detection, identification, and mitigation or termination of such events. These factors are the plant configuration, the ability to respond to the event, and the characterization of the initiator. These are summarized in Table 2.12-1.

TABLE 2.12-1

FACTORS WHICH AFFECT THE RISK ASSOCIATED WITH AN INITIATOR

Plant Configuration...
- System alignment with the RCS.
- Initial water level in the RCS.
- Availability of mitigating systems.
- Use of temporary seals (e.g., nozzle dams)

Ability to Respond...
- Detection of a draining event.
- Identification of the initiator.
- Termination or mitigation of the event.

Characterization of the Initiator...
- Probability of the initiator.
- Rate of drainage from the RCS.

Plant configuration is most notably characterized by system alignments with the RCS during various modes of shutdown operation. These alignments define the possible drain paths from the reactor vessel. The initial water level in the RCS influences operator response time. The use of temporary seals in the RCS (e.g., nozzle dams) and interfacing systems during maintenance and refueling activities can either be the source of an initiator (e.g., if the dam fails) or preclude mitigating actions by defeating injection paths (e.g., if an in place dam blocks circulation). Plant configuration is also characterized by the availability of mitigating systems. Mitigating systems must have a sufficient source of borated water and the ability to deliver this water to the reactor vessel at a rate greater than or equal to the rate at which water is draining from the RCS. Finally, maintenance activities must not preclude mitigating systems from being used to respond to the event.

Another factor that can affect the risk associated with an initiator is the ability to quickly determine that a loss of coolant is occurring (detection) and the source of the loss (identification). This defines instrumentation and control requirements to respond to draining events.

The analysis presented in this section was conducted by examining design drawings and piping and instrumentation diagrams for System 80+ to define potential drain paths from the reactor vessel and to consider these drain paths in the context of the factors shown in Table 2.12-1. A potential drain path is any opening in the RCS (seal, manway) or any interfacing system piping path that can take primary coolant away from the RCS. Many openings and interfacing systems are designed specifically to allow fluid to leave the RCS or interfacing system (e.g., relief valves) or to circulate primary coolant for normal letdown, purification, charging (CVCS), sampling (SS) activities or shutdown cooling (SCS).

A shutdown risk drain path results in an unplanned loss of primary coolant from the RCS with the accompanying lowering of the water level in the reactor vessel. The path could be short (seal leakage) or relatively long (via piping of an interfacing system). The driving head for the draining flow will depend on the relative conditions between the coolant in the reactor vessel and the conditions at the end of the drain path. This includes RCS pressure, elevation head, pump head, and backpressure.

For purposes of this analysis, a shutdown risk drain path is categorized as either major or minor. A major drain path is one that, based on analysis for certain specified plant configurations, could result in a rapid drain flowrate. The preferred recovery would be to isolate the drainage source before the RCS water level reaches the break level and to add makeup to the RCS. It is possible, however, that such a major path could drain the RCS to the bottom of the hot leg elevation too rapidly before the operator could take mitigative action. Such an occurrence could result in a loss of SCS due to insufficient water level. The identification of major drain path does not imply that such a path is likely or probable for System 80+, but only that it is possible and that its potential consequence requires special attention be directed to prevention and recovery procedures. Minor drain paths are those that result in a drain flowrate that can be compensated for using available make-up systems, or are otherwise insignificant.

The identification of a minor drain path requires no further action. The identification of a major drain path requires specific procedural guidance to aid the operator in avoiding this path. It also results in providing the operator the means and guidance to recover from such an event. The means to detect, mitigate and recover from such postulated major drainage events are those described in Sections 2.3, 2.4, and 2.8 of this report.

2.12.3.1 Potential Drain Paths Directly from the Reactor Coolant System

Potential drainage paths directly from the Reactor Coolant System are associated with the reactor coolant pumps, the steam generators, the In-Core Instrument Seals and the reactor cavity seal. Note that reactor cavity seal leakage is not an actual RCS leakage but it is a form of inventory loss during Mode 6. Table

2.12-2 identifies those paths which are major (i.e., have the potential to rapidly drain the RCS to a critical water level) and minor (i.e., can be controlled by available systems).

TABLE 2.12-2

POTENTIAL DRAIN PATHS DIRECTLY FROM THE REACTOR COOLANT SYSTEM

Major Drain Paths

Steam Generator Nozzle Dam Failure
Steam Generator Manway Opening

Minor Drain Paths

Reactor Coolant Pump Seal Leakage
ICI Seal Table/Housing Leakage
Steam Generator Tube Rupture
Reactor Cavity Seal Leakage

2.12.3.1.1 Major Drain Paths Directly from RCS

The failure of temporary steam generator dams and the opening or leakage through steam generator manways could lead to a rapid loss of primary coolant perhaps to an RCS water level at the bottom of the hot legs. A discussion of steam generator nozzle dam integrity is presented in Section 2.3.3.3 of this report. The System 80+ design includes a requirement to establish a mid loop vent pathway before operating in reduced inventory. When opened to the containment atmoshphere, it provides sufficient venting capacity to prevent RCS pressurizations and subsequent dam failure. Guidance to address the safety and risk aspects of nozzle dam installation timing is presented in Section 2.3.3.3 of this report. System 80+ procedural guidance will preclude manway openings that would lead to a loss of reactor coolant.

2.12.3.1.2 Minor Drain Paths Directly from the RCS

There are three stages of RCP seals for each System 80+ RCP and each of the three seals are capable of operating at full RCS pressure. However, the reactor coolant pump can potentially suffer some leakage from pump seals during any mode. Seal leakage is detected by a RCP bleed-off flow alarm (F-156, -166, -176, -186). The source of leakage can be identified to a specific pump. Drainage from RCP seals would be manageable and can be compensated by available systems.

The System 80+ In-Core Instrumentation (ICI) system design employs instrument tubes that terminate in the refueling cavity at an elevation several feet above the reactor vessel flange. The System 80+ design does not employ temporary thimble tube seals. Even so, there has been concern expressed in Section 6.7.2 of NUREG-1449, (DRAFT) that evolutions could exist that would provide a potentially significant flow path between the bottom of the reactor vessel and the top of the seal table, particularly if the RCS is pressurized. Table evolutions are prohibited by procedural guidance (see also Section 2.3.3.5 of this report) while the vessel head is on and mid-loop evolutions are in progress, thus, preventing seal leaks. An evaluation of heavy load handling for System 80+ relative to ICI seal table is discussed in Section 2.11 of this report. Travel paths for the closure head and internals from the reactor vessel to the respective storage stands are arranged so that the transported loads do not pass directly over the ICI seal table. This precludes the possibility of a load drop accident falling on the ICI table.

A steam generator can leak primary coolant through tube failure during any mode when the RCS is pressurized. An evaluation of steam generator tube rupture initiated in a shutdown mode is presented in Section 4.6.3 of this report. The leaka from a ruptured tube during shutdown is minor relative to reaching a RCS water level at the bottom of the hot legs.

Reactor cavity seal failure could be postulated during Mode 6 when the refueling pool is full. Although such a drainage could be a concern relative to any fuel being transported, the drainage would be self limiting to level of the reactor vessel flange and the SCS will be uninterrupted.

2.12.3.2 Potential Drainage Paths Through Interfacing Systems

Potential RCS interfacing system drainage paths from the Shutdown Cooling System (SCS), the Safety Injection System (SIS), the Chemical and Volume Control System (CVCS) and the Sampling System (SS) are illustrated in Figures 2.12-1, 2.12-2, 2.12-3 and 2.12-4. The originating points of the drainage paths are location on the Reactor Coolant System. The paths include piping, valves, pumps, heat exchangers and orifices. The greek symbol ϕ represents the piping outer diameter. The terms IC and OC are used to show whether a path segment is inside containment or outside containment, respectively. The "letter-number" number designation in the boxes generally refers to system valves which are of the motor operated, manually operated, check or relief type. The letter "F" followed by a number referes to a flow measuring device. Those paths represented by the darker/bold lines identify major drain paths. The end points of these paths are various tanks or systems assumed to be open for maintenance.

An assessment of these paths was made relating potential flow rates and the time it would take for the RCS water level to reach the bottom of the hot-legs. An assessment of the relative probability, of single versus multiple valve misalignments or failures was not considered at this time. All paths were considered possible, even though it is recognized, multiple misalignments are less likely.

2.12.3.2.1 Potential Drainage Paths From The RCS Through the SCS (SCS Trains: From RCS Hot Leg 1 Through DVI Nozzle 1A and From RCS Hot Leg 2 Through DVI Nozzle 1B)

This discussion is specific to train 1 but applies to train 2 as well.

This overall path represents one of the two normal shutdown cooling trains. As long as this path is isolated from the RCS during Modes 2, 3 and part of 4 loss of coolant from the RCS through the SCS is prevented. While the SCS is in operation during part of Mode 4 and during Modes 5 and 6 there exists potential paths from the SCS through which the primary coolant passing through the SCS could be drained. The main initiators to open a drain path would be an overpressurization leading to the lifting of a relief valve (which fails to reseat) and/or operator error opening a valve or series of valves to an open system. A valve failure is another possible initiator. An open system is a system which has been drained for maintenance activities.

The SCS suction piping contains two motor operated isolation valves (SI-651 and SI-653) in series inside the containment (see Figure 2.12-1). These valves are closed during Modes 1, 2 and 3. In addition, there is also a motor operated valve (SI-655) outside the containment. All three valves can be operated from the control room and have position indication in the control room. An alarm exists to notify the operator if the two motorized valves inside containment are not fully closed coincident with high RCS pressure. Operator actions require that the RCS be depressurized below the maximum pressure for SCS operation in order to clear the permissive SCS interlock. Therefore, drainage from the RCS through the SCS to interfacing systems in the normal flow path direction is prevented during Modes 2 and 3. Flow will occur through the SCS train during part of Mode 4 and throughout Modes 5 and 6.

The potential drain paths from the SCS as shown in Figure 2.12-1 are summarized in Table 2.12-3. The 30 paths of Figure 2.12-1 have been broken down into groups of similar drain path characteristics.

TABLE 2.12-3

GROUPING OF PRIMARY COOLANT DRAINAGE PATHS FROM THE SCS

Minor Drain Paths

Group	Paths
A. Thermal Relief Valve Discharge	1, 3, 18, 19, 21, 22, 25, 27, 28
B. Paths to the Sampling System	6, 12
C. Paths to the CVCS	5, 8, 9, 15, 17
D. Paths to the CCWS	10, 11, 14
E. Paths to SIT #1	23
F. Paths to IRWST, RDT, and EDT Through Manual Valves and Small Piping	24, 26, 29, 30

Major Drain Paths

G. Paths Through Motor Operated Valves and Large Piping to the IRWST	4, 16
H. SCS Suction Relief Valve Discharge	2
I. Paths Through large Manual Valves to CS Pump Suction and Discharge	7, 13
J. Path to the Refueling Pool	20

Group A through F paths are minor paths and include relief valves, paths through small piping (1/2 in - 3 in O.D.) to assumed "open" systems, SC pump seal leakage, SC mini-flow heat exchanger tube leakage, SC heat exchanger tube leakage and a postulated path to the SITs.

The paths of groups A through F, if they were to occur and lead to a loss of primary coolant, could be mitigated with available equipment and make up sources during Modes 4, 5 and 6. The discharge would be slow enough such that a loss of primary coolant to the bottom of the hot legs should not occur before detection and mitigation have been accomplished. No new design features, technical specifications or procedural guidance are identified for the paths in these groups.

Groups G through J represent major paths that, if established, could result in a rapid loss of reactor coolant during Modes 5 and 6. Depending on the availability of equipment and systems to perform mitigative action during these modes such a rapid discharge may lead to an RCS water level at the bottom of the hot legs with a concurrent loss of both SCS trains. Procedural guidance to aid the operator in addressing these paths is specified in Section 2.1. The recovery action for this scenario is discussed in Section 2.4.3.1.

2.12.3.2.2 Potential Drainage Paths from the RCS to the SIS/SCS (From DVI Nozzles 1A, 2A, 1B and 2B)

The potential drain paths from the RCS through the SIS/SCS, originating at the DVI nozzles, are shown in Figure 2.12-2.

The potential drain paths presented in Figure 2.12-2 are "reverse" paths relative to the normal safety injection flow direction. As a result, in order to assume RCS drainage from the DVI nozzles, it is postulated in this analysis that multiple failures of check valves occur.

The DVI nozzles in System 80+ are located several (4-5) feet above the hot leg and cold legs. Therefore, loss of coolant through a DVI nozzle would be self limiting. The level of primary coolant would stabilize at the level of the DVI nozzle, and not result in a loss of shutdown cooling. No new design features, technical specifications or procedural guidance have been identified for these paths associated with flow from DVI nozzles.

2.12.3.2.3 Potential Drainage Paths from the RCS to CVCS

The potential drain paths from the RCS through the CVCS are shown in Figure 2.12-3. The potential drain paths presented in Figure 2.12-3 are the normal letdown, charging, RCP seal injection, RCP seal leak off, RCP seal bleed off and drain paths associated with the CVCS design. A major opening in the letdown or charging line needs to occur for any appreciable drainage to occur.

The paths defined for the CVCS, if established, would be manageable with available make up sources during Modes 2, 3, 4, 5 or 6. This discharge would be slow enough such that a loss of primary coolant to the hot leg level should not occur before detection and mitigation have been accomplished. No new design features, technical specification or procedural guidance are identified for paths associated with the CVCS.

2.12.3.2.4 Potential Drainage Paths from the RCS to the SS

The potential drain paths from the RCS through the SS are shown in Figure 2.12-4. The potential drain paths presented in Figure 2.12-

4 are normal sampling paths. A major opening in the sampling lines would need to occur for a net loss of primary coolant to occur.

The paths defined for the SS, if they were to occur, would be manageable with available make up sources during Modes 2, 3, 4, 5 or 6. The discharge would be slow enough such that a loss of primary coolant to the hot leg level should not occur before detection and mitigation have been accomplished. No new design features, technical specifications or procedural requirements are identified for paths associated with the SS.

2.12.4 RESOLUTION

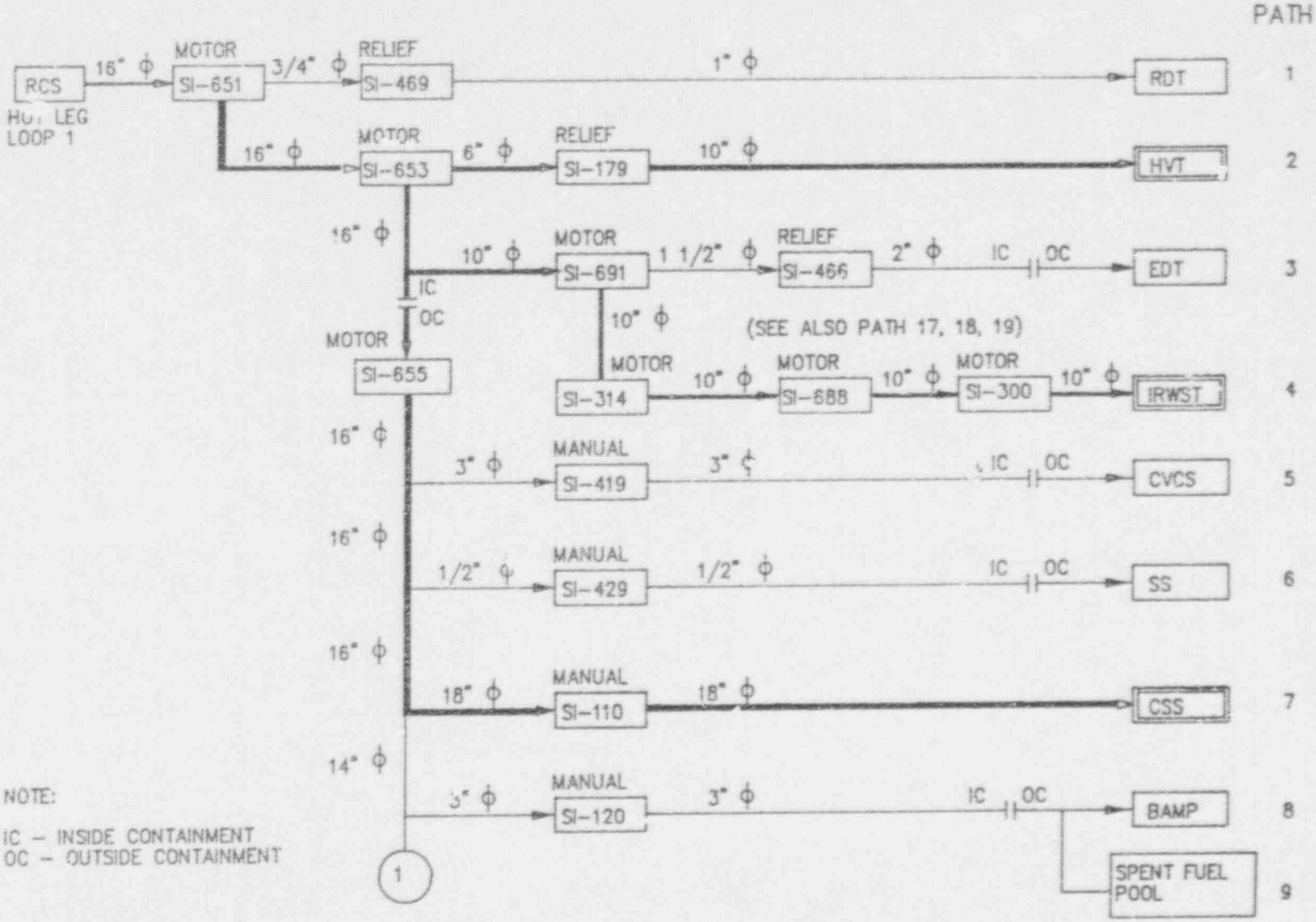
The shutdown risk issue of the potential for draining the System 80+ RCS is resolved primarily by design features, technical specifications and procedural guidance to prevent a drainage event from occurring and to allow the operator to recover in a timely manner if such an event occurs.

The vast majority of potential paths reviewed were judged to be minor such that the drain flow rate can be compensated using available detection and mitigating systems or are otherwise insignificant. System 80+ design features, technical specifications and procedural guidance are sufficient for such paths.

An examination of the potential drainage paths for various System 80+ plant arrangements and operating configurations has provided candidate paths, that if assumed to be opened, could lead to a rapid loss of primary coolant. The candidate paths primarily involve those opened by misoperation or misalignment of one or multiple valves by the operator. The importance of such potential major drainage paths to a shutdown risk scenario has led to procedural guidance (see Section 2.1) being specified to aid the operator in addressing these paths

The issue of potential RCS drain paths is ultimately resolved, from a core uncovery prevention perspective, by the use of System 80+ design features to detect, mitigate and recover from postulated loss of shutdown cooling events as described in Section 2.4 of this report.

SYSTEM 80+™



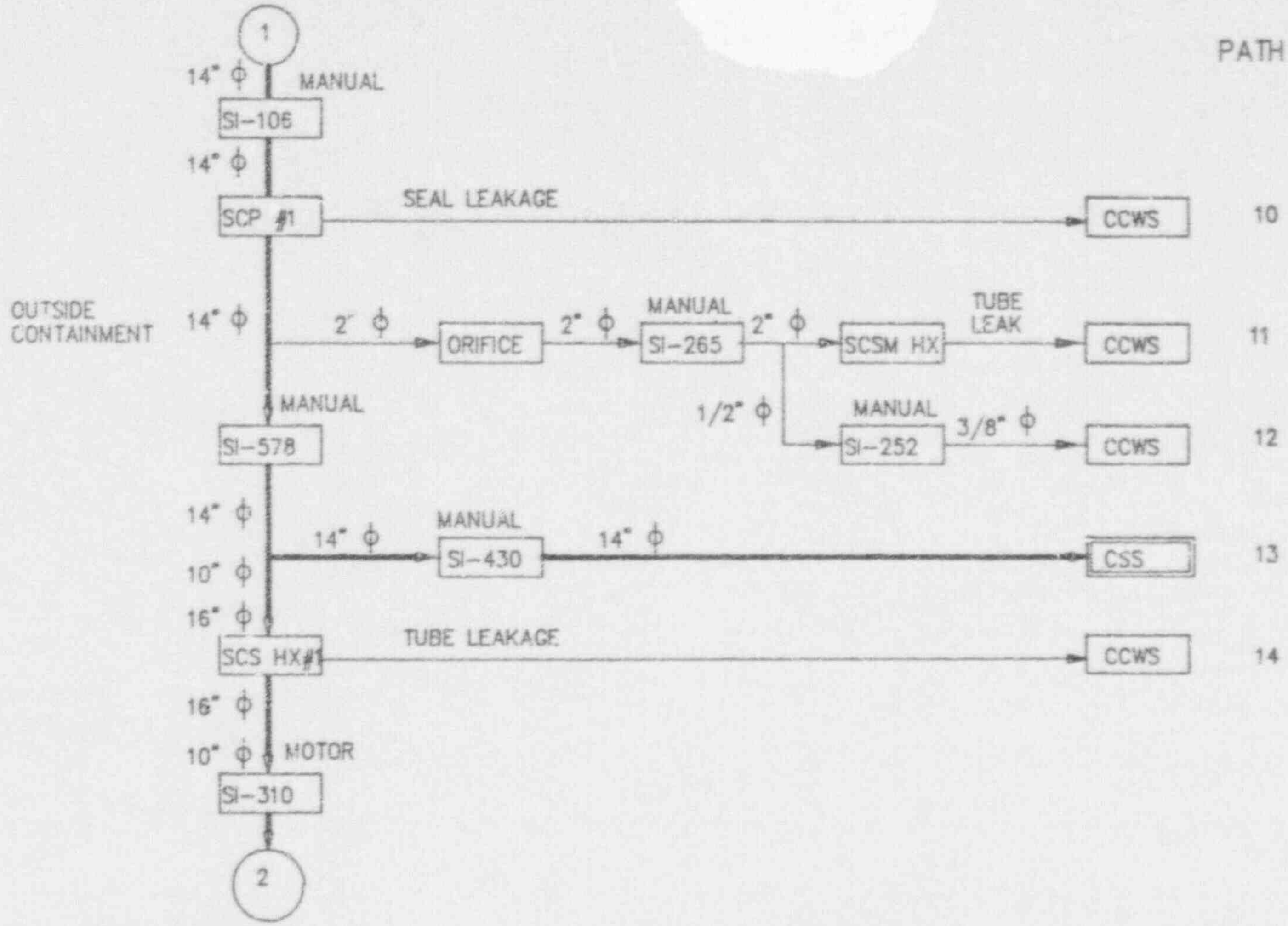
NOTE:

IC – INSIDE CONTAINMENT
OC – OUTSIDE CONTAINMENT

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS
FROM SCS TRAIN NO. 1

Figure 2.12-1

Sheet 1 of 5

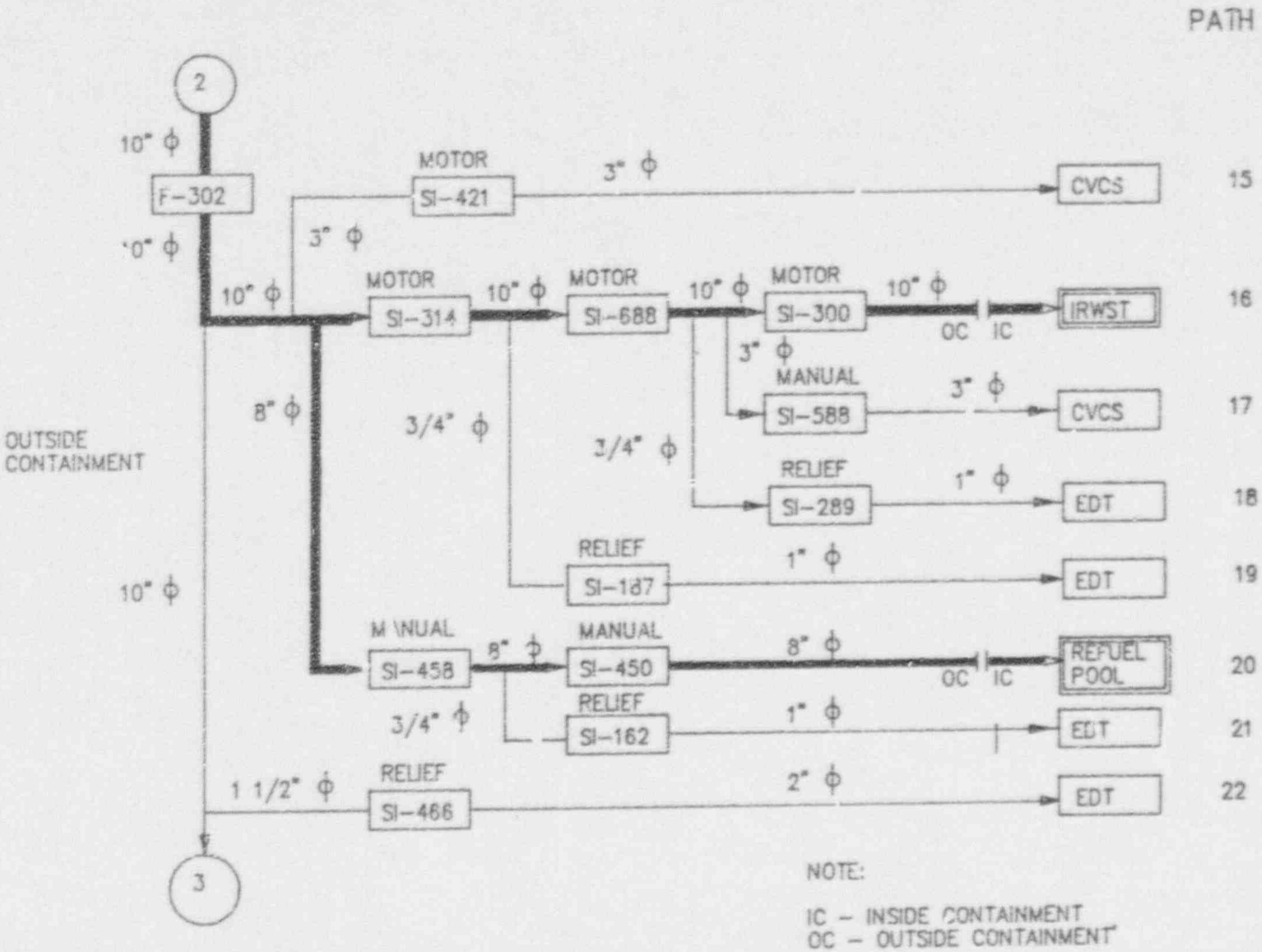


System 80+

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM SCS TRAIN NO. 1

Figure 2.12-1

Sheet 2 of 5

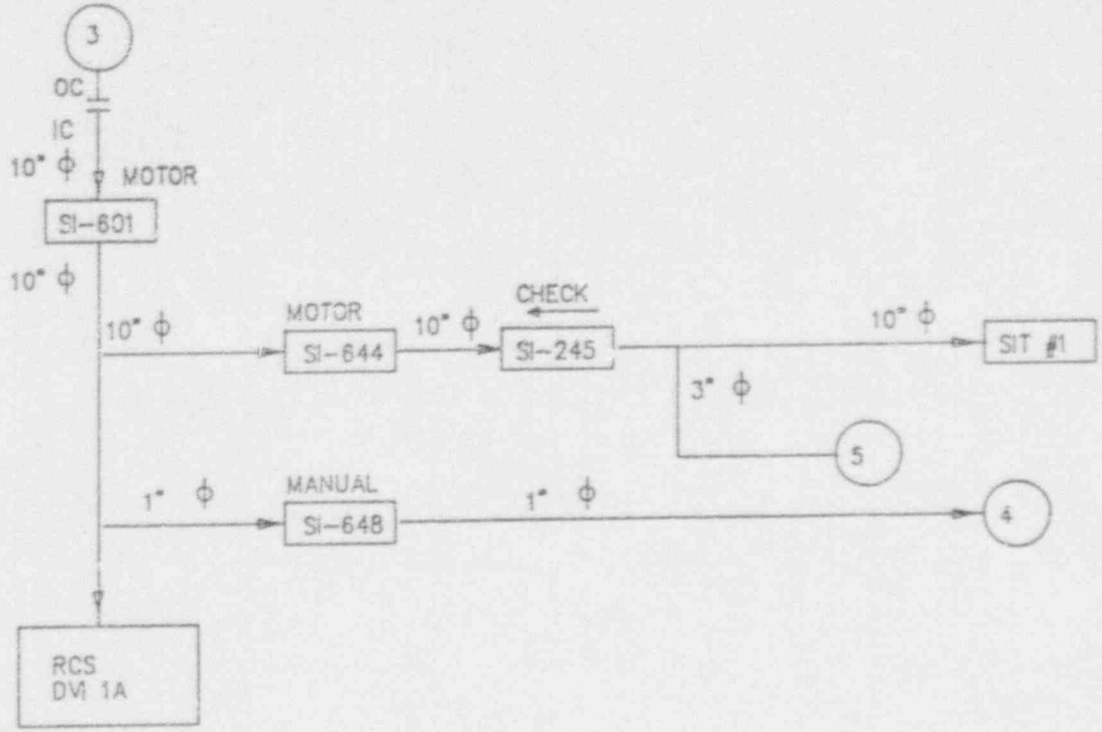


POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS
FROM SCS TRAIN NO. 1

Figure
2.12-1

Sheet 3 of 5

PATH



23

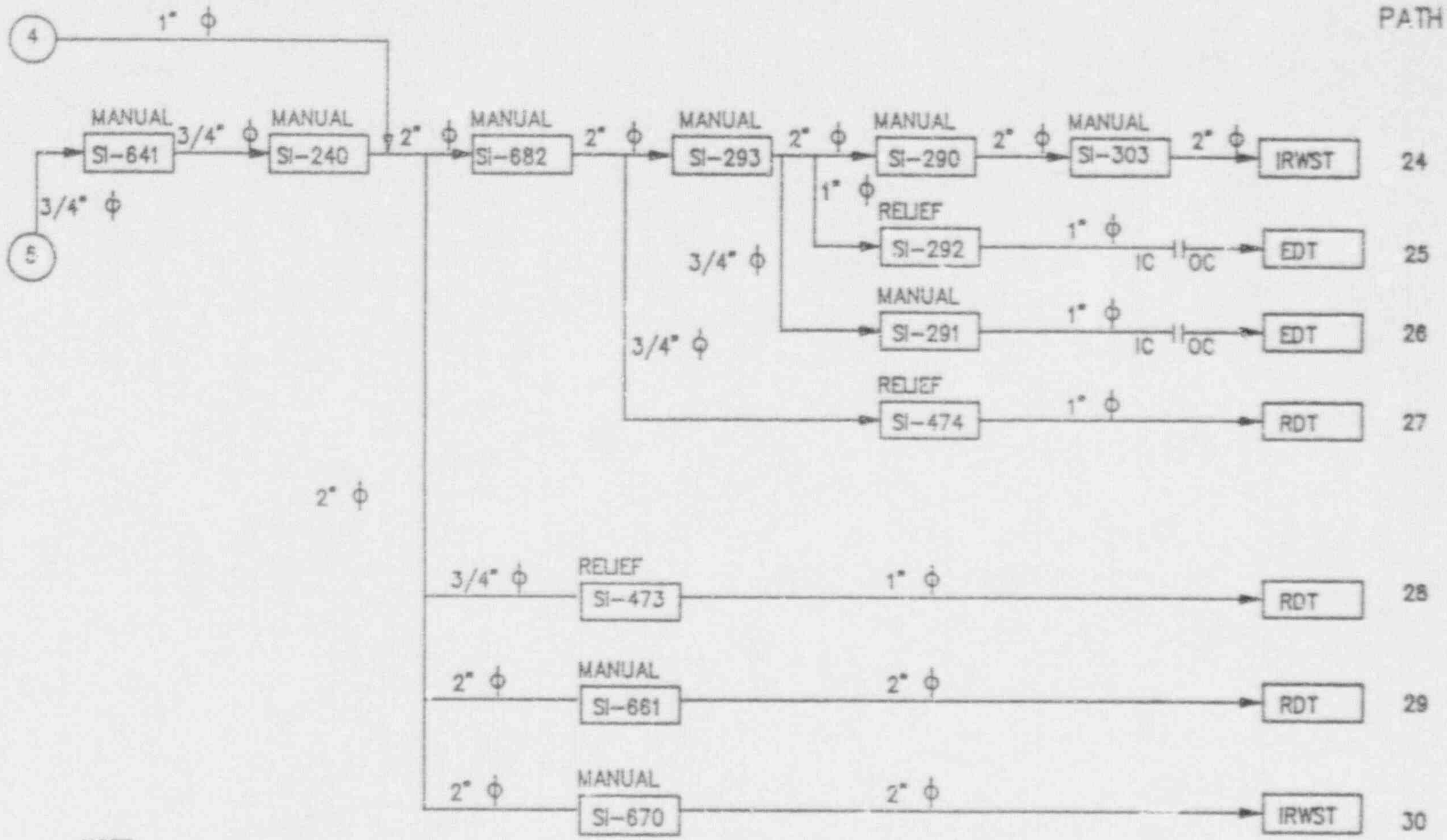
NOTE:

IC - INSIDE CONTAINMENT
OC - OUTSIDE CONTAINMENT

SYSTEM 80+™

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS
FROM SCS TRAIN NO. 1

Figure
2.12-1



NOTE:

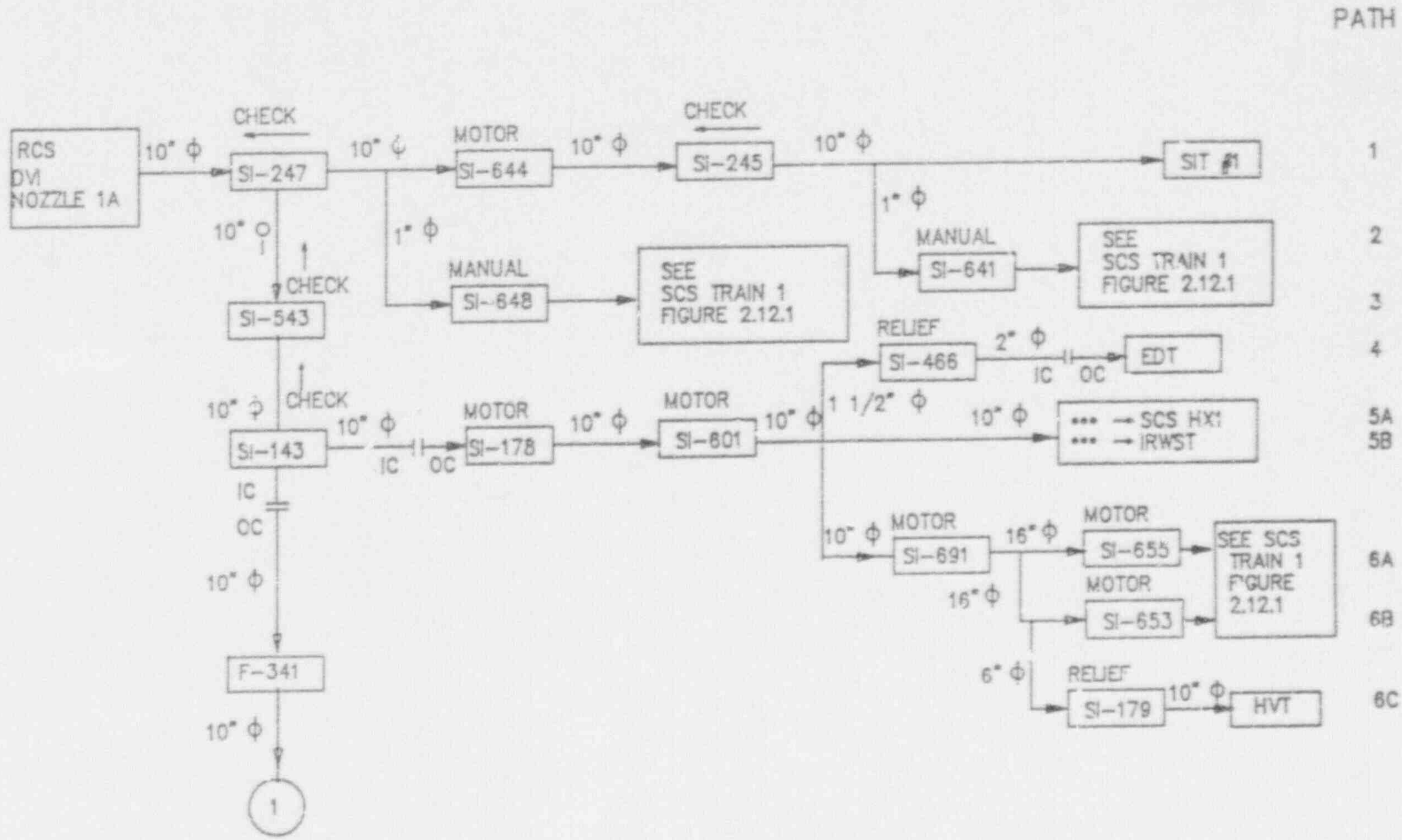
IC – INSIDE CONTAINMENT
OC – OUTSIDE CONTAINMENT

SYSTEM 80+

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM SCS TRAIN NO. 1

Figure 2.12-1

SYSTEM 80+™



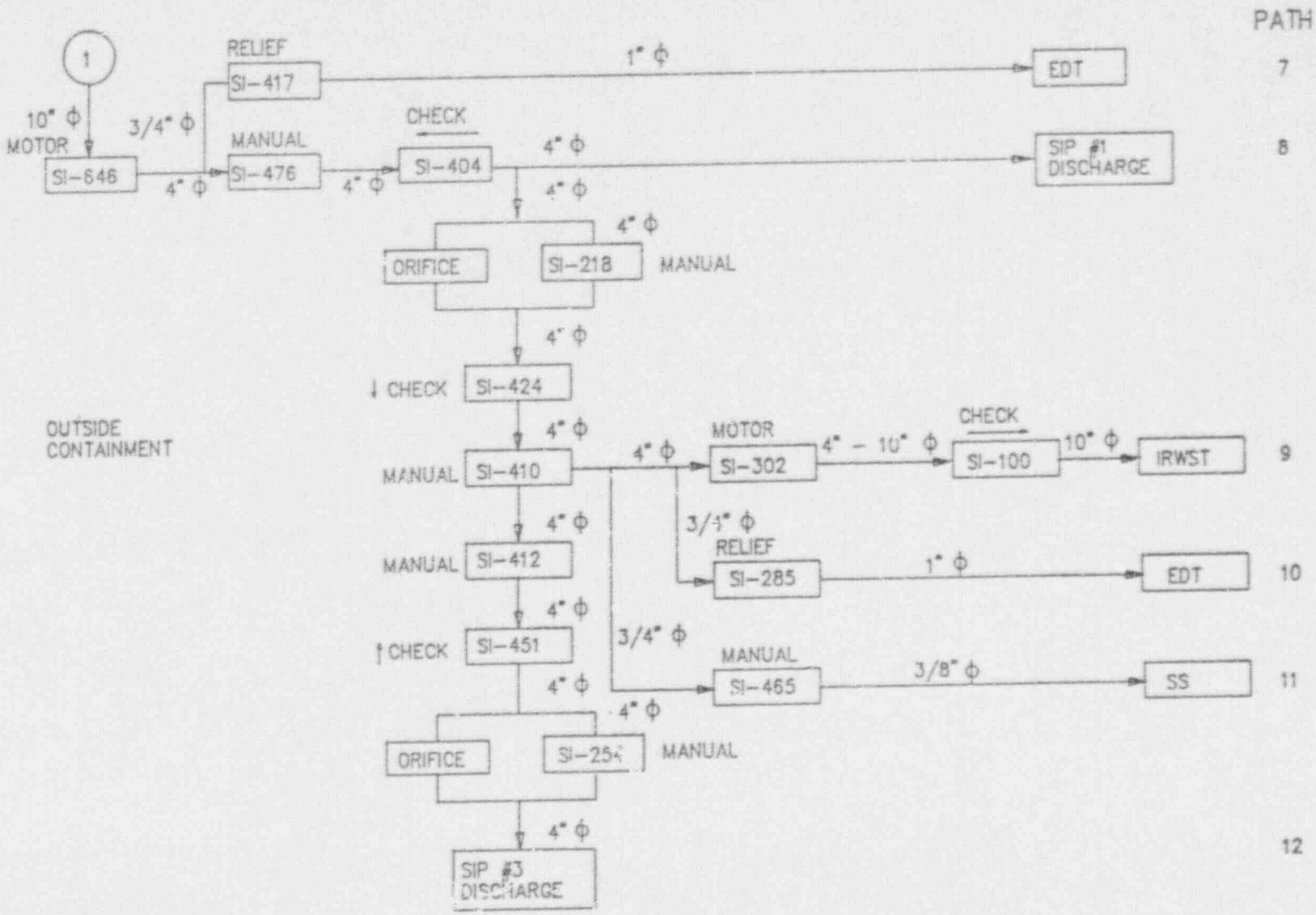
NOTE:

IC – INSIDE CONTAINMENT
OC – OUTSIDE CONTAINMENT

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS
FROM SIS/SCS DVI NOZZLE 1A

Figure 2.12-2

Sheet 1 of 2

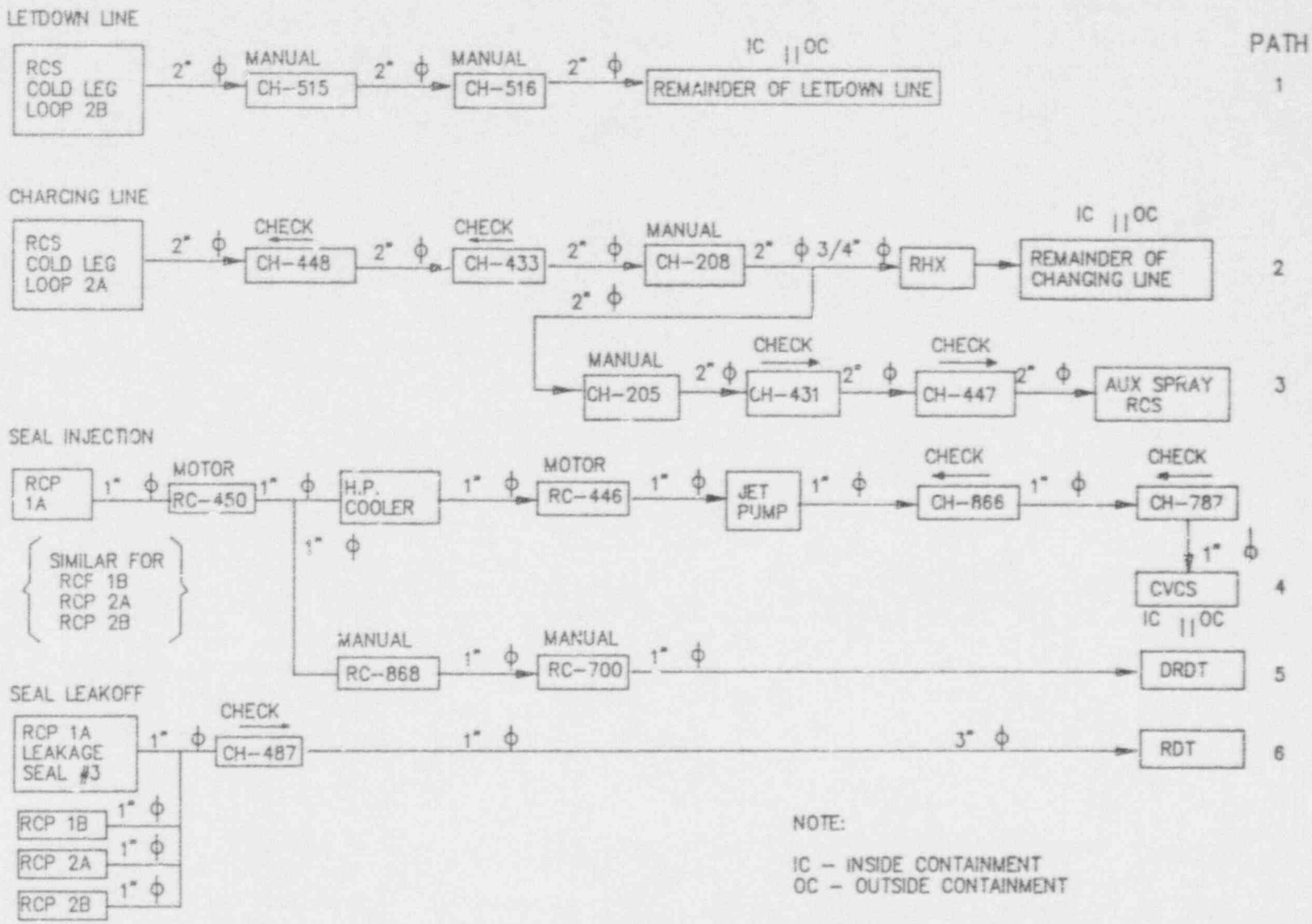


SYSTEM 80+

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM SIS/SCS DVI NOZZLE 1A

Figure 2.12-2

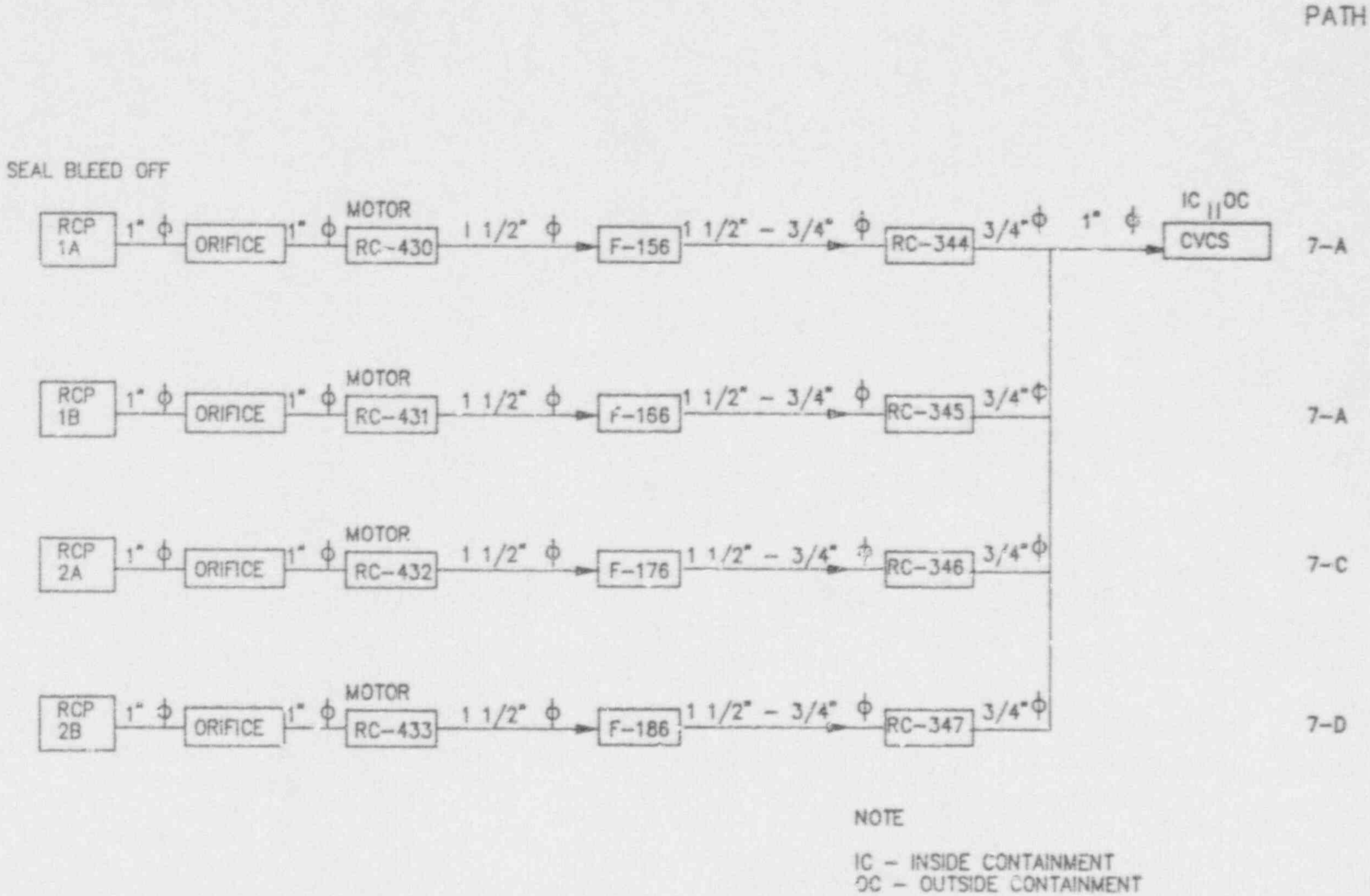
Sheet 2 of 2



POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM CVCS

Figure 2.12-3

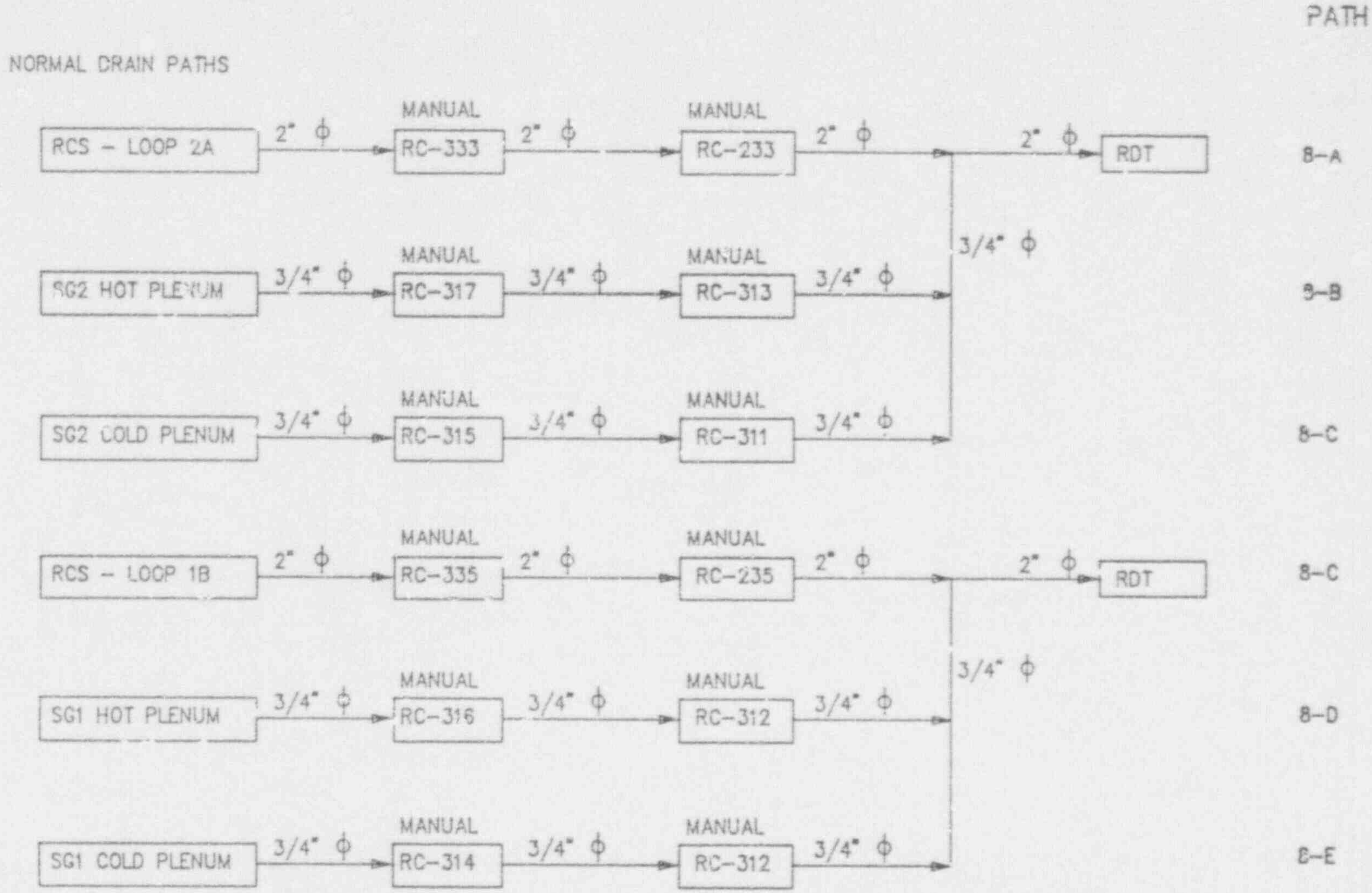
Sheet 1 of 4



POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM CVCS

Figure 2.12-3

Sheet 2 of 4

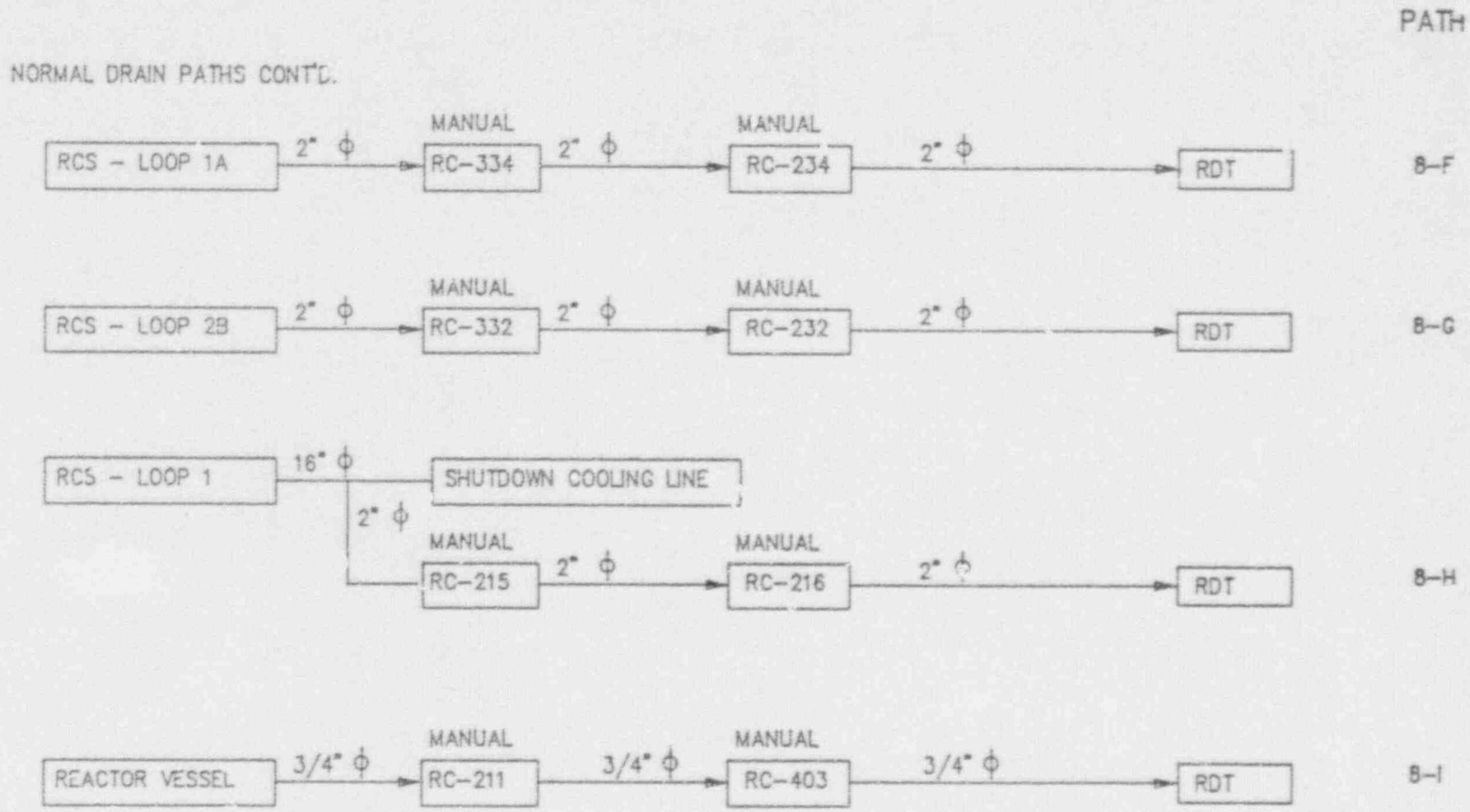


SYSTEM 80+

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM CVCS

Figure 2.12-3

Sheet 3 of 4

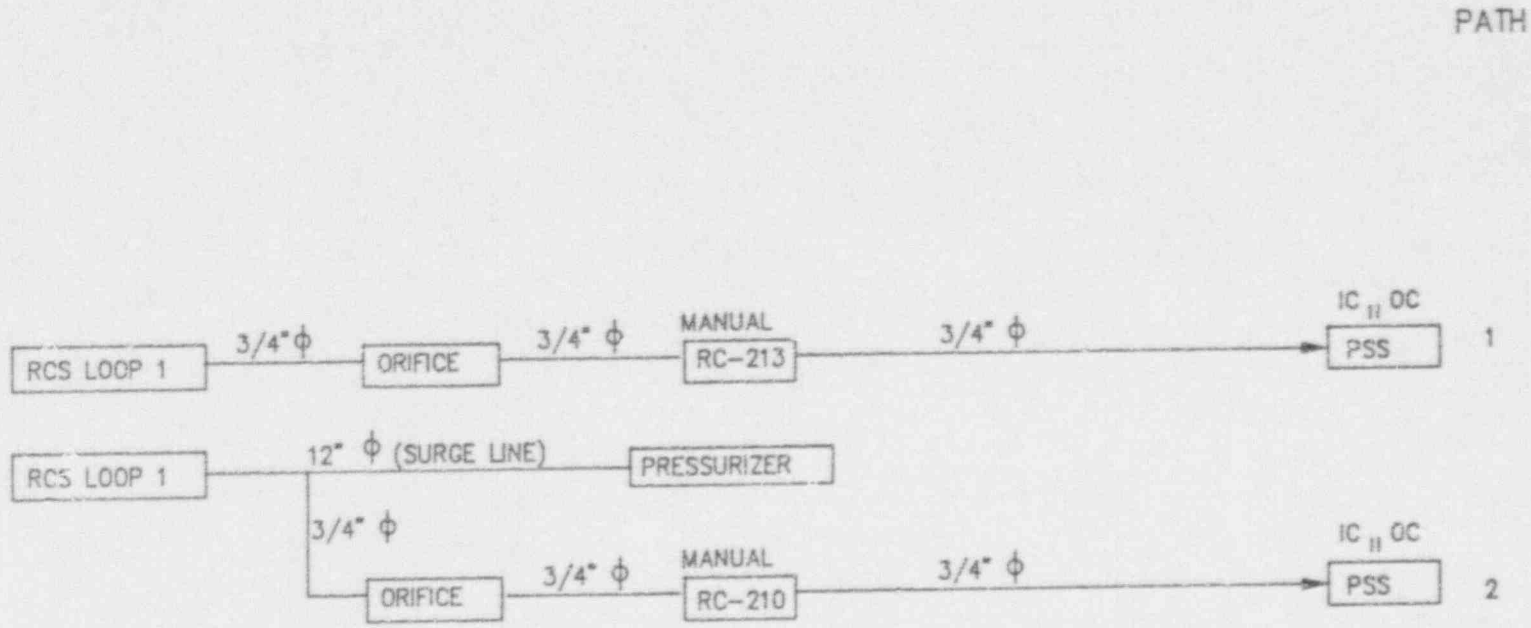


SYSTEM 80+™

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM CVCS

Figure 2.12-3

Sheet 4 of 4



NOTE:

IC – INSIDE CONTAINMENT
OC – OUTSIDE CONTAINMENT

SYSTEM 80+™

POTENTIAL RCS INTERFACING SYSTEM DRAINAGE PATHS FROM PPS

Figure 2.12-4

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2.13 FLOODING AND SPILLS

2.13.1 ISSUE

Essential systems may be at higher risk for failure due to flooding and spills during shutdown because of the varied and interrelated maintenance activities that may be in progress simultaneously. Past events have involved, for example, spills from the component cooling water system, service water system, condensers, and refueling pool seals. The issue addressed here is the potential for loss of decay heat removal as a consequence of spills and internal flooding that may disable components of the shutdown cooling system.

2.13.2 ACCEPTANCE CRITERIA

The flood protection design will provide separation of redundant equipment to ensure decay heat removal (DHR) systems availability and capability are not precluded due to flooding and spills.

2.13.3 DISCUSSION

The flood protection provided insures a boundary of separation between redundant DHR systems. The separation includes components and structures to prevent the migration of water. Preventing the migration of water eliminates the potential for rendering redundant DHR equipment inoperable.

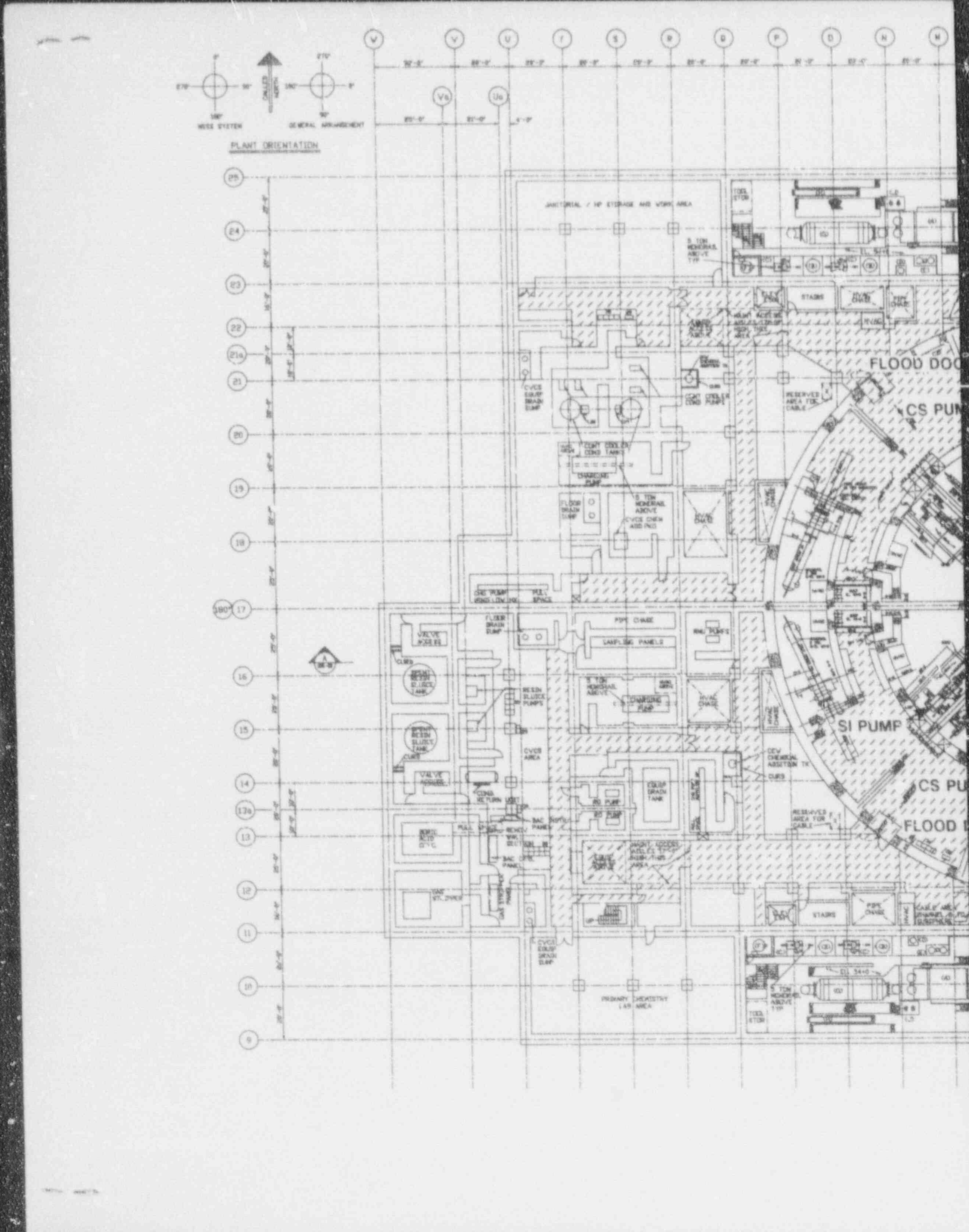
The System 80+ design provides separation and flood barriers to prevent the flood of redundant equipment. The design features a divisional separation. This divisional separation is a wall in the Nuclear Annex and the Reactor Building Sub-Sphere. The wall forms a barrier between the Division 1 and the Division 2 mechanical and electrical equipment. This wall contains no unsealed penetrations below the 70′ elevation level. This wall is along column line 17 (see CESSAR-DC Figures 1.2-4 and 1.2-5, reproduced here as Figures 2.13-1 and 2.13-2). Additional separation of the divisions is provided by the floor drain systems. The sumps and floor drains located in the Nuclear Annex and the Reactor Building Sub-Sphere are divisionally separated. This design feature prevents the migration of floodwater from one division to the other through the floor drains.

The Systems 80+ design utilizes flood doors to provide separation within the same division. In the Reactor Building Sub-Sphere, the flood doors provide quadrant separation, therefore equipment is protected from floods within the same division. Flood doors also provide protection for Reactor Building Sub-Sphere Quadrants A and B from flooding outside the sub-sphere. This protects the Shutdown Cooling Systems from floods that could occur in the Nuclear Annex and migrate into the sub-sphere. Flood doors also provide protection for the Vital Electrical Equipment located in the Nuclear Annex on elevation 50' (see Figure 2.13-1).

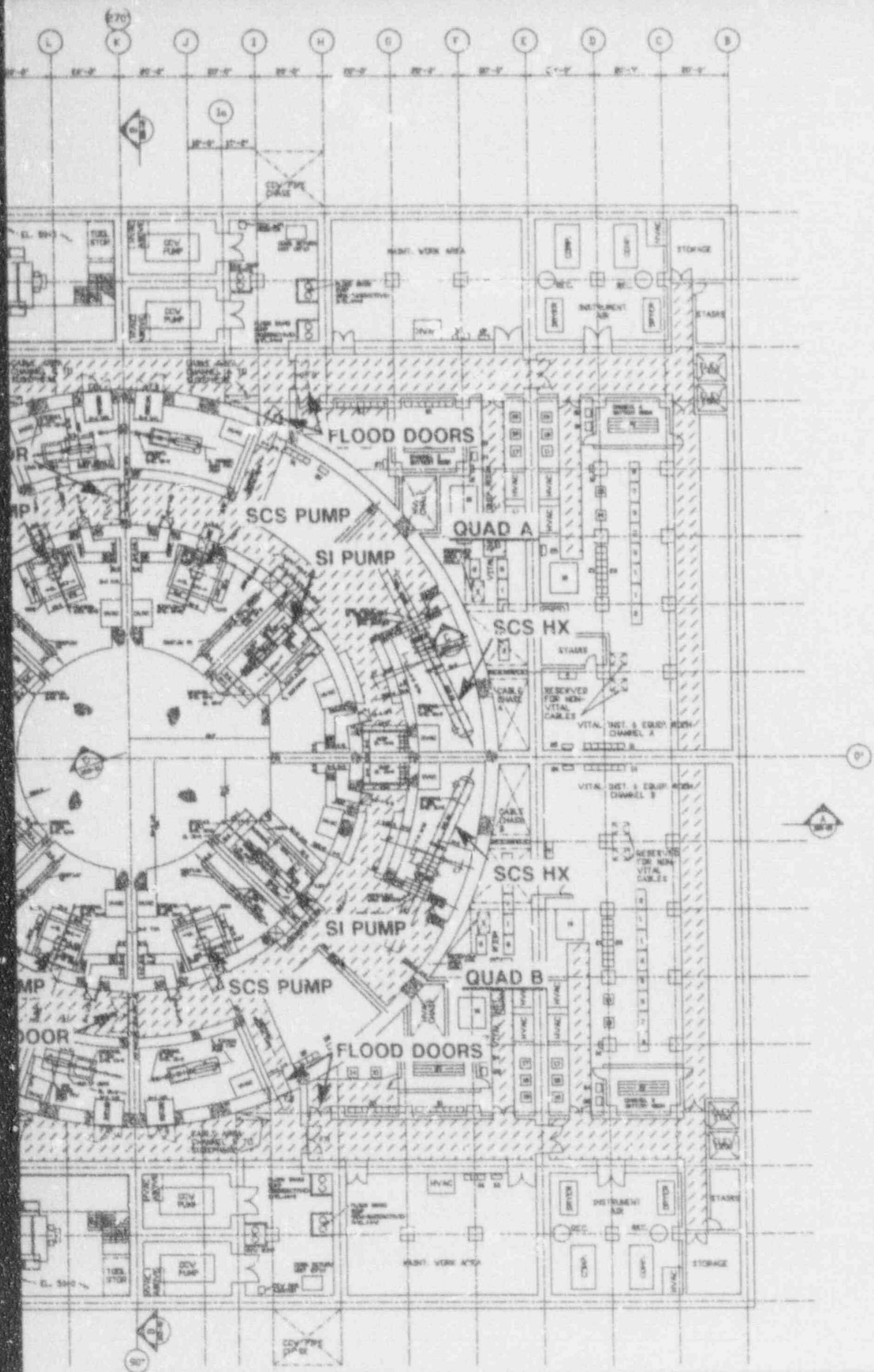
The System 80+ does not have any raw water systems inside the Nuclear Annex or Reactor Building. This design provides a significant contribution to flood protection because the flood sources are finite. Two significant sources of water are the Component Cooling Water System and the Emergency Feedwater Storage Tanks. Emptying the entire volume of water contained in a division of either of these systems will not flood above the 70' elevation. Therefore, no migration of water to the other division or to other protected areas (e.g., electrical equipment) will occur due to the flood. This ensures the redundant systems and equipment located in the other division are available for decay heat removal.

2.13.4 RESOLUTION

The System 80+ flood protection design features are consistent with acceptance criteria outlined above in Section 2.13.2. These features resolve the issue of flooding and spills during shutdown operations on System 80+ by providing separation of redundant equipment required for decay heat removal. This separation provides the availability of DHR when a flood has occurred within the Nuclear Annex or Reactor Building Sub-Sphere.



PLANT ORIENTATION
GENERAL ARRANGEMENT
JANITORIAL / HP STORAGE AND WORK AREA
FLOOD DOO
CS PUM
SI PUMP
CS PU
FLOOD
STAIRS
HVAC CHASE
PIPE CHASE
SAMPLING PANELS
VALVE AISLES
RESIN SLUICE PUMPS
CVCS AREA
CHARGING PUMP
FLOOR DRAIN SUMP
CVCS EQUIP DRAIN SUMP
EQUIP DRAIN TANK
PRIMARY CHEMISTRY LAB AREA
5 TON MONORAIL ABOVE TYP
TOOL STOR
RESERVED AREA FOR CABLE



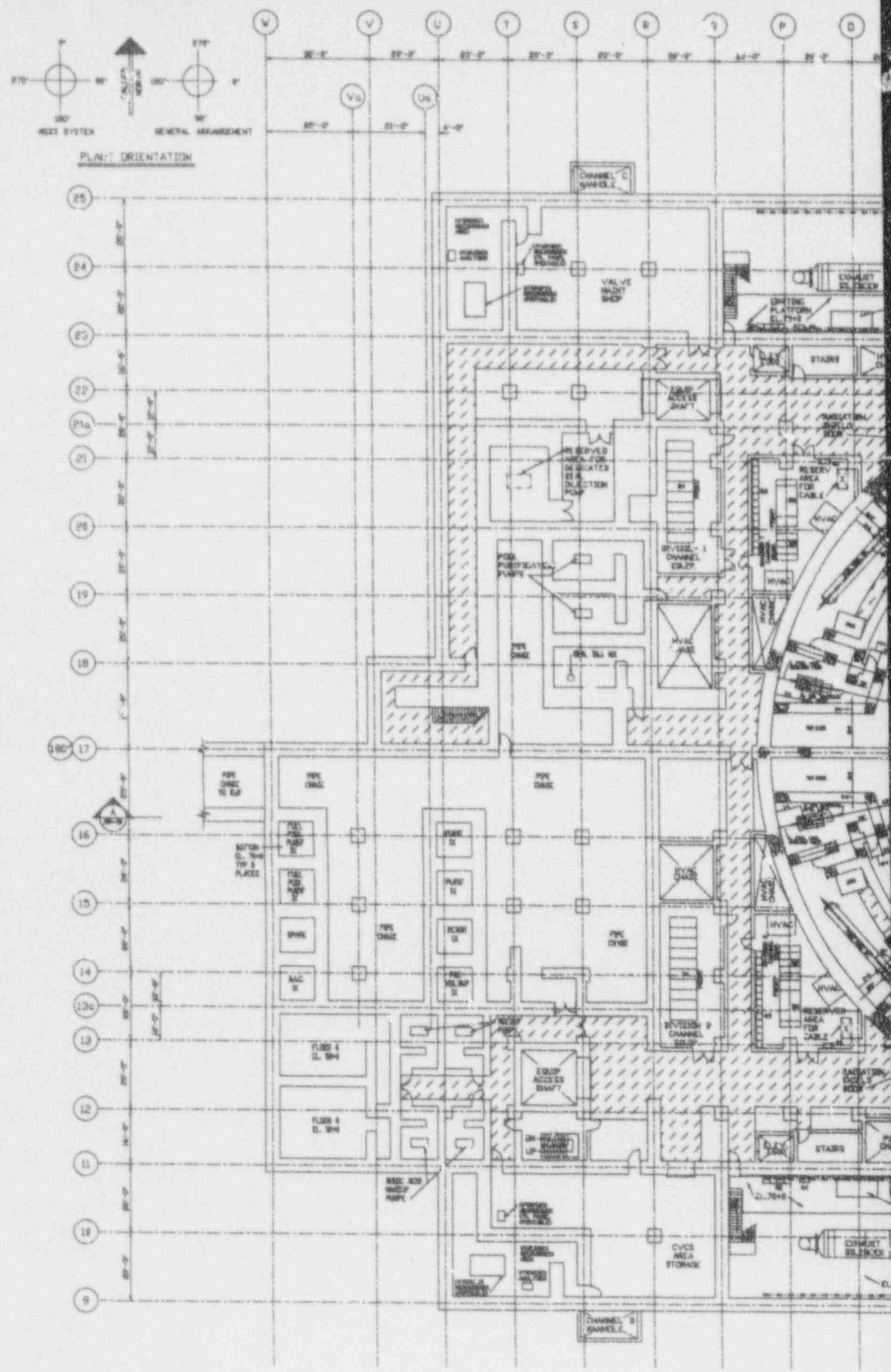
16' 0' 16' 32' 48'

SYSTEM 80+™	NUCLEAR ISLAND DETAILED ARRANGEMENT PLAN AT EL. 50+0	Figure 2.13-1

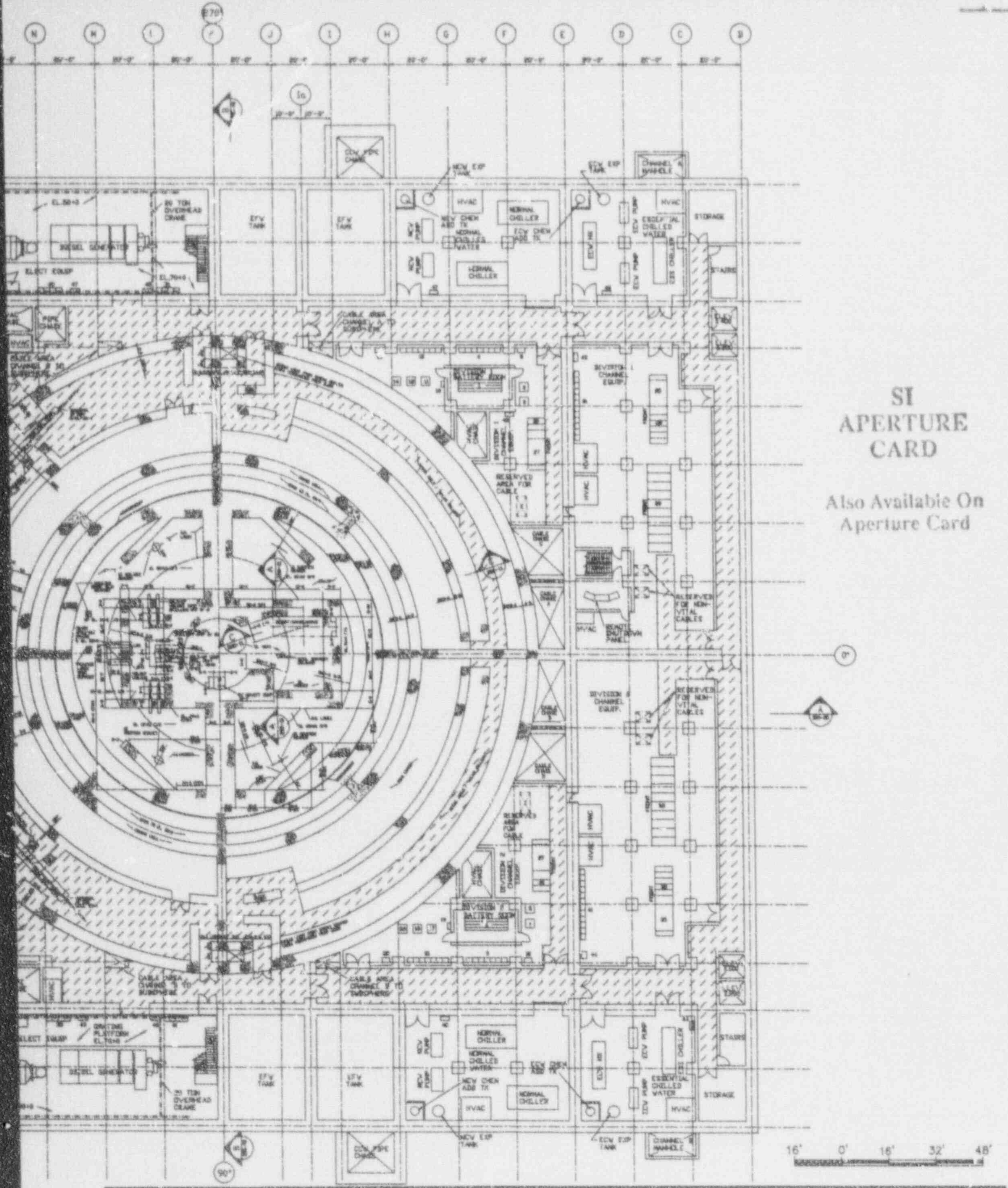
SI
APERTURE
CARD

Also Available On
Aperture Card

9208070093-07



PLANT ORIENTATION
GENERAL ARRANGEMENT
CHANNEL C MANHOLE
VALVE MAINT SHOP
EXHAUST SILENCER
STAIRS
RESERVED AREA FOR DEDICATED SEAL INJECTION PUMP
HVAC
EQUIP ACCESS SHAFT
CVCS AREA STORAGE
CHANNEL D MANHOLE



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SYSTEM 80+™

NUCLEAR ISLAND DETAILED ARRANGEMENT
PLAN AT EL. 70+0

Figure
2.13-2

9208070093-08

3.0 PROBABILISTIC RISK ASSESSMENT

3.1 PRA SUMMARY AND CONCLUSIONS

An assessment of the risk associated with internal events during shutdown modes of operation was performed. The scope of this assessment included internal events during Mode 4 through 6 operation.

Event trees were developed and quantified for loss of decay heat removal (DHR) and loss of coolant inventory for Modes 4 through 6. Loss of offsite power and criticality events were not quantified after an initial review showed these events to be a small contributor to risk. In quantifying the core damage frequency (CDF), emphasis was placed on the human error probabilities (HEPs) because earlier studies have shown that these dominate the shutdown risk. The system failure rates were either taken from the System 80+ PRA or estimated using simplified fault trees. Table 3.1-1 summarizes the operator error rates, mechanical failure rates and event tree branch failure rates that are developed in Section 3.4.

The results from the Human Reliability Analysis reflect engineering judgement and assumptions associated with current operations practice. As further design and operations detail become available, the analysis will be updated as part of the PRA maintenance program to reflect a more accurate assessment of the impact of human error at shutdown. It is believed, however, that the analysis presented here reflects the correct level of dominance in certain events with respect to risk and that further analysis will provide more accuracy, with respect to the models, but should not affect the results of the dominant sequences.

Table 3.1-2 summarizes the contributors to core damage frequency by modes and initiating event. Mode 6 LOCA represents 69% of the risk. The leading contributor is a LOCA outside containment with failure to isolate while the refueling cavity is full. Loss of DHR in Mode 6 while the refueling cavity is full is the second leading contributor to risk (17%). In both sequences, the IRWST is empty and feed and bleed is not available. If one of the two SCS trains is not restored, then core damage will result.

Table 3.1-3 compares the CDF for shutdown events with those for power operation. The CDF for internal events during shutdown modes is 15% larger than for internal events at power and smaller in size than at power external events. The EPRI goal is to have CDF less that 1.0E-5/ry. The CDF from shutdown is significantly less than this goal and the sum of the CDF is also less than the EPRI goal. This PRA contributed to technical specification and instrumentation changes. One example of such a change was a technical specification change requiring two SIS trains be available in Modes 5 and 6 when the IRWST is available.

Table 3.1-1

SUMMARY OF BRANCH POINT FAILURE RATES

	Operator Error	Mechanical Failure	Total	Description
REP	INCL	INCL	1.0E-02	REPair during 81 hour coolant boil-off
CS2	INCL	INCL	3.1E-03	Containment Spray system (1 of 2)
DP	3.0E-03	8.0E-04	3.8E-03	Depressurize with SDS
MUI	3.1E-03	1.0E-03	4.1E-03	Make Up Inventory
OI	5.0E-02	4.0E-02	9.0E-02	Operator Isolates leak
OR	0.84 *1.0E-03	0.16	1.6E-01	Operator Restarts SCS train
OS1	2.8E-03	2.0E-02	2.3E-02	Operator Starts standby SCS train (1 of 1)
OS2	2.8E-03	2.0E-03	4.8E-03	Operator Starts 1 of 2 SCS trains
SGHR	3.4E-02	7.0E-04	3.5E-02	Operator starts SG Heat Removal
SGCOM	3.4E-05	INCL	3.4E-05	Commission error in continued use of SG
SIP2	2.3E-3	7.0E-04	3.0E-03	Manually start 1 of 2 SIS
SCSFB	3.1E-03	1.8E-03	4.9E-03	Manually use SCS for Feed and Bleed
SIFB2	2.7E-03	1.5E-03	4.2E-03	Manually use SIS for Feed and Bleed(1 of 2)
BOC	3.0E-03	0.1	1.0E-01	Boil-Off using CVCS
OIC	8.2E-03	8.0E-04	9.0E-03	Operator Isolates leak at Containment

TABLE 3.1-2

FREQUENCY OF CORE DAMAGE FROM SHUTDOWN EVENTS

LOSS OF DHR MODE	CDF	LOCA CDF	TOTAL
4	2.3E-9	2.3E-8	2.5E-8
5	4.1E-10	5.4E-9	5.8E-9
5 REDUCED INVENTORY	6.5E-8	2.0E-8	8.5E-8
6	1.3E-7	5.3E-7	6.6E-7
TOTAL	2.0E-7	5.7E-7	7.7E-7

TABLE 3.1-3

COMPARISON OF CORE DAMAGE FREQUENCIES

POWER OPERATION, INTERNAL EVENTS*	6.7E-7
POWER OPERATION, EXTERNAL EVENTS*	1.2E-6
SHUTDOWN, INTERNAL EVENTS	7.7E-7

* FROM SYSTEM 80+ PRA[7]

3.2 PRA INTRODUCTION

Until recently, emphasis has been on the safety of power plants during power operation. This was due to the fact that the plant is in this configuration most of the time and the core power, decay heat rate and fission product inventory are highest at this time. The System 80+ PRA[7] documents the risk associated with the operation of this ALWR at normal power. More recently, people have been investigating the risk of plants during shutdown and refueling. During these modes of operation, the plant has lower decay heat generation rates and fission product inventory. The plant configuration is not as well defined as in full power operation because of the maintenance and testing that is being performed. This section estimates the risk of operation of this plant in Modes 4 through 6. Mode 1 through 3 are covered in Ref. 7.

The awareness of the risks of plant operation during refueling and maintenance outages developed slowly. Although no core damage has occurred during reactor outages, a few events have occurred which were precursors to more severe accidents. One of the first events to increase the awareness of risks in outages was the loss of the refueling cavity seal at Connecticut Yankee on August 21, 1984. In this event, 200,000 gallons of water quickly spilled into the containment, draining the refueling cavity. This event would have been more difficult to handle if the refueling had actually started. The seal failure had not been considered in the safety analysis.

Another event which increased the awareness of the risks during outages was the Vogtle 1 event on March 20, 1990. The event started with a truck backing into equipment in a switch yard, causing a loss of power to the first auxiliary transformer. The second auxiliary transformer was out for maintenance. One of the diesels was also out for maintenance. The second kept tripping due to an instrument failure. This combination of maintenance activities and failures led to a station blackout and loss of Decay Heat Removal (DHR). Under normal conditions, with the vessel filled or with the refueling cavity flooded, the operator would have many hours to restore DHR. In this incident, the plant was in mid-loop operation and the primary inventory was greatly reduced. When DHR was restored in 41 minutes, the primary coolant temperature had risen 46 deg F to 136 deg F. This incident demonstrates the unusual plant configurations that can exist during an outage and the risks associated with maintenance activities and mid-loop operation.

During 1991, there were a rash of incidents during shutdown. After four events occurred within six days in March, the NRC issued Information Notice No. 91-22 describing these events. One plant had two incidents during the same outage. There were at least seven events where loss of DHR occurred in 1991. All these events increased the awareness of the risks during outages.

The NRC requested additional information from the ALWR participants pertaining to shutdown risk. The EPRI ALWR Requirements Document then was modified to include a risk assessment for shutdown modes. This analysis satisfies that requirement. This analysis uses a simplified event tree approach to estimate the core damage frequency (level 1 part of a PRA), with only a qualitative evaluation of the radiological releases.

The first step in the analysis was the identification of the initiating events of potential interest. This was done by first defining the plant conditions (in terms of physical parameters such as temperature, pressure, and inventory for the RCS) that will exist for different plant evolutions. For each of these operating conditions, general category of initiating events were then defined. These initiating events were small LOCAs, Loss of Decay Heat Removal (DHR), Loss of AC, and Boron Dilution. The frequencies for these events were determined by operational history.

For each plant condition and initiating event, the plant and operator response was estimated based on the advanced instrumentation, procedures, technical specifications, and safety systems employed in the System 80+ design. The plant states and operator response were modeled and quantified using simplified event trees. The unavailability of each system was estimated using simplified assessments and adaptation of models developed for power operations. Care was taken in estimating the reliability of human actions. Earlier studies found that operator actions are one of the dominant factors in this analysis.

This analysis was performed with the insight obtained from the previous PRAs. In 1981, NSAC-84 looked at the shutdown risk at Zion. This study concluded that failures during reduced inventory operation accounted for 61% of the Core-Damage Frequency (CDF). Operator actions were required in almost all sequences. Operator failure to determine the proper actions to restore DHR accounted for 56% of the total CDF. Loss of DHR also accounted for 56% of the CDF. NUREG/CR-5015 tended to confirm the findings in NSAC-84. The Seabrook Shutdown PRA concluded that 82% of the CDF was due to loss of DHR and 71% was from reduced inventory operation. The study also showed that early health risks were dominated by LOCAs with the containment open. The NRC's Shutdown PRA for Surry (as summarized in NUREG-1449) showed the importance of plant specifics such as the controls of the ADVs, and the response to Generic Letter 88-17. The insights gained from reviewing these PRAs helped in analyzing the System 80+ plant.

This analysis is an extension of the CESSAR-DC System 80+ PRA. The System 80+ PRA used the standard "small event tree/large fault tree" approach used by most of the industry. A detailed discussion of the method employed is given in Section 2.0 of Reference 7. This section describes how that procedure was modified. The modifications were suggested by EPRI[9]. The scope of the Shutdown PRA is to evaluate the core damage frequency (level 1 PRA) using a simplified assessment. Only a qualitative evaluation of the radiological consequences are presented.

Event trees were developed for the accident sequences for each plant state in Modes 4 through 6 given in Table 3.2-1. The plant states were developed based on what equipment was available to mitigate the event. Mode 3 was not considered in this study because the plant configuration is very similar to Mode 1 and 2 and therefore, the effects are enveloped in the Mode 1 analysis.

The event trees are based on the transient studies for shutdown events described in Reference 4. Assumptions about operating or maintenance actions are based on current plant practices or improvements suggested in recent shutdown studies (e.g. NUREG-1449) and are listed in the event tree element descriptions. This will facilitate verification when the plant is complete and operating. The event trees are supported by fault trees and Human Reliability Analysis (HRA) models. This analysis is for a simplified assessment for the operating conditions other than power operation conditions to ensure that there are no unrecognized or unacceptable sources of risk associated with these conditions. This assessment is limited in scope because of the limited level of operational detail that is available at this time and because many requirements aimed at addressing problems at existing operating plants are currently being developed.

The first step in the analysis is the identification of the initiating events of potential interest and the estimation of the frequencies for these events. A search of the earlier shutdown risk assessments, LER data base, and NPRDS was performed. The initiating event frequencies were proportioned to the plant states based on the fraction of the outage time spent in each state. The plant states represent plant modes, or part of a plant mode, which have certain physical parameters and equipment availability (both safety and operational).

For each plant state and initiating event, a functional assessment of the plant response is made. A team of engineers, including specialists in thermal-hydraulics, operator error analysis, plant design, and outage management, were assembled. The team developed the plant response to each transient, including the sequence of events, available instrumentation and alarms, human response, and system response. The times to core damage were also estimated.

Emphases was on the human performance, which has been shown in past studies to be very important in satisfactorily assessing the shutdown risk. The event trees were developed with participation of the full team.

The branch points of the event trees were evaluated using simplified fault trees for the responding systems. Human error rates were evaluated using Human Reliability Analysis models. These models are similar to event trees and model the operators actions sequentiality, including recovery. The models also include operator interaction with the available instrumentation. This detailed analysis of operator actions is used because earlier studies showed that operator actions dominated the analyses. Best estimate assumptions were made about the operator's environment.

Also, little use has been made of such time based models as the human cognitive reliability model. This is because more data would be needed to evaluate the performance impact of the redesigned control room on the time lines associated with certain tasks. Consequently, consideration for the impact of time available to perform a task, and other factors utilized by the cognitive reliability model, have been dealt with by judicious application of certain performance shaping factors defined in the System 80+ PRA. These are:

Availability of necessary indication
Accuracy of indication
Training
Workload
Annunciated
Stress
Level of Experience
Quality/availability of procedures
Ergonomic design of display/control

Each of the above factors can contribute a factor by which the Human Error Probability (HEP) can be modified, given the judgement of the analyst. This modification provides a value that more accurately reflects the probability of human error.

The estimated unavailability of plant systems is based on an adaptation of models developed for power operation. Earlier studies have shown that the core damage frequencies were dominated by operator error. Therefore, less detail is provided in the system analysis. The assumptions used for each system are presented in the discussion of each event tree branch point.

TABLE 3.2-1

PLANT STATES AND INITIATING EVENTS

Plant States

MODE 4, normal inventory

MODE 5, normal inventory

MODE 5, Reduced inventory

MODE 6, Refueling cavity empty

MODE 6, Refueling cavity full

Initiating Events

LOCA, inside containment

LOCA, outside containment

Loss of DHR

Loss of Offsite Power

Boron Dilution

3.3 INITIATING EVENT FREQUENCIES

A search of relevant literature and databases was conducted in order to assess the frequency of occurrence for the specified events actually experienced at pressurized water reactors during plant shutdown periods.

The initiating events identified and examined consisted of:

- Boron and Reactivity Events;
- Loss of Electrical Power;
- Loss of Reactor Coolant;
- Loss of Decay Heat Removal

The INPO Licensee Event Reports database constitutes the most reliable source of documentation for licensee events, and was searched for the above listed events.

The literature search included direct examinations of the following:

A. NUREG-1449, "Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States (Draft)", published 2/92

B. INPO 91-007, "Selected Significant Operating Experience Report Recommendations 1980-1990", published 9/91

C. NSAC-52, "Residual Heat Removal Experience Review and Safety Analysis, Pressurized Water Reactors", published 1/83

D. FI L-1344, "PWR Low Power and Shutdown Accident Frequencies Programs, Phase 1A - Coarse Screening Analysis, 11/13/91, Prepared for NRC"

E. NRC Information Notice [illegible]-55, issued 8/31/90

F. NRC Information Notice 91-22, issued 3/19/91

The documents listed above were based to a large extent on examinations of LERs, but also provided documentation for a number of events not documented in the [illegible] LER database. Additionally, the documents above also drew [illegible]mation from other literature, including:

G. NSAC-144, "Loss of Offsite [illegible]r At U.S. Nuclear Power Plants, All Years Through 1988", published 1989

H. NUREG/CR-4550, Volume 1, Rev 1, SAND86-2084, Jan 1990

J. Sequence Coding and Search System, Office of Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission.

In total, the literature and database provide a reasonably complete source of data for calculating the event frequencies. Nevertheless in order to further ensure that such frequencies have been calculated conservatively, total reactor years have been calculated based on the earliest date recorded for each event, as summarized in Table 3.3-1.

The frequency for each initiating event was distributed over all the plant states based on the fraction of time that the plant is in each configuration. A 23 day refueling schedule was developed for the System 80+. This schedule was divided into each plant state listed in Table 3.2-1. The number of hours in Modes 4 and 5 was then doubled to account for forced outages. The first column of Table 3.3-2 gives the fraction of time (given as %) that the plant is in each of these states. The frequencies for loss of DHR and LOCA are then distributed over the various plant states based on the percent of time in each plant state. This distribution assumes that the human errors and mechanical failures that cause the initial event are random in nature.

TABLE 3.3-1

OBSERVED FREQUENCIES OF DHR EVENTS IN PWRs

Event	Earliest Event Date	Number of Events	Reactor Years (see note *)	Frequency (per reactor-yr)
Boron/Reactivity	03/14/82	12	747.3	.02
Loss of Electrical Power	06/07/73	52	1412.3	.04
Loss of Reactor Coolant	11/14/79	51	924.7	.06
Loss of Shutdown Cooling	09/02/76	232	1165.3	.20

*note: total reactor-years (PWR) between "Earliest Event Date" and 01/01/92

TABLE 3.3-2

INITIATING EVENT FREQUENCY FOR PLANT STATES

PLANT STATE	% HOURS IN STATE	FREQUENCIES, /RY LOSS OF DHR	LOCA
MODE 4	21	0.042	0.013
MODE 5	27	0.054	0.016
MODE 5 REDUCED INVENTORY	18	0.036	0.011
MODE 6 REFUELING CAVITY NOT FLOODED	16	0.032	0.009
MODE 6 REFUELING CAVITY FLOODED	18	0.036	0.011
SUM	100	0.20	0.06

3.4 ACCIDENT SEQUENCES

For each of the accident sequences considered in this study, an event tree was developed and evaluated. The event tree starts with the initiating event frequency developed in Section 3.3 and describes the sequence of events as discrete events which are completed either successfully or not. Each specific sequence leads to either core damage or a safe plant condition. The following subsections discuss each event tree and their branch points. Similar branch points are used in many of the event trees. Such event trees are described in some detail the first time they are used and referred to in later uses.

The event tree branches are composed of an operator error and a system mechanical failure. Since earlier shutdown risk studies have identified operator error as a significant contributor to risk, emphases has been placed on operator error. The Human Reliability Analysis (HRA) trees are also given and discussed in this section at the branch point where they are first used. System fault trees for hardware failures are not presented in this report, but are presented in the System 80+ PRA[7].

3.4.1 LOSS OF DHR, MODE 4

Figure 3.4-1 gives the event tree for loss of DHR during Mode 4 operation. The following paragraphs discuss each branch point of the event tree. The operator has approximately 2 hours to restore DHR[21] before core damage, assuming that the loss of DHR occurs at the beginning of the outage (a conservative assumption). In this mode, two SIS trains are available and the IRWST is full. It is also assumed that the SGs are still available.

LDHRM4

The initiating event frequency for loss of SCS while in mode 4 is 0.042/ry. The derivation for this frequency is given in Section 3.3.

OR (Operator Restores)

In 16% of the DHR losses, equipment failures were identified as the cause of loss of DHR[3]. It is assumed no operator action will restore these mechanical failures in the short term in the operating SCS train.

In the remaining cases, the SCS train is lost because of some operator error and can be restored by the operator taking some manual action. The operator has the ability to detect loss of the SCS with flow alarms, CCW alarms, temperature readout, pump suction and discharge readout, and pump current readout. The operator will have procedures and training in the operation of the SCS system and will be using it at regular intervals.

The performance of the SCS operating train may be lost because of some operator error that causes the pumps to trip but does no significant damage to the system. In this case the operator may be able to restart the operating SCS train by restarting the pump. In order to achieve this, the operator must identify that there has been a loss of shutdown cooling (task A), restart the pump (task B), adjust the SDC flow control valve(task c) and adjust the SDC temperature controller as necessary (task D, see Figure 3.4-2).

The operator can identify the loss of SDC by SDC alarms, SDC flow alarms, Component cooling water alarms, pump suction and discharge indications, pump component indications and Decay heat removal critical function alarms. Once the identification has been achieved, the process of restart will proceed according to the available lower mode functional recovery procedures.

Quantification

Task	HEP	PSF(specific)	Source (NUREG-CR-1278)
A	0.0001	/5 (control room ergonomics)	20-23
B	0.001 + 0.0005/5	/5 (control room ergonomics)	13-3
C	0.001 + 0.0005	/5 (control room ergonomics)	13-3
D	0.001 + 0.0005	/5 (control room ergonomics)	13-13

HEP $= 0.0001/5 + 0.0011/5 + 0.0015/5 + 0.0015/5$
$= 1.0 \times 10^{-3}$

The total failure rate for this branch point is the sum of the mechanical failure rate (0.16) and recovery from operator error. It is dominated by the mechanical failures and is: OR = 0.16

OS1 (Operator Starts 1 of 1 trains)

If the operator can't start the first SCS train, he will go to start the second SCS train. The technical specifications requires that the train be available. It must be manually started. This event tree branch includes both operator failure to start the train and the probability of mechanical failure of the train to start and run. The CSS pump can be aligned to substitute for the SCS pump. This action is included in the OS1 failure rate. The mechanical failure for a single train is 2.0E-2.

Since the technical specifications require that a redundant train of the Shutdown cooling system be available, the operator may be able to start this manually if re-starting the original train was unsuccessful.

Assuming that the train is available and operable, the operator would need to identify the need to make use of the redundant train (task A), start the SDC pump (task B), ensure that the SDC flow control valve is controlling the SDC flow (task C), ensure that the SDC temperature controller is performing correctly (task D-see Figure 3.4-3).

Quantification

Task	HEP	PSF(specific)	Source (NUREG-CR-1278)
A	0.0001 +0.01	/5 (control room ergonomics)	20-23 20-7
B	0.001 + 0.0005/5	/5 (control room ergonomics)	13-3
C	0.001 + 0.0005	/5 (control room ergonomics)	13-3
D	0.001 + 0.0005	/5 (control room ergonomics)	13-13

HEP $= 0.0101/5 + 0.0011/5 + 0.0015/5 + 0.0015/5$
$= 2.8 \times 10^{-3}$

The total failure rate is the sum of the mechanical and operator failure rates and is 2.3E-2. It is dominated by mechanical failure.

SGHR (Steam Generator Heat Removal)

The operator normally uses the SGs for heat removal in Modes 1 through 3 and will try to use them after failure to restore the SCS trains. By Technical Specification, he must have a SG available if 2nd SCS train is out of service. He only has electric feedwater pumps available. In many cases the SGs are filled with water when laid up, and in this case, the operator has additional time to start the feedwater pumps. The secondary side can be vented through the ADVs.

The operator normally uses the steam generators during modes 1 through 3 and will be required to attempt to use them after failure to restore the SDC trains. Technical specifications require that at least one steam generator be available if the 2nd train of SDC is out of service.

In order to utilize this method of decay heat removal, the operator needs to identify the need to use a steam generator (task A), start the electric emergency feedwater pumps (task B), when the steam generator pressure rises to 950 psia to vent the ADV (task C monitor, task D actuate ADVs), and monitor the decay heat removal (task E, see Figure 3.4-4).

The indications available to the operator to identify the need for this method include SDC alarms, component indications for the availability of the SDC system and critical function decay heat removal alarms. The actions associated with this method can all be achieved from the control room. These actions are adequately covered in the lower mode functional recovery procedures.

Quantification

Task	HEP	PSF (specific)	Source (NUREG-CR-1278)
A	0.0001 +0.01	x2 (stress)	20-23 20-7
B	(0.001 + 0.0005/5)x2	x2 (stress)	13-3
C	0.001	x2 (stress)	13-3
D	0.001 + 0.001 + 0.0005	x2 (stress)	13-13
E	0.001	x2 (stress)	20-10

HEP = 0.0101*2 + 0.0022*2 + 0.001*2 + 0.0025*2 +0.001*2
= 3.4×10^{-2}

The mechanical failure to start and run 1 of 2 electric feedwater pumps was estimated as 7.0E-4. For this branch point, the total failure rate is 3.5E-2 and is dominated by operator error.

SIFB2 (Safety Injection system Feed and Bleed, 1 of 2 trains)

The operator has the option of going to a feed and bleed operation. Two SI trains are available in the division with the Diesel also available. One of the two pumps will supply sufficient flow. In addition, one of the two charging pumps could also be used but was not modeled here. The primary system must be vented with the Safety Depression System (SDS). The failure rate for SIFB2 is the sum of the failure of the operator to initiate feed and bleed and mechanical failures.

While in mode 4 or lower, if the operator looses shutdown cooling he will attempt to satisfy decay heat removal. Assuming that all else fails, the operator would attempt to initiate feed and bleed cooling.

To initiate feed and bleed cooling the operator must first identify that feed and bleed cooling is required (task A). Then ensure that the RCPs are tripped (task B) and ensure that the line-up from the IRWST through the SI pumps to the DVI line is available (task C). Since RCS pressure is below the shutoff head of the Safety Injection Pumps already, safety injection initiation would need to be achieved manually (task D). Then they must open the Safety Depressurization Valves (task E) and the Safety Depressurization Block Valves (task F) to allow circulation. In Mode 5, reduced inventory operation, opening the SDS valves is not necessary because the pressurizer manway is removed. Finally the operator would monitor flow to ensure the correct operation of the system (task G - see Figure 3.4-5). To be successful, Feed and Bleed Cooling must be initiated at or before the time at which the primary safety valves lift.

All actions can be performed from the control room. Procedures would be available in the lower mode functional recovery procedure for loss of secondary side heat removal. Inclusion of this event represents failure to initiate feed and Bleed cooling in mode 4.

Quantification

Task	HEP	PSF (specific)	Source (NUREG-CR-1278)
A	0.0001+0.01	/5 (control room ergonomics	20-23 20-7

B	0.05*0.05	/5 (control room ergonomics	20-22
C	0.05*0.05*0.05*0.05	/5 (control room ergonomics	20-22
D	0.001*0.001	/5 (control room ergonomics	20-12
E	0.001*0.001	/5 (control room ergonomics	20-12
F	0.001*0.001	/5 (control room ergonomics	20-12
G	0.001	/5 (control room ergonomics	13-3

HEP = $0.0101/5 + 0.0025/5 + 0.05^4/5 + (0.001*0.001)/5 + (0.001*0.001)/5 + (0.001*0.001)/5 + 0.001/5$
$= 2.7 \times 10^{-3}$

The mechanical failures consist of failure of both SI trains (7.0E-4) and the SDS (8.0E-4). Total failure for feed and bleed is: SIFB2 = 4.2E-3 and is dominated by operator error.

BOC (Boil-Off using CVCS)

Using either 1 of 2 charging pumps or the boric acid makeup pump as a backup, water can be added directly to the reactor vessel from the Boric Acid Storage Tank (BAST). There are approximately 80,000 gal. of borated water available and by matching the boil-off rate, the water in the BAST can be used to cool the core for approximately 12 hrs. There is an additional 20,000 gal of water available in two of the four SITs that could be added to the core through gravity feed and give the operators an additional 3 hours. It is assumed that if BOC is successful, DHR is restored in the approximate 12 hours during boil-off.

BOC failure rate consists of two failure rates, failure to feed with the CVCS and failure to restore some DHR capability during the approximate 12 hours.

During a Loss of Coolant Accident in the lower modes, making up inventory loss may be achieved via a different method than at power. It is possible to makeup inventory from the Boric Acid Storage tank through the CVCS and the charging pumps.

This requires that a line up be established from the BAST to the suction line for a charging pump, then the charging pump can deliver the inventory to the RCS.

The actions on the part of the operator would be to identify the need for makeup (task A), open the gravity feed line from the BAST to the charging pumps i.e. valve CH-532 (task B) and CH-536 (task C), ensure that one of the two charging pumps is operating (task D), and monitor the makeup (task E - see Figure 3.4-6).

All actions can be performed from the control room. Procedures would be available in the lower mode functional recovery procedure for loss of secondary side heat removal. Inclusion of this event represents a failure to makeup inventory coolant from the CVCS.

Quantification

Task	HEP	PSF (specific)	Source (NUREG-CR-1278)
A	0.0001+0.01	/5 (control room ergonomics	20-23 20-7
B	0.001 + 0.0005	/5 (control room ergonomics	13-3
C	0.001 + 0.0005	/5 (control room ergonomics	13-3
D	0.001 + 0.0005/5	/5 (control room ergonomics	13-3
E	0.001	/5 (control room ergonomics	13-3

HEP = 0.0101/5 + 0.0015/5 + 0.0015/5 + 0.0011/5 + 0.001/5
= 3.0×10^{-3}

In this scoping study, we did not explicitly analyze the probability of restoring DHR in approximately 12 hours, but assumed a failure rate of 0.1. The operator has the options of restoring any of 4 SI trains, 2 SCS trains or 2 CSS trains. He could also find additional water for his BAST and continue boil-off. As an example of such repairs, after the severe Brown's Ferry cable fire (March,1975), operators successfully restored DHR using temporary jumpers. BOC failure rate is dominated by the probability of repair and BOC = 0.1.

Figure 3.4-1 gives the event tree with the branch failure rates discussed above. In this event tree, one sequence leads to core damage with a frequency of 2.3E-9.

3.4.2 **LOSS OF DHR, MODES 5,6, REFUELING CAVITY EMPTY**

Figure 3.4-7 gives the event tree for loss of DHR during Mode 5 operation when the coolant level is not reduced and during Mode 6 operation while the IRWST is still full. During this time, two SIS trains and one CSS train is available. It is assumed that the SGs are not available and the system is being cooled with one SCS, and one in standby.

This event tree is similar to the previous tree. The operator has approximately 2.2 hours to restore DHR assuming that the sequence occurs when the plant first enters Mode 5 (highest decay heat) and not in later Mode 5 or 6 operations. The following paragraphs discuss each branch point of the event tree.

DHRCE (Decay Heat Removal loss with refueling Cavity Empty)

The initiating event frequency for loss of SCS while in Mode 5 is 0.054/ry. In Mode 6, with the refueling cavity empty, the frequency is 0.032. The derivation for this frequencies is given in Section 3.3. The total frequency is the sum, DHRCE = 0.086 .

OR (Operator Restores)

The failure rate for the operator to restore the SCS train is (see Section 3.4.1): OR = 1.6E-1 .

OS1 (Operator Starts)

The failure rate for the operator to start the second SCS train is (see Section 3.4.1) : OS1 = 2.3E-2 .

SIFB2 (Safety Injection train Feed and Bleed)

The failure rate for the operator to start the feed and bleed operation is 4.2E-3 and discussed in Section 3.4.1.

SCSFB (Shutdown Cooling System for Feed and Bleed)

If the SIS fails, the reactor inventory and DHR can be maintained by using the SCS in a feed and bleed mode. The SCS can be aligned to the IRWST and used to inject water. Heat removal is through the SCS coolers. If the SCS pumps fail, the CSS pumps can be aligned to substitute for the SCS pumps.

While in mode 4 or lower and the operator attempts to satisfy decay heat removal, assuming that all else fails, the operator would attempt to initiate feed and bleed cooling. Also given that the safety injection pumps may be unavailable it is possible to use the SCS pumps for this purpose.

To initiate feed and bleed cooling using the SCS, the operator must first identify that feed and bleed cooling is required (task A). Then ensure that the RCPs are tripped (task B) and the cross-connect valve SI-110 is opened to ensure the line-up from the IRWST is available (task C). This must then be checked by another operator, who could fail in either of two ways; task D - the 2nd operator makes a checking error and then changes the valve position to reflect his incorrect belief of the correct position, and task D'- a simple checking error with a report to the control room that the valve change was successful. The operators would need to start the Shutdown Cooling Pumps manually (task E). Then they must open the Safety Depressurization Valves (task F) and the Safety Depressurization Block Valves (task g) to allow circulation. In Mode 5, reduced inventory operation, the pressurizer manway is removed and opening the SDS valves is not necessary. Finally the operator would monitor flow to ensure the correct operation of the system (task H - see Figure 3.4-8). To be successful Feed and Bleed Cooling must be initiated at or before the time at which the primary safety valves lift.

All actions, except one, can be performed from the control room. Procedures would be available in the lower mode functional recovery procedure for loss of secondary side heat removal. Inclusion of this event represents failure to initiate feed and bleed using the SCS and the IRWST.

Quantification

Task	HEP	PSF (specific)	Source (NUREG-CR-1278)
A	0.0001+0.01	/5 (control room ergonomics	20-23
B	$(0.05)^2$	/5 (control room ergonomics	20-22
C	0.001	/5 (control room ergonomics	20-6
D	0.1*0.001	/5 (control room ergonomics	
D'	0.1		

E	0.001+0.001	/5 (control room ergonomics	
F	0.001*0.001	/5 (control room ergonomics	
G	0.001*0.001	/5 (control room ergonomics	
H	0.001	/5 (control room ergonomics	20-12

$$HEP = a + b + cd' + ce + d + e + cf + f + cg + g + ch + h$$

$$= 0.0101/5 + 0.0025/5 + 0.0001/5 + 0.0001/5 + 0.000002/5 + 0.002/5 + 0.000000001/5 + 0.000001/5 + 0.000000001/5 + 0.000001/5 + 0.000001/5 + 0.001/5$$

$$= 3.1 \times 10^{-3}$$

The mechanical failures for SCSFB are the mechanical failures for SCS injection (MUI) and the mechanical failure of the SDS (DP). SDS is needed to return the coolant to the IRWST tank and not to depressurize the system. The total failure rate is:
SCSFB = 4.9E-3.

<u>BOC (Boil-Off using the Cvcs system)</u>

As discussed in Section 3.4.1, the failure rate to successfully cool the core and restore DHR is 0.1.

Figure 3.4-7 gives the event tree with the branch failure rates discussed above. In this event tree, one sequence leads to core damage with a frequency of 6.5E-10.

3.4.3 LOSS OF DHR, MODE 5, REDUCED INVENTORY

Reduced inventory is defined as having the primary coolant level 3 ft. below the flange or lower. Experience developed with operating plants and results of earlier Shutdown PRAs has shown that because of the short time for coolant boiling given loss of DHR (approximately 15 minutes assuming mid loop operation), the plant has technical specifications and operational guidance for operation in this mode. Figure 3.4-9 gives the event tree for loss of DHR during Mode 5 operation when the coolant level is reduced. This event tree is also used to evaluate LOCAs during reduced inventory because the operator would treat both events the same way. For this event, the operator has approximately 1.5 hours to restore DHR[21] before core damage assuming that the loss of DHR occurs at the first time in the outage that the plant is operated at reduced inventory (a conservative assumption). The following paragraphs discuss each branch point of the event tree.

DHR5R (loss of Decay Heat Removal in mode 5, Reduced inventory)

The initiating event frequency for loss of SCS while in mode 5 is 0.047/ry. This frequency includes both loss of DHR (0.036) and the frequency for LOCAs in this mode (0.011). LOCAs were included here because the operator would perceive them as a loss of DHR. The derivation for this frequency is given in Section 3.3.

OR (Operator Restores)

The failure rate for the operator to restore the SCS train, discussed in Section 3.4.1, is: OR = 1.6E-1 .

MUI (Make Up Inventory)

For reduced inventory events, it is assumed that the operator must diagnose and increase the coolant level before starting the second SCS train. We assumed the operator would use the SCS system for this task and align it to the IRWST. He could also use the CVCS system, but this was not explicitly modeled. Inclusion of the CVCS make up would not significantly reduce the failure rate because the failure rate is dominated by operator error.

While in the lower modes, making up inventory loss may be achieved via a different method than at power. It is possible to makeup inventory from IRWST through the SC system.

This requires that a line up be established from the IRWST to the suction line for a shutdown cooling pump, then the SC pump can deliver the inventory to the RCS.

The actions on the part of the operator would be to identify the need for makeup (task A), Ensure the RCPs are tripped (task B), locally open the cross-connect valve (task C), have this checked by another operator (task D - checking failure and reposition of valve to wrong position based on incorrect checking and task D' - checking failure and report to control room that change was successful), and start the pump (task E - see Figure 3.4-10).

Most actions can be performed from the control room. Procedures would be available in the lower mode functional recovery procedure for loss of secondary side heat removal. Inclusion of this event represents a failure to makeup inventory coolant from the IRWST through the SCS.

Quantification

Task	HEP	PSF(specific)	Source (NUREG-CR-1278)
A	0.01+0.0001	/5 (control room ergonomics)	20-23 20-2
B	0.05 x 0.05	/5 (control room ergonomics)	20-12
C	0.001	/5 (local ergonomics)	20-12
D	(0.1 x 0.001)		13-13
D'	0.1		13-13
E	0.001+0.001	/5 (control room ergonomics)	20-12

HEP = a + b + cd' + ce + d + e
= 0.0101/5 + 0.0025/5 + 0.0001/5 + 0.0000002/5 + 0.0001 + 0.002/5
= 3.1×10^{-3}

The mechanical failure of the SCS to make up inventory is 1.0E-3. The total failure rate is: MUI = 4.1E-3, and is predominately operator error.

OS1 (Operator Starts)

The failure rate for the operator to start the second SCS train is 2.3E-2 and discussed in Section 3.4.1.

SIFB2 (Safety Injection train Feed and Bleed, 1 of 2 trains)

In reduced inventory mode, suggested new technical specifications require that two SIS train be available. As noted in Section

3.4.1, in this mode, the pressurizer manway has been removed and opening the SDS valves is not necessary. The failure rate is: S'FB2 = 4.2E-3 .

BOC (Boil-Off using the Cvcs system)

As discussed in Section 3.4.1, the failure rate to successfully cool the core using boil-off and restore DHR is 0.1.

Figure 3.4-9 gives the event tree with the branch failure rates discussed above. In this event tree, two sequences lead to core damage and the total CDF is 8.5E-8.

3.4.4 LOSS OF DHR, MODE 6, REFUELING CANAL FLOODED

At this time in the refueling, the refueling cavity and canal is flooded. The IRWST is empty and in general, not available for any make up, safety injection, or feed and bleed operation. The steam generators also are not available for decay heat removal (assumed isolated with nozzle dams). Because of the lower decay heat and large volume of water in the refueling cavity, the operator has 81 hours to restore DHR before core damage[21]. Figure 3.4-11 gives the event tree for this event.

DHRCF (Decay Heat Removal with the Refueling Cavity Filled)

The initiating event frequency for loss of SCS while in Mode 6, cavity flooded, is 0.026/ry. The derivation for this frequency is given in Section 3.3.

OR (Operator Restores)

The failure rate for the operator to restore the SCS train is OR = 1.6E-1 and is discussed in Section 3.4.1.

OS1 (Operator Starts)

The failure rate for the operator to start the second SCS train is 2.3E-2 and is discussed in Section 3.4.1.

REP (Repair)

Having failed to restore or start either SCS train in a timely manner, the operators now have approximately 81 hours to repair or restore DHR, or replenish the water in the refueling cavity. In this scoping study, we did not explicitly analyze the probability of restoring DHR in approximately 81 hours but assumed a failure rate of 0.01. The operator has the options of restoring any of the 2 SCS trains or 2 CSS trains. He could also refill the RWST and use any 1 of 4 SIS trains that he could make operational in a feed and bleed mode. Finally, he could also find additional water for his refueling cavity and continue boil-off.

BOC (Boil-Off using the CVCS)

As discussed in Section 3.4.1, the failure rate to successfully cool the core and restore DHR is 0.1.

Figure 3.4-11 gives the event tree with the branch failure rates discussed above. In this event tree, one sequence leads to core damage and the CDF is 1.3E-7. This is the second largest sequence in the study. It represents a sequence where there are only 2 trains for a DHR available (two SCS trains) and no capability to use any other paths (SIFB2, SCSFB).

3.4.5 LOCA, MODE 4, PRESSURE ABOVE 500 PSIG

Mode 4 is hot shutdown and includes the period of time that the primary system is being cooled and depressurized (or heated and pressurized). In mode 4, the coolant temperature varies from 350°F to 210°F. Above 500 psig, the SCS system is not available but the SIS, and SITs are. This plant configuration is very similar to higher modes and are modeled here because it represents a mode where the SGs are being used and depressurization is required to get onto SCS or a feed and bleed mode. It is assumed that the temperature is above 317°F, and the pressure is above 500 psig. Two CSS trains, the IRWST, two RCS loops, and two SIS trains are available. The SCS trains are available only after depressurization. The low pressure and temperature part of Mode 4 is represented by the Mode 5 normal inventory event tree described in the next section. The Mode 4 tree is given in Figure 3.4-12.

<u>M4LOCA</u>

The frequency of a LOCA in Mode 4 is 0.013/ry (Section 3.3).

<u>OI (Operator Isolates leak)</u>

Most of the LOCAs in shutdown modes are caused by operator errors in aligning valves and other operations and are quickly corrected. Others are caused by mechanical failures that can not be easily isolated.

Given that most of errors are caused by operators inadvertently opening valves or creating leak paths, it is assumed that most of these occurrences are caught either by the operator who caused it or by operator check work already performed.

With this assumption, it is reasonable to assume that the type of checking being performed would be associated with some kind of alerting factors associated with the type of situation i.e sound of rushing water when none should be present, visual indication of the leak etc.

For the purposes of this analysis, the quantification of this factor will make use of the value for special one-of-a-kind checking with alerting factors. This is because of the unique nature of most of the activities associated with the lower modes and the concept that this will be the type of error the operator will be attuned to.

Quantification

Task	HEP	PSF(specific)	Source (NUREG-CR-1278)
A	0.05		20-22

HEP = 0.05

For leaks caused by mechanical failures it was assumed that 4% could not be isolated and are sufficiently large to be true LOCAs. The total failure to isolate is the sum of the mechanical and operator failures and is : OI = 0.09.

SIP2 (Safety Injection Pumps)

In Mode 4, and at these pressures, two SI trains are available and are automatically actuated. Operator action to initiate SI is not required and the failure rate for both trains to start and run is 7.0E-4. The IRWST is available as a water supply.

CS2 (Containment Spray)

To remove decay heat from the containment, one of two containment spray trains must start and run. Failure of CS is 3.10E-3.

SGCOM (Steam Generator Operator Commission Error)

The operator was using the SGs before this event started and, after isolating the leak, would continue to use the SGs for heat removal. This branch element represents failure of the operator to continue using this DHR path.

Typically the method employed to cooldown the RCS using the steam generators in the lower modes is to fill the steam generator using the emergency feedwater system then switch off and let this boil away.

Since the operator action involves checking the steam generator level and initiating the emergency feed this operator error has two components. Task A - failure to initiate steam generator heat removal (SGHR) and task B - operator fails to check for the initiation (see Figure 3.4-13).

Quantification

Task	HEP	PSF (specific)	Source (NUREG-CR-1278)
A	3.4×10^{-3}	see SGHR	see SGHR
B	0.01		20-22

HEP = $3.4 \times 10^{-3} \times 0.01$
SGCOM = HEP= 3.4×10^{-5}

DP (DePressurization)

If the SIS fails or heat can not be removed through the SGs, than the operator must depressurize the primary system in preparation to use the SCS or CSS to add inventory and remove decay heat. The operator must manually actuate the Safety Depressurization System (SDS).

In order to use the shutdown cooling pumps or containment spray pumps to add inventory the operator must depressurize the system. This is achieved by utilizing the safety depressurization system.

In order to achieve depressurization the operator must identify the need for depressurization using the SDS (task A), open the safety depressurization valves (task B), open the safety depressurization block valves (task C), and monitor the flow through the system to ensure that it is operating properly (task D - see Figure 3.4-14).

These actions can be performed from the control room and would be part of the lower mode functional recovery procedure.

Quantification

Task	HEP	PSF(specific)	Source (NUREG-CR-1278)
A	0.01+0.0001	/5 (control room ergonomics)	20-23 20-2
B	0.001 x 0.001	x2 (stress)	20-12
C	0.001x 0.001	x2 (stress)	20-12
D	0.001		13-13

HEP = 0.0101/5 + (0.000001)*2 + (0 000001)*2 +0.001
= 3.0×10^{-3}

Mechanical failure of 1 of 2 MOVs in the SDS to open is 8.0E-4. The total failure to depressurize is: DP = 3.8E-3 and is dominated by operator error.

OS2 (Operator Starts one of 2 SCS trains)

Having depressurized the system, the operator can now start one of two SCS systems. Since the plant was pressurized, both trains are assumed available. The operator error in starting 1 of 2 SCS trains is assumed to be the same as that for starting 1 SCS train and is 2.8E-3 (Section 3.4.1). Mechanical failure of both SCS trains is 2.0E-3 and the total failure rate is: OS2 = 4.8E-3.

SIFB2 (Safety Injection to Feed and Bleed, 1 of 2 trains)

Assuming that the normal DHR paths can not be used and the operator has depressurized the system, the operator can now go to a feed and bleed operation. This operation is not available if the SIS had failed earlier in the event sequence. The failure rate for this branch is: SIFB2 = 4.2E-3 and is discussed in Section 3.4.1.

Figure 3.4-12 gives the event tree with the branch failure rates discussed above. In this event tree, eight sequences lead to core damage and the total CDF is 2.3E-8. Half of the sequences and almost all of the risk is caused by failure to depressurize so that the SCS or feed and bleed trains can be employed.

3.4.6 LOCA, MODES 5, 6 (IRWST FULL)

In Mode 5, and some part of Mode 6, the IRWST is available for safety injection and two SIS trains are available for both injection and feed and bleed operation. Figure 3.5-15 gives the event tree for this sequence.

The starting point for this event is that the plant is depressurized and one SCS train is in operation. The SGs are assumed to be isolated. Two SIS trains are available for manual actuation in Mode 5 and Mode 6 with the IRWST full. One CS pump is also available for injection or feed and bleed.

L56IR (LOCA Mode 5 and 6, IRWST Available)

The frequency for this event is 0.025. It consists of Mode 5 LOCAs (0.016) and Mode 6 LOCAs with the IRWST full (0.009). LOCAs occurring during Mode 5 Mid loop operation would be diagnosed as loss of DHR by the operator and are addressed in Section 3.4.3.

OI (Operator Isolates leak)

The failure of the operator to isolate the leak is discussed in Section 3.4.5 and is: OI = 9.0E-2 .

SIP2 (Safety Injection Pump, 1 of 2)

In Mode 5 and 6 with the IRWST full, two SI trains and the IRWST are available. SIS would be manually actuated.

While in lower modes, the system pressure would be lower than the Safety Injection setpoint, and since procedures require the override of the ESFAS actuation for normal progression below, it would be necessary for the operators to manually initiate Safety Injection. The actions required for this task are that the operator must identify the need for safety injection actuation (task A), ensure the correct line up for the required Safety Injection pump (task B), then start the Safety Injection pump (task C, see Figure 3.4-16).

All of these actions can be performed from the control room, and are governed by lower mode emergency procedures. Inclusion of this event in the fault tree represents the failure of the operator to manually initiate Safety Injection.

Quantification

Task	HEP	PSF (specific)	Source (NUREG-CR-1278)
A	0.0001+0.01	/5 (control room ergonomics	20-23
B	$(0.01)^2$		20-22
C	0.001 + 0.0005/5	/5 (control room ergonomics	20-12

HEP = 0.0101/5 + 0.0001 + 0.0011/5
= 2.3×10^{-3}

The mechanical failure rate for one of two trains of SIS to start and run is 7.0E-4. The operator error rate is 2.3E-3 and the total failure rate is: SIP2 = 3.0E-3 and is dominated by operator error.

OS1 (Operator Starts one SCS train)

Having isolated the leak, the operator can now start one of the SCS systems. It is assumed that the leak caused the other train to be unavailable. The failure rate is: OS1 = 2.3E-2 and discussed in Section 3.4.1.

SIFB2 (Safety Injection to Feed and Bleed)

If the leak isolation was successful but starting the SCS train was not successful, then the operator can continue to cool the core by operating one of two SI pumps after having opened the SDS to return the fluid to the IRWST. This failure rate SIFB2 = 4.2E-3 and is discussed in Section 3.4.1.

SCSFB (Shutdown Cooling System for Feed and Bleed)

If the SIS fails, the reactor inventory and DHR can be maintained by using the SCS in a feed and bleed mode. The use of the SC pump is included in the SCS fault tree. This branch point failure rate

was evaluated in Section 3.4.2 and is:
SCSFB = 4.9E-3.

BOC (Boil-Off using the CVCS)

As discussed in Section 3.4.1, the failure rate to successfully cool the core and restore DHR is 0.1.

Figure 3.4-15 gives the event tree with the branch failure rates discussed above. In this event tree, three sequences lead to core damage and with total CDF being 8.5E-9. The dominant sequence is failure to isolate the leak, followed by failure of the SIS and SCS to feed and bleed.

3.4.7 LOCA OUTSIDE CONTAINMENT, MODE 6

The LOCA outside containment (Figure 3.4-17) is an interfacing type LOCA where the coolant inventory is lost and in Mode 6 with the refueling cavity filled, the IRWST is not available. This means that the SIS is not available and no feed and bleed path is available (SIFB2 or SCSFB).

L6OC (LOCA Mode 6 Outside Containment)

The frequency for this event is 0.0055 assuming that half of the Mode 6 LOCAs occurred inside containment and the other half occur outside.

OI (Operator Isolates leak)

The failure of the operator to isolate the leak is discussed in Section 3.4.5 and is: OI = 9.0E-2.

OIC (Operator Isolates at Containment interface)

If the leak was not initially isolated locally (OI), the operator will try to isolate the leak at the containment penetrations using 1 of 2 MOVs that are in series.

During a Loss of Coolant Accident in the lower modes and once the makeup issue has been addressed, the operators' primary concern will be isolating the leak that is causing the flow outside containment. This does not necessarily mean identifying the leak only dealing with the flow path to outside containment. In order to mitigate this, the operator would need to actuate a close signal to either of the two containment isolation valves.

The actions performed to achieve isolation at the containment would be, to identify the need to isolate once core decay heat removal has been satisfied (task A), actuate the controls to close valve 1 (task B), and close valve 2 (task C), then verify the success of this approach by monitoring the RCS level indication (task D, see Figure 3.4-18).

All actions can be performed from the control room. Procedures would be available in the lower mode functional recovery procedure for loss of secondary side heat removal.

Quantification

Task	HEP	PSF (specific)	Source (NUREG-CR-1278)
A	0.0001+0.01	/5 (control room ergonomics	20-23 20-7
B	0.001 + 0.0005	x2 (stress)	13-3
C	0.001 + 0.0005	x2 (stress)	13-3
D	0.001	/5 (control room ergonomics	13-3

HEP = 0.0101/5 + 0.0015x2 + 0.0015x2 + 0.001/5
= 8.2×10^{-3}

The mechanical failure of 1 of 2 MOVs was estimated to be 8.0E-4 and the total failure rate is: OIC = 9.0E-3 and is dominated by operator error.

OS1 (Operator Starts one SCS train)

Having isolated the leak, the operator can now start one of the SCS systems. It is assumed that the leak caused the other train to be unavailable. The failure rate is: OS1 = 2.3E-2 and is discussed in Section 3.4.1.

REP (REPair)

At this point in the sequence, the operator has successfully isolated the leak but now has a loss of DHR event, with neither of the SCS trains working and no feed and bleed capability. As discussed in Section 3.4.4, failure to restore either SCS train was estimated as: REP = 0.01.

BOC (Boil-Off using the CVCS system)

As discussed in Section 3.4.1, the failure rate to successfully cool the core and restore DHR is 0.1.

Figure 3.4-17 gives the event tree with the branch failure rates discussed above. In this event tree, two sequences lead to core damage and the total CDF of 4.6E-7. The dominant sequence in this event (and this study) is the LOCA outside containment that is not isolated. The second sequence represents a loss of DHR and requires operator action to repair one of the two SCS trains.

3.4.8 LOCA INSIDE CONTAINMENT, MODE 6 (REFUELING CAVITY FULL)

In Mode 6, with the refueling cavity filled, if the LOCA occurs inside the containment, the coolant will drain back into the IRWST and be available for injection or feed and bleed using any of the SCS pumps or the CS pump in the make-up (MUI) mode. The coolant also becomes available for a feed and bleed mode using the SCS and CS trains. Figure 3.4-19 gives the event tree for this sequence.

The starting point for this event is that the plant depressurized and one SCS train in operation. The SGs are assumed to be isolated. No SIS trains are available. One CS pump and both SCS pumps are available for injection after the coolant drains back into the IRWST.

L6IC Loca Mode 6 Inside Containment

The frequency for this event is 0.0055. This assumes that half of the Mode 6 LOCAs occurs inside containment.

OI (Operator Isolates leak)

The failure of the operator to isolate the leak is discussed in Section 3.4.5 and is: OI = 9.0E-2 .

MUI (Make Up Inventory)

In Mode 6 with the IRWST empty, SIS is not available but injection is possible with SCS and CS pumps (Section 3.4.3): MUI = 4.1E-3 .

OS1 (Operator Starts one SCS train)

The failure rate is: OS1 = 2.3E-2 and is discussed in Section 3.4.1.

SCSFB (Shutdown Cooling System for Feed and Bleed)

If the SIS fails, the reactor inventory and DHR can be maintained by using the SCS or the CS pump in a feed and bleed mode. This branch point failure rate was evaluated in Section 3.4.2 and is: SCSFB = 4.9E-3.

BOC (Boil-Off using the Cvcs system)

As discussed in Section 3.4.1, the failure rate to successfully cool the core and restore DHR is 0.1.

Figure 3.4-19 gives the event tree with the branch failure rates discussed above. In this event tree, three sequences lead to core damage and with total CDF being 6.3E-8. The dominant sequence is failure to restore the second SCS train (including the CS pump) including feed and bleed.

3.4.9 LOSS OF OFFSITE POWER

In the previous Shutdown Risk Studies summarized in NUREG 1449[3] loss of offsite power (LOOP) was not a major contributor to risk. In the Seabrook Shutdown PRA (May, 1988), LOOP contributed 6% of the core damage risk. This sequence was only qualitatively studied in this analysis because of the low frequency for LOOP for the System 80+ plant. Section 2.4.3.2 describes AC power reliability. The System 80+ has the capability to draw from four different AC sources including a combustion turbine. With two independent incoming sources and switchyards, the EPRI ALWR Utility Requirements Document gives the probability of losing both switchyard as 7.7E-3. When this is coupled with failure of 1 Diesel and failure of the combustion turbine, the risk becomes very small. Additionally, in Section 3.3 it was estimated that the refueling cavity is flooded for 29% of the time the plant is in Modes 3 through 6. During this period, a long recovery time exists for restoration of AC power.

3.4.10 CRITICALITY EVENTS

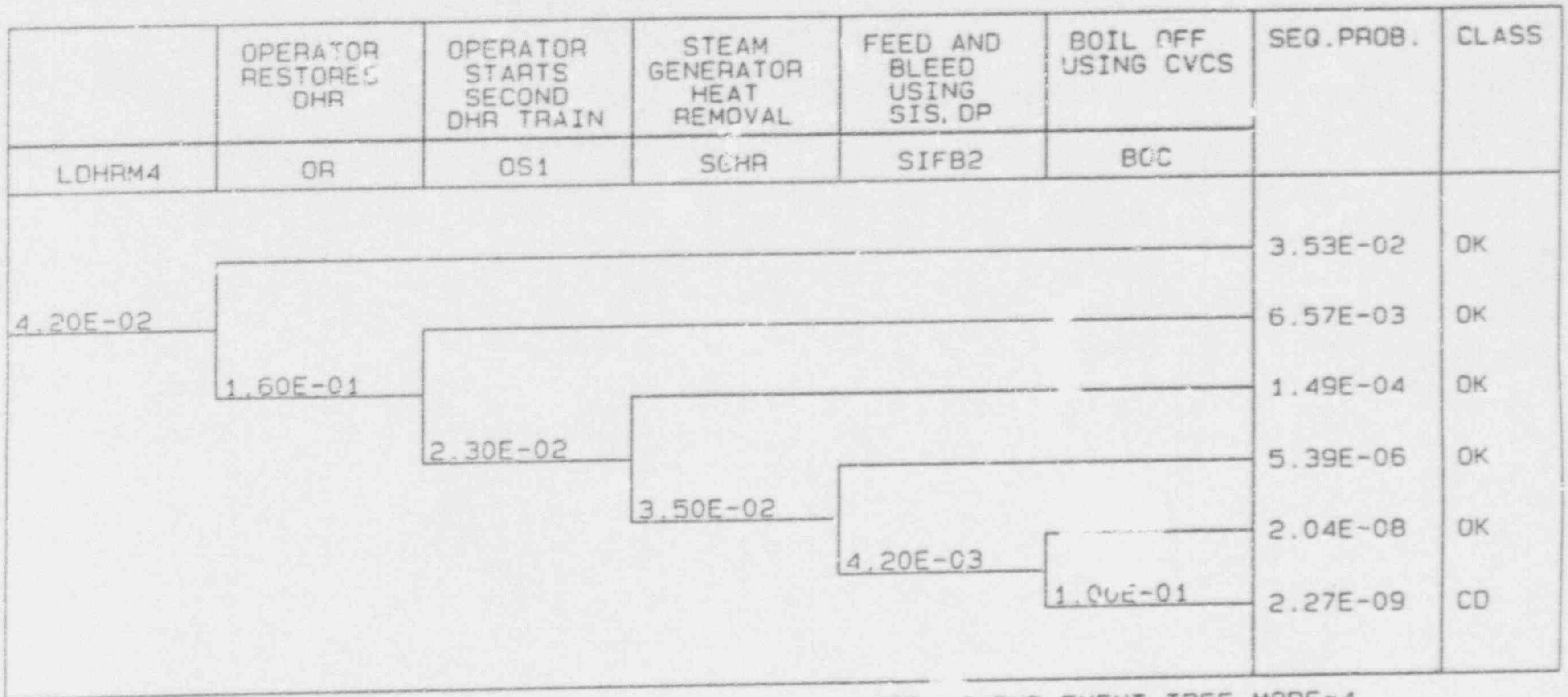
In the previous Shutdown Risk Studies summarized in NUREG 1449[3] reactivity events were not a major contributor to risk. Boron dilution could be either a rapid injection of deborated water or a slow dilution. Section 2.6 discusses rapid boron dilution events and concludes that the reactor would stay subcritical, even for the maximum credible size slug. A slow boron dilution event would be detected and terminated resulting in acceptable consequences.

The critical function monitoring system has been incorporated into The System 80+ and applicable for shutdown modes. The probability of missing a violation of one of these critical functions, particularly, Reactivity Control is small. The increased concern of the operators with reactivity events, due to the possibility of personnel hazards associated with having operators in containment, causes their stress level to increase positively and increases their vigilance.

Because the risk of criticality events is believed to be small, compared to loss of DHR and LOCAs, these events were not quantified.

FIGURE 3.4-1

EVENT TREE FOR LOSS OF DHR, MODE 4



LOSS OF RHR EVENT TREE MODE=4

FIGURE 3.4-2

Operator Fails to Restore the Operating Train of the Shutdown Cooling System

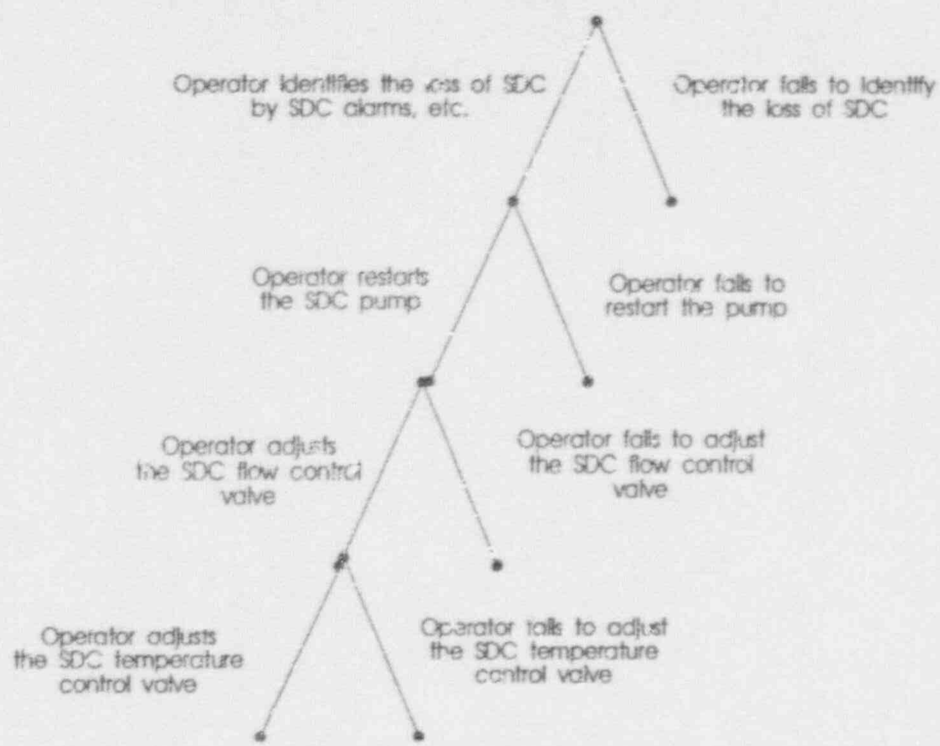


FIGURE 3.4-3

Operator Fails to Start the
Redundant Train of
the Shutdown Cooling System

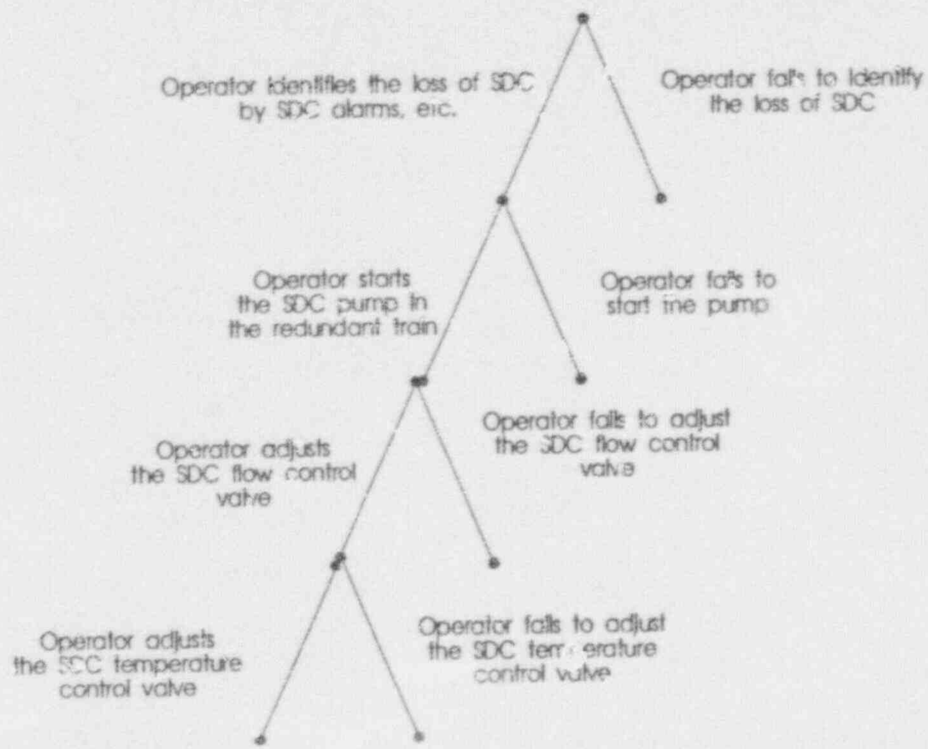


FIGURE 3.4-4

Operator Fails to Make Use of the Steam Generators as Emergency Decay Heat Removal

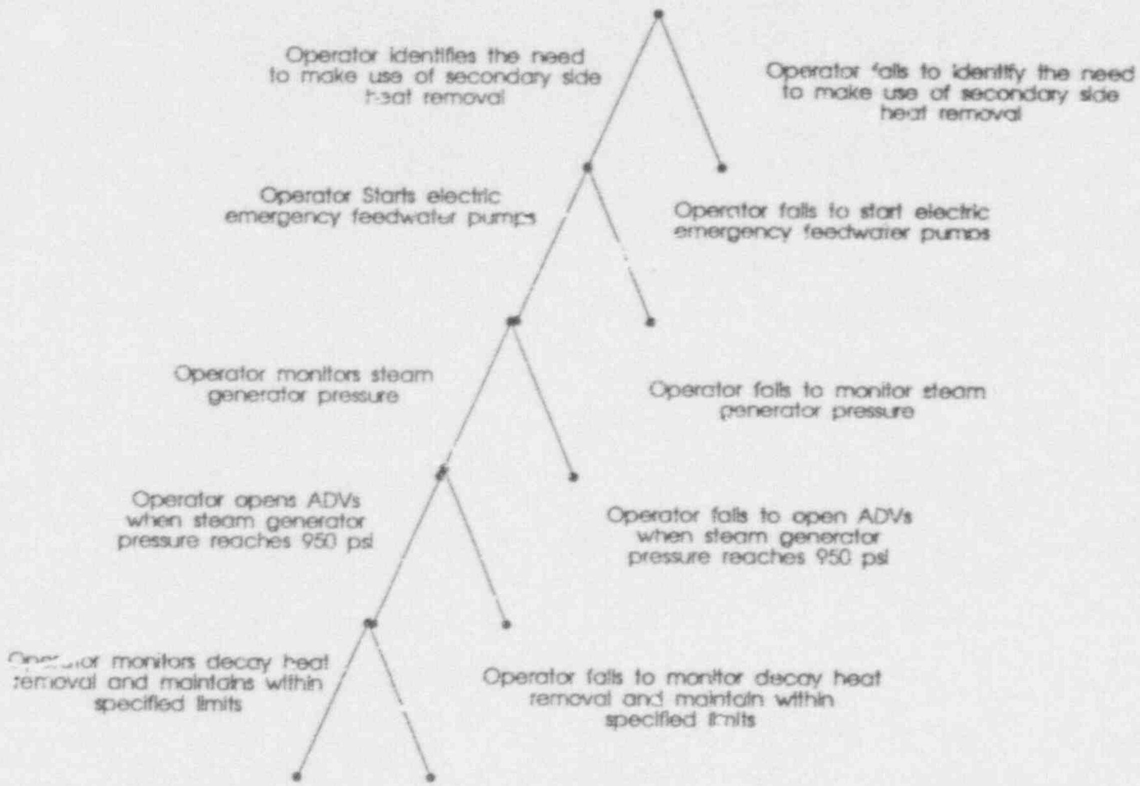


FIGURE 3.4-5

Operator Fails to Initiate
Feed and Bleed Cooling

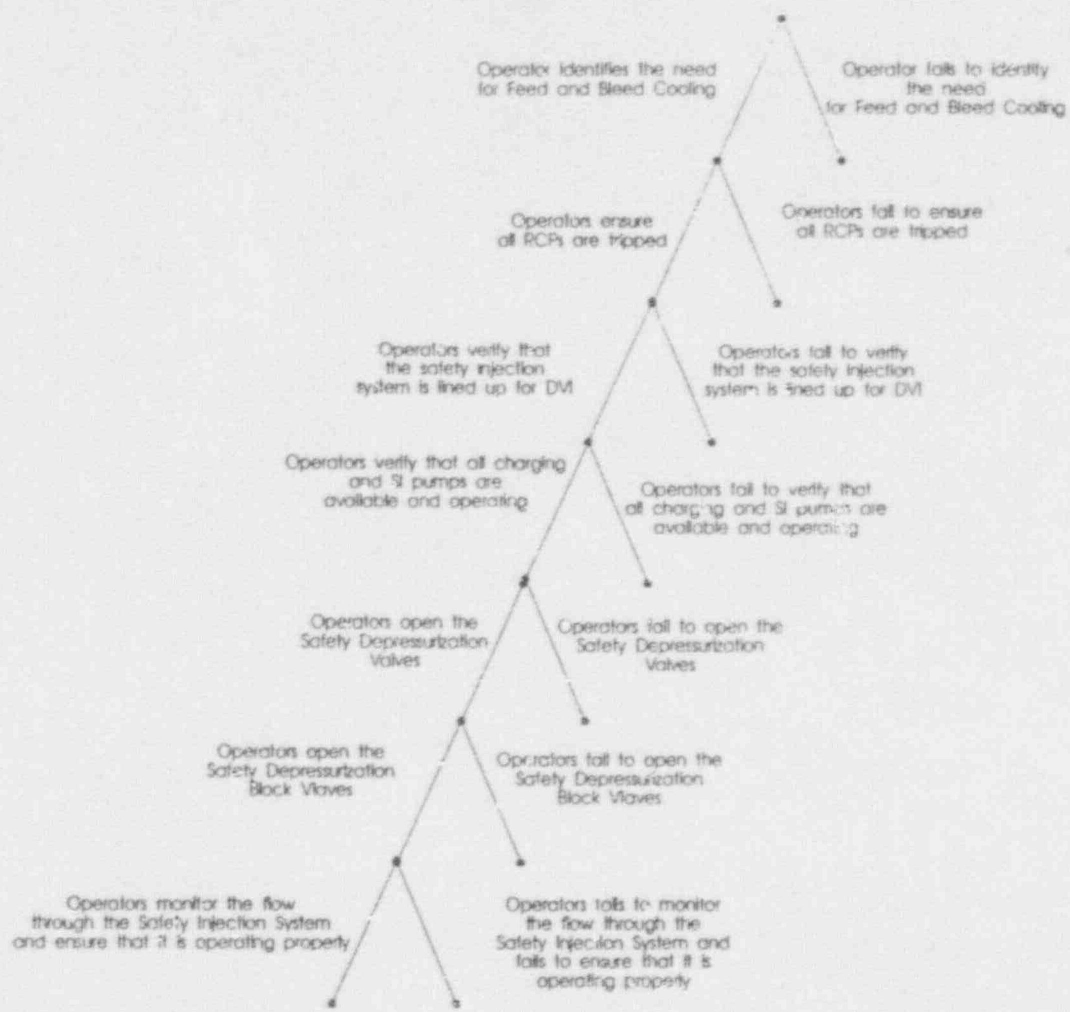


FIGURE 3.4-6

Operator Fails to Inject Inventory
from the Boric Acid Storage Tank to the RCS

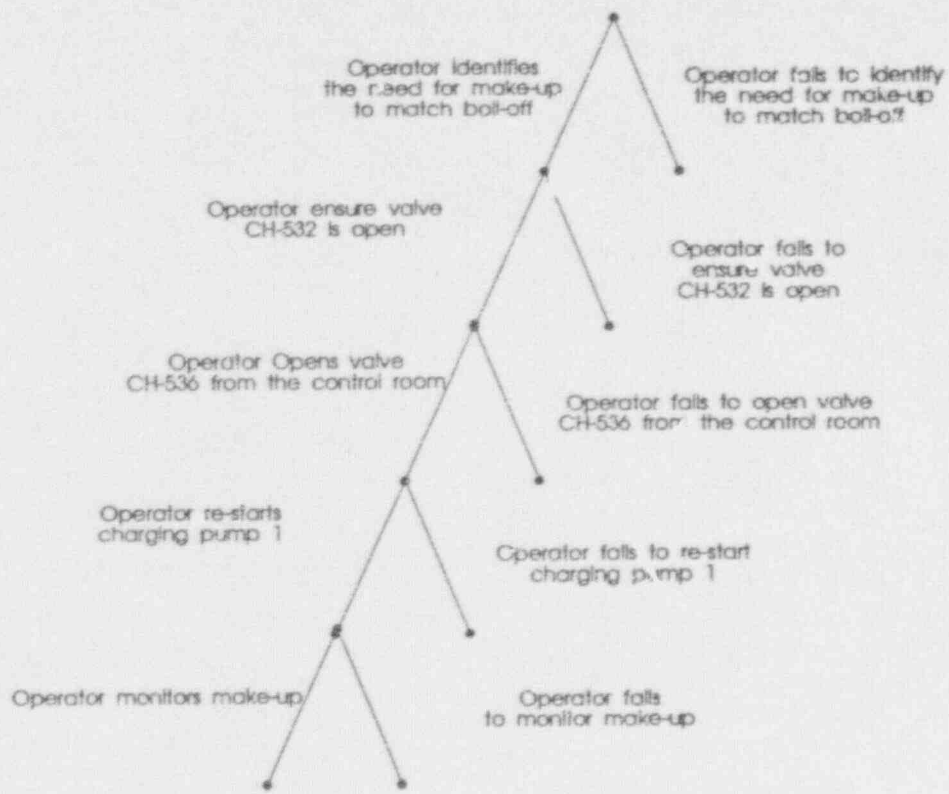
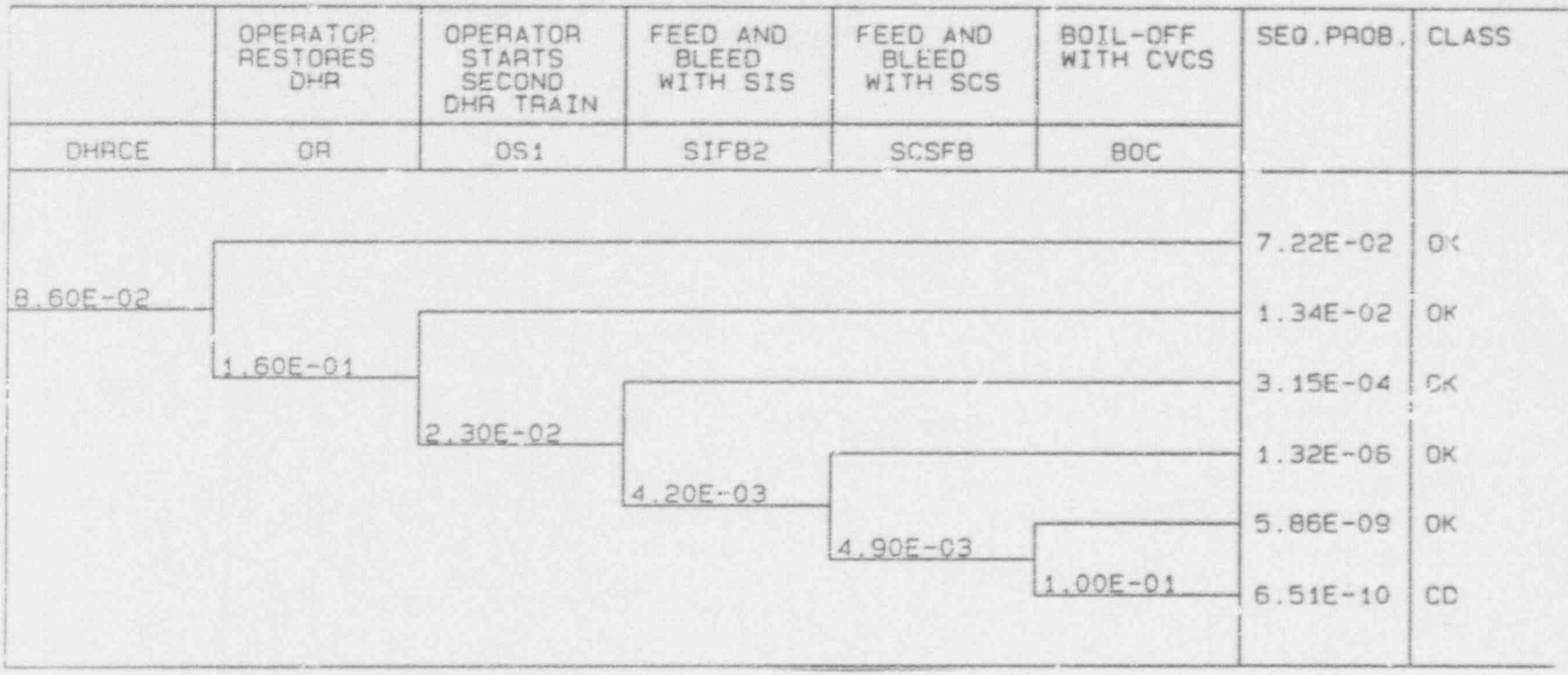


FIGURE 3.4-7

EVENT TREE FOR LOSS OF DHR, MODE 5,6
REFUELING CAVITY EMPTY



Operator Fails to Initiate Feed and Bleed Cooling Utilizing the Shutdown Cooling System

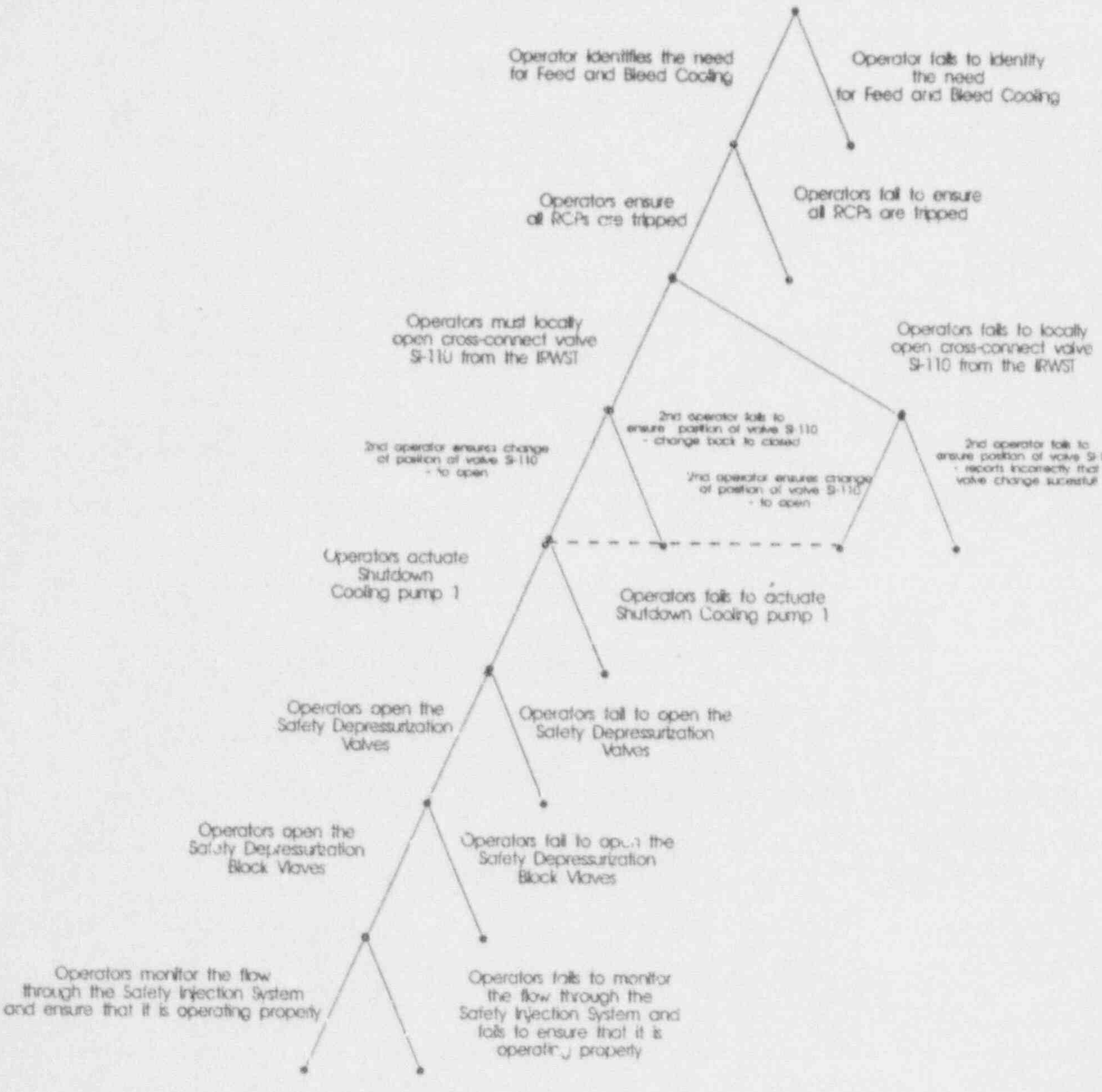


FIGURE 3.4-8

FIGURE 3.4-9

EVENT TREE FOR LOSS OF DHR, MODE 5
REDUCED INVENTORY

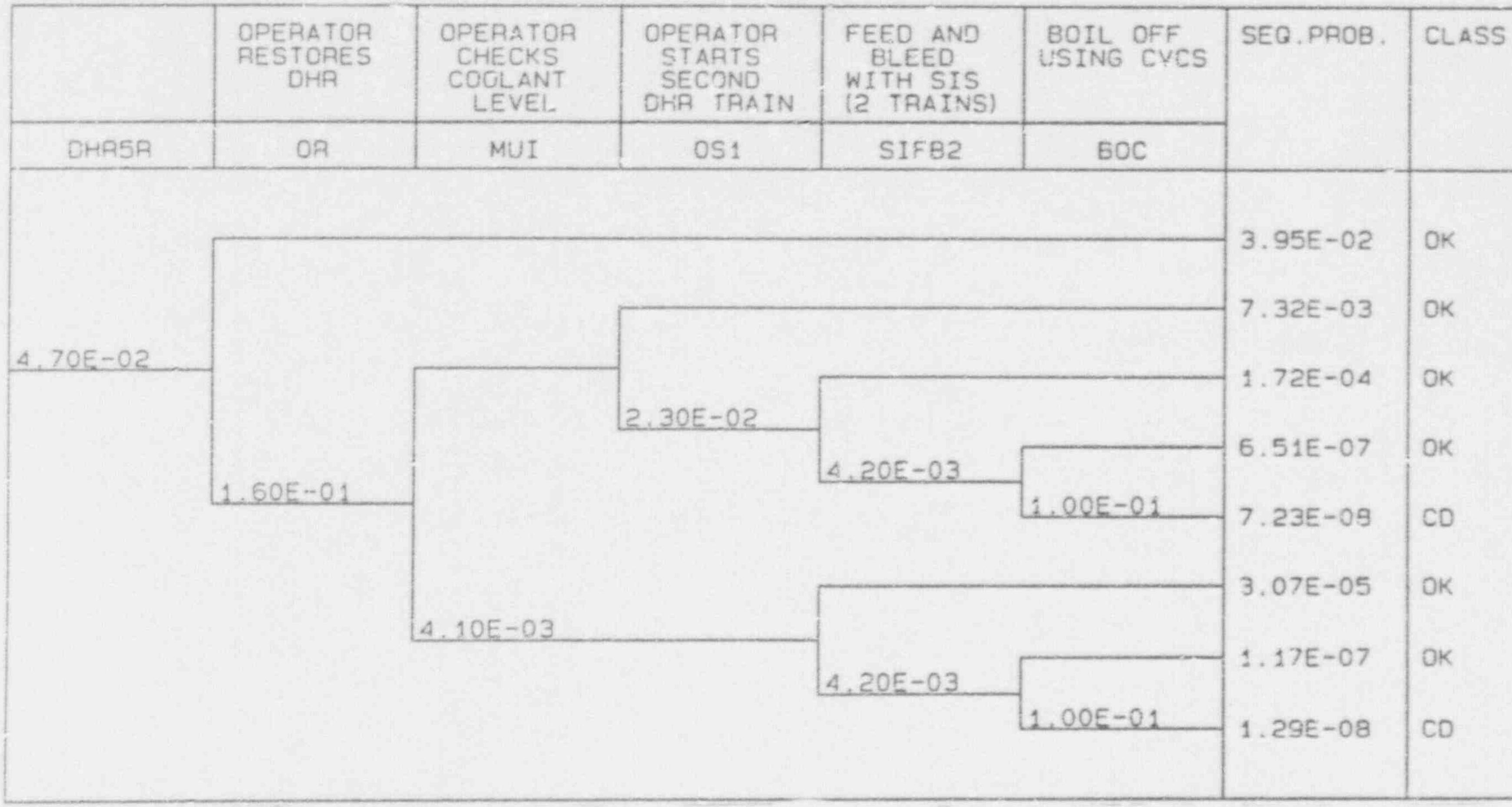


FIGURE 3.4-10

Operator Fails to Initiate Makeup Utilizing the Shutdown Cooling System

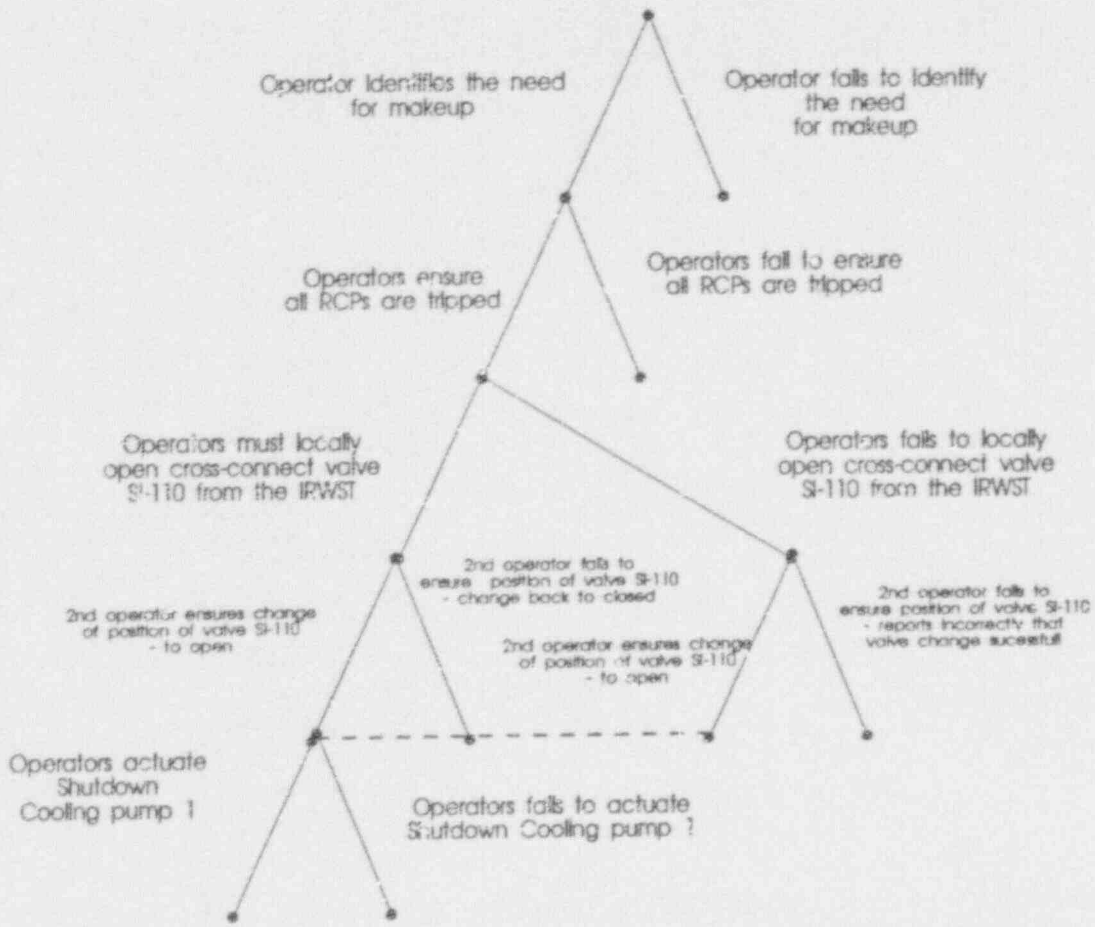


FIGURE 3.4-11

EVENT TREE FOR LOSS OF DHR, MODE 6
REFUELING CAVITY FULL

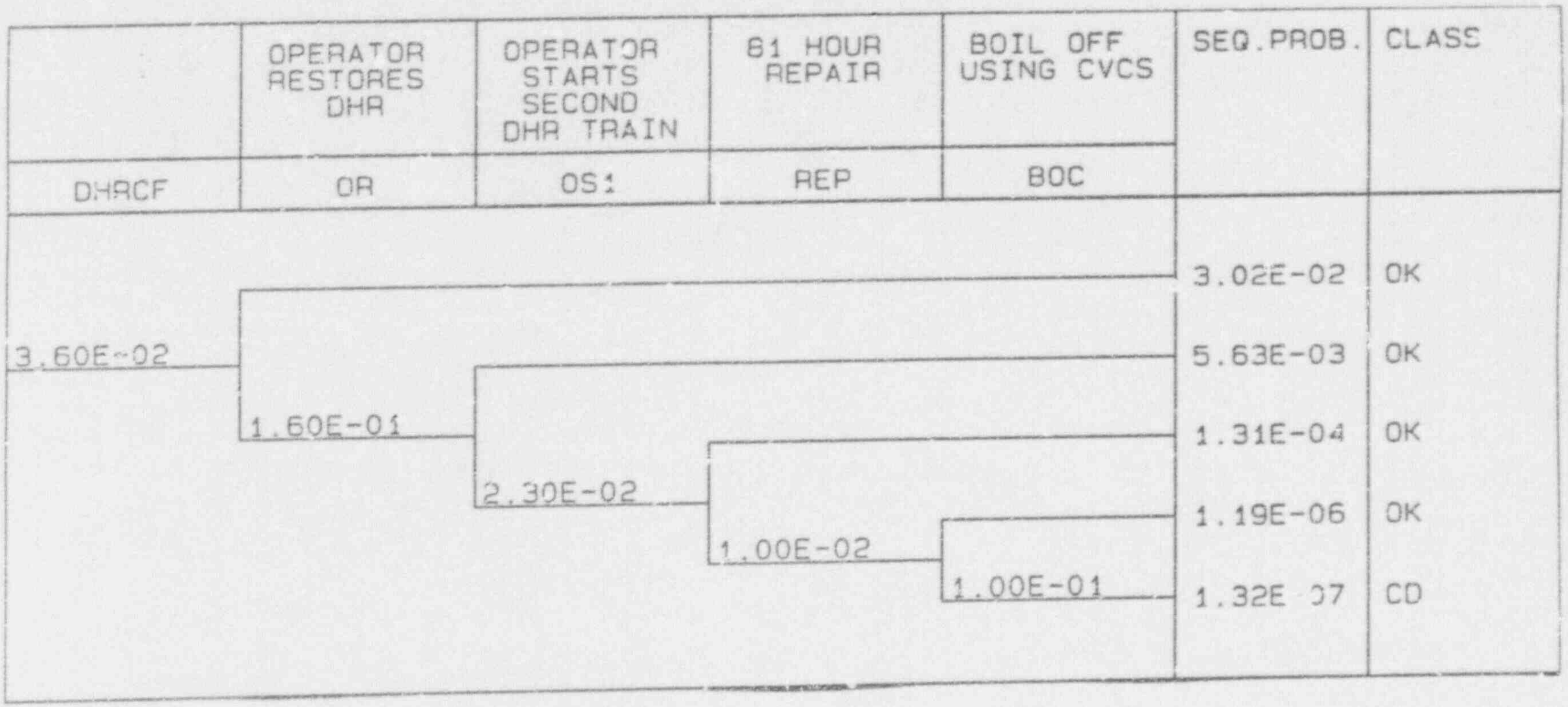


FIGURE 3.4-12

EVENT TREE FOR LOCA, MODE 4

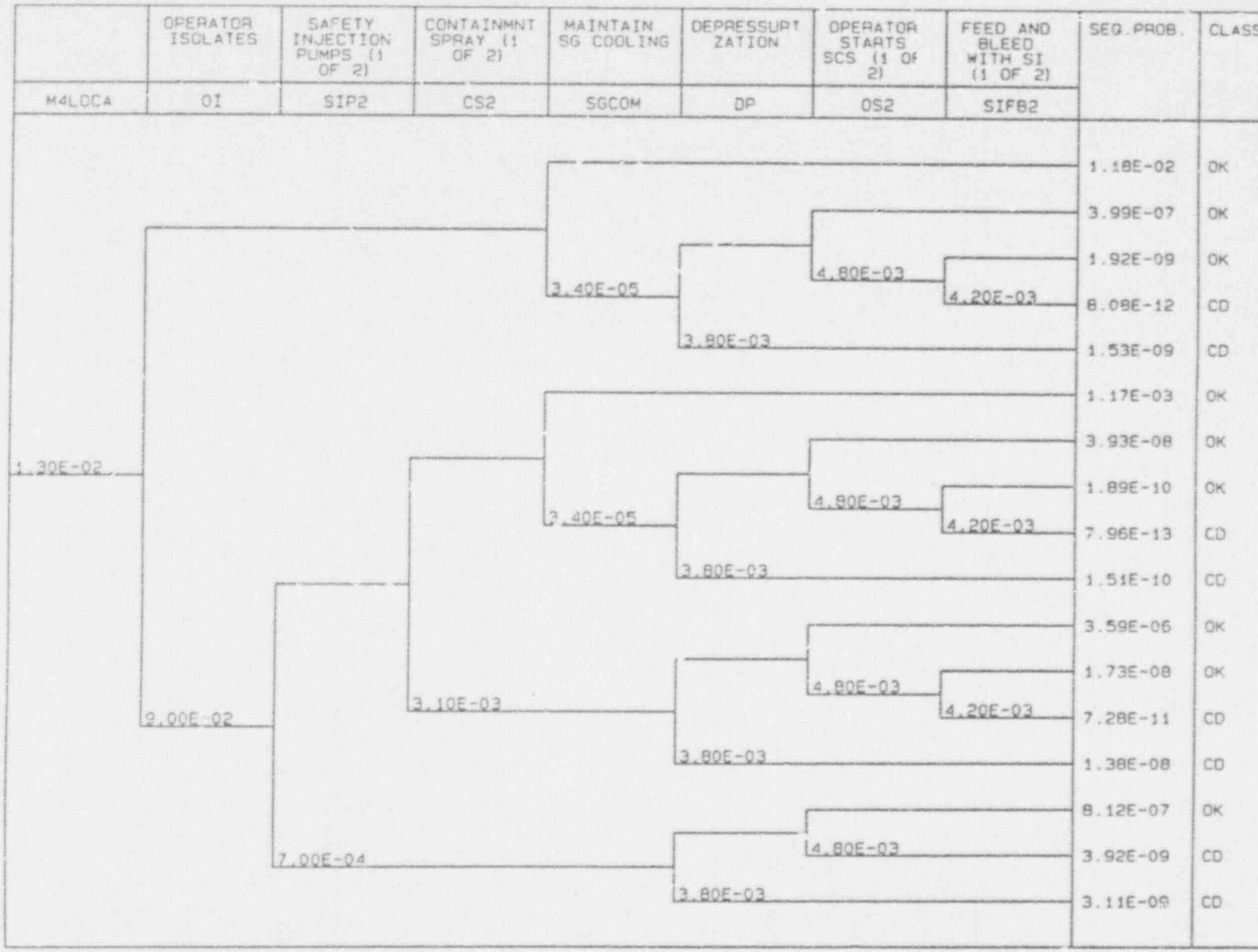


FIGURE 3.4-13

Operator Fails to Continue to
Make Use of the Steam Generators
as Emergency Decay Heat Removal

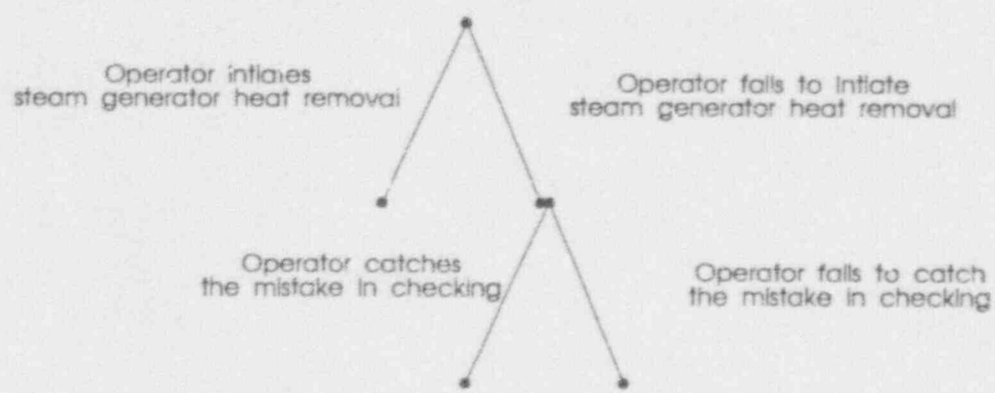
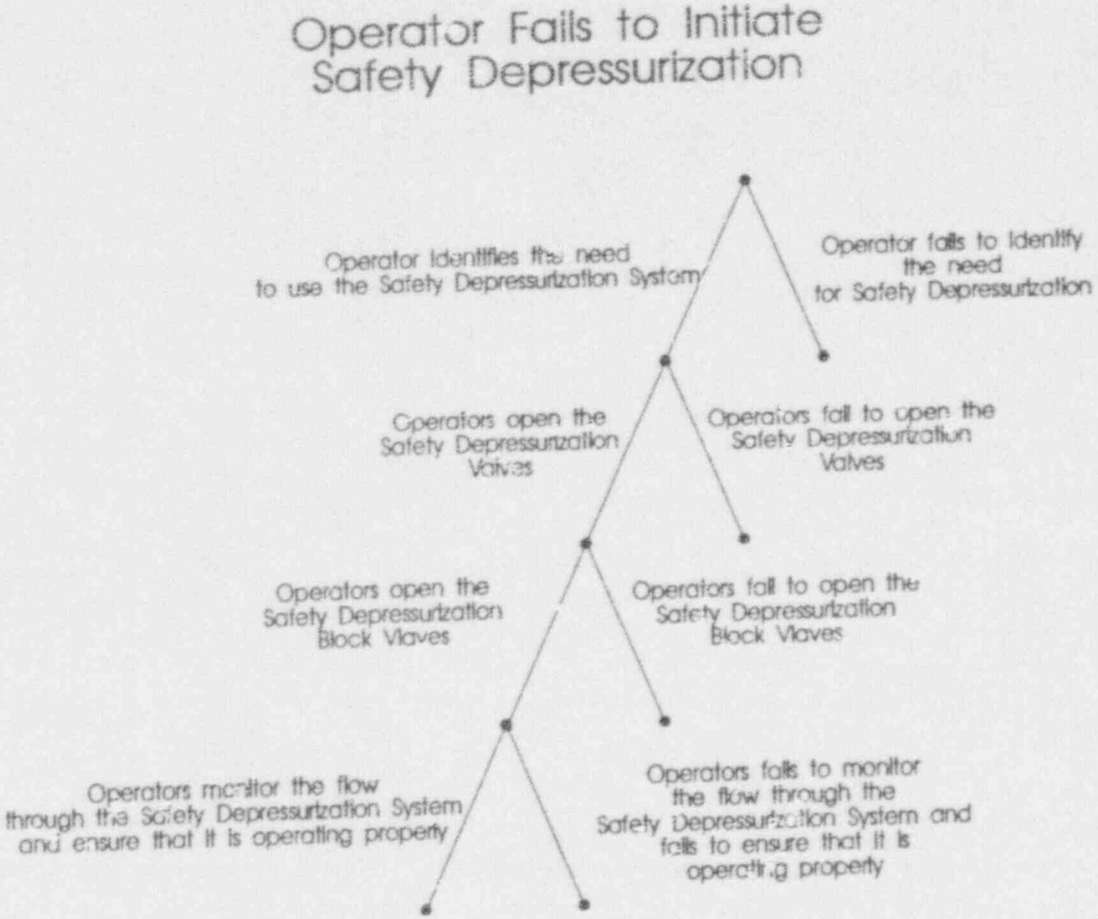


FIGURE 3.4-14



Operator Fails to Initiate
Safety Depressurization
Operator identifies the need
to use the Safety Depressurization System
Operator fails to identify
the need
for Safety Depressurization
Operators open the
Safety Depressurization
Valves
Operators fail to open the
Safety Depressurization
Valves
Operators open the
Safety Depressurization
Block Vlaves
Operators fail to open the
Safety Depressurization
Block Vlaves
Operators monitor the flow
through the Safety Depressurization System
and ensure that it is operating properly
Operators fails to monitor
the flow through the
Safety Depressurization System and
fails to ensure that it is
operating properly

FIGURE 3.4-15

EVENT TREE FOR LOCA
MODES 5,6 (IRWST AVAILABLE)

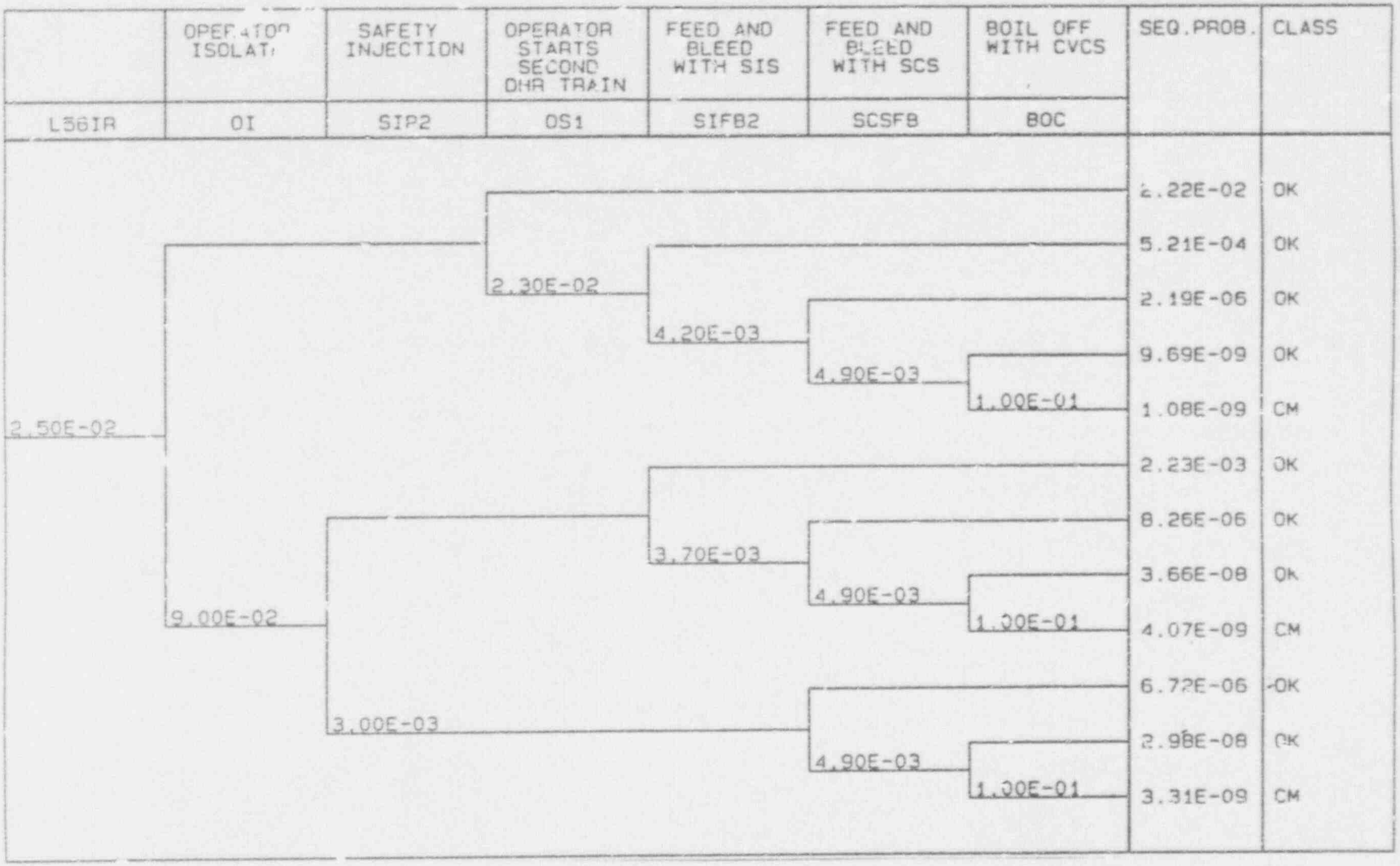


FIGURE 3.4-16

Operator Fails to Manually Initiate Safety Injection

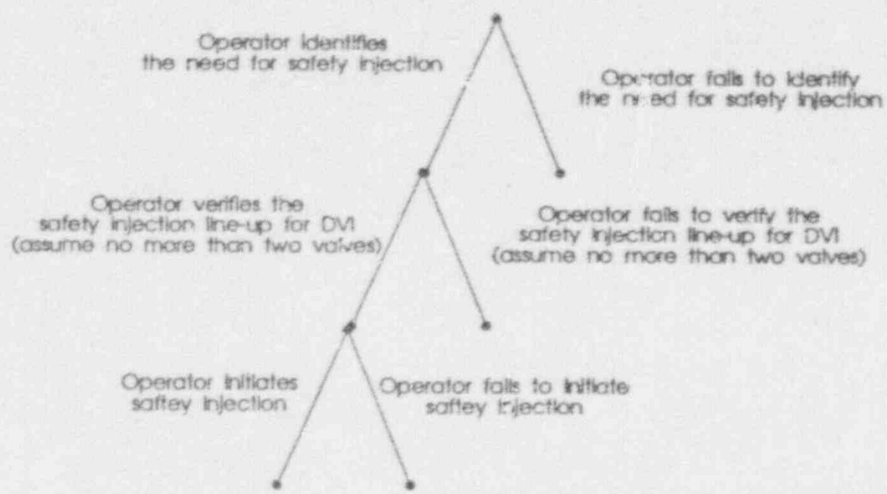


FIGURE 3.4-17

EVENT TREE FOR LOCA, MODE 6
LOCA OUTSIDE CONTAINMENT

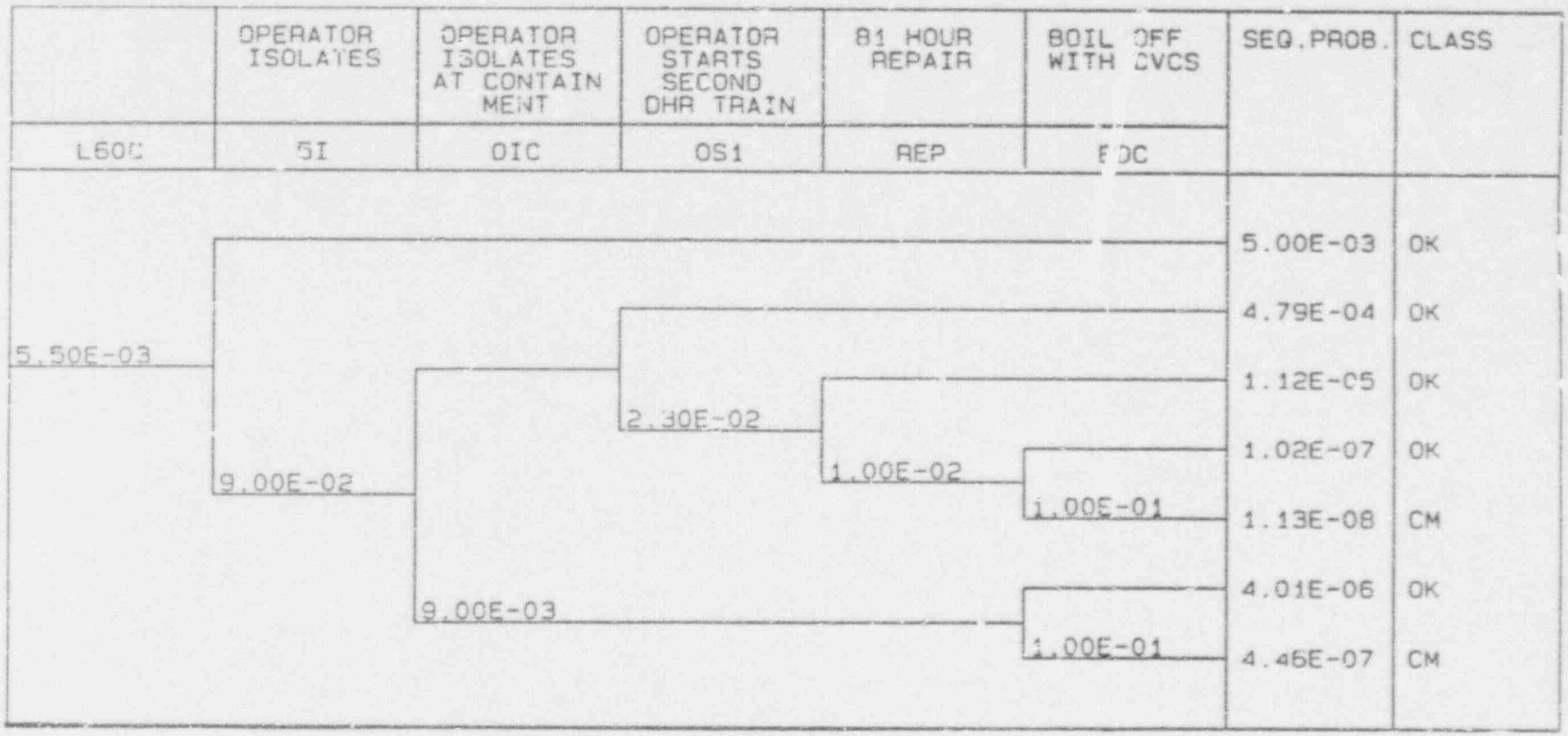
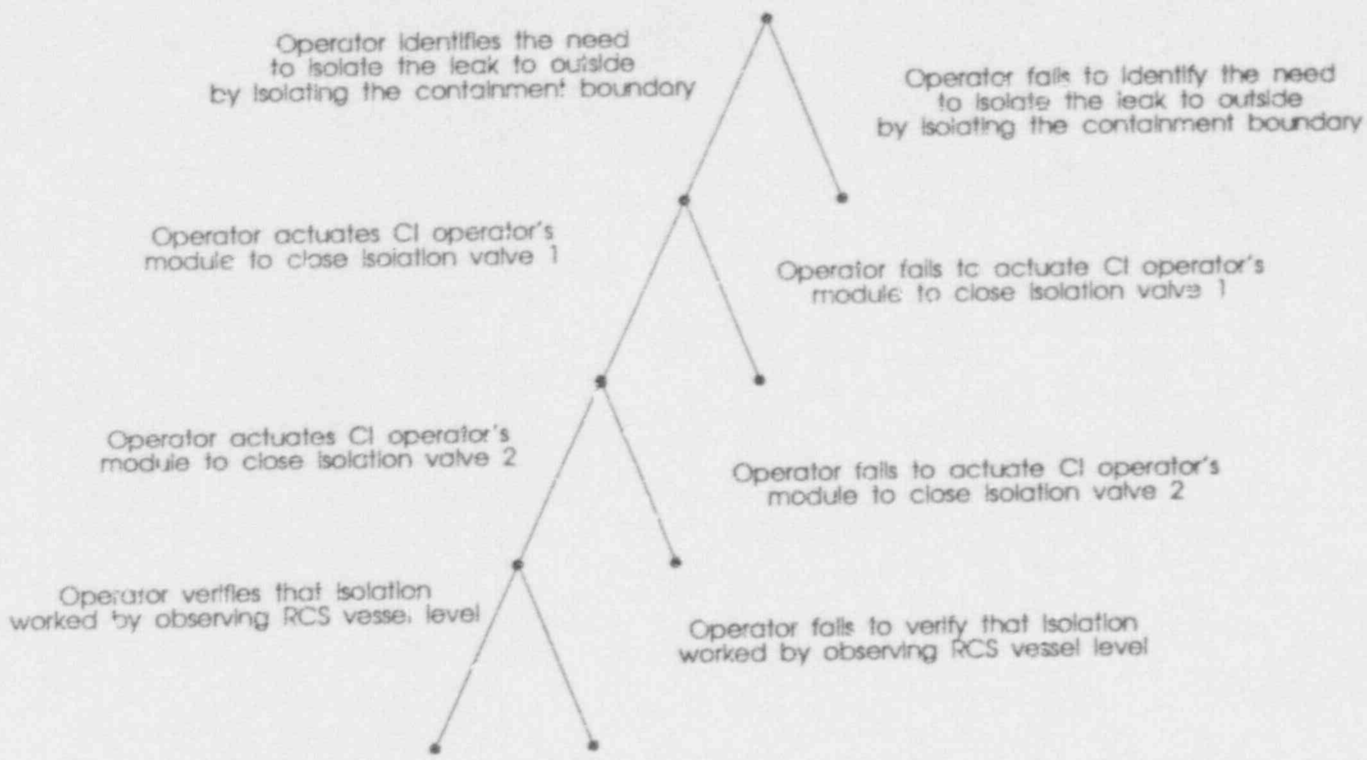


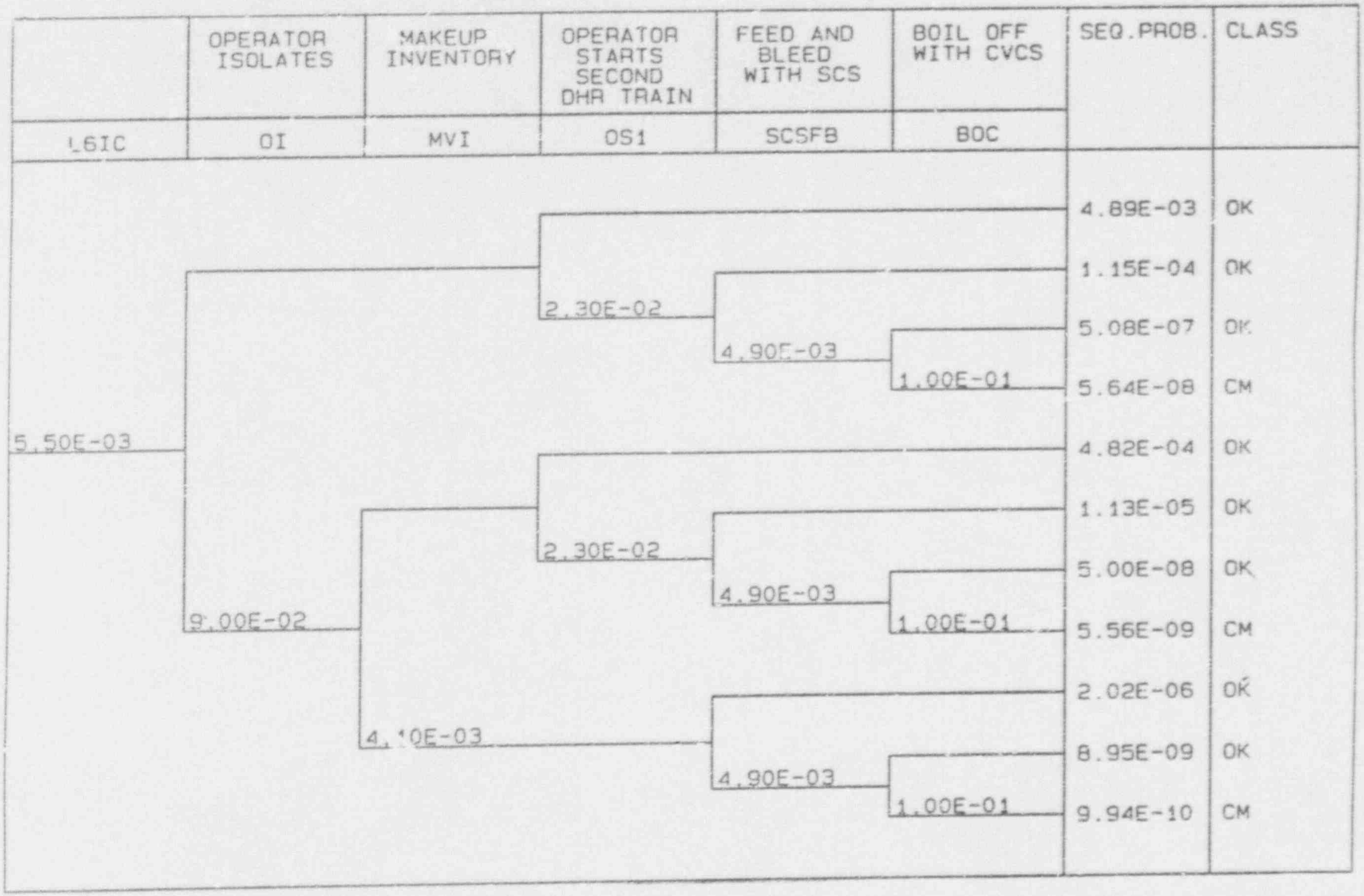
FIGURE 3.4-18

Operator Fails to Isolate
the Leak at the Containment Boundary



<u>**FIGURE 3.4-19**</u>

<u>**EVENT TREE FOR LOCA, MODE 6,**</u>
<u>**LOCA IN CONTAINMENT**</u>



3.5 RADIOLOGICAL CONSEQUENCES

The analysis presented in Section 3.4 quantifies the probability of core damage during various shutdown modes. For a Level III PRA this analysis would be continued to quantify the risk to the off-site population from the release of the fission products. The fission product inventory is reduced during shutdown because of two effects. If the accident occurs after the fuel shuffling is completed, one third of the core contains fresh fuel with no fission products. Also, as the outage continues, the nuclear inventory is reduced by fission product decay.

To demonstrate the effects of fission product decay on the radiological consequences, an evaluation of the nuclide inventory was performed starting with the nuclide inventory associated with 4 days after shutdown. This time was selected because it represents the minimum time during which mid-loop operation can be initiated. Tables 3.5-1 and 3.5-2 illustrate the effects of the fission product decay process on the overall core radioactive nuclide inventory and the concentration of potentially volatile fission products. A review of the radionuclide decay chain indicates that the fission product inventory has decreased by 30% by the end of a 20 day refueling. Furthermore, the concentration of potentially volatile nuclide releases will be reduced by at least a factor of 5. If the shutdown is extended to 40 days, the nuclide inventories would be one half of the four-day level and the concentration of the volatile fission products would be only 6% of that potentially available at 4 days into shutdown.

TABLE 3.5-1

FRACTIONAL CORE RADIOACTIVITY FOLLOWING SHUTDOWN

DAYS AFTER SHUTDOWN	FRACTIONAL RADIOACTIVITY*
4	1.0
20	0.62
40	0.45

* VALUES NORMALIZED TO RADIONUCLIDE CONCENTRATIONS AT 4 DAYS

TABLE 3.5-2

FRACTIONAL DECAY OF SELECT RADIOACTIVE NUCLIDE GROUPS FOLLOWING SHUTDOWN

NUCLIDE GROUP	DAYS AFTER SHUTDOWN		
	4 DAYS	20 DAYS	40 DAYS
NOBEL GASES	1.0	.13	.02
IODINE	1.0	.25	.04
CESIUM	1.0	.95	.90

4.0 APPLICABILITY OF CHAPTER 15 ANALYSES

4.0.1 FORMAT AND CONTENT

The purpose of this section is to present evaluations which confirm the analyses presented in Chapter 15 of CESSAR-DC conservatively bound the outcome of transients and accidents initiated during shutdown modes (Mode 2 subcritical or Modes 3 through 6) for the System 80+ Standard Design.

The approach used in the documentation of the events in Chapter 15 of CESSAR-DC is to present the results for the events with the most adverse consequences. As a result, reference is most frequently to events postulated to occur in Mode 1 or Mode 2 critical. Only in certain cases which intrinsically involve shutdown modes (e.g. startup of an inactive reactor coolant pump) are shutdown modes stressed. The purpose of this section is to ensure that all operating Modes have been treated in the documentation for Chapter 15 events. The analysis models used are the same as used in Chapter 15 and have been approved by the NRC.

Table 4.0-1, together with Figure 4.0-1 and Table 4.0-2 present the complete range of initial conditions used for the analyses of Chapter 15 events for all Modes: 1 through 6.

The following sections have been organized to parallel the sections of Chapter 15 of CESSAR-DC. For example, Section 4.1.1 treats the same group of initiating events that are documented in Section 15.1.1 of CESSAR-DC.

TABLE 4.0-1

INITIAL CONDITIONS

Core Power	% of 3800 MWt	0 to 102[1]
Axial Shape Index	--	$-0.3 \le \text{ASI} \le +0.3$[2]
Reactor Vessel Inlet Coolant Flow Rate	% of 445600 gpm	95 to 116[3]
Pressurizer Water Level	% distance between upper tap and lower tap	26 to 60[4]
Core Inlet Coolant Temperature		
<90% Power	°F	543 to 565[5]
≥90% Power	°F	553 to 563
Pressurizer Pressure	psia	1905 to 2375[5]
Steam Generator Water Level		
Low	% Wide Range[6]	33.7[8],[9] 40.7
High	% Narrow Range[7]	95.0

(1) Core power is that due to decay heat in Modes 3 through 6.
(2) ASI = (area under axial shape in lower half of core - area under axial shape in upper half of core)/(total area under axial shape). A range of valves of ASI from -0.6 to +0.6 was considered for subcritical core conditions.
(3) For Modes 3 through 6 see TABLE 4.0-2.
(4) Between 0 and 100% in Modes 4 and 5. Pressurizer is empty in Mode 6 when the refueling pool is empty.
(5) For Modes 3 through 6 see Figure 4.0-1.
(6) Percent of distance between the wide range instrument taps. See Chapter 5 of CESSAR-DC for details.
(7) Percent of distance between the narrow range instrument taps. See Chapter 5 of CESSAR-DC for details.
(8) For steam and feedwater line breaks only.
(9) ≥ 25% SG water level in Modes 3 and 4 and in Mode 5 for loops filled and additional RCS loop/SDC division not OPERABLE. Not applicable for Mode 5 with loops not filled and Mode 6.

TABLE 4.0-2

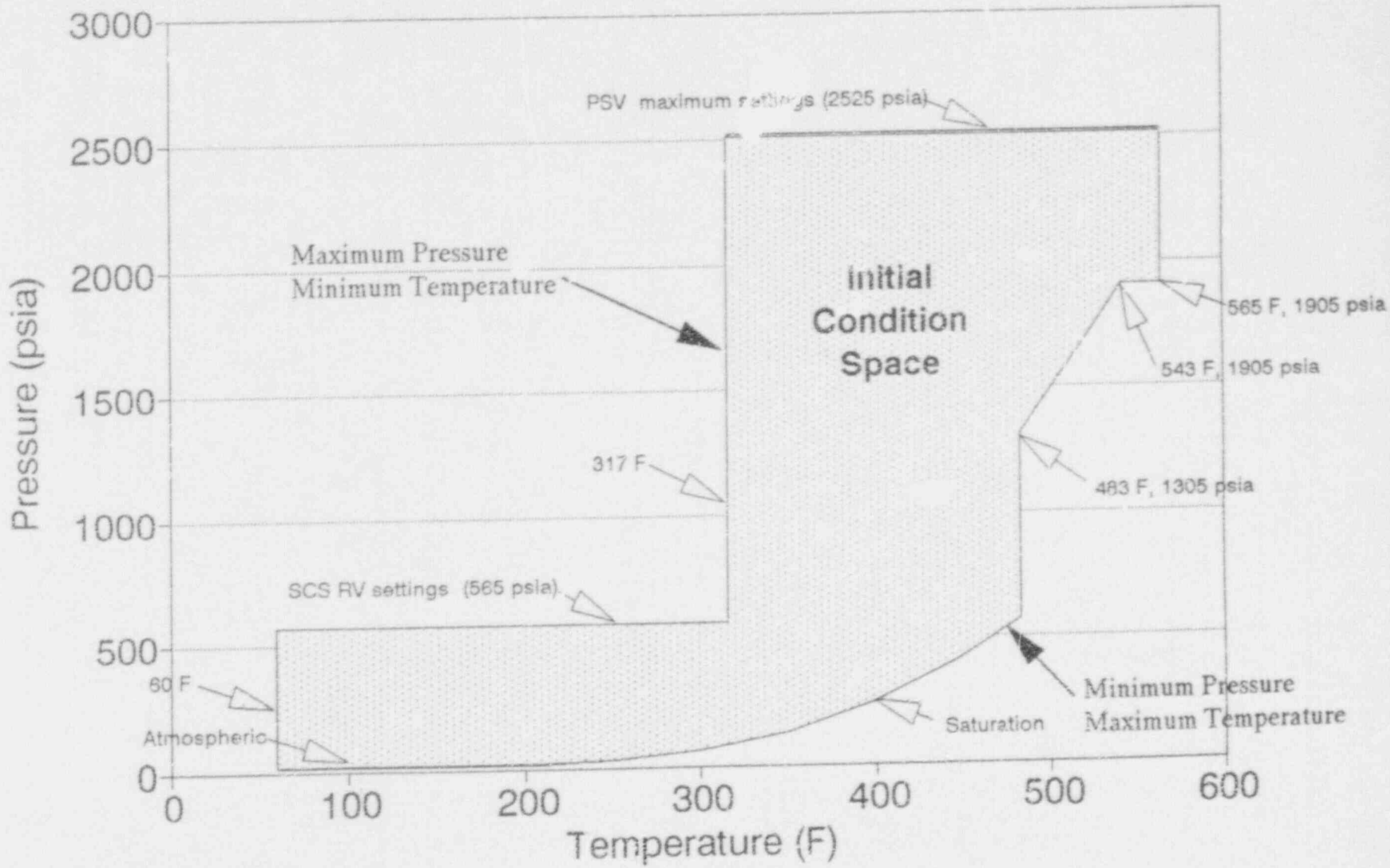
REACTOR VESSEL INLET COOLANT FLOW RATE

MODE	SYSTEM	FLOW RATE (%)
3	RCP	33 to 116
4	RCP	33 to 116
	SCS	0.94 to 2.24
5 (Loops Filled)	RCP	33 to 116
	SCS	0.94 to 2.24
5 (Loops Not Filled)	SCS	0.22 to 2.24
6	SCS	0.94 to 2.24

SYSTEM 80+™

INITIAL CONDITIONS FOF PRESSURE AND TEMPERATURE IN MODES 3 THROUGH 6

Figure 4.0-1



4.1 INCREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

4.1.0 INTRODUCTION

The purpose of this section is to present evaluations which confirm that all increase in heat removal by the secondary system events postulated to be initiated in a shutdown Mode have acceptable consequences for the System 80+ Standard Design.

Section 15.1 of CESSAR-DC documents results which show that all increase in heat removal by the secondary system events have acceptable consequences if they are explicitly postulated to occur in Mode 1 or Mode 2 critical for the System 80+ Standard Design. This is demonstrated for steam system piping failures inside and outside containment (Section 15.1.5) by analyses for both Mode 1 and Mode 2 critical. The choice of initial conditions for the other analyses of Section 15.1 to minimize the transient DNBR for any operating condition ensures that the results presented bound those for all of Mode 1 and Mode 2 critical.

4.1.1 DECREASE IN FEEDWATER TEMPERATURE

The consequences of decrease in feedwater temperature events initiated in a shutdown mode are bounded by those of the increase in feedwater flow events presented in Section 4.1.2. The increase in feedwater flow events of Section 4.1.2 are initiated at the coldest possible feedwater temperature and the highest feedwater flow rate. This extreme combination of conditions results in the most severe reactor coolant system overcooling transient and, consequently, the greatest potential for a return to criticality with subsequent power generation and potential for DNB.

4.1.2 INCREASE IN FEEDWATER FLOW

Evaluation of the consequences of increase in feedwater flow events postulated to be initiated in a shutdown mode shows that the results are no more adverse than those of the full power event documented in Section 15.1.2 of CESSAR-DC. The minimum transient value of DNBR is predicted to be greater than 3 for the most adverse combination of conditions, thus fuel integrity is not challenged. All increase in heat removal events analyzed in this section are characterized by decreasing steam generator pressures and RCS pressure, thus there is no approach to 110% of the design pressure of the steam generators or RCS.

Increase in feedwater flow events are only applicable when the steam generators are being used as a heat sink. This could occur in Mode 2 subcritical, Mode 3, or Mode 4 when the shutdown cooling system (SCS) is not being used for decay heat removal. The turbine-generator would be off-line. Steam would be exiting the steam generators via the atmospheric dump valves or the steam bypass control valves. Normal feedwater flow would be entering the steam generators from the startup feedwater system via the main feedwater piping. An increase in feedwater flow could occur via either the main or emergency feedwater systems.

Administrative controls require main feedwater pumps to be unavailable for inadvertent delivery of feedwater to the steam generators in shutdown modes. (See Table 2.1.1.) There are, therefore, two increase in feedwater flow event scenarios which can be postulated as potentially bounding events for shutdown modes:

1. Inadvertent EFAS Actuation: The initiating event is assumed to be a spurious Emergency Feedwater Actuation Signal (EFAS) for one steam generator. Each steam generator is fed from a separate Emergency Feedwater (EFW) train and each EFW train is actuated by a separate EFAS. The postulated initiating event results in starting both the turbine-driven and motor-driven EFW pumps to the affected steam generator. The cavitating venturi in the EFW supply pipeline limits the flow to less than 800 gpm. The minimum temperature from the EFW storage tanks is greater than 40°F.

2. Maximum Startup Feedwater Flow: The initiating event is assumed to be one control valve failing open, diverting all flow from the startup feedwater (SUFW) pump to one steam generator. One SUFW pump supplies both steam generators and there is a separate control valve for each steam generator. A bounding value of the feedwater flow is 4000 gpm (more than twice the specified 5% of main feedwater flow and greater than the expected runout flow). The water source is assumed to be the condensate storage tank which is conservatively assumed to be at 32°F.

To cover these postulated scenarios with extreme, bounding assumptions, a spectrum of cases were investigated using feedwater flows rates from less than 800 to 4000 gpm, all at 32°F, and all initiated from the most adverse set of initial conditions.

The most adverse initial conditions for excess feedwater flow events initiated in a shutdown mode occur in Mode 3. A core inlet temperature of 565°F maximizes the positive moderator and Doppler reactivity addition caused by the RCS cooldown. (Parametric cases demonstrated that the most adverse results occurred with the maximum initial temperature.) Initiating at a lower core inlet temperature results in less positive moderator and Doppler reactivity coefficients and in a lower rate of RCS overcooling. Further, less than four reactor coolant pumps (RCPs) can be operating in Mode 3 (as opposed to Mode 2 subcritical). This parameter has the most significant effect on the minimum DNBR. All cases were, therefore, initiated in Mode 3.

The maximum k_{eff} allowed by Technical Specifications in Mode 3 provides the greatest potential for reaching criticality and consequent power generation due to the cooldown event prior to encountering a reactor trip on low steam generator pressure or high steam generator level. The excess feedwater flow events were, therefore, initiated at k_{eff} = 0.99. It was assumed that one or more regulating CEAs was inserted and all remaining regulating CEAs and shutdown CEAs were fully withdrawn.

To maximize the cooldown rate and the time required to reach the high steam generator water level trip setpoint, the events were assumed to be initiated at the minimum Mode 3 technical specification steam generator water level of 25% wide range. Further, at the start of each event it was assumed that the decay heat production was zero. Consequently, all supplied feedwater was "excess" and contributed to the RCS overcooling.

Decreasing core coolant flow reduces the minimum DNBR for a given level of power generation. However, the maximum rate of RCS overcooling -- and the consequent potential for power generation -- for these events occurs with four RCPs operating. The reactor coolant flow low trip prevents operation with the reactor trip breakers closed and less than one RCP operating in each loop for Modes 3 or 4. Further, with less than all RCPs in operation a reactor trip would be generated two decades lower in power -- due to the automatic removal of the CPC bypass (see the discussion in Section 4.4.1) -- than when all RCPs are in operation. In addition, any postulated occurrence which would result in tripping of operating RCPs after event initiation -- e.g. a loss of offsite power -- would cause a reactor trip on low flow and terminate any approach to criticality earlier than that calculated without the loss of flow. It has been determined via parametric studies that the net effect of these factors is that the minimum transient DNBR occurs for postulated events for which all four RCPs are in operation.

These cases included the effect of the most reactive CEA stuck in the fully withdrawn position. There were no single failures found which could adversely impact these events with respect to reducing the transient minimum DNBR. The calculation of the maximum post-trip reactivity included the effect of a failure of one emergency generator to start, run, or load (resulting in unavailability of two safety injection pumps).

The rate of cooldown for the excess feedwater flow events is less dependent upon the steam generator temperature (and resultant pressure) than it is for the steam line break events. Further, the maximum cooldown rate attainable with the spectrum of potential flows is such that all of the excess feedwater flow events were mitigated at low core powers by a high logarithmic power trip or

CPC trip. Consequently, the most adverse results were calculated to occur for the highest flow rate and the highest initial RCS temperature.

The investigation of this spectrum of cases with the assumed conservative initial conditions found that the minimum transient DNBR for increased feedwater flow events postulated to be initiated in a shutdown mode is greater than 3. Further, the maximum reactivity following reactor trip was more negative than -3%$\Delta\rho$. There was, therefore, no post-trip power generation or approach to DNB.

Since the minimum transient DNBR for the events to which the events of Section 15.1.2 of CESSAR-DC were referenced was 1.24, the consequences of events in shutdown modes are no more adverse than those of the events presented in CESSAR-DC.

4.1.3 INCREASED MAIN STEAM FLOW

As noted in Section 15.1.3 of CESSAR-DC, the steam flow due to an increased main steam flow event is the same as (or less than) that due to an inadvertent opening of a steam generator relief or safety valve event. Further, there are no other differences between these events which affect their consequences. Therefore, the conclusions of Section 4.1.4 of this report apply also to an increased main steam flow event.

4.1.4 INADVERTENT OPENING OF A STEAM GENERATOR RELIEF OR SAFETY VALVE

Evaluation of the inadvertent opening of a steam generator relief or safety valve events postulated to be initiated in a shutdown mode shows that the results are less adverse than those of the events documented in Section 15.1.4 of CESSAR-DC.

This evaluation was completed as integral to the study of steam system piping failures postulated to be initiated in a shutdown mode. The transient caused by an inadvertent opening of a steam generator relief or safety valve is identical to that caused by a steam line break of area equal to that of a relief or safety valve. The study presented in Section 4.1.5 covered a full spectrum of break sizes and initial conditions, including all and less than all reactor coolant pumps running. As documented in Section 4.1.5, the minimum transient DNBR for a steam system piping failure in a shutdown mode is greater than 2. The minimum transient DNBR for inadvertent opening of a steam generator relief or safety valve events postulated to be initiated in a shutdown mode is, therefore, also greater than 2. Since the minimum transient DNBR for the events of Section 15.1.4 of CESSAR-DC was 1.24, the consequences of the events presented in CESSAR-DC bound those of events in shutdown modes.

4.1.5 STEAM SYSTEM PIPING FAILURES INSIDE AND OUTSIDE CONTAINMENT

Evaluation of steam system piping failures inside and outside containment, postulated to be initiated in a shutdown mode, shows that the results are less adverse than those of the events documented in Section 15.1.5 CESSAR-DC.

The evaluation presented in this section focuses on fuel performance as measured by the departure from nucleate boiling ratio (DNBR) for verification of fuel integrity. Steam system piping failures are characterized by decreasing reactor coolant system (RCS) and steam generator pressures. Therefore the RCS pressure remains well below 110% of design pressure and the pressure-temperature limits for brittle fracture, ensuring that the integrity of the RCS is maintained, and the steam generator pressure remains below 110% of design pressure ensuring that the integrity of the secondary system is maintained. The two-hour inhalation dose at the EAB (Exclusion Area Boundary) is also examined to confirm that, if such an event were postulated to be initiated in a shutdown mode, the value meets the Standard Review Plan Acceptance Criteria of Reference 6.

For shutdown modes the reactor core is subcritical with power being generated only by decay heat. Substantial margins to DNB exist at the time of a postulated event initiation. Steam system piping failures would cause a decrease in the temperature of the reactor coolant and in the RCS and steam generator pressures. The decrease in the reactor coolant temperature would result in an increase in core reactivity due to the negative moderator temperature coefficient. If the cooldown were sufficiently large, a return to criticality followed by an increase in core power might occur. This could create a potential for degrading the margins to DNB. There are two possibilities to be considered for a return to criticality for these events:

a. cooldown sufficient to reach criticality prior to reactor trip and

b. extended cooldown after reactor trip of sufficient magnitude to reach criticality if there were insufficient safety injection boration to prevent a return to criticality.

The initial reactor core and steam generator temperatures have particularly significant effects for steam system piping failures. The total potential magnitude of the possible RCS cooldown rises with increasing initial steam generator temperature. In addition, the initial rate of cooldown would be greater if the initial steam generator temperature were higher. Further, both the potential rate and the total potential magnitude of the reactivity increase caused by cooldown rise with increasing reactor core temperature.

Steam system piping failures would, therefore, be expected to have the most adverse consequences if they were assumed to be initiated at the highest possible initial temperatures, if event mitigation were not affected by the initial conditions.

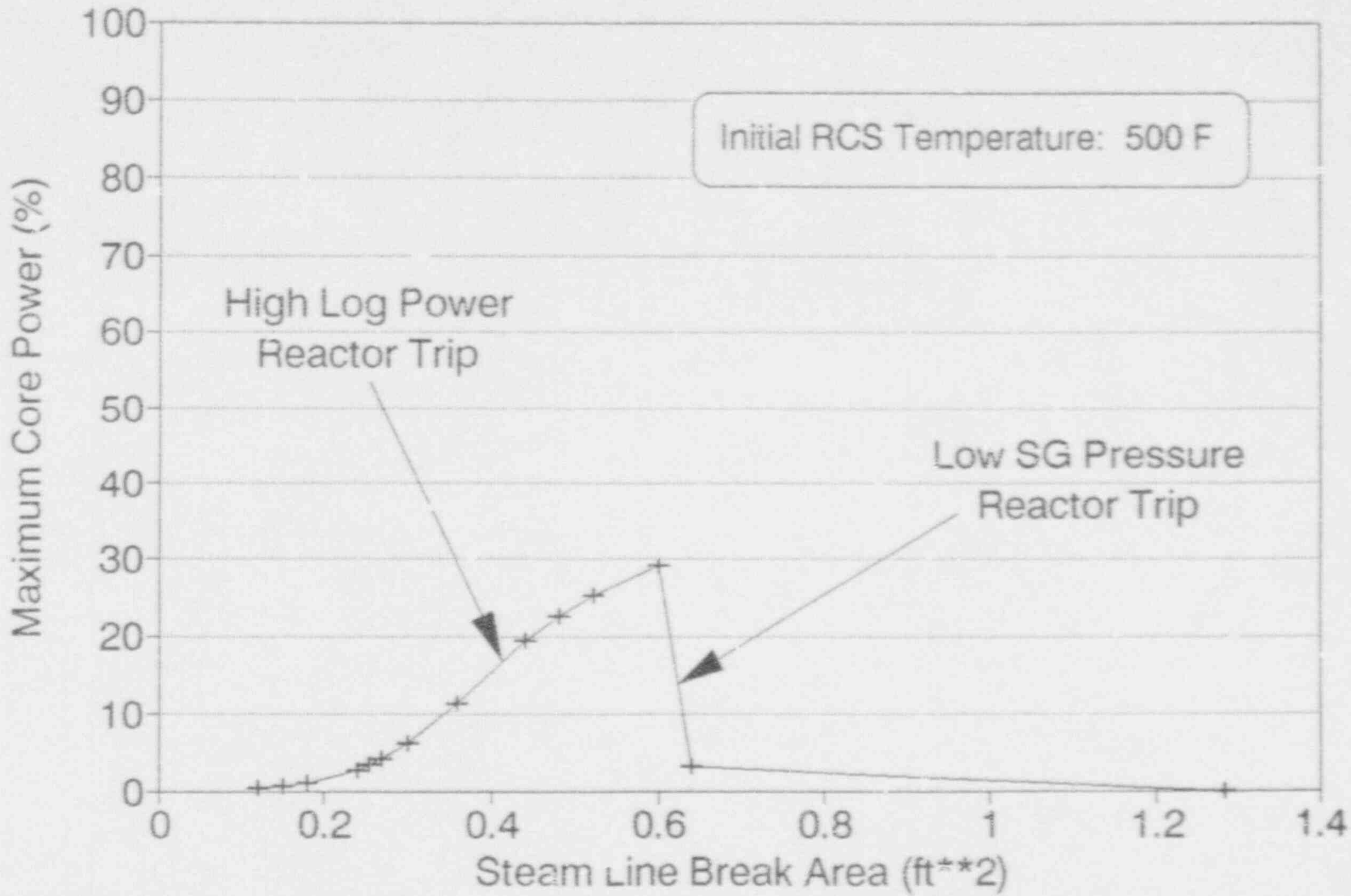
Event mitigation could, however, be delayed by decreasing the rate and extent of cooldown. The evaluations presented here have, therefore, explored the entire range of conditions from the maximum possible initial temperatures to those for which the changes in temperature induced by the cooldown would be insufficient to result in a return to criticality. Further, a full range of break sizes have been explored, up to and including a double-ended guillotine break of a main steam line upstream of a MSIV. Table 4.0-1 presents a full list of the ranges of initial conditions considered.

As noted above, one of the possibilities to be considered for a return to criticality for these events is a cooldown sufficient to cause criticality prior to reactor trip (assuming the core is initially at the maximum allowed reactivity for a shutdown mode). Exploration of a spectrum of break sizes shows that for the more rapid transients caused by larger breaks and higher initial temperatures, a reactor trip would be initiated by a low steam generator pressure signal prior to reaching criticality, thus precluding any fission power generation. For slower transients (smaller breaks and lower initial temperatures) the low steam generator trip pressure would not be reached before the core was calculated to reach criticality and some fission power generated. This would result in the generation of a reactor trip signal at a low power level by one of two reactor trip functions: a CPC trip or a high logarithmic power level trip.

Figure 4.1-1 illustrates these effects for a spectrum of break sizes with an initial RCS average temperature of 500 °F. In this figure reactor trip is due to a high logarithmic power level signal for smaller break sizes and a low steam generator pressure trip signal for larger break sizes. For events initiated under conditions which would result in a CPC trip (e.g. less than four reactor coolant pumps operating), the trip signal would be generated when the reactor power was two orders of magnitude lower, resulting in significantly lower powers than those shown in Figure 4.1-1. (See the discussion of CPC trip in Section 4.4.1.) The core powers reached for the shutdown mode case are, however, all substantially lower than that of the limiting Mode 1 case documented in CESSAR-DC. Further, the minimum transient DNBR for the shutdown mode cases was greater than 2. There is, therefore, no approach to loss of fuel integrity for steam system piping failures postulated to be initiated in a shutdown mode. The minimum DNBR of the events documented in Section 15.1.5 of CESSAR-DC bound those of events in shutdown modes.

The second potential possibility for a return to criticality for steam system piping failures postulated to be initiated in a shutdown mode is extended cooldown after reactor trip of sufficient magnitude to reach criticality (if there is insufficient safety injection boration). Consideration of the maximum possible integral reactivity change due to cooldown shows that the Technical Specification Shutdown Margin (6.5%$\Delta\rho$) is sufficient to prevent a return to criticality following reactor trip for postulated steam system piping failures for which the initial RCS average temperature is less than 500 °F -- even if no safety injection boration were to occur. A series of cases was run to show that, for initial RCS average temperatures between 500 and 565 °F (the maximum temperature for shutdown modes) and with other initial conditions within the limits of Table 4.0-1, a safety injection actuation signal would be generated on low pressurizer pressure and sufficient boration would occur to prevent a return to criticality. These cases included the effect of the most reactive CEA stuck in the fully withdrawn position and of a single failure of either a failure of one emergency generator to start, run, or load (resulting in unavailability of two safety injection pumps) or of one MSIV failing to close. The maximum post-trip reactivity for these cases was -1.2%$\Delta\rho$, which is significantly more negative than the limiting case documented in Section 15.1.5 of CESSAR-DC. No fission power was generated and there was no approach to DNB.

The mass of steam released to the environment for steam system piping failures postulated to be initiated in a shutdown mode is bounded by that for the Mode 2 analysis presented in CESSAR-DC. Further, no loss of fuel integrity is calculated to occur for the shutdown mode events. The two-hour inhalation dose at the EAB is, therefore, bounded by that presented in Section 15.1.5 of CESSAR-DC.



SYSTEM 80+™

MAXIMUM CORE POWER vs STEAM LINE BREAK AREA

Figure 4.1-1

4.2 DECREASE IN HEAT REMOVAL BY SECONDARY SYSTEM

4.2.0 INTRODUCTION

The purpose of this section is to present evaluations which confirm that all decrease in heat removal by the secondary system events postulated to be initiated in a shutdown Mode have acceptable consequences for the System 80+ Standard Design.

Section 15.2 of CESSAR-DC documents results which show that all decrease in heat removal by the secondary system events have acceptable consequences if they are explicitly postulated to occur in Mode 1 or, in general, in Mode 2 critical for the System 80+ Standard Design. However, if there is a question as to whether an event has already been considered in Mode 2 critical, this Mode is also included in the evaluation.

The focus of the evaluations presented in this section is on ensuring that the peak primary and secondary pressures are less than 110% of their design pressures, that the pressure-temperature limits for brittle fracture of the reactor coolant system (RCS) are not violated, and that fuel integrity is maintained for the events considered. Fuel performance, as measured by the departure from nucleate boiling ratio (DNBR), is used for verification of fuel integrity.

4.2.1 LOSS OF EXTERNAL LOAD

Since the turbine is not on line, a loss of external load is not possible in a shutdown Mode.

4.2.2 TURBINE TRIP

Since the turbine is not on line, a turbine trip is not possible in a shutdown Mode.

4.2.3 LOSS OF CONDENSER VACUUM (LOCV)

A LOCV event postulated to occur in a shutdown mode would result in less severe consequences than the event documented in Section 15.2.3 of CESSAR-DC, since only decay heat is being generated by the reactor core.

The LOCV event is only applicable when the condenser is being used as a heat sink. This could occur in Mode 2 subcritical, Mode 3, or Mode 4 when the shutdown cooling system (SCS) is not being used for decay heat removal. The turbine-generator would be off-line and steam would be entering the condenser via the steam bypass control valves. Loss of decay heat removal in Modes 4 through 6, when the SCS is being utilized, is addressed in Section 2.4.

The dominant factor which determines the peak primary and secondary pressure following a LOCV event is the magnitude of the energy mismatch between the primary and secondary systems. This mismatch is very much less for events postulated to occur in a shutdown mode than for the event of Section 15.2.3 of CESSAR-DC, even when an instantaneous termination of steam flow and feedwater flow is assumed. The maximum peak primary and secondary pressure will, therefore, be less for a LOCV postulated to occur during a shutdown mode than for this event at full power. Consequently, there is no approach to 110% of the design pressure of the steam generators or RCS. The LOCV event would not challenge the pressure-temperature limits for brittle fracture of the RCS, since the condenser is not on line (shutdown cooling conditions have been established) when LTOP is active.

Likewise, fuel integrity is maintained for LOCV events initiated in a shutdown mode, due to the relatively low reactor core heat fluxes associated with decay heat. Decreased coolant flow is the only parameter which can significantly reduce the minimum DNBR, since reactor power does not increase and RCS pressure increases for this event. Loss of offsite power (LOP) is the only single failure which can impact coolant flow. Because the plant is in a shutdown mode, there would be no turbine trip after the LOCV event, consequently, there would be no perturbation to the electrical grid which could cause a LOP. However, analyses have shown that even when the LOCV event is initiated with no reactor coolant pumps (RCPs) operating at the highest decay heat flux value (just after reactor shutdown), the minimum value of DNBR for this event is greater than 9. For colder conditions the minimum DNBR is even higher. For example, when the LOCV event is initiated just prior to establishing shutdown cooling conditions in Mode 4 and natural circulation conditions exist (i.e. no RCPs operating), the minimum value of DNBR is greater than 100.

4.2.4 MAIN STEAM ISOLATION VALVE CLOSURE

The comparison between main steam isolation valve (MSIV) closure and LOCV events made in Section 15.2.4 of CESSAR-DC applies for shutdown Modes, also. The evaluation of the LOCV event presented in Section 4.2.3 assumes a faster reduction in steam flow rate than would result from MSIV closure. The consequences of the MSIV closure event are, therefore, no more adverse in shutdown Modes than those for the LOCV presented in Section 4.2.3.

4.2.5 STEAM PRESSURE REGULATOR FAILURE

This event does not apply to the SYSTEM 80+ Standard Design and is, therefore, not evaluated here.

4.2.6 LOSS OF NON-EMERGENCY AC POWER TO THE STATION AUXILIARIES

The results of the loss of non-emergency AC power to the station auxiliaries (LOAC) event are the same as those for the loss of reactor coolant flow event presented in Section 4.3.1.

4.2.7 LOSS OF NORMAL FEEDWATER FLOW

A postulated loss of normal feedwater flow (startup feedwater flow) during a shutdown Mode would be less adverse than the LOCV event. The analysis assumptions for the LOCV event result in termination of steam flow, as well as termination of startup feedwater flow, causing a more severe decrease in heat removal by the secondary system. The consequences of the loss of normal feedwater flow are, therefore, bounded by the consequences of the LOCV event for shutdown Modes.

4.2.8 FEEDWATER SYSTEM PIPE BREAKS

Depending on the break size and location and the response of the feedwater system, the effect of a postulated feedwater system pipe break can vary from a heatup to a cooldown of the RCS. Based on the same arguments given in Section 15.2.8.1 of CESSAR-DC, the heatup event is considered in this section. The cooldown potential would be worse for a steam line break, which is discussed in Section 4.1.5. A heatup event is mitigated by the pressurizer safety valves or the shutdown cooling (SCS) relief valves when RCS temperatures are above or below, respectively, the LTOP enable/disable temperatures, the main steam safety valves, and the emergency feedwater (EFW) system.

A feedwater system pipe break postulated to occur in a shutdown Mode would result in less severe consequences than the event documented in Section 15.2.8 of CESSAR-DC due to the lower initial reactor power level. DNB is not of concern due to the low initial core power levels, in addition to the pressurization following event initiation. Further, the EFW system is capable of removing decay heat event with only one EFW pump in operation. The dominant factor which determines peak primary and secondary pressures is the magnitude of the energy mismatch between the primary and secondary systems. This mismatch is very much less for events postulated to occur in shutdown Modes than for the event of Section 15.2.8 of CESSAR-DC. There is, therefore, no approach to 110% of steam generator design pressure, since the maximum pressure will be much less than that for the full power event. For the same reason there is no approach to the criterion of 110% of RCS design pressure when RCS temperatures are above the LTOP enable/disable temperatures. For RCS temperatures below the LTOP enable/disable temperatures the design of the SCS relief valves ensures that the pressure-temperature limits for brittle fracture of the RCS are not violated.

4.3 DECREASE IN REACTOR COOLANT FLOW RATE

4.3.0 INTRODUCTION

The purpose of this section is to present evaluations which confirm that all decrease in reactor coolant flow rate events postulated to be initiated in a shutdown Mode have acceptable consequences for the System 80+ Standard Design.

Section 15.3 of CESSAR-DC documents results which show that all decrease in reactor coolant flow rate events have acceptable consequences if they are explicitly postulated to occur in Mode 1 or Mode 2 critical for the System 80+ Standard Design. This is demonstrated for total loss of reactor coolant flow (Section 15.3.1) by explicit analyses. The choice of initial conditions for the other analyses of Section 15.3 to minimize the transient DNBR for any operating condition ensures that the results presented bound those for all of Mode 1 and Mode 2 critical.

Decrease in reactor coolant flow rate in Modes 4 through 6 when the shutdown cooling system (SCS) is being used for decay heat removal is addressed in Section 2.4 as integral to the evaluation of loss of decay heat removal capability. Therefore this section addresses events postulated to be initiated in Mode 2 subcritical, Mode 3 or Modes 4 and 5 when the SDS is not being used.

4.3.1 TOTAL LOSS OF REACTOR COOLANT FLOW

Evaluation of the factors affecting the consequences of the total loss of reactor coolant flow event shows that if this event is postulated to be initiated in shutdown Modes, the results are less adverse than those of the CESSAR-DC Chapter 15.3 full power event.

Loss of offsite power is the postulated initiating event for the total loss of reactor coolant flow event in Modes 1 or 2. All systems available to mitigate the Mode 1 transient are available in Mode 2 subcritical. The initial conditions for Mode 2 subcritical include four pumps operating, temperature and pressure identical to Mode 1, a low power level, and total energy stored in the reactor core much less than at full power. Therefore, a very large margin to DNB exists at the initiation of the event and the heat to be removed during the event is much less than for an event initiated at full power. The minimum DNBR for this event is substantially higher for Mode 2 than that for the full power case.

In addition, the initiating event could be postulated to be loss of power to any operating RCPs in Mode 3 or in Modes 4 or 5 when the SCS is not being used. Natural circulation is, however, sufficient for the removal of decay heat in these Modes. Thus no approach to DNB would occur. The consequences of the Chapter 15.3 full power event are therefore more adverse than an event in these Modes.

The full power four pump loss of flow transient produces RCS and steam generator pressures which are less than 110% of their design values. Transients postulated to be initiated in Modes 2, 3 or 4 when RCS temperatures are above the LTOP enable/disable temperatures, and for which the rate of heat production is orders of magnitude below full power values, would therefore yield even greater margins to the design pressure values. For transients postulated to be initiated in Modes 4 or 5 with RCS temperatures below the LTOP enable/disable temperatures, the design of the SDC relief valves ensures that the pressure-temperature limits for brittle fracture are not violated.

4.3.2 FLOW CONTROLLER MALFUNCTION CAUSING FLOW COASTDOWN

This event is categorized as a Boiling Water Reactor event in SRP 15.3.2 and is, therefore, not evaluated here.

4.3.3 SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER

The major parameter of concern for the single reactor coolant pump rotor seizure with loss of offsite power event documented in Section 15.3.3 of CESSAR-DC is the minimum hot channel DNBR. This is minimized by higher power conditions. Lower power Modes would, therefore, not produce any conditions which are more adverse than those presented in CESSAR-DC.

The second parameter of concern is the peak RCS pressure attained. The full power single reactor coolant pump rotor seizure with loss of offsite power event produces RCS pressures which are less than 110% of their design values. Transients postulated to be initiated in Modes 2, 3, or 4 when RCS temperatures are above the LTOP enable/disable temperatures, and for which the rate of heat production is orders of magnitude below full power values, would therefore yield even greater margins to the design pressure values. For transients postulated to be initiated in Modes 4 or 5 with RCS temperatures below the LTOP enable/disable temperatures the design of the SCS relief valves ensures that the pressure-temperature limits for brittle fracture of the RCS are not violated.

In addition, at these low power levels a concurrent turbine trip which results in a loss of offsite power is not an issue since the turbine is not in operation below 5% power.

4.3.4 REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER

Since a postulated reactor coolant pump shaft break (SB) transient results in a less rapid flow coastdown than a rotor seizure (RS) event, the results of the SB event are bounded by those of the evaluation of Section 4.3.3.

4.4 REACTIVITY AN^ POWER DISTRIBUTION ANOMALIES

4.4.0 INTRODUCTION

The purpose of this section is to present evaluations which confirm that all reactivity and power distribution anomaly events postulated to be initiated in a shutdown Mode have acceptable consequences for the System 80+ Standard Design.

4.4.1 UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL FROM SUBCRITICAL OR LOW POWER CONDITIONS

Evaluation of the consequences of an uncontrolled CEA withdrawal event postulated to be initiated from a shutdown mode shows that the results are less adverse than those of the event documented in Section 15.4.1 of CESSAR-DC.

The event documented in CESSAR-DC was initiated from low power, critical conditions. The Technical Specifications include requirements which ensure that the most adverse subcritical CEA withdrawal event scenario is the inadvertent withdrawal of a regulating CEA bank. For the evaluation presented here, therefore, events which postulate initia . subcritical conditions and an uncontrolled withdrawal of a re, lating CEA bank were analyzed to demonstrate that the SAFDL on DNBR is not violated and that no fuel melting is predicted to occur.

The essential reason that withdrawal of a regulating CEA ba k from subcr'tical is less adverse than the same event at low power, core critical conditions is that one of two reactor trip functions terminates the subcritical event at low power levels: a CPC trip or a high logarithmic power level trip. The setpoints for these trip functions are such that the maximum power levels reached for this event are much lower than those for the low power event.

The CPCs may be bypassed at power levels below 0.0001%. This bypass is automatically removed upon exceeding this power level. Although a reactor trip would not occur when the CPCs were bypassed, the CPCs continue to perform their calculations and can be in a tripped condition. The CPCs would be in a tripped condition if less than all four reactor coolant pumps were running or if the calculated radial peaking were out of range due to the presence of an undesired CEA bank in the core. As the core fission power increases during the CEA withdrawal event the 0.0001% power bypass is removed and, if the CPCs are in a tripped condition, a reactor trip is generated.

The high logarithmic power level trip is required to be operable in all shutdown modes when the reactor trip breakers are closed and the CEA drive mechanism is capable of CEA withdrawal. Although the high logarithmic power level trip can be bypassed during Modes 1 and 2 critical, it cannot be bypassed during shutdown conditions.

For those CEA withdrawal events which do not generate a CPC trip upon removal of the 0.0001% power bypass, the high logarithmic power level trip will produce a reactor trip for which the setpoint is 0.01% power. (The corresponding setpoint used in the analyses is 0.05%, as documented in Table 15.0-2 of CESSAR-DC.) If, however, the transient is the withdrawal of one of the early regulating banks, or if less than all reactor coolant pumps are in operation, a reactor trip would be generated two decades lower in power upon the removal of the CPC bypass at 0.0001% power.

CEA withdrawal events initiated from subcritical conditions were analyzed with assumptions which bound all shutdown conditions and determine the consequences when reactor trip is due to each of the above functions. The cases analyzed included:

A. Regulating bank withdrawal, worst combination of burn-up dependent parameters, four pumps running, reactor trip on high logarithmic power level.

B. Regulating bank withdrawal, worst combination of burn-up dependent parameters, less than four pumps running, reactor trip upon removal of the CPC 0.0001% power bypass due to CPC pump counting.

The case with full forced reactor coolant flow experienced a peak heat flux of approximately 5% of full power heat flux. This is well below the value of 34.8% calculated for the event documented in Section 15.4.1 of CESSAR-DC. The DNBR for this case remained well above the DNBR SAFDL.

Due to the earlier reactor trip, the case with fewer than all four reactor coolant pumps running experienced a peak heat flux increase to less than 2% of full power heat flux. This low value of heat flux would not cause DNB.

The deposited energy calculation assumed that all of the energy produced in the short power excursion is deposited in the fuel with no heat transfer from the fuel. The evaluation shows that the hot spot in the core does not experience melt for any withdrawal of a regulating CEA bank from subcritical.

In summary, the System 80+ Technical Specifications ensure that the reactor will not become critical due to the inadvertent withdrawal of a shutdown CEA bank. The CPC and high logarithmic power level trip functions ensure that the consequences of an inadvertent withdrawal of a regulating CEA bank from subcritical conditions are substantially less adverse than those documented in Section 15.4.1

of CESSAR-DC. This event will not result in the violation of the DNBR SAFDL or in fuel melt.

4.4.2 UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL AT POWER

This event is not an issue for shutdown Modes since its intent is to examine high power operation only.

4.4.3 SINGLE CONTROL ELEMENT ASSEMBLY DROP

A postulated single control element assembly drop at power is analyzed for approach to the DNBR limit in CESSAR-DC, Section 15.4.3. For Mode 2 subcritical through the other subcritical Modes, a dropped rod only adds more negative reactivity to an already subcritical core and is, therefore, much less adverse than the full power event documented in CESSAR-DC.

4.4.4 STARTUP OF AN INACTIVE REACTOR COOLANT PUMP

Chapter 15.4.4 of CESSAR-DC presents analysis of startup of an inactive reactor coolant pump events which show that events postulated to be initiated in Modes 3 through 6 have acceptable consequences for the System 80+ Standard Design. (Operation with less than 4 RCPs is not permitted in Modes 1 or 2.)

4.4.5 FLOW CONTROLLER MALFUNCTION CAUSING AN INCREASE IN BWR CORE FLOW RATE

This event is categorized as a Boiling Water Reactor event in SRP 15.4.5 and is, therefore, not evaluated here.

4.4.6 INADVERTENT DEBORATION

Analyses of inadvertent deboration events in shutdown Modes have been presented in Chapter 15 of CESSAR-DC. An additional evaluation which considers rapid deboration is presented in Section 2.6 of this report.

4.4.7 INADVERTENT LOADING OF A FUEL ASSEMBLY INTO THE IMPROPER POSITION

This event has been evaluated in Section 15.4.7 of CESSAR-DC and is not mode dependent.

4.4.8 CONTROL ELEMENT ASSEMBLY (CEA) EJECTION

The CEA ejection analysis documented in Section 15.4.8 of CESSAR-DC is for an ejection from full power initial conditions. This case was found to be more limiting than an ejection from Mode 2 critical initial conditions. The evaluation documented in Section 15.4.8

credited the technical specification limits on allowable CEA insertion given in Technical Specifications 3.1.6 and 3.1.7, which apply in Mode 1 and in Mode 2 critical.

Technical Specifications 3.1.6 and 3.1.7 do not apply directly for Mode 2 subcritical or for Modes 3 through 5. However, the requirements of Technical Specification 3.1.2, which do apply in these shutdown modes and which use the criteria of Technical Specifications 3.1.6 and 3.1.7 ensure that the full power CEA ejection case remains limiting.

For Mode 2 subcritical and for Modes 3 through 5, Technical Specification 3.1.2.a requires that the calculated critical position be within the limits of Technical Specifications 3.1.6 and 3.1.7 when the reactor trip breakers are closed. This requirement ensures that a CEA ejection postulated to be initiated at these conditions would result in less net positive reactivity insertion than for a case initiated from a critical position. The case described in Section 15.4.8 of CESSAR-DC, therefore, remains limiting for conditions under which the reactor trip breakers are closed.

When the reactor trip breakers are open in Modes 3 through 5, Technical Specification 3.1.2.b requires that the value of k_{eff} must remain less than 1.0 when the highest worth CEA is excluded from the calculation. This requirement ensures that the reactor would not reach criticality for a CEA ejection event postulated to be initiated under these conditions.

The full power event of Section 15.4.8 of CESSAR-DC is, therefore, the limiting CEA ejection event.

4.5 INCREASE IN RCS INVENTORY

4.5.0 INTRODUCTION

The purpose of this section is to present evaluations which demonstrate that all increase in RCS inventory events postulated to be initiated in a shutdown Mode have acceptable consequences for the System 80+ Standard Design.

Section 15.5 of CESSAR-DC documents results which show that all increase in RCS inventory events have acceptable consequences if they are explicitly postulated to occur in Mode 1 or, in general, in Mode 2 critical for the System 80+ Standard Design. If there is a question as to whether an event has already been considered in Mode 2 critical, however, this Mode is also included in the evaluation.

The focus of the evaluations presented in this section is on ensuring that the peak primary pressure is less than 110% of design pressure and that the pressure-temperature limits for brittle fracture of the RCS are not violated. Fuel performance, as measured by the departure from nucleate boiling ratio (DNBR), is used for verification of fuel integrity. Peak secondary pressure is also evaluated, as necessary, to ensure it remains less than 110% of its design pressure.

4.5.1 INADVERTENT OPERATION OF THE ECCS

The evaluation presented in Section 15.5.1 of CESSAR-DC establishes that a postulated inadvertent operation of the ECCS would have acceptable consequences for any Mode for the System 80+ Standard Design.

4.5.2 CVCS MALFUNCTION-PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION WITH LOSS OF OFFSITE POWER

Peak RCS pressure due to a postulated malfunction/actuation of a charging pump in Modes 2 through 4 (before LTOP is active), is well within 110% of design pressure. Further, the pressure-temperature limits for brittle fracture of the RCS are not challenged for a postulated malfunction/actuation of a charging pump in Modes 4 through 6 (when LTOP is active or when the reactor vessel head is off).

In Modes 2 subcritical through 4, before shutdown cooling and LTOP are placed in service, the peak RCS pressure is limited by the pressurizer safety valves. Since only decay heat exists under these conditions, the peak pressures during the CVCS malfunction event would be substantially less severe than the Mode 1 case described in CESSAR-DC. It should be noted that the centrifugal charging pumps are protected from runout at low RCS pressures by design.

In Modes 4, 5, and 6 when LTOP is active (or in Mode 6 with the reactor vessel head off and LTOP not active), the CVCS malfunction event would be less limiting than the inadvertent SIS actuation described in Section 4.5.1 above, due to the much lower flow from one charging pump versus the four SI pumps.

4.6 DECREASE IN REACTOR COOLANT SYSTEM INVENTORY

4.6.0 INTRODUCTION

The purpose of this section is to present evaluations which demonstrate that all decrease in RCS inventory events postulated to be initiated in a shutdown Mode have acceptable consequences for the System 80+ Standard Design.

Section 15.6 of CESSAR-DC documents results which show that all decrease in RCS inventory events have acceptable consequences if they are explicitly postulated to occur in Mode 1 or, in general, in Mode 2 critical for the System 80+ Standard Design. If there is a question as to whether an event has already been considered in Mode 2 critical, however, this Mode is also included in the evaluation.

Fuel performance, as measured by the departure from nucleate boiling ratio (DNBR), is used for verification of fuel integrity.

4.6.1 INADVERTENT OPENING OF A PRESSURIZER SAFETY/RELIEF VALVE

The LOCA evaluations presented in Section 4.6.5 of this report show that the inadvertent opening of a pressure safety/relief valve is at a non-limiting location for LOCAs postulated to occur in shutdown Modes. The inadvertent opening of a pressurizer safety valve as described in the Standard Review Plan 15.6.1 is, therefore, a non-limiting event in the Safety Injection System evaluations.

4.6.2 DOUBLE-ENDED BREAK OF A LETDOWN LINE OUTSIDE CONTAINMENT

The MODE 1 analysis presented in Section 15.6.2 of CESSAR-DC credited a number of non-safety grade alarms for the detection of a letdown line break. Credit for these alarms was rejected by the NRC in RAI 440.104, and ABB-CE was asked to reanalyze the event using only safety grade equipment.

While ABB-CE believes that a double ended letdown line break would be detected as described in CESSAR-DC Section 15.6. an alternate resolution to mitigating this event is being considered which will utilize only safety grade equipment. Thus a revised letdown line break analysis for MODE 1 along with the evaluation for shutdown modes will be provided in the fall of 1992.

4.6.3 STEAM GENERATOR TUBE RUPTURE

Evaluation of the consequences of a Steam Generator Tube Rupture (SGTR) accident postulated to be initiated in a shutdown mode shows that the results are less adverse than those of the full power event documented in Section 15.6.3 of CESSAR-DC. Consequently, the radiological doses are well within the 10 CFR 100 guidelines and fuel integrity is not challenged.

The worst case initial conditions for a SGTR accident initiated in a shutdown mode would be in Mode 3, at the highest possible RCS temperature and pressure and lowest possible RCS flow (less than four reactor coolant pumps operating). This would maximize the initial leak rate and flashing fraction of the leaked fluid. Also, the worst case single failure would be the assumption that the atmospheric dump valve (ADV) on the affected steam generator (SG) sticks open after the operator attempts to close this valve, as in Section 15.6.3 of CESSAR-DC.

Since the turbine-generator is off-line in Mode 3, there would be no perturbation to the electrical grid which could cause a loss of offsite power (LOP). A consequence of a LOP would be a further reduction in coolant flow, which would increase the core exit temperature (hence increasing the flashing fraction of the leaked fluid). However, even if the very unlikely event of a LOP were to be assumed, fuel integrity would not be challenged, since only decay heat is being generated and natural circulation is sufficient for decay heat removal.

For a SGTR accident postulated to be initiated in a shutdown mode, there are a number of plant parameters and alarms available in the control room that will enable the operators to diagnose the event. These include:

- Indications of event:
  - Decreasing pressurizer pressure
  - Decreasing pressurizer liquid level
- Indications of event and of which SG is affected:
  - Increasing SG liquid level
  - Increasing SG liquid blowdown radiation level
  - Increasing main steam line radiation level
- Additional indications of event if the steam bypass system is being used for cooldown:
  - Increasing steam jet air ejector radiation level
  - Increasing stack radiation level

The sequence of events for a SGTR accident postulated to occur in Mode 3 would be:

A. Prior to the SGTR accident, the reactor was shut down according to normal procedures, consequently, the turbine-generator is off line. A postulated iodine spike caused by a reactor trip or primary system depressurization (event generated iodine spike, GIS) would be unlikely to occur under these conditions. However, it is assumed that either a GIS has occurred or the RCS radioactivity concentration was at its technical specification limit (pre-accident iodine spike, PIS), since this resulted in the most adverse RCS radioactivity concentrations when the SGTR accident was assumed to be initiated in Mode 1 (as documented in 15.6.3 of CESSAR-DC). Also it was assumed that the secondary activity is at the Technical Specification limit of 0.1 microcurie per gram I-131 dose equivalent, since this assumption also maximizes the radiological doses. Although a LOP is very unlikely under these circumstances, a LOP is conservatively assumed to occur concurrent with event initiation. It is assumed that the ADVs are being used to cool down the plant, as opposed to the usual method of utilizing the steam bypass control valves. This results in the accumulation of radiological doses from the very beginning of the event. The maximum plant cooldown rate is achievable with the partial opening of one ADV on each SG. One ADV on each SG is, therefore, assumed to be open at the time of event initiation.

B. The SG liquid blowdown radiation monitor would immediately provide the operator with the information which would enable him to determine which SG is damaged. The SG liquid blowdown radiation alarm would be activated within seconds of event initiation, since it would be set to alarm below the 0.1 microcurie/gram technical specification limit. Based on the adverse RCS and SG radioactive concentrations at event initiation, the special purpose main steam line area radiation monitors may also alarm.

   For the double ended rupture of a SG tube the operator would also have immediate indication of event occurrence in the form of rapidly decreasing pressurizer pressure and level and increasing SG level. These parameter changes would then result in a high SG liquid level alarm, a low pressurizer pressure alarm, and a low pressurizer liquid level alarm after the high SG blowdown radiation alarm.

C. Acting upon these indications, within thirty minutes after event initiation it was assumed that the operator has diagnosed the event and knows which SG has the damaged tube. At this point the operator isolates feedwater to the affected SG, closes the main steam isolation valves to both steam generators, and attempts to close the ADV on the affected SG.

D. The operator determines that the ADV did not close (continued control room indication of steam flow) and closes the block valve upstream of the stuck open ADV within 30 minutes of the initial attempt to isolate the affected SG (i.e. within one hour of event initiation).

E. The operator commences cooldown to shutdown cooling entry conditions, by using the unaffected SG ADV. The operator also uses the pressurizer gas vent and SI flow to decrease RCS pressure and control subcooling. The operator steams the affected SG as necessary to prevent overfilling.

A comparison of the above sequence of events with the worst case SGTR accident in 15.6.3 of CESSAR-DC (see Table 15.6.3-7), shows that a SGTR accident postulated to occur in Mode 3 would result in less integrated steam released to the environment. This is due to the fact that there would be no release by the main steam safety valves, since there is no initial transient imbalance between reactor power and turbine power. The integrated steam release through the stuck open ADV and the flashing fraction of the leaked primary fluid, while the affected ADV is discharging to the atmosphere, are essentially the same for the postulated Mode 3 and full power events. Thus the concentration of radioactive nuclides in steam released to atmosphere is no greater for the Mode 3 event than for the event documented in CESSAR-DC. The total radiological release for this event would, therefore, be less than that of the full power event.

If the SGTR were postulated to occur at lower RCS temperature and pressure than that assumed above, the radiological doses would be even less than the above event. This would be due to less integrated steam released to the environment and the lower concentration of radioactive nuclides in this released steam, because of the lower fraction of primary fluid flashed to steam in the both the affected and unaffected SGs.

The indications of event occurence and the event consequences are somewhat different if a SGTR is postulated to be intiated when the shutdown cooling system is in operation in Mode 4 or Mode 5 (when the RCS loops are filled). (A SGTR accident would not have any consequences in Mode 6 since primary and secondary pressures are both at atmospheric pressure.) The plant parameters and alarms available in the control room which would enable the operators to diagnose an event under these circumstances include:

- Indication of event for all leak sizes and of which SG is affected:

  - Increasing SG liquid level

* indications of event for larger leak sizes (the cooldown rate may mask the leak rate for these indications when the SGTR leak rate is small):

  - Decreasing pressurizer pressure

  - Decreasing pressurizer liquid level

  - Imbalance between charging and letdown flow rates

The leakage rate could range from 0.0 to approximately 315 gallons per minute (assuming a double ended break of one steam generator tube) under these circumstances. At the maximum leak rate the operator would have more than three-quarters of an hour in which to diagnose the event and take appropriate mitigating actions. (This conservatively assumes that the initial SG level is at 100% wide range, which is much greater than the normal water level when the SG is isolated or in wet layup). The mitigating actions could include utilizing the SG blowdown system to prevent overfilling the SG and minimizing the pressure difference between the primary and secondary systems. In the unlikely case the SG was overfilled, the main steam line pipe supports are designed to accomodate the water loads. At lower leak rates the operator would have even more time to take corrective action. The SCS relief valves ensure the pressure-temperature limits for brittle fracture of the RCS would not be violated, although they would not be actuated for this event. There would be no approach to the criterion of 110% of steam generator design pressure. Also, fuel integrity would not be challenged, since no approach to DNB would occur. The resulting radiological doses would be much less than for the SGTR accident initiated in Modes 3 and 4 and, consequently, would be well within 10 CFR 100 limits.

4.6.4 RADIOLOGICAL CONSEQUENCES OF MAIN STEAM LINE FAILURE OUTSIDE CONTAINMENT (BWR)

The radiological consequences of main steam line failure outside containment (BWR) do not apply to the System 80+ Standard Design and are, therefore, not evaluated here.

4.6.5 LOSS-OF-COOLANT ACCIDENT

Consequences of a LOCA initiated from Modes 2 through 4 are bounded by the consequences reported for a LOCA from Mode 1 since the containment spray and annulus ventilation systems which are available in Mode 1 are also available in Modes 2 through 4.

For a LOCA initiated from Mode 5, the evaluation in Section 5 concludes that the top of the core will not uncover. Fuel clad damage is prevented when the core remains covered so the source term for radiological dose calculations is based on only the radioactivity in the coolant. Prior to entry into Mode 5 from Mode 4, the radioactive concentration in the coolant is verified to be less than the limits in Technical Specification 3.4.15. For conservatism, the radioactive source for the Mode 5 LOCA is taken as the total activity from the limit concentration in a volume of water equal to the normal full RCS and all of the radioactivity is postulated to be released to the atmosphere through an open hatch within two hours. The calculated offsite doses are smaller than the doses calculated for the Mode 1 LOCA.

4.7 RADIOA'TIVE MATERIAL RELEASE FROM A SUBSYSTEM OR COMPONENT

4.7.0 INTRODUCTION

The purpose of this section is to present evaluations which confirm that all radioactive material release from a subsystem or component events postulated to be initiated in a shutdown Mode have acceptable consequences for the System 80+ Standard Design.

4.7.1 RADIOACTIVE GAS WASTE SYSTEM FAILURE

This section of the Standard Review Plan has been deleted (Reference 26 of Section 15.0)

4.7.2 RADIOACTIVE LIQUID WASTE SYSTEM LEAK OR FAILURE

This section of the Standard Review Plan has been deleted (Reference 26 of Section 15 0)

4.7.3 POSTULATED RADIOACTIVE RELEASES DUE TO LIQUID CONTAINING TANK FAILURES

This event has been evaluated in Section 15.7.3 of CESSAR-DC and is not Mode dependent.

4.7.4 FUEL HANDLING ACCIDENT

This event has been evaluated in Section 15.7.4 of CESSAR-DC and is not Mode dependent.

4.7 5 SPENT FUEL CASK DROP ACCIDENTS

This event has been evaluated in Section 15.7.4 of CESSAR-DC and is not Mode dependent.

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5.0 APPLICABILITY OF CHAPTER 6 LOCA ANALYSES TO LOWER MODES OF OPERATION

5.1 ISSUE

A majority of the analysis of the Loss-Of-Coolant-Accident and all criteria associated with the accident have focused on scenarios starting from 102% of rated thermal power as prescribed in 10CFR50, Appendix K. In this section, scenarios initiated from all other modes of operation will be addressed to demonstrate that the analyses performed in CESSAR-DC are the bounding cases for all modes of operation. This section will identify the scenarios anticipated for non-Mode 1 operation, and where required the acceptance criteria for the different scenarios.

5.2 ACCEPTANCE CRITERIA

The acceptance criteria for lower operating mode LOCAs is established to be the same as those for higher operating mode LOCAs (Reference 19):

1) Peak clad temperature < 2200°F.
2) < 17% peak local clad oxidation.
3) < 1% core wide oxidation.
4) Maintain coolable geometry.
5) Maintain long-term cooling.

5.3 DISCUSSION

The types of LOCAs and corresponding break sizes in lower modes are as follows: the large break loss-of-coolant accident (i.e., double-ended guillotine pipe breaks, etc.) analyzed in Chapter 6 of CESSAR-DC is not considered appropriate for lower modes of operation (Reference 2). As such only small break LOCAs are considered. The following lower mode scenarios are considered: most adverse misoperation of valves, the likelihood of cross train maintenance errors, and the possibility of steam generator nozzle dam blowout. The limiting size and location for a "small" break LOCA for Modes 3 and 4 is a direct vessel injection (DVI) line discharge leg (0.4 square feet). A DVI line break at this location would minimize injection flow into the RCS. Modes 5 and 6 consider a loss of decay heat removal (DHR) resulting from a break in the bottom of the hot leg or a lower head instrument line (.003 square feet).

A discussion of the equipment which would be available to mitigate the consequences of a LOCA in each mode of operation, the effectiveness of that equipment under the conditions for that mode, and the applicability of analyses to that mode are as follows:

Mode 1: In Mode 1, RCS temperature is >350°F and power is >5%. The CESSAR-DC analysis for LOCAs in this mode concludes that all criteria are met.

Mode 2: In Mode 2, RCS temperature is >350°F and power is <5%. The equipment available in Mode 1 is also available in Mode 2. Mode 2 LOCA results are bounded by Mode 1 because the decay heat and stored energy, which are of concern to meeting LOCA criteria, are proportional to the lower power level in Mode 2.

Mode 3: In Mode 3, RCS temperature is >350°F and k_{eff} is <.99. For the case where RCS pressure is >900 psia, the equipment available in Mode 1 (SIT, 4 SI pumps) is available. Because the stored energy and decay heat is lower, this parameter space in Mode 3 is bounded by Mode 1 for LOCA. For the case where pressure is <900 psia, 4 SI pumps are available. Although at a higher temperature than Mode 4, the parameter space in Mode 3 is bounded by the Mode 4 analysis because Mode 4 will not credit automatic SI actuation. Furthermore, despite the fact that SITs would not be available when the pressure is <900 psia, this Mode 3 space is bounded by the Mode 1 analysis because there is less RCS pressure to drive the LOCA leak flow.

Mode 4: RCS temperature is <350°F. Four subspaces are considered:

1) Conditions:

pressure >900 psia and temperature >317°F. SITs and 2 SI pumps on automatic.

Conclusions:

Space 1) is bounded by a Mode 4, space 4, analysis included in this report (which credits neither SITs nor SI pumps on automatic) because the SITs are available to accommodate the higher pressure and 2 SI pumps are available to accommodate higher temperatures.

2) Conditions:

Pressure < 900 psia and temperature >317°F: 2 SI pumps on automatic.

Conclusions:

Space 2) is bounded by the Mode 4, space 4, analysis because 2 SI pumps are available to accommodate the higher temperature.

3) Con ations:

Pressure > 900 psia and temperature < 317°F.

Conclusions:

Space 3) is bounded by the Mode 4, space 4, analysis because SITs are available to accommodate the higher ssure.

4. ions:

essure < 900 psia and temperature < 317°F.

sions:

analysis (space 4 described in Section 5.3.1) which credited neither automatic SITs nor SI pumps on automatic was performed for this report.

Mode 5: RCS temperature ≤210°F. An analysis was performed which assumed the maximum Technical Specifications cooldown rate of 100°F/hr. At the time of entry into Mode 5, a loss of shutdown cooling was assumed to result from a LOCA in the bottom of the hot leg. Although Technical Specifications require an RCS level at mid-loop (due to the SCS being required to operate), the LOCA was assumed to start with an RCS level at the bottom of the hot leg. Approximately twelve minutes was required for the RCS level to drop below the top of the core. The manual start of one SI pump within ten minutes after the LOCA would be sufficient to cool the core after a LOCA in Mode 5. The manual start of three SI pumps at ten minutes after the LOCA would be sufficient to prevent boiling after a LOCA in Mode 5. The break of a lower head instrument line (0.0 3 square feet) was considered in Mode 5 and required approximately one hour for the RCS level to drop to the bottom of the hot leg initially from the mid-elevation height of the RCS piping. In Mode 5, the break of a lower head instrument line was, therefore, bounded by a break in the bottom of a hot leg.

Mode 6: Temperature is <135°F. The equipment available in Mode 5 is available in Mode 6. Because the temperature is lower in Mode 6, the Mode 6 analysis will yield acceptable consequences with one SI pump operable within ten minutes.

Subsection 5.3.1 describes the primary system boundary conditions and event scenario for the postulated LOCA used in this study. Subsection 5.3.1 also compares and contrasts this lower operating mode event scenario to the conservative design basis licensing LOCA event normally associated with ECCS evaluation analyses.

Subsections 5.3.2 and 5.3.3 describe the System 80+ plant parameters and conditions for the analysis and the computer codes and analysis methods used in the LOCA calculations. Subsection 5.3.4 details the objectives and bases of the LOCA analysis.

Subsection 5.3.5 describes the results of an analysis of a limiting LOCA during Mode 4. These calculations show that hot fuel rod conditions remain in compliance with ECCS Acceptance Criteria during an assumed 10 minute time delay for operator action without SI pump availability. Furthermore, the analysis for the postulated LOCA shows that availability of 1 SI pump at the 10 minute mark maintains the hot rod cladding temperatures in compliance with the ECCS Acceptance Criteria.

5.3.1 DESCRIPTION OF LOCA SCENARIO

Following powered operation of the NSSS, cooldown proceeds at the Technical Specifications maximum rate of 100°F/hour (the maximum cooldown rate shown in Reference 18). Therefore, a primary coolant temperature of 317°F could be reached as early as 2.4 hours after shutdown.

Safety injection tanks (SIT) and safety injection (SI) pumps are available to mitigate LOCAs from lower modes. SITs are available for pressures >900 psia. SI pumps are automatically actuated for temperatures >317°F.

If a postulated LOCA transient were to occur at pressures and temperatures slightly below these conditions (i.e., pressure <900 psia, temperature <317°F, and time >2.4 hours), the LOCA would be significantly less dynamic than a design-basis LOCA transient from full power operating conditions (i.e., 2250 psia, ~600°F and full fission power and associated decay heat). Factors which would significantly mitigate the potential and consequences of a lower operating mode LOCA compared to a full power LOCA are (1) lower initial primary system pressure which would limit the internal forces on the piping and the duration of the blowdown, (2) lower coolant flow rate out of a postulated break and slower depressurization rate which would reduce inventory loss and flashing rate, and (3) lower decay heat levels which would lessen the core boiloff rate.

Based on these factors, a postulated lower operating mode LOCA followed by, if necessary, timely operator action to initiate safety injection flow would be expected to be much less severe than a LOCA from full power conditions. The most severe lower operating mode LOCA scenario would occur for (1) the largest potential pipe break, (2) after the most rapid possible cooldown from full power, (3) after reducing temperature slightly below which no SI pumps are required to be on automatic, (4) after reducing pressure slightly below which SITs are not available, and (5) the longest expected time for mitigating operator action. The largest and most harmful potential pipe break would be a significant leak in one of the direct vessel injection (DVI) lines of the reactor coolant system corresponding to the flow area of the DVI line. This DVI break size of 0.4 ft^2 was chosen even though LBB technology would eliminate 14 from consideration which envelopes the size and limiting location of all traditional small break LOCAs. Decay heat levels based on a time period of 2.4 hours after shutdown is assumed. No operator action for 10 minutes is also assumed. Forced circulation through the core during lower mode operation would tend to prolong the time of adequate core cooling during a postulated LOCA; therefore, for conservatism, the RCPs are tripped before the start of the event. An aggressive cooldown of the secondary side of the steam generators would considerably benefit the RCS heat removal process for a postulated LOCA; therefore, for conservatism, the steam generator secondary sides are isolated for the event.

5.3.2 SELECTION OF REFERENCE PLANT PARAMETERS AND CONDITIONS FOR MODE 4 ANALYSIS

A limiting set of values is selected from among the plant parameters and conditions. RCS temperature was selected at the maximum at which no SI pumps would automatically actuate due to SIAS. RCS pressure was selected at the maximum at which no SITs would be available. Table 5-1 is a list of initial conditions.

5.3.3 ANALYSIS COMPUTER CODES

This task required the selection of realistic inputs such as decay heat to provide as much realism in representation of the system transient response during a LOCA as possible. An adaptation of the Realistic Evaluation Model (REM) for small break LOCA was selected for this reason. This model is a second-generation small break LOCA evaluation model intended to replace the 1974 EM currently used for ECCS licensing calculations. Topical reports describing the REM were submitted to the NRC starting in 1988 and are currently under review (see References 12 through 16).

For design basis LOCA calculations from plant initial primary pressures of 2250 psia, the largest break size analyzed using the CEFLASH-4AS code has historically been a 0.5 ft^2 break. For the 0.4 square foot DVI line lower mode LOCA analysis, the REM version of the CEFLASH-4AS code was used. A realistic model for decay heat is used, which is based on the 1979 ANS Standard 5.1 plus two sigma uncertainty plus actinide decay.

The REM version of the PARCH code was used for calculating the hot rod heatup (References 12 through 16). The PARCH base deck included a realistic decay heat.

5.3.4 LOCA ANALYSIS FOR MODE 4

The LOCA analysis examines the hot rod heatup response during a LOCA with respect to the ECCS Acceptance Criteria of peak cladding temperature and peak local cladding oxidation. The objective of this analysis is to determine if the calculated response of the hot rod remains in compliance with the ECCS Acceptance Criteria crediting operator action in a 10 minute time frame.

A bounding analysis, starting at 2.4 hours after shutdown, allowed the LOCA to proceed without safety injection. Primary coolant inventory is assumed to be lost through an opening in the direct vessel injection line at the vessel penetration to the upper annulus primary piping. When the two-phase level falls to the top of the active core, there is a reduction in core cooling and the fuel rods begin a heatup driven by the core decay heat power and at higher temperatures by the heat added from cladding oxidation. As cladding temperatures increase, fuel rod swelling and rupture may occur.

For this analysis, the PARCH code is used for calculating hot rod heatup. The hot rod in the core is initialized by the PARCH code with 900 psia and 317°F primary coolant conditions. A limiting axial power shape is assumed for the LOCA. At 8500 seconds (~2.4 hrs), the coolant inventory and, consequently, core cooling is reduced. Figure 5-1 shows the resulting hot rod heatup calculation with safety injection initiated ten minutes after break.

5.3.5 RESULTS OF LOCA ANALYSIS FOR MODE 4

This realistic model produces a cladding heatup rate of about 3.5°F/sec following core uncovery and causes the cladding to exceed 2200°F in approximately 16 minutes from time of break.

The LOCA event is analyzed for realistic or credible thermal-hydraulic blowdown conditions. The objective of this analysis was to determine requirements for Technical Specifications to assure adequate cooling flow in lower modes of operation. The realistic analysis examined the RCS primary coolant and hot fuel rod transient response during the blowdown phase of the LOCA.

For this analysis, a break in one of the Direct Vessel Injection (DVI) lines is postulated. For traditional "small" break scenarios, this is the largest and most limiting location for a break in the primary system because a break in the DVI line dictates that safety injection flow delivered through this line be lost to the containment. The flow area of the DVI line is 0.4 ft^2 and, therefore, the largest effective break area.

For this analysis, modified input for the REM version of the CEFLASH-4AS code for calculating the thermal-hydraulic system response is used. With special features and model options in the REM version, a cooldown from full power is simulated to achieve a set of initial conditions at 2.4 hours. The calculation is then restarted at this time with the break size indicated above to study the system response during the LOCA. The thermal-hydraulic boundary conditions from CEFLASH-4AS are then input into the PARCH code to determine the hot rod heatup during core uncovery.

The primary system at the start of the LOCA is at 900 psia and 317°F. The reactor coolant pumps have been stopped and the steam generators (steam dump and bypass system) have been isolated. The operation of the SCS is also not simulated.

Because it is not safety grade, no charging flow is credited in the calculations. The first set of calculations are made with no SI delivery. The results of these calculations are given in Subsection 5.3.5.1 below. A second calculation for the limiting break size is then made where SI delivery is initiated within 10 minutes. The results of this calculation are given in Subsection 5.3.5.2

5.3.5.1 Results of LOCA Case With No SI Delivery

The following discussion presents thermal-hydraulic results for a LOCA break size of 0.4 ft^2. The break is postulated to occur in a DVI line at the vessel penetration. LOCA transient results are shown up until time peak clad temperature (PCT) exceeds 2200°F approximately 16 minutes from initiation of break.

The purpose of the analysis is to define the RCS inventory makeup requirements. The 0.4 ft^2 break size is the cross-sectional area of the DVI line. For traditional "small" break scenarios (full power, mode 1), this is the most severe break location and is also the limiting location for lower modes of operation as shown in following section.

Primary Pressure

The primary system pressure transient for the 0.4 ft^2 break size at the DVI line location is shown in Figure 5-2. The subcooled decompression from 900 to 100 psia occurs within the first minute. The depressurization proceeds until the steam production in the core and its volume expansion from superheating due to the combination of secondary-to-primary steam generator heat transfer, core heat transfer from uncovered fuel rods, and from wall heat transfer exceeds the steam volumetric break flow. The primary system then begins a gradual repressurization.

Reactor Vessel Two-Phase Mixture Level

Figure 5-3 shows the two-phase mixture level in the reactor vessel for the DVI line break. Inventory is lost above the level of the hot leg elbow within the first several minutes of the LOCA. The mixture level remains at this level near the hot leg centerline (25.87 ft) until the steam generator U-tubes and hot legs empty. During this draining period, steam produced by heat transfer from the fuel rods swells the mixture level in the core and is released at the surface to make its way down the hot leg countercurrent to the draining liquid and around the U-tubes through the loop seal and pump to the break in the DVI line. Figure 5.3-3 shows that the mixture level drops below the top of the core within approximately 7 minutes from time of break due to boiloff.

Hot Spot Cladding Temperature

The cladding temperature results using the PARCH code for the hot spot on the hot fuel rod is shown in Figure 5-4. For the limiting DVI line break location, before the mixture level drops below the top of core, the cladding temperature follows the saturation temperature of the primary coolant. After the two-phase mixture level drops below the top of the core, cladding heatup begins first at elevations near the top of the core and then progressively to lower elevations in the core which have more local power. Figure 5-4 shows the hot spot elevation temperature which is located roughly 10% of the active core height below the top of the core. There is an increase in cladding heatup rate beginning at roughly 1600°F due to the exothermic Zircaloy oxidation reaction. The time at which the hot spot cladding temperature exceeds 2200°F, the ECCS acceptance criterion for PCT, is 16 minutes.

5.3.5.2 Initiation of SI Delivery Within Ten Minutes After Break

The results presented below show that for break sizes of 0.4 ft^2 or less, operator action within 10 minutes to initiate SI injection would mitigate the postulated LOCA, i.e., prevent the cladding temperature from exceeding 2200°F.

To determine the effectiveness of restoring cooling flow to the reactor cooling system (RCS) the 0.4 ft^2 break size was postulated to occur at several locations, in a hot leg and a cold leg of the RCS as well as the DVI line. Ten minutes after the initiation of the LOCA, a cooling flow of 980 gpm is credited (equivalent to minimum run-out flow of one SI pump).

For the DVI line break, Figure 5-5 shows that injected cooling flow restores a positive core flow and causes the two-phase mixture level in the core to swell and recover the fuel rods. The fuel rods are recovered within 25 minutes from time of injection. The two-phase mixture levels for the hot and cold legs as well as for the DVI line break are shown in Figure 5-6 for the ten minutes of non-delivery after the break. For the hot and cold leg break locations the level does not drop below the top of the core, clearly showing the DVI line break location to be limiting.

Figure 5-7 shows the corresponding fuel rod hot spot cladding temperature transient for the postulated DVI line break. The PCT of the cladding hot spot with cooling flow restored in 10 minutes after break is compared to the case without coolant flow restoration which resulted in a runaway heatup driven by oxidation. The restoration of cooling flow within 10 minutes prevented the cladding temperature from reaching the point of significant Zircaloy oxidation and a runaway cladding heatup.

A lack of significant Zircaloy oxidation results in the maintenance of core geometry after LOCAs in lower modes of operation. The post-LOCA long-term cooling analysis for Mode 1 operation given in CESSAR-DC bounds long-term cooling analyses for LOCAs in lower modes because the decay heat levels are significantly lower.

The results for this Mode 4 LOCA analysis show that restoration of a cooling flow of 980 gpm (equivalent to minimum runout flow of a SI pump) within 10 minutes of the start of a LOCA will mitigate the consequences for all break sizes of at least 0.4 ft^2 or less.

5.4 RESOLUTION

Analysis of small break LOCAs which are considered possible in operating Modes 2 through 6 were either limited by the Mode 1 analysis in CESSAR-DC or the Mode 4 analysis presented in this report. For the lower mode LOCAs not bounded by Mode 1 analyses, this Mode 4 analysis is bounding.

The analysis presented in this section demonstrated that a LOCA event from $t_{RCS} \leq 317°F$ and $P_{RCS} \leq 900$ psia can be mitigated provided that the equivalent of at least one SI pump is injecting to the RCS no later than 10 minutes after the start of the LOCA. For lower mode LOCAs not bounded by Mode 1 analyses, the break size and location analyzed is limiting for small breaks which could occur in lower modes with neither SI pumps on automatic nor SITs available.

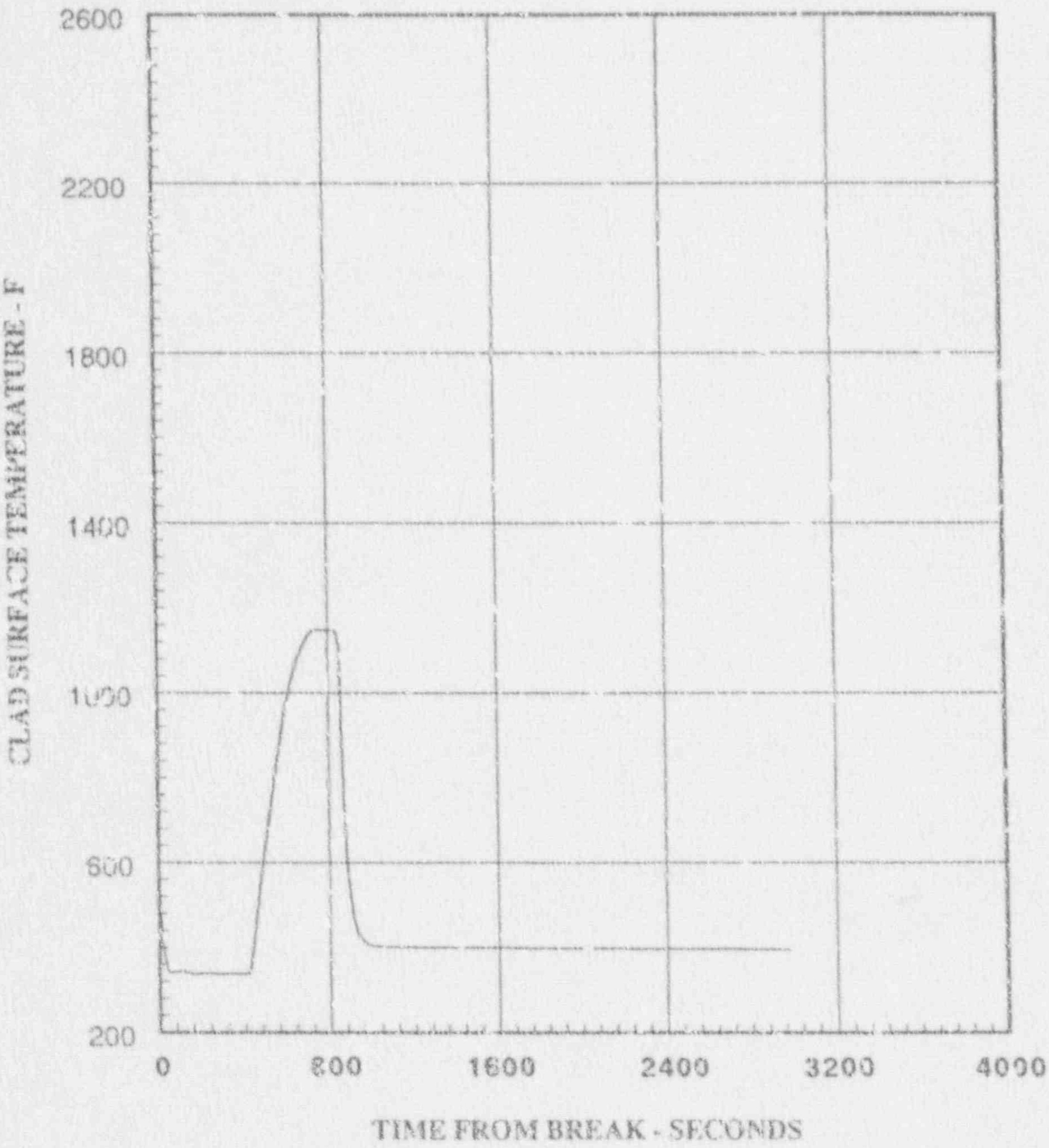
For the case where SI pumps are not on automatic, the transient response for the postulated break in the DVI line nozzle of 0.4 ft^2 shows that in approximately seven minutes from time of break the two-phase level drops below the top of the core and without cooling flow injection the cladding exceeds 2200°F sixteen minutes from time of break. The time interval for exceeding ECCS acceptance criteria for PCT is considerably larger than the 10 minute delay time assumed for operator action. Due to the 10 minute requirement for deliveries of injection flow, ABB-CE has added a technical specification to require operability of two Safety Injection Trains in Modes 4 with RCS temperature < 317°F and Modes 5 and 6. (See Table 2.2-1)

Provided that cooling flow equivalent to one SI pump can be provided within a ten minute period after a lower mode LOCA, it is concluded from the results of the analysis that the acceptance criteria for LOCAs detailed in Section 5.2 are met.

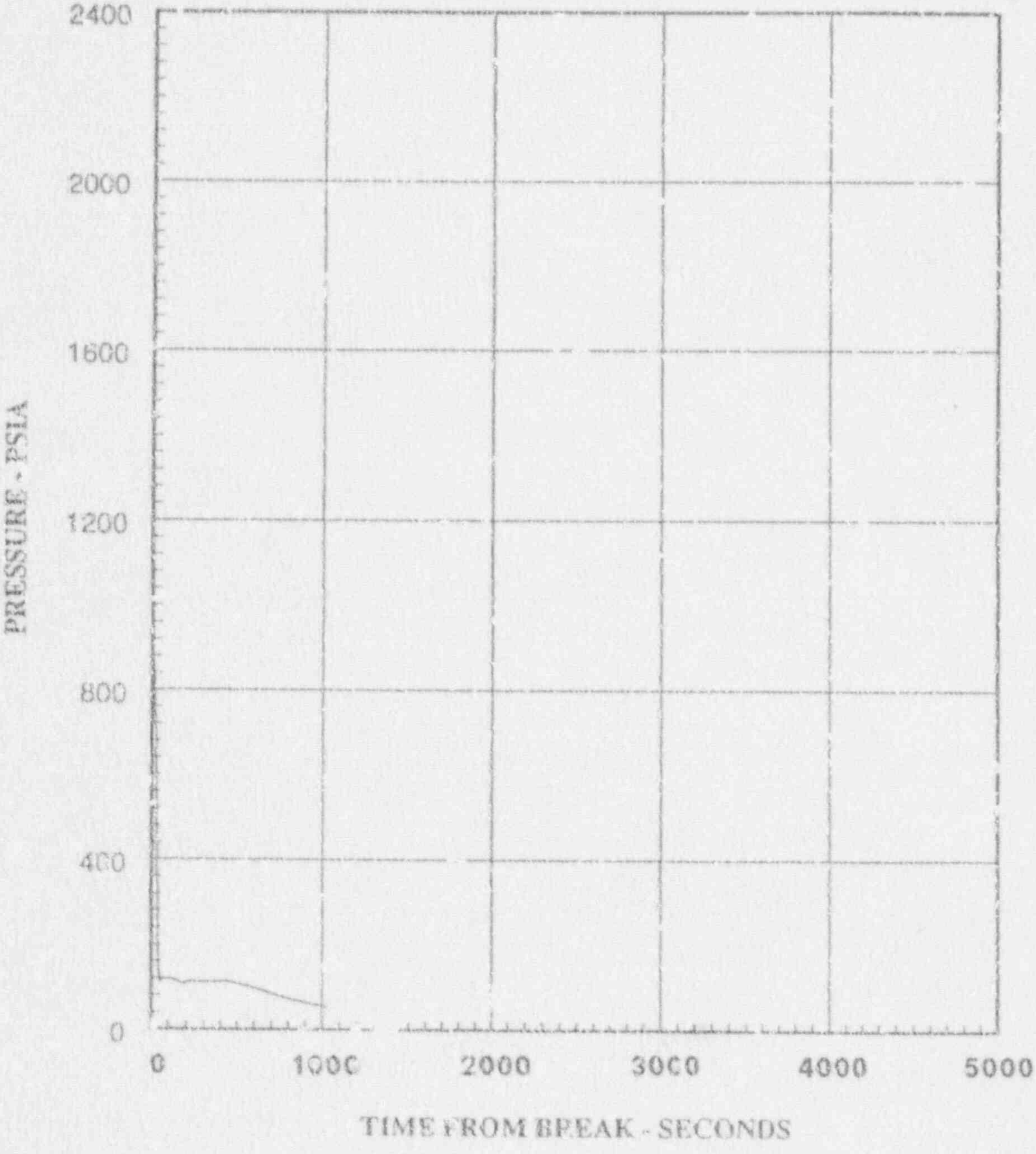
TABLE 5-1

SYSTEM 80+ LOCA ANALYSIS
MODE 4 INITIAL CONDITIONS

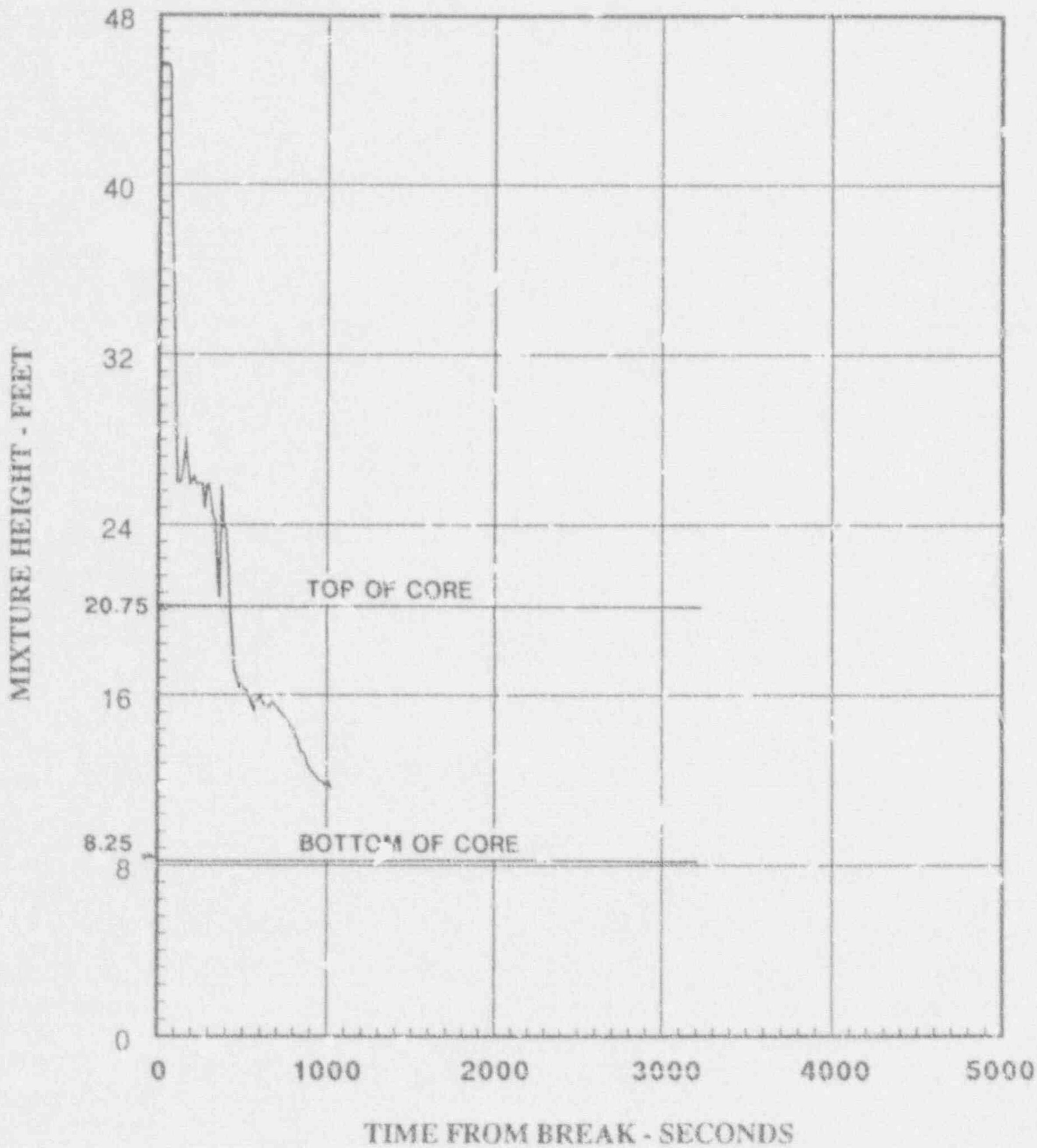
Parameter	System 80+
RATED CORE POWER, MWT	3800
TIME TO ENTER MODE 4, HRS AFTER SHUTDOWN	>2.4
INITIAL PRESSURE, PSIA	900
INITIAL TEMPERATURE, °F	317
SI PUMPS	NOT ON AUTOMATIC
SIT's	NOT AVAILABLE
STEAM GENERATOR	ISOLATED
REACTOR COOLANT PUMPS	TRIPPED BEFORE START OF EVENT



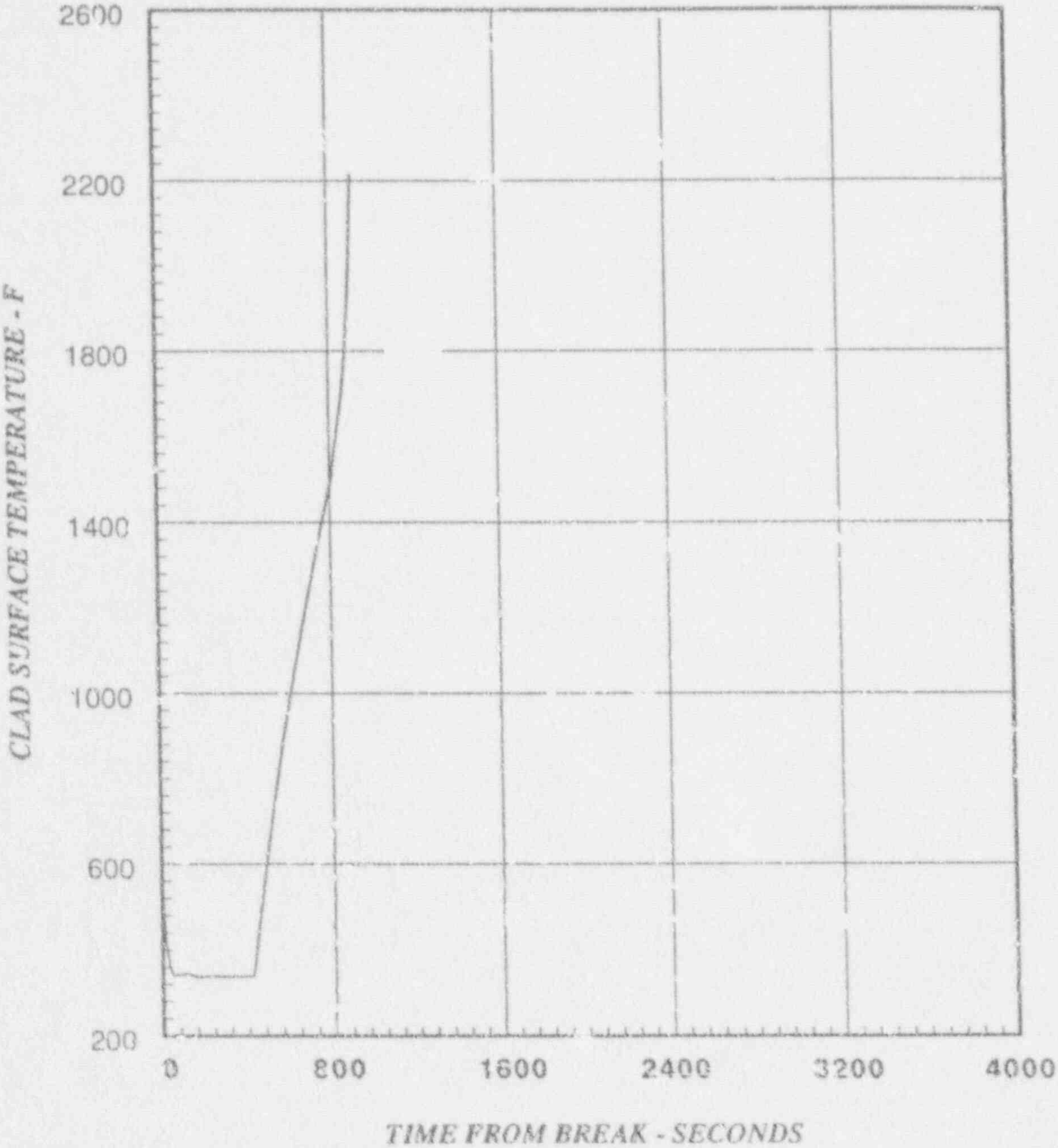
SYSTEM 80+™	CLAD SURFACE TEMPERATURE SAFETY INJECTION INITIATED AT 10 MINUTES DVI LINE BREAK	Figure 5-1



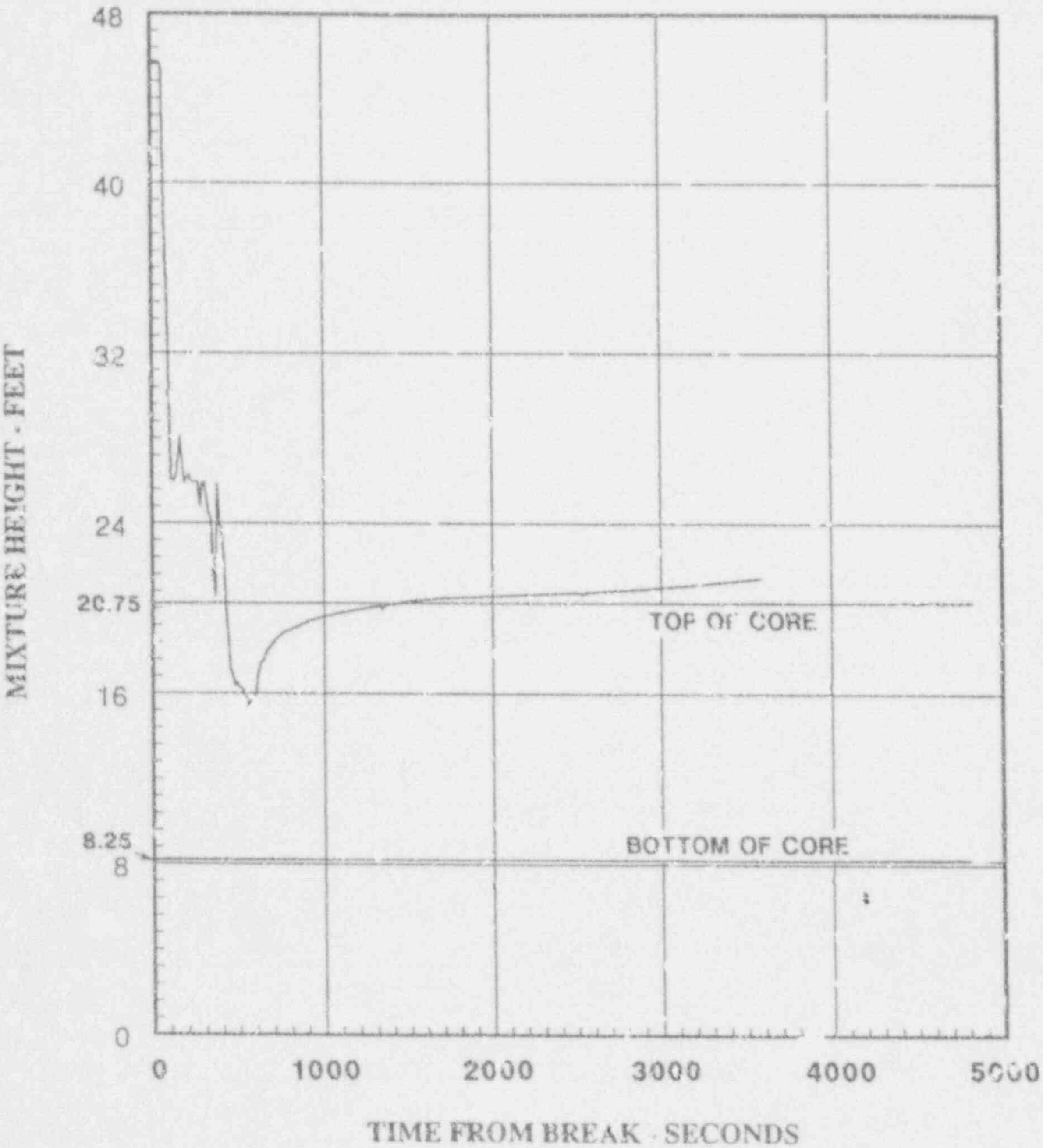
SYSTEM 80+™	PRESSURIZER PRESSURE NO SAFETY INJECTION DVI LINE BREAK	Figure 5-2



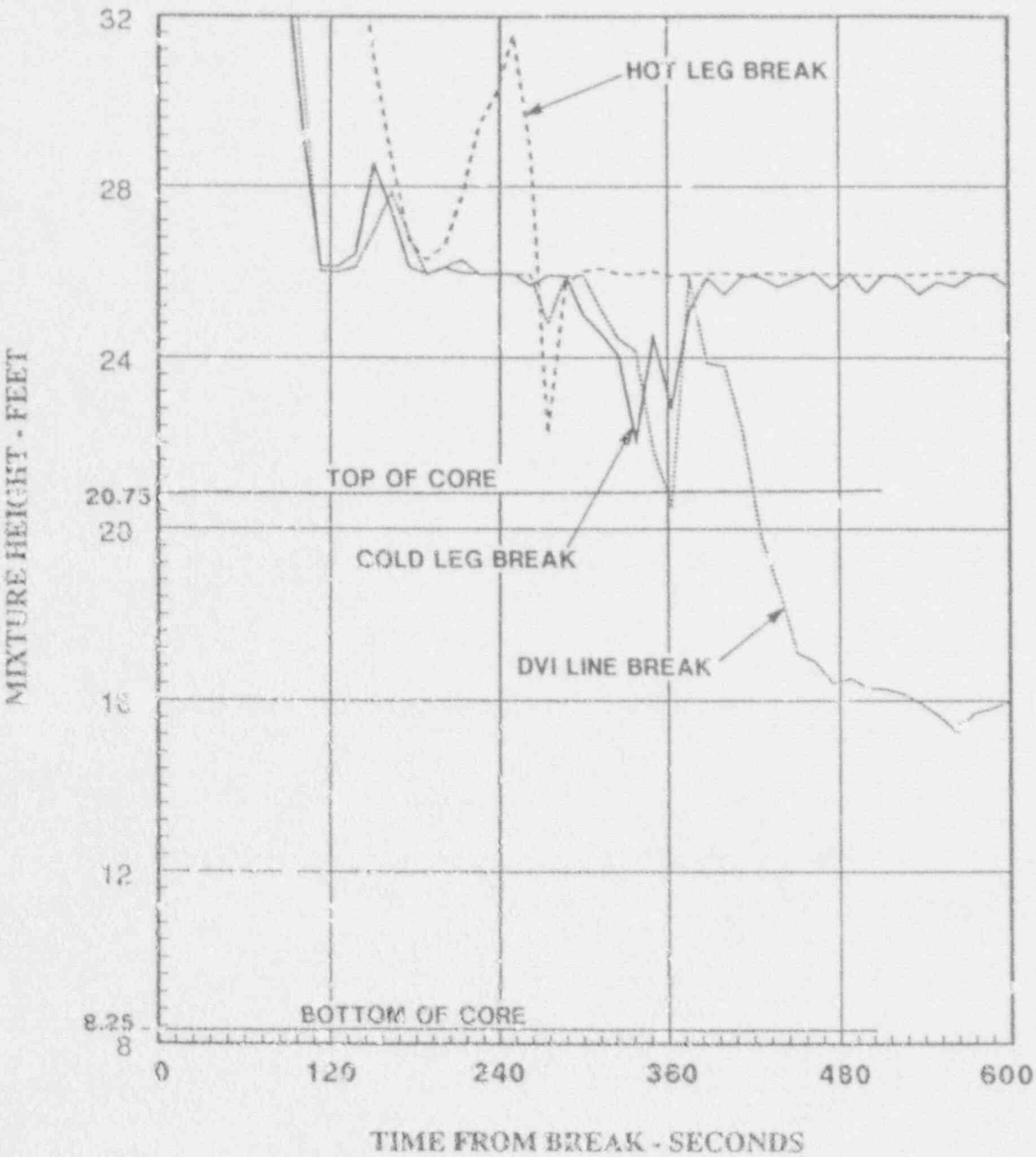
SYSTEM 80+™	REACTOR VESSEL MIXTURE HEIGHT NO SAFETY INJECTION DVI LINE BREAK	Figure 5-3



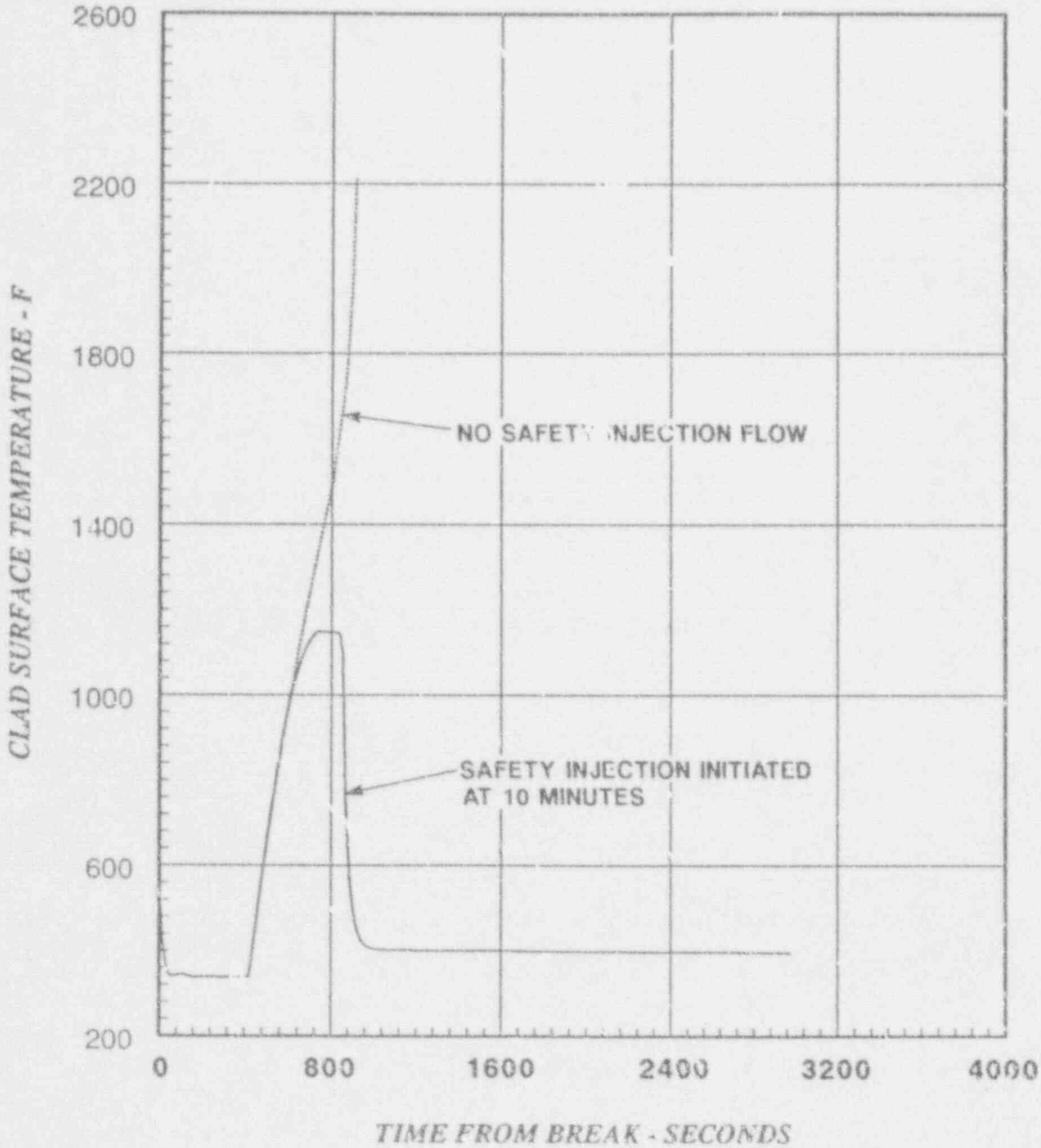
SYSTEM 80+™	CLAD SURFACE TEMPERATURE NO SAFETY INJECTION DVI LINE BREAK	Figure 5-4



SYSTEM 80+™	REACTOR VESSEL MIXTURE HEIGHT SAFETY INJECTION INITIATED AT 10 MINUTES DVI LINE BREAK	Figure 5-5



SYSTEM 80+™	REACTOR VESSEL MIXTURE HEIGHT THREE BREAK LOCATIONS COMPARED	Figure 5-6



SYSTEM 80+™	COMPARISON OF HOT SPOT CLADDING TEMPERATURE DVI LINE BREAK WITH AND WITHOUT SAFETY INJECTION	Figure 5-7

6.0 APPLICABILITY OF CHAPTER 6 CONTAINMENT ANALYSES

6.1 INTRODUCTION

CESSAR-DC Section 6.2.1.1 discusses containment functional design. A series of loss of coolant accidents (LOCAs) and main steam line breaks (MSLBs) were analyzed to determine the resulting containment pressure and temperature for comparison with the containment design pressure and the equipment environmental qualification envelope. The highest containment pressures and temperatures occur when the NSSS stored energy is maximized and the containment heat removal capability is minimized. Maximum RCS stored energy occurs when the plant is at 102 percent power. Maximum steam generator stored energy occurs at 0 percent power (hot standby). Consistent with the Standard Review Plan (SRP), a series of LOCAs were analyzed at 102 percent power and a series of MSLBs were analyzed at powers from 102 percent to 0 percent. The 0 percent MSLB with the failure of a containment spray train is the design basis event (DBE) for System 80+. These cases are presented in CESSAR-DC.

In going from Mode 2 to 6, stored energy is removed from the NSSS. If the safeguards features available in Modes 1 and 2 were available through Mode 6, there would be no question that the DBE identified in CESSAR-DC was limiting. However, some safeguards equipment is removed from service at lower modes. Table 6-1 lists the availability of safeguards equipment credited in the containment analyses as a function of operating mode. Since the Main Steam Isolation Signal (MSIS) and Containment Spray Actuation Signal (CSAS) may be removed from service in Modes 5 and 6, an evaluation of LOCAs and MSLBs in these modes must be made. In addition, a LOCA initiated from zero power (Mode 2) was analyzed. This report discusses the results of these evaluations. The results show that the events presented in CESSAR-DC remain limiting for both containment pressure and equipment environmental qualification. Table 6-2 presents a list of cases that were considered.

6.2 LOSS OF COOLANT ACCIDENTS (LOCAs)

Section 6.2.1.1 of CESSAR-DC presents the results of the containment pressure and temperature analysis for a series of hot leg, suction leg, and discharge leg LOCAs. Consistent with SRP 6.2.1.3, the cases were based on an initial power level of 102 percent. The limiting LOCA in terms of containment peak pressure is the Double Ended Hot Leg Slot (DEHLS) break.

As power level decreases from 102 percent, the hot leg coolant and core temperatures decrease. At the same time, the mass of coolant and pressure on the steam generator secondary sides increases. As a result, primary side stored energy decreases and secondary side energy increases. To show that the cases presented in CESSAR-DC are limiting, a 0 percent power LOCA has been analyzed. Although the case in CESSAR-DC which produced the highest LOCA containment peak pressure was the DEHLS, the Double Ended Suction Leg Slot (DESLS) break with minimum safety injection (most limiting cold leg break) was selected for this analysis because the effect of the increased secondary inventory at no load has more impact on cold leg breaks. Table 6-3 lists the assumptions and initial conditions for this case. This case is actually a Mode 2 case. With the RCS and SG coolant at 556 F, this represents the case with the most NSSS energy of any Mode 2 case. Table 6-4 provides the chronology of events table. The containment peak pressure for this case is 42.0 psig compared to 44.96 psig for the equivalent case at 102 percent power. Results are shown in Figures 6-1 and 6-2.

For Modes 3 and 4, the NSSS stored energy is less than for the case analyzed above. Containment spray is still available so that LOCAs for these modes would produce lower containment pressures and temperatures. For Modes 5 and 6, the Containment Spray Actuation Signal (CSAS) may not be activated. As a result, should a LOCA occur, the containment sprays would not be available; however, since the RCS coolant temperature for Mode 5 is less than 210 F, a LOCA in Modes 5 and 6 would not result in any significant containment pressurization.

Since the LOCAs described in Chapter 6.2.1 of CESSAR-DC are more severe than a LOCA during shutdown modes as far as containment pressurization is concerned, the annulus transient described in Chapter 6.2.1.8 of CESSAR-DC bounds all modes.

6.3 MAIN STEAM LINE BREAKS (MSLBs)

In CESSAR-DC, MSLBs were analyzed at 102, 50, 20, and 0 percent power, representing Modes 1 and 2. The cases were analyzed with either the failure of an MSIV or the loss of a containment spray train. The 0 percent power case with the loss of a containment spray train produced a containment peak pressure of 48.34 psig. This pressure was the highest of any LOCA or MSLB and this case is the containment DBE. The 0 percent cases analyzed in CESSAR-DC are Mode 2 cases. Since they were based on SG pressures of 1100 psia and RCS and SG temperatures of 556 F, they represent the cases with the most stored energy for Mode 2. Mode 2 cases with less stored energy would be less limiting.

In Mode 3 and 4, the NSSS stored energy is less than Modes 1 and 2. As shown in Table 6-1, main steam isolation and containment spray are still available in these modes. Therefore, a MSLB during these modes would not be more limiting than a MSLB during Mode 1 or Mode 2.

In Mode 5 or 6, main steam isolation and containment spray may not be available. On the other hand, the RCS coolant temperature in

Mode 5 will be less than 210 F. If the SG coolant temperature was also at 210 F, no containment pressurization would occur following a MSLB. An analysis has been performed conservatively assuming that the SG coolant was still at 350 F following shutdown cooling of the RCS to 210 F. Table 6-5 lists the assumptions and initial conditions. Table 6-6 lists the chronology of events. The containment peak pressure for this case is 13.4 psig, well below the CESSAR-DC DBE result. Results for this Mode 5 MSLB are shown on Figures 6-3 and 6-4.

6.4 INADVERTENT OPERATION OF CONTAINMENT HEAT REMOVAL SYSTEMS

During shutdown the containment is purged using either the low or high volume containment purge. An inadvertent actuation of the spray system with the containment purge valves open will result in an insignificant decrease in the containment internal pressure. The parameters affecting the negative containment pressure are the containment atmosphere initial conditions and the spray water temperature. The source of the spray water for the System 80+ design is the IRWST. Figure 3.5.4.1 of Chapter 16 of CESSAR-DC which specifies acceptable IRWST temperatures for a range of containment atmosphere temperatures is based on the properties of steam and is not mode dependent.

6.5 CONCLUSION

CESSAR-DC Section 6.2.1 provides containment analyses to support the establishment of the containment design pressure and temperature and an envelope for equipment environmental qualification. A spectrum of primary and secondary line breaks were analyzed. With the exception of the 0 percent power MSLB cases (Mode 2), all of the cases analyzed were for Mode 1. As discussed in the sections above, NSSS stored energy decreases in going from Mode 2 to Mode 6. Safeguards equipment important to containment analyses (containment spray and main steam isolation) are available in all modes with the possible exception of Modes 5 and 6. The analyses above show that by the time the plant is in Modes 5 or 6, the NSSS energy has been reduced to the point where if a postulated primary or secondary line break were to occur, the resulting containment pressure and temperature would be less severe than those presented in CESSAR-DC even with containment spray and main steam isolation unavailable. This result ensures also that the annulus transient presented in CESSAR-DC bounds all Modes.

The inadvertent containment spray actuation event presented in CESSAR-DC Section 6.2.1 is used to determine the maximum external containment design pressure. The analysis presented is not mode dependent.

TABLE 6-1

ESFAS INSTRUMENTATION

SIGNAL	APPLICABLE MODES
CSAS	1,2,3,4 (Note 1)
MSIS	1,2,3,4

Note 1: Table 3.3.10-1 of CESSAR-DC Chapter 16 does not show CSAS applicable for Mode 4. Section 2.2 of this report expands the applicability of CSAS to include Mode 4.

TABLE 6-2

CASES ANALYZED

MODE	LOCA	MSLB
1	102% Power DEHLS, DESLS, DEDLS CESSAR-DC	102%, 50%, 20% CESSAR-DC
2	0% DESLS Current Report	0% CESSAR-DC
3	Analysis Not Required Note 1	Analysis Not Required Note 1
4	Analysis Not Required Note 1	Analysis Not Required Note 1
5	Analysis Not Required Since RCS T < 210 F	Case Analyzed With RCS T At 210 F and SG T At 350 F Current Report
6	Analysis Not Required Since RCS T < 135 F	Analysis Not Required Since Less Limiting Than Mode 5

Note 1: Less NSSS stored energy than Modes 1 and 2. Same ESF available as in Modes 1 and 2.

TABLE 6-3

INITIAL CONDITIONS FOR LOCA INITIATED FROM ZERO POWER

Parameter	Value
Reactor Coolant System	
Average Coolant Temperature, F	556
Containment	
Initial conditions are consistent with CESSAR-DC Chapter 6, Table 6.2.1-18.	

TABLE 6-4

ACCIDENT CHRONOLOGY FOR LOCA INITIATED FROM ZERO POWER

Time, sec	Event
0.00	Break occurs
18.00	Start Safety Injection Tank Injection
21.98	Peak Containment Pressure before End of Blowdown
22.00	End of Blowdown
25.90	Downcomer Full
71.00	Containment Spray Injection
71.80	Peak Containment Pressure Subsequent to End of Blowdown
100.00	Safety Injection Tank Empty
108.30	End of Reflood
202.57	End of Post Reflood

1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

TABLE 6-5

INITIAL CONDITIONS FOR MSLB INITIATED FROM MODE 5

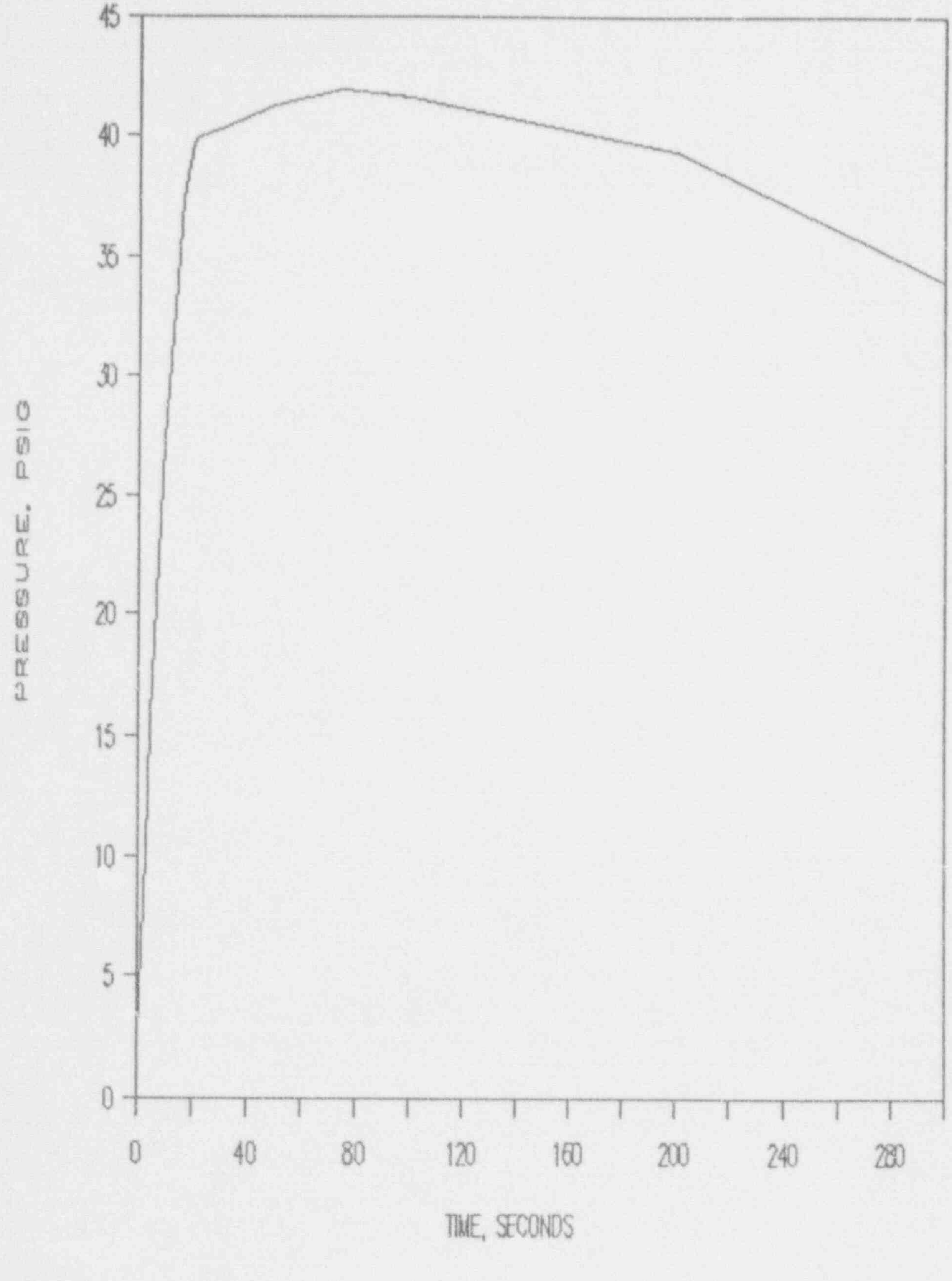
Parameter	Value
Reactor Coolant System	
Average Coolant Temperature, F	210
Steam Generator Secondary Pressure, psia	132.8
Steam Generator Secondary Temperature, F	350
Containment	
Initial conditions are consistent with CESSAR-DC Chapter 6, Table 6.2.1-18.	

TABLE 6-6

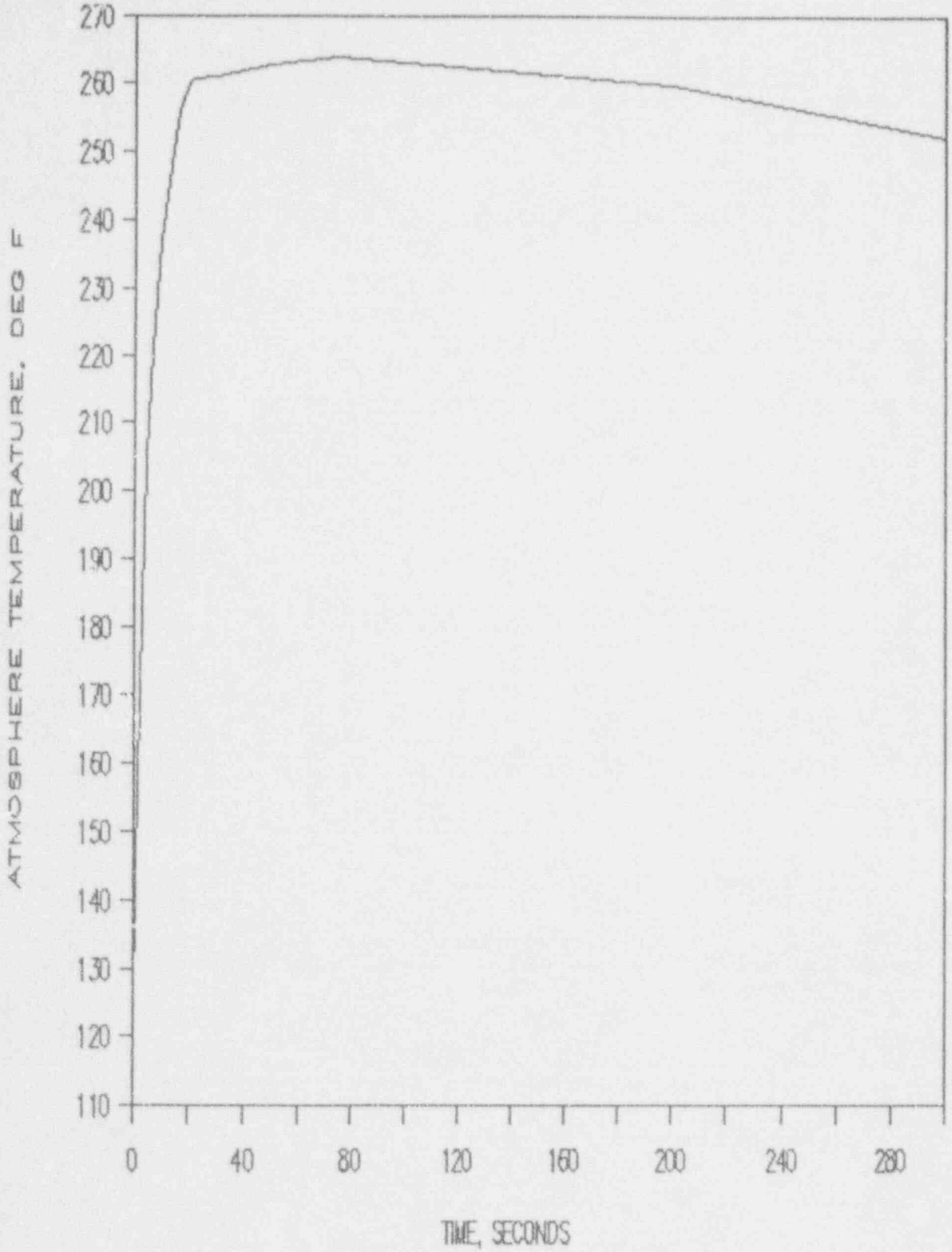
ACCIDENT CHRONOLOGY FOR MSLB INITIATED FROM MODE 5

Time, sec	Event
0.00	Break occurs
146.71	Peak Containment Temperature Peak Containment Pressure

Note: MSIS and Containment Sprays are assumed not to be available in this mode



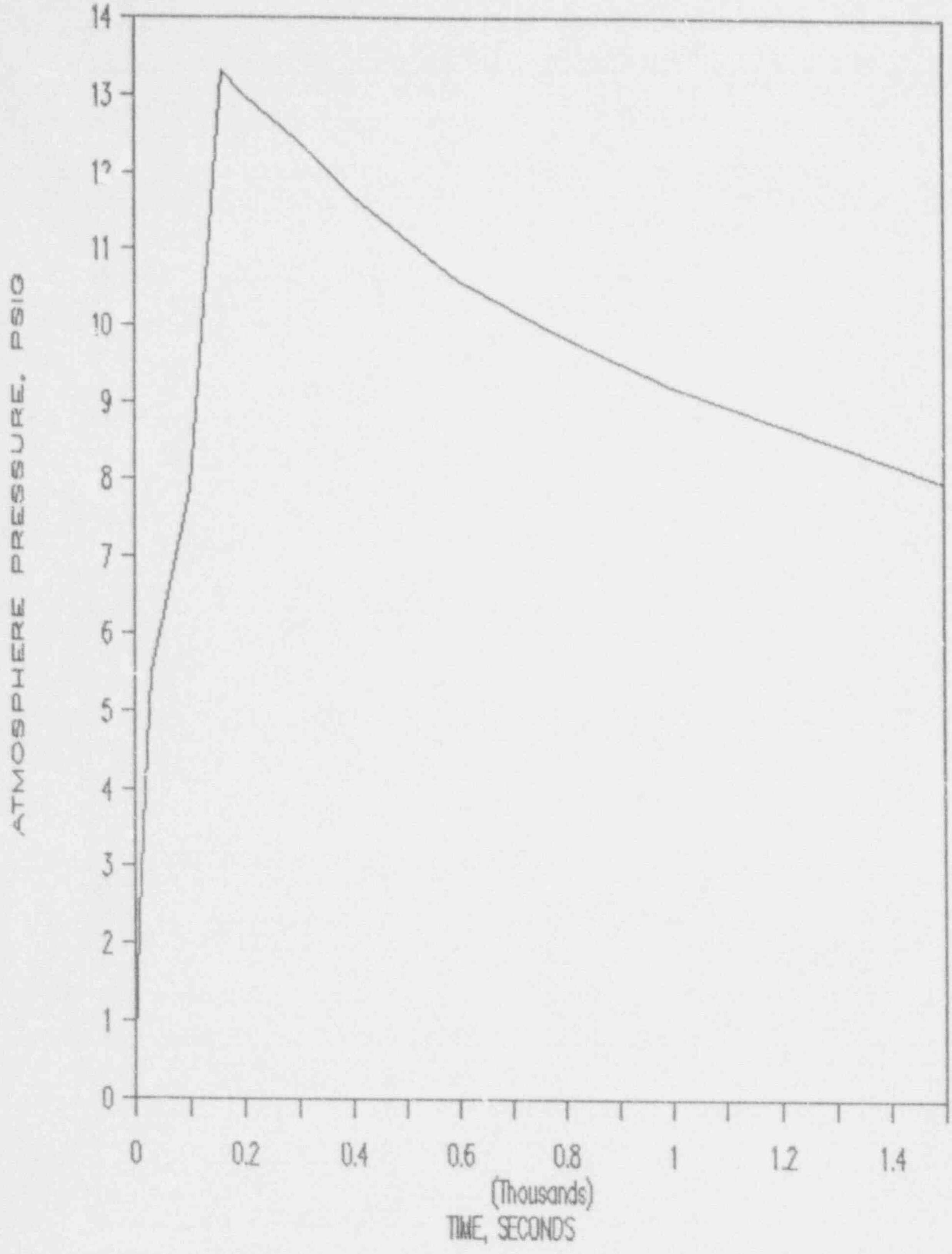
SYSTEM 80+™	CONTAINMENT PRESSURE vs. TIME FOR LOCA FROM ZERO POWER	Figure 6-1



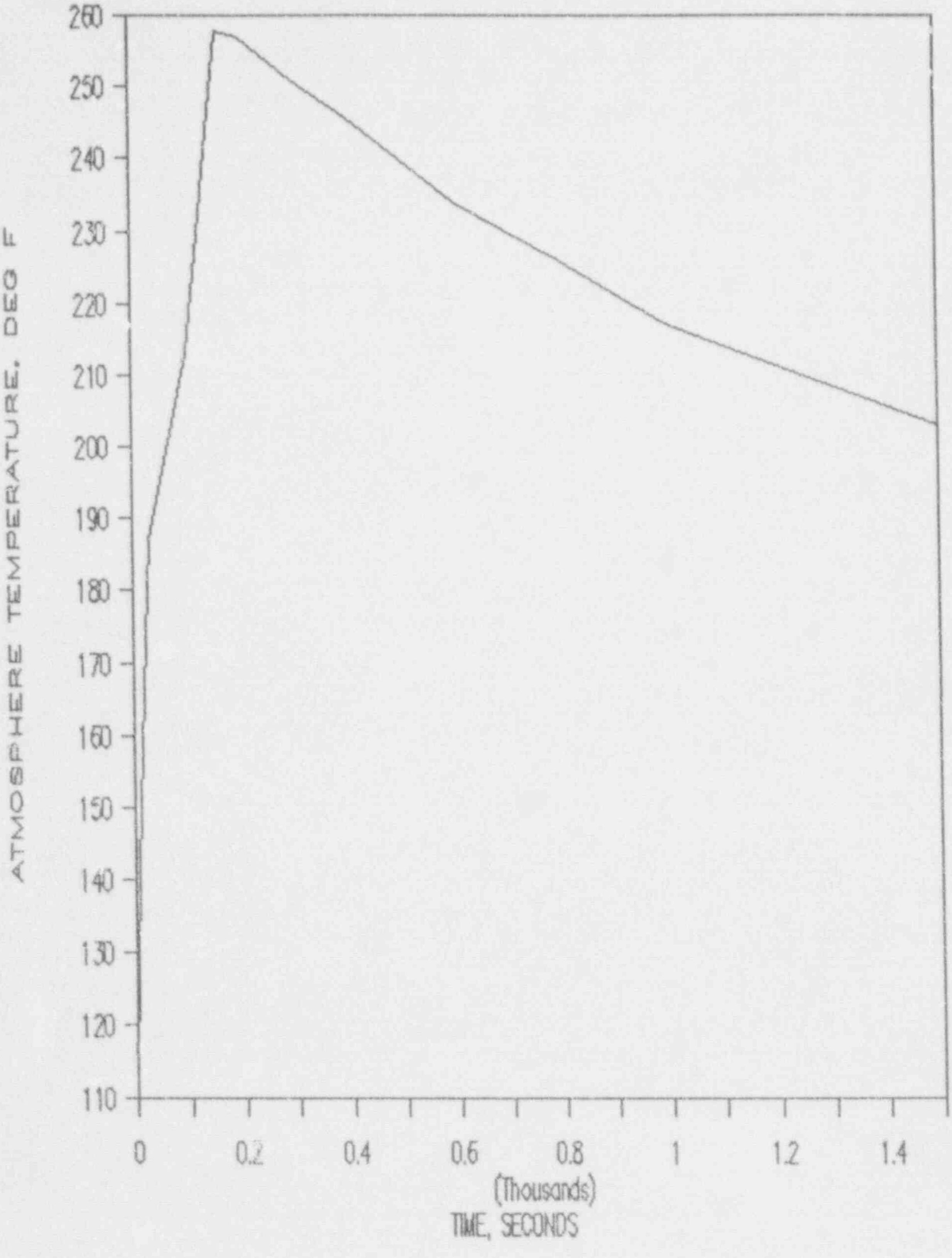
SYSTEM 80+™

CONTAINMENT ATMOSPHERE TEMPERATURE vs. TIME
FOR LOCA FROM ZERO POWER

Figure 6-2



SYSTEM 80+™	CONTAINMENT PRESSURE vs. TIME FOR MSLB FROM MODE 5	Figure 6-3



SYSTEM 80+™	CONTAINMENT ATMOSPHERE vs. TIME FOR MSLB FROM MODE 5	Figure 6-4

7.0 SYSTEM 80+ DESIGN FEATURES FOR SIMPLICITY OF SHUTDOWN OPERATIONS

7.1 INTRODUCTION

The System 80+ evolutionary ALWR design takes maximum benefit from prior design and operating experience. It is an objective that this benefit be evident in design features that aid outage planning, reduce operator stress and simplify operator training. Previous sections of this report describe and evaluate features of System 80+ that will improve the overall shutdown operations. In the following discussion, the outage benefits accruing from these design features are presented.

7.2 DISCUSSION

There are several features of the System 80+ design which will aid in the management of an outage. Many of these same features relieve some of the stresses and pressures placed on the licensed operators. These features are presented in Sections 7.2.1 through 7.2.9.

7.2.1 TECHNICAL SPECIFICATIONS FOR REDUCED INVENTORY

Technical Specifications for the System 80+ design specify restrictions on operation in Reduced Inventory. Reduced Inventory is determined by water level in the Reactor Coolant System (RCS). This plant operational condition is defined as "RCS level greater than 3 feet below the reactor vessel flange". These specifications provide guidance to the operations staff and the outage management team. This guidance ensures that equipment assumed to be available for accident mitigation is operable. This aids the outage planners by identifying equipment on which maintenance cannot be accomplished during Reduced Inventory. This planning process reduces the chance for removal of components relied upon for detection and response to accidents. These specifications provide the Senior Licensed Operator a clear standard for determining minimal equipment availability. This will alleviate some of the stress placed on the operator to make the final judgement as to whether equipment is required to be operable for Reduced Inventory operations.

7.2.2 SHUTDOWN COOLING SYSTEM

The Shutdown Cooling System (SCS) design provides two divisions for decay heat removal capability. These two divisions are completely redundant, that is, they share no components or equipment. This redundancy provides the operator with a standby decay heat removal system if any component fails to perform its function. This assurance of a standby system availability reduces some of the pressures and stresses placed on the operator when no standby system is available.

Another feature of the SCS is that it is not a subsystem of the Emergency Core Cooling System. Therefore, the SCS is not required to be operable in Modes 1 through 4. This feature of System 80+ design increases the availability of SCS during Mode 5, Mode, 6 and Reduced Inventory. In addition, this feature aids the outage planning team by allowing maintenance and repair of SCS components and equipment to be accomplished during power operations. This feature eliminates the necessity of finding a window during the outage to allow work on decay heat removal equipment.

Besides the features discussed above, the SCS is designed to provide faster venting of the pumps. If SCS pumps become vapor bound due to misoperation, venting is required. The vent piping for the pumps is hard piped and directed to the floor drain sumps. This allows the plant equipment operator to quickly vent the pump without attaching vent rigs. These vent rigs waste valuable time if recovery from a loss of decay heat removal is required.

7.2.3 CONTAINMENT SPRAY SYSTEM

The Containment Spray System (CSS) design provides two divisions of equipment which can be utilized as an alternate decay heat removal flow path. The CSS pumps are interchangeable with the SCS pumps. This feature provides the operations staff with increased flexibility in the area of forced circulation. Therefore, this alternate alignment for forced coolant flow during shutdown conditions reduces stresses placed on the operators since it increases the redundancy and therefore reliability of the System 80+ decay heat removal capability. With these alternate pumps, the operators have assurances that redundant equipment is available.

7.2.4 COMPONENT COOLING WATER SYSTEM

The Component Cooling Water System (CCW) design has two redundant divisions. Each of the two divisions contains two pumps and two heat exchangers.

This interdivisional redundancy of system components provides flexibility for the management of the maintenance outage. Therefore, major components (e.g., pumps and heat exchangers) requiring maintenance can be removed from service without affecting the availability or reliability of the interdivisional equipment. This enhancement of system design provides the outage planner with options to facilitate easier outage scheduling.

7.2.5 STATION SERVICE WATER SYSTEM

The Station Service Water System (SSW) design has two redundant divisions. Each of the two divisions contains two pumps. This interdivisional redundancy of the pumps provide flexibility for outage planning. The outage planner can schedule a pump for maintenance without affecting the availability or reliability of the interdivisional equipment nor the redundant division equipment.

7.2.6 ELECTRICAL DISTRIBUTION SYSTEM

The Electrical Distribution System (EDS) design has two redundant safety divisions. (Refer to Figure 2.4-5.) Each division is capable of being powered from four separate and diverse sources. These sources include:

1. Switchyard Interface I,
2. Switchyard Interface II,
3. Diesel Generators, and
4. Combustion Turbine.

The EDS provides the outage planner with the flexibility to remove a source of power for maintenance and still maintain other reliable sources to the safety buses. Therefore, required maintenance activities are scheduled without reducing the reliable sources of power to unacceptable levels. These same features provide the licensed operator with alternate sources to which safety buses can be aligned. The operator is aware of these approved alternate alignments through procedures and training. Therefore, the stress placed upon the operator to align to any available source regardless of guidance is reduced. In addition, operator training is facilitated by the procedural guidance.

Another feature of the EDS design is the use of 4 safety buses, 2 per Division. The 1E loads are evenly distributed on the buses to ensure redundancy of system components. For example, each bus powers 1 of [illegible] Component Cooling Water pumps. This feature provides flexibility for the outage planner. One bus can be removed from service for maintenance and redundant components still have a power supply available.

7.2.7 NUPLEX 80+ ADVANCED CONTROL COMPLEX

The NUPLEX 80+ Advanced Control Complex (ACC) is an integral part of the System 80+ design. The design goals of NUPLEX 80+ include the integration of NSSS and balance of plant systems into a unified control complex, reduction of human errors that affect plant safety and improving the reliability of the man-machine interface through redundancy, segmentation and diversity.

Control room information provided by NUPLEX 80+ is consistent with operator information requirements when performing operational tasks during plant evolutions or responding to unexpected conditions. The operator can obtain information from a number of sources in the NUPLEX 80+ ACC. These sources include:

- A large plant overview status board known as the Integrated Process Status Overview (IPSO).
- Alarm tiles and associated message windows.
- Discrete indicators provide frequently used and important information.
- CRT displays containing essentially all power plant information.

More detailed information on the NUPLEX 80+ ACC can be found in Chapter 18 of System 80+ CESSAR-DC.

The NUPLEX 80+ ACC utilizes the same parameter conventions for the indicators and alarms for shutdown operations as required for power operations. The features of each which simplify operator training, aid in outage planning and reduce operator stress are described below.

- IPSO - IPSO provides the operators, especially Senior Reactor Operators with an overview of plant status during shutdown conditions. This overview allows the operators to view system status during outage activities. Having an overview of the plant will reduce uncertainty of the availability of required safety systems. This knowledge of the availability reduces the stress placed on the operators by uncertainties.

- Alarms - Mode and equipment dependent alarms are a special feature of NUPLEX 80+ ACC. This feature eliminates the alarming of alarms not applicable to the current mode, operating conditions, or equipment status. A large amount of maintenance activities involved with the outage affect control room alarms. The mode and equipment dependent alarms eliminate operator response to nuisance alarms caused by authorized work being performed. Outage work may be planned, alarms disabled and unnecessary investigation by operators into these alarms eliminated.

- Discrete Indicators - Discrete Indicators provide several simplifying attributes for operators. Automatic ranging scales on Discrete Indicators allow accurate indication over the entire range of system design with the same indicator. Using the same indicator for all conditions of operation, including shutdown, avoids confusion for the operators. This feature allows training to utilize the same indicators on a simulator. It also eliminates the utilization of indicators solely for shutdown. Discrete Indicators receive multiple channel input signals to be displayed on one indicator. These signals are validated and provided the operator with reliable indication even if some channels are removed from service. Individual channel inputs to the Discrete Indicators alarm to alert the operator when one has been removed from service. This allows the operator to check the status of information provided. Using validated displays reduces stress on the operator by eliminating doubt of instrument availability and accuracy.

- CRT Displays - CRT displays for the NUPLEX 80+ ACC are arranged in a structured information hierarchy. This structure provides the operator information consistent with operational needs. Levels of display information start with IPSO and continue through detailed plant information. A feature of the CRT display is graphic representation of systems. This reinforces system layout training and leads to better understanding by the operator. It provides consistency for the operators which reduces stress. Color representation of valves to indicate operable/inoperable status gives the operator the information to determine flowpath status. This feature also provides status of maintenance in progress on important valves in the plant.

7.2.8 REDUCED INVENTORY INSTRUMENTATION

The System 80+ design provides the instrumentation to insure the Control Room Operator (CRO) is informed of the decay heat removal system performance and the reactor coolant system level and temperature. The instrumentation includes:

1. Reactor Coolant System Level,
    - Heated Junction Thermocouple
    - dP
2. Reactor Coolant Temperature,
    - Core Exit Thermocouple
    - Heated Junction Thermocouple
3. Shutdown Cooling System Flow,
4. Shutdown Cooling System Pressure,
5. Shutdown Cooling System Temperature, and
6. Shutdown Cooling Pump Motor Current.

See Section 2.8, Instrumentation, of this report for a discussion of this instrumentation. The instrumentation is coupled with the Nuplex 80+ Advanced Control Complex (ACC) to provide the CRO with indications and alarms to monitor reduced inventory operations. (See Section 7.2.7 above for a description of Nuplex 80+ ACC features).

The CRO has the responsibility to keep the reactor core cooled and covered during reduced inventory operations. Although the burden of responsibility placed on the CRO cannot be relieved, the CRO's tasks are made simpler to perform. With the System 80+ instrumentation, the operator is not required to rely on local gauges and/or temporary instruments installed only for shutdown operation. This design increases the operator's confidence level of parameter indications and therefore decreases the stress operators are placed under when in reduced inventory operations.

7.2.9 CONTAINMENT

The containment for the System 80+ is a 200 foot diameter, spherical design steel vessel with a free volume of 3.3 million cubic feet. The spherical design incorporates a large operating deck inside containment with 21,500 square feet of floor space.

The containment structure utilizes internal boundaries for ventilation systems and therefore eliminates a significant portion of ductwork in containment. The elimination of ductwork reduces the amount of outage activities required in containment for ventilation system maintenance and repair.

The design of the containment operating deck includes open floor space allocated for storage and maintenance during outage periods. Portions of the operating deck are suitable for pre-staging and laydown of equipment in support of maintenance activities. Examples of items that may be prestaged are:

Valve maintenance tools and test equipment,
Reactor vessel and head equipment, and
Steam Generator inspection and repair equipment.

Pre-staging equipment required for containment work activities in advance eliminates having to open the equipment hatch unexpectedly due to work schedule and scope changes.

The layout of the operating deck allows for multiple maintenance activities during the outage and reduces the number of times the equipment hatch must be opened. Valve maintenance, reactor vessel stud cleaning and reactor coolant pump work is performed in shielded areas on the perimeter of the operating deck. The space provided for these maintenance activities combined with crane support and pre-staged tools eliminates the need to transfer components through the equipment hatch to work spaces outside containment.

The elimination of equipment hatch openings during critical plant evolutions such as RCS reduced inventory operations helps to ensure containment integrity is maintained. The design simplifies outage planning by providing space for prestaging and work activities to be accomplished in parallel without reliance on equipment hatch opening.

7.3 CONCLUSION

The System 80+ design has incorporated features which are consistent with the objective outlined above in Section 7.1. The features discussed provide the outage management team with redundancy, diversity, and guidance to simplify outage planning. In addition, these features provide the operator with reliable and redundant equipment and indications. This also provides the operator with some relief from the stresses experienced when no redundancy or parameter indication is available. Operator training is simplified due to equipment redundancy and diversity available in shutdown operations.

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8.0 CONCLUSIONS

This report has provided responses to issues on shutdown risk raised by NRC RAIs. The report shows that the System 80+ design features along with Technical Specifications and operational guidance will result in acceptable consequences from accidents during shutdown.

System 80+ is engineered with features that enhance shutdown safety: 1) by deliberate system engineering, equipment specification and plant arrangements for shutdown operation, 2) by mode dependent control logic that assists and limits operations, 3) by instrumentation, displays and alarms that clearly portray plant status in each mode and 4) by thorough procedural guidance and Technical Specifications that address important shutdown evolutions. This report shows that these features successfully prevent the occurrence of shutdown risk events or mitigate the consequences of the events.

The PRA study performed for this report shows that the core damage frequency for internal events while the plant is in shutdown modes is about the same as the frequency while the plant is at power operation. Evaluations of SAR Chapter 6 and 15 events while in shutdown modes show that all acceptance criteria are met. In addition to the Chapter 6 and 15 analyses, the System 80+ design was reviewed with regard to other issues such as flooding and spills, fires, the dropping of heavy loads, and containment closure times. Again, all acceptance criteria were met.

As a result of the shutdown risk study, several changes to the Technical Specifications will be made. In addition, two design changes will be made to provide improved RCS water level indication during midloop operation. One of these changes will be the addition of two narrow range delta P cells between the DVI nozzle and the SDC nozzle at the hot leg. The other change will be the addition of two heated junction thermocouple strings to cover the hot leg region. These changes will provide a more accurate measurement of the water level in the vicinity of the hot leg elevation.

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9.0 REFERENCES

1. Letter LD-92-038, C. B. Brinkman (ABB-CE) to D. M. Crutchfield (NRC) dated March 25, 1992.

2. Memo Letter, "Summary of Meeting Held on December 18, 1991 Regarding Shutdown Risk", T. V. Wambach (NRC), dated January 30, 1992.

3. NUREG-1449, "Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States", Draft Report dated February, 1992.

4. USNRC Generic Letter No. 88-17, "Loss of Decay Heat Removal", dated October 17, 1988.

5. USNRC AEOD Special Report, "Review of Operating Events Occurring During Hot and Cold Shutdown and Refueling", dated December 4, 1990.

6. NUREG-0800, USNRC Standard Review Plan, Revision 1, July, 1981.

7. Jaquith, R.E., et.al., "Probabilistic Risk Assessment for the System 80+ Standard Design", Combustion Engineering Inc., DCTR-RS-02, January, 1991.

8. Letter from James H. Wilson (NRC) to E. E. Kintner (EPRI) dated September 5, 1991.

9. Brockhold, G. (EPRI), Memo to ALWR Utility Steering Committee, ALWR-92-18, January 15, 1992.

10. This Reference was deleted.

11. ANSI/ANS-58.8-1984.

12. CEN-373-P, Volume 1, "Realistic Small Break LOCA Evaluation Model, Calculational Models," April 1988.

    Volume 2, "Application of Evaluation Model," December 1988.

    Volume 2 Supplement 1-P, "Application of Evaluation Model to Calvert Cliffs Units 1&2, September 1989.

    Volume 3, "Computer Program Input and Output Description," December 1988.

13. Letter LD-88-030, "Submittal of Realistic SBLOCA Evaluation Model," A. E. Scherer (ABB CE) to J. A. Norberg (NRC), April 27, 1988.

14. Letter LD-88-155, "Submittal of Volumes 2 and 3 of Combustion Engineering's Realistic Small Break Loss-Of-Coolant-Accident Evaluation Model," A. E. Scherer (ABB CE) to J. A. Norberg (NRC), December 9, 1988.

15. Letter LD-89-001 "Addendum to Volume 3 of Combustion Engineering's Realistic Small Break Loss-of-Coolant Accident Evaluation Model," A. E. Scherer (ABB CE) to J. A. Norberg (NRC), January 11, 1989.

16. Letter LD-89-099, "Supplement 1 to Volume 2 of Combustion Engineering's Realistic Small Break LOCA Evaluation Model," A. E. Scherer (ABB CE) to J. A. Norberg (NRC), August 28, 1989.

17. ANSI-N18.2-1973.

18. "System 80+, CESSAR-DC," Technical Specification, 3.4.3.

19. 10CFR50.46.

20. CENPD-138, Supplement 2-P, "PARCH, A FORTRAN-IV Digital Program to Evaluate Pool Boiling, Axial Rod and Coolant Heatup," January, 1977.

21. Chu, T-L, et. al., "PWR Low Power and Shutdown Accident Frequencies Program, Phase 1A - Course Screening Analysis," Brookhaven National Laboratory, Letter Report FIN L-1344, November 13, 1991.

APPENDIX A

RESPONSES TO

REQUESTS FOR ADDITIONAL INFORMATION

APPENDIX A

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APPENDIX A (Continued)

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* Response was previously submitted and is reproduced in Section A2.

A1.0 INTRODUCTION

Letters from the NRC that transmitted Requests for Additional Information (RAIs) on shutdown related topics are listed in Section 3.0 of this Appendix as References A-1 through A-6. ABB-CE provided individual responses to some of these RAIs in References A-7 through A-13 and A-15. These responses are reproduced in this Appendix. The remaining RAIs related to shutdown risk were listed in the ABB-CE letter, Reference A-14 along with a commitment to provide responses via this report. These responses are also given in this Appendix, where the response may refer to the content of applicable sections of this report. The combination of the specific responses provided in the Appendix along with the overall report content fulfills all outstanding commitments to provide shutdown risk information in support of the CESSAR-DC review process.

A2.0 RAIs

The following pages provide the usual format for question and response to the RAIs. Responses to all but one of the RAI's listed in the Table of Contents are provided. The one remaining response, to Question 720.98, will be submitted in the July 31, 1992 final submittal of this report.

Question 440.14:

Table B1.3-1 of Appendix B provides comparisons of severe accident frequency for System 80+ versus System 80. Recent scoping studies have indicated that events when not at power (i.e., shutdown) can provide a significant risk contribution.

Have these events been analyzed and incorporated into the PRA and if so provide relevant information in the summary table? If not evaluated, provide a schedule for submitting this additional analysis.

*Response 440.14:

A shutdown risk assessment is being performed for the System 80+ ALWR and will be provided to the NRC by July 31, 1992. This risk assessment includes a Shutdown PRA which is being performed using the methodology described in the revised EPRI PRA Groundrules and Key Assumptions Document. A comparison of the results for System 80+ and System 80 will not be possible because a Shutdown PRA is not available for the earlier plant.

*This response, and the mentioned risk assessment, supplement the previous response to this RAI in Reference A-15.

Question 440.16(a):

Generic Letter (GL) 87-12 requested information regarding lower RCS inventory operation. Please provide a response to the generic letter with respect to the System 80+.

*Response 440.16(a):

Generic Letter 87-12 requested each licensee of operating PWRs and holder of construction permits for PWRs to "provide the NRC with a description of the operation of [the] plant during the approach to a partially filled RCS condition and during operation with a partially filled RCS to ensure [the plant] meet[s] the licensing basis." The description provided in response to Generic Letter 87-12 was to include each of the following nine (9) items, which are in turn responded to.

Generic Letter Item 1:

A detailed description of the circumstances and conditions under which [the] plant would be entered into and brought through a draindown process and operated with the RCS partially filled, including any interlocks that could cause a disturbance to the system. Examples of the type of information required are the time between full-power operation and reaching a partially filled condition (used to determine decay heat loads); requirements for minimum steam generator (SG) levels; changes in the status of equipment for maintenance and testing and coordination of such operations while the RCS is partially filled; restrictions regarding testing, operations, and maintenance that could perturb the nuclear steam supply system (NSSS); ability of the RCS to withstand pressurization if the reactor vessel head and steam generator manway are in place; requirements pertaining to isolation of containment; the time required to replace the equipment hatch should replacement be necessary; and requirements pertinent to reestablishing the integrity of the RCS pressure boundary.

Response to Item 1:

Responses these items are provided in the Shutdown Risk Report; refer to Sections 2.1, 2.2. 2.3, and 2.5.

Generic Letter Item 2:

A detailed description of the instrumentation and alarms provided to the operators for controlling thermal and hydraulic aspects of the NSSS during operation with the RCS partially filled. [D]escrbied temporary connections, piping, and instrumentation used for this RCS condition and the quality control process to ensure proper functioning of such connections, piping and instrumentation, including assurance that they do not contribute to loss of RCS inventory or otherwise lead to perturbation of the NSSS while the RCS is partially filled. [A]lso provide a description of [the] ability to monitor RCS pressure, temperature, and level after the RHR function may be lost.

Response to Item 2:

The response to this item is provided in Section 2.8 of the Shutdown Risk Report.

Generic Letter Item 3:

Identification of all pumps that can be used to control NSSS inventory. Include: (a) pumps require[d] operable or capable of operation (include information about such pumps that may be temporarily removed from service for testing or maintenance); (b) other pumps not included in item a (above); and (c) an evaluation of items a and b (above) with respect to applicable TS requirements.

Response to Item 3:

The response to this item is provided in Sections 2.1, 2.2, 2.3 and 2.4 of the Shutdown Risk Report.

Generic Letter Item 4:

A description of the containment closure condition require[d] for the conduct of operations while the RCS is partially filled. Examples of areas of consideration are the equipment hatch, personnel hatch, containment purge valves, SG secondary-side condition upstream of the isolation valves (including the valves), piping penetrations, and electrical penetrations.

Response to Item 4:

The response to this time is provided in Section 2.5 of the Shutdown Risk Report.

Generic Letter Item 5:

Reference to and a summary description of procedures in the control room of [the] plant which describe operation while the RCS is partially filled. [The] response should include the analytic basis used for procedures development. [The staff is] particularly interested in treatment of draindown to the condition where the RCS is partially filled, treatment of minor variations from expected behavior such as caused by air entrainment and de-entrainment, treatment of boiling in the core with and without RCS pressure boundary integrity, calculations of approximate time from loss of RHR to core damage, level differences in the RCS and the effect upon instrumentation indications, treatment of air in the RCS/RHR system, including the impact of air upon NSSS and instrumentation response, and treatment of vortexing at the connection of the RHR suction line(s) to the RCS.

Example how [the] analytic basis supports the following pertaining to [the] facility: (a) procedural guidance pertinent to timing of operations, required instrumentation, cautions, and critical parameters; (b) operations control and communications requirements regarding operations that may perturb the NSSS, including restrictions upon testing, maintenance and coordination of operations that could upset the condition of the NSSS; and (c) response to loss of RHR, including regaining control of RCS heat removal, operations involving the NSSS if RHR cannot be restored, control of effluent from the containment if containment was not in an isolated condition at the time of loss of RHR, and operations to provide containment isolation if containment was not isolated at the time of loss of RHR (guidance pertinent to timing of operations, cautions and warnings, critical parameters, and notifications is to be clearly described).

Response to Item 5:

The response to this item is provided in Sections 2.1, 2.2, 2.3, 2.4, 2.5, 2.8, 2.9, 2.10 and 2.12.

Generic Letter Item 6:

A brief description of training provided to operators and other affected personnel that is specific to the issue of operation while the RCS is partially filled. [The NRC staff is] particularly interested in such areas as maintenance personnel training regarding avoidance of perturbing the NSSS and response to loss of decay heat removal while the RCS is partially filled.

Response to Item 6:

Operator training is the responsibility of the utility, since the material is plant specific and requires information concerning personnel organization and plant procedures. However, any information on avoidance of, and response to, a loss of decay heat removal that results from C-E's efforts preparing the Shutdown Risk Report will be included in procedure guidelines for the System 80+ plant. Refer to

Section 2.1 of the Shutdown Risk Report for detailed information.

Generic Letter Item 7:

Identification of additional resources provided to operators while the RCS is partially filled, such as assignment of additional personnel with specialized knowledge involving the phenomena and instrumentation.

Response to Item 7:

Per NUREG-0737, the Shift Technical Adviser shall be knowledgeable of, and thoroughly trained in, all aspects of abnormal operation. Since the Shift Technical Adviser will have access to all available information resulting from C-E's Shutdown Risk Assessment program, as well as thorough training, it is anticipated the Shift Technical Adviser will be a key person during partially-filled RCS operation. The identification of any additional resources beyond the normal complement of control room personnel is not the responsibility of the NSSS designer or Architect Engineer. C-E will, however, make any recommendations deemed appropriate to System 80+ licensees.

Generic Letter Item 8:

Comparison of the requirements implemented while the RCS is partially filled and requirements used in other Mode 5 operations. Some requirements and procedures followed while the RCS is partially filled may not appear in the other modes. An example of such differences is operation with a reduced RHR flow rate to minimize the likelihood of vortexing and air ingestion.

Response to Item 8:

The response to this item is provided in Sections 2.1, 2.2, 2.3 and 2.4 of the Shutdown Risk Report.

Generic Letter Item 9:

As a result of consideration of these issues, [licensees of operating PWRs and holders of construction permits for PWRs] may have made changes to [the] current program related to these issues. If such changes have strengthened [the] ability to operate safely during a partially filled situation, describe those changes...

<u>Response to Item 9</u>:

The response to this item is provided throughout the Shutdown Risk Report.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(b):

Please describe instrumentation provided to the operator during shutdown operations which characterize the state of the reactor coolant system (RCS). Include RCS level, RCS temperature, and shutdown cooling system (SCS) performance and provide a description of the appropriateness and accuracy of each instrument with respect to its intended function. Also, include identification of audible and visual alarms used to delineate out-of-range conditions, including the values which constitute those conditions.

*Response 440.16(b):

The response to this item is provided in Section 2.8 of the Shutdown Risk Report.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(c):

NUREG-1269 identified that containment was open throughout the April 10, 1987 event at Diablo Canyon, and there were no procedures to reasonable assure containment closure in the event of progression of the accident to a core damage condition. Address this situation with respect to the System 80+ design and the anticipated methods that will be used to operate the plant. Include such design considerations as the need for removal of the equipment hatch and improvements in the System 80+ design which facilitate rapid replacement of the hatch should the need arise. Similarly address other containment penetrations and potential bypass paths.

*Response 440.16(c):

The response to this item is provided in Sections 2.1 and 2.5 of the Shutdown Risk Report.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(d):

NUREG-1269 contains the statement "Design of the nuclear steam supply system (NSSS) did not appear to provide detailed provisions for mid-loop operation." Please address this identified deficiency in PWR design with respect to the System 80+ design. Include identification of and discussion of each of the design changes in the System 80+ which represents an improvement over existing designs and establish the adequacy of the System 80+ design for lowered RCS inventory operation.

*Response 440.16(d):

The response to this item is provided in Sections 2.3 and 2.4 of the Shutdown Risk Report.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(e) (Shutdown Operations):

NUREG-1269 identified that containment was open throughout the April 10, 1987 event at Diablo Canyon, and there were no procedures to reasonably assure containment closure in the event of progression of the accident to a core damage condition. Address this situation with respect to the System 80+ design and the anticipated methods that will be used to operate the plant. Include such design considerations as the need for removal of the equipment hatch and improvements in the System 80+ design which facilitate rapid replacement of the hatch should the need arise. Similarly address other containment penetrations and potential bypass paths.

*Response 440.16(e):

The NRC position on the subject of containment closure and plant procedural and design measures required to prevent and to mitigate the consequences of a Reactor Coolant System (RCS) overheating event during Cold Shutdown in preparation of and during Refueling was promulgated by Generic Letter No. 88-17, "Loss of Decay Heat Removal," dated October 17, 1988. In this guidance, the NRC set a limit of 2 hours for Combustion Engineering NSSS plants to establish containment closure, which constitutes isolation of all penetrations which could provide a release path for radioactive material, should the RCS overheat and boil. In a shutdown, refueling outage plant condition, release paths are the equipment hatch, the personnel locks, and any penetrations being tested or maintained. The guidance of the NRC Generic Letter 88-17 allows each plant to establish procedures and conduct closure drills to demonstrate that the 2-hour closure requirement is achievable. For purposes of design certification, release paths such as the equipment hatch and personnel locks, will be designed to be closable within 2 hours. The owner/operator will be responsible for employing the guidance of Generic Letter 88-17 to assure via procedures, drills, and administrative means that all containment release paths are closable within the prescribed 2 hours.

*This response was previously transmitted by Reference A-15.

Question 440.16(f):

The Diablo Canyon event and subsequently obtained information have shown operating procedures to be inadequate for lowered RCS inventory operation. What plans exist for recommending improved procedures and administrative controls to System 80+ owners/ operators so that this situation is eliminated. What changes will be made to the Emergency Procedure Guidelines (EPGs) (CEN-182) to accommodate this need?

*Response 440.16(f):

Sections 2.1 and 2.2 of the Shutdown Risk Report address Reduced Inventory Operating Guidelines and Technical Specifications. Emergency operating guidance for Reduced Inventory Operations are discussed throughout the Shutdown Risk Report. At present, there are no provisions to revise the EPG's (CEN-152). (See Response to RAI 440.141)

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(g):

What equipment exists in the System 80+ that can be used to assure adequate core cooling in the event of a complete loss of SCS?

*Response 440.16(g):

Section 2.4.3.1 of the Shutdown Risk Evaluation Report addresses shutdown event initiation and analyses. The discussion in this section examines event initiators, the design features which improve the SCS's resistance to initiators, the ability to recover from initiators and the equipment, operator actions, operating procedures and technical specifications to cope with a prolonged loss of the SCS's.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(h):

The Vogtle loss of all safety-related AC power event occurred in March 1990 and the NRC incident investigation team (IIT) identified many areas of concern involving shutdown operation and they are documented in NUREG-1410. Please address these staff concerns with respect to the System 80+ design.

*Response 440.16(h):

The major concerns raised in NUREG-1410 are:

(a) risk-management concepts applied to outage planning and scheduling during shutdown;

(b) power availability during shutdown modes;

(c) diesel generator instrumentation and control system availability;

(d) coping with the loss of DHR;

(e) technical specifications for reduced inventory operations.

Item (a) is addressed in general by most of the sections in the Shutdown Risk Evaluation Report. Item (b) is addressed in sections 2.4.3.1 and 2.4.3.2. Item (c) is addressed in section 2.4.3.3. Item (d) is addressed in section 2.4.3.1 and item (e) in sections 2.2 and 2.3.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(i):

Evidence exists that certain Technical Specifications (TSs) may not be optimum when consideration is given to operation during non-power conditions. For example, requirements for SCS suction valve interlocks impact upon SCS reliability, SCS flow rate requirements may overly restrict flow rate range and increase the likelihood of loss of SCS due to vortexing, and TSs written on the basis of the state of the NSSS and/or containment may be impacted. Please address this topic with respect to the System 80+ design and provide recommendations for improvement, particularly with respect to the unique design aspects of System 80+.

*Response 440.16(i):

Technical Specifications for shutdown modes are discussed in section 2.2 of the Shutdown Risk Evaluation Report.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.16(j):

Safety analysis reports (SARs) typically concentrate on power operation when consideration is given to many of the potential operational transients. The recent experience from the events in operating reactors indicated that further evaluation for plant operation at lower modes may be required. Hence, it may be prudent to address non-power operation in more depth than has been traditional. What plans exist, if any, with respect to this topic and the System 80+ program?

*Response 440.16(j):

The System 80+ program encompassed an extensive evaluation to assess the vulnerability of the System 80+ design to various transients. The results of this evaluation are provided in the System 80+ Shutdown Risk Evaluation Report. Sections 2.4, 2.5, 2.6, 4.0, 5.0, and 6.0 of this report present transient analyses covering the extent of events of concern for shutdown operations. Sections 2.4 through 2.6 concentrate on the loss of decay heat removal and rapid boron dilution events. Section 4.0 represents the evaluation of the impact of CESSAR-DC Chapter 15 events occurring during shutdown modes of operation. Section 5.0 represents the evaluation of the impact of the CESSAR-DC Section 6.3 loss of coolant accidents occurring during shutdown modes of operation. Section 6.0 evaluates the impact of the CESSAR-DC Section 6.2 events on the containment response when these events are initiated from shutdown modes of operation.

In addition, to supplement the above evaluations Section 3.0 of the System 80+ Shutdown Risk Evaluation Report presents a Probabilistic Risk Assessment which covers various event sequences which can occur during shutdown operations.

This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

<u>Question 440.35</u>:

Since operation with less than all 4 RC pumps is allowed during shutdown modes, discuss the effects of this initial condition on the CEA withdrawal event from these modes, particularly with respect to the pressure transient.

*<u>Response 440.35</u>:

The effect of an initial condition of less than all four reactor coolant pumps operating on the consequences of the CEA withdrawal is included in the evaluation of this event contained in Section 4.4.1 of the Shutdown Risk Evaluation Report.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.36:

Discuss the adequacy of a high neutron flux alarm to indicate a boron dilution event in sufficient time during Modes 3, 4 or 5.

*Response 440.36:

The high neutron flux alarm is activated when the SRM (Source Range Monitoring) ratio exceeds its setpoint. The SRM ratio is defined as follows:

$$\frac{\textit{Source Range Signal (t)}}{\textit{Source range signal at start of dilution}}$$

For Mode 3, 4 and 5 operation, time is calculated from event initiation to loss of shutdown margin. From this time, a selected operator action time which exceeds SRP criteria is subtracted to determine the latest allowable time for alarm actuation. The analysis ensures that at this time the SRM ratio will have exceeded its setpoint.

*This response was previously transmitted by Reference A-9. Changes have been made as noted by the bars in the margin.

Question 440.37:

Standard Review Plan 15.4.6 requires redundancy of alarms that alert the operator to an unplanned boron dilution event. Describe the redundant alarms available in each operating mode.

*Response 440.37:

The following pre-trip alarms are available for operational Modes 1 and 2: a high power or, under certain conditions, a high pressurizer pressure pre-trip alarm in Mode 1 or a high logarithmic power pre-trip alarm in Mode 2. Furthermore, a high RCS temperature alarm may also occur prior to trip. In operational Modes 3 through 6, a single failure proof boron dilution alarm will alert the operator to an unplanned boron dilution event.

In addition to the above mentioned alarms, there are also sampling and boronometer indications which would provide information in the case of a boron dilution event.

*This response was previously transmitted by Reference A-9. Changes have been made as noted by the bars in the margin.

Question 440.49

Provide a discussion of the procedures and plant systems used to take the plant from normal operating conditions to cold shutdown conditions. This discussion should include, heat removal, depressurization, flow circulation, and reactivity control.

*Response 440.49

The principal systems utilized in taking the plant from Mode 1, Power Operation, to Mode 5, Cold Shutdown are:

Reactor Coolant System
Feedwater System
Feedwater Control System
Reactivity Control System
Boron Control System
Chemical & Volume Control System
Shutdown Cooling System
Pressurizer Level Control System
Steam Bypass Control System
Pressurizer Pressure Control System
Liquid and Gaseous Waste Management Systems
Main Steam System
Condensate System

Reactivity control capability is discussed in Sections 7.7.1.1.1; 7.7.1.1.7; 9.3.4.1.3.3; 9.3.4.2.1 (last paragraph), and 9.3.4.2.3C. Power is reduced by increasing the boron concentration in the RCS to reduce k-effective to ≤ 0.99. At low power the rods are inserted. The operator borates to the cold shutdown boron concentration consistent with the Technical Specifications prior to the beginning of cooldown. This margin is maintained throughout cooldown by making up shrinkage volume by means of the CVCS with water at the cold shutdown margin boron concentration.

Cooldown is effected by the systems described, and techniques discussed in Sections 5.4.7.2.6.A; 9.3.4.2.3C; 7.7.1.1.2.1; 7.7.1.1.2.2; 7.7.1.1.4; 7.7.1.1.5 and 10.4.7.2.4. Additionally, the following precautions, limits and techniques are utilized during cooldown:

1. The reactor coolant pumps continue to run until they are manually tripped

   o Four RCPs shall not be operated below approximately 500°F

   o During cooldown RCP 1A and 1B shall be running to maintain pressurizer spray capability until they are required to be shutdown for some other reason

- o The RCPs shall not be operated when the system pressure is below cavitation or seal operation limits

2. The RCS pressure is maintained at 2250 psia until cooldown is initiated.

3. Pressurizer pressure and level controls are placed in manual mode at the beginning of cooldown, and power to heaters is reduced.

4. Core flow is maintained throughout cooldown by RCPs and/or shutdown cooling system pumps.

5. The bubble in the pressurizer is maintained as long as possible.

6. Volume Control Tank (VCT) gas space is vented to reduce fission gas and hydrogen gas prior to cooldown.

7. Letdown flow is directed, as required, to the gas stripper to remove dissolved gas.

8. Initially, heat is removed from RCS by dumping steam:

   - o Steam may be dumped to the condensers through the Steam Bypass System, or to the atmosphere through the Atmospheric Dump Valves (ADV).

   - o Feed control is in manual during cooldown using the startup pump and manual control valves.

   - o The MSIS setpoint is adjusted to 200 psi below existing steam pressure as cooldown progresses.

9. As RCS water cools, pressure is decreased by manually adjusting pressurizer spray to cool the vapor space. Pressurizer pressure is controlled such that saturation margin limit is not exceeded, and such as to comply with the pressure-temperature curves specified for the plant.

10. As pressurizer pressure decreases the SIAS & CIAS setpoints are decreased to 400 psi below existing pressurizer pressure.

11. RCS cooldown rate shall be maintained within Technical Specifications (TS) at all times during cooldown.

12. Pressurizer water temperature should exceed RCS water temperature by no more than 350°F and no less than 50°F whenever there is a bubble in the pressurizer.

Response 440.49 (continued)

13. Auxiliary pressurizer spray is utilized to reduce pressurizer pressure whenever normal spray is inadequate or not available.

14. When the pressurizer pressure is approximately 400 psia and the RCS temperature decreases to 350°F, cooldown is transferred to the Shutdown Cooling System (SCS). Cooldown from this point is fully described in Section 5.4.7.2.6A. Steaming and feed may be terminated.

*This response was previously transmitted by Reference A-12

Question 440.54:

Discuss the alarms and indications which would inform the operators that the SCS suction line isolation valve has closed while the plant is in shutdown cooling? Is there any common mode failure which would result in isolation valves in both trains being closed while in shutdown cooling? Are there any manual maintenance valves whose closure could isolate the SCS suction, if so, describe procedures and controls to restrict this possibility?

*Response 440.54:

The SCS suction line isolation valves are SI-651, SI-652, SI-653, SI-654, SI-655, and SI-656, as shown on CESSAR-DC Figure 6.3.2-1C. Valves SI-651, SI-653, and SI-655 are in line with shutdown cooling pump 1. Valves SI-652, SI-654, and SI-656 are in line with shutdown cooling pump 2. There are several alarms and indications to inform the operators that a SCS suction valve has closed while the plant is in shutdown cooling:

- Valve position indications is provided in the main control room.

- If a suction valve were to close, a drop in SCS pump flow for the affected train would actuate a low shutdown cooling flow alarm.

- SCS pump current and pressure indicators in the control room would indicate a loss of flow.

- Valves SI-651, SI-652, SI-653, and SI-654 are alarmed when not fully open with concurrent low RCS temperature (below the LTOP enable temperature).

There is no interlock to automatically close the SCS suction valves if RCS pressure increases during shutdown cooling operation. The suction valve interlock with pressurizer pressure described in Section 5.4.7.2.3.A.2 only provides a permissive open signal to allow the operator to open the valves when aligning the SCS.

Electrical power assignments are as follows (all valves can be powered from the emergency diesel generators or the alternate AC power source):

Valves SI-651 and SI-655 are on electrical train A.
Valve SI-653 is on electrical train C.
Valves SI-652 and SI-656 are on electrical train B.
Valve SI-654 is on electrical train D.

Because of the redundancy and diversity of power supplies, no postulated single failure would result in loss of shutdown cooling capability as one shutdown cooling train would remain operable.

Manually operated isolation valves SI-106 and SI-107 in the shutdown cooling pump suction lines are normally locked open and administratively controlled.

*This response was previously transmitted by Reference A-10.

Question 440.70

Describe the means provided for ECCS pump protection including instrumentation and alarms available to indicate degradation of ECCS pump performance. The staff's position is that suitable means should be provided to alert the operator promptly to possible degradation of ECCS pump performance. All instrumentation associated with monitoring the ECCS pump performance should be operable without offsite power, and should be able to detect conditions of low discharge flow.

*Response 440.70

The following instrumentation is used to determine Safety Injection and Shutdown Cooling pump performance. This instrumentation is shown in Figures 6.3.2-1A, B, and C and described in Section 6.3.5.3 of CESSAR-DC.

Channel	Function	Control Room Features
P-302, 305	SCS Pump Discharge Pressure	Indication
P-306, 307, 308, 309	SI Pump Discharge Pressure	Indication
P-319, 329, 339, 349	SI Line Pressure	Indication Alarm (High)
P-390, 391	SI Hot Leg Injection Pressure	Indication Alarm (High)
F-302, 305	SCS Line Flow	Indication Alarm (Low)
F-306, 307, 308, 309	SI Pump Discharge Flow	Indication Alarm (Low)
F-311, 321, 331, 341	DVI Nozzle Injection Line Flow	Indication
F-390, 391	SI Hot Leg Injection Flow	Indication

The normal power supplies for the above instrumentation are the 120 VAC vital I&C buses, which are powered from either the Class 1E 480 VAC buses or the 125 VDC buses through inverters (See CESSAR-DC Figure 8.3.2-2). If offsite power is lost, the Class 1E 480 VAC buses may be powered via the 4.16 KV safety buses by the emergency diesel generators (See CESSAR-DC Figure 8.3.1-1) or by the alternate AC power source (gas turbine).

Testing to confirm that SI and SCS pump performance is within specification is included in the Safety Injection System Test sections of Preoperational Tests, Section 14.2.12.1 of CESSAR-DC. In addition, Technical Specification 3.5.2 (CESSAR-DC Section 16.8.2) provides requirements for testing safety injection flowrates.

*This response was previously transmitted by Reference A-12

Question 440.86(f):

(f) Expand the table of assumed initial conditions to include the worst initial conditions for each event considering events occurring at all modes of plant operation.

*Response 440.86(f):

(f) The table of assumed initial conditions (of CESSAR-DC, Section 15.0) has been expanded to include the worst initial conditions for each event considering events occurring at all modes of plant operation. This expanded table is presented in Section 4.0 of the Shutdown Risk Evaluation Report.

*This response and the mentioned report section and CESSAR-DC change fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.91:

Most of the Chapter 15 and 6.3.3 (LOCA) analyses are performed based on the event being initiated at full power operation. The staff requires that C-E provide an assessment on the consequences of the transients and accidents initiated at low power levels or lower modes of plant operation such as shutdown operations. This is required to demonstrate that the analyses performed in CESSAR-DC are the bounding cases for all modes of plant operation.

*Response 440.91:

This assessment is provided in the System 80+ Shutdown Risk Evaluation Report. Section 4.0 of the report contains the assessment of CESSAR-DC Chapter 15 events and Section 5.0 contains the assessment of CESSAR-DC Section 6.3.3 events. Also see the response to RAI 440.16[illegible].

*The response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.109 (15.6.3)

Provide the results of an analysis for the potential boron dilution event during the recovering phase following a SGTR when backfill from the secondary system through the ruptured steam generator occurred.

*Response 440.109

The System 80+ Emergency Procedure Guides will include steps to prevent backfill from the secondary system through the ruptured steam generator by maintaining a positive pressure difference between the primary and secondary systems. (See Section 2.1 of the System 80+ Shutdown Risk Evaluation Report.) Therefore, boron dilution should not occur and has not been analyzed. A further note is made that backfill is not necessary to prevent overfilling of the larger System 80+ steam generator as the result of a SGTR event.

*This response was previously transmitted by Reference A-11. Changes have been made as noted by the bars in the margin.

Question 440.129 (Shutdown and Low Power Operations: USI A-45, USI A-31, GSI-99, GSI-22):

For the purpose of advanced reactor design reviews, the term shutdown risk encompasses operation when the reactor is subcritical or in transition between subcriticality and power operations up to five percent RATED THERMAL POWER; i.e., for the System 80+ design between MODE 6 and MODE 2 where the modes of operation are defined in CESSAR-DC Chapter 16, Table 1.1-1.

It should be noted that the NRC risk evaluation program is an ongoing study where the projected completion date is scheduled for the end of the 1991 calendar year. At such time, additional concerns not addressed in Generic Letter (GL) 88-17 will be emerging and additional measures may be required of the System 80+ design in order to ensure there is an adequate level of protection for the public health and safety during shutdown and low power operations. The following shutdown risk RAIs are supplemental to RAI 440.16 issued in December of 1990, and the corresponding responses should be specifically addressed in CESSAR-DC Appendix A and the associated sections of CESSAR-DC.

(GSI-99: Loss of RHR Capability in PWRs)

The System 80+ resolution of GSI-99 states that midloop operation heatup analyses are performed to provide a basis for operating procedure guidelines. In order to assure that NSSS behavior is fully understood under loss of decay heat removal (DHR) events in MODE 5 and MODE 6, please provide an assessment including the following analysis of the relationship between time after shutdown, decay heat, RCS heatup rate, and boil-off rate for the System 80+ design for shutdown conditions:

(1) Profile of total shutdown heat generation (fission and fission product decay heat) in terms of percent of RATED THERMAL POWER versus the time after shutdown from entry into MODE 2 up to 1 year following shutdown using the appropriate bounding reactor operating history parameters (i.e., cycle length, cycle burnup, etc...).

(2) Fuel rod heatup rate (F/minute) versus time after shutdown with the steam generator nozzle dams in place (with and without the pressurizers steam vent path (SDS and PSVs) operable).

(3) Time to reach a peak clad temperature of 2200 F versus time after shutdown (with appropriate assumption for initial rod temperature, hot rod, PLHGR, etc...)

(4) Time to core damage versus time after shutdown with the S/G nozzle dams in place (i.e. no reflux cooling), SDS vents open, and vessel head on/off. Also include the corresponding times

when bulk boiling is fully developed in the core for the above conditions.

Also provide a simplified RCS elevation reference diagram indicating minimum levels for RCS inventory for SCS use in mid-loop operation so as to preclude air binding/vortexing of the RHR pumps illustrating water levels and major systems and components including the reactor vessel, S/Gs, and pressurizer, top of core, etc...

*<u>Response 440.129</u>:

Analyses have been performed in order to understand the loss of decay heat removal events in Modes 5 and 6. For Mode 5 the RCS loops need not be filled and the maximum RCS temperature is 210F. For Mode 6 the RCS loops are not completely filled and the maximum RCS temperature is 135F.

<u>Decay Heat</u>

The earliest time for entry into Mode 5 operation, based on the maximum cooldown rate,is approximately 3.5 hours after shutdown. Long before that time the fission contribution to the total shutdown heat generation rate becomes negligible and the decay heat (fission products and actinides) constitutes the source of power from the core. Thus, this response addresses the time dependent decay heat generation rate.

The ABB-CE decay heat function is based on the model described in the ANS Standard 5.1 (Reference 440.129 -1). In addition, for decay times beyond 100,000.0 seconds the actinide portion of the decay heat is based on the actinide correction factor given in Reference 440.129 -2.

The decay heat profile as a function of time after shutdown is given in Figure 440.129-1 This profile has been used for the heatup analysis of fuel and coolant described below.

<u>Heatup of Fuel and Coolant</u>

The fuel rod and coolant heatup analysis has been performed with the assumption that the steam generator nozzle dams are in place (i.e. no reflux cooling). Also, the RCS pressure has been assumed to be one atmosphere. This assumption is appropriate for Mode 6 (vessel head closure studs less than fully tensioned or head removed). Also, this assumption is conservative for Mode 5 as a higher RCS pressure is associated with a higher fluid saturation temperature which results in a longer time to reach boiling after loss of shutdown cooling.

Heatup to Boiling

For Mode 5 the maximum fluid temperature cited in the Technical Specifications is 210F. This is close to the fluid saturation temperature (212F) at the assumed 1 atmosphere pressure. Hence, for Mode 5, the time to heatup to the fluid boiling point is approximately zero following loss of shutdown cooling. For Mode 6 the maximum fluid temperature cited in the Technical Specifications is 135F. For this initial condition the time to heatup to boiling has been analyzed for various assumed times of loss of shutdown cooling (referenced to the time of reactor shutdown). The assumed times of loss of shutdown cooling range from the earliest entry into shutdown cooling (3.5 hrs. after reactor shutdown) out to one year after reactor shutdown.

The heatup analysis accounted for the heatup of the core (UO2 and clad) mass and the mass of liquid in the vessel up to the bottom of the CSB nozzle (hot leg bottom). Credit was not taken for heatup of any liquid that may be in the RCS piping or for the mass of the vessel and internals up to mid-loop height. The time when bulk boiling is developed in the core as a function of time of loss of shutdown cooling is given in Table 440.129-1.

Boiloff of Liquid Above Top of Active Core

For both Modes 5 and 6 net boiling will deplete the liquid inventory. All portions of the core remain at the liquid saturation temperature until the top of the core is uncovered. Thereafter, the upper portions of the core receive some cooling from the flow of steam evolved in the lower portions.
For the present analysis it is conservatively assumed that the core hot spot is uncovered at the time that the liquid level drops to the top of the active core.

The time span for the liquid, between the bottom elevation of the CSB nozzle (bottom of hot leg) and the top elevation of the active core, to boil off is given in Table 440.129-1 as a function of time of loss of shutdown cooling.

Hot Spot Heatup

Heatup of the core hotspot is assumed to occur in an adiabatic fashion. Heat input to the hotspot is consistent with the long term axial power shape which is flatter than the worst axial shape that can occur under full power conditions.

The hotspot heatup rate as a function of time of loss of shutdown cooling is given in Table 440.129-2. This heatup spans the fuel rod temperature range from 212F (liquid saturation) to 1800F. Beyond 1800F the exothermic reaction between zirconium and steam adds significant amounts of heat to the clad and fuel. This causes the clad temperature to reach a value of 2200F in a time which is short relative to the time to rise to 1800F based only on long term decay heat. For this reason the time to reach a peak clad temperature of 2200F is taken to be consistent with the time to heatup to 1800F. Also this same time represents the time for core damage to occur.

Table 440.129-2 also gives the time span for the fuel rod to heatup to a temperature of 1800F as a function of time of loss of shutdown cooling. This time span includes the times for fluid and core heatup and liquid boiloff as given in Table 440.129-1.

Reactor Coolant System Elevations

Figure 440.129-2 shows the various elevations within the RCS related to midloop operation and boiloff to the top of the core.

*This response fulfills the commitment in Reference A-14 relevant to this RAI.

TABLE 440.129-1

TIMES TO BULK BOILING OF CORE LIQUID AND TO COMPLETE BOILOFF OF LIQUID ABOVE ACTIVE CORE

(All times in seconds)

Time of Loss of Shutdown Cooling	Time Span to Bulk Boiling in Core (Mode 6)*	Time Span to Boiloff of Liquid Above Active Core (Modes 5 and 6)	Total Time Span from Loss of Shutdown Cooling (Mode 5)	(Mode 6)
12,500. (3.5 hrs)	413.	714.	714.	1127.
50,000. (14 hrs)	558.	964.	964.	1522.
100,000. (1.2 days)	676.	1167.	1167.	1843.
500,000. (5.8 days)	957.	1653.	1653.	2610.
1,000,000. (11.6 days)	1460.	2522.	2522.	3982.
5,000,000. (8.3 days)	3150.	5441.	5441.	8591.
10,000,000. (16.5 weeks)	4546.	7852.	7852.	12,398.
31,536,000. (1 yr.)	10,256.	17,718.	17,718.	27,974.

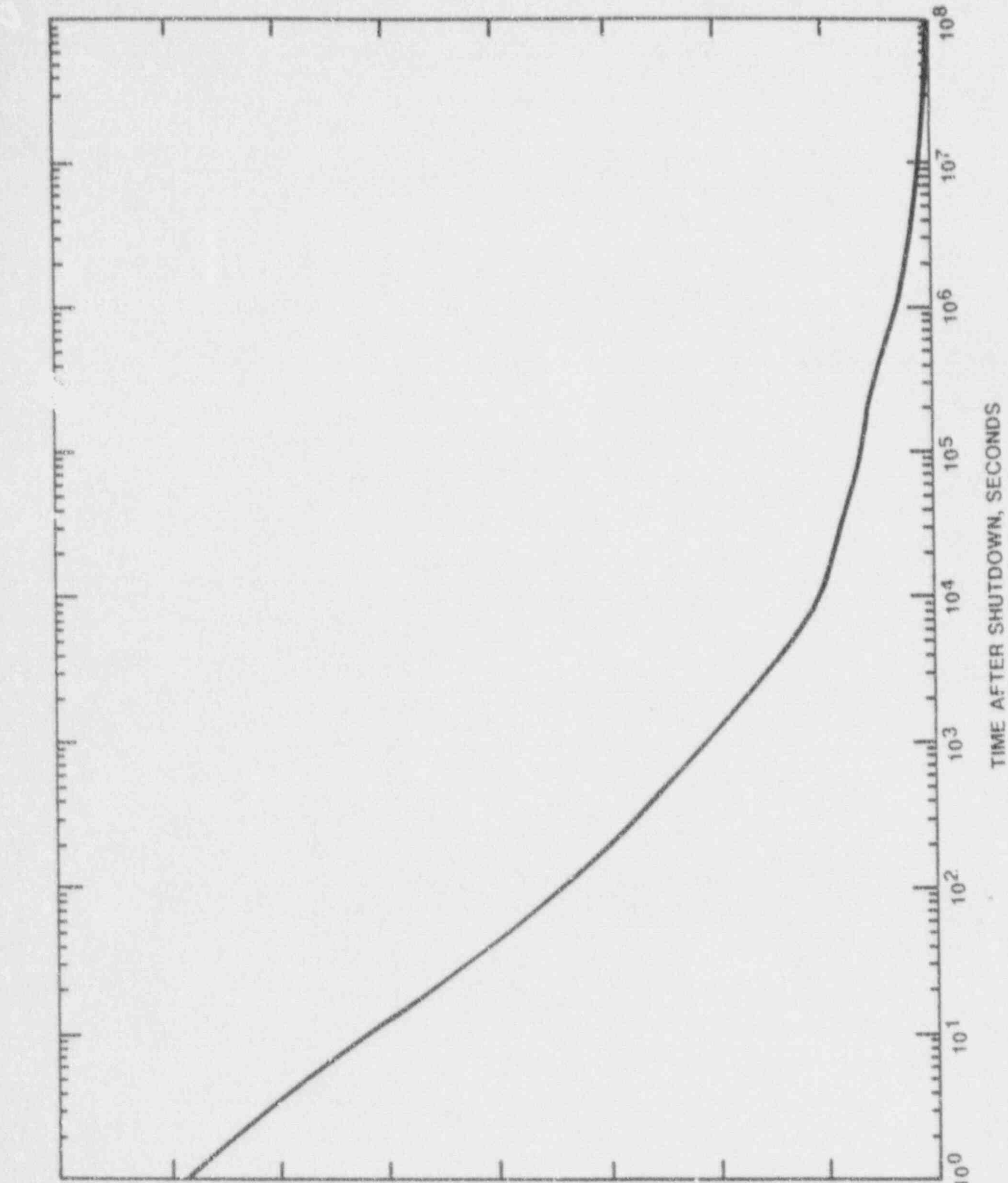
*For Mode 5 the coolant is essentially at the boiling point for the assumed 1 atmosphere pressure.

TABLE 440.129-2

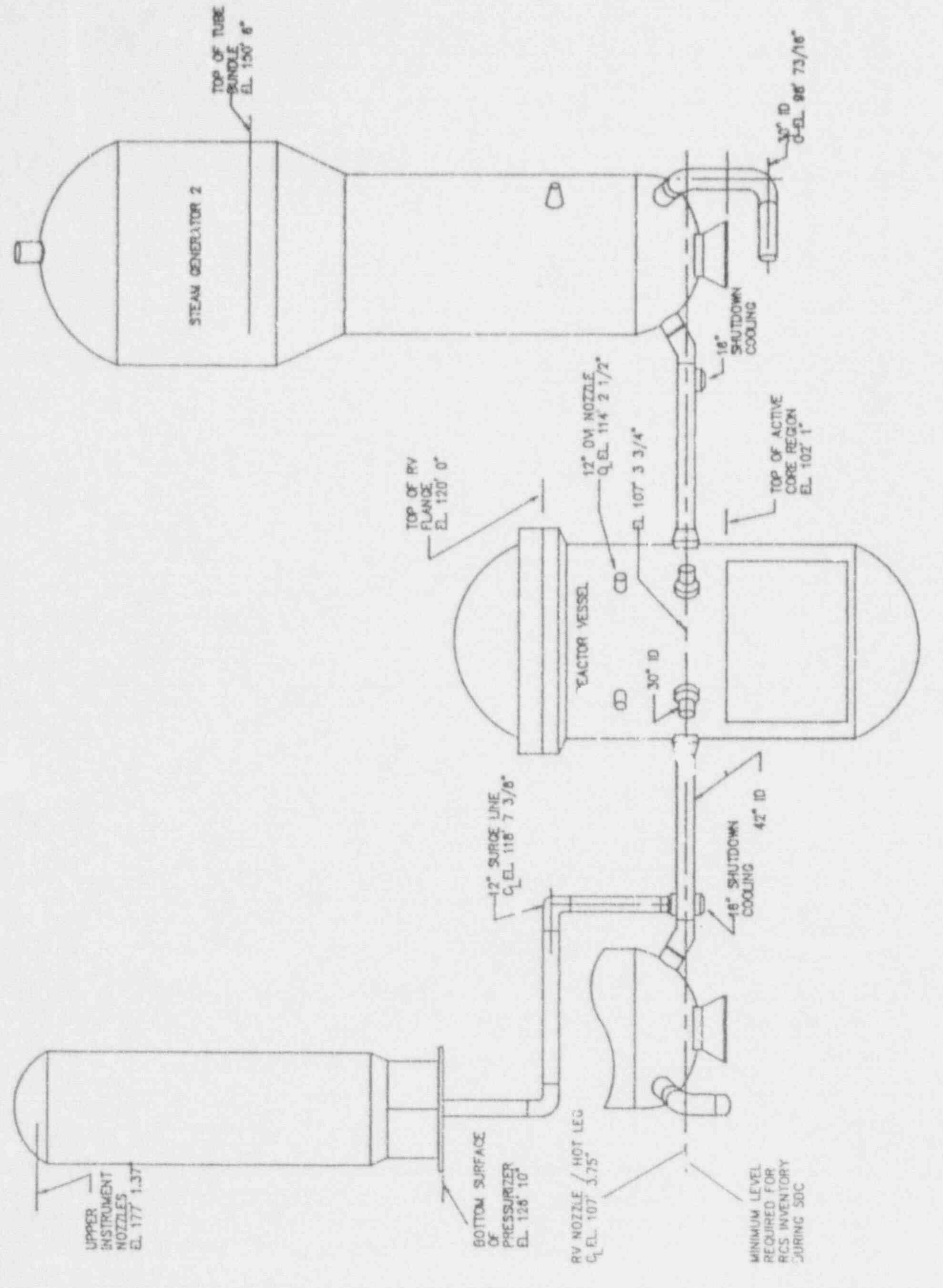
HOTSPOT HEATUP TO 1800F

(Times in seconds, rate in degrees F/min.)

Time of Loss of Shutdown Cooling	Hot Spot Heatup Rate (Modes 5 and 6)	Time Span to Reach 1800F (Modes 5 and 6)	Total Time Span from Loss of Shutdown Cooling (Mode 5)	(Mode 6)
12,500. (3.5 hrs)	138.	688.	1402.	1815.
50,000. (14 hrs)	103.	929.	1893.	2451.
100,000. (1.2 days)	85.	1125.	2292.	2968.
500,000. (5.8 days)	60.	1594.	3247.	4204.
1,000,000. (11.6 days)	39.	2431.	4953.	6413.
5,000,000. (8.3 days)	18.	5235.	10,676.	13,826.
10,000,000. (16.5 weeks)	13.	7562.	7852.	19,960.
31,536,000. (1 yr.)	5.6	17014.	17 718.	44,989.



SYSTEM 80+™	LCNG TERM DECAY HEAT INCLUDING ACTINIDES AND UNCERTAINTIES	Figure 440.129-1



SYSTEM 80+™

REACTOR COOLANT SYSTEM ELEVATIONS RELATED TO SHUTDOWN COOLING OPERATIONS

Figure 440.129-2

Question 440.130:

One of the actions provided in the System 80+ GSI-99 resolution is that containment isolation will be initiated if the RCS temperature reaches 200 F. What are the bases and analyses for determining this as the appropriate set point for containment isolation for the System 80+ design. Include consideration of personal hazards which may exist if boiling occurs in the RCS during closure operations. What alternate shutdown events, such as loss of coolant, might result in fuel damage and containment bypass prior to your assumed two hour closure period.

*Response 440.130:

The 200 F set point for containment isolation has been changed in CESSAR-DC to the initiation of containment isolation upon detection of the loss of decay heat removal capability. The methods used to detect the loss of decay heat removal capability are reviewed in Section 2.8 of the Shutdown Risk Report.

This change was based on the analyses reported on in Section 2.5 of the Shutdown Risk Evaluation Report that addressed the issue of the consequences of the loss of decay heat removal capability in Modes 5 and 6 and potential exposure of the public to radiation from an open containment.

The objective of this study was to compute the potential exposure to the public from an open containment following loss of core heat removal events in Modes 5 and 6 that could result in the coolant reaching saturation and boiling. The analyses assumed no operator intervention to recover core cooling. The analyses also assumed no credit for detection of the loss of decay heat removal before the coolant reached saturation.

Events were considered in Mode 5, at reduced inventory (loss of shutdown cooling at the earliest recommended time, 2 days, to achieve reduced inventory), Mode 5 at full inventory (a LOCA occurring within 2.4 hours of shutdown, resulting in earliest time to reach saturation), and Mode 6 in refueling configuration (loss of core cooling at the earliest recommended time, 3.5 days, to remove the head).

The time at which the containment must be closed was established by the limits on radiological exposure to the public, set by 10CFR100 as;

1. For pipe breaks, at full inventory, limiting site boundary dose to < 25 rem whole body dose and < 300 rem thyroid dose at the EAB after a two hour period following the start of the release,

2. For the reactor with loss of core cooling, limiting site boundary dose to < 2.5 rems, whole body, and <30 rem thyroid dose at the EAB after a two hour period following the start of the release.

The System 80+ containment has two personnel locks and one equipment hatch. Technical Specifications require that one of the two doors on each of the personnel locks and the equipment hatch be closed during Mode 5, at reduced inventory, and Mode 6 during refueling. The doors of the personnel locks require 10 minutes to close and seal. The equipment hatch is designed to close, without power, in an hour.

The time available for utility personnel to close the containment is determined considering radiation exposure and temperature limits within the containment for the events considered. These limits were based on;

1. Limiting whole body dose to utility personnel to < 2.5 rems.

2. Limiting internal dose to utility personnel to < 520 MPC per quarter,

3. Temperature limits inside containment based on a minimum work time of 10 minutes needed to close personnel hatches in Mode 5, at reduced inventory, and Mode 6, and 60 minutes to close the equipment hatch in Mode 5 at full inventory.

For Mode 5, at reduced inventory, the integrated two hour whole body and thyroid doses are below the acceptance limits of 2.5 rem (whole body) and 30 rem (thyroid). In addition, radiation and temperature within the containment are within limits to give utility personnel up to 30 minutes to evacuate and close personnel locks in the containment.

In Mode 5, for full inventory, the integrated two hour whole body and thyroid doses are below the acceptance limits of 25 rem (whole body) and 300 rem (thyroid). Internal radiation levels for utility personnel are within acceptable limits provided either air supplied or self-contained breathing units are used. Whole body dose is also within acceptance limits. Temperature within the containment are at levels that could limit the time available to utility personnel to close the containment equipment hatch within the assumed one hour period. Ways to decrease the time needed to close the equipment hatch and lengthen the work time within containment need to be evaluated: e.g., the use of fan coolers to reduce temperature, improved equipment hatch design to reduce closure time, review of procedures and training to reduce time to evacuate and close the containment.

In Mode 6, the integrated two hour whole body and thyroid doses are below the acceptance limits of 2.5 rem (whole body) and 30 rem (thyroid). Radiation and temperature levels in the containment should provide utility personnel up to 30 minutes to evacuate and close the personnel hatches in the containment.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.131

Since the System 80+ no longer has RWST gravity feed capability due to the location of the In-containment RWST, discuss other methods of restoring RCS water during midloop operations via gravity feed. Also, CESSAR-DC page A-45i states that a safety injection pump and "another means would be available during cold shutdown" to add water to the RCS. What is the other means and has this system/method been accounted for in the Technical Specifications?

*Response 440.131

The response to this item is contained in Sections 2.3 and 2.4 of the Shutdown Risk Report.

*This response and the mentioned report sections fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.132

It would appear necessary to modify the proposed ECCS Technical Specifications (CESSAR-DC Chapter 16) to reflect all shutdown operational modes with respect to the RCS makeup capability including midloop operations as recommended in Generic Letter 88-17 and adopted in the System 80+ proposed resolution of GSI-99. System 80+ GSI-99 resolution states that at least one safety injection train could be available during midloop and the System 80+ LTOP proposed T/S 3.4.11 states that a maximum of one SI pump shall be operable in MODES 4, 5, and 6. Why is only a single SI train desirable for this condition? (If the limitation of 1 SI pump for MODES 4, 5, and 6 is necessary for LTOP consideration, one other alternative available means would offer greater RCS makeup capability.) An appropriate T/S for SI train(s) operability for MODE 5 and MODE 6, reflective of LTOP concerns, should be proposed. Also, the proposed T/S 3.5.4 for the IRWST should specify a minimum IRWST level and boron concentration for MODE 5 and MODE 6 so that adequate net positive suction head (NPSH) is available should SI pump(s) actuation be necessary during MODE 5 and MODE 6.

*Response 440.132

Technical Specifications to address shutdown risk concerns are discussed in Section 2.2 of the Shutdown Risk Evaluation Report.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.133:

During midloop operations, if a SI pump is actuated due to loss of DHR, what System 80+ provisions are made to accommodate the added RCS mass and resulting pressure transient for MODE 5, and MODE 6? Is the low temperature overpressure protection (LTOP) system adequately sized to handle the load?

*Response 440.133

The low temperature overpressure protection (LTOP) valves, SI-179 and SI-189 shown in CESSAR-DC Figure 6.3.2-1C, are specifically designed to limit RCS pressure in response to a mass addition or energy addition transient during Modes 5 and 6. The analysis supporting the selection of the LTOP valve set pressure and rated flow rate is described in section 5.2.2.10 of CESSAR-DC. As described in CESSAR-DC Section 5.2.2.10.2.1 a mass addition transient is defined to include the inadvertent actuation of all four safety injection pumps and one charging pump when the RCS is in a water solid condition. Such considerations are conservative and bound the situation where the RCS is not water solid (as would be the case during midloop) and only one safety injection pump is actuated.

*This response fulfills the commitment in Reference A-14 relevant to this RAI.

Question 440.134 (16.0, GSI-99):

Since the safety despressurization system is a safety grade system, propose technical specifications for SDS operability for all appropriate modes of plant operation (include full power conditions).

Response 440.134

The safety depressurization system is not relied on for mitigation of Design Basis Events and, consequently, does not require a Technical Specification for operability.

Question 440.135:

What System 80+ provisions are there to make the on-site alternate AC power supply available during shutdown operations?

*Response 440.135

Since the System 80+ on-site alternate AC (AAC) power supply is a non-safety source of power, it is not considered applicable to be included in the plant Technical Specifications.

Under the guidance of NRC Generic Letter 88-17, "LOSS OF DECAY HEAT REMOVAL," however, the AAC power supply could be used to provide power supply flexibility needed to enhance availability of safe shutdown-maintaining equipment. Procedural and administrative control will be utilized in the comprehensive shutdown/refueling procedures/scheduling to ensure that adequate power supplies, including the AAC power supply, are readily available to power equipment required to maintain safe shutdown and refueling conditions. Such administrative directives and procedures developed by the owner/operator will base their instructions on a shutdown risk analysis for applicable conditions and incidents.

*This response fulfills the commitment in Reference A-14 relevant to this RAI.

Question 440.136:

In the event a SCS or DVI component is taken out of service for maintenance and the line downstream of the respective component is drained, are there any SCS or DVI line interfaces that have the potential for inadvertently refilling these lines with deborated water?

*Response 440.136

Issues involving boron dilution due to deborated water introduced into the RCS from the Shutdown Cooling System (SCS) or Safety Injection System (SIS) during maintenance of inline components, or due to the introduction of a deborated water slug during startup or refueling are addressed in section 2.6 of the Shutdown Risk Evaluation Report.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.137:

What analyses, if any, are performed in CESSAR-DC to address the potential for a loss of shutdown margin and consequences of a resulting power excursion caused by injection of a water slug with reduced boron concentration via an RCS loop, SCS line, or safety injection line during startup and refueling operations?

*Response 440.137

Section 2.6 of the System 80+ Shutdown Risk Evaluation Report addresses the potential for a consequences of the injection o_ an unborated water slug into the core. The results, the evaluation indicates that considering the injection of the largest credible unborated water slug, which was determined to be via the DVI lines, the core will remain subcritical.

*This response and the mentioned report section fulfill the commitment in Reference A-11 relevant to this RAI.

Question 440.139

As mentioned in RAI 440.109, discuss the potential for boron dilution during the recovering phase following a SGTR when backfill from the secondary system through the ruptured S/G occurs. This analysis should also be provided in support of GSI-22, CESSAR-DC Section 15.4.6, etc. ...

*Response 440.139

The issue of a "potential" boron dilution resulting from a SGTR accident was addressed in the response to RAI 440.109.

*This response was previously transmitted by Reference A-11

Question 440.140:

How will plant instrumentation be designed to operate properly during shutdown operations, and what key parameters will be monitored? The answer to this question should address particularly the issues of instrument availability and appropriate ranges for shutdown measurements, including:

a. A description for any deviations, bases and justifications of the deviations, from the Generic Letter 88-17 recommendations that each plant provide two independent RCS level indications, two independent core exit temperature measurements, the capability of continuously monitoring decay heat removal (DHR) system performance whenever a DHR system is being used for cooling the RCS, and visible and audible indications of abnormal conditions in temperature, level, and DHR system performance.

b. Indicate what instruments identified in resolution of GSI-99 (CESSAR-DC Appendix A) and CESSAR-DC Section 5.4.7 are classified as safety related and therefore within the scope of environmental qualification and quality assurance criteria. For those that are not so classified, provide a description of the quality assurance program that will be used to provide reliable instruments with accurate information in the expected ranges of shutdown measurements that will be enhance operator confidence in the instrument, and the training program for operators to understand and interpret and the data provided by the instruments.

*Response 440.140

The response to this item is provided in Sections 2.1, 2.2, 2.3 and 2.8 of the Shutdown Risk Report.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.141:

Emergency operating procedures (EOP) are generally developed for use in normal plant operation assuming the availability of the plant systems. During shutdown, however, many systems will be out for maintenance and the plant is in a different configuration. What is the CE System 80+ emergency procedure guidelines for the development of enhanced EOPs to provide better operator guidance for shutdown and low power operation? Are there any additional entry conditions to address shutdown and lower power operations? What will the scope of EOP enhancement be, and will they be symptom- or event-oriented?

Response 440.141:

A comprehensive assessment of risks associated with shutdown operations was performed for the System 80+ design and the results are summarized in the Shutdown Risk Report. Abnormal and accident events postulated to be initiated during shutdown operation were evaluated and means to prevent, detect and monitor them and to mitigate consequences were developed.

Based on this analyses, guidance was developed to respond to abnormal events initiated from shutdown conditions. The guidance is intended to be used for development by the plant owner/operator of appropriate procedures to govern shutdown operations. It is not intended to formally incorporate guidance for shutdown accident response into the EOPs, since the number of possible initiators and contributing occurrences is extremely large. The appropriate approach for reducing shutdown risks is to adequately plant outage activities and sequences, have sufficient means for monitoring the availability and performance of systems, and to use the diverse and redundant means incorporated in the design to mitigate consequences. These are addressed in the Shutdown Risk Report. Abnormal operating procedure or contingency actions produced by the plant owner/operator based on the plant designer's guidance are expected to be symptom oriented. Once the problem is identified, available success paths are evaluated and appropriate actions are taken to utilize available means for mitigation.

Question 440.142:

How has the plant design been enhanced to provide operators with adequate control of activities and plant conditions during shutdown? What design features reduce the likelihood of cross train maintenance errors (e.g., inadvertent isolation of the redundant train required to be operable) or the necessity of isolating multiple trains for component repairs?

*Response 440.142:

The System 80+ design features to reduce inadvertent errors and improve early operator evaluation of any failures resulting in a loss of coolant are:

1. Integrated Process Status Overview (IPSO) display with critical function and system status specific to the shutdown modes;

2. CRT displays with system lineups and component status;

3. Alarms that are dependent on plant mode and equipment status.

A more detailed description of System 80+ instrumentation that addresses shutdown conditions is presented in Section 2.8 of the System 80+ Shutdown Risk Evaluation Report.

In addition to design features, System 80+ has specific technical specifications and procedural guidance that are provided to reduce the likelihood of personnel errors. A detailed description is provided in Sections 2.1 and 2.2 of the System 80+ Shutdown Risk Evaluation Report.

The System 80+ plant arrangement, including the separation of redundant divisions tends to reduce the likelihood of cross train maintenance errors and the necessity of isolating multiple trains for component repairs. There is no communication between divisions, including piping.

A significant System 80+ design enhancement to the Shutdown Cooling System (SCS) is its dedication to the Decay Heat Removal (DHR) function. The system is comprised to two identical, redundant, and totally separate trains, each capable of performing the required DHR function. The System 80+ SCS components do not double for components in other safety systems during Modes 1 through 4. In particular, the system is not credited in the safety analysis as part of the safety injection system.

Dedicated heat exchangers have been provided in each SCS train. Previous designs required the SCS heat exchanger to double as the containment spray heat exchanger during Modes 1 through 4 and part of Mode 5. The System 80+ design eliminates the need for system realignment when entering into or securing from shutdown cooling. The elimination of these manual actions decreases the opportunity for operator error and uncertainty during Modes 5 and 6 when maintenance is performed.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.143:

Describe in detail what changes have been incorporated into CESSAR-DC Chapter 16 Technical Specifications (TSs) to deal with shutdown operations. Have these changes been considered:

a. TS conditions of risk-significant shutdown operation conditions.

b. Establishment of minimum requirements during shutdown operations including those that control containment, DHR system flow rate, equipment operability, operation and availability, and instrumentation.

In support of this response, you should provide supporting analyses that have been performed, for System 80+ to develop the technical bases for procedures, instrumentation installation and response, equipment/NSSS interaction and response, and Limiting Conditions for Operation of TSs relative to shutdown and low power operations.

Response 440.143:

Changes to the CESSAR-DC Chapter 16 Technical Specifications required as a result of shutdown risk assessment were developed to insure availability and operability of systems to prevent and detect abnormal and accident events, monitor system performance and mitigate consequences. A new set of TS were developed for reduced RCS operations in Modes 5 and 6. Technical bases for the TS modifications and additions were developed. Details of the TS changes are provided in Section 2.2 and technical bases in the remainder 2 of the Shutdown Risk Report.

<u>Question 440.144</u>:

What system design features have been incorporated in the System 80+ to increase the allowable water level operating band during mid-loop operation to prevent a loss of decay heat removal capability and water flooding the steam generator and containment?

*<u>Response 440.144</u>:

The response to this item is provided in Section 2.8 of the Shutdown Risk Report.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.145:

High steam velocity may prevent water from falling because of counter-current flow limit. In the event of a loss of reactor vessel inventory, can the configuration of upper internals in the System 80+ result in high steam velocity and prevent water in the refueling cavity from reaching the core?

*Response 440.145:

The response is to the shutdown risk evaluation for the effects of PWR upper internals are discussed in section 2.10 of the Shutdown Risk Evaluation Report. The analysis indicates that a sufficiently long period of time will exist before any steam is generated and that plant operators will have sufficient time to restore shutdown cooling. This is a consequence of water in the refueling cavity reaching the core by natural circulation through the upper internals thereby cooling the core and extending the time to boiling from several minutes to over 30 minutes for the highest anticipated initial coolant temperature. For lower initial coolant temperatures several hours are required to reach boiling.

*This response and the mentioned report section fulfill the commitment in Reference A-14 relevant to this RAI.

Question 440.146:

How did the plant design incorporate the consideration that outage and maintenance activities require only minimal isolation of important systems and components?

*Response 440.146:

The System 80+™ Design utilizes divisional separation of important systems and components to ensure the ability of the design to comply with the following recommendations of NRC Generic Letter 88-17, "LOSS OF DECAY HEAT REMOVAL:"

"(3) Equipment

(a) Assure that adequate operating, operable, and/or available equipment of high reliability is provided for cooling the RCS and for avoiding a loss of RCS cooling.

(b) Maintain sufficient existing equipment in an operable or available status so as to mitigate loss of DHR or loss of RCS inventory should they occur. This should include at least one high pressure injection pump and one other system. The water addition rate capable of being provided by each equipment item should be at least sufficient to keep the core covered.

"Reliable equipment is equipment that can be reasonably expected to perform the intended function."

To further enhance divisional separation, the System 80+™ Design utilizes four safety injection pumps to ensure the availability of at least one high pressure injection pump, as specified in (b) above. Additionally, the SIS design allows full flow pump testing without injecting water to the core, which minimizes RCS perturbations. The System 80+™ Design also allows shutdown cooling system pumps to be interchangeable with containment spray pumps, thus allowing further redundancy and flexibility in shutdown operations.

Because of the complete divisional separation of important systems and equipment in the System 80+™ Design, proper administrative control of maintenance activities together with the plant technical specifications will ensure that sufficient equipment and systems remain operational and available as required to maintain safe shutdown and refueling conditions.

*This response fulfills the commitment in Reference A-14 relevant to this RAI.

Question 440.147:

What design measures have been taken to ensure that demands on equipment during shutdown operations are consistent with equipment design operating range? You should consider the possibility of additional equipment which could be potentially useful during shutdown conditions if its control monitoring and operating parameters were appropriately selected during design.

*Response 440.147:

The System 80+™ Design fulfills the regulatory requirements of NRC Generic Letter 88-17, "LOSS OF DECAY HEAT REMOVAL," regarding level and temperature instrumentation compatibility with shutdown and refueling conditions and parameters. Instrument ranges will be such as to ensure sufficient accuracy for plant shutdown/refueling modes. The following statement will be added (part added underlined) to CESSAR-DC, Section 5.4.7.2.2.B, to clarify "a" on page 5.4-25:

"a. Two independent, highly reliable instruments are provided for RCS level management. These instruments function to monitor RCS level, to preclude SCS suction line vortexing and air entrainment. Level instrument ranges are optimized to encompass all reduced RCS inventory conditions."

One aim of the System 80+™ Design is to utilize equipment for specific and unique purposes. An example of this is the use of the Shutdown Cooling Pumps for shutdown cooling alone, instead of using the pumps for shutdown cooling and low head safety injection. However, in instances where equipment serves both plant operating and non-operating functions, the equipment will be specified for procurement so that the full range of design requirements is met. Additionally, operating guidance will be provided to the plant owners to ensure cognizance of the operating envelope of this equipment.

In addition, the CESSAR-DC design includes the following features to facilitate continued SCS operations during reduced RCS inventory:

a. Two independent, highly reliable instrument systems (dP based and HJTC based) are provided for RCS level measurement. These instruments function to monitor RCS level, to preclude SCS suction line vortexing and air entrainment. Level instrument ranges are optimized to encompass all reduced RCS inventory conditions.

b. Two independent thermocouples are provided to measure core exit temperature, with a large range optimized for SCS and refueling modes.

c. Instruments which will monitor the state of SCS performance (such as pump suction pressure, vortexing monitoring equipment, flow instrumentation and/or pump motor current) are provided. These instruments function to sufficiently eliminate SCS pump loss events by monitoring the formation of vortexing and subsequent air entrainment.

d. SCS suction isolation valves are not automatically closed in the event of an RCS pressurization during shutdown cooling. This precludes a loss of shutdown cooling by automatic closure of the isolation valves.

e. The plant design provides other means of initiating alternate cooling for loss of SCS events. The plant design also ensures that a vent pathway is available to prevent pressurization.

*This response fulfills the commitment in Reference A-14 relevant to this RAI.

Question 440.148:

Will there be any maintenance activities for the System 80+ that will require isolation of IRWST pump suction inlets (or allow foreign material in the sump with potential for blockage)? If s., this would preclude operation of safety systems. What guidance can be provided to minimize this potential risk? Have TSs been provided limiting such maintenance activities?

*Response 440.148:

No maintenance activities that will require isolation of the IRWST pump suction inlets are possible because the inlets will be submerged during all modes of operation. Maintenance in the IRWST is only possible during mode 6, when IRWST inventory has been transferred to the refueling pool. During refueling operations, the Shutdown Cooling System pumps utilize the IRWST ECCS suction connections to fill the refueling cavity. Due to NPSH and vortexing considerations, the suction inlets are sufficiently submerged to protect the SCS pumps while the pumps are in operation.

While maintenance is being performed in the IRWST, the possibility exists for foreign material to accumulate in the tank. The System 80+ design includes provisions to prevent this debris from entering or blocking the ECCS suction lines. The suction lines are isolated from areas of high maintenance (i.e., away from the IRWST spargers) to decrease the possibility that debris will reach the inlets. Large vertical screens capable of filtering particles greater than 0.09 inches diameter are located within the IRWST to effectively block debris. Should maintenance be required in areas where maintenance-generated trash would not be filtered by the debris screens, a mesh "cage" that completely surrounds the suction inlets would prevent debris from entering the lines. A complete discussion of this issue is provided in section 2.9.3 of the Shutdown Risk Evaluation Program Report.

Using procedural guidance provided by the plant designer in Section 2.1 of the final submittal of the System 80+ Shutdown Risk Evaluation Report, the owner-operator will develop plant specific procedures that require that maintenance-generated trash be removed from the IRWST before refilling the tank.

* This response supplements this report and together they fulfill the commitment to respond in Reference A-14.

Question 440.149:

Will there be procedures to prevent conducting those activities during lowered inventory operation that could perturb the RCS inventory or could lead to a loss of decay heat removal given a single malfunction?

*Response 440.149

The Shutdown Risk Evaluation Report examines ways in which losses of the SCS can occur in sections 2.4 and 2.12. Procedural recommendations to prevent, detect and mitigate such events are identified in Section 2.1.

* This response and the mentioned report sections fulfills the commitment to Reference A-14 relevant to this RAI.

Question 440.150:

For shutdown operations, what design modifications have been made to minimize the likelihood and consequences of loss of AC power during outage activities?

*Response 440.150:

AC Power reliability is discussed in the "System 80+ Shutdown Risk Evaluation Report". Please refer to Sections 2.4.3.2 and 2.4.3.3 of the report for a complete response to the question.

* This response and the mentioned report sections fulfill the commitment to Reference A-14 relevant to this RAI.

Question 440.151:

Several probabilistic safety assessment studies performed for low power and shutdown conditions for the existing plants indicated that losses of decay heat removal during mid-loop operation of PWRs and operator errors dominate the risk. Your response to RAI 440.14 has qualitatively described a number of System 80+ design enhancements to decrease shutdown risk. However, to demonstrate adequate treatment of the issue, CE should conduct an analysis that provides a structured evaluation specifically identifying the System 80+ design's vulnerabilities to shutdown and low power operations. This evaluation can take the form of a quantitative probabilistic assessment or an appropriately detailed engineering assessment. It is essential that the assessment be of sufficient depth to identify remaining significant shutdown and low power vulnerabilities and identify any potential corrective actions.

*Response 440.151:

As noted in the revised response to RAI 440.14, ABB-CE is performing a detailed Shutdown Risk Assessment including both a detailed engineering assessment and a Shutdown PRA. This assessment is included in the Shutdown Risk Evaluation Report and addresses both operator actions and reduced inventory operation.

* This response and the mentioned report sections fulfill the commitment to Reference A-14 relevant to this RAI.

Question 410.54:

The safety evaluation of both the new and spent fuel storage areas includes an evaluation of the effects of dropping a fuel assembly and its handling tool from a height of two feet above the storage rack. Provide the following additional information in accordance with SRP 9.1.2, Item III.2.e guidance: Verify that the drop of any allowed lighter loads at a greater height does not result in a higher potential energy than a fuel assembly and its handling tool dropped from its normal operating elevation. Perform an evaluation of this in accordance with SRP 9.1.4 guidance.

*Response 410.54:

The spent fuel racks have been evaluated and the results show that the rack k_{eff} will be less than .95 under the following postulated accident conditions:

(1) Drop of a fuel assembly handling tool from its maximum lift height over the fuel racks.

(2) Drop of a fuel assembly and the handling tool from their maximum lift height over the fuel racks.

(3) Drop of other items, such as a failed fuel canister with a fuel assembly, from their maximum lift height over the fuel racks.

*This response was previously transmitted by Reference A-13

Question 410.54

The response to RAI 410.54 is incomplete. Please provide the values for the maximum lifting height assumed for each case analyzed.

*Response 410.54

Lift heights and grapple weights are not known prior to final procurement of the refueling machine used in the fuel building. System 80+ spent fuel racks can absorb an impact energy of 93,100 inch-lbs without exceeding the rack K_{eff} criteria. The refueling equipment will be designed so that the maximum impact energy resulting from a dropped fuel assembly and handling tool, a dropped handling tool or any other dropped fuel handling related load from their maximum respective lift heights will not exceed the energy absorbing capacity of the fuel rack while maintaining K_{eff} criteria. In addition, the owner-operator, using procedural guidance provided by the plant designer in Section 2.1 of the final submittal of the System 80+ Shutdown Risk Evaluation Report, will develop administrative controls to limit the size and lift height of any other non-fuel handling loads that are carried over the fuel racks such that this maximum impact energy is not exceeded.

*This response was previously transmitted by Reference A-13. Changes have been made as noted by the bars in the margin.

Question 410.65

You have stated in Section 9.1.2.3.1.3 that one of the accidents considered in the design of the spent fuel pool storage racks is a fuel assembly and its handling tool "falling into a blocked-off fuel storage cavity." Supply additional information concerning the mechanical blocking assemblies to allow determination of the extent of penetration of a fuel assembly into a blocked cavity.

*Response 410.65

The spent fuel racks provide storage for 363 fuel assemblies in Region I (50% density) and 544 fuel assemblies in Region II (75% density). The restricted rack cells contain cell blockers which prevent the placement of a fuel assembly into the restricted cells. The racks have been analyzed based on a postulated accident condition of a fuel assembly fully inserted into a restricted cell. Taking pool boron concentrations into consideration, the results show that the rack k_{eff} is less than .95.

The cell blockers cannot be inadvertently removed once installed as special tooling is required to unlock and remove them from the spent fuel storage racks.

*This response was previously transmitted by Reference A-8

Question 410.66

Your submittal does not provide information concerning the handling of heavy loads in the vicinity of the spent fuel pool. Provide an evaluation of the capability of the spent fuel loading pit to withstand a dropped heavy load. The evaluation should include a shipping cask drop without breach of the pit area or loss of spent fuel pool water.

*Response 410.66

The spent fuel cask laydown area is separated from the spent fuel pool by a gate and a structurally reinforced concrete wall. The gate is closed, sealed, and locked during all cask handling operations. The floor in the laydown area has been designed to withstand the impact of a shipping cask dropped from a height of 30 feet without breaching the integrity of the floor plate.

Any small water loss as a result of local damage to the laydown area wall liner cannot be communicated to the spent fuel pool due to the closed gate and the integrity of the independent spent fuel pool liner. Damage to the gate is prevented during cask handling by stops on the bridge crane rail that limit cask travel and by the recessed gate design.

Design features to address the spent fuel cask drop accident are summarized in CESSAR-DC, Section 15.7.5, Amendment H.

*This response was previously transmitted by Reference A-8

Question 410.72

Provide the fuel building layout drawings which show the (1) overhead heavy load paths and (2) safety-related equipment locations in the vicinity of those paths susceptible to damage by failure of electrical interlocks, swinging of the load, or other mechanisms for causing damage.

* Response 410.72

The containment polar crane, the cask handling crane, and the fuel handling crane are designed to prevent the drop of a heavy load such as the reactor vessel head and the spent fuel shipping cask. In addition, predetermined load paths for major lifts (see Figures 9.1-19 and 9.1-20), operator training, and regular crane maintenance minimize the possibility of load mishandling.

Limit switches, electrical interlocks and mechanical interlocks prevent improper crane operation which might result in a fuel handling accident. This is also discussed in Section 9.1.4.2.1.1. The spent fuel cask handling hoist is restricted from movement over the new and spent fuel storage areas when the fuel racks contain fuel assemblies. The new fuel handling hoist is restricted from movement over the spent fuel storage area when the spent fuel racks contain fuel assemblies.

In accordance with the regulatory position of Regulatory Guide 1.13 and General Design criteria 61 of Appendix A to 10 CFR 50, the hoists are also restricted from passing over the spent fuel pool cooling system or ESF systems which could be damaged by dropping the load.

Set points for the hoist interlocks are set to preclude falling or tipping of the loads into the fuel storage areas.

Typically, administrative controls prepared by the Owner-Operator preclude movement of heavy loads within the containment building pool when the refueling machine contains a fuel assembly. During heavy load movement, the fuel transfer tube valve is closed to avoid water level changes in the fuel building during postulated accident conditions such as dropping the heavy load on the reactor vessel pool seal.

THe first sentence of the last paragraph of Section 9.1.4.3.1 has been modified to state: "Administrative controls prepared by the Owner-Operator..."

*This response was previously transmitted by Reference A-8

Question 410.73

Provide containment layout drawings showing the react. vessel head storage location, the upper guide structure storage stand, the load paths from the reactor to those locations, and safety-related equipment in the vicinity of the load paths susceptible to damage by load handling accidents.

* Response 410.73

Figure 9.1-19 depicts the load paths of the reactor vessel closure head, the core support barrel (CSB), and the upper guide structure (UGS) from the reactor vessel to their respective storage areas during the refueling outage. The designated load path for each component passes over the reactor vessel flange. An analysis has shown that in the event the reactor vessel head or the internals are dropped on the reactor vessel, the core will be maintained in a coolable condition.

Typically, operating procedures prepared by the Owner-Operator control the lift height of the UGS to minimize its clearance with the pool floor and the polar crane is positioned to insure direct travel from the reactor vessel to the UGS storage area. Additionally, the ICI holding frame is installed over the seal table at the operating floor level during fuel handling. This prevents the UGS from moving over the seal table. Therefore, operating procedures preclude the UGS from being lifted above the seal table or being closer than approximately five feet to the seal table, thereby making seal table damage a remote possibility. However, under a postulated load drop on the seal table, the seal table would fail resulting in containment pool draindown to the reactor vessel flange area. Since ICI tubes are only restrained laterally and not vertically, the tubes would be bent down to the level of the reactor vessel flange. Any tube failure, therefore, would in all likelihood be at or near the reactor vessel flange level which would result in a water level within the reactor vessel similar to that prior to reactor vessel head removal. The accident condition would not be any more severe than that analyzed for the reactor vessel head drop on the reactor vessel flange.

There are no other unprotected safety-related components within the load paths of the reactor vessel head, UGS and CSB. An unprotected component is defined as a component that is not protected by the pool walls and/or operating floor.

The transfer tube valve will be closed during these handling evolutions to preclude water level changes in the fuel building.

The following sentence will be added to the end of the first paragraph of Section 9.1.4.3.1: "The Owner-Operator's operating procedures will control the load paths and height of the reactor vessel closure head, the core support barrel and the upper guide structure above the pool floor.

*This response was previously transmitted by Reference A-8

Question 410.103

a. Section 9.1.1.1 states compliance with the "intent" of Regulatory Guide 1.13 as a design basis. Considering that Regulatory Guide 1.13 pertains to spent fuel storage, explain what parts of the Guide, and to what extent, are met by the new fuel storage design.

b. Section 9.1.1.3.3 states that "new fuel storage racks and facilities are qualified as Seismic Category I." Identify the "facilities" which are so qualified.

c. Section 9.1.1.2 does not provide sufficient descriptive information on features illustrated in the figures. For instance, what is the function of "L" insert slots and boxes? How are the "cell blockers" attached to the structure? What is the equipment in the "new fuel inspection area"? What is their seismic classification?

d. The new fuel storage capacity changed from 166 in Amendment E to 121 in Amendment I. What is the design basis for the storage capacity of the system?

e. According to SRP Section 9.1.1, the design of the new fuel storage facility is acceptable if the integrated design is in accordance with, among other criteria, General Design Criteria 61 and 62 of 10 CFR 50, Appendix A. Specific criteria necessary to meet the requirements of GDC 61 and 62 are ANS 57.1 and ANS 57.3 as they relate to the prevention of criticality and to the aspects of radiological design. Provide information on the extent of compliance of the design to ANS 57.1 and ANS 57.3.

f. According to SRP Section 9.1.1, design calculations should show that the storage racks and the anchorages can withstand the maximum uplift forces available from the lifting devices without an increase in k_{eff}. A statement in the Safety Analysis that excessive forces cannot be applied due to the design is acceptable if justification is provided.

g. It is the position of the Plant Systems Branch that the vaults and racks of the new fuel storage facility are to be designed to preclude damage from dropped heavy objects. Provide the design features included in the design which either preclude the fall of heavy objects onto the racks or preclude damage from a drop of the load with the maximum potential energy.

h. Reference to Section 9.1.1.3.1.2.D in Section 9.1.1.3.1.1, regarding potential moderators such as fire extinguishing aerosols, appears to be in error. Should it be 9.1.1.3.1.2.C?

i. According to SRP Section 9.1.1, the failure of non-seismic Category I systems or structures located in the vicinity of the new fuel storage racks should not cause an increase in k_{eff} beyond the maximum allowable. Provide analysis that this condition is met or include in your application a commitment to the above condition as a design criterion.

*<u>Response 410.103</u>

a. Although Regulatory Guide 1.13 pertains to the design of spent fuel storage racks, it is also used for the design of the new fuel racks. The applicable portions of the Regulatory Guide that are met are defined by Paragraphs 9.1.1.1.A and 9.1.1.1.C.

b. The "facilities" associated with new fuel storage consist of the storage vault and the rack restraint system. The seismic category of other building components associated with handling fuel assemblies is noted in Table 3.2-1. (see response to NRC RAI 210.1)

c. The L-insert slots are provided in the wall of the fuel rack cavity (box) to permit the L-insert to be locked to the fuel cavity by its locking tab after it has been installed. The design of the locking tab and slot is such that the L-inserts can be remotely removed from the fuel racks, if required.

The cell blockers are installed in the fuel racks before the fuel assemblies are placed in the fuel rack and before the pool is flooded. The design is basically two concentric tubes with end restraints that limit the engagement of the tubes in the rack cavity wall (to avoid protrusion into an adjacent fuel rack cavity). The tubes are collapsed, installed into the fuel rack cavity, expanded into the holes in the fuel rack cavity wall, then locked together with a captured pin. In this manner the cell blockers are positively locked to the fuel racks but can be remotely removed if desired.

*This response was previously transmitted by Reference A-13. Changes have been made as noted by the bars in the margin.

The new fuel inspection area is provided for the inspection of new fuel assemblies after they have been removed from their shipping container and before they have been placed in the fuel racks. It will contain a Seismic Category II inspection device to ascertain if the fuel assemblies meet the dimensional requirements for installation into the reactor vessel. Visual inspections will also be performed to check for shipping damage and to ensure that protective wrapping material has been removed.

d. The number of new fuel assemblies required for a 12 month refueling cycle, an 18 month refueling cycle, and a 24 month refueling cycle was evaluated. This evaluation disclosed that a 24 month cycle is controlling from the standpoint of the maximum number of new fuel assemblies required, i.e., 108. Since the rack structure is square, the minimum array to accommodate 108 fuel assemblies at a density of 50% is two 11 x 11 fuel rack modules or 121 fuel assemblies.

e. The fuel handling equipment located in the new fuel storage area meets the requirements of ANS 57.1. The new fuel racks meet the requirements of ANS 57.3.

f. The lifting capacity of the overhead crane that is used to remove new fuel assemblies from the new fuel rack is restricted by either adjusting the motor stall torque or using load limiting devices. (See paragraphs 9.1.1.3.1.1.D and 9.1.4.2.1.7.B).

g. The new fuel racks are located at the opposite end of the fuel building from the spent fuel pool to eliminate the possibility of moving heavy loads near the new fuel storage area. (See response to Question i). Using procedural guidance provided by the plant designer in Section 2.1 of the final submittal of the System 80+ Shutdown Risk Evaluation Report, the owner-operator will develop administrative controls to limit the size of the load that can be carried over the new fuel racks so that the design impact energy that the racks can absorb without affecting k_{eff} will not be exceeded.

h. The reference section of Section 9.1.1.3.1.1 that discusses potential moderators should be 9.1.1.3.1.2.B instead of 9.1.1.3.1.2.D. This change will be incorporated in the next submittal.

i. The new fuel storage racks are located in a concrete vault at the opposite end of the fuel building from the spent fuel pool area to preclude passage of the spent fuel shipping cask overhead crane over the racks during the handling operations associated with spent fuel inspection, handling, and shipping.

This location minimizes the number of systems or structures located in the vicinity of the new fuel storage facility. All systems or structures in the vicinity will be designated as Seismic Category II to preclude their failure and entry into the new fuel storage area.

The new fuel storage racks will be designed to limit the rack k_{eff} to 0.98 based on the postulated accident conditions and assumptions of Paragraph 9.1.1.3.1. Using the procedural guidance provided by the plant designer in Section 2.1 of the final submittal of the System 80+ Shutdown Evaluation Report, the owner-operator will develop administrative controls to prohibit carrying any load over the loaded fuel racks whose impact energy, if dropped, will exceed the impact energy of the postulated dropped fuel handling tool or the combination of the dropped fuel handling tool and fuel assembly. The maximum impact energy shall be limited such that dropped loads do not change the K_{eff} of the fuel array to more than 0.98.

Question 410.104(d):

(d) According to SRP Section 9.1.2, the design of the spent fuel storage facility is acceptable if the integrated design is in accordance with General Design Criterion 63, as it relates to monitoring systems provided to detect conditions that could result in the loss of decay heat removal capabilities, to detect excessive radiation levels, and to initiate appropriate safety functions. Acceptance for meeting this criterion is based on conformance with Paragraph 5.4 of ANS 57.2. Provide the design features which satisfy GDC 63 and discuss compliance with Paragraph 5.4 of ANS 57.2.

*Response 410.104(d):

(d) The design of the spent fuel storage facility meets the intent of Paragraph 5.4 of ANS 57.2. As an example, the facility incorporates monitoring systems to verify pool water temperature to ensure adequate fuel assembly cooling, radiation detectors to determine if radiation levels exceed predetermined setpoints and alarms to notify plant personnel of abnormal conditions.

*This response was previously transmitted by Reference A-13.

Question 410.107

a. Evaluate the structural design features of the refueling cavity water seal that would preclude a leak or failure from occurring. Include the possibility of a fuel assembly or other structure dropping on the seal.

b. If a seal failure/leak occurred, determine the time to lower a fuel assembly below the reactor vessel flange level before unacceptable dose rates from a lowered water level above spent fuel in the reactor core.

c. For a postulated seal failure/leak, evaluate containment dose rates from a lowered level above spent fuel in reactor core.

d. For a postulated seal failure/leak, evaluate the following parameters: makeup capacity, emergency procedures, fully loaded spent fuel pool thermal-hydraulic and dose effects including dose rate to someone trying to manually close the transfer tube valve to hydraulically isolate the spent fuel pool from the leak, time to cladding damage without operator action. Specifically provide the maximum allowable time to isolate the spent fuel pool from the transfer tube and refueling pool before there are unacceptably high dose rates in the spent fuel pool area and inadequate spent fuel pool cooling due to the level dropping below the minimum NPSH requirement above the elevation of the pool cooling suction inlet piping.

*Response 410.107

a. The refueling pool seal is designed to be installed in one piece between the reactor vessel flange and the pool floor. All fabrication welds will be liquid penetrant inspected prior to installation to ensure adequacy. After the seal assembly has been set in place, it will be permanently attached to the reactor vessel flange and to an embedment plate in the pool floor. Penetrations in the seal plate for ventilation and access to the ex-core instrumentation will be covered by bolted access hatches equipped with double seals when the pool is flooded. The annulus between the seals will be pressure tested after the hatches have been installed to determine the sealing adequacy.

*This response was previously transmitted by Reference A-13. Changes have been made as noted by the bars in the margin.

The pool seal is designed to withstand OBE displacements without leakage. The pool seal is designed to limit potential leakage resulting from SSE displacements. Pool seal inspection will be required as part of the post seismic recovery procedure. The pool seal is also designed to accommodate, without leakage, relative displacements between the pool floor and the reactor vessel due to normal plant operation.

During refueling operations with the pool flooded, the heavy lift components that pass over the pool seal are the reactor vessel head, the upper guide structure with its lift rig, and the upper guide structure lift rig. Administrative controls as provided in CESSAR-DC Section 9.1.4 require that prior to transfer of heavy loads over the pool seal, the fuel transfer tube valve or the gate between the fuel building transfer system canal and the spent fuel pool shall be closed. This is done to preclude any change to the spent fuel pool water level during a postulated heavy load drop on the pool seal which may result in containment pool draindown. In addition, administrative controls as provided in CESSAR-DC Section 9.1.4 preclude the movement of heavy loads over the pool seal if the refueling machine contains a fuel assembly. The refueling machine is designated seismic category II so that it will not fall on the pool seal during the seismic accelerations. The maximum clearance between the bottom of the refueling machine and the top of the pool seal is less than two inches to minimize the impact energy for the postulated accident condition of a dropped fuel assembly on the pool seal. The pool seal has been designed so that it will not leak as a result of this impact load.

b. It has been determined that a 24 square inch opening in the pool seal will result in pool draindown to the reactor vessel flange level in approximately 4 hours without additional water being added to the pool. It has also been determined that present plant systems are capable of maintaining the pool water level in the event there is a 24 square inch opening in the pool seal. A fuel assembly can be lowered below the reactor vessel flange level from the fully withdrawn position within 3 minutes.

c. With the water at the reactor vessel flange level, the radiation level at the pool seal area as a result of the fuel assemblies within the core will not be significantly greater than that with the reactor vessel head in place. The exposed CEA extension shafts will result in an increase in the overall radiation level. However, if it is necessary to do maintenance on the reactor vessel pool seal, temporary shielding can be placed around the extension shafts to reduce the radiation levels in the work area.

d. The responses to parts a, b, and c of this RAI address the concerns of this question.

Question 720.98 (Tasks 2.1.5, 2.1.8, 2.1.10, 2.1.11)

The bottom line core damage frequency estimate for the System 80+ design appears to be very low. Given these low estimates, address how the System 80+ PRA evaluated initiating events that have a lower frequency than those normally postulated, but may have more serious consequences. Examples include the question, "What does a 1E-5/yr steam generator tube rupture initiator look like and how is it handled in the PRA?", "What do various 1E-5 common cause failures look like, and how were they looked for and evaluated in the PRA?", and "What is the effect of multiple failures/equipment outages during modes other than full power?"

Response 720.98

The System 80+ PRA does not address initiating events with very low frequencies, in part because there is little information on what these initiating events might be. ABB-CE is currently updating the System 80+ PRA to reflect some system design changes. ABB-CE is willing to address this type of initiating event in the updated PRA. However, ABB-CE does request that the NRC provide some guidance as to how to identify a reasonable set of such initiators and the level and type of analysis expected. ABB-CE has evaluated the Shutdown Risk potential of System 80+ in response to other NRC requests for additional information (RAI). In that evaluation, equipment not specified to be available in the Technical Specifications was assumed to be out of service. Multiple failures of equipment are addressed in the event trees and fault trees. The results of the shutdown risk analysis show that the risk during shutdown is equal to the risk in normal operation.

Question 722.94:

Provide a description of the design of the equipment hatch and its ability to be rapidly reclosed during shutdown, if necessary. Include a discussion of the need for AC power or any other support systems in order to effect closure, and the pressure seal arrangement, ie., whether the hatch is pressure-seating as opposed to pressure-opening (which would require full bolting to accomplish sealing under pressure). Discuss any strategies/procedures for rapidly closing major penetrations during shutdown.

*Response 722.94:

The equipment hatch is described in the "System 80+ Shutdown Risk Evaluation Report". Please refer to Section 2.5.3.2.3 of the report for a complete response to the question.

* This response and the mentioned report sections fulfill the commitment to Reference A-14 relevant to this RAI.

Question 280.1

Provide the fire protection analysis and/or interface requirements to ensure that safe shutdown can be achieved, assuming that all equipment in any one fire area will be rendered inoperable by fire and that re-entry into the fire area for repairs and operator actions is not possible with exception of the control room. For the control room, provide the fire protection analyses and/or interface requirements having an independent alternative shutdown capability that is physically and electrically independent of the control room. Also, provide the fire protection requirements for redundant shutdown systems in the reactor containment building that will ensure, as much as practicable, that one shutdown division will be free of fire damage. Additionally, also ensure that smoke, hot gases, or the fire suppressant will not migrate into other fire areas to the extent that they could adversely affect safe shutdown capabilities, including operator actions.

*Response 280.1

A fire protection analysis of each fire area is conducted as part of the Fire Hazards Analysis. The System 80+ design basis, as stated in CESSAR-DC Section 9.5.1 (as revised in Amendment I), is to assure the ability to achieve Safe Shutdown following fire in any fire area outside of containment. This includes loss of all equipment in any given area and effects of electrical interaction which may disable equipment outside of the immediate area. The plant is arranged so that Safe Cold Shutdown can be achieved following fire in any area outside of containment without need for repairs or extraordinary operator action. Emergency shutdown from outside the control room is described in CESSAR-DC Sections 7.4.1.1.10 and 7.4.2.5. Outside of containment, redundant divisions of safety related equipment are separated by three hour fire rated boundaries. In the control complex (and most locations in the Nuclear Annex) redundant safety related divisions of protective electrical channels are separated by three hour fire rated barriers so that loss of all equipment in these areas would not affect either division of safety related equipment required to achieve cold shutdown. Inside containment Engineering Analysis conducted as part of the Fire Hazaro Analysis assure that fire at any location which can disable more than one channel of cold shutdown equipment will not affect the ability to achieve cold shutdown using equipment which would not be affected by fire at that location.

Smoke control is recognized as an important element of the Plant Fire Protection design features. In the subsphere area, containment, Fuel Pool building, Reactor Annex and Diesel Generator building the HVAC System has smoke control capability by allowing any area to be purged with 100% outside air. In the control complex, dedicated smoke exhaust fans are provided for the control room and TSC. In addition, a smoke exhaust system is provided for each channel of safety related equipment. A connection to the normal HVAC system intake is used for fresh air supply. Smoke detectors are installed in return air ducts to alarm and annunciate in the control room. Smoke dampers are arranged for remote operation from the control room.

The System 80+ design does not have connections (door or ventilation openings) between redundant safety-related divisions. This further mitigates the possibility that smoke and products of combustion of fire suppression agents will affect redundant safety-related equipment.

*This response was previously transmitted by Reference A-8

A3.0 REFERENCES

A-1 Letter, Reactor Systems Branch RAIs, T. V. Wambach (NRC) to E. H. Kennedy (C-E), dated December 24, 1990

A-2 Letter, Reactor Systems Branch RAIs, T. V. Wambach (NRC) to E. H. Kennedy (C-E), dated January 31, 1991

A-3 Letter, Reactor Systems Branch RAIs, T. V. Wambach (NRC) to E. H. Kennedy (C-E), dated May 13, 1991

A-4 Letter, Reactor Systems Branch RAIs, T. V. Wambach (NRC) to E. H. Kennedy (C-E), dated August 21, 1991

A-5 Letter, Plant Systems Branch RAIs, T. V. Wambach (NRC) to E. H. Kennedy (C-E), dated October 10, 1991

A-6 Letter, Risk Assessment Branch RAIs, T. V. Wambach (NRC) to E. H. Kennedy (C-E), dated October 30, 1991

A-7 Letter LD-91-013, E. H. Kennedy (C-E) to USNRC, dated March 15, 1991.

A-8 Letter LD-91-014, E. H. Kennedy (C-E) to USNRC, dated March 26, 1991.

A-9 Letter LD-91-019, E. H. Kennedy (C-E) to USNRC, dated May 6, 1991.

A-10 Letter LD-91-024, E. H. Kennedy (C-E) to USNRC, dated May 16, 1991.

A-11 Letter LD-91-062, E. H. Kennedy (C-E) to USNRC, dated November 27, 1991.

A-12 Letter LD-91-071, E. H. Kennedy (C-E) to USNRC, dated December 24, 1991.

A-13 Letter LD-92-017, C. B. Brinkman (C-E) to USNRC, dated February 12, 1992.

A-14 Letter LD-92-008, E. H. Kennedy (C-E) to USNRC, dated January 29, 1992.

A-15 Letter LD-91-018, E. H. Kennedy (C-E) to USNRC, dated April 26, 1991.

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APPENDIX B

PROPOSED REVISIONS TO THE ABB-COMBUSTION ENGINEERING

STANDARD SAFETY ANALYSIS REPORT-

DESIGN CERTIFICATION

B1.0 INTRODUCTION

The evaluations in the Shutdown Risk Evaluation Report and the responses provided in Appendix A to Requests for Additional Information (RAI's) have resulted in revisions to the ABB-CE CESSAR-DC. These proposed revisions are provided in this Appendix and will be incorporated into CESSAR-DC by a later Amendment.

B2.0 CESSAR-DC PROPOSED REVISIONS

The following pages from CESSAR-DC are marked with the proposed revisions.

APPENDIX B

TABLE OF CONTENTS

4. Shutdown Cooling Flow

A shutdown cooling flow indicator in each train of the SCS measures shutdown cooling flow, and indicates the flowrate in the control room. A low flow alarm is provided in the control room.

In addition, the CESSAR-DC design includes the following features to facilitate continued SCS operations during reduced RCS inventory:

a. Two independent, highly reliable instrument~~s~~ systems are provided for RCS level measurement. These instruments function to monitor RCS level, to preclude SCS suction line vortexing and air entrainment. Level instrument types and corresponding instrument ranges are optimized to encompass all reduced RCS inventory conditions.

b. Two independent thermocouples are provided to measure core exit temperature, with a range optimized for SCS and refueling modes.

c. Instruments which will monitor the state of SCS performance (such as pump suction pressure, vortexing monitoring equipment, flow instrumentation and/or pump motor current) are provided. These instruments function to sufficiently eliminate SCS pump loss events by monitoring the formation of vortexing and subsequent air entrainment. I

d. SCS suction isolation valves are not automatically closed in the event of an RCS pressurization during shutdown cooling. This precludes a loss of shutdown cooling by automatic closure of the isolation valves.

e. The plant design provides other means of initiating alternate cooling for loss of SCS events. The plant design also ensures that a vent pathway is available to prevent pressurization (see Section 6.7).

Although the features described above do not exclusively describe SCS system instrumentation, they are provided in this section since they focus on precluding RHR system failures due to loss of the SCS pumps.

Piping

All SCS piping is austenitic stainless steel. All piping joints and connections are welded, except for a minimum number of flanged connections that are used to facilitate equipment maintenance or accommodate component design. SCS piping is designed to accommodate venting the SCS pumps to the RCS, if necessary, with as few high points as practical. I

15. ACCIDENT ANALYSES

15.0 ORGANIZATION AND METHODOLOGY

This chapter presents analytical evaluations of the Nuclear Steam Supply System (NSSS) response to postulated disturbances in process variables and to postulated malfunctions or failures of equipment. Such incidents (or events) are postulated and their consequences analyzed despite the many precautions which are taken in the design, construction, quality assurance, and plant operation to prevent their occurrence. The effects of these incidents are examined to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations. Insert (A)

15.0.1 CLASSIFICATION OF TRANSIENTS AND ACCIDENTS

15.0.1.1 Format and Content

This chapter is structured according to the format and content suggested by Reference 1 and required by Reference 26.

15.0.1.2 Event Categories

Each postulated initiating event has been assigned to one of the following categories: H

A. Increased Heat Removal by Secondary System

B. Decreased Heat Removal by Secondary System

C. Decreased Reactor Coolant Flow

D. Reactivity and Power Distribution Anomalies

E. Increase in RCS Inventory

E. Decrease in RCS Inventory

G. Radioactive Release from a Subsystem or Component

The assignment of an initiating event to one of these seven categories is made according to Reference 26.

(A) All Modes have been considered.

initiation of containment isolation upon detection of the loss of RHR.

- o Plant communication systems are described in CESSAR-DC Section 9.5.2. The system normally used for plant shutdown operation and maintenance is the Intraplant Sound-Powered Telephone System. Phone jacks connect specific areas of the plant and the control room, and the system is powered from diesel-backed power sources. The communications panel in the control room is described in CESSAR-DC Section 18.7.4.13.

- o Redundant vent lines are provided between the pressurizer and the in-containment refueling water storage tank to prevent significant pressurization of the RCS if boiling occurs with the steam generator nozzle dams installed.

- o The SCS suction isolation valves do not have an auto-closure interlock. As described in CESSAR-DC Section 7.6.1.1.1, the valves are interlocked to prevent them from being opened if the RCS pressure has not decreased to an acceptable value. The interlocks are redundant so that no single failure can prevent the operator from aligning the valves in at least one SCS inlet line after RCS pressure requirements have been satisfied. I

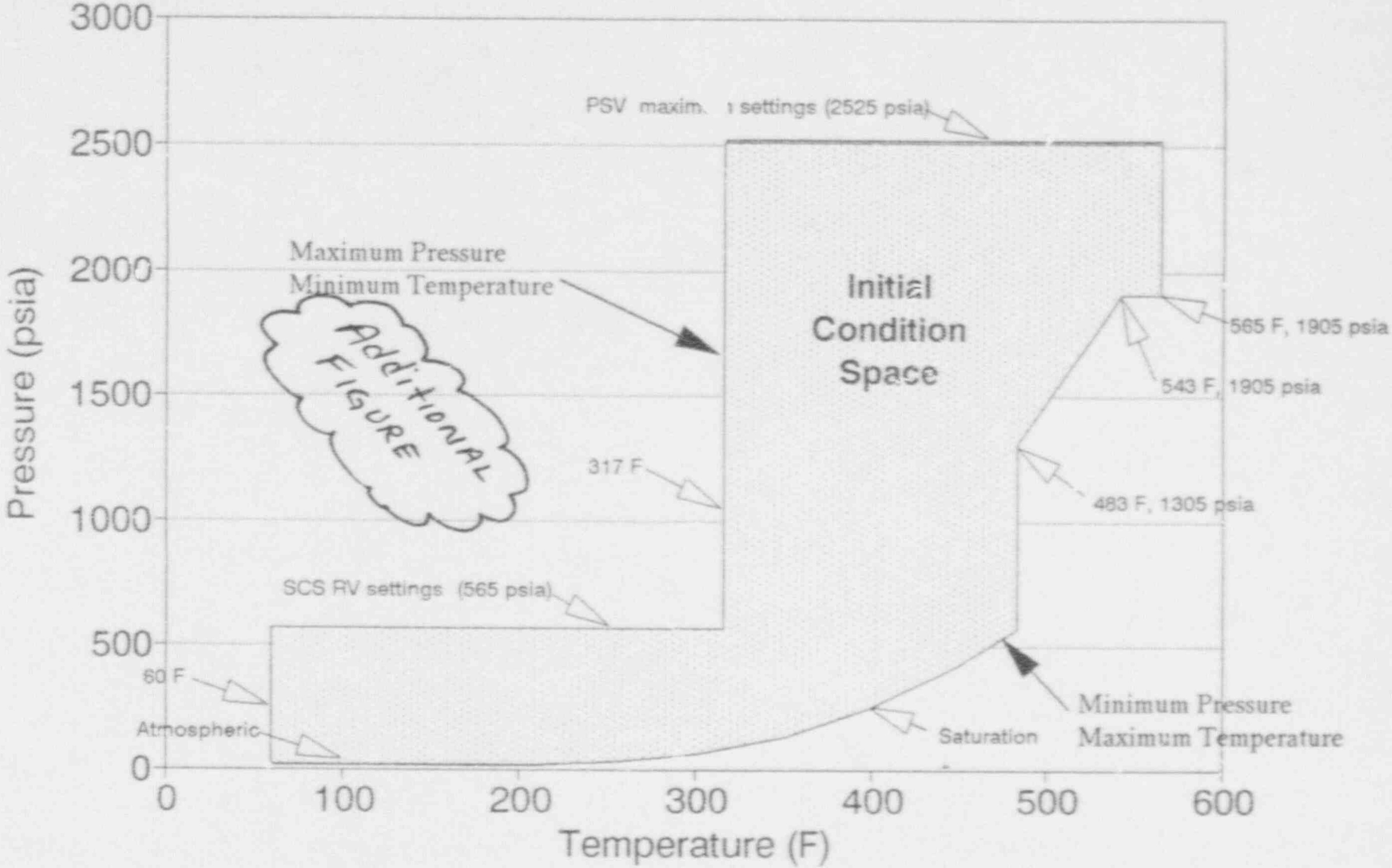
- o The plant design is such that both a high pressure safety injection pump and another means could be available during cold shutdown to add water to the RCS to mitigate loss of RHR capability or RCS inventory if needed.

In addition to the design features previously described, midloop operation heatup analyses are performed to provide a basis for operating procedure guidelines. These include the relationships between time after shutdown and decay heat, RCS heatup rate and boil-off rate. Guidelines are provided for reduced inventory operating and administrative procedures, including verifying availability of equipment, avoiding concurrent operations that perturb the RCS, and ~~closing containment if the RCS temperature reaches 200°F.~~ Instrumentation used during SCS operation with reduced RCS inventory is described in CESSAR-DC Section 5.4.7.2.6.

Since the foregoing design features and guidelines for operations with reduced RCS inventory meet the intent of the recommendations in GL 88-17, this issue is resolved for the System 80+ Standard Design.

REFERENCES

1. NUREG-0933, "A Status Report on Unresolved Safety Issues", U.S. Nuclear Regulatory Commission, December 1989.



SYSTEM 80+™

INITIAL CONDITIONS FOR PRESSURE AND TEMPERATURE IN MODES 3 THROUGH 6

Figure 15.0-2

TABLE 15.0-3

INITIAL CONDITIONS

Core Power	% of 3800 MWt	0 to 102[1]
Axial Shape Index	--	$-0.3 \le$ ASI $\le +0.3$[2]
Reactor Vessel Inlet Coolant Flow Rate	% of 445600 gpm	95 to 116[3]
Pressurizer Water Level	% distance between upper tap and lower tap	26 to 60[4]
Core Inlet Coolant Temperature		
<90% Power	°F	543 to 565[5]
≥90% Power	°F	553 to 563
Pressurizer Pressure	psia	1905 to 2375[5]
Steam Generator Water Level		
Low	% Wide Range[6]	33.7[8],[9] 40.7
High	% Narrow Range[7]	95.0

(1) Core power is that due to decay heat in Modes 3 through 6.
(2) ASI = (area under axial shape in lower half of core - area under axial shape in upper half of core)/(total area under axial shape). A range of values of ASI from -0.6 to +0.6 was considered for subcritical core conditions.
(3) For Modes 3 through 6 see TABLE 15.0-3a.
(4) Between 0 and 100 % in Modes 4 and 5. Pressurizer is empty in Mode 6.
(5) For Modes 3 through 6 see Figure 15.0-2.
(6) Percent of distance between the wide range instrument taps. See Chapter 5 of CESSAR-DC for details.
(7) Percent of distance between the narrow range instrument taps. See Chapter 5 of CESSAR-DC for details.
(8) For steam and feedwater line breaks only.
(9) ≥ 25% SG water level in Modes 3 and 4 and in Mode 5 for loops filled and additional RCS loop/SDC division not OPERABLE. Not applicable for Mode 5 with loops not filled and Mode 6.

Additional TABLE

TABLE 15.0-3a

Reactor Vessel Inlet Coolant Flow Rate

MODE	SYSTEM	FLOW RATE (%)
3	RCP	33 to 116
4	RCP	33 to 116
	SCS	0.94 to 2.24
5 (Loops Filled)	RCP	33 to 116
	SCS	0.94 to 2.24
5 (Loops Not Filled)	SCS	0.22 to 2.24
6	SCS	0.94 to 2.24

Additional Table

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APPENDIX C

PROCEDURAL GUIDANCE TO SUPPORT REDUCED RCS INVENTORY OPERATIONS

REDUCED INVENTORY OPERATIONAL GUIDANCE

1.0 OBJECTIV~

Append' C provides guidance to develop reduced inventory operati _ guidelines and procedures. It contains information provided by the plant designer based on analysis and review of reduced inventory operations.

2.0 INITIAL CONDITIONS

2.1 The reactor is subcritical, [K_{eff} < .99] for greater than (96 hrs).

2.2 RCS core exit temperature [< 150°F].

2.3 RCS level > El. [117'-0"].

2.4 Technical specification surveillance requirements for reduced inventory are met.

2.5 Maintenance activities are not being performed on the shutdown cooling system or the operable containment spray pump.

3.0 PRECAUTIONS

3.1 Reduced inventory operations duration should be minimized due to reduce risk of core uncovery due to the loss of decay heat removal.

3.2 Perturbations affecting RCS level should be minimized during reduced inventory operations to minimize the possibility of loss of decay heat removal capabilities.

3.3 Isolation (closure of a containment isolation valve) in the non-operating loop can reduce the possibility of an inadvertent draindown to the RCS.

3.4 Operations directly affecting the reactor vessel pressure boundary, i.e. In-core Instrumentation Seal Table evolutions, shall be minimized during mid-loop operations.

4.0 OPERATIONAL GUIDANCE

4.1 Verify RCS vent path established per Technical Specification (3.10.3).

4.2 Verify that the shutdown cooling/containment spray cross connection isolation valves are administratively closed.

4.3 Perform the RCS drain procedure to lower RCS level to the desired reduced inventory elevation identified below:

Scheduled Maintenance Activity	RCS Elevation
S/G cold leg nozzle dams	[ ]
S/G hot leg nozzle dams RCP seal housing removal	[ ]
DVI nozzle 2A or 2B valve maintenance	[ ]

4.4 Monitor the following RCS/SDC system parameters during reduced inventory operations.

RCS core exit temperature	[List instruments]
SDC system flow rate	[ ]
RCS boron concentration	[ ]
SDC system temperature	[ ]
RCS pressure	[ ]
RCS level	[ ]

NOTE

Decay heat production decreases steadily with time after shutdown. Shutdown cooling system flow rate should be throttled to match heat removal requirements to reduce the possibility of vortexing.

4.5 Adjust SDC flow rate to match decay heat removal requirements. Minimum flow must be maintained > (3000 gpm).

4.6 Perform the scheduled maintenance activities while in the reduced inventory mode.

NOTE

Should reduced inventory maintenance require the installation of S/G nozzle dams, the cold leg dams shall be installed first, prior to the hot leg dams and removed last, after hot leg nozzle dam removal.

4.7 After the completion of the desired maintenance activities, restore RCS level to greater than elevation [117'-0"] per the applicable RCS make-up procedure.

5.0 ABNORMAL OPERATING CONDITIONS

5.1 Loss of shutdown cooling flow.

NOTE

There are a number of potential initiators that lead to the loss of shutdown cooling flow. The more probable initiators and the immediate actions to restore decay heat removal are discussed below.

A. Pump failure, i.e., bearing failure, motor failure, shaft breakage, etc.

Actions

1. Verify RCS level > minimum RCS level [El -xxx]

2. Align the alternate SDC division, if required, for decay heat removal.

3. Start alternate division SDC system pump and verify decay heat removal capability.

4. Align the containment spray pump in the failed division for operation; hold system in standby.

5. Determine cause of SDC pump failure and determine most reliable means (division) of heat decay removal. Realign plant systems, if required, to support decay heat removal operation. If technical specification surveillance requirements/LCOs cannot be met, actions should be taken to raise RCS level to > elevation [117'-0"] as soon as possible.

B. SDC flow degradation due to vortexing

1. Secure the operating SDC pump.

2. Restore RCS level using one or more of the systems identified below. The methods of level restoration are specified in the order of preference:

   a. Operable safety injection system

   b. Alternate SDC system via IRWST (requires manual valve realignment)

   c. Operable containment spray pump

d. Charging pump alignment to the BAST or designated alternate borated water source (verify boron concentration and level before use)

e. Safety injection tanks (verify level before use)

3. Start alternate division SDC system pump and verify decay heat removal capability.

4. Vent (if necessary) and verify containment spray pump operability as backup to SDC pump.

5. Vent failed loop SDC system pump.

6. Determine most reliable means (division) of decay heat removal. Realign plant systems, if required, to support decay heat removal operation. If technical specification surveillance requirements/LCOs cannot be met, actions should be taken to raise RCS level to > elevation [117'-0"]- as soon as possible.

C. Inadvertent SDC pump suction isolation valve closure

1. Align, if necessary, and start the alternate SDC division pump to restore decay heat removal.

2. Realign the failed division flow path. If the SDC pump cannot be aligned, align the failed division containment spray pump.

3. Determine most reliable means (division) of decay heat removal. Realign plant systems, if required, to support decay heat removal operation. If technical specification surveillance requirements/LOCs cannot be met, actions should be taken to raise RCS level to > elevation [117'-0"] as soon as possible.

D. Loss of offsite power/station blackout

1. Align, if necessary, and start the alternate division SDC pump if power is available to the alternate pump.

2. If no power is available, restore power immediately.

3. Verify diesel generator operation and align/start the applicable division SDC pump to restore decay heat removal.

4. Start and align the combustion turbine, if available, to the Class 1E buss.

5. Determine most reliable means (division) of decay heat removal. Realign plant systems, if required, to support decay heat removal operation. If technical specification surveillance requirements/LOCs cannot be met, actions should be taken to raise RCS level to > elevation [117'-0"] as soon as possible.

5.2 Loss of coolant inventory

1. Stop/isolate leak.

2. Secure the operating RHR pump if vortexing is indicated.

NOTE

In the event of decay heat removal interruption due to the loss of forced shutdown cooling flow, alternate methods of decay heat removal, i.e., S/Gs (if available) should be considered.

3. Restore RCS inventory as described in Section 5.1.B.2.a through e.

4. Restore SCS flow after inventory recovery and associated venting operations are completed.

APPENDIX D

TECHNICAL SPECIFICATION MARKUPS OF LCO AND APPLICABILITY FOR SHUTDOWN OPERATIONS

APPENDIX D

TABLE OF CONTENTS

1.1 DEFINITIONS (continued)

Term	Definition
CONTAINMENT SHIELD BUILDING INTEGRITY (continued)	c. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O-rings) is OPERABLE.
CONTROLLED LEAKAGE	See LEAKAGE-CONTROLLED.
CORE ALTERATION	CORE ALTERATION shall be the movement or manipulation of any fuel, sources, or reactivity control components [excluding CEAs withdrawn into upper guide structure] within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe conservative position.
Division DOSE EQUIVALENT I-131	(see attached) DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) which alone would produce the same thyroid dose as the quantity and isotropic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites".
$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives greater than 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.
ENGINEERED SAFETY FEATURE RESPONSE TIME	The ENGINEERED SAFETY FEATURE RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its actuation setpoint at the sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required

(continued)

1.1 DEFINITIONS (continued)

Term	Definition
ENGINEERED SAFETY FEATURE RESPONSE TIME (continued)	positions, pump discharge pressures reach their required values, etc.) Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any sequence of sequential, overlapping, or total steps such that the entire response time is measured.
Estimated Critical Position	(see attached)
IDENTIFIED LEAKAGE	See LEAKAGE-IDENTIFIED.
KN-1	(see attached)
LEAKAGE-CONTROLLED	CONTROLLED LEAKAGE shall be the seal water flow from the reactor coolant pump seals.
LEAKAGE-IDENTIFIED	IDENTIFIED LEAKAGE shall be: a. Leakage, except CONTROLLED LEAKAGE, into closed systems, such as pump seal or valve packing leaks that are captured and conducted to a sump or collecting tank, or b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems, or not to be PRESSURE BOUNDARY LEAKAGE, or c. Reactor Coolant System leakage through a steam generator to the secondary system.
LEAKAGE-PRESSURE BOUNDARY	PRESSURE BOUNDARY LEAKAGE shall be leakage, except steam generator tube leakage, through a non-isolable fault in a Reactor Coolant System component body, pipe wall, or vessel wall.
LEAKAGE-UNIDENTIFIED	UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE or CONTROLLED LEAKAGE.
MID-LOOP	(see attached)

(continued)

1.1 DEFINITIONS (continued)

Term	Definition
PRESSURE BOUNDARY LEAKAGE	See LEAKAGE-PRESSURE BOUNDARY.
PROCESS CONTROL PROGRAM	PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, tests, and determinations to be made to ensure that processing and packaging of solid radioactive wastes (based on demonstrated processing of actual or simulated wet solid wastes) will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.
RATED THERMAL POWER	RATED THERMAL POWER (RTP) shall be a total reactor core heat transfer rate to the reactor coolant of 3800 MWt.
REACTOR PROTECTION SYSTEM RESPONSE TIME	The REACTOR PROTECTION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power is interrupted to the CEA drive mechanism.
REPORTABLE EVENT	A REPORTABLE EVENT shall be any of those conditions specified in 10 CFR 50.73.
RCS REDUCED INVENTORY	(see attached)
SHUTDOWN MARGIN	SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. No change in part strength CEA position, and b. All full length CEAs (shutdown and regulating) are fully inserted except for the single CEA of highest reactivity worth which is assumed to be fully withdrawn.

(continued)

1.1 DEFINITIONS (continued)

Term	Definition
SITE BOUNDARY	The SITE BOUNDARY shall be that line beyond which the land is neither owned, nor leased, nor controlled by the licensee.
SOFTWARE	The digital computer SOFTWARE for the Reactor Protection System shall be the program codes and their associated data, documentation and procedures.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
Train	(see attached)
UNIDENTIFIED LEAKAGE	See LEAKAGE-UNIDENTIFIED.
UNRODDED INTEGRATED PEAKING FACTOR - F_r	The UNRODDED INTEGRATED RADIAL PEAKING FACTOR (F_r) is the ratio of the peak pin power to the average pin power in the unrodded core, excluding tilt.
UNRODDED PLANAR RADIAL PEAKING FACTOR - F_{xy}	The UNRODDED PLANAR RADIAL PEAKING FACTOR (F_{xy}) is the maximum ratio of the peak to the average power density of the individual fuel rods in any of the unrodded horizontal planes, excluding tilt.

TECH SPEC DEFINITIONS

DIVISION

ONE OR MORE TRAINS THAT SHARE A COMMON COMPONENT, e.g. AC POWER. DIVISIONS ARE THE HIGHEST LEVEL OF SEPERATION AND INDEPENDENCE.

ESTIMATED CRITICAL POSITION (ECP)

A CALCULATED SET OF REACTOR CONDITIONS AND/OR PARAMETERS THAT DEFINE A CRITICAL REACTOR STATE. (Keff=1.0)

KN-1

KN-1 IS THE K EFFECTIVE CALCULATED BY CONSIDERING THE ACTUAL CEA CONFIGURATION AND ASSUMING THAT THE FULLY OR PARTIALLY INSERTED FULL-LENGTH CEA OF THE HIGHEST INSERTED WORTH IS FULLY WITHDRAWN.

MID-LOOP

PWR CONDITION WITH FUEL IN THE REACTOR VESSEL AND LEVEL BELOW THE TOP OF THE HOT LEGS AT THEIR JUNCTION TO THE REACTOR VESSEL.

REDUCED INVENTORY

PWR CONDITION WITH FUEL IN THE REACTOR VESSEL AND LEVEL LOWER THAN THREE FEET BELOW THE REACTOR VESSEL FLANGE.

TRAIN

A SET OF SAFETY RELATED COMPONENTS THAT PERFORM A SAFETY FUNCTION. TRAINS PERFORMING REDUNDANT FUNCTIONS ARE PHYSICALLY, ELECTRICALLY AND MECHANICALLY SEPERATED TO THE EXTENT NECESSARY TO INSURE INDEPENDENT PERFORMANCE OF ITS SAFETY FUNCTION.

16.4 3.1 REACTIVITY CONTROL SYSTEMS

16.4.1 3.1.1 SHUTDOWN MARGIN - T_{AVG} > ~~210°F~~ 135°F

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 Shutdown Margin - T_{avg} > ~~210°F~~ 135°F

LCO 3.1.1 SHUTDOWN MARGIN (SDM) shall be ≥ [6.5% Δk/k].

NOTE

With all CEAs verified fully inserted by two diverse position indicators, the CEA of highest reactivity worth does not have to be assumed withdrawn.

APPLICABILITY: MODES 3*, ~~and~~ 4*, AND 5*

* SEE SPECIAL TEST EXCEPTIONS 3.1.8 AND 3.1.10.

16.4.2 3.1.2 SHUTDOWN MARGIN - T_{avg} ≤ ~~210°F~~ 135°F

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Shutdown Margin - T_{avg} ≤ ~~210°F~~ 135°F

LCO 3.1.2 ~~SHUTDOWN MARGIN (SDM) shall be ≥ [3.0% Δk/k].~~
a. WITH RTCB'S CLOSED, THE ESTIMATED CRITICAL POSITION (ECP) SHALL BE WITHIN THE LIMITS OF TECHNICAL SPECIFICATIONS 3.1.6 AND 3.1.7.
b. WITH RTCBS OPEN, k_{N-1} SHALL BE LESS THAN 1.0.

APPLICABILITY: MODE ~~5~~S 3,* 4,* AND 5.*

* SEE SPECIAL TEST EXCEPTIONS 3.1.8 AND 3.1.10.

16.4.8 3.1.10 SPECIAL TEST EXCEPTIONS - CEDMS TESTING

3.1 REACTOR

3.1.10 Special Test Exception - CEDMS TESTING

LCO 3.1.10

The SHUTDOWN MARGIN requirement of Specification 3.1.1~~.2~~ ~~and the SHUTDOWN MARGIN and K_{N-1} requirements of Specification 3.1.1.2~~ may be suspended for pre-startup tests to demonstrate the OPERABILITY of the control element drive mechanism system provided:

a. No more than one CEA is withdrawn at any time.

b. No CEA is withdrawn more than 7 inches.

c. The K_{N-1} requirement of Specification 3.1.1~~.2~~ is met prior to the start of testing.

d. All other operations involving positive reactivity changes are suspended during the testing.

APPLICABILITY: MODES 4 and 5.

3.1 REACTOR

3.1.11 BORON DILUTION ALARMS

LCO 3.1.11 BOTH STARTUP CHANNEL HIGH NEUTRON FLUX ALARMS SHALL BE OPERABLE

APPLICABILITY: MODES 3*, 4, 5, AND 6

* WITHIN 1 HOUR AFTER THE NEUTRON FLUX IS WITHIN THE STARTUP RANGE FOLLOWING A REACTOR SHUTDOWN.

16.6 3.3 INSTRUMENTATION

16.6.1 3.3.1 RPS INSTRUMENTATION: PRESSURIZER, CONTAINMENT, STEAM GENERATOR, REACTOR COOLANT FLOW, LOSS OF LOAD

3.3 INSTRUMENTATION

3.3.1 Reactor Protective System (RPS) Instrumentation:
Pressurizer, Containment, Steam Generator, Reactor Coolant Flow, Loss of Load

LCO 3.3.1 The RPS Instrumentation channels and the associated operating bypasses, shall be OPERABLE with the Limiting Safety System Settings of Table 3.3.1-1.

APPLICABILITY AS SHOWN IN TABLE 3.3.1-1. ~~MODES 1 and 2.~~

Amendment I
December 21, 1990

TABLE 3.3.1-1

REACTOR PROTECTIVE INSTRUMENTATION

LIMITING SAFETY SYSTEM SETTINGS

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALLOWABLE VALUE
1. Pressurizer Pressure - High	4	3	1, 2	≤ [ ] psia
2. Pressurizer Pressure - Low	4	3	1, 2	≥ [ ] psia
3. Containment Pressure - High	4	3	1, 2	≤ [ ] psig
4. Steam Generator Pressure - Low	4/SG	3/SG	1, 2, 3*	≥ [ ] psia
5. Steam Generator Level - Low	4/SG	3/SG	1, 2	≥ [ ] %
6. Steam Generator Level - High	4/SG	3/SG	1, 2	≤ [ ] %
7. Reactor Coolant Flow - Low	4/SG	3/SG	1, 2, 3*, 4*, 5*	Ramp: ≤ [ ] psid/sec Floor: ≥ [ ] psid

NOTES

1. The Pressurizer Pressure - Low trip setpoint may be manually decreased as pressurizer pressure is reduced provided the margin between pressurizer pressure and the setpoint is maintained at ≤ 400 psi. Below 400 psia, the trip may be manually bypassed. The bypass shall be automatically removed whenever pressurizer pressure is ≥ 500 psia, and the setpoint shall be automatically increased as pressurizer pressure is increased.

2. The Steam Generator Pressure - Low trip setpoint may be manually decreased as steam generator pressure is reduced, provided the margin between steam generator pressure and the setpoint is maintained at ≤ 200 psi. The setpoint shall be increased automatically as steam generator pressure is increased.

3. The Reactor Coolant Flow - Low trip setpoints may be manually adjusted when THERMAL POWER is $< 10^{-4}$%.

4. The Steam Generator Level-Low trip setpoint varies with reactor power and is rate limited with a preset low power value.

* WITH THE RTCBs IN THE CLOSED POSITION, THE CEA DRIVE SYSTEM CAPABLE OF CEA WITHDRAWAL, AND FUEL IN THE REACTOR VESSEL

16.6.5 3.3.5 CORE PROTECTION CALCULATORS

3.3 INSTRUMENTATION

3.3.5 Core Protection Calculators (CPCs)

LCO 3.3.5 Four Core Protection Calculator (CPC) channels, and the associated operating bypass, shall be OPERABLE.

APPLICABILITY: MODES ~~1 and 2.~~ 1, 2, 3*, 4*, AND 5*

-----NOTES-----

1. The DNBR and LPD trips may be manually bypassed when THERMAL POWER is less than 10^{-4}% RTP. The bypass shall be automatically removed when THERMAL POWER is greater than or equal to 10^{-4}% RTP.

2. During special testing pursuant to LCO 3.1.9 and 3.4.16, the trips may be manually bypassed below 5% RTP. The bypass shall be automatically removed when THERMAL POWER is ≥ 5% RTP.

* WITH THE RTCBs IN THE CLOSED POSITION, THE CEA DRIVE SYSTEM CAPABLE OF CEA WITHDRAWAL, AND FUEL IN THE REACTOR VESSEL.

16.6.12 3.3.12 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM (ESFAS) INSTRUMENTATION - MANUAL ACTUATION

3.3 INSTRUMENTATION

3.3.12 Engineered Safety Features Actuation System (ESFAS) Instrumentation - Manual Actuation

LCO 3.3.12 The ESFAS Manual Actuation Channels of Table 3.3.12-1 shall be OPERABLE.

APPLICABILITY: As specified in Table 3.3.12-1.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Number of channels OPERABLE one less than the Total Number of Channels of Table 3.3.12-1.	A.1	Restore the inoperable channel to OPERABLE status.	48 hours
	OR		
	A.2.1	Be in MODE 3.	54 hours
		AND	
	A.2.2	Be in MODE 4.	60 hours
	A.2.2	Be in MODE 5.	84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.3.12.1 Perform a CHANNEL FUNCTIONAL TEST.	[18 months]

CROSS-REFERENCES - None

TABLE 3.3.12-1

ESFAS INSTRUMENTATION - MANUAL ACTUATION

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES
1. Safety Injection (SIAS)	2 sets of 2	2 sets of 2	1, 2, 3, 4
2. Containment Spray (CSAS)	2 sets of 2	2 sets of 2	1, 2, 3, 4
3. Containment Isolation	2 sets of 2	2 sets of 2	1, 2, 3, 4
4. Main Steam Line Isolation (MSIS)	2 sets of 2	2 sets of 2	1, 2, 3, 4
~~5. Containment Cooling (CCAS)~~	~~2 sets of 2~~	~~2 sets of 2~~	~~1, 2, 3, 4~~
~~6.~~ 5 Emergency Feedwater (EFAS)	2 sets of 2 per SG	2 sets of 2 per SG	1, 2, 3, 4
~~7. Safety Depressurization (SDAS)~~	~~2 sets of 2~~	~~2 sets of 2~~	~~1, 2, 3, 4~~

CSAS 1-4
ALL

16.6.14 3.3.14 ACCIDENT MONITORING INSTRUMENTATION

AMI
3.3.14

3.3 INSTRUMENTATION

3.3.14 Accident Monitoring Instrumentation (AMI)

LCO 3.3.14 The Accident Monitoring Instrumentation specified in Table 3.3.14-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, ~~and~~ 3 AND AS SPECIFIED IN TABLE 3.3.14-1

TABLE 3.3.14-1

(Sheet 1 of 2)

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE
1. Containment Pressure (WR)	2	1
(NR)	4	[2]
2. Reactor Coolant Outlet Temperature (T-hot) Wide Range (WR)	4	1
3. Reactor Coolant Inlet Temperature (T-cold) - WR	4	1
4. Reactor Coolant Pressure - WR	2	1
5. Pressurizer Water Level	2	1
6. Steam Line Pressure	2/SG	1/SG
7. Steam Generator (SG) Water Level - WR	2/SG	1/SG
8. In containment Refueling Water Storage Tank Water Level	2	1
9. Emergency Feedwater Flow Rate	2/SG	1
10. Reactor Coolant System Subcooled Margin Monitor	2	1
11. Pressurizer Safety Valve Status	1/valve	1/valve
12. Reactor Vessel Water Level Narrow Range	2	1
13. Core Exit Thermocouples	15/core quadrant	2/core quadrant
14. Emergency Feedwater Storage Tank Water Level	2/tank	1/tank
15. Wide Range Neutron Flux	2	1
16. Reactivity Cavity Level	2	1
17. Containment Area Radiation	2	1
18. Containment Hydrogen Concentration	2	1
19. Containment Isolation Valve Position	1 pair/valve	1 pair/valve

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TABLE 3.3.14-1 (Cont'd)

(Sheet 2 of 2)

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE
20. RCS Radiation Level	2	1
21. Containment Spray Flow	1	1
22. Containment Atmosphere Temperature	2	1
23. Safety Injection Flow	4	2
24. Safety Injection Tank Level	1/tank	1/tank
25. Safety Injection Tank Pressure	1/tank	1/tank
26. Shutdown Cooling Flow	2	2
27. Shutdown Cooling Hx Outlet Temperature	2	2
28. Steam Generator Safety Valve and (ADV) Position	1 pair/valve	1 pair/valve
29. Emergency Ventilation Damper Position	1 pair/damper	1 pair/damper
30. Component Cooling Water Flow to ESF System	1	1
31. Component Cooling Water Temperature to ESF System	1	1
32. DC Bus Voltage	2	2
33. Diesel Generator Voltage	2	2
34. Diesel Generator Current	2	2
35. Diesel Generator Status	2	2
36. 4.16 kV Switchgear Voltage	2	2
37. 480 V Switchgear Voltage	2	2
38. 4.16 kV Switchgear Current	[ ]	[ ]
39. 480 V Switchgear Current	[ ]	[ ]

ADD TO TABLE 3.3.14-1

40. SG LIQUID BLOWDOWN RADIATION MONITOR

41. MAIN STEAM LINE RADIATION MONITOR

42. STEAM JET AIR EJECTOR RADIATION MONITOR

43. STACK RADIATION MONITOR

~~* ALSO REQUIRED TO BE OPERABLE IN MODES 4 AND 5~~
~~WITH ONE OR MORE RCS COOLANT LOOPS IN OPERATION.~~

TABLE 3.3.10-1

(Sheet 1 of 2)

ESFAS INSTRUMENTATION

FUNCTIONAL UNIT			TOTAL NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALLOWABLE VALUES
1.	SIAS					
	a.	Containment Pressure - High	4	3	1, 2, 3, 4	[ ] psig
	b.	Pressurizer Pressure - Low	4	3	1, 2, 3, 4	[ ] psia
2.	CSAS					
	a.	Containment Pressure - High-High	4	3	1, 2, 3, 4	[ ] psig
3.	CIAS					
	a.	Containment Pressure - High	4	3	1, 2, 3	[ ] psig
	b.	Pressurizer Pressure - Low	4	3	1, 2, 3	[ ] psia
4.	MSIS					
	a.	Steam Generator (SG) Pressure - Low	4/SG	3/SG	1, 2, 3, 4	[ ] psia
	b.	Containment Pressure - High	4	3	1, 2, 3, 4	[ ] psig
	c.	Steam Generator Level - High	4/SG	3/SG	1, 2, 3, 4	[ ] %

TABLE 3.3.11-1

ESFAS LOGIC

FUNCTIONAL UNIT	TOTAL NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES
1. Safety Injection Actuation Signal (SIAS)			
a. Local Coincidence Logic	4	4	1, 2, 3, 4
b. Initiation Logic	4	4	1, 2, 3, 4
c. Actuation Logic	4	4	1, 2, 3, 4
2. Containment Spray Actuation Signal			
(CSAS)	4	4	1, 2, 3, 4
a. Local Coincidence Logic	4	4	1, 2, 3, 4
b. Initiation Logic	4	4	1, 2, 3, 4
c. Actuation Logic			
3. Containment Isolation Actuation Signal			
(CIAS)	4	4	1, 2, 3
a. Local Coincidence Logic	4	4	1, 2, 3, 4
b. Initiation Logic	2	2	1, 2, 3, 4
c. Actuation Logic			
4. Main Steam Isolation Signal (MSIS)			
a. Local Coincidence Logic	4	4	1, 2, 3, 4
b. Initiation Logic	4	4	1, 2, 3, 4
c. Actuation Logic	2	2	1, 2, 3, 4
5. Emergency Feedwater Actuation Signal - 1 (EFAS-1)			
a. Local Coincidence Logic	4/SG	4/SG	1, 2, 3
b. Initiation Logic	4/SG	4/SG	1, 2, 3, 4
c. Actuation Logic	4/SG	4/SG	1, 2, 3, 4
6. Emergency Feedwater Actuation Signal - 2 (EFAS-2)			
a. Local Coincidence Logic	4/SG	4/SG	1, 2, 3
b. Initiation Logic	4/SG	4/SG	1, 2, 3, 4
c. Actuation Logic	4/SG	4/SG	1, 2, 3, 4

16.7.3 3.4.3 RCS PRESSURE AND TEMPERATURE (P/T) LIMITS

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 The combination of RCS pressure, RCS temperature and RCS heatup and cooldown rates shall be maintained within the limits specified in Figure 3.4.3-1.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
----------NOTE---------- All Required Actions must be completed whenever this Condition is entered. ------------------		
A. Requirements of the LCO not met.	A.1 Restore parameter(s) to within limits.	30 minutes
	AND	
	A.2 Determine RCS is acceptable for continued operation.	72 hours
B. Required Actions and associated Completion Times not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5 with RCS pressure < [500] psig.	36 hours

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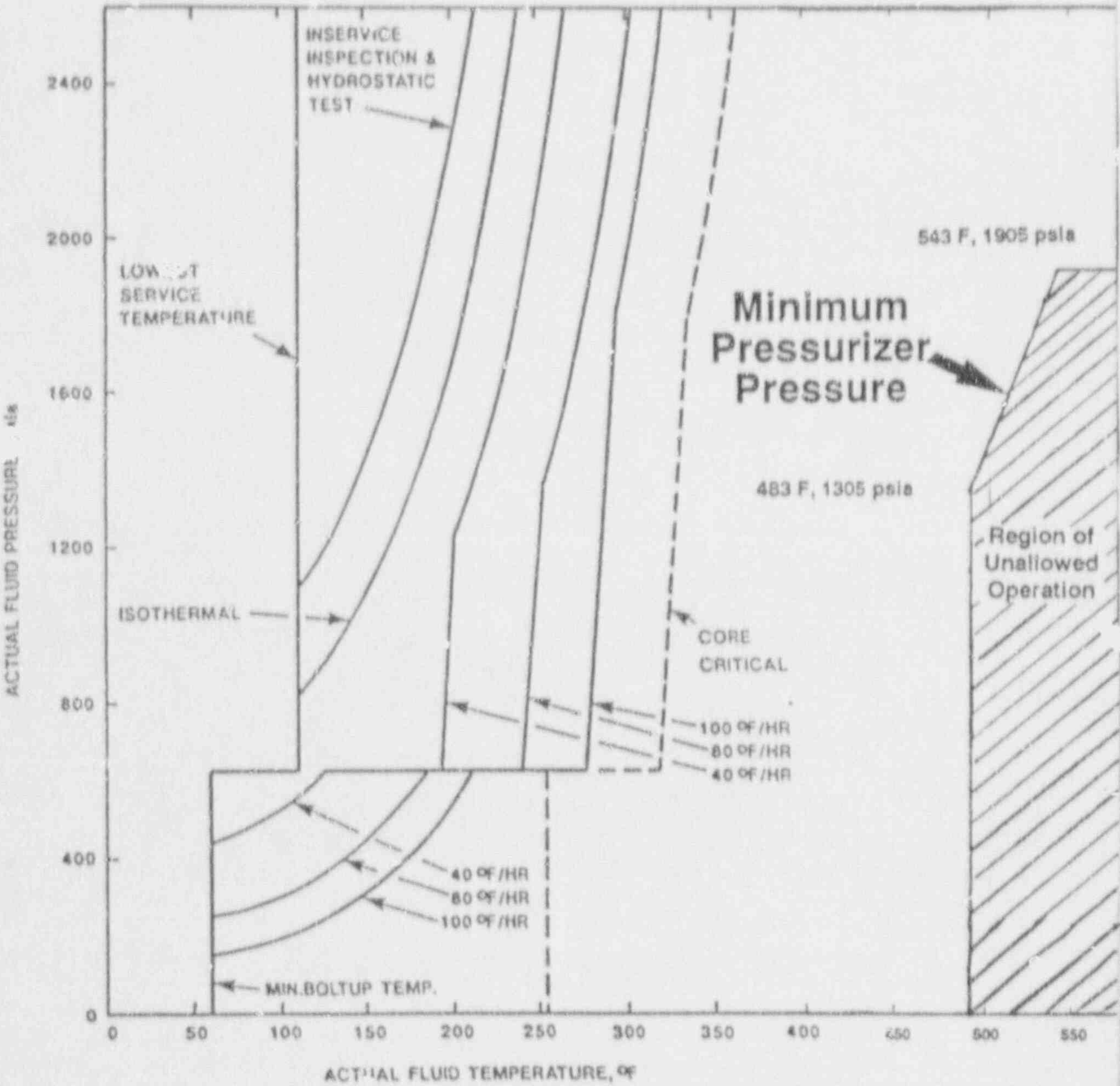
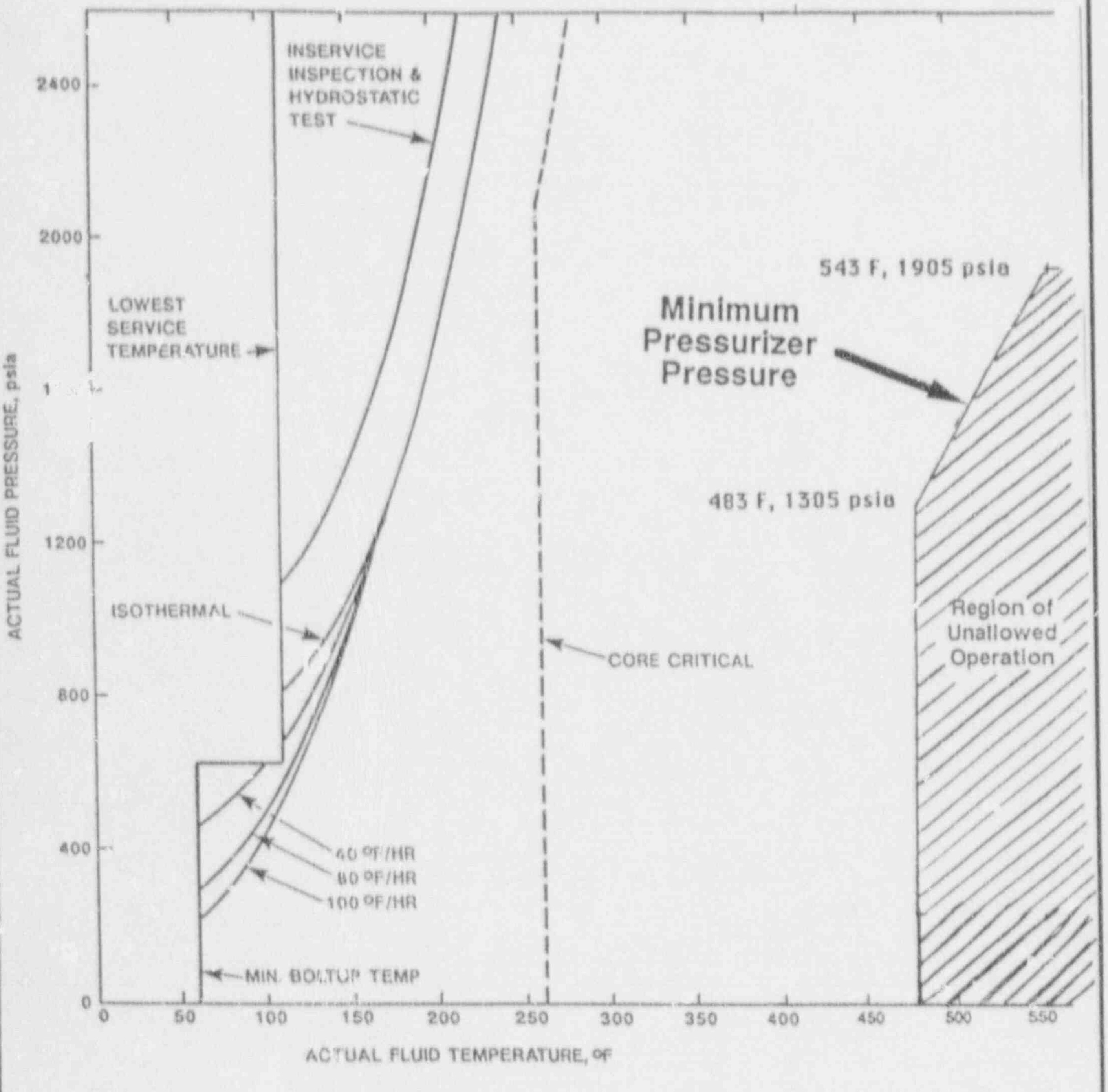


RCS PRESSURE AND TEMPERATURE LIMITS
FIGURE 3.4.3-1A



RCS PRESSURE AND TEMPERATURE LIMITS
FIGURE 3.4.3-1B

16.7.11 3.4.11 LOW TEMPERATURE OVERPRESSURE PROTECTION (LTOP) SYSTEM

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Low Temperature Overpressure Protection (LTOP) System

as follows

LCO 3.4.11 LTOP System shall be OPERABLE ~~with a maximum of one Safety Injection pump OPERABLE, and:~~

a. Two SCS Relief Valves with lift settings $\leq$ [550] psig and associated block valves open, or

b. The RCS depressurized with both divisions of Rapid Depressurization valves open.

APPLICABILITY: MODE 4, with any RCS cold leg temperature $\leq$ [317°F],
MODE 5,
MODE 6, with the reactor vessel head on

NOTE

LCO 3.0.4 is not applicable.

16.8.3 3.5.3 SIS DIVISIONS - SHUTDOWN

SIS Divisions - Shutdown
3.5.3

3.5 SAFETY INJECTION SYSTEM (SIS)

3.5.3 SIS Divisions - Shutdown

LCO 3.5.3 Two Safety Injection (SI) divisions, with one pump in each division, shall be OPERABLE.

APPLICABILITY: MODES 4, 5, AND 6 ~~MODE 4 RCS Temp > 317°F.~~ except MODE 6 with RCS level > R_x vessel flange elevation [120'-0"]

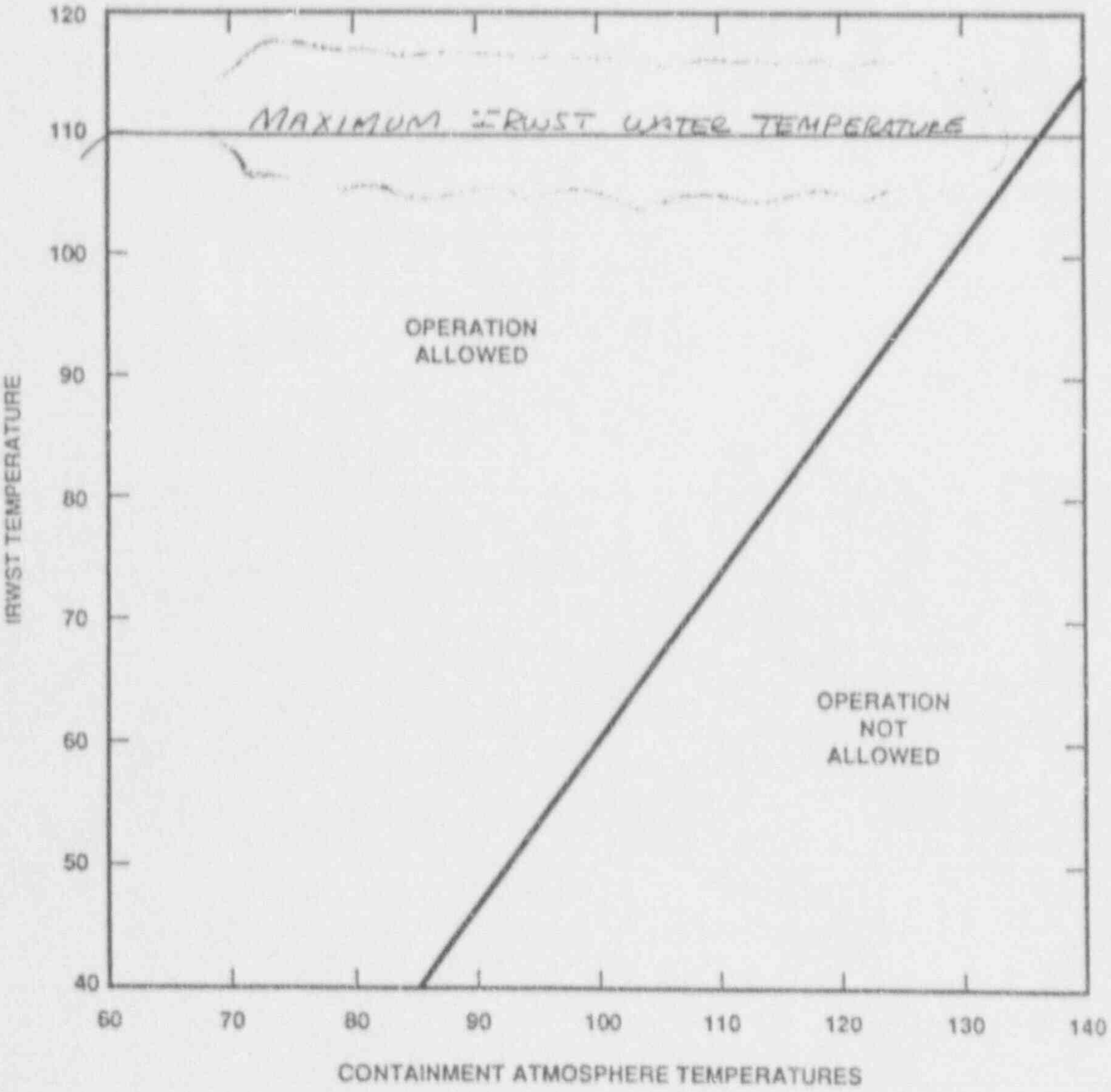
16.8.4 3.5.4 IN-CONTAINMENT REFUELING WATER STORAGE TANK (IRWST)

3.5 SAFETY INJECTION SYSTEM (SIS)

3.5.4 In-containment Refueling Water Storage Tank (IRWST)

LCO 3.5.4 The IRWST shall be OPERABLE.

APPLICABILITY: [illegible] MODES [illegible] except MODE 6 with
[illegible]S level > 120 ft - 0 inches



ALLOWED IRWST TEMPERATURE VS. CONTAINMENT ATMOSPHERE TEMPERATURE

FIGURE 3.5.4-1

16.11.2 3.8.2 AC SOURCES - SHUTDOWN

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources - Shutdown

LCO 3.8.2 The following AC Electrical Power Sources shall be OPERABLE:

a. One circuit between the offsite transmission network and ~~the~~ onsite Class 1E distribution system, ~~and~~ of each division, and

b. One diesel generator.

APPLICABILITY: MODES 5 and 6~~, when handling irradiated fuel.~~

16.11.5 3.8.5 DC SOURCES - SHUTDOWN

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 <u>DC Sources - Shutdown</u>

LCO 3.8.5 DC Power Source Division ~~one or Division 2~~ shall be OPERABLE.
Coinciding with the associated / operable diesel generator

APPLICABILITY: MODES 5, and 6,
When handling irradiated fuel.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Required DC Power Source [Division] inoperable.	A.1	Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>		
	A.2	Suspend handling of irradiated fuel.	Immediately
	<u>AND</u>		
	A.3	[Initiate action to] suspend operations with a potential for draining the reactor vessel.	Immediately
	<u>AND</u>		
	A.4	Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>		
	A.5	Initiate action to restore required DC Power Source [Division] to OPERABLE status.	Immediately

16.11.8 3.8.8 DISTRIBUTION SYSTEMS - SHUTDOWN

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Distribution Systems - Shutdown

LCO 3.8.8 The Division 1 or Division 2 Power Distribution System associated with the operable diesel generator shall be OPERABLE.

APPLICABILITY: MODES 5 and 6.
When handling irradiated fuel.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required [Division] inoperable.	A.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2 Suspend handling of irradiated fuel.	Immediately
	AND	
	A.3 [Initiate action to] suspend operations with a potential for draining the reactor vessel.	Immediately
	AND	
	A.4 Suspend operations involving positive reactivity additions.	Immediately
	AND	
	A.5 Initiate action to restore required [Division] to OPERABLE status.	Immediately

16.12.4 3.9.4 SHUTDOWN COOLING (SDC) AND COOLANT CIRCULATION - HIGH WATER LEVEL

3.9 REFUELING OPERATIONS

3.9.4 Shutdown Cooling (SDC) and Coolant Circulation - High Water Level

Two divisions at least one division shall be

LCO 3.9.4 ~~One SDC loop~~ shall be OPERABLE and in operation.

---NOTE---

The required SDC loop may be removed from operation for ≤ one hour per [2] hour period, provided:

a. No operations are permitted that would cause dilution of the RCS boron concentration.

APPLICABILITY: MODE 6 with the water level ≥ 24 feet above top of the reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDC loop requirements not met.	A.1 Suspend operations involving a reduction in reactor coolant boron concentration.	Immediately
	AND	
	A.2 Suspend operations involving an increase in reactor decay heat load.	Immediately
	AND	
	A.3 Initiate actions to satisfy SDC loop requirements.	15 minutes

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APPENDIX E

TECHNICAL SPECIFICATIONS FOR REDUCED RCS INVENTORY OPERATIONS

3.10 REDUCED RCS INVENTORY OPERATIONS

3.10.1 Reactor Trip Circuit Breakers

LCO 3.10.1 The RTCB's shall be open

APPLICABILITY: MODE 5 REDUCED RCS INVENTORY

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
RTCB's Closed	Open RTCB's	[Immediately]

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.10.1.1 Verify RTCB's OPEN	[12 hours]

3.10 REDUCED RSC INVENTORY OPERATIONS

3.10.2 Reduced RCS Inventory Operations - Instrumentation

LCO 3.10.2 The following reactor coolant system instrumentation shall be operable.

a. Two independent means of monitoring RCS level indication; one narrow range and one wide range instrument. And,

b. Two independent and diverse means of monitoring RCS temperature. And,

c. Two independent indications available to monitor SCS performance in the loop on service for decay heat removal.

APPLICABILITY: MODE 5 REDUCED RCS INVENTORY
and
MODE 6 REDUCED RCS INVENTORY

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. WR RCS Level Indication INOPERABLE	A.1. Initiate action to restore Instrument to OPERABLE Status. And,	[Immediately]
	A. Monitor RCS Temp	[Every 30 minutes]
	B. Monitor SCS Performance	[Every 30 minutes]
	C. Monitor NR Level	[Every 30 minutes]

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. NR RCS Level Indication INOPERABLE	B.1. Initiate Action to restore Instrument to OPERABLE status. And,	[Immediately]
	A. Monitor RCS Temp	[Every 30 minutes]
	B. Monitor SCS Performance	[Every 30 minutes]
	C. Monitor WR level	[Every 10 minutes]
	AND	[Immediately]
	B.2. Initiate action to restore RCS level to > [EL-117'0"]	
C. One RCS Temperature Indication INOPERABLE	C.1. Initiate action to restore instrument indication to OPERABLE status. And,	[Immediately]
	A. Monitor RCS Level	[Every 30 minutes]
	B. Monitor SCS Performance	[Every 30 minutes]
	C. Monitor OPERABLE Temperature Instrument	[Every 30 minutes]

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two RCS Temperature Indication INOPERABLE	D.1. Initiate Action to restore one instrument to OPERABLE status. And,	[6 hours]
	A. Monitor RCS level	[Every 10 minutes]
	B. Monitor SCS performance	[Every 10 minutes]
	AND	[Immediately]
	D.2. Initiate action to restore RCS level to > [EL-117'0"]	
E. SCS Performance Indications INOPERABLE	E.1. Initiate action to restore instrument to OPERABLE status.	[Immediately]
	AND	
	A. Monitor RCS Temp	[Every 10 minutes]
	B. Monitor RCS Level	[Every 10 minutes]
	OR	
	E.2. Align decay heat removal systems to the alternate loop.	[2 hours]

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.2.1	Perform a CHANNEL CHECK of RCS Level; One WR and One NR	[6 hours]
SR 3.10.2.2	Perform a CHANNEL CHECK of RCS Temperature	[6 hours]
SR 3.10.2.3	Perform a CHANNEL CHECK of SCS performance in the loop removing decay heat.	[6 hours]
SR 3.10.2.4	Perform a CHANNEL CALIBRATION of RCS level, temperature and SCS performance.	[60 days]

3.10 REDUCED RCS INVENTORY OPERATIONS

3.10.3 Reduced RCS Inventory Operations - Vent Paths

LCO 3.10.3 A RCS Vent Path of ≥[Pressurizer Manway Removal] is established and maintained

APPLICABILITY: MODE 5 REDUCED RCS INVENTORY
and
MODE 6 REDUCED RCS INVENTORY WITH RX VESSEL HEAD IN PLACE*

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS Vent Path Isolated	A.1. Initiate action to restore Vent Path.	[Immediately]
	AND	
	A.2. Complete restoration of vent path.	[6 hours]
	AND	
	A.3. Monitor RCS temperature, level and SCS performance.	[Hourly]

* 1 or More bolts tensioned

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and completion time not met.	B.1 Restore RCS Level to > [E1 117'0"]	[6 hours]

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.3.1	Verify Pressurizer Manway is removed and unobstructed or an equivalent vent path is established.	[12 hours]

3.10 REDUCED RCS INVENTORY OPERATIONS

3.10.4 Reduced RCS Inventory Operations - Heat Removal

LCO 3.10.4

a. Two Shut Down Cooling (SDC) divisions shall be OPERABLE, and at least one division shall be in operation.

b. The Containment Spray Pump shall be OPERABLE in the operating division.

APPLICABILITY: MODE 5 REDUCED RCS INVENTORY
and
MODE 6 REDUCED RCS INVENTORY

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SDC division INOPERABLE.	A.1 Restore division to OPERABLE status,	[Immediatey]
B. Required Action and associated Completion Time not met.	B.1 Raise RCS level to > [EL-117'0"].	[6 hours]

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. No SDC division in operation.	C.1 Suspend all operations involving reduction in RCS boron concentration. AND C.2 Initiate action to restore one SDC division to OPERABLE status and place in operation. AND C.3 Initiate action to raise RCS level to > [EL-117'0"]	[Immediately] [Immediately] [Immediately]

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Containment Spray Pump in operating division INOPERABLE	D.1 Initiate action to place the alternate division in operation if the containment spray pump in that division is OPERABLE.	[6 hours]
	AND	
	D.2 Monitor SCS performance.	[Every 30 minutes]
	AND	
	D.3 Restore INOPERABLE Containment Spray Pump.	[48 hours]
E. Required Action and Completion time of Item D.3 not met.	E.1 Raise RCS Level > [EL-117'0"]	[6 hours]

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.10.4.1	Verify at least one SDC division operating	[12 hours]
SR 3.10.4.2	Verify correct breaker alignment and indicated power available to the SDC pump that is not in operation and the OPERABLE Containment Spray Pump.	[24 hours]

3.10 REDUCED RCS INVENTORY OPERATIONS

3.10.5 Reduced RCS Inventory Operations - Containment Integrity

LCO 3.10.5 The containment building penetrations shall be in the following status:

a. The equipment hatch closed and held in place by [a minimum of four bolts,]

b. One door in each airlock closed,

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere is either:

1. Closed by an isolation valve, blind flange, manual valve, or equivalent, or

2. Capable of being closed by an OPERABLE Containment Purge and Exhaust Isolation System.

APPLICABILITY: MODE 5 REDUCED INVENTORY
and
MODE 6 REDUCED INVENTORY

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetrations not in the required status.	A.1. Restore Containment penetration to required status.	[6 hours]

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and Completion time not met.	B.1 Restore RCS level to > [EL-117'0"]	[6 hours]

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.5.1	Verify each required containment building penetration is in its required status.	[12 hours]
SR 3.10.5.2	Verify the surveillance requirements of 3.9.3.2 are met.	[18 months]

3.10 REDUCED RCS INVENTORY OPERATIONS

3.10.6 Reduced RCS Inventory Operations - AC Power Availability

LCO 3.10.6 The following AC Electrical Power Sources shall be OPERABLE.

a. Two independent sources of AC power to each division supplying the Class 1E Distribution System,

AND

b. A Diesel Generator in either division.

APPLICABILITY: MODE 5 REDUCED RCS INVENTORY
and
MODE 6 REDUCED RCS INVENTORY

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One source of A.C. Power to either division INOPERABLE.	A.1. Perform S.R. 3.8.1.1	[1 hour] then every 12 hours
	AND	
	A.2. Restore division to operable status	[30 hours]

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One Source of A.C. Power to each division operable	B.1 Restore either division to two operable sources	[12 hours]
C. Required Diesel Generator INOPERABLE	C.1 Perform S.R. 3.8.1.1 AND C.2 Restore required diesel generator to operable status	[1 hour] then every 12 hours [12 hours]
D. Required Action A, B or C not met within required Completion Time.	D.1 Raise RCS level > [EL-117'0"]	[6 hours]

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.10.6.1	Verify diesel generator operability per 3.8.1.2, 3.8.1.4, 3.8.1.5, 3.8.1.9 and 3.8.1.18	As specified by applicable SR's

3.10 REDUCED RCS INVENTORY OPERATIONS

3.10.7 Reduced RCS Inventory Operations - DC Distribution System

LCO 3.10.7 The following DC Electric Power Sources shall be OPERABLE

a. One Division of the DC Distribution System coinciding with the operable Diesel Generator. And,

Power is available to the opposite division 125 vdc & 120 VAC Distribution Centers.

APPLICABILITY: MODE 5 REDUCED RCS INVENTORY
and
MODE 6 REDUCED RCS INVENTORY

ACTIONS

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	Required DC Power Division INOPERABLE	A.1	Restore to Operable Status	[4 hours]
B.	Opposite division distribution Centers INOPERABLE	B.1	Restore to OPERABLE status	[12 hours]
C.	Required Action A or B not met within required Completion Time.	C.1	Raise RCS level to >[EL-117'0"]	[6 hours]

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.10.7.1	Perform S.R. 3.8.4.1 through 3.8.4.8 on the OPERABLE division of the DC Distribution System	Per 3.8.4.1 through 3.8.4.8 frequency