RCVD (INF) 7/1/J

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2
EMERGENCY PROCEDURE NUMBER 2-0120043
REVISION 0

INADEQUATE CORE COOLING (ICC)

October 29, 1981

REV ____________ FRG ____________
Approval ____________ Plt Mgr ________

TOTAL NO. OF PAGES 9

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1.0 SCOPE

To provide awareness to the operator of degraded core cooling conditions. Assumes all RCP's are stopped.

2.0 SYMPTOMS

> NOTE: Any of the following symptoms may be an indication of an approach to inadequate core cooling.

2.1 DNB considerations (alarms)

2.1 Indications/Alarms

2.1.1 Nuclear Instrument Channel Deviation, erratic
L-34, L-40

2.1.2 Variable Overpower (RPS)
L-9, L-17

2.1.3 Hi Local Power Density (RPS)
L-22, L-30

2.1.4 TM/LP
H-1, H-2, H-3, H-4, L-36, L-44

2.1.5 Azimuthal Tilt
L-22, L-30, L-43

2.1.6 KW/ft.
K-17, H-5, H-6, H-7, H-8, L-43

2.1.7 Axial Power
L-22, L-30, L-43

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2.0 SYMPTOMS: (Cont.)

2.2 Heat Sink Considerations

2.2 Indications/Alarms

2.2.1 S/G level at or near zero
G-1, G-9

2.2.2 S/G pressure rises to dump valve setpoint, unless a break occurs, in which case pressure would be continually decreasing.
P-17, P-19

2.2.3 Coincident pressure decrease in the secondary side S/G and the RCS.
P-17, P-19, RTGB203, RTGB206

T_h & T_c sub-cooled and decrease, then increase sharply.
H-5, H-6, H-7, H-8

2.2.4 After approx. constant temperature, the primary coolant temperature increases well above secondary saturation temperature.
K-17

2.2.5 Opening of PORV's
H-12, H-20, H-9, H-10, H016, H-24

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2.0 SYMPTOMS: (Cont.)

2.3 LOCA Considerations

2.3 Indications/Alarms

2.3.1 Decreasing motor amps on RCP's or erratic indication

2.3.2 Rapidly decreasing secondary side S/G/RCS Δ P

2.3.3 RCS saturated conditions RTGB203

2.3.4 RCS Superheated conditions RTGB203, DDPS, core exit thermocouples

2.3.5 Heat transfer from secondary to primary

2.3.6 Erratic or off-scale przr level indication RTGB203

2.3.7 Invalid ex-core nuclear detector indication due to voiding. RPS

2.3.8 Invalid in-core neutron detector indications due to core uncovery. DDPS

2.3.9 Excessive core exit thermocouple readings. DDPS

2.4 Plant conditions that could lead to ICC

2.4 Indications/Alarms

2.4.1 Reactor trip (TM/LP)

2.4.2 LOCA

2.4.3 Loss of feedwater

2.4.4 Main Steam line break

2.4.5 S/G tube rupture

2.4.6 Loss of RC flow

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4.0 IMMEDIATE OPERATOR ACTION

4.1 Ensure control of S/G levels	4.1 With Main or AFW

> NOTE: If only one S/G is available as a heat sink, adequate core cooling can still be maintained.

4.2 Ensure control of steam flow	4.2 With SBCS or ADS
4.3 With steam flow and FW flow, maintain T_h 20°F below saturation temperature for existing RCS pressure	4.3 Pressure control with przr heaters or auxiliary spray
4.4 Ensure CVCS can maintain przr level	
4.5 Verify natural circulation:	
4.5.1 Loop Δ T less than full power Δ T (44°F)	
4.5.2 T_c constant or decreasing	
4.5.3 T_h stable, not steadily increasing	
4.5.4 No abnormal differences between T_h RTD's and core exit thermocouples	
4.6 If natural circulation lost;	4.6 As indicated by:
	4.6.1 RCP motor amps decreasing
	4.6.2 Secondary/Primary Δ P rapidly decreasing or equal
	4.6.3 T_h/T_c essentially equal
	4.6.4 Erratic przr level or off scale
	4.6.5 Erratic excore NIS
	4.6.6 Core exit thermocouples indicate super heated conditions

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4.0 IMMEDIATE OPERATOR ACTION: (Cont.)

4.7 Make preparations to supply core cooling with HPSI pumps via cold leg injection, using the PORV's to initiate core cooling.

5.0 SUBSEQUENT ACTIONS

	CHECK
5.1 Restart RCP's if possible, using the following starting criteria:	______
5.1.1 A LOCA does not exist	______
5.1.2 RCS pressure/temperature permit restart	______
5.1.3 RCP services (power, oil lift, CCW, etc.) are available	______
5.2 If a steamline or FW line break is indicated, FW should be admitted to the non-affected S/G only	______
5.3 If condensate is limited, conduct a plant cooldown and initiate SDC prior to running out of water	______
5.4 Refer back to EP that led to this procedure for further instructions	______

6.0 PURPOSE/DISCUSSION:

Inadequate core cooling (ICC) is a term that defines a reactor core condition that is degraded beyond that anticipated during normal plant operations. The ICC conditions could result from operator error or a combination of equipment failures. In order to induce ICC, established operating procedures must have been violated or equipment failures greater than considered credible in design criteria have occured.

This procedure is to be considered as a guide to avoid ICC and not a replacement for procedures which refer to specific accidents or conditions.

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6.0 PURPOSE/DISCUSSION: (Cont.)

On CE plants the core is protected from DNB by either the TM/LP Trip or by the core protection calculators. these systems trip the reactor automatically if the design DNBR is approached, assuring that a lower DNBR, which could lead to ICC, is not reached. A postulated flow blockage in the core support plate or fuel channel would result in a flow maldistribution in the core, that could result in a lower DNBR. Any evidence of core non-symmetry should be investigated.

Loss of feedwater to both S/G during power operation has the potential of producing conditions which could lead to ICC.

Compliance with LOCA guidelines assures that the appropriate corrective actions are accomplished. The ~~loca~~ LOCA discussed is synonymous with a small break LOCA.

If core parameters violate tech. specs. or are approaching these limits the reactor must be tripped.

Whenever any break results in the release of high energy fluid to containment, indications associated with containment parameters must be compared and verified.

If a break in the secondary system is suspected feedwater should be provided only to the S/G known to be intact.

Do not exceed 75^{o}F/hr cooldown rate during steam dump operation.

If a SIAS occurs, operate the HPSI pumps until the RCS is at least 50^{o} subcooled, and there is level indication in the przr. Restart HPSI pumps as necessary to maintain this condition.

If RAS occurs assure that flow rates are > minimum HPSI pump flow, (30 gpm). If necessary stop charging pps until one HPSI pp is operating. Restart pps as necessary to maintain 50^{o} F subcooling.

If a S/G tube rupture is suspected isolate the faulted S/G. Feed and dump steam from the intact S/G only.

Maximum safety injection flow and PORV operation is suggested only as an alternative due to multiple malfunctions. It is the least desirable means of inventory and pressure control.

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7.0 REFERENCES:

7.1 St. Lucie Unit #1 Emergency Procedures
7.2 St. Lucie Unit #1 FSAR Chapter 6
7.3 CE guidelines CEN 152
7.4 Draft of NUREG 0799

8.0 RECORDS REQUIRED:

8.1 Normal log entries
8.2 Applicable recorder charts

9.0 APPROVAL:

Reviewed by the Facility Review Group_____________________ 19___
Approved by_____________________,Plant Manager_____________________ 19___

REV____ Reviewed by the Facility Review Group_____________________ 19___
Approved by_____________________,Plant Manager_____________________ 19___

"L A S T P A G E"

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Attachment to L-81-433
October 6, 1981

A. Response to fire protection questions generated in the September 23, 1981 FPL/NRC meeting

B. Revisions to various 440. series questions

C. Revised FSAR Chapter 15

RESPONSES TO FIRE PROCTECTION QUESTIONS GENERATED IN THE SEPTEMBER 23, 1981 FPL/NRC MEETING

QUESTION: State the ability to have the capability to go to cold shutdown within 72 hours of a fire event using only onsite power.

ANSWER: St. Lucie Unit #2 has the capability to power all the equipment necessary to go to cold shutdown utilizing only onsite power. Systems necessary to achieve and maintain cold shutdown (one train) from either the control room or emergency control station(s) will be repaired within 72 hours.

Where alternative or dedicated shutdown capability is provided for a specific fire area, the ability to achieve and maintain cold shutdown conditions within 72 hours will be provided.

QUESTION: Address the following instrumentation recommended to be included on the hot shutdown panel.

a. Pressurizer pressure and level
b. Reactor coolant hot leg temperature and either cold leg temperature or TAVG.
c. Steam generator pressure and level (widerange)
d. Source range flux monitor
c. Actual flow measurements for all pumps used.
d. Level indication for all tanks used (CST).

ANSWER: The instrumentation and control capabilities of the Hot Shutdown Panel (HSDP) can be found in Table 7.4-2 of the FSAR. (copy attached)

a) The HSDP has indication for both pressurizer level and pressure.

b) The HSDP has cold leg temperature indication. Based on past operating experience at St. Lucie Unit #1 with natural circulations cooldown and the control and indication of steam generator parameters, the utilization of cold leg temperature indication only is deemed adequate.

c) The HSDP has steam generator wide range pressure indications and narrow range level indications. The narrow range level indication reads from 57 inches below the top of the tube bundle to the separator section of the steam generator.

d) The HDSP has neutron level monitors. We do however consider these monitors unnecessary because:

1) The control rods (with one stuck rod) adds sufficient negative reactivity to maintain a shutdown margin in hot standby with no boron and,
2) The two sources of water utilized for reactor coolant system makeup have high boron concentration

e) AFW pump flow indication.

The HSDP presently has pump run indicating lights for these pumps. In addition there is local indication for each pump section strainer P, suction pressure and discharge pressure which will indicate flow through the pumps.

CCW pump flow indication
In the event that it is necessary to verify that we have not lost CCW, there is local indication for suction strainers P and pump discharge pressure which will indicate pump flow.

ICW pump flow indication
In the event that it is necessary to verify that we have not lost ICW flow there is local flow indication in the CCW building for each CCW/ICW heat exchange.

In addition, CCW & ICW performance can be evaluated utilizing local temperature indication on the CCW/ICW heat exchanger.

f) CST level indication
In the event that it is necessary to verify the level in the condensate storage tank there is a local mechanical indicator.

QUESTION: Discuss the storage and repair of cable damaged by fire and necessary for cold shutdown.

ANSWER: For those areas where redundant cable is assumed to be damaged by fire a sufficient quantity of cable shall be stored on site to insure the repair of cable necessary for cold shutdown.

As a temporary measure, for expedicious repair only; sections of cable which have been damaged will be replaced. Proper testing will be conduct to assure that the portions of cable not being replaced are undamaged. In all cases the splicing of cable will be considered an emergency condition only. At the earliest possible time a new cable will be run from the power supply to the equipment for those cables damaged by fire and necessary for cold shutdown.

QUESTION: Supply a list of equiment that is necessary to achieve and maintain cold shutdown.

ANSWER: A cold shutdown list is attached which also indicates the equipment necessary for hot standby.

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
1. Diesel Generator	* DO Pump 2A	1	MCC 2A7 SWGR 2A2 & 2A3	8 37
	* DO Pump 2B	2	MCC 2B7 SWGR 2B2 & 2B3	9 34 II
	* DO Storgae Tank 2-A	1		
	* DO Storage Tank 2-B	2		
	* DG-2A Set	8		
	* DG-2B Set	9		
	* I-SE-17-1A & 2A (DG Fuel Oil Supply Valves)	8	DG-2A Eng Term Blocks 2A1 & 2A2 120 V-AC PP-211, MCC 2A7 SWGR 2A2 & 2A3	8 8 37
	* I-SE-17-1B & 2B (DG Fuel Oil Supply Valves)	9	DG-2B Eng Term Blocks 2B1 & 2B2 120 V-AC PP-212, MCC 2B7 SWGR 2B2 & 2B3	9 9 34 II
	* LS-17-542A, 543A, 552A -550A, 551A, 553A (DG Day Tank Level Switches)	8	DG Eng Term Blocks 2A1 & 2A2 120 V-AC PP-211, MCC 2A7 SWGR 2A2 & 2A3	8 8 37
	* LS-17-542B, 543B, 552B -550B, 551B, 553B (DG Day Tank Level Switches)	9	DG Eng Term Block 2B1 & 2B2 120 V-AC PP-212, MCC 2B7 SWGR 2B2 & 2B3	9 9 34 II

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FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
2. Auxiliary Feedwater	* AFW Pump 2A	6	SWGR 2A3	37
	* AFW Pump 2B	6	SWGR 2B3	34 II
	* AFW Pump 2C	6	Aux Steam & Mech Controller	
	* I-MV-09-9 (AFW Pump 2A Iso Valve)	6	MCC 2A5, SWGR 2A2 & 2A3	37
	* I-MV-09-10 (AFW Pump 2B Iso Valve)	6	MCC 2B5, SWGR 2B2 & 2B3	34 II
	* I-MW-09-11 (AFW Pump 2C Iso Valve)	6	Local Starter	
	* I-MV-09-12 (AFW Pump 2C Iso Valve)	6	Local Starter	
	* I-MV-08-12 (Aux Turbine Steam Supply)	6	125 V-DC 2A Bus	
	* I-MV-08-13 (Aux Turbine Steam Supply)	6	125 V-DC 2B Bus	
	* I-SE-09-2 (AFW Pump 2A Iso Valve)	6	125 V-DC 2A Bus	
	* I-SE-09-3 (AFW Pump 2B Iso Valve)	6	125 V-DC 2B Bus	
	* I-SE-09-4 (AFW Pump 2C Iso Valve)	6	125 V-DC 2B Bus	
	* I-SE-09-5 (AFW Pump 2C Iso Valve)	6	125 V-DC 2A Bus	

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FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
2. Auxiliary Feedwater	* I-HCV-08-1A, 1B (Main Steam Iso Valves)	6		
	* I-MV-08-1A, 1B (Main Steam Iso Bypass Valves)	6		
	* Turbine Stop Valves	6	EHC System	

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FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
3. Chemical & Volume Control	* Charging Pump 2A	18I	SWGR 2A2 & 2A3	37
	* Charging Pump 2B	18II	SWGR 2B2 & 2B3	34II
	* Charging Pump 2C	18III	SWGR 2AB SWGR 2A2 & 2A3 SWGR 2B2 & 2B3	28 37 34II
	* Boric Acid Makeup Tank 2A & 2B	17		
	* V-2553 (Charging Pump 2C Bypass)	18	SWGR 2AB	28
	* V-2554 (Charging Pump 2B Bypass)	18	SWGR 2A2	37
	* V-2555 (Charging Pump 2A Bypass)	18	SWGR 2B2	34II
	* V-2508 & 2509 (BAMT Gravity Feed Valves)	17	MCC 2B5, SWGR 2B2 & 2B3	34II
	* V-2504 (RWT Supply Valve)	18	MCC 2B5, SWGR 2B2 & 2B3	34II
	* I-SE-02-01 (Charging Line Iso Valve)	14	RTGB-205 125 V-DC Bus 2A	42 34II
	* I-SE-02-02 (Charging Line Iso Valve)	14	RTGB-205 125 V-DC Bus 2B	42 34II
	* I-SE-02-03 (Aux Spray Iso Valve)	14	Transfer Control Panel 2A 125 V-DC Bus 2A	42 34II

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FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
3. Chemical & Volume Control (Cont'd)	*I-SE-02-04 (Aux Spray Iso Valve)	14	Transfer Control Panel 2B 125 V-DC Bus 2B	42 34II
	*BAMT 2A Heater Banks	17	MCC 2A5, SWGR 2A2 & 2A3 MCC 2B5, SWGR 2B2 & 2B3	37 34II
	*BAMT 2B Heater Banks	17	MCC 2A6, SWGR 2A2 & 2A3 MCC 2B6, SWGR 2B2 & 2B3	37 34II
	*TIC -2206 (Temp Controller)	17	MCC 2A5, SWGR 2A2 & 2A3	37
	*TIC-2207 (Temp Controller)	17	MCC 2B5, SWGR 2B2 & 2B3	34II
	*TIC-2208 (Temp Controller)	17	MCC 2A6, SWGR 2A2 & 2A3	37
	*TIC-2209	17	MCC 2B6, SWGR 2B2 & 2B3	34II
	*Boric Acid Heat Trace Dist Transfer 2A	51	MCC 2A5, SWGR 2A2 & 2A3	37
	Dist Transfer 2B	51	MCC 2B5, SWGR 2B2 & 2B3	34II

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SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
4. Reactor Coolant	*Pressurizer Heaters 2A (150 KW Proportional)	14	Htr Distr Bank P1 Panel	14
			SCR Prop Pwr Controller 2A	34I
			Press Htr Bus 2A3	34I
			SWGR 2A3	37
	*Pressurizer Heaters 2B (150 KW Proportional)	14	Htr Distr Bank P2 Panel	14
			SCR Prop Pwr Controller 2B	34I
			Press Htr Bus 2B3	34I
			SWGR 2B3	34II

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FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
5. HVAC Equipment	* Elec Equip Rm Supply Fan (2 HVS-5A)	48	MCC 2A5 SWGR 2A2 & 2A3	37
	* Elec Equip Rm Supply Fan (2HVS-5B)	48	MCC 2B5, SWGR 2B2 & 2B3	34II
	* Elec Equip Room Exh Fan (2HVE-11)	43	MCC 2A6, SWGR 2A2 & 2A3	37
	* Elec Equip Room Exh Fan (2 HVE-12)	43	MCC 2B6, SWGR 2B2 & 2B3	34II
	* Reactor Supports Supply Fan (2 HVE-3A)	14	MCC 2A5, SWGR 2A2 & 2A3	37
	* Reactor Supports Supply Fan (2 HVS-3B)	14	MCC 2B5, SWGR 2B2 & 2B3	34II
	* * ECCS Area Supply Fan (2 HVS-4A)	39	SWGR 2A2 & 2A3	37
	* * ECCS Area Supply Fan (2 HVS-4B)	39	SWGR 2B2 & 2B3	34II
	* * ECCS Area Exhaust Fan (2 HVE-9A)	39	MCC 2A6, SWGR 2A2 & 2A3	37
	* * ECCS Area Exhaust Fan (2 HVE-9B)	38	MCC 2B6, SWGR 2B2 & 2B3	34II
	* Power Roof Ventilator (2 RV-3)	34I	MCC 2A5, SWGR 2A2 & 2A3	37
	* Power Roof Ventilator (2 RV-4)	34I	MCC 2B5, SWGR 2B2 & 2B3	34I
	* * Control Room AC 2 HVA/ACC-3A)	42II	MCC 2A6, SWGR 2A2 & 2A3	37
	* * Control Room AC (2 HVA/ACC 3B)	42II	MCC 2B6, SWGR 2B2 & 2B3	34II
	* * Control Room AC (2HVA/ACC 3C)	42II	MCC 2A[illegible] SWGR 2A2 & 2A3, 2B2 & 2B3	34I 37/34II

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ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
6. Makeup Water	Primary Water Pump 2A	5	MCC-2A2	37
	Primary Water Pump 2B	5	MCC-2B2	34II

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ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
7. Electrical Equipment	* Emergency Lighting LP 227	42	125 V-DC Bus 2A	34II
	* Emergency Lighting LP 228	42	125 V-DC Bus 2B	34II
	* Emergency Lighting LP 216	42	MCC 2A6, SWGR 2A2 & 2A3	37
	* Emergency Lighting LP 226	42	MCC 2B6, SWGR 2B2 & 2B3	34II
	* Station Battery Charger 2A	34II	MCC 2A5, SWGR 2A2 & 2A3	37
	* Station Battery Charger 2B	34II	MCC 2B5, SWGR 2B2 & 2B3	34II
	* Station Battery Charger 2AB	34II	MCC 2AB, SWGR 2AB	28

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ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
8. Instrumentation	PT-1102A (Pressurizer Pressure)	14	RTGB-206 Inst Bus 2 MA, Static Inv Cab 2A	42 34I
	PT-1102B (Pressurizer Pressure)	14	RTGB-206 Inst Bus 2 MB, Static Inv Cab 2B	42 34I
	PT-1102C (Pressurizer Pressure)	14	RTGB-206 Inst Bus 2 MC, Static Inv Cab 2C	42 34I
	PT-1102D (Pressurizer Pressure)	14	RTGB-206 Inst Bus 2 MC, Static Inv Cab 2D	42 34I
	LT-1110X (Pressurizer Level)	14	RTGB-203 120 V-AC PP-201 MCC 2A6, SWGR 2A2 & 2A3	42 34I 37
	LT-1110Y (Pressurizer Level)	14	RTGB 205 120 V-AC PP-202 MCC 2B6, SWGR 2B2 & 2B3	42 34I 34II
	TE-1115 (RCS Temperature)	14	RTGB-203 120 V-AC PP-201 MCC 2A6, SWGR 2A2 & 2A3	42 37 37
	TE-1125 (RCS Temperature)	14	RTGB-205 120 V-AC PP-202 MCC 2B6, SWGR 2B2 & 2B3	42 34I 34II
	PT-08-1A (Steam Gen Pressure)	6	Transfer Control Panel 2A RTGB 202 MCC 2A6, SWGR 2A2 & 2A3 120 V PP-201	37 42 37 34I
	PT-08-1B (Steam Gen Pressure)	6	Transfer Control Panel 2B RTGB 202 MCC 2B6, SWGR 2B2 & 2B3 120 V-PP-202	34II 42 34II 34I

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ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
8. Instrumentation (Cont'd)	* LT-9013A, 9023A (Steam Gen Level)	14	RTGB 202 125 V-DC Inst Bus MA, Stat Inv Cab MA MCC 2A5, SWGR 2A2 & 2A3	42 34I 37
	* LT-9013B, 9023B (Steam Gen Level)	14	RTGB-202 125 V-DC Inst Bus MB, Stat Inv Cab MB MCC 2B5, SWGR 2B2 & 2B3	42 34I 34II
	* LT-9013C, 9023C (Steam Gen Level)	14	RTGB-202 125 V-DC Inst Bus MC, Stat Inv Cab MC MCC 2A5, SWGR 2A2 & 2A3	42 34I 37
	* LT-9013D, 9023D (Steam Gen Level	14	RTGB-202 125 V-DC Inst Bus MD, Stat Inv Cab MD MCC 2B5, SWGR 2B2 & 2B3	42 34I 34II
	* LT-2206 (BAMT Level)	17	MCC 2A6, SWGR 2A2 & 2A3 PP-201	37 34I
	* LT-2206 (BAMT Level)	17	MCC 2B6, SWGR 2B2 & 2B3 PP-202	34II 34I
	* LT-12-11 (CST Level)	10	RTGB-202 120 V-AC PP-201 MCC 2A6, SWGR 2A6 & 2A3	42 34I 37
	* LT-12-11B (CST Level)	10	RTGB-202 120 V-AC PP-202 MCC 2B6, SWGR 2B6 & 2B3	42 34I 34II

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ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
8. Instrumentation (Cont'd)	* FT-09-2A2 (AFW Pump 2A Flow)	6		
	* FT-09-2B2 (AFW Pump 2B Flow)	6		
	* FT-09-2C2 (AFW Pump 2C Flow)	6		
	* * FI-14-1A (CCW Pump 2A Flow)	3	PP-201 MCC 2A6, SWGR 2A2 & 2A3	34I 37
	* * FI-14-1B (CCW Pump 2B Flow)	3	PP-202 MCC 2B6, SWGR 2B2 & 2B3	34I 34II
	* * FIS-21-9A (ICW Pump 2A Flow)	13	PP-201 MCC 2A6, SWGR 2A2 & 2A3	34I 37
	* * FIS-21-9B (ICW Pump 2B Flow)	13	PP-202 MCC 2B6, SWGR 2B2 & 2B3	34I 34II
	* * FT-25-21A1 (ECCS Exh Fan 9A Flow)	39		
	* * FT-25-21-B1 ECCS Exh Fan 9B Flow	38		
	* * FT-3306 (LPSI Pump 2A Flow)	16I		
	* * FT-3301 (LPSI Pump 2B Flow)	16II		

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SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
9. Miscellaneous Valves	PCV-1100E & 1100F (Pressurizer Spray)	14		
(Valves whose spurious operation could prevent safe plant shutdown)	V-1460 (RCS Vent Iso Valve)	14		
	V-1461 (RCS Vent Iso Valve)	14		
	V-1462 (RCS Vent Iso Valve)			
	V-1463 (RCS Vent Iso Valve)	14		
	V-1464 (RCS Vent Iso Valve)	14		
	V-1465 (RCS Vent Iso Valve)	14		
	V-1466 (RCS Vent Iso Valve)	14		
	V-2515 (Letdown Iso Valve)	14		
	V-2516 (Letdown Iso Valve)	14		
	V-2522 (Letdown Iso Valve)	24		
	LCV-2110P & 2110Q (Letdown Control)	24		
	V-1474 (PORV)	14		

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
9. Miscellaneous Valves (Cont'd)	V-1475 (PORV)	14		
	V-1476 (PORV Iso Valve)	14		
	V-1477 (PORV Iso Valve)	14		
	I-MV-08-14 & 16 (ADV Iso Valve)	6	Local Starters	
	I-MV-08-15 & 17 (ADV Iso Valve)	6	Local Starters	
	PCV-8801, 8802, 8803, 8804, 8805 (Condenser Dump Valves)	47		

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
10. Safety Injection	* Refueling Water Tank	4		
	* * LPSI Pump 2A	16I	SWGR 2A3	37
	* * LPSI Pump 2B	16II	SWGR 2B3	34II
	* * V-3480 (SDC Iso Valve)	14II	MCC 2B5, SWGR 2B2 & 2B3	34II
	* * V-3481 (SDC Iso Valve)	14II	MCC 2A5, SWGR 2A2 & 2A3	37
	* * V-3651 (SDC Iso Valve)	14II	MCC 2B6, SWGR 2B2 & 2B3	34II
	* * V-3652 (SDC Iso Valve)	14II	MCC 2A5, SWGR 2A2 & 2A3	37
	* * V-3545 (SDC Crosstie)	14II	MCC 2AB, SWGR 2A2/2B2 & 2A3/2B3	34I 37/34II
	* * V-3664 (SDC Iso Valve)	24	MCC 2A6, SWGR 2A2 & 2A3	37
	* * V-3665 (SDC Iso Valve)	24	MCC 2B5, SWGR 2B2 & 2B3	34II
	* * FCV-3306 (SDC Control)	16I	MCC 2A5, SWGR 2A2 & 2A3	37
	* * FCV-3301 (SDC Control)	16II	MCC 2B6, SWGR 2B2 & 2B3	34II
	* * HCV-3657 (SDC Control)	16I	MCC 2A5, SWGR 2A2 & 2A3	37

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
10 Safety Injection (Cont'd)	* * HCV-3512 (SDC Control)	16II	MCC 2B5, SWGR 2B2 & 2B3	34II
	* * V-3456 (SDC Block Valve)	16I	MCC 2A5, SWGR 2A2 & 2A3	37
	* * V-3457 (SDC Block Valve)	16II	MCC 2B5, SWGR 2B2 & 2B3	34II
	* * V-3517 (SDC Block Valve)	16I	MCC 2A5, SWGR 2A2 & 2A3	37
	* * V-3658 (SDC Block Valve)	16II	MCC 2B6, SWGR 2B2 & 2B3	34II
	* * V-3444 (SDC Block Valve)	16I		
	* * V-3432 (SDC Block Valve)	16II		
	* * 2I-V7161 (1514) (CS Block Valve)	24		
	* * 2I-V7164 (1514) (CS Block Valve)	24		
	* * HCV-3615 (SIS Block Valve)	16I	MCC 2A5, SWGR 2A2 & 2A3	37
	* * HCV-3635 (SIS Block Valve)	16II	MCC 2B6, SWGR 2B2 & 2B3	34II

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
10. Safety Injection (Cont'd)	** V-3733, 3735, 3737 & 3739 (SIT Vents)	14		
	** V-3734, 3736, 3738 & 3740 (SIT Vents)	14		

ST. LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
11. Main Steam	* I-MV-08-18A & 19A (Atmospheric Dump Valves)	6		
	* I-MV-08-18B & 19B (Atmospheric Dump Valves)	6		

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

	SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
12.	Component Cooling Water	** CCW Pump 2A	3	SWGR 2A3	37
		** CCW Pump 2B	3	SWGR 2B3	34II

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
13. Intake Cooling Water	* * ICW Pump 2A	13	SWGR 2A3	37
	* * ICW Pump 2B	13	SWGR 2B3	34II

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
14. Hot Shutdown Panel (Only items not listed above)	* *SIAS "A" Block	34II		
	* *SIAS "B" Block	34II		
	*LI-9113 (Steam Gen Level)	6		
	*LI-9123 (Steam Gen Level)	6		
	*PI-8113 (Steam Gen Pressure)	6		
	*PI-8123 (Steam Gen Pressure)	6		
	*PI-1108 (Pressurizer Pressure)	14		
	*PI-1107 (Pressurizer Pressure)	14		
	*LI-1105 (Pressurizer Level)	14		
	*LI-1106 (Pressurizer Level)	14		
	*TI-1115-1 (RCS Temperature)	14		
	*TI-1125-1 (RCS Temperature)	14		
	* *TI-3351Y (SDC Temperature)	16I		

ST LUCIE UNIT NO. 2
FIRE HAZARD ANALYSIS
ESSENTIAL EQUIPMENT LIST BY SYSTEM

SYSTEM	NORMAL MODE EQUIPMENT REQUIRED	FIRE AREA	POWER SOURCE & CABLE	FIRE AREA
14. Hot Shutdown Panel ** (Cont'd)	TI-3352Y (SDC Temperature)	16II		
	VM-1606-1 (Diesel Gen 2A Volts)	8		
	VM-1616-1 (Diesel Gen 2B Volts)	9		
	WM-1606-1 (Diesel Gen 2A Watts)	8		
	WM-1616-1 (Diesel Gen 2B Watts)	9		
	JI-001A1 (Neutron Flux)	8		
	JI-001B1 (Neutron Flux)	9		

*Equipment Required for Hut Standby.
**Equipment Required for Cold Shutdown.

C-E Power Systems
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POWER SYSTEMS

St. Lucie Plant
Unit No. 2 - 1978-890 MW Extension

Mr. K. N. Chow
Ebasco Services, Inc.
2 World Trade Center
80th Floor
New York, NY 10048

Subject: Revisions to NRC/RSB (440.X) Responses

Dear Mr. Chow:

Revisions to the responses for the following NRC questions are attached:

1. Question 440.7: Revised to include effects of moderate energy line break on core cooling.

2. Question 440.18: Revised to confirm commitment to redundant pressurizer heater cutoff on low level.

3. Question 440.25: Revised to reflect final locked rotor analysis.

440-67 / 440-69

4. Question 440.81(d): Revised to provide additional discussion on the single failure for the feedwater line break analysis.

5. Question 440.81(f): Revised to include a discussion of conservatisms in the feedwater line break methodology.

If you have any questions on these revisions, please call S. E. Ritterbusch.

Very truly yours,

J. C. Moulton
Project Manager

JCM/SER/cw

cc: E. Z. Zuchman
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E. R. Bottrill G. Boissy

LL2/2907 1/80

"SAR/ER CHANGE REQUEST"

Change Number ________
By PLE/EPL

PART I INITIATION

(1) To: Ebasco

(2) From C-E

(3) Project: St. Lucie 2

(4) Subject: NRC Questions

(5) Change Affects: [X] FSAR [ ] ER

(6) The Affected Areas is: Sections(s) ________ Page(s) ________

(7) Recommended change and reason(s) for requesting change: (Note: Attach marked up copy of all affected pages).

Revisions to 440.7, 440.18, 440.25, 440.81(d), and 440.81(f) to fulfill commitments

(8) Change will impact the following: ie. Specs, Dwgs, Other Disciplines/Organizations

None

PART II REVIEW

(9) To: ________
Reviewing Organizations Review Part I and Note Impact Below

Response Requested By: ________

(10) From: ________
Project Licensing Engineer/Environmental Project Leader

(11) Impact on Reviewing Organization

a. Section ________ Page(s) ________ (Note: Attach marked up copy of all affected pages).

b. Other Impact ________

(12) Reviewers Signature ________ Date ________

PART III APPROVAL

(13) Required Concurrences:

a. Approved S. E. Ritterbusch SER Date 9/21/81
Originating Engineer

b. Approved ________ Date ________
Responsible Supervisor

c. Approved ________ Date ________
PLE/EPL

d. Approved ________ Date ________
Project Engineer

e. Client Approval ________ Date ________
FP&L Letter Number

(14) Disposition [ ] Implemented [ ] Not Implemented Date ________

(15) Comments: ________

cc: Project Engineer

ORIGINAL RETAINED IN PLE OR EPL FILES

Question 440.7

Provide the following information related to pipe breaks or leaks in high or moderate energy lines outside containment associated with the RHR system when the plant is in a shutdown cooling mode:

1. Determine the maximum discharge rate from pipe break for the systems outside containment used to maintain core cooling.
2. Determine the time frame available for recovery based on these discharge rates and their effect on core cooling.?
3. Describe the alarms available to alert the operator to the event, ? the recovery procedures to be utilized by the operator; the time available for operator action.

A single failure criterion consistent with Standard Review Plan 3.6.1 and Branch Technical Position APCSB 3-1 should be applied in the evaluation of the recovery procedures utilized.

Response

The moderate energy analysis was performed in order to determine the highest flood level within the ECCS areas in accordance with SRP 3.6.1 and 3.6.2. In order to maximize the flood conditions, the analysis conservatively utilized a leak rate of 620 gpm and a minimum operator action of thirty (30) minutes. The moderate energy flooding analysis verified the validity of the present design under these conditions.

High and moderate piping failure outside the containment which could affect the shutdown cooling system have been investigated. Any fluid leakage either from the shutdown cooling system or nearby high energy system would be routed to the ECCS supply room. Each sump is provided with a duplex pump and two seismic category I level measurement devices. Any leakage into these sumps would initiate a control room alarm, thereby informing the operator of a piping failure. The ECCS area is also provided with two safety related radiation monitors to measure any airborne effluent to aid the operator in identifying the leakage source. A complete description of these monitors is provided in FSAR subsection 11.5.2.2.10.

In additon to the two aforementioned leakage detection systems, any significant Shutdown Cooling System leakage would be detected immediately by the Reactor Coolant System parameters displayed in the control room. Pressurizer water level indication and low pressurizer level alarms are provided in the Control Room by LT-1110X and LT-1110Y. In addition to the level instrumentation, both high pressurizer pressure range channels of 1500-2500 psia (PI1102A, B, C, D) and low pressurizer pressure range channels of 0-750 psia (PIC-1103,1104,1105,1106) are provided. This instrumentation is sufficinet to alert the operator of any abnormal RHR system operators.

INSERT A 9/11/81

Insert A 9/11/81

The above moderate energy line break analysis was performed to demonstrate that the resulting flooding would not affect equipment required for safe shutdown. Nonetheless, an additional analysis was performed to show that the plant operator has at least 20 minutes after the first alarm to identify and isolate the damaged train prior to any significant effect on core cooling. This time is available because the water in the RCS above the hot and cold leg piping acts as a reservoir which must be drained prior to any effect on shutdown cooling (SDC) system performance or core cooling (the SDC system takes suction from the RCS hot leg piping).

The RCS volume above the hot and cold leg piping includes the SG tubes, the SG inlet and outlet plenums, the reactor vessel upper head, the pressurizer surge line, and the pressurizer vessel for a total volume of approximately 4700 ft^3. Taking credit for draining of only the SG active tubes and pressurizer volume required to cover the top of the heaters results in a reservoir of 2467 ft^3 (18,454 gallons). With a leak rate of 620 gpm there is at least 20 minutes between the pressurizer low level alarm (heater uncovery) and uncovery of the SDC suction piping. Therefore, SDC system performance, coolant circulation through the reactor vessel, and core cooling are maintained.

SL-2 Round One Questions

440.18 (15.2.2.1) Discuss the system used to provide pressurizer heater cutoff on low level. Is there any single failure that could result in the heaters remaining energized when they have lost submergence. If so, discuss the consequences of this occurrence. In your answer, you may wish to consider the event which occurred at the Spert III facility in Idaho where a pressurizer was heated to a point where it lost integrity.

Response:

Florida Power and Light has committed to incorporating a redundant low pressurizer level cutoff signal to the pressurizer heaters. These signals will de-energize the heaters prior to to the water level dropping below their tops so that no single failure in the protection system can cause them to be energized while uncovered.

No FSAR change is required.

8/19/81

SL-2 ROUND ONE QUESTIONS

440.25 (15.3.3) Provide a detailed analysis on the consequences of a RCP shaft seizure event. Justify selection of limiting single failures. The time at temperature studies which justify your claims of peak clad temperature being limited to 1300°F are not accepted by the staff. In assessing fuel failures, any rod which experiences a DNBR of less than 1.19 must be assumed failed. Confirm that the results of the analysis meet the acceptance criteria of SRP 15.3.3.(2). Provide your assumptions on flow degradation due to the locked rotor in the faulted loop, and reference appropriate studies which verify these assumptions. Also provide a similar analysis for the locked rotor event presented in section 15.3.4.1, and show that acceptable consequences result.

Response

The most severe single failure in conjunction with the RCP shaft seizure event is the loss of offsite power on turbine trip, as discussed in the response to 440.9. Results show a minimum DNBR of 0.36 at 3.6 seconds, resulting in 13% of the fuel rods experiencing DNB (see the response to 440.11). The 2-hour thyroid dose assuming 13% failed fuel and the technical specification SG tube leakage is approximately 8 rems. The peak RCS pressure is less than or equal to 2694 psia (see the response to 440.8).

The flow coastdowns which were used in the analysis of the one pump resistance to forced flow are presented in Figures 440.25-1 and 440.25-2. The seized shaft is assumed to instantaneously stop at time 0.0 with the seized rotor acting only as a resistance to flow. This coastdown was generated using the COAST code as documented in CENPD-98 (see Reference 1).

Reference:

1. "Coast Code Description", CENPD-98, April 2, 1973.

A change to the FSAR, ~~Appendix 15.C.3 will be submitted in September 1981.~~ Section 15.3, accompanies this response.

Detailed analyses of the RCP shaft seizure event have been provided in revised sections 15.3.3, 15.3.4, and 15.3.5. The rate of flow coastdown is predicted by the coast computer code as described in Section 15.0.4.

Question No.

440.67 In light of recent operating experiences (the St. Lucie Unit 1 natural circulation cooldown event of June 11, 1980, and re-analyses of SAR Chapter 15 design bases events by St. Lucie in February 1981) a potential deficiency has been identified with the CESEC computer program and NSSS model. As the pressurizer cools down and the system pressure decreases, steam can form in the reactor vessel upper head due to flashing of the hot coolant in this stagnant region. The steam bubble in the reactor vessel upper head displaces coolant from the reactor vessel into the pressurizer and the steam in the vessel head will determine the system pressure. The CESEC model used for the steam generator tube rupture event does not account for this occurrence. Further, CESEC analyses which predict that the pressurizer will empty, or that the reactor coolant system saturates, do not appear to correctly calculate the system thermal hydraulic response and are not justified for use. These events are to be re-analyzed with a suitable model or additional justification is to be provided for the CESEC analyses to demonstrate that the computer program conservatively accounts for the formation of steam in the reactor coolant system.

Response

The Chapter 15 events performed with CESEC do not explictly include analyses of natural circulation cooldowns. However, a comparison has been made between CESEC and data from the St. Lucie 1 natural circulation cooldown event. This information will be provided in a document describing the CESEC-III computer code (see response to Question 440.80(k)). Additionally, comparative analyses will be performed between CESEC-II and CESEC-III. CESEC analyses have indicated that for the steam generator tube rupture, the letdown line break, and the steam line break events, the pressurizer empties and/or the reactor coolant system (RCS) saturates. Since the steam line break event was analyzed using CESEC-III, no comparative analysis will be performed for this event. The steam generator tube rupture and letdown line break events belong to the decrease in RCS inventory event category. The most limiting event in this category with respect to void formation, the steam generator tube rupture event, will most significantly emphasize differences between CESEC-II and CESEC-III in the calculational results. Conclusions from this analysis will bound those which would have been ascertained from a comparative analysis for the letdown break event. ~~Therefore, qualification of CESEC-II against CESEC-III for the steam generator tube rupture event will provide the necessary justification for the use of CESEC-II to analyze the letdown line break event in addition to the justification for the use of the code to predict system response for the steam generator tube rupture event. Submittal of the comparison to the NRC will be the end of September of 1981.~~

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Additional information on CESEC-III, will be prepared by 9/30/81.

INSERT C

Therefore, qualification of CESEC-II against CESEC-III for the steam generator tube rupture event will provide the necessary justification for the acceptability of Chapter 15 analyses conclusions for depressurization events.

(continued on next page)

For all Chapter 15 events for which the pressurizer fluid is calculated to drain into the hot leg, or the system pressure drops below the saturation pressure of the hottest fluid in the system, the hottest fluid will be located in the relatively stagnant upper head region of the reactor vessel. The CESEC-II code, used in the FSAR Chapter 15 analyses did not explicitly model the steam formation in the reactor vessel upper head (except for steam line break analyses which used CESEC III) region. The latest version of CESEC, namely CESEC-III, appropriately models steam formation and collapse in the upper head region of the reactor vessel. Heat transfer from metal structures to the reactor coolant system (RCS) fluid is modeled in addition to flashing of the reactor coolant into steam during depressurization of the RCS. Following the reactor coolant pump (RCP) coastdown due to loss of offsite power or manual shutoff following SIAS, thermal-hydraulic decoupling of the upper head region is characterized in CESEC-III by progressively decreasing flow to the upper head from the upper plenum region. Table 440.67-1 summarizes the significant differences between the two CESEC code versions which impact depressurization transients. (Note that the 3-D feedback impacts only the steam line break analyses).

The steam generator tube rupture event presented in the FSAR was reanalyzed, using the CESEC code version known as CESEC III. The re-analysis of the SGTR event without loss of offsite power indicated the following:

The modeling of the stagnant upper head region with metal structure heat transfer results in the formation of voids in this region. The void volume in the upper head region peaks at about 289 cu. ft. during the transient and gradually decreases under the combined action of the HPSI flow and the cooldown at the steam generators. The duration of the voids is a strong function of the rate of cooldown of the primary side and the HPSI flow rate.

Figure 440.67-1 provides a comparison of pressurizer pressures predicted by the CESEC II and CESEC III codes. The effect of upper head voids on primary system pressure is illustrated in this figure. It shows similar trends for the RCS pressures during the transient. However, subsequent to reactor trip, the pressure predicted by the CESEC III code decreases at a lower rate than that predicted by the CESEC II code. This is due to the formation of voids in the upper head region, which controls the system pressure decay after the emptying of the pressurizer subsequent to reactor trip. The voids in this region are calculated to collapse at about 1700 seconds under the combined effect of charging flow, safety injection flow, reduced primary-to-secondary leak, and cooldown at the steam generators. The CESEC III code predicts refilling of the pressurizer and repressurization of the RCS as a result of the net mass influx into the RCS, subsequent to collapse of the upper head voids. The CESEC II code predicts refilling of the pressurizer and RCS re-pressurization much earlier than CESEC III, since it does not explicitly account for upper head void formation and collapse.

Figure 440.67-2 shows the behavior of the liquid volume in the reactor vessel above the top of the hot legs for the CESEC III analysis. The amount of voids predicted is not large enough to expand the steam bubble beyond the upper head region and to the elevation of the hot legs.

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Additionally, the prediction of the upper head bubble does not alter the conclusions of the previous CESEC II analyses. That is, for the SGTR event the major concern is with radiological releases to the environment. A breach of the primary system boundary provides a pathway for radioactive primary coolant release into the secondary side and subsequently into the atmosphere. The offsite accident dose for a SGTR event is dependent on the integrated primary to secondary leak as well as the total main steam safety valve (MSSV) steam releases. As seen from Table 440.67-2, both CESEC II and CESEC III codes predict comparable values for these parameters. The minimum DNBR for both analyses remains above 1.19 for the duration of the event. Thus, from the results of this comparison, it can be concluded that the impact on the offsite doses is insignificant. Additionally, the comparison demonstrated that the plant is maintained in a stable condition by the collapse of the upper head voids due to automatic actions.

Subsequent to operator action, the operator can bring the plant to the shutdown cooling entry conditions, by cooling down the RCS at a prescribed cooldown rate using the intact steam generator, the condenser, and the feedwater system and by following specific plant procedures.

For the steam generator tube rupture with loss of offsite power event (see response to Question 440.69) similar conclusions as for the SGTR event without loss of offsite power can be made. For this case, the operator will not have the condenser available for cooldown, and would use the atmospheric dump valves. Additionally, the RCS will be in a natural circulation cooldown mode as a result of the coastdown of all RCS pumps following loss of offsite power. The analysis demonstrated that natural circulation cooldown of the RCS is not impaired as the amount of voids predicted is not large enough to expand the steam bubble beyond the upper head region and to the elevation of the hot legs.

The conclusions from the comparative analyses for the SGTR event bound the other depressurization events in Chapter 15.6 for which void formation is less limiting and/or non-existent. This is due to slower cooldown rates and higher minimum RCS pressures for these depressurization events. Thus, the qualification of CESEC II against CESEC III for the SGTR event provides the necessary justification for the acceptability of the Chapter 15 analyses conclusion for depressurization events.

C.

TABLE 440.67-1

SUMMARY OF SIGNIFICANT DIFFERENCES
BETWEEN CESEC-II AND CESEC-III

MODEL	CESEC-III	CESEC-II
THERMAL HYDRAULIC	26 NODES, UPPER HEAD EXPLICITLY MODELED	16 NODES
RCS FLOW	EXPLICITLY MODELED	INPUT TABLE
RCP's	FOUR, EXPLICITLY MODELED	TWO
WALL HEAT	EXPLICITLY MODELED	NONE
SGTR OPTION	CRITICAL FLOW CHECK	DARCY EQUATION
MIXING IN RV	ASYMMETRIC RESPONSE EXPLICITLY MODELED	ASYMMETRIC RESPONSE INCLUDED IN REACTIVITY CALCULATION FOR SLB
3-D FEEDBACK	YES	NO

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TABLE 440.67-2

COMPARISON OF RESULTS FOR THE STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER

	CESEC-II	CESEC-III
PRIMARY-SECONDARY INTEGRATED LEAK (LBM) AT 1800 SECONDS	61,480	61,010
INTEGRATED MSSV STEAM RELEASE (LBM) AT 1800 SECONDS	76,370	69,470
MINIMUM DNBR	>1.19	>1.19

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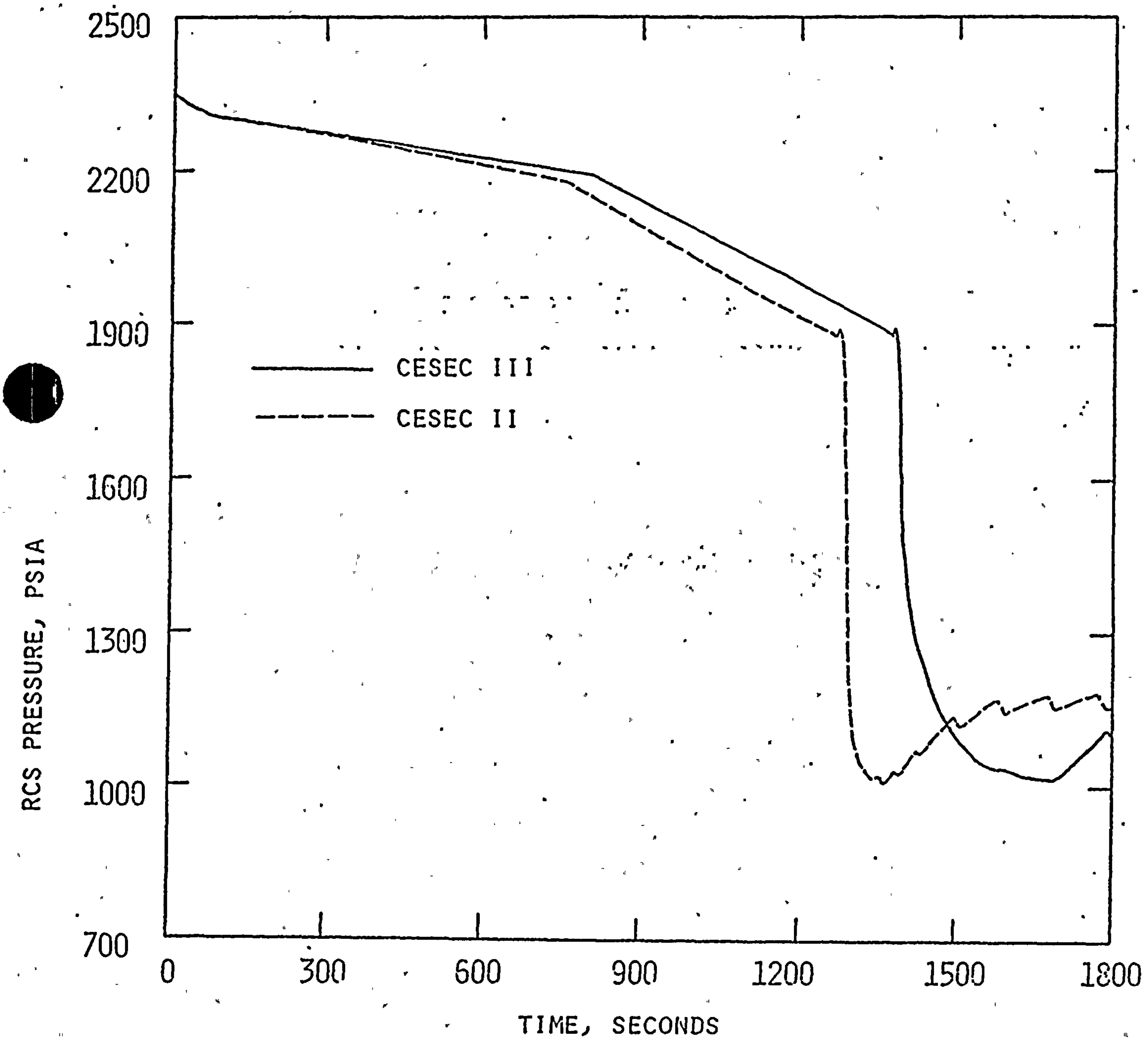

FIGURE 440.67-1

STEAM GENERATOR TUBE RUPTURE FOR ST. LUCIE 2 WITHOUT LOSS OF OFFSITE POWER - REACTOR COOLANT SYSTEM PRESSURE VS. TIME

440.67
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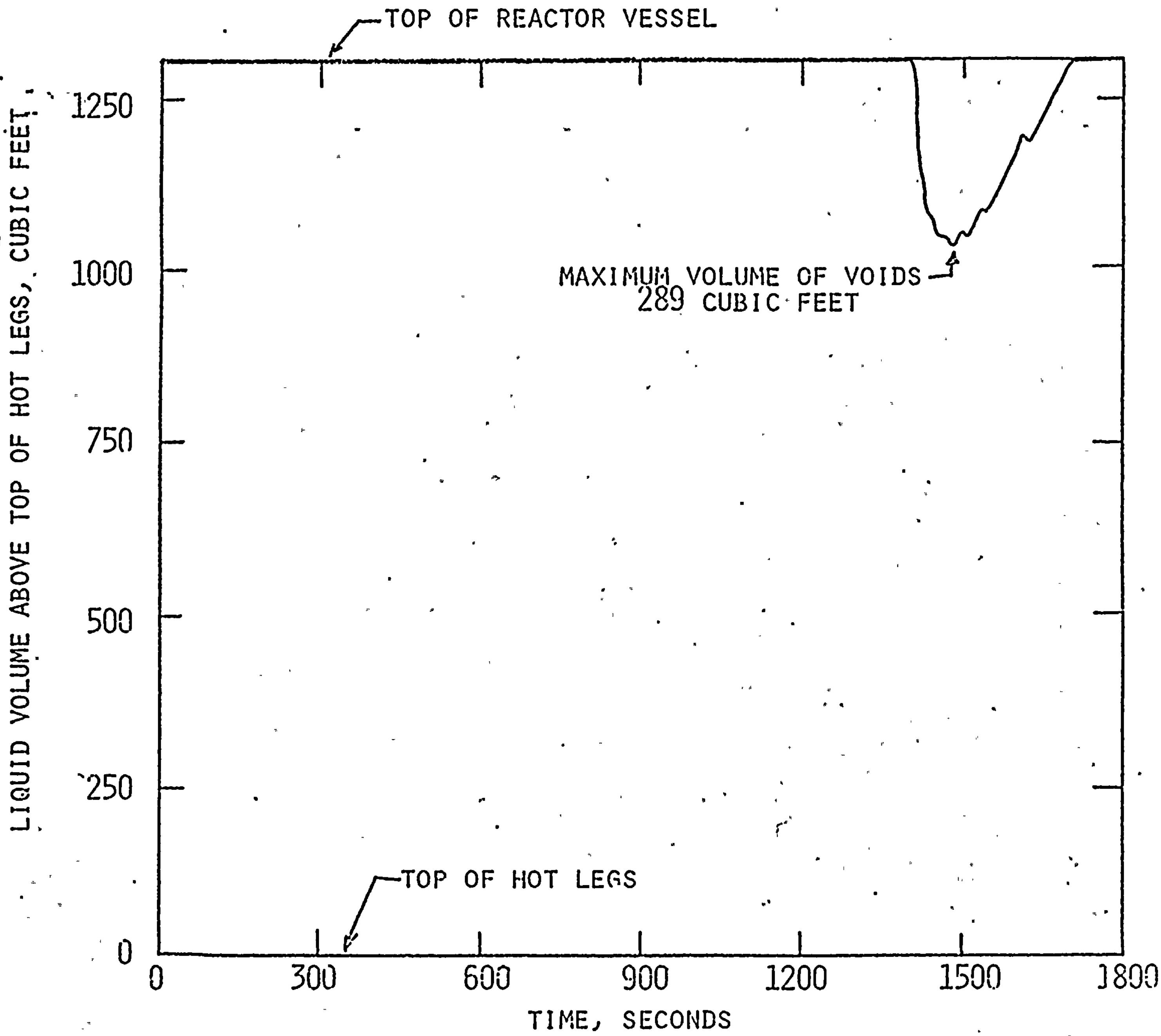

FIGURE 440.67-2

STEAM GENERATOR TUBE RUPTURE FOR ST. LUCIE 2 WITHOUT LOSS OF OFFSITE POWER - VOID FORMATION IN TOP OF REACTOR VESSEL

SL-2 Round One Questions

440.69 (15.6.2) SRP 15.6.3 acceptance criteria requires that this event be analyzed with a concurrent loss of offsite power. Provide an analysis for the limiting case which includes a concurrent loss of offsite power.

Response:

An analysis of the steam generator tube rupture (SGTR) event with concurrent loss of offsite power was performed. The results of this analysis show that the offsite doses are less than for the inadvertent opening of a letdown relief valve event presented in Section 15.6.3.1. A discussion of this event is presented in Appendix 15 C-~~6~~5.

A change to the FSAR, Appendix 15 C.~~6~~5 accompanies this response.

(d) There are no single failures identified in Table 15.0-6 which can adversely impact the consequences (i.e., pressurization) associated with the feedwater line break (FWLB) event addressed in Subsection 15.2.5.2. As a result of evaluation method applied to the FWLB analysis, the only mechanisms for mitigation of the reactor coolant system (RCS) pressurization are the pressurizer safety valves, the reactor coolant flow and main steam safety valves. The last two influence the RCS-to-steam generator heat transfer rate.

INSERT D1 ~~There are no credible failures which can degrade pressurizer safety valve or main steam safety valve capacity.~~ A decrease in RCS to steam generator heat transfer due to reactor coolant flow coastdown can only be caused by a failure to fast transfer to offsite power or a loss of offsite power following turbine trip (i.e., two or four pump coastdown, respectively). The FWLB analysis of Subsection 15.2.5.2 considers the worst of the two, the loss of offsite power.

INSERT D3

This evaluation of single failure impacts is consistent with FWLB analyses performed for other Combustion Engineering plants. No credible single failures can aggravate the RCS pressurization associated with the FWLB combined with a loss of offsite power following turbine trip.

INSERT D2

(e) Automatic auxiliary feedwater actuation will provide flow within two minutes of reactor trip; thereby, terminating the pressurizer level increase and any potential for filling the pressurizer.

Additional information on CESEC-III will be prepared by September 30, 1981.

Inserts for FSAR page 440.81-3

INSERT D1

Nor are there any credible failures which can reduce steam flow to the affected steam generator.(1)

INSERT D2 (this is a footnote)

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(1) It should be noted the coincident occurrences (failures) considered in Chapter 15 do not include spurious independent failures, only consequential failures and pre-existing failures. Accordingly, spurious closure of a main steam isolation valve is not considered credible during the FWLB event.

INSERT D3

The assumed time for MSIV closure is consistent with the timing of a MSIS generated by low steam generator pressure. As shown in Table 15.2.5.2-1 of the FSAR the MSIS on this parameter is not expected to occur until 163 seconds, 137 seconds after reactor trip. For the FSAR analysis, no credit was taken for either a reactor trip or MSIS being generated on high containment pressure. Analysis of the FWLB has shown that the occurrence of this reactor trip and MSIS earlier than the presently assumed trip would reduce the peak RCS pressure due to the earlier reduction of core power. MSIS occurring at or after the present reactor trip at 26 seconds will have no effect on peak RCS pressure because complete closure of the MSIVs occurs essentially at the same time as the peak RCS pressure. Although the MSIVs are designed to close within six seconds, five seconds was used for this analysis. The termination of heat removal from the unaffected steam generator is not rapid enough to produce an increase in the RCS pressure for this analysis.

Additionally, the high primary system pressures reported in Subsection 15.2.5.2 are due to the conservatively assumed coincident occurrence of a loss of normal ac power. WASH 1400 estimates the conditional probability of this at 1×10^{-3} (Ref. Appendix III, Section 6.3). From this we can easily conclude that the joint recurrence frequency for the initiating event with a concurent loss of ac power is less than 10^{-7} per plant year. Therefore, the event analyzed in Subsection 15.2.5.2 is indeed sufficiently low to satisfy the Level C Service categorization, as defined in Section 3 of the ASME Pressure Vessel Code.

An additional conservatism of the FSAR analysis, that should be pointed out, is that no credit is taken for PORV operation which would tend to minimize the peak primary system pressure.

INSERT B

~~Discussion of the conservatisms inherent in the analysis of~~ feedwater line breaks will be provided by September 30, 1981, including:

i) modeling of steam generator heat transfer,

ii) prediction of fluid conditions at the break location,

iii) correlation for prediction of break discharge rate,

iv) treatment of steam generator low water level trip,

v) selection of plant initial conditions, and

vi) selection of the "worst" break size.

~~No FSAR change is required.~~

INSERT B

The methodology utilized for analyzing feedwater line break (FWLB) for St. Lucie 2(SL-2) is that documented in Appendix 15B of CESSAR FSAR. The major evaluation areas unique to FWLB which SL-2 metholology addresses include the selection/treatment of:

a. Affected steam generator heat transfer.

b. Fluid conditions at the break.

c. Affected steam generator low level trip.

d. Break discharge.

e. Plant initial conditions.

f. Break size.

The methodology utilized simplified models rather than justifying detailed best estimate models to determine an upper limit for the reactor coolant system (RCS) pressurization transient. The following description will show that the SL-2 method is valid and conservative.

Affected Steam Generator Heat Transfer

RCS pressurization is largely a function of the rate which the affected steam generator heat transfer decreases as its inventory is depleted. The overall heat transfer coefficient will decrease as the steam generator tubes are exposed to increasing void fractions which force the tubes from the normal nucleate boiling heat transfer regime into transition boiling and eventually into liquid deficient heat transfer. Transition boiling is anticipated when the local void fraction exceeds 0.9. A gradual heat transfer reduction is expected, starting when the affected generator liquid inventory decreases to approximately 70,000 lbm forcing portions of the tubes into transition boiling, and continuing as transition boiling and then liquid deficient heat transfer propagate throughout the tubes. Figure 440.81.f-1 shows the expected behavior of the overall heat transfer coefficient, along with the behavior assumed for SL-2 evaluations.

440.81 (f)
3/6

B . . .

Appendix 15B of CESSAR FSAR documents the sensitivity of RCS pressurization to steam generator heat transfer behavior. The study verified that RCS pressurization is maximized by under-estimating the affected steam generator liquid mass corresponding to the initiation of heat transfer degradation (i.e., over-estimating the rate of heat transfer decrease). Therefore, SL-2 conservatively assumed heat transfer characteristics which were biased to under-estimate the liquid inventory at which degradation was initiated. The SL-2 model simply assumed heat transfer decreases instantaneously upon steam generator dryout.

Fluid Conditions at the Break.

The enthalpy of the fluid discharged from the feedline break partially determines the heat removal capability of the affected steam generator. Minimizing the discharge enthalpy reduces the heat removal and,thereby maximizes the RCS pressurization. The model for SL-2 was biased to conservatively under-estimate the discharge enthalpy. Figure 440.81.f-2 shows the behavior of the discharge enthalpy during steam generator dry-out predicted by the SL-2 method, along with the expected behavior.

The expected enthalpy response for SL-2 can be understood by considering relatively high location of the feedwater nozzle and distribution ring on the steam generator. Fluid discharge from a feedline break is drawn from the downcomer section through the feedwater distribution ring. Saturated liquid in the downcomer normally covers the feedwater ring. During FWLB the downcomer liquid will be depleted lowering the water level and uncovering the ring. A two phase fluid (high enthalpy) will de discharged thereafter. Feedwater ring uncovery and the associated high enthalpy will occur before the steam generator liquid inventory decreased below 100,000 lbm.

For SL-2 FWLB evaluation a simplistic model was used. The model assumes that saturated liquid is discharged from the break unitl no liquid remains in the steam generator.

Affected Steam Generator Low Level Trip

Reactor trip on a steam generator low water level can mitigate the RCS heatup and pressurization during FWLB. The SL-2 method for calculating affected steam generator low level trip was biased to conservatively delay the trip. Steam generator level is inferred from the measured elevation head associated with the downcomer fluid between two instrument tap locations. When the measured head decreases below a pre-determined setpoint a steam generator low level trip signal is generated. As the downcomer level decreases during FWLB low level trip is expected to occur with greater than 70,000 lbm of liquid in the affected steam generator.

The SL-2 method simply and conservatively assumed affected steam generator low water level does not occur until all liquid is depleted.

440.51 (f)
4/6

B ...

Break Discharge Rate

Maximizing the break discharge rate, when combined with underpredicting the discharge fluid enthalpy, reduces the heat removal capability of the affected steam generator and thereby aggravates RCS heatup and pressurization. The SL-2 evaluation conservatively estimated the flow rate assuming instantaneous establishment of frictionless critical flow through the break as predicted by the Henry/Fauske correlation*.

Plant Initial Conditions

Initial conditions (e.g., RCS pressure, steam generator, liquid inventory and core burnup) can be selected to maximize the RCS heatup and pressurization. The SL-2 FWLB evaluation selected the most adverse set of initial conditions within the allowable plant operating space, based on engineering judgement supported by sensitivity studies like those documented in Appendix 15B of CESSAR FSAR.

Break Size

The most adverse break size (.25 ft^2) was identified for SL-2 based on sensitivity studies consistent with the modeling assumptions previously described.

In summary, the FWLB evaluation method for SL-2 utilized simplifying assumption which incorporated many conservative biases with respect to the prediction of maximum RCS pressure (e.g., treatment of the affected steam generator heat transfer, fluid conditions at the break, and affected steam generator low level trip). The maximum RCS pressure predicted for limiting break size by the evaluation model is a conservative estimate which will not be exceeded by any feedwater line break event.

As documented above and in Appendix 15B of CESSAR FSAR, the SL-2 evaluation method for FWLB is valid and conservative.

Pressure Limits

The allowable pressure limits for feedwater line break events have been agreed upon as 110% of design pressure for the feedwater line break event by itself, and 120% of design pressure for the feedwater line break plus a coincident occurrence (eg., the loss of offsite power). The worst feedwater line break event without a coincident occurrence produces a peak RCS pressure which is less than 110% of design pressure (2750 psia), see Section 15.2.3.2.1.

A change to the FSAR Section 15.2.3.2.1 accompanies this response.

---

* R. E. Henry, H. K. Fauske, "The Two Phase Critical Flow of One-Component Mixtures in Nozzles, Orfices, and Short Tubes," Journal of Heat Transfer, Transections of the ASME, May, 1971.

440.81(f)
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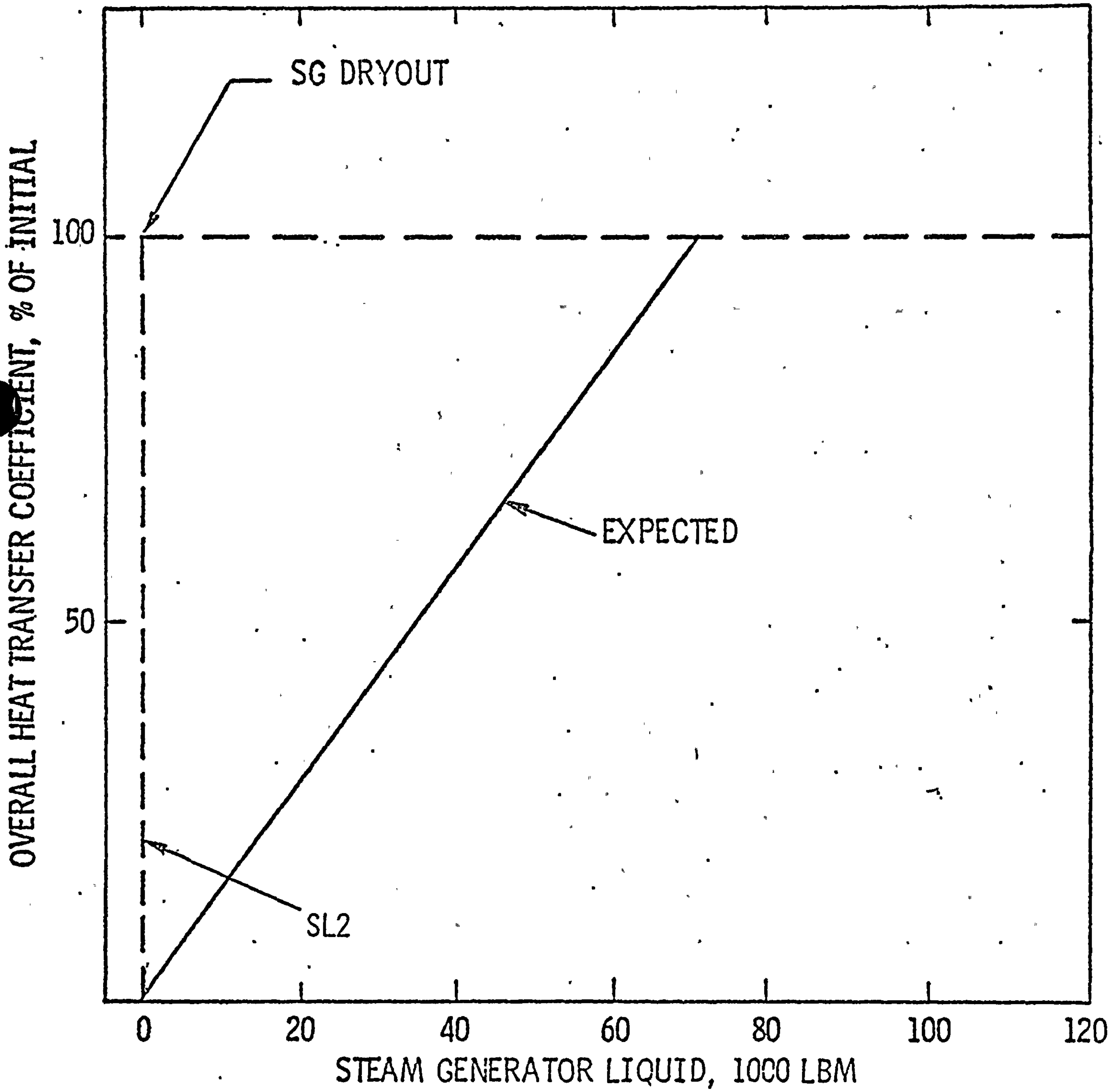
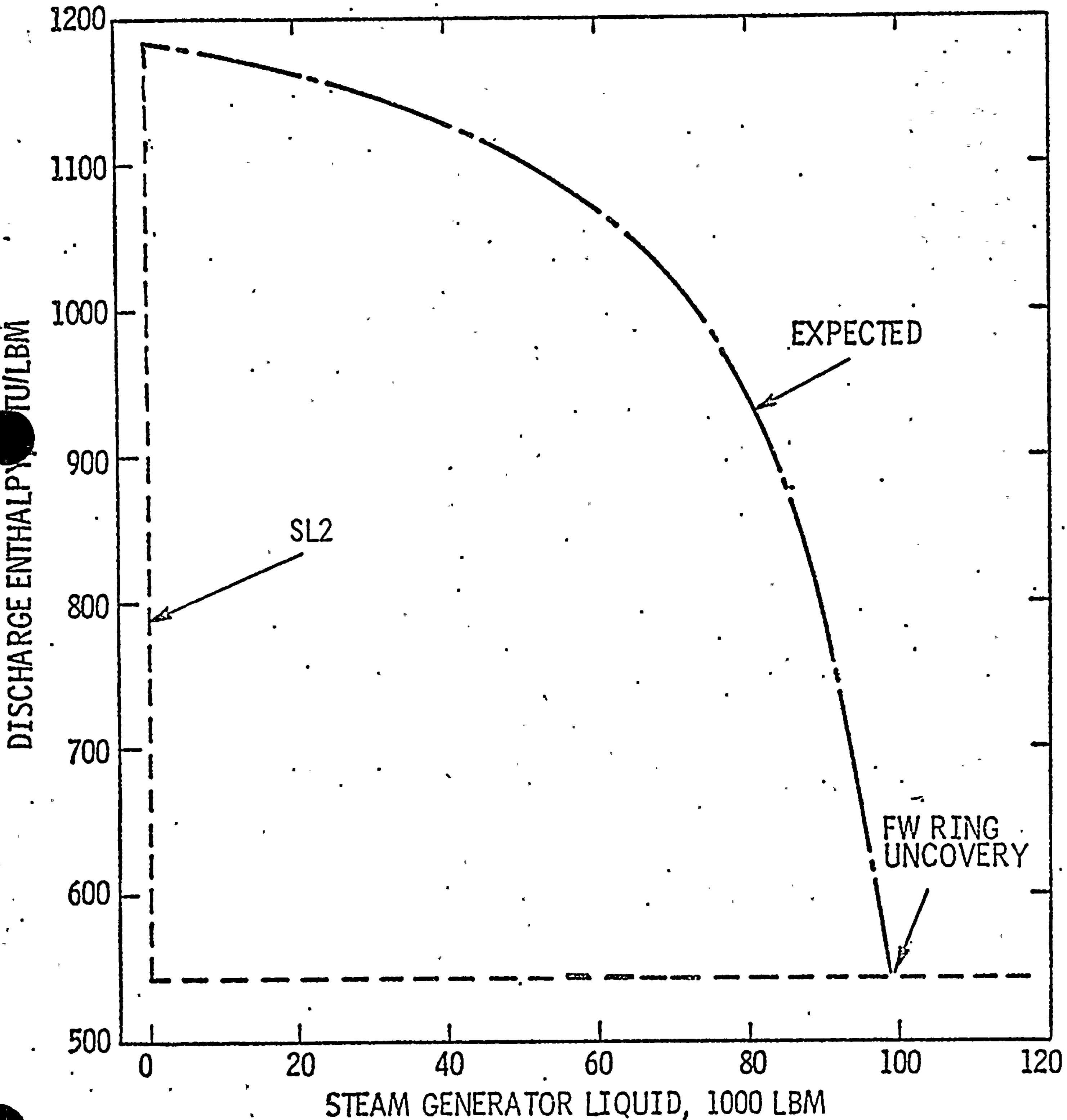
B...



FP&L	STEAM GENERATOR HEAT TRANSFER CHARACTERISTICS	Figur 440.81(

440.81 (f)
5/6

B . . .



FP&L	DISCHARGE ENTHALPY vs STEAM GENERATOR LIQUID INVENTORY	Figure 440.81(

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POWER
SYSTEMS

St. Lucie Plant
Unit No. 2 - 1978-890 MW Extension

Mr. K. N. Chow
Ebasco Services, Inc.
2 World Trade Center
80th Floor
New York, NY 10048

Subject: FSAR Chapter 15 Revisions

Dear Mr. Chow:

The revisions listed below are attached. These revisions resulted from NRC review of Chapter 15.

Section 1.9.8:	Documentation of Fuel Rod Failure Criterion (NRC/RSB Question 440.11).
Section 15.1.5:	Steam Line Break Analysis (NRC/AEB)
Section 15.2.5:	Feedwater Line Break Analysis Revision (NRC/ASB)
Section 15.3.3:	Seized Pump Shaft Analysis (NRC/RSB Question 440.25)
Section 15.4.2:	Part-Length Subgroup Drop Revision (NRC/CPB)
Appendix 15C.3:	CEA Ejection With Loss of Offsite Power Analysis (NRC/AEB)
Appendix 15C.4:	Total Loss of AC Power (Station Blackout)
Appendix 15C.5:	Steam Generator Tube Rupture With Loss of Offsite Power

If you have any questions on these revisions, please call S. E. Ritterbusch.

Very truly yours,

J. C. Moulton
Project Manager

JCM/SER/cw

cc: D. J. Chin
J. E. Sheetz
E. Z. Zuchman
L. Tsakiris
L. V. Pelosi
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R. E. Havner
E. R. Bottrill
M. Floyd
C. E. Waddell
G. Boissy

SL2/2907 1/80

"SAR/ER CHANGE REQUEST"

Change Number ______
By PLE/EPL

PART I INITIATION

(1) To: Ebasco

(2) From C-E

(3) Project: St. Lucie 2

(4) Subject: Safety Analysis

(5) Change Affects: [X] FSAR [ ] ER

(6) The Affected Areas is: Sections(s) 15.X Page(s) ______

(7) Recommended change and reason(s) for requesting change: (Note: Attach marked up copy of all affected pages).

Revisions and additions resulting from NRC review

(8) Change will impact the following: ie. Specs, Dwgs, Other Disciplines/Organizations

None

PART II REVIEW

(9) To: ______
Reviewing Organizations Review Part I and Note Impact Below

Response Requested By: ______

(10) From: ______
Project Licensing Engineer/Environmental Project Leader

(11) Impact on Reviewing Organization

a. Section ______ Page(s) ______ (Note: Attach marked up copy of all affected pages).

b. Other Impact ______

(12) Reviewers Signature ______ Date ______

PART III APPROVAL

(13) Required Concurrences:

a. Approved S. E. Ritterbusch SER Date 9/21/81
Originating Engineer

b. Approved ______ Date ______
Responsible Supervisor.

c. Approved ______ Date ______
PLE/EPL

d. Approved ______ Date ______
Project Engineer

e. Client Approval ______ Date ______
FP&L Letter Number

(14) Disposition [ ] Implemented [ ] Not Implemented Date ______

(15) Comments: ______

cc: Project Engineer

ORIGINAL RETAINED IN PLE OR EPL FILES

Per a memorandum and order issued on May 23, 1980[11], the NRC has ordered applicants for operating licenses to meet the requirements of NUREG-0588[12] to satisfy the aspects of 10CFR50 Appendix A, General Design Criterion 4 which relates to environmental qualification of safety-related equipment. FP&L has initiated a program to review safety related electrical equipment qualifications in light of NUREG-0588 requirements. An amendment is anticipated to be available by January 1982. 0

1.9.8 DOCUMENTATION OF FUEL ROD FAILURE

~~Documentation of~~ The fuel rod failure criterion used in the analysis of the one pump resistance to forced flow (locked rotor, Section 15.3) event ~~will be presented in Appendix 15C in a later amendment.~~ is consistent with that used for other Chapter 15 analyses. See Section 15.0.4.4.3(b) for a description of the fuel rod failure criterion 440.11 0

15.1 INCREASED HEAT REMOVAL BY THE SECONDARY SYSTEM

15.1.1 MODERATE FREQUENCY EVENTS

There is no event group in Table 15.0-2 which results in an increase in heat removal by the secondary system and has an estimated frequency of occurrence which would classify it as a Moderate Frequency event.

15.1.2 INFREQUENT EVENTS

15.1.2.1 Limiting Offsite Dose Event-Increased Feedwater Flow with a Failure to Achieve a Fast Transfer of a 4.16 kV Bus

15.1.2.1.1 Identification of Event and Causes

All Infrequent event groups from the Increased Heat Removal by the Secondary System event type and the Infrequent event group combinations shown in Table 15.1.2-1 were compared to find the event resulting in the maximum site boundary doses. Increased feedwater flow with a failure to achieve a fast transfer of a 4.16 kV bus was identified as the limiting Infrequent event.

offsite

The event groups and event group combinations evaluated and the significance of the site boundary doses for each are indicated in Table 15.1.2-1. All events indicated as insignificant (I) would produce offsite doses well within the acceptance guideline in Table 15.0-4. All events indicated as significant (S) produce offsite doses within the acceptance guideline. 2
No combinations of event groups and other failures, other than those shown in Table 15.1.2-1 fall in the Infrequent category.

An increased feedwater flow may occur due to opening of one or more of the main feedwater control valves in excess of feedwater requirements, increase of steam driven auxiliary feedwater pumps speed, or misoperation of the feedwater heater drain system. (See Table 15.0-1 for a list of initiating events in each event group.)

Opening of all main feedwater control valves, which results in the largest increase in feedwater flow, was used to simulate this event. In this analysis, a failure to achieve a fast transfer of a 4.16 kV bus occurs immediately after turbine trip, assumed to result in the loss of condenser vacuum. 2

Of the two event groups, increased feedwater flow and increased main steam flow through the turbine, considered in the Infrequent frequency category, increased main steam flow through turbine will not cause a reactor trip, and therefore, will not result in steam releases to the atmosphere. Increased feedwater flow with failure to achieve a fast transfer to a startup transformer is the limiting combination, since failure to achieve a fast transfer of a 4.16 kV bus is assumed to result in loss of condenser availability 2
causing steam releases to occur either through the main steam safety valves (MSSVs) or through the atmospheric dump valves (ADVs) thus maximizing the offsite doses. 2

15.1.5 LIMITING FAULT 3 EVENTS

INSERT NEW SECTION (ATTACHED)

~~15.1.5.1 Limiting Offsite Dose Event~~

~~None of the Limiting Fault-3 event groups and event group combinations~~
~~resulting in an increased heat removal by the secondary system shown in~~ 2
~~Table 15.1.5-1 release a significant amount of radioactivity to the at-~~
~~mosphere. The additional failures and events considered here produce~~
~~results incrementally more adverse than the increased feedwater flow~~
~~with a failure to achieve a fast transfer of a 4.16 kV bus described in~~
~~Subsection 15.1.2.1. The offsite doses which would occur during the most~~
~~adverse of these event groups and event group combinations are well within~~ 2
~~the acceptance guideline specified in Table 15.0-4.~~

15.1.5.2 Limiting Reactor Coolant System Pressure Event

All Limiting Fault-3 event groups and event group combinations resulting
in an increased heat removal by the secondary system shown in Table
15.1.5-1 are characterized by decreasing Reactor Coolant System (RCS) 2
pressure. The peak RCS pressure which would occur during the most adverse
of these events does not approach the acceptance guideline specified in
Table 15.0-4.

15.1.5.3 Limiting Fuel Performance Event - Loss of Main Steam With Loss of Offsite Power as a Result of Turbine Trip

15.1.5.3.1 Identification of Event and Causes

All Limiting Fault-3 (LF-3) event groups from the Increased Heat Removal by the Secondary System event type and the LF-3 event group combinations shown in Table 15.1.5-1 were compared to find the limiting fuel performance event. The loss of main steam-large, inside containment with loss of offsite power as a result of turbine trip was identified as the limiting LF-3 event.

The event groups and event group combinations evaluated and the sig-
nificance of the approach to the fuel performance acceptance guidelines 2
are indicated in Table 15.1.5-1. All event groups or event group combina-
tions indicated as insignificant (I) produce fuel performance well within
the acceptance guideline in Table 15.0-4. All events indicated as signifi-
cant (S) produce a fuel performance within the acceptance guideline. 2

The loss of main steam-large, inside containment may occur due to a break
in the 34/36 inch main steam line. 2

Breaks ranging from 0.056 ft^2 area up to the double-ended rupture of the 2
34/36 inch main steam line are included in this event group. Events with
break areas less than 0.056 ft^2 are classified in the small loss of main
steam event group. The potential for degradation in fuel performance was 2
maximized by an intermediate size break (2.27 ft^2) (see Subsection
15.1.5.3.3 for details). The loss of offsite power as a result of turbine
trip causes the coastdown of all reactor coolant pumps.

Of all the event groups and event group combinations considered in the LF-3 category, loss of main steam events caused by large steam line breaks, both

15.1.5 LIMITING FAULT 3 EVENTS

15.1.5.1 Limiting Offsite Dose Event - Loss of Main Steam Outside Containment, Upstream of MSIV With Loss of Offsite Power as a Result of Turbine Trip.

15.1.5.1.1 Identification of Event and Causes

All Limiting Fault-3 event groups and event group combinations resulting in an increased heat removal by the secondary system shown in Table 15.1.5-1 were compared to find the event resulting in the maximum offsite doses. The loss of main steam-large, outside containment, upstream of MSIV with loss of offsite power as a result of turbine trip and with technical specification primary to secondary leakage through the steam generator tubes was identified as the limiting LF-3 event.

The event groups and event group combinations evaluated and the significance of the offsite doses for each are indicated in Table 15.1.5-1. All events indicated as insiginficant (I) would produce offsite doses well within the acceptance guideline in Table 15.0-4. All events indicated as significant (S) produce offsite doses within the acceptance guideline.

The loss of main steam-large, outside containment may occur due to a break in the 34 inch main steam line.

Breaks ranging from 0.056 ft^2 area up to the double-ended rupture of the 34 inch main steam line break are included in this event group. Events with break areas less than 0.056 ft^2 are classified in the small loss of main steam event group. The offsite doses were maximized by assuming an intermediate break (1.8 ft^2) which results in a minimum DNBR below 1.19. Technical specification tube leakage also increased the offsite doses. The loss of offsite power as a result of turbine trip causes the coastdown of all reactor coolant pumps.

Of the two event groups, loss of main steam-large inside containment and loss of main steam-large outside containment, in the LF-3 category, loss of main steam-large, inside containment will not cause a significant amount of steam release to the atmosphere and therefore will not result in significant offsite doses. Loss of main steam-large, outside containment with a loss of offsite power and a technical specification tube leakage is the limiting event combination, since the decreased RCS flow due to the loss of power results in degradation of fuel performance, and the technical specification tube leakage maximizes the release of activity to the atmosphere.

15.1.5.1.2 Sequence of Events and Systems Operation

Table 15.1.5.1-1 presents a chronological list and timing of system actions which occur following the large loss of main steam event outside containment with a loss of offsite power as a result of turbine trip.

The sequence of events and systems operation are identical to those presented in 15.1.5.3.2 and Figure 15.1.5.3-1 with the exception of the reactor trip set points and the response of systems acutated by the occurrence of high containment pressure. High containment pressure is not present in this event.

Table 15.1.5.1-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient. The operation of these systems is consistent with the guidelines of Subsection 15.0.2.3.

Table 15.1.5.1-3 contains a matrix which describes the extent to which safety systems are assumed to function during the transient.

15.1.5.1.3 Analysis of Effects and Consequences

a) Mathematical Models

The NSSS response to a loss of main steam with loss of offsite power as a result of turbine trip was simulated using the CESEC computer program described in Subsection 15.0-4. The transient minimum DNBR values were calculated using the TORC code which used the CE-1 CHF correlation described in Subsection 15.0-4.

b) Input Parameters and Initial Conditions

From the range of values for each of the principal process variables given in Subsection 15.0-3, a set of initial conditions contained in Table 15.1.5.1-4 was chosen that produces the lowest minimum DNBR. Additional clarification of the assumptions and parameters listed in Table 15.1.5.1-4 follows.

Maximum initial core power, maximum initial core inlet temperature, mimimum initial core mass flowrate and initial RCS pressure are chosen to minimize the DNBR, and maximize offsite doses.

The moderator temperature coefficient and break size were varied to delay the occurrence of reactor trip either on low steam generator pressure or high core power level, thus maximizing the core heat flux. An intermediate break size corresponding to 1.8 ft^2 effective steam flow area per steam generator with a moderator coefficient of -1.6×10^{-4} $\Delta\rho/F$ results in the lowest value of minimum DNBR and maximum degradation of fuel performance.

In order to further maximize the degradation in fuel performance and, thus, to maximize offsite doses, the time of turbine trip and the loss of offsite power, which caused four reactor coolant pumps to coastdown, is chosen so that the low reactor coolant flow trip condition occurs coincident with the low steam generator pressure reactor trip.

In this event, the turbine is assumed to trip prior to reactor trip due to depressurization of Main Steam System. The reactor trip on low hdyraulic oil pressure is expected to occur during this event. In this analysis it is conservatively assumed that this trip does not occur prior to reactor trip on low reactor coolant flow or low steam generator pressure.

The Pressurizer Pressure Control System and the Pressurizer Level Control System are assumed to be in the manual mode of operation and, therefore, do not function to mitigate depressurization of the Reactor Coolant System (RCS). This results in low RCS pressure which mimimizes the DNBR.

The highest one pin radial peak with the most top peaked axial power shape is chosen to minimize the DNBR during the transient.

c) Results

The dynamic behavior of important NSSS parameters following this event are presented on Figures 15.1.5.1-1 to 14. Table 15.1.5.1-1 summarizes some of the important results of this event and the times at which minimum and maximum parameter values discussed below occur.

A break in the main steam line outside containment causes an increase in steam flow, resulting in depressurization of the steam generators as shown on Figure 15.1.5.1-9. The pressure decrease initiates a low steam generator pressure trip and, subsequently, generates a main steam isolation signal (MSIS). MSIS closes the main steam isolation valves and main feedwater isolation valves isolating the intact steam generator while the steam generator connected to the ruptured line continues to blow down through the break.

The decreasing secondary pressure and temperature leads to an increase in primary to secondary heat transfer rate which causes the primary coolant (core average) temperature to decrease. Prior to reactor trip due to a negative moderator temperature coefficient, the decreasing core average temperature causes moderator reactivity to increase, resulting in an increase of core power. After reactor trip, the core power further decreases to decay power level as shown on Figure 15.1.5.1-1.

The increasing core heat flux and the decreasing reactor coolant flow rate result in a decreasing minimum DNBR as shown on Figure 15.1.5.1-8. The reactor trip causes the core heat flux to decrease resulting in a subsequent increase in minimum DNBR. The minimum DNBR experienced during a loss of main steam with a loss of offsite power as a result of turbine trip is 0.88 resulting in 3.1 percent of the fuel pins in DNB.

During this event, two sources of radioactivity contribute to the offsite dose, the initial activity in the steam generator inventory, which is assumed to be 0.1 μCi/cc dose equivalent I-131, and the activity which is added to the steam generator during the transient due to assumed Technical specification primary to secondary leakage through the steam generator tubes of 1 gallon/minute.

During the cooldown, steam releases from the intact steam generator via the MSSVs and ADVs contribute to the offsite dose.

The offsite dose due to the loss of main steam-large, outside containment with loss of offsite power and with technical specification primary to secondary leakage through the steam generator tubes results in no more than a 64 rem two hour inhalation thyroid dose at the exclusion area boundary. The total offsite doses during this event are shown in Table 15.1.5.1-5.

15.1.5.1.4 Conclusions

This evaluation shows that the plant response to the loss of main steam-large, outside containment with loss of offsite power as a result of turbine trip and with technical specification primary to secondary leakage through the steam generator tubes results in maximum offsite doses which are within the acceptance guideline in Table 15.0-4.

TABLE 15.1.5.1-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR A LARGE LOSS OF MAIN STEAM EVENT, OUTSIDE CONTAINMENT UPSTREAM OF MSIV WITH A LOSS OF OFF-SITE POWER AFTER TURBINE TRIP

Time (Sec)	Event	Analysis Set Point or Value	Success Paths: Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Maintenance of AC Power	Containment Integrity	Plant Habit Habitability	Radioactive Effluent Control
0.0	1.8 ft^2 break in a 34 inch main steam line	--								
47	Turbine trip assumed				X					
	- Off-site power lost	--								
	- Diesel generator starting signal	--					X			
	- Four RCPs coastdown	--								
47	Maximum reactor power, %	134								
48.1	Reactor trip signal generated on low RCS flow, % of rated flow or low steam generator pressure, psia	93 590	X							
50.9	Minimum DNBR	0.88								
66.4	MSIS generated on low SG pressure, psia	460	X		X					
68.0	SIAS generated on low pressurizer pressure, psia	1578	X	X		X	X	X	X	X
69	Pressurizer empties	--								
130	HPSI flow begins	--								
311	Affected steam generator empties	--								
650	Operator actuates auxiliary feedwater to intact SG	--			X					

TABLE 15.1.5.1-1 (Cont'd)

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR A LARGE LOSS OF MAIN STEAM EVENT, OUTSIDE CONTAINMENT UPSTREAM OF MSIV WITH A LOSS OF OFF-SITE POWER AFTER TURBINE TRIP

Time (Sec)	Event	Analysis Set Point or Value	Success Paths							
			Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Maintenance of AC Power	Containment Integrity	Plant Habit Habitability	Radioactive Effluent Control
1800	1. Operator actuates atmospheric dump valves to commence cooldown of RCS	--			X					
	2. Operator loads the following on safety buses charging pumps pressurizer heaters									
	3. Operator borates to cold shutdown concentration	--	X							
	4. Operator clears SIAS and reestablishes letdown	--				X				
7200	Off-site Power restored	--								
12,240+	Shutdown cooling initiated, °F/psia	350/275		X						

TABLE 15.1.5.1-2

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR THE LOSS OF MAIN STEAM-LARGE, OUTSIDE CONTAINMENT UPSTREAM OF MSIV WITH THE LOSS OF OFFSITE POWER AFTER TURBINE TRIP

SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	MANUAL MODE THROUGH-OUT TRANSIENT	NORMAL AUTOMATIC MODE INOPERATIVE ON LOSS OF A.C.	MANUAL MODE INOPERATIVE ON LOSS OF A.C.	FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater System			X			
2. Turbine-Generator Control System	X					
3. Steam Bypass Control System				X		
4. Pressurizer Pressure Control System				X		3
5. Pressurizer Level Control System				X		
6. Control Element Drive Mechanism Control System	X					
7. Reactor Regulating System				X		
8. Reactor Coolant Pumps				X		1
9. Chemical and Volume Control System				X		3
10. Condenser Evacuation System				X		
11. Turbine Gland Sealing System				X		
12. Component Cooling Water System	X			X		2,4
13. Turbine Cooling Water System		X				
14. Intake Cooling Water System	X					2,4
15. Condensate Transfer System			X			
16. Circulating Water System				X		
17. Spent Fuel Pool Cooling System				X		3
18. AC Power (Non-Safety)			X			
19. AC Power (Safety)	X					2
20. D. C. Power		X				1
21. Power Operated Relief Valves		X				
22. Instrument Air System			X			3
23. Waste Management-Liquid				X		

NOTES:
1. System has no automatic mode.
2. Lose power on loss of offsite power, then automatically loaded on diesel generator.
3. Operator must connect to safety bus for operation.
4. Only essential portions of the system are available.

TABLE 15.1.5.1-3

UTILIZATION OF SAFETY SYSTEMS FOR THE LOSS OF MAIN STEAM-LARGE, OUTSIDE CONTAINMENT UPSTREAM OF MSIV WITH THE LOSS OF OFF-SITE POWER AFTER TURBINE TRIP

	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACKUP TO NONSAFETY GRADE SYSTEM	FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	X				
2. Engineered Safety Features Actuation Systems	X				2
3. Diesel Generators and Support Systems	X				
4. Reactor Trip Switch Gear	X				
5. Main Steam Safety Valves					
6. Pressurizer Safety Valves					
7. Main Steam Isolation Valves	X				
8. Main Feedwater Isolation Valves	X				
9. Auxiliary Feedwater System	X				
10. Safety Injection System	X				
11. Shutdown Cooling System (CCW & ICW)	*X				
12. Atmospheric Dump Valve System	*X				
13. Containment Isolation System					
14. Containment Spray System					
15. Iodine Removal System					
16. Containment Combustible Gas Control System					
17. Containment Cooling System	X				1

NOTES:

* Manually actuated during normal cool down

1. Normally operating system (in nonsafety mode)
2. Permissive blocks of SIAS and MSIS are manually actuated to permit shutdown depressurization.

Systems not checked are not utilized during this event.

TABLE 15.1.5.1-4

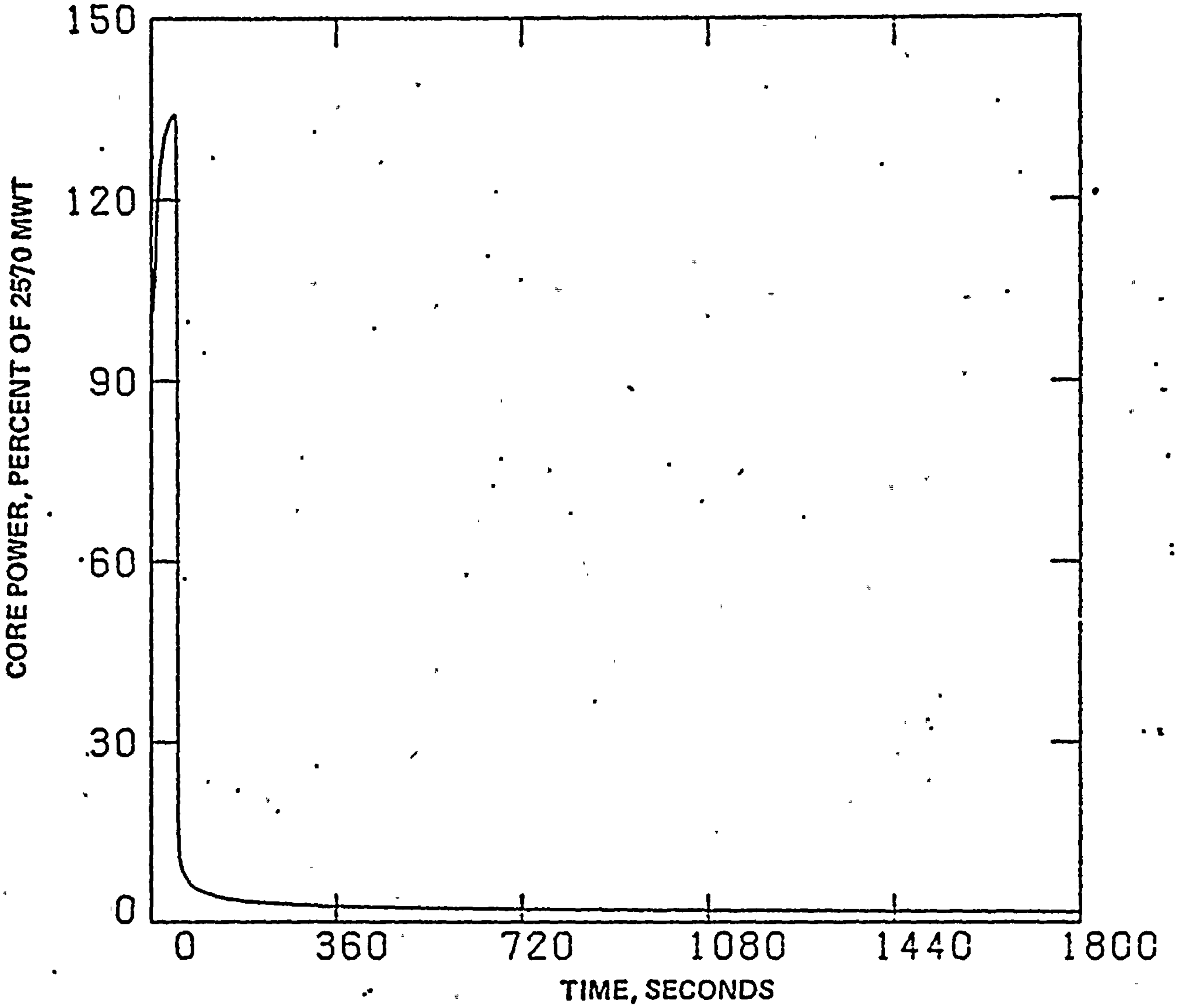
ASSUMED INPUT PARAMETERS AND INITIAL CONDITIONS FOR LOSS OF MAIN STEAM, LARGE, OUTSIDE CONTAINMENT UPSTREAM OF MSIV WITH LOSS OF OFFSITE POWER AS A RESULT OF TURBINE TRIP

Parameter	Assumed Value
Initial Power Level, MWt	2621.4
Initial Core Inlet Coolant Temperature, F	551
Initial Core RCS Flow Rate, gpm	370,000
Initial RCS Pressure, psia	2,150
Initial Pressurizer Water Volume, % Level	53
Axial Shape Index	-0.3
Doppler Coefficient Multiplier	1.0
Moderator Temperature Coefficient, $10^{-4}\Delta\rho/F$	-1.6
CEA Worth for Trip, $10^{-2}\Delta\rho$	-6.676
Break Size, ft^2	1.8

TABLE 15.1.5.1-5

OFFSITE DOSES

	Two Hour Exclusion Area Boundary Dose	Entire Event Low Population Zone Dose
Thyroid	64 rem	
Whole Body		



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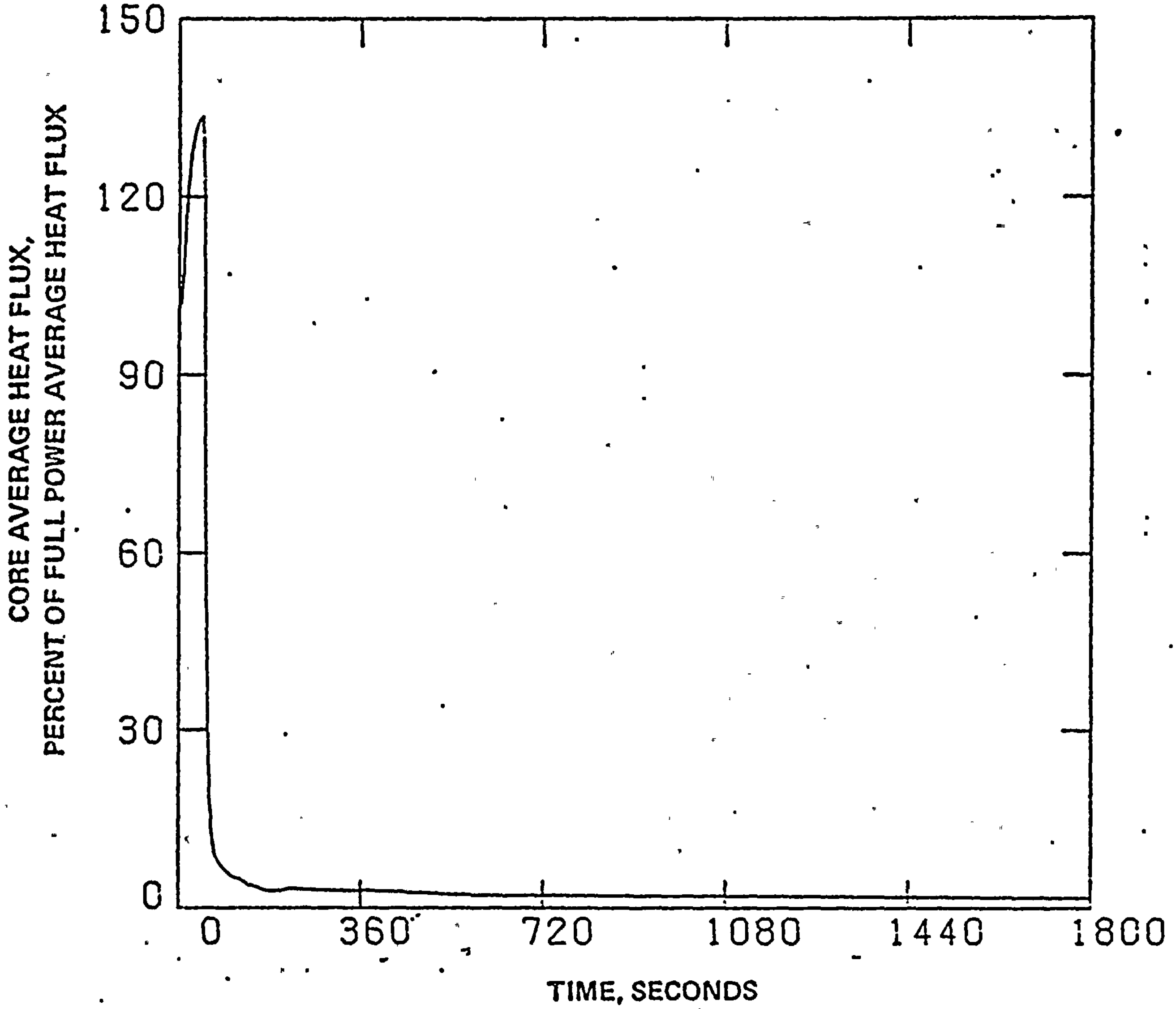
CORE POWER VS TIME

FIGURE 15.1.5.1-2



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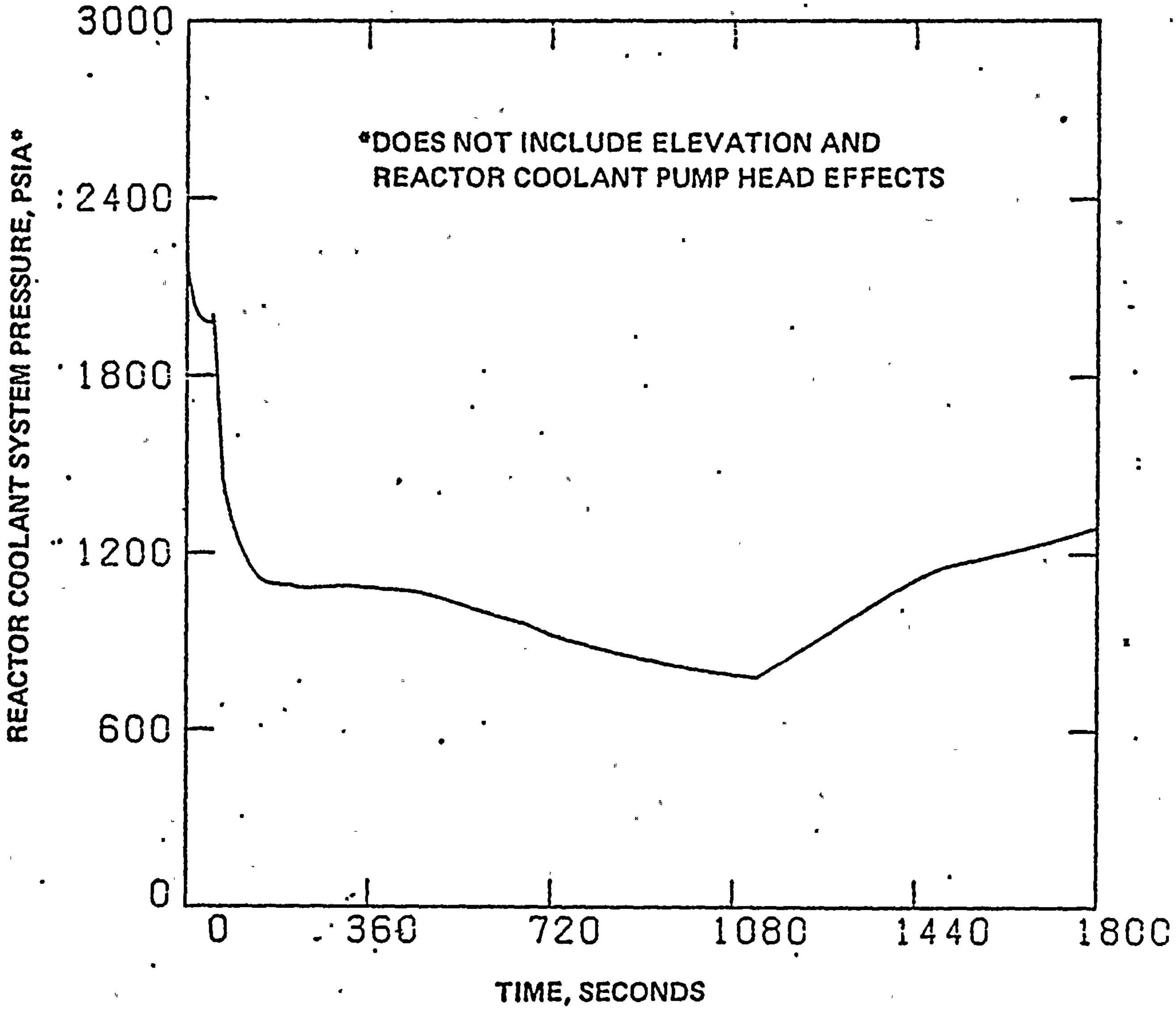
CORE AVERAGE HEAT FLUX
VS TIME

FIGURE 15.1.5.i-3



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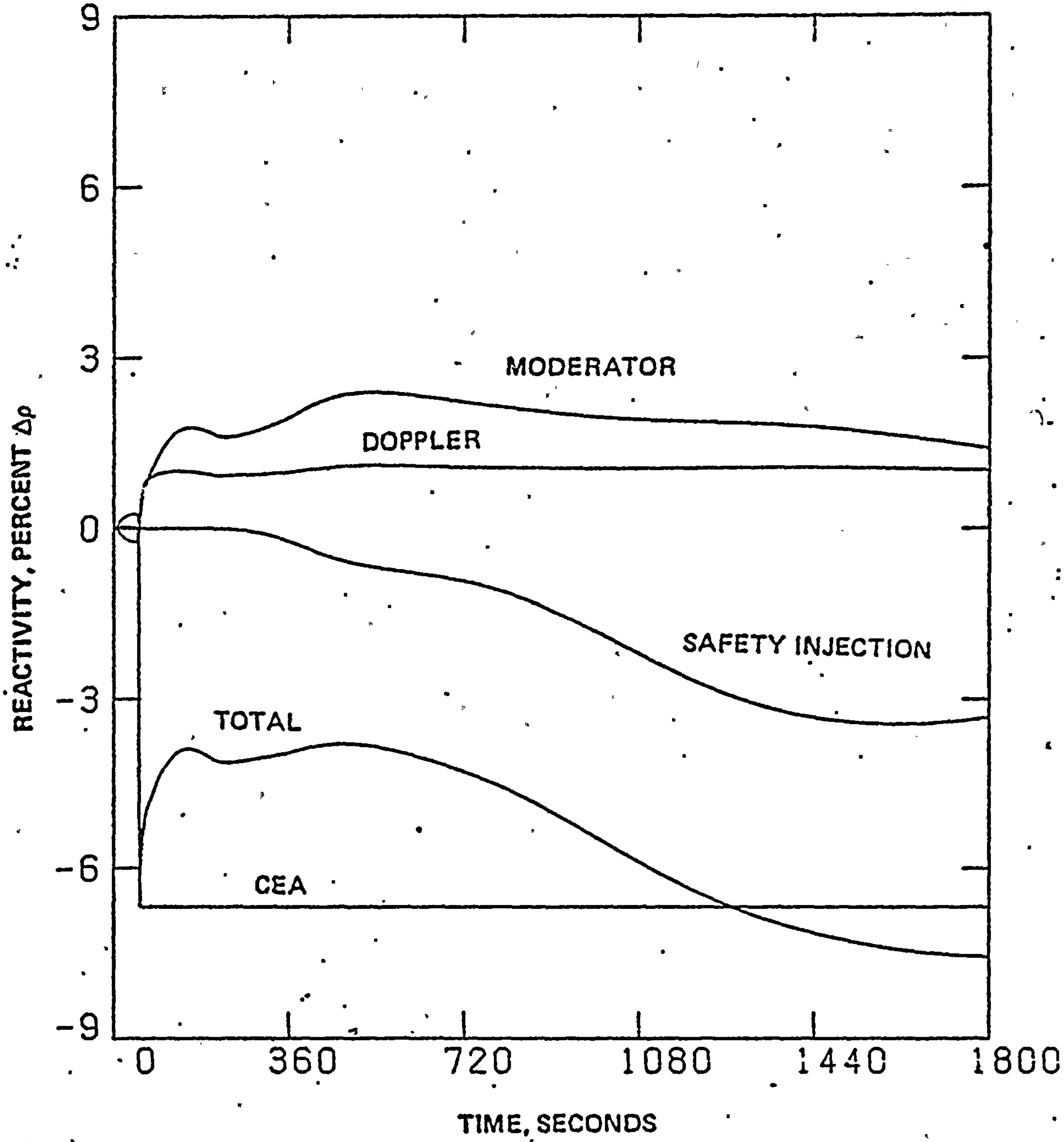
REACTOR COOLANT SYSTEM
PRESSURE VS TIME

5



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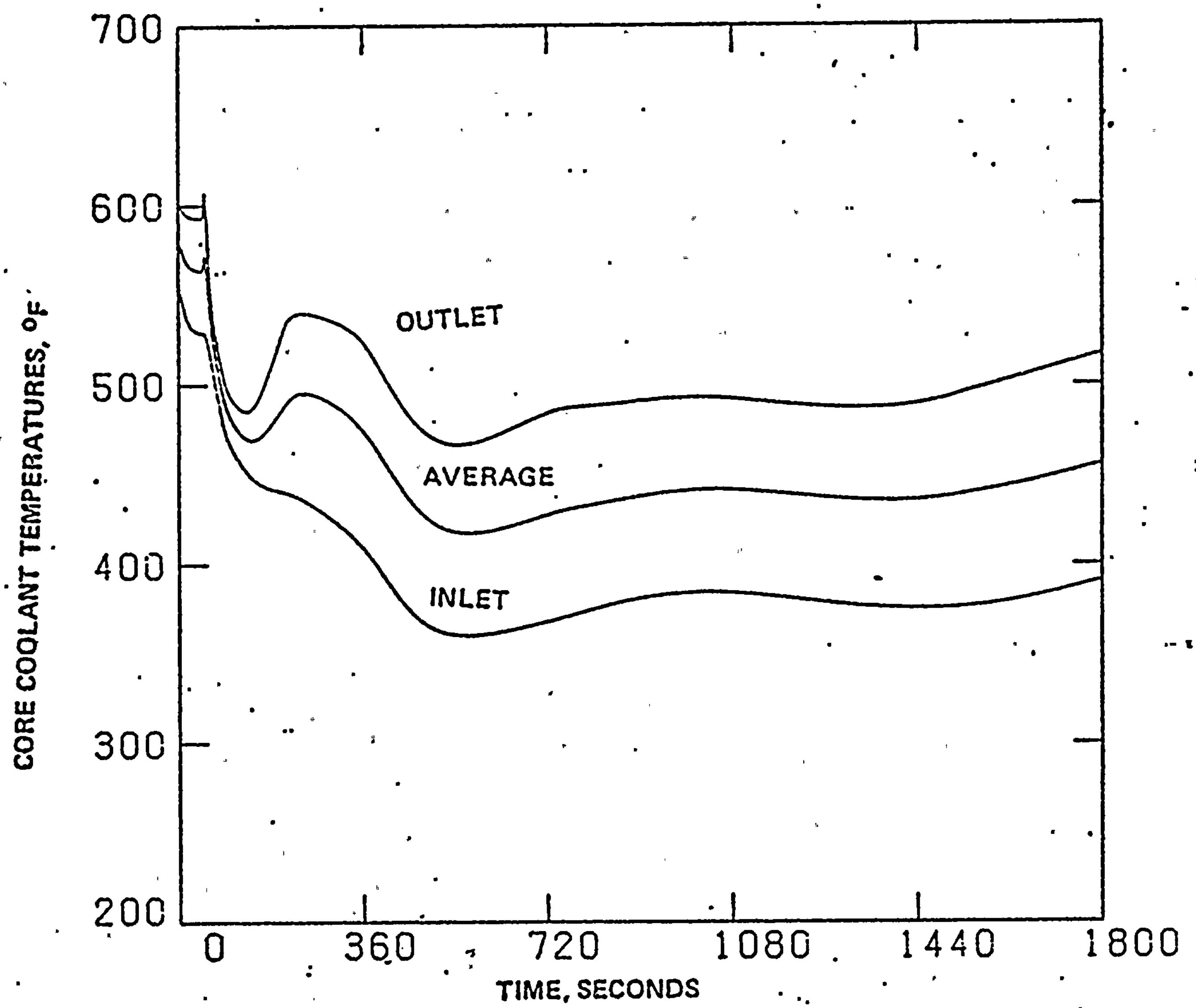
REACTIVITY VS TIME



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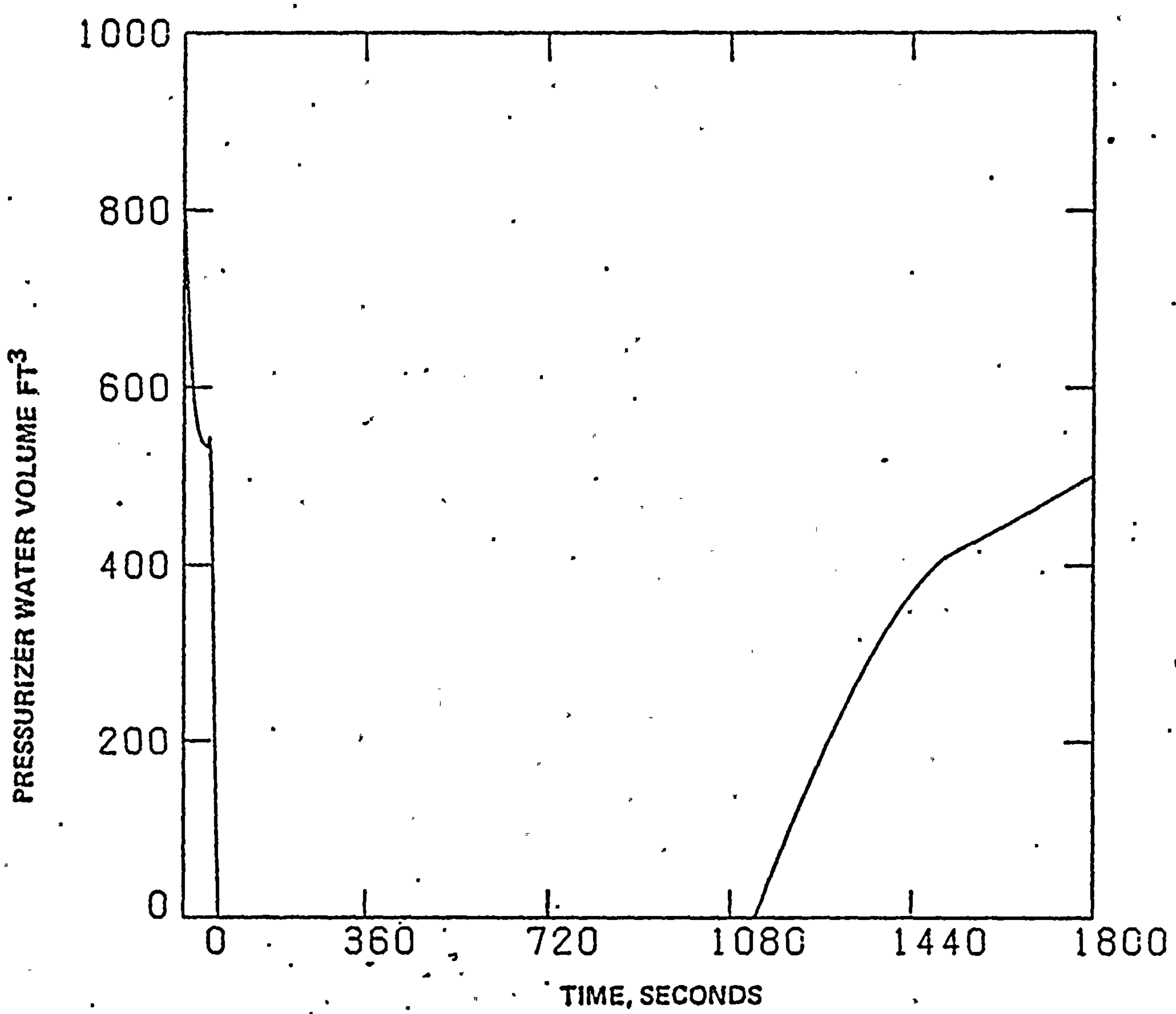
CORE COOLANT TEMPS. VS. TIME
FIGURE 15.1.5.1-5



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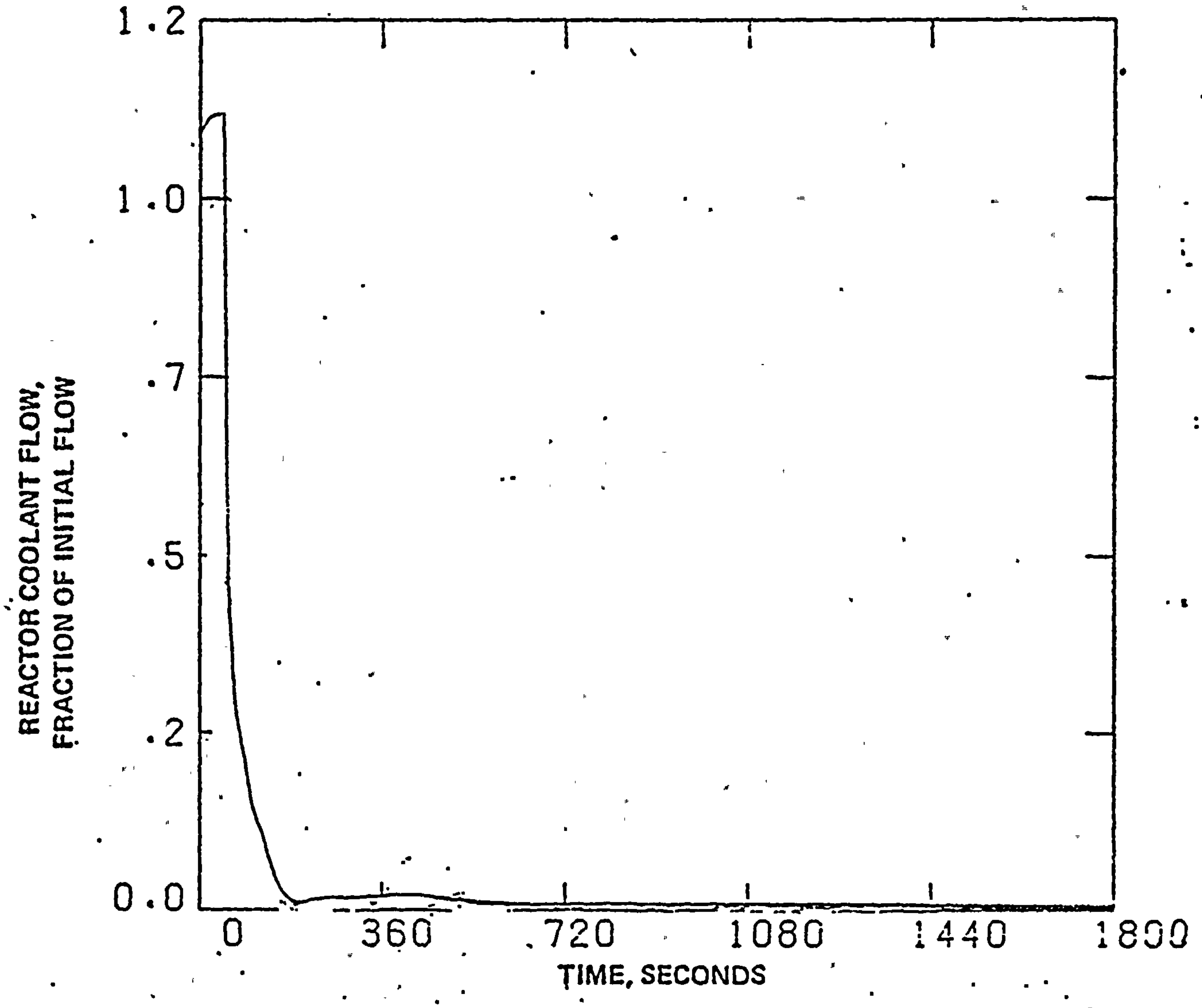
PRESSURIZER WATER VOLUME VS. TIME
FIGURE 15.1.5.1–7



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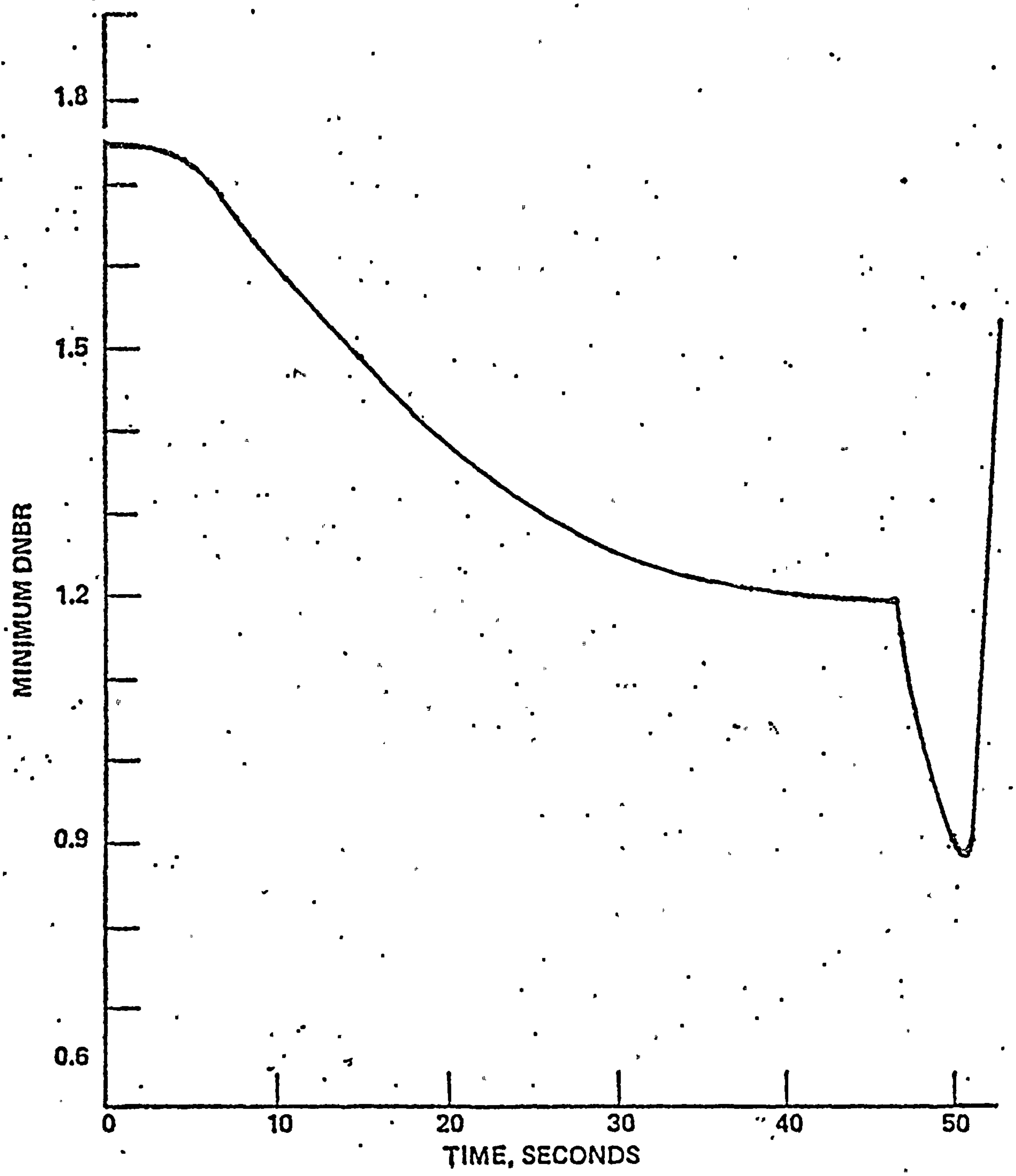
REACTOR COOLANT FLOW VS TIME



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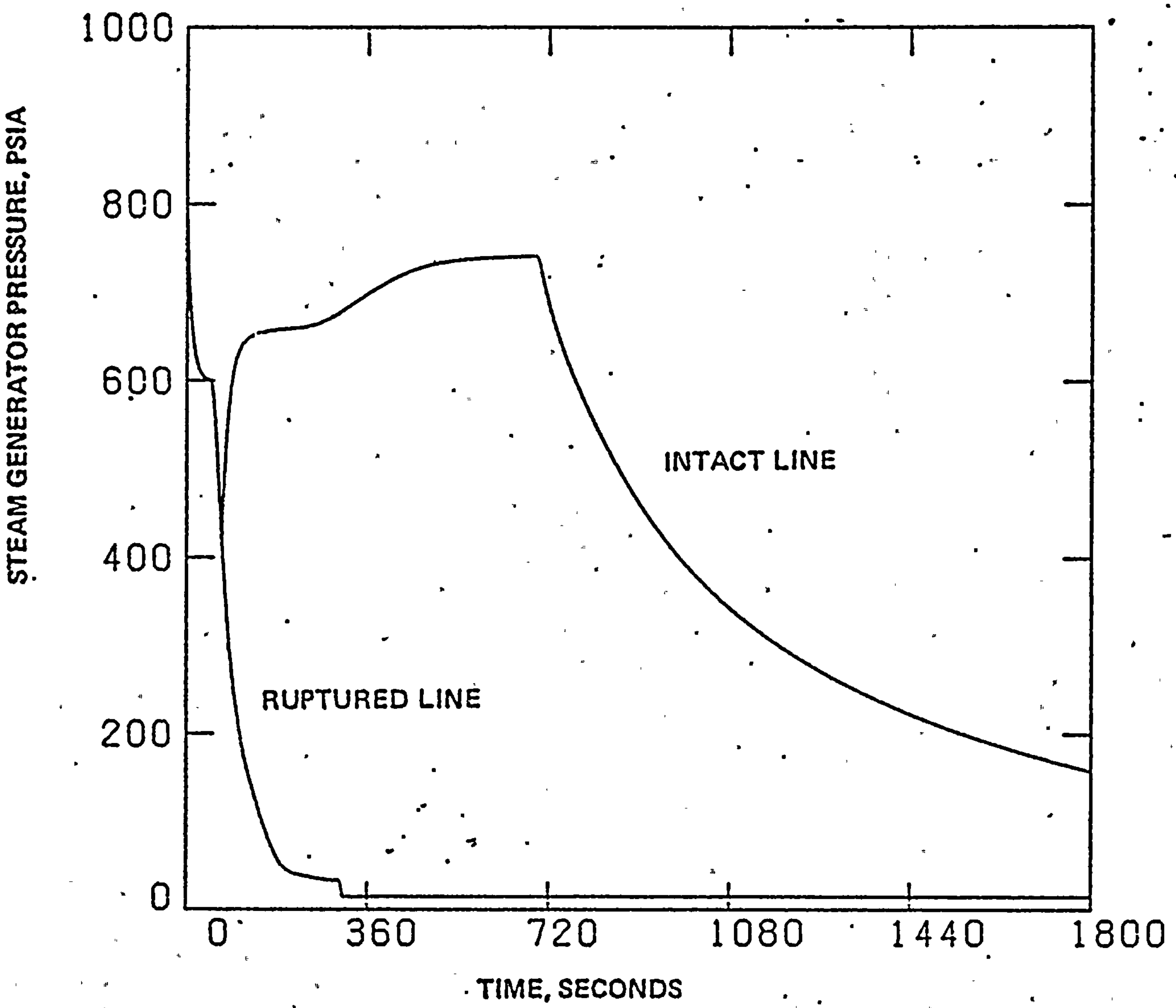
MINIMUM DNBR VS TIME

FIGURE 15.1.5.1-9



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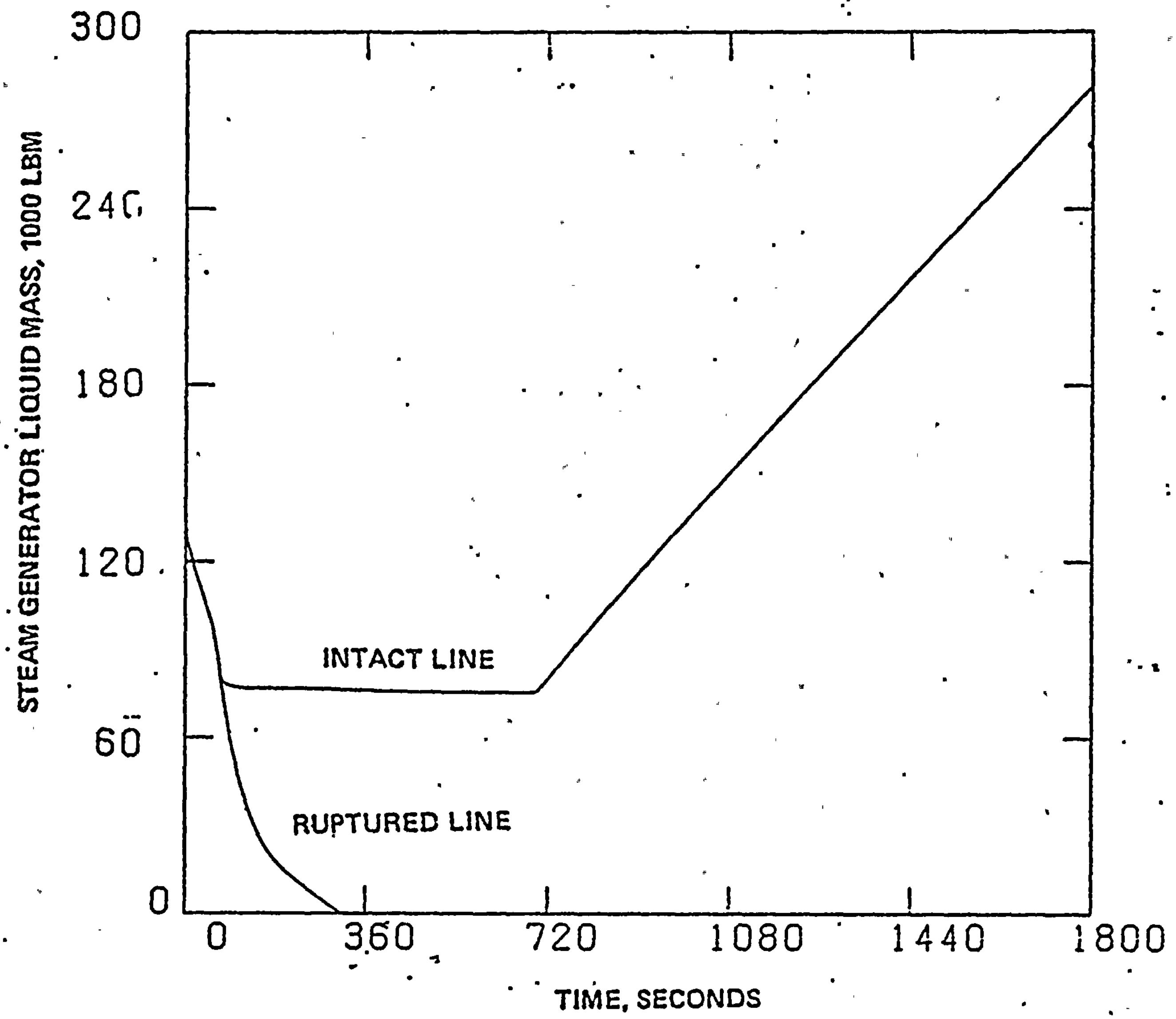
STEAM GENERATOR PRESSURE
VS TIME

FIGURE 15.1.5.1-10



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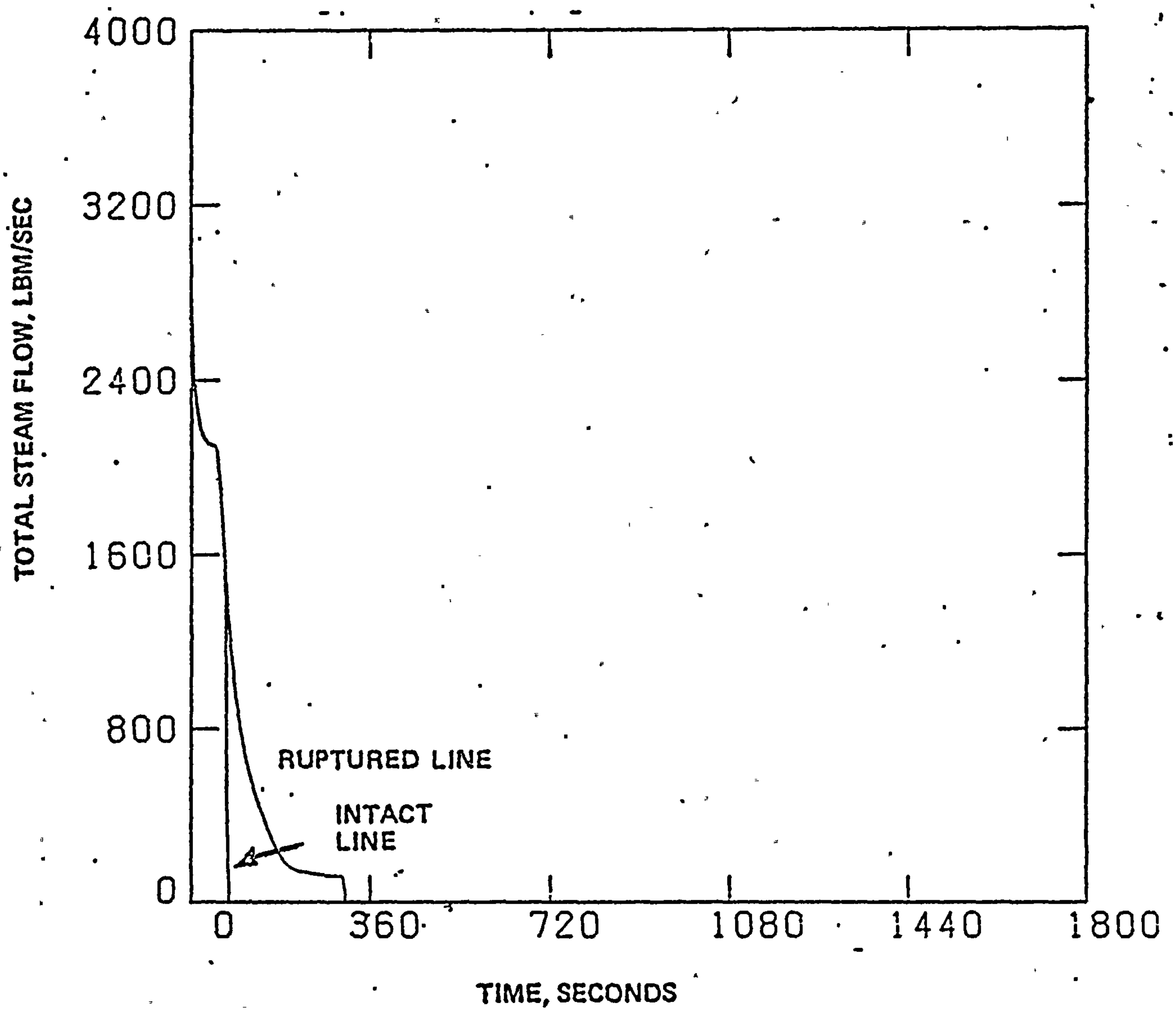
STEAM GENERATOR LIQUID
MASS VS TIME

FIGURE 15.1.5.1-11



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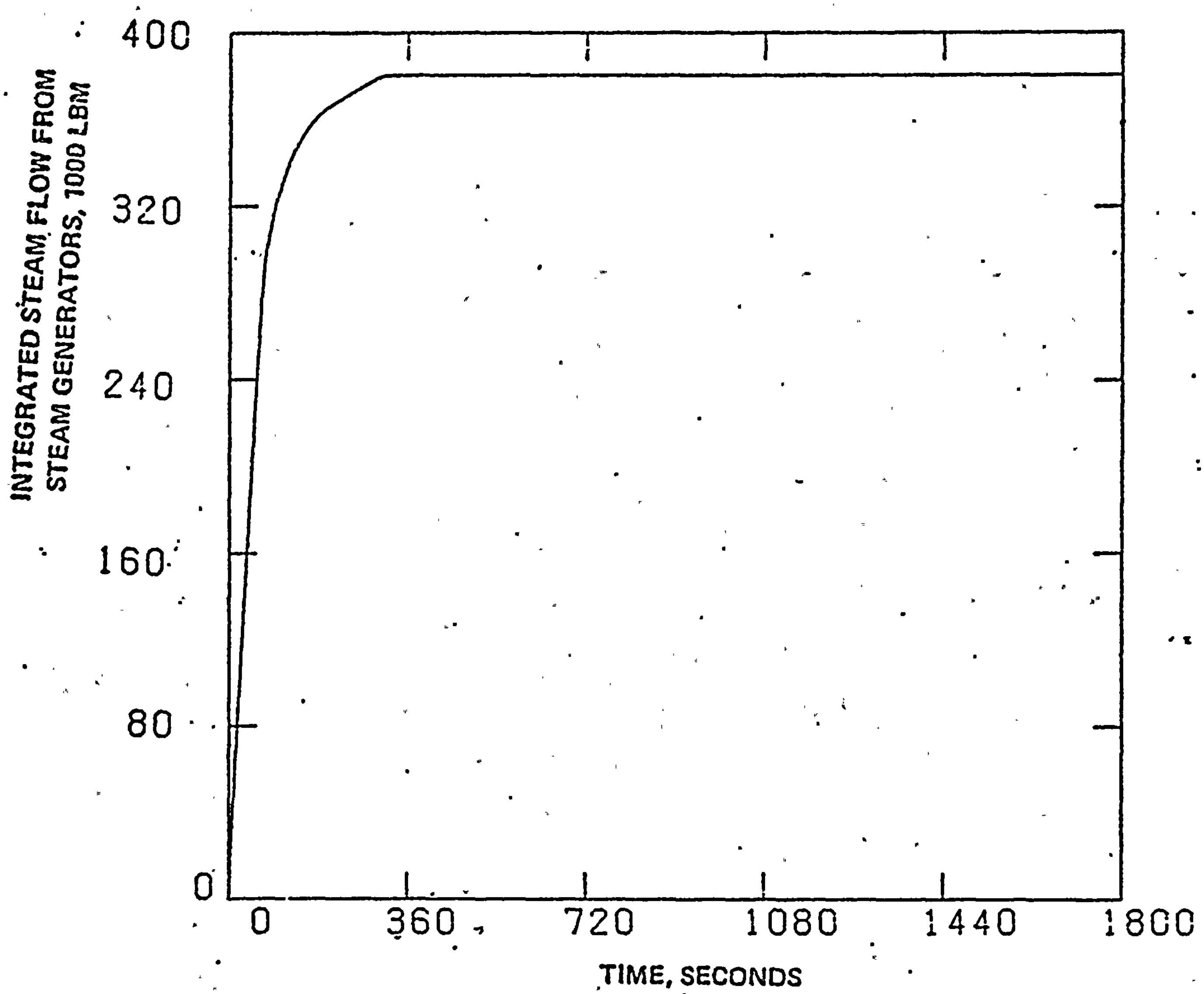
TOTAL STEAM FLOW VS TIME

FIGURE 15.1.5.1-12



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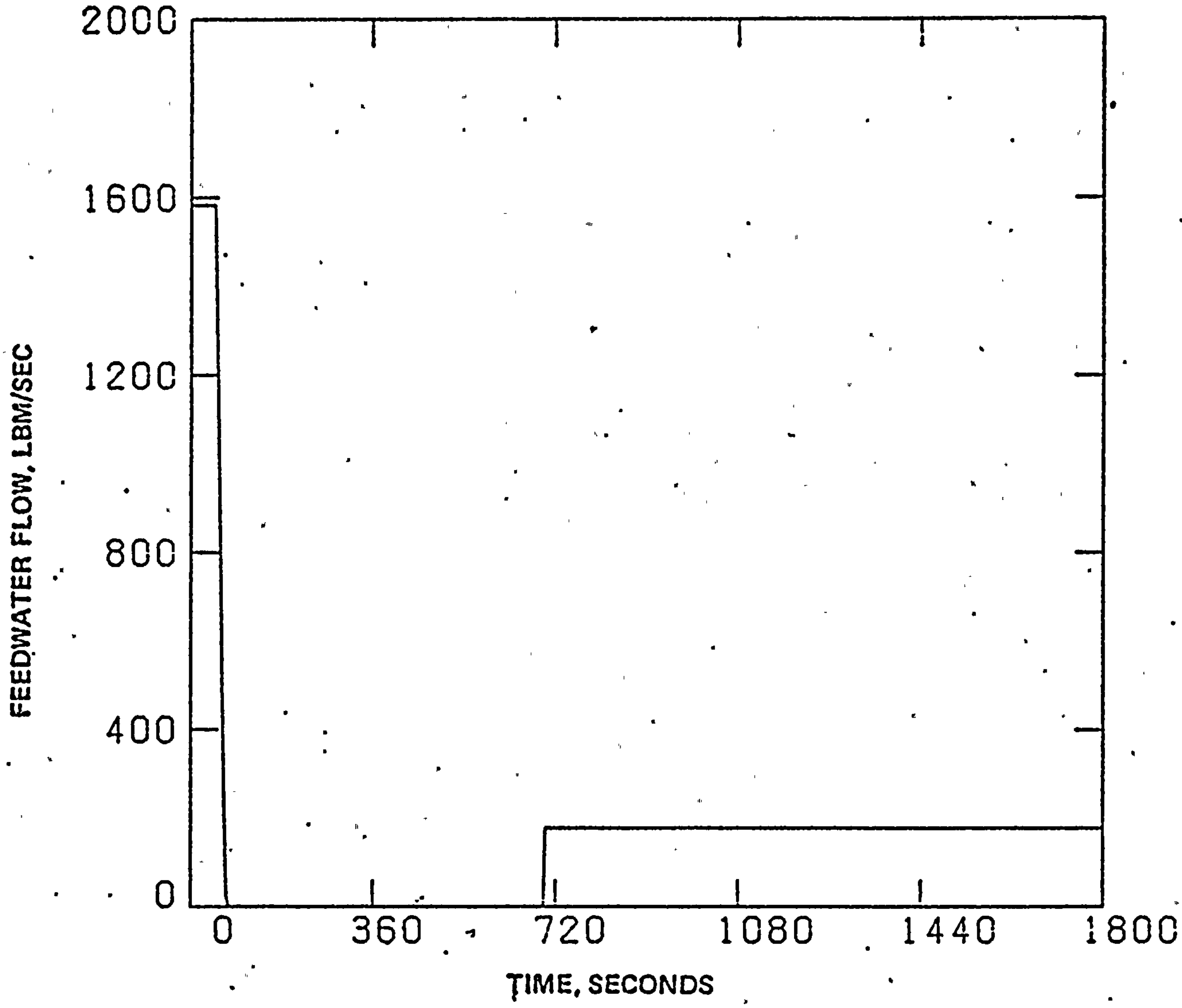
INTEGRATED STEAM FLOW
VS TIME

FIGURE 15.1.5.1-13



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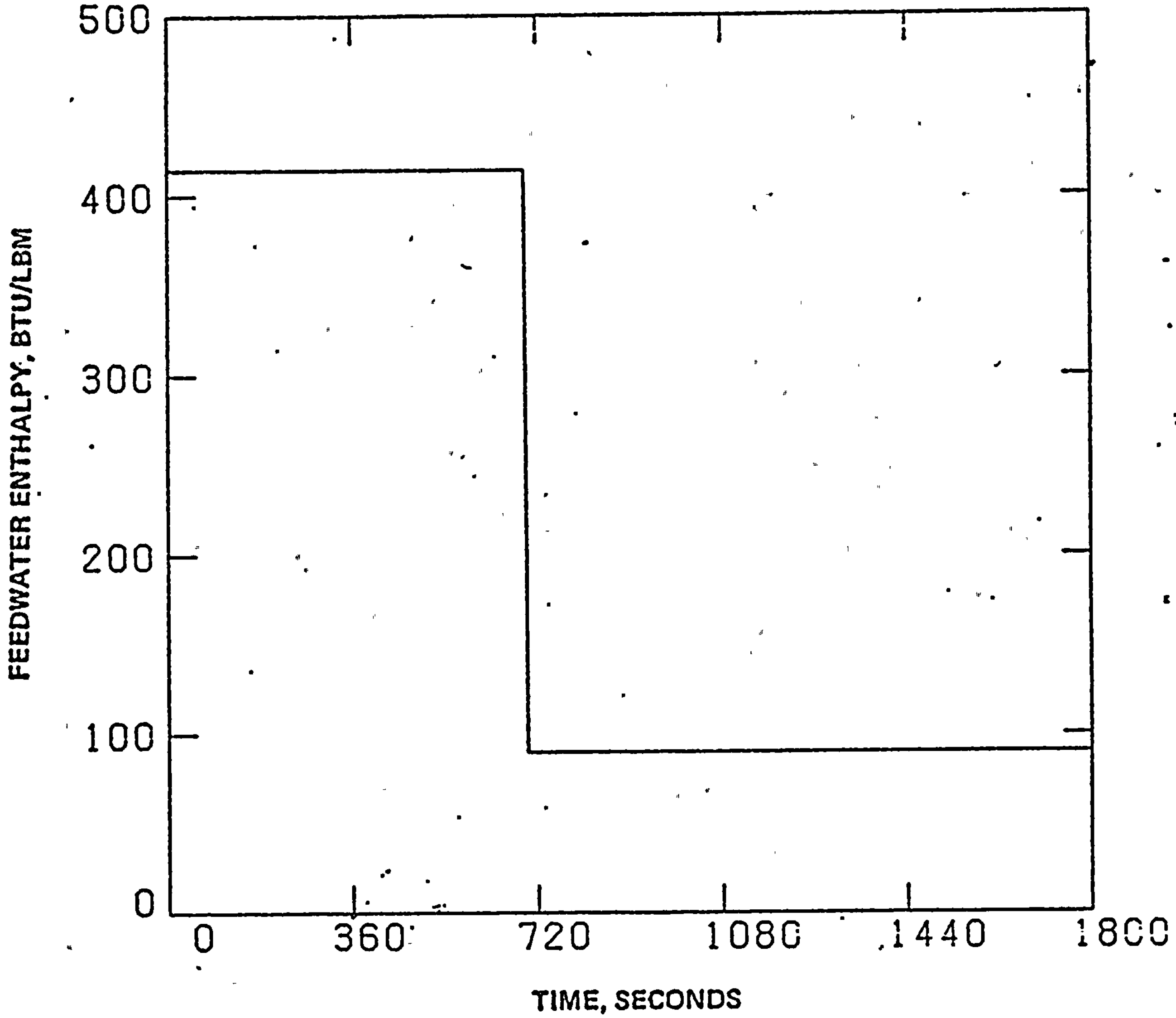
FEEDWATER FLOW VS TIME

FIGURE 15.1.5.1-14



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FEEDWATER ENTHALPY VS TIME

FIGURE 15.1.5.1-15

Section 15.2 Revision

15.2.2.3 Limiting Fuel Performance Event

None of the Infrequent event groups and event combinations resulting in a decreased heat removal by the secondary system shown in Table 15.2.2-1 produce a significant approach to fuel performance guidelines. The degradation in fuel performance which would occur during the most adverse of these event groups or event group combinations does not result in a DNBR less than 1.19 and therefore is within the acceptance guidelines in Table 15.0-4.

15.2.3 LIMITING FAULT-1 EVENTS

15.2.3.1 Limiting Offsite Dose Event

None of the LF-1 event group and event group combinations in resulting in a decreased heat removal by the secondary system shown in Table 15.2.3-1 release a significant amount of radioactivity to the atmosphere. The site boundary dose, which would occur during the most adverse of these event groups or event group combinations, is well within the acceptance guideline specified in Table 15.0-4.

15.2.3.2 Limiting Reactor Coolant System Pressure Event - Loss of Condenser Vacuum with Loss of Offsite Power as a Result of Turbine Trip

15.2.3.2.1 Identification of Event and Causes

All Limiting Fault 1 (LF-1) event groups from the Decreased Heat Removal by the Secondary System event type and the LF-1 event group combinations shown in Table 15.2.3-1 were compared to find the event resulting in the maximum Reactor Coolant System (RCS) pressure. The loss of condenser vacuum with loss of offsite power as a result of turbine trip was identified as the limiting LF-1 event.

Insert A

The event groups and event combinations evaluated and the significance of the RCS pressure increase for each are indicated in Table 15.2.3-1. All of the events indicated as insignifcant (I) produce a maximum RCS pressure well within the acceptance guideline in Table 15.0-4.

A loss of condenser vacuum may occur due to the failure of the Circulating Water System to supply cooling water, the failure of the Main Condenser Evacuation System to remove noncondensible gases, or the inleakage of an excessive amount of air through a turbine gland. (See Table 15.0-1 for a list of all initiating events in each event group).

None of the initiating events considered in the loss of condenser vacuum event group were analyzed. Instead, an event which bounds the potential RCS pressure increase due to the events in this event group was analyzed. For this bounding event it is assumed that coincident with the loss of condenser vacuum, the turbine trips instantly. In this analysis, loss of offsite power as a result of turbine trip is assumed to occur after turbine trip.

All the event groups other than loss of condenser vacuum (including the loss of external load with an low probability independent occurrence) con-

Insert A to page 15.2-114.

The maximum RCS pressure for a feedwater line break without any coincident occurrences is 2715 psia. Analysis has shown this maximum RCS pressure is produced by a feedwater line break of 0.25 ft^2 and is higher than the peak pressure produced by any other size feedwater line break, large or small.

between core heat addition and steam generator heat removal prior to the CEA insertion and, hence, to maximize the peak RCS pressure. The affected steam generator is assumed to instantaneously lose all heat transfer capacity when total depletion of its liquid inventory by boil-off and discharge occurs. The break area, which resulted in the highest peak RCS pressure, was found to be 0.25 ft^2.

Using the highest initial core power maximizes the RCS heat-up which is the driving force of the pressurization. Variations of initial core inlet temperature and initial reactor coolant flow had negligible effects on the peak RCS pressure. The highest initial core inlet temperature and the lowest initial reactor coolant flow were used in the analysis. The Pressurizer Pressure Control System is placed in the automatic mode, such that it delays reactor trip, thus prolonging the RCS heat-up and increasing RCS pressurization. Using the smallest CEA worth and the least negative moderator temperature coefficient maximizes the heat flux overshoot after reactor trip, increasing the RCS heat-up.

The highest initial pressurizer liquid volume and manual operation of Pressurizer Level Control System were used to allow the maximum increase of pressurizer level, maximizing the transient effect of RCS pressure increase during heat-up. However, the selection of Pressurizer Level Control System operating mode and initial pressurizer liquid volume has only a small impact on the peak RCS pressure. Auxiliary feedwater was assumed to be activated by the plant operator within five minutes of the low steam generator level trip condition to prevent the pressurizer from filling solid. The assumed flow to the intact steam generator is 500 gpm. ✓ Insert A2 2

To maximize RCS pressure, the SBCS is assumed to be in the manual mode.

In order to eliminate the impact of uncertainty in the water level of the affected steam generator, reactor trip on a low water level is not assumed to occur until dryout of the affected steam generator.

It is anticipated that equipment may be actuated by high containment pressure during this event. These actions are identified in the sequence of events, but are conservatively assumed not to occur in the quantitative analysis of the NSSS response to this event. 2

c) Results

The dynamic behavior of important NSSS parameters following loss of feedwater inventory with loss of offsite power as a result of turbine trip is presented in Figures 15.2.5.2-2 to 20. Table 15.2.5.2-1 summarizes some of the important results of this event and the times at which the minimum and maximum parameter values discussed below occur.

A rupture in the main feedwater line instantaneously terminates feedwater flow to both steam generators and causes liquid flow from the

ert A2 (to page 15.2 - 150)

(The peak RCS pressure occurs at 31.6 seconds. Analysis has shown that if only one motor-driven AFW pump automatically starts delivering 320 gpm to the intact steam generator at 146 seconds, the peak pressure will be unchanged and the pressurizer will be prevented from filling solid.)

15.3.3 LIMITING FAULT-1 EVENTS

15.3.3.1 Limiting Offsite Dose Event

None of the Limiting Fault-1 (LF-1) event groups and event group combinations resulting in a decrease in Reactor Coolant System flow rate shown in Table 15.3.3-1 release a significant amount of radioactivity to the atmosphere. The additional failures and events considered here produce results only incrementally more adverse than the loss of offsite power described in Subsection 15.3.2.1. The offsite doses which would occur during the most adverse of these events are well within the acceptance guideline in Table 15.0-4. 2

15.3.3.2 Limiting Reactor Coolant System Pressure Event

None of the Limiting Fault-1 event groups and event group combinations resulting in a decrease in reactor coolant flow rate shown in Table 15.3.3-1 produce Reactor Coolant System pressures greater than that produced by the loss of offsite power event described in Subsection 15.3.2.2. Therefore, the conclusions of Subsection 15.3.2.2 also apply to this section. 2

15.3.3.3 Limiting Fuel Performance Event

None of the Limiting Fault-1 event groups and event group combinations resulting in a decrease in Reactor Coolant System flow rate shown in Table 15.3.3-1 produce a significant approach to fuel performance limits. The limiting event combination with respect to fuel performance is a one pump resistance to forced flow (shaft seizure) with a failure to achieve a fast transfer of a 6.9 kV bus to a startup transformer. ~~This is assumed to result in the loss of forced flow from three reactor coolant pumps. For this event, no more than 5.0 percent of the fuel pins are calculated to experience DNB. Peak cladding surface temperatures remain less than 1500 F, which indicates that cladding failure is not expected. Therefore, the results of this event are within the acceptance guideline for fuel performance given in Table 15.0-4.~~ 2

This results in the loss of forced flow from two additional reactor coolant pumps. For this event, no more than 5.0 percent of the fuel pins are calculated to experience DNB. The results of this event are within the acceptance guideline for fuel performance given in Table 15.0-4.

SL2-FSAR

15.3.4 LIMITING FAULT-2 EVENTS

15.3.4.1 Limiting Offsite Dose Event

None of the Limiting Fault-2 (LF-2) event groups and event group combinations resulting in a decrease in Reactor Coolant System flow rate shown in Table 15.3.4-1 release a significant amount of radioactivity to the atmosphere. The additional failures and events considered here produce results only incrementally more adverse than the loss of offsite power described in Subsection 15.3.2.1. The offsite doses which would occur during the most adverse of these events are well within the acceptance guideline in Table 15.0-4. 2

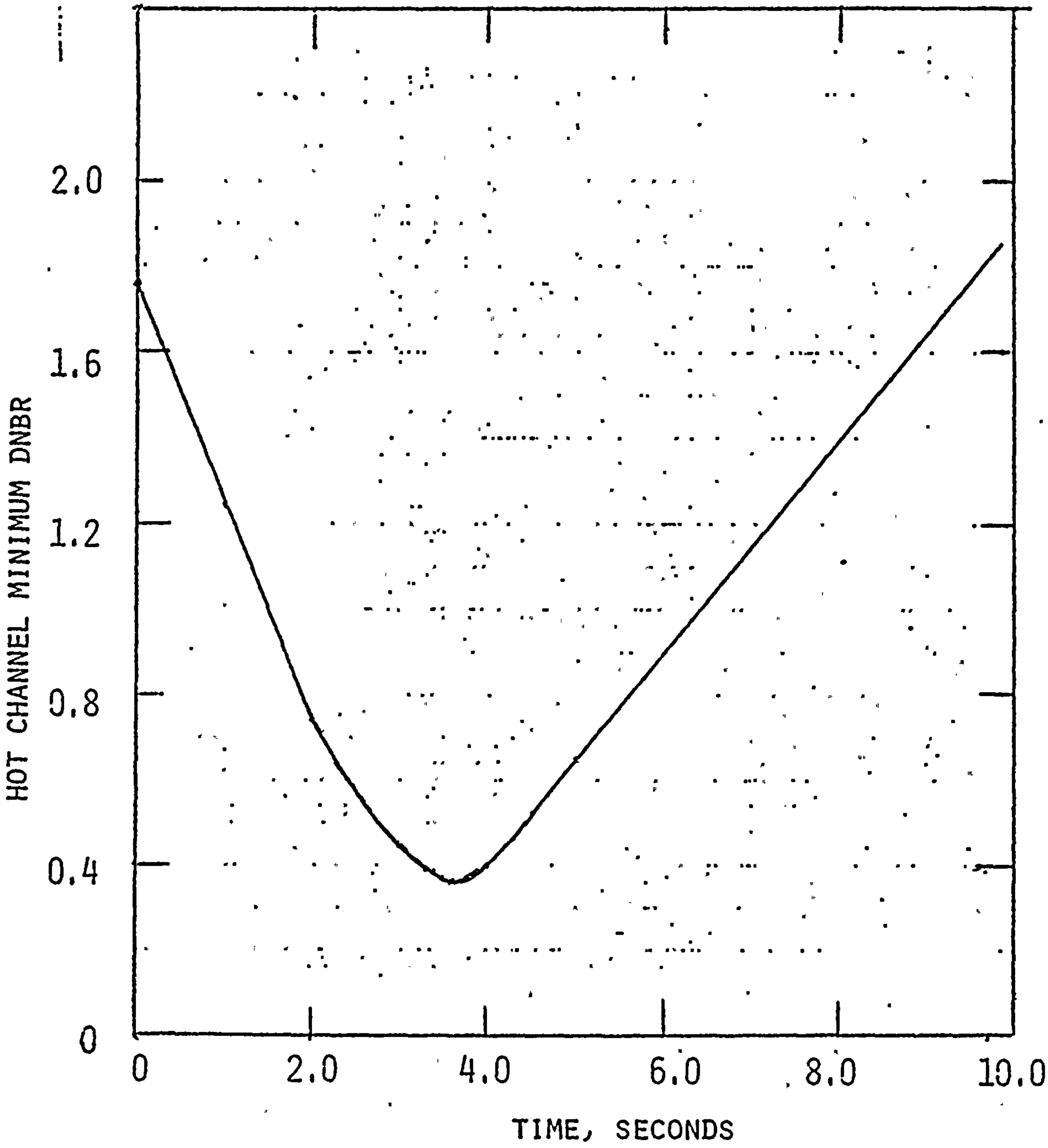
15.3.4.2 Limiting Reactor Coolant System Pressure Event

None of the Limiting Fault-2 event groups and event group combinations resulting in a decrease in reactor coolant flow rate shown in Table 15.3.4-1 produce Reactor Coolant System pressures greater than that produced by the loss of offsite power event described in Subsection 15.3.2.2. Therefore, the conclusions of Subsection 15.3.2.2 also apply to this subsection. 2

15.3.4.3 Limiting Fuel Performance Event

None of the Limiting Fault-2 event groups and event group combinations resulting in a decrease in Reactor Coolant System flow rate shown in Table 15.3.4-1 produce a significant approach to fuel performance limits. The limiting event combination with respect to fuel performance is a one pump resistance to forced flow (shaft seizure) with a loss of offsite power as a result of turbine trip. This results in the loss of forced flow from all reactor coolant pumps. ~~For this event, no more than 13.0 percent of the fuel pins are calculated to experience DNB. Peak cladding surface temperatures remain less than 1500 F, which indicates that cladding failure is not expected. Therefore, the results of this event are within the acceptance guideline for fuel performance given in Table 15.0-4.~~ 2

The transient minimum CE-1 DNBR of 0.362 occurs at 3.6 seconds. A plot of the minimum DNBR vs. time for the first 10 seconds of the transient is provided in Figure 15.3.4.3-1. For this event, no more than 13.0 percent of the fuel pins are calculated to experience DNB. The initial conditions for the most adverse case are identical to those listed in Table 15.3.5.1-4. The results of this event are within the acceptance guideline for fuel performance given in Table 15.0-4.



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HOT CHANNEL MINIMUM DNBR
VS. TIME
FIGURE 15.3.4.3-1

15.3.5 LIMITING FAULT-3 EVENTS

INSERT NEW SECTION (ATTACHED)

~~15.3.5.1 Limiting Offsite Dose Event~~

~~None of the Limiting Fault-3 (LF-3) event groups~~ and event group combinations resulting in a decrease in Reactor Coolant System flow rate shown in Table 15.3.5-1 release a significant amount of radioactivity to the atmosphere. The additional failures and events considered here produce results only incrementally more adverse than the loss of offsite power described in Subsection 15.3.2.1. The offsite doses which would occur during the most adverse of these events are well within the acceptance guideline in Table 15.0-4. 2

15.3.5.2 Limiting Reactor Coolant System Pressure Event

None of the Limiting Fault-3 event groups and event group combinations resulting in a decrease in reactor coolant flow rate shown in Table 15.3.5-1 produce Reactor Coolant System pressures greater than that produced by the loss of offsite power event described in Subsection 15.3.2.2. Therefore, the conclusions of Subsection 15.3.2.2 also apply to this section. 2

15.3.5.3 Limiting Fuel Performance Event

None of the Limiting Fault-3 event groups and event group combinations resulting in a decrease in Reactor Coolant System flow rate shown in Table 15.3.5-1 produce fuel performances worse than that produced by the one reactor coolant group resistance to forced flow with a loss of offsite power as a result of turbine trip event combination described in Subsection 15.3.4.3. The results of Subsection 15.3.4.3, which are within the LF-3 acceptance guideline on fuel performance, also apply to this section. 2

15.3.5 LIMITING FAULT-3 EVENTS

15.3.5.1 Limiting Offsite Dose Event-One Pump Resistance to Forced Flow (Shaft Seizure) with a Loss of Offsite Power as a Result of Generator Trip with Technical Specification Steam Generator Tube Leakage and Failure to Restore Offsite Power in Two Hours

15.3.5.1.1 Identification of Event and Causes

All of the Limiting Fault-3 (LF-3) event groups from the Decrease in Reactor Coolant System flow rate event type and LF-3 event combinations shown in Table 15.3.5-1 were compared to find the event resulting in the maximum offsite doses. The one pump resistance to forced flow with a loss of offsite power concurrent with generator trip, technical specification steam generator tube leakage, and failure to restore offsite power in two hours (1PRFF+LOP+FROP+TL) was identified as the limiting LF-3 event. This event maximizes the RCS heat-up and duration of condenser inoperability, therefore, maximizing the transfer of radioactivity from the secondary system to atmosphere. All of the other events considered, including those with a low probability independent occurrence, produce a smaller RCS heat-up and/or a shorter duration of condenser inoperability.

The event groups and event combinations evaluated and the significance of the site boundary dose for each are indicated in Table 15.3.5-1. All of the events indicated as insignificant (I) produce offsite doses well within the acceptance guideline in Table 15.0-4. All events indicated as significant (S) produce offsite doses within the acceptance guideline.

A one pump resistance to forced flow (shaft seizure) event can be caused by seizure of the upper or lower thrust-journal bearings. Loss of offsite power concurrent with the generator trip may be caused by a complete loss of the external electrical grid triggered as a result of the turbine trip. The loss of offsite power causes a loss of power to the start-up transformers which prevents the plant electrical loads from being transferred to them from the unit auxiliary transformers. Therefore, the onsite loads will lose power and the plant will experience a simultaneous loss of feedwater flow, condenser inoperability, and a coastdown of all reactor coolant pumps. Approximately 10 seconds after the loss of offsite power occurs the diesel generators start providing power to the two plant 4.16kV safety buses. The steam generator tube leak rate is assumed to be at the technical specification value. No credit is taken for restoration of offsite power prior to initiation of shutdown cooling.

15.3.5.1.2 Sequence of Events and System Operation

Table 15.3.5.1-1 presents a chronological list and time of system actions which occur following the shaft seizure of a reactor coolant pump. Loss of offsite power is assumed to occur concurrent with the generator trip at 1.0 seconds after the event initiation. Refer to Table 15.3.5.1-1 while reading this and the following section. The success paths referenced are those given on the sequence of events diagram (SED), Figure 15.3.5.1-1. This figure, together with Table 15.0-6, which contains a glossary of SED symbols and acronyms, may be used to trace the actuation and interaction of the systems used to mitigate the consequences of this event. The timings in Table 15.3.5.1-1 may be used to determine when, after event initiation, each action occurs.

The sequence presented demonstrates that the operator can cool the plant down to cold shutdown during the event. If offsite power can be restored, then the operator may elect instead to stabilize the plant at a mode other than cold shutdown. All actions required to stabilize the plant and perform the required repairs are not described here.

The sequence of events and systems operations described below represent the way in which the plant was assumed to respond to the event initiator. Many plant responses are possible. However, certain responses are limiting with respect to the acceptance guidelines for this section. Of the limiting responses, the most likely one to be followed was selected.

Table 15.3.5.1-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient. The operation of these systems is consistent with the guidelines of Subsection 15.0.2.3.

Table 15.3.5.1-3 contains a matrix which describes the extent to which safety systems are assumed to function during the transient.

The success paths in the sequence of events diagram, Figure 15.3.5.1-1, are as follows:

Reactivity Control:

A reactor trip signal (RTS) is automatically generated by the Reactor Protective System on low reactor coolant flow. The RTS opens the reactor trip circuit breakers to deenergize the control element drive mechanism (CEDM) bus power supply interrupting power to the CEDM holding coils, allowing the control element assemblies to fall into the core.

The charging pumps are manually loaded onto the safety bus and started. The RCS boron concentration is increased to the cold shutdown level by replacing the RCS volume shrinkage with borated water. This water is supplied from the boric acid makeup tanks (BAMT) by opening the gravity feed line valves and closing the volume control tank discharge valve.

Reactor Heat Removal:

The Reactor Coolant System provides natural circulation to remove core heat following coastdown of the undamaged reactor coolant pumps. The steam generators provide primary to secondary heat transfer.

The shutdown cooling system (SCS) is manually actuated when the RCS temperature and pressure have been reduced to 350°F and 275 psia, respectively. The SCS provides sufficient flow to cool the RCS to cold shutdown conditions.

Secondary System Integrity:

The CEDM bus undervoltage relays sensing the interruption of power on the CEDM power supply buses, generate a turbine trip signal (TTS). The TTS causes the digital electro-hydraulic control system to close the turbine stop and control valves. Upon the loss of offsite power both main feedwater pumps lose power and coast down. The steam generator pressure increases to the main steam safety valves (MSSV) setpoint, and they open to dissipate heat from the RCS. The MSSVs close when the secondary system pressure drops and will cycle open and closed throughout the transient. An auxiliary feedwater actuation signal is generated on low steam generator water level. The auxiliary feedwater flow to the steam generators is controlled automatically by the Auxiliary Feedwater Actuation System. The condensate storage tank is the auxiliary feedwater source. The operator closes the main steam isolation valves and uses the atmospheric dump valve system to dump steam to the atmosphere to cool down the RCS until shutdown cooling entry conditions are reached.

Primary System Integrity:

The pressurizer assists in the control of the RCS pressure and volume changes during the transient by compensating for the initial expansion of the RCS fluid.

As the reactor coolant system (RCS) pressure increases, one of the two Power Operated Relief valves (PORVs) opens, discharging steam to the quench tank, where it is condensed and contained. When the plant is at power, the other PORV is isolated (by a closed block valve) to avoid an excessive discharge of reactor coolant (see Section 5.4.13.2). As RCS pressure decreases, the PORV closes.

Following isolation of the RCP controlled bleedoff line by the loss of instrument air a relief valve lifts discharging the bleedoff flow to the quench tank. During cooldown, the operator controls the auxiliary sprays to reduce the RCS pressure. The operator uses the charging pumps to replace the RCS volume shrinkage.

Radioactive Effluent Control

Due to the loss of instrument air to pneumatically operated valves on loss of offsite power, several lines penetrating containment will be isolated. Those lines isolated include: RCP controlled bleedoff, various sampling lines, reactor drain tank drain line, nitrogen supply, waste gas header, containment air monitoring lines, containment sump pump discharge, and steam generator blowdown lines. These actions are automatically initiated but do not contribute toward the mitigation of the event.

Maintenance of AC Power:

A low voltage on the 4.16 KV safety buses generates an undervoltage signal which starts the diesel generators. The non-safety buses are automatically separated from the safety buses and all loads are shed. After each diesel generator set has attained operating voltage and frequency, its output breaker closes connecting it to its safety bus. ESF equipment is then loaded in sequence on to this bus.

15.3.5.1.3 Analysis of Effects and Consequences

a) Mathematical Models

The NSSS response to one pump resistance to forced flow (shaft seizure) with a loss of offsite power as a result of turbine trip was simulated using the CESEC computer program described in Subsection 15.0.4. The DNBR was calculated using the TORC computer code which uses the CE-1 CHF correlation described in Subsection 15.0.4.

b) Input Parameters and Initial Conditions

The ranges of initial conditions considered are given in Subsection 15.0.3. Table 15.3.5.1-4 gives the initial condititons used in this analysis. The rational for selecting the values of the initial conditions which have a first order effect on the analysis follows. Using the highest core power maximizes the RCS heat-up, which is the driving force of the secondary steam release. The lowest primary system pressure was assumed in conjunction with the opening of one of the two power operated relief valves in order to maximize the number of fuel pins which will experience DNB. A high core inlet temperature was chosen since it yields the earliest opening of the main steam safety valves. The steam generator inventory and heat transfer was modeled to maximize the radiological consequences of the event. The lowest core flow rate is used because it results in a larger percentage of fuel pins which experience DNB. Using the most positive moderator temperature coefficient and the minimum available scram CEA worth tends to maximize the heat flux after a reactor trip occurs, increasing the RCS heat-up. Assuming the operator initiates plant cooldown at 30 minutes maximizes the offsite doses. During this event two sources of radioactivity contribute to the offsite doses, the initial activity in the steam generator and the activity associated with a one gallon per minute steam generator tube leak. The initial secondary activity is assumed to be at the Technical Specification limit of 0.1 μCi/gm dose equivalent I-131. The activity assumed to be present in the reactor coolant leaking through the steam generator tubes is 0.4 μCi/gm (see Subsection 15.0.4.3.1).

c) Results

The dynamic behavior of important NSSS parameters following a one pump resistance to forced flow (shaft seizure) with a loss of offsite power is presented on Figures 15.3.5.1-2 to -11. Table 15.3.5.1-1 summarizes the significant results of the event. Refer to Table 15.3.5.1-1 while reading this section.

The one pump resistance to forced flow (shaft seizure) event results in a flow coastdown in the affected loop and a consequent reduction in flow through the core. The reactor is tripped on a low flow signal. The reactor trip causes a turbine trip signal to occur. The flow in the unaffected cold legs increases until the loss of offsite power (concurrent with generator trip) occurs. At this time the flow in the unaffected cold legs begins to decrease as a result of the reactor coolant pump coastdown. The loss of offsite power also causes a loss of main feedwater and condenser inoperability. The turbine trip with the SBCS and the condenser unavailable leads to a rapid buildup in secondary system pressure and temperature. This increase in pressure is shown in Figure 15.3.5.1-9. The opening ofthe MSSVs limits this pressure increase. The flow rate out the MSSVs is shown in Figure 15.3.5.1-10. The integral flow out of the MSSVs is shown in Figure 15.3.5.1-11. The increasing temperature of the secondary system leads to a reduction of the primary to secondary heat transfer. Concurrently, the failed reactor coolant pump and the three reactor coolant pumps coasting down (Figure 15.3.5.1-8) result in reduced RCS flow which further reduces the heat transfer capability of the RCS. This decrease in heat removal from the RCS leads to an increase in the core coolant temperatures as shown in Figure 15.3.5.1-5. The core coolant temperatures peak shortly after the time of reactor trip on low RCS flow.

The increase in RCS temperature leads to an increase in RCS pressure, as shown in Figure 15.3.5.1-4, caused by the thermal expansion of the RCS fluid (see Figure 15.3.5.1-7). The RCS pressure reaches a maximum value of 2427 psia at 6.25 seconds. After this time, the RCS pressure decreases rapidly due to the declining core heat flux (see Figure 15.3.5.1-3), in combination with the opening of the MSSVs. Opening of the MSSV limits the peak temperature and pressure of the secondary system.

During the first few seconds of the transient, the combination of decreasing flow rate, increasing RCS temperatures, and increasing core power (see Figure 15.3.5.1-2) results in a decrease in the fuel pins' DNBR. The transient minimum DNBR of 0.362 occurs at 3.6 seconds as indicated in Table 15.3.5.1-1. Figure 15.3.4.3-1 shows the variation of the minimum DNBR with time. The negative CEA reactivity inserted after reactor trip causes a rapid power and heat flux decrease which causes the DNBR to increase again. For this event no more than 13.0 percent of the fuel pins are calculated to experience DNB. All fuel pins which experience DNB are conservatively assumed to fail (see Section 15.3.4.3).

The offsite doses for this event result from steam released through the main steam safety valves (MSSVs) and atmsopheric dump valves (ADVs). The MSSVs are open intermittently during the first 30 minutes of the transient (see Figure 15.3.5.1-10).

At 30 minutes, the operator is assumed to use the ADVs to begin cooldown. The total amount of steam released through the MSSVs is shown in Figure 15.3.5.1-11. Table 15.3.5.1-1 shows the integrated steam release from the MSSVs and the ADVs. The radiological release produced by the transient results in a 7.8 rem two hour thyroid inhalation dose at the exclusion area boundary. The two hour and entire event doses for both thyroid and whole body are shown in Table 15.3.5.1-5.

15.3.5.1.4 Conclusion

The evaluation shows that the plant response to a one pump resistance to forced flow (shaft seizure) with a loss of offsite power, technical specification steam generator tube leakage, and failure to restore offsite power in two hours results in a maximum offsite doses which are within the acceptance guideline in Table 15.0-4.

TABLE 15.3.5.1-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR ONE PUMP RESISTANCE TO FORCED FLOW (SHAFT SEIZURE) WITH A LOSS OF OFFSITE POWER AS A RESULT OF GENERATOR TRIP, TECHNICAL SPECIFICATION STEAM GENERATOR TUBE LEAKAGE, AND FAILURE TO RESTORE OFFSITE POWER IN TWO HOURS

Time (Sec)	Event	Analysis Set Point or Value	Success Paths: Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Restoration of AC Power			
0.0	Seizure of RC pump shaft -affected pump begins coastdown	---								
0.45	Reactor trip signal generated on low RCS flow, % of rated flow	93	X							
[illegible]85	Turbine trip on loss of power on CEDM power supply buses.	---			X					
0.98	Auxiliary feedwater actuation signal generated on low SG water level, ft above tubesheet	25.5			X					
1.0	Generator Trip/Loss of Offsite Power -Diesel generator starting signal -Unaffected reactor coolant pumps and MFW pumps lose power and coastdown	---					X			
2.1	Maximum Reactor Power, %	105.6								
3.6	Minimum Transient DNBR	0.362								
3.7	Main Steam Safety Valves* open, unaffected loop	1010			X					
4.4	Main Steam Safety Valves* open, affected loop, psia	1010			X					
4.5	PORV opens, psia	2370				X				
6.3	Maximum RCS pressure, psia	2427								
8.0	Maximum SG pressure unaffected loop, psia	1040								
[illegible]0	Maximum SG pressure affected loop, psia	1028								
10.4	PORV closes, psia	2346				X				

* MSSVs cycle during first 400 seconds

TABLE 15.3.5.1-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR [illegible]E PUMP RESISTANCE TO FORCED FLOW (SHAFT SEIZURE) WITH A LOSS OF OFFSITE POWER AS A RESULT OF GENERATOR TRIP, TECHNICAL SPECIFICATION STEAM GENERATOR TUBE LEAKAGE, AND FAILURE TO RESTORE OFFSITE POWER IN TWO HOURS

Time (Sec)	Event	Analysis Set Point or Value	Success Paths							
			Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Restoration of AC Power			
121	Auxilairy Feedwater begins to enter SGs, lbm/sec (per SG)	66.7			X					
1800	Operator opens ADV to initiate plant cooldown	—			X					
	Operator loads the following on safety bus:	—								
	-instrument air compressor		X			X				
	-charging pumps		X			X				
	-pressurizer heater					X				
	-closes MSIVs				X					
14,544	Operator aligns SCS, ^{o}F psia	350/275		X						
	Total steam release to atmosphere, lbm	1,065,000								

* MSSVs cycle until operator actuates ADVs at 1800 seconds.

TABLE 15.3.5.1-2

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR ONE PUMP RESISTANCE TO FORCED FLOW (SHAFT SEIZURE) WITH A LOSS OF OFFSITE POWER AS A RESULT OF GENERATOR TRIP, TECHNICAL SPECIFICATION STEAM GENERATOR TUBE LEAKAGE, AND FAILURE TO RESTORE OFFSITE POWER IN TWO HOURS

SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	MANUAL MODE THROUGH-OUT TRANSIENT	NORMAL AUTOMATIC MODE INOPERATIVE ON LOSS OF A.C.	MANUAL MODE INOPERATIVE ON LOSS OF A.C.	FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater System			X			
2. Turbine-Generator Control System	X					
3. Steam Bypass Control System				X		
4. Pressurizer Pressure Control System				X		1
5. Pressurizer Level Control System				X		
6. Control Element Drive Mechanism Control System	X					
7. Reactor Regulating System				X		
8. Reactor Coolant Pumps				X	X	4,5
9. Chemical and Volume Control System				X		1,2
10. Condenser Evacuation System				X		
11. Turbine Gland Sealing System				X		
12. Component Cooling Water System	X					2,3
13. Turbine Cooling Water System				X		
14. Intake Cooling Water System				-		2,3
15. Condensate Transfer System				X		
16. Circulating Water System				X		
17. Spent Fuel Pool Cooling System				X		1
18. AC Power (Non-Safety)			X			
19. AC Power (Safety)	X					2,3
20. D. C. Power		X				4
21. Power Operated Relief Valves	X					
22. Instrument Air System			X			1
23. Waste-Management-Liquid				X		

NOTES:
1. Operator must connect the safety bus for operation.
2. Only essential portions of the system are available
3. Lose power on loss of offsite power, then automatically loaded on diesel generator.
4. System has no automatic mode.
5. A locked rotor on one RCP is the initiating event.

TABLE 15.3.5.1-3

UTILIZATION OF SAFETY SYSTEMS FOR ONE PUMP RESISTANCE TO FORCED FLOW (SHAFT SEIZURE) WITH A LOSS OF OFFSITE POWER AS A RESULT OF GENERATOR TRIP, TECHNICAL SPECIFICATION STEAM GENERATOR..TUBE LEAKAGE, AND FAILURE TO RESTORE OFFSITE POWER IN TWO HOURS

	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACKUP TO NONSAFETY GRADE SYSTEM	FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	X				
2. Engineered Safety Features Actuation Systems			X		1
3. Diesel Generators and Support Systems	X				
4. Reactor Trip Switch Gear	X				
5. Main Steam Safety Valves	X				
6. Pressurizer Safety Valves			X		
7. Main Steam Isolation Valves	*X		X		
8. Main Feedwater Isolation Valves	*X		X		
9. Auxiliary Feedwater System	*X				
10. Safety Injection System					
11. Shutdown Cooling System (CCW & ICW)	*X				
12. Atmospheric Dump Valve System	*X				
13. Containment Isolation System		X			2
14. Containment Spray System					
15. Iodine Removal System					
16. Containment Combustible Gas Control System					
17. Containment Cooling System					3

NOTES:

* Manually actuated during normal cool down

1. Permissive block of SIAS and MSIS are manually actuated to permit shutdown depressurization.
2. Portions of this system are actuated as a result of loss of instrument air.
3. Normally operating system (in nonsafety mode)

Systems not checked are not utilized during this event.

TABLE 15.3.5.1-4
ASSUMED INPUT PARAMETERS AND INITIAL CONDITIONS FOR ONE PUMP RESISTANCE TO FORCED FLOW (SHAFT SEIZURE) WITH A LOSS OF OFFSITE POWER AS A RESULT OF GENERATOR TRIP, TECHNICAL SPECIFICATION STEAM GENERATOR TUBE LEAKAGE, AND FAILURE TO RESTORE OFFSITE POWER IN TWO HOURS

Parameter	Assumed Value
Initial Core Power Level, Mwt	2630
Core Inlet Coolant Temperature, F	551
Core Flow Rate, gpm	370,000
RCS Pressure, psia	2150
Initial Pressurzier Volume, % level	40
Steam Generator Water Level, % of narrow range tap span	35
Doppler Coefficient Multiplier	0.85
Moderator Temperature Coefficient, $10^{-4} \Delta\rho/F$	+0.4[(a)]
CEA Worth for Trip, $10^{-2} \Delta\rho$	-5.5

(a) This value is outside the range specified in Subsection 15.0.3.2.2 and is chosen to maximize RCS heatup.

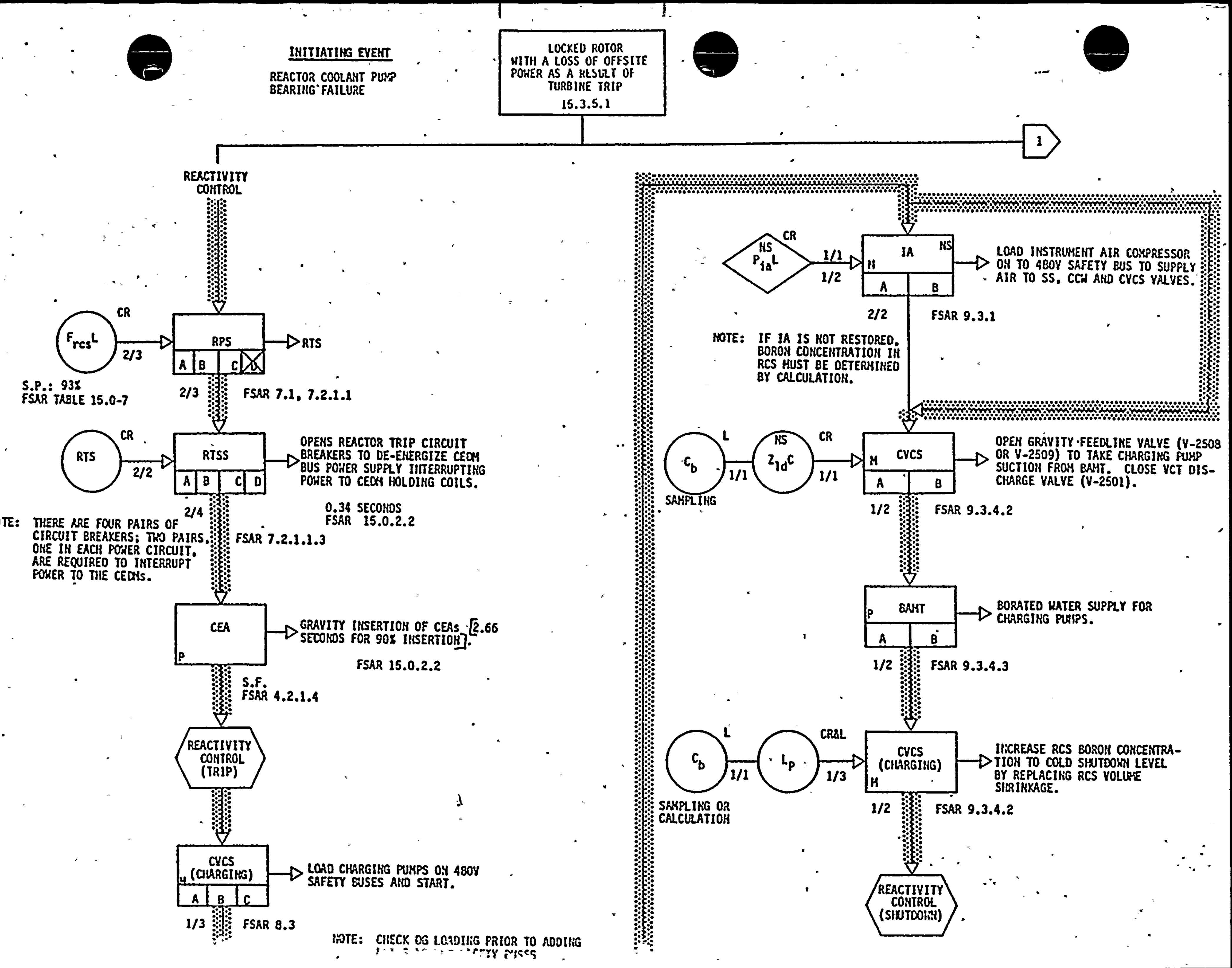
TABLE 15.3.5.1-5

OFFSITE DOSES

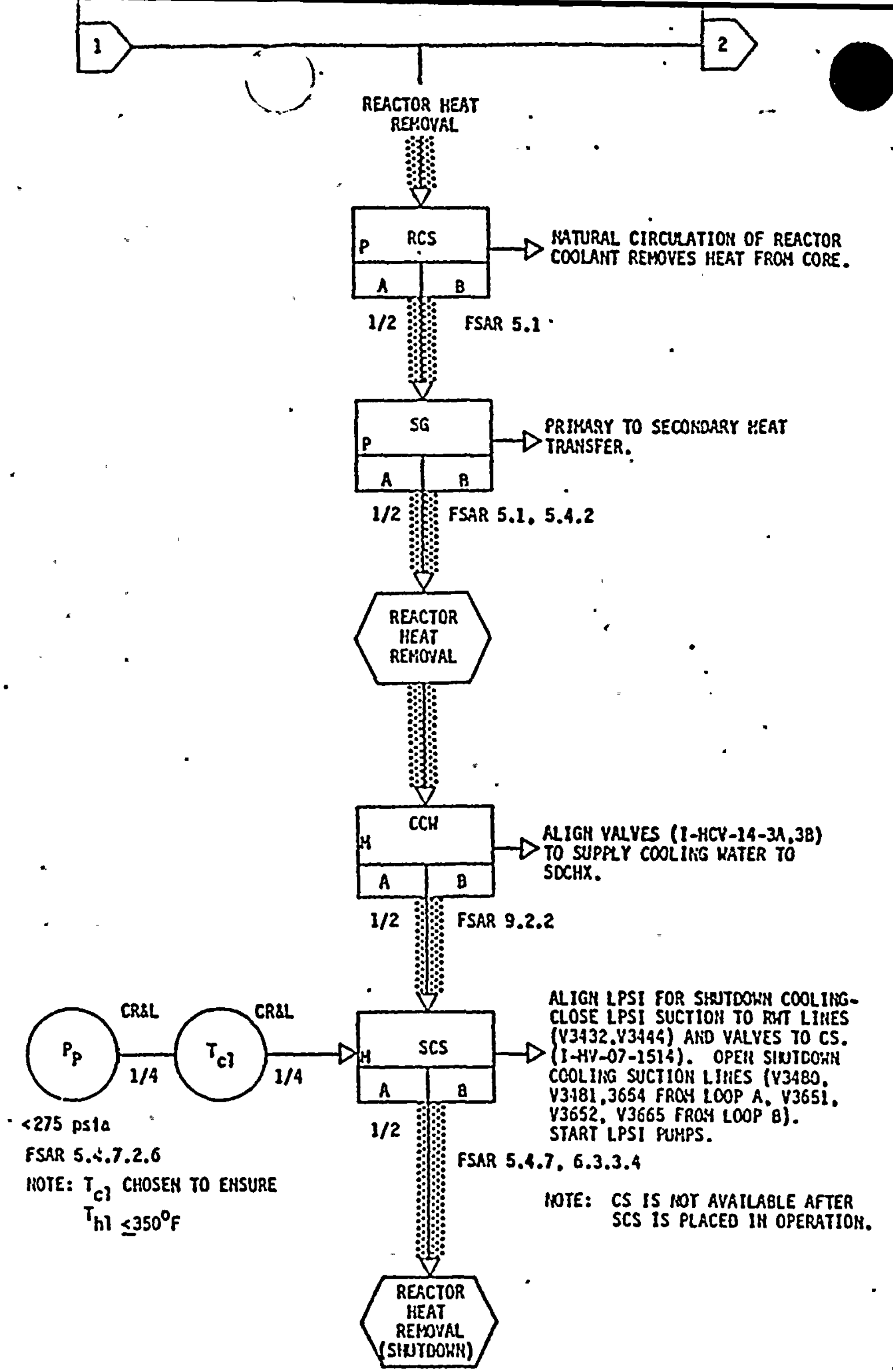
	Two Hour Exclusion Area Boundary Dose	Entire Event Low Population Zone Dose
Thyroid	7.8 rem	(Later)*
Whole Body	(Later)*	(Later)*

*to be supplied by Ebasco

14" x 17" Originals of the sequence of events diagram on the following pages (Figures 15.3.5.1-1a to 15.3.5.1-1h) are available for reproduction (C-E, S. Ritterbusch).

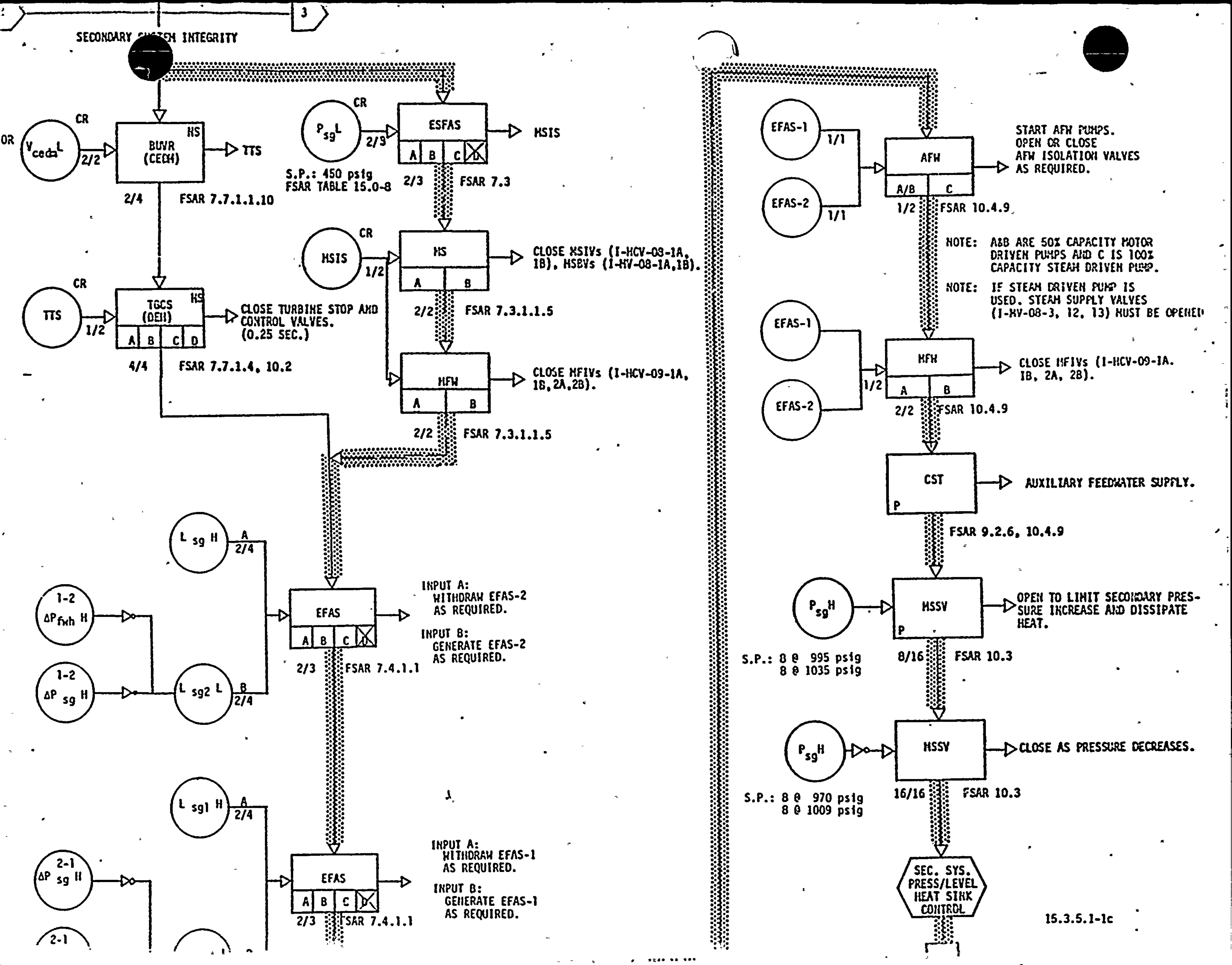


INITIATING EVENT
REACTOR COOLANT PUMP BEARING FAILURE
LOCKED ROTOR WITH A LOSS OF OFFSITE POWER AS A RESULT OF TURBINE TRIP
15.3.5.1
1
REACTIVITY CONTROL
CR
$F_{rcs}L$
2/3
RPS
A B C D
RTS
S.P.: 93%
FSAR TABLE 15.0-7
2/3
FSAR 7.1, 7.2.1.1
CR
RTS
2/2
RTSS
A B C D
OPENS REACTOR TRIP CIRCUIT BREAKERS TO DE-ENERGIZE CEDM BUS POWER SUPPLY INTERRUPTING POWER TO CEDM HOLDING COILS.
0.34 SECONDS
FSAR 15.0.2.2
2/4
NOTE: THERE ARE FOUR PAIRS OF CIRCUIT BREAKERS; TWO PAIRS, ONE IN EACH POWER CIRCUIT, ARE REQUIRED TO INTERRUPT POWER TO THE CEDMs.
FSAR 7.2.1.1.3
CEA
P
GRAVITY INSERTION OF CEAs [2.66 SECONDS FOR 90% INSERTION].
FSAR 15.0.2.2
S.F.
FSAR 4.2.1.4
REACTIVITY CONTROL (TRIP)
CVCS (CHARGING)
M
A B C
LOAD CHARGING PUMPS ON 480V SAFETY BUSES AND START.
1/3
FSAR 8.3
NOTE: CHECK DG LOADING PRIOR TO ADDING
NS
CR
$P_{ia}L$
1/1
1/2
IA
NS
M
A B
LOAD INSTRUMENT AIR COMPRESSOR ON TO 480V SAFETY BUS TO SUPPLY AIR TO SS, CCW AND CVCS VALVES.
2/2
FSAR 9.3.1
NOTE: IF IA IS NOT RESTORED, BORON CONCENTRATION IN RCS MUST BE DETERMINED BY CALCULATION.
C_b
L
SAMPLING
1/1
NS
$Z_{1d}C$
CR
1/1
CVCS
M
A B
OPEN GRAVITY FEEDLINE VALVE (V-2508 OR V-2509) TO TAKE CHARGING PUMP SUCTION FROM BAMT. CLOSE VCT DISCHARGE VALVE (V-2501).
1/2
FSAR 9.3.4.2
BAMT
P
A B
BORATED WATER SUPPLY FOR CHARGING PUMPS.
1/2
FSAR 9.3.4.3
C_b
L
SAMPLING OR CALCULATION
1/1
L_p
CR&L
1/3
CVCS (CHARGING)
M
INCREASE RCS BORON CONCENTRATION TO COLD SHUTDOWN LEVEL BY REPLACING RCS VOLUME SHRINKAGE.
1/2
FSAR 9.3.4.2
REACTIVITY CONTROL (SHUTDOWN)



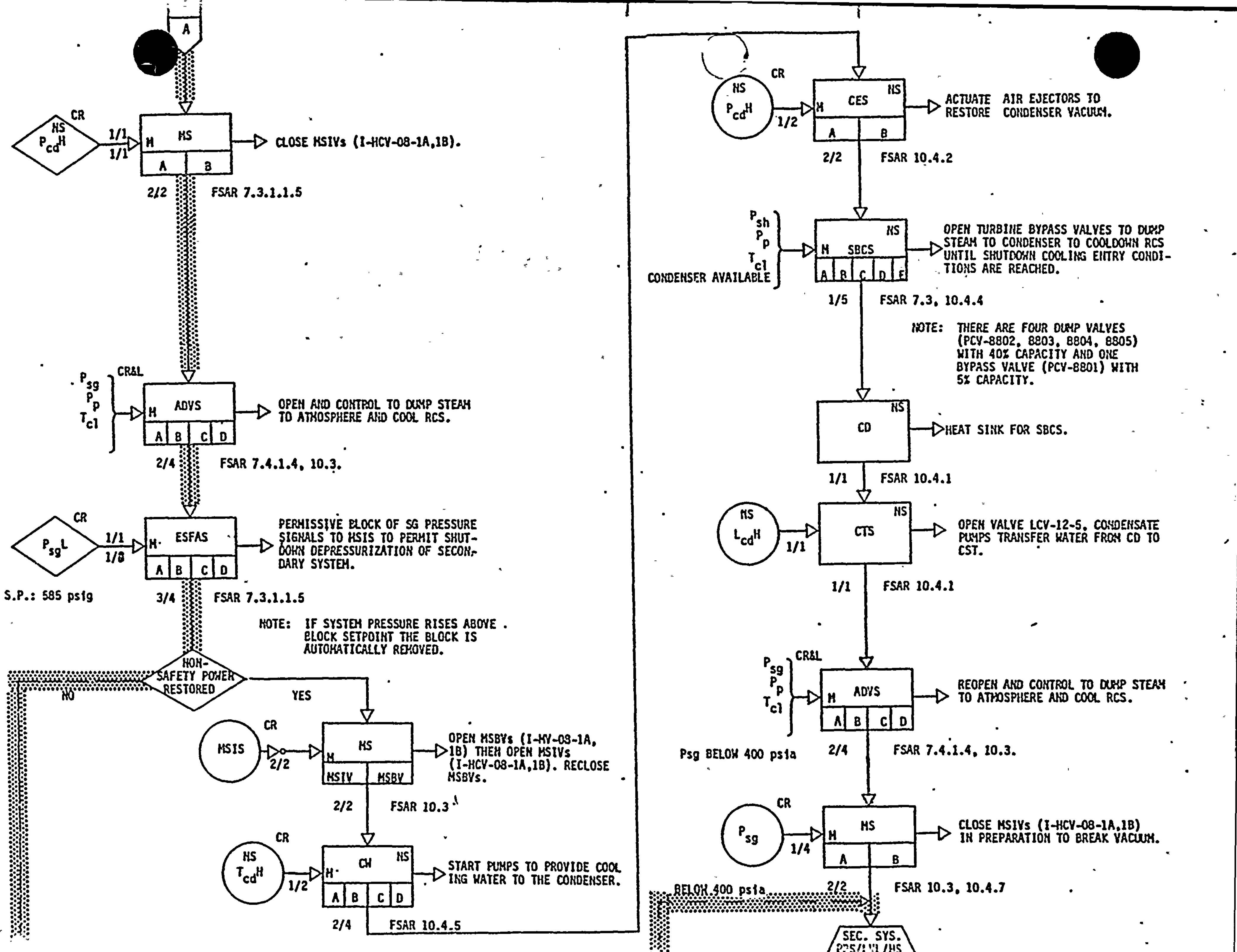
1
2
REACTOR HEAT REMOVAL
RCS
P
A
B
NATURAL CIRCULATION OF REACTOR COOLANT REMOVES HEAT FROM CORE.
1/2
FSAR 5.1
SG
P
A
B
PRIMARY TO SECONDARY HEAT TRANSFER.
1/2
FSAR 5.1, 5.4.2
REACTOR HEAT REMOVAL
CCW
H
A
B
ALIGN VALVES (I-HCV-14-3A,3B) TO SUPPLY COOLING WATER TO SDCHX.
1/2
FSAR 9.2.2
P_P
CR&L
1/4
T_{cl}
CR&L
1/4
SCS
H
A
B
ALIGN LPSI FOR SHUTDOWN COOLING-CLOSE LPSI SUCTION TO RWT LINES (V3432,V3444) AND VALVES TO CS. (I-HV-07-1514). OPEN SHUTDOWN COOLING SUCTION LINES (V3480, V3481,3654 FROM LOOP A, V3651, V3652, V3665 FROM LOOP B). START LPSI PUMPS.
<275 psia
FSAR 5.4.7.2.6
NOTE: T_{cl} CHOSEN TO ENSURE $T_{hl} \leq 350^{\circ}F$
1/2
FSAR 5.4.7, 6.3.3.4
NOTE: CS IS NOT AVAILABLE AFTER SCS IS PLACED IN OPERATION.
REACTOR HEAT REMOVAL (SHUTDOWN)

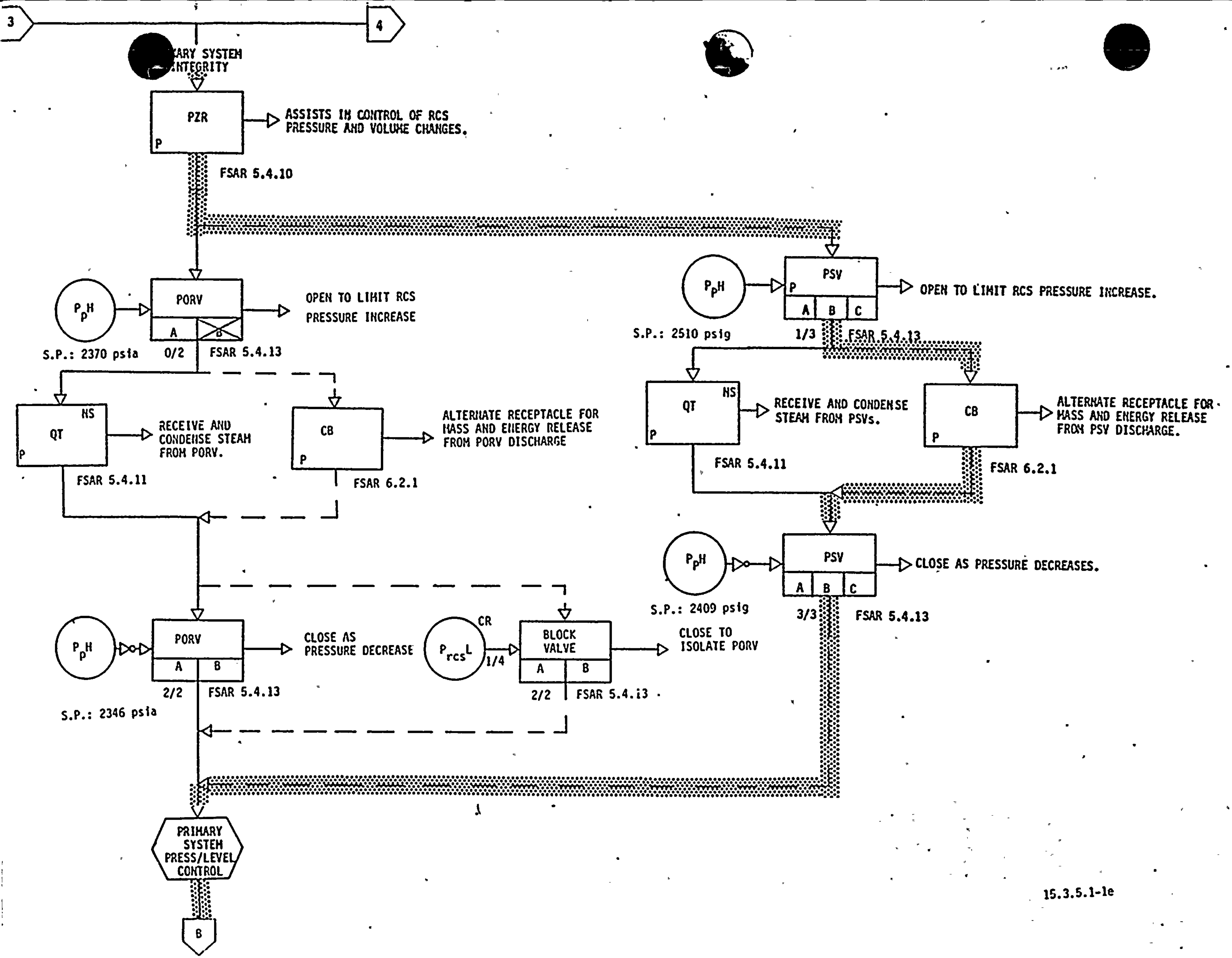
15.3.5.1-1b



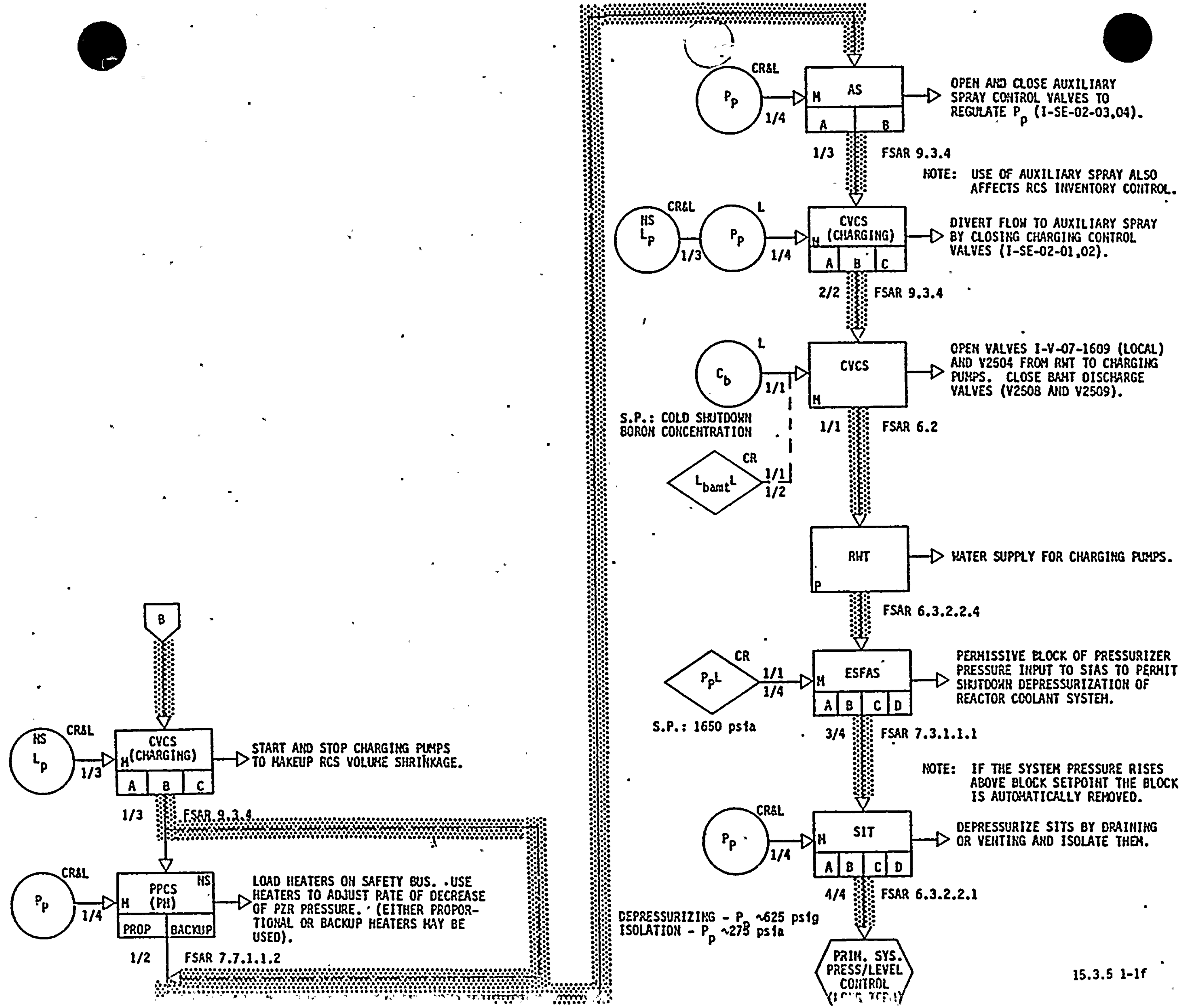
3
SECONDARY SYSTEM INTEGRITY
CR
OR
BUVR (CEDM)
HS
TTS
2/2
2/4
FSAR 7.7.1.1.10
TTS
TGCS (DEH)
A B C D
1/2
CLOSE TURBINE STOP AND CONTROL VALVES. (0.25 SEC.)
4/4
FSAR 7.7.1.4, 10.2
ESFAS
A B C D
MSIS
2/3
S.P.: 450 psig
FSAR TABLE 15.0-8
FSAR 7.3
MSIS
MS
A B
1/2
CLOSE MSIVs (1-HCV-08-1A, 1B), MSBVs (1-HV-08-1A,1B).
2/2
FSAR 7.3.1.1.5
MFW
A B
CLOSE MFIVs (1-HCV-09-1A, 1B, 2A, 2B).
2/2
FSAR 7.3.1.1.5
A
2/4
1-2
B
2/4
EFAS
A B C D
INPUT A:
WITHDRAW EFAS-2
AS REQUIRED.
INPUT B:
GENERATE EFAS-2
AS REQUIRED.
2/3
FSAR 7.4.1.1
A
2/4
2-1
EFAS
A B C D
INPUT A:
WITHDRAW EFAS-1
AS REQUIRED.
INPUT B:
GENERATE EFAS-1
AS REQUIRED.
2/3
FSAR 7.4.1.1
2-1
EFAS-1
EFAS-2
1/1
1/1
AFW
A/B C
START AFW PUMPS.
OPEN OR CLOSE
AFW ISOLATION VALVES
AS REQUIRED.
1/2
FSAR 10.4.9
NOTE: A&B ARE 50% CAPACITY MOTOR DRIVEN PUMPS AND C IS 100% CAPACITY STEAM DRIVEN PUMP.
NOTE: IF STEAM DRIVEN PUMP IS USED, STEAM SUPPLY VALVES (1-HV-08-3, 12, 13) MUST BE OPENED
EFAS-1
EFAS-2
MFW
A B
1/2
CLOSE MFIVs (1-HCV-09-1A, 1B, 2A, 2B).
2/2
FSAR 10.4.9
CST
P
AUXILIARY FEEDWATER SUPPLY.
FSAR 9.2.6, 10.4.9
MSSV
P
OPEN TO LIMIT SECONDARY PRESSURE INCREASE AND DISSIPATE HEAT.
S.P.: 8 @ 995 psig
8 @ 1035 psig
8/16
FSAR 10.3
MSSV
CLOSE AS PRESSURE DECREASES.
S.P.: 8 @ 970 psig
8 @ 1009 psig
16/16
FSAR 10.3
SEC. SYS. PRESS/LEVEL HEAT SINK CONTROL

15.3.5.1-1c

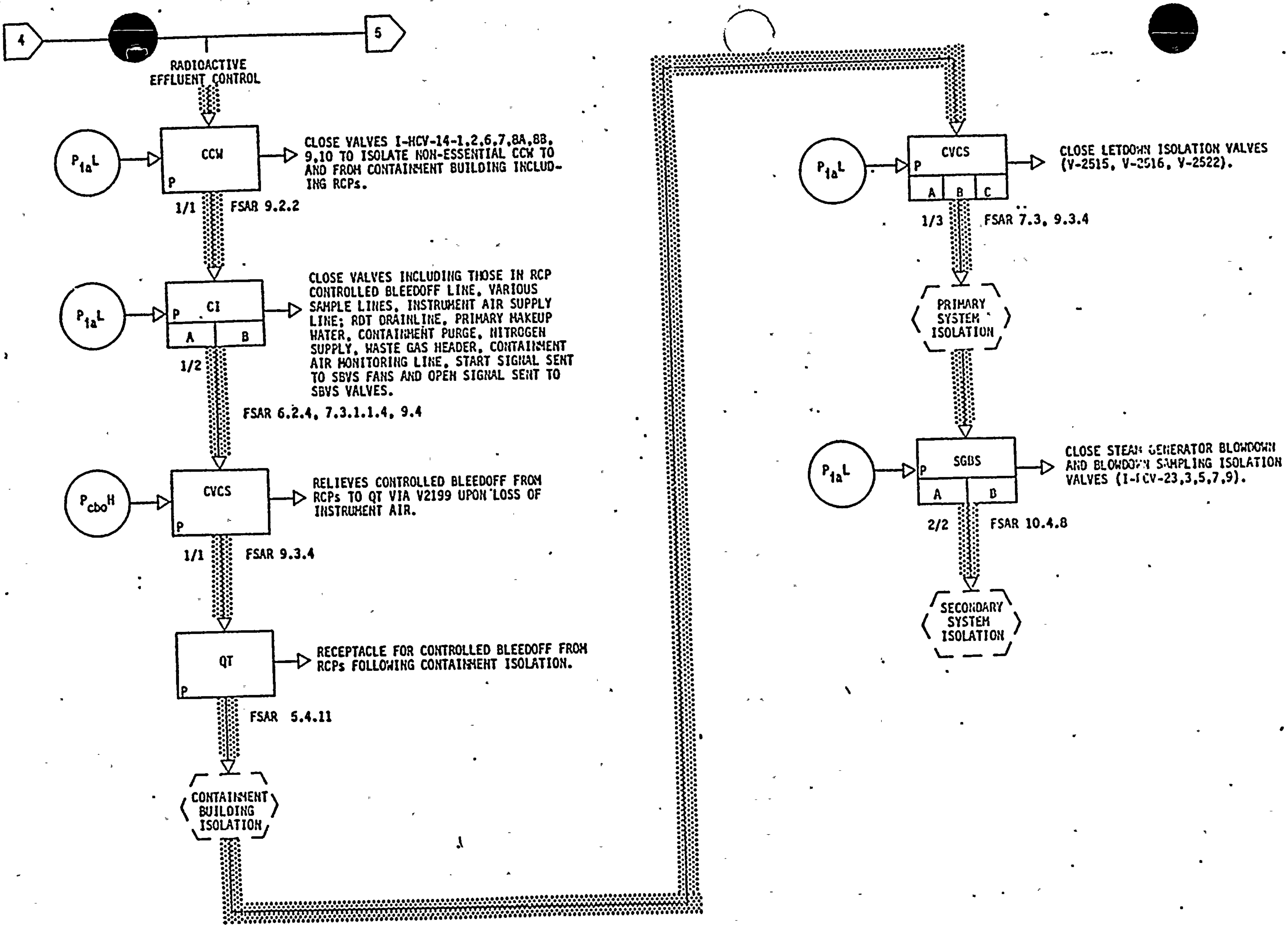

A
CR
NS
$P_{cd}H$
1/1
1/1
H
NS
A B
CLOSE MSIVs (I-HCV-08-1A,1B).
2/2
FSAR 7.3.1.1.5
CR&L
P_{sg}
P_p
T_{cl}
H
ADVS
A B C D
OPEN AND CONTROL TO DUMP STEAM TO ATMOSPHERE AND COOL RCS.
2/4
FSAR 7.4.1.4, 10.3.
CR
$P_{sg}L$
1/1
1/8
H
ESFAS
A B C D
PERMISSIVE BLOCK OF SG PRESSURE SIGNALS TO MSIS TO PERMIT SHUTDOWN DEPRESSURIZATION OF SECONDARY SYSTEM.
S.P.: 585 psig
3/4
FSAR 7.3.1.1.5
NOTE: IF SYSTEM PRESSURE RISES ABOVE BLOCK SETPOINT THE BLOCK IS AUTOMATICALLY REMOVED.
NON-SAFETY POWER RESTORED
NO
YES
CR
MSIS
2/2
H
NS
MSIV MSBV
OPEN MSBVs (I-HV-08-1A, 1B) THEN OPEN MSIVs (I-HCV-08-1A,1B). RECLOSE MSBVs.
2/2
FSAR 10.3
CR
NS
$T_{cd}H$
1/2
H
CW
NS
A B C D
START PUMPS TO PROVIDE COOLING WATER TO THE CONDENSER.
2/4
FSAR 10.4.5
CR
NS
$P_{cd}H$
1/2
H
CES
NS
A B
ACTUATE AIR EJECTORS TO RESTORE CONDENSER VACUUM.
2/2
FSAR 10.4.2
P_{sh}
P_p
T_{cl}
CONDENSER AVAILABLE
H
SBCS
NS
A B C D E
OPEN TURBINE BYPASS VALVES TO DUMP STEAM TO CONDENSER TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED.
1/5
FSAR 7.3, 10.4.4
NOTE: THERE ARE FOUR DUMP VALVES (PCV-8802, 8803, 8804, 8805) WITH 40% CAPACITY AND ONE BYPASS VALVE (PCV-8801) WITH 5% CAPACITY.
CD
NS
HEAT SINK FOR SBCS.
1/1
FSAR 10.4.1
NS
$L_{cd}H$
1/1
CTS
NS
OPEN VALVE LCV-12-5, CONDENSATE PUMPS TRANSFER WATER FROM CD TO CST.
1/1
FSAR 10.4.1
CR&L
P_{sg}
P_p
T_{cl}
H
ADVS
A B C D
REOPEN AND CONTROL TO DUMP STEAM TO ATMOSPHERE AND COOL RCS.
Psg BELOW 400 psia
2/4
FSAR 7.4.1.4, 10.3.
CR
P_{sg}
1/4
H
MS
A B
CLOSE MSIVs (I-HCV-08-1A,1B) IN PREPARATION TO BREAK VACUUM.
BELOW 400 psia
2/2
FSAR 10.3, 10.4.7
SEC. SYS. PPS/LVL/HS

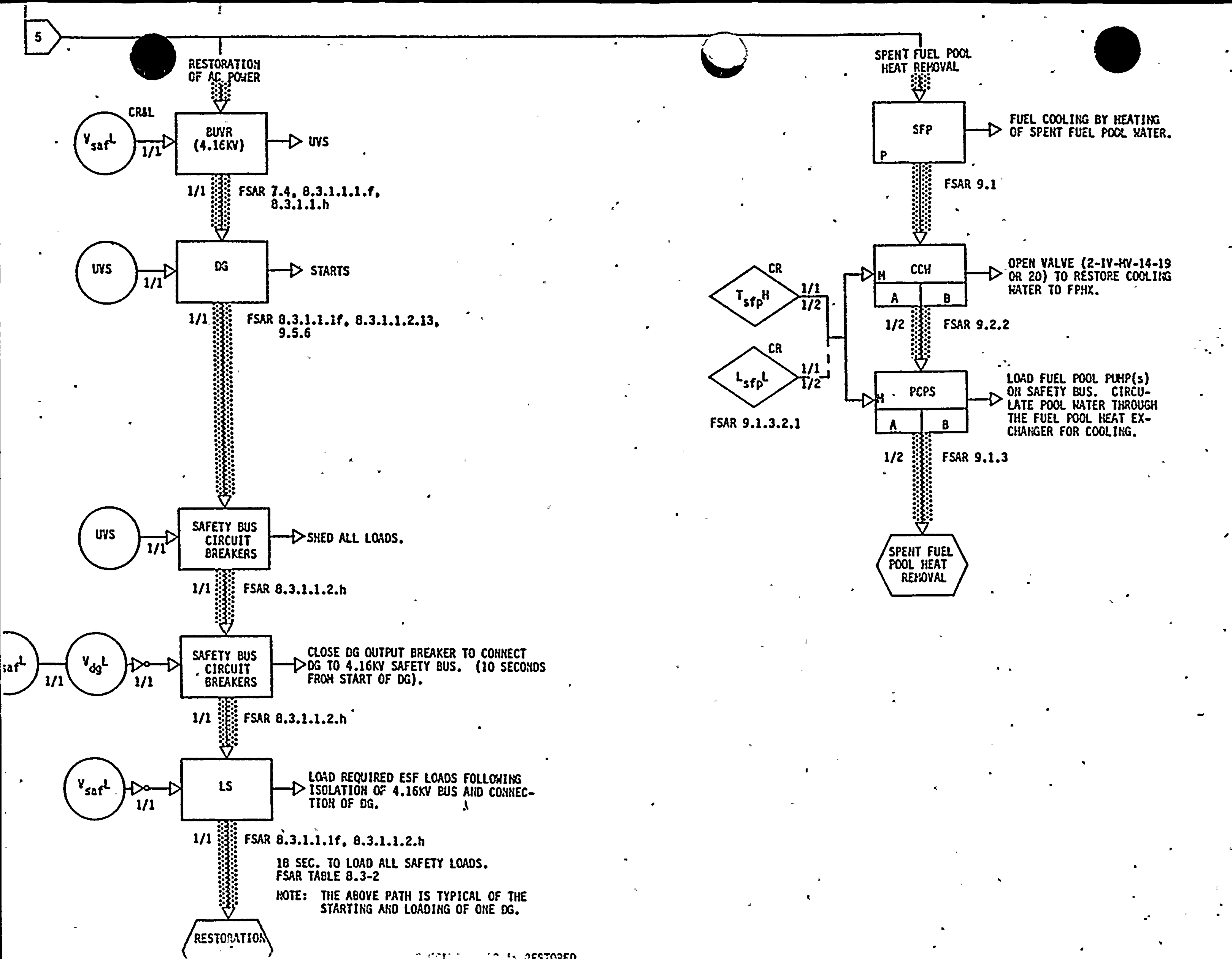

3
4
SYSTEM
PZR
P
ASSISTS IN CONTROL OF RCS PRESSURE AND VOLUME CHANGES.
FSAR 5.4.10
PORV
A
B
OPEN TO LIMIT RCS PRESSURE INCREASE
P_pH
S.P.: 2370 psia
0/2
FSAR 5.4.13
QT
NS
P
RECEIVE AND CONDENSE STEAM FROM PORV.
FSAR 5.4.11
CB
P
ALTERNATE RECEPTACLE FOR MASS AND ENERGY RELEASE FROM PORV DISCHARGE
FSAR 6.2.1
PSV
P
A
B
C
OPEN TO LIMIT RCS PRESSURE INCREASE.
P_pH
S.P.: 2510 psig
1/3
FSAR 5.4.13
QT
NS
P
RECEIVE AND CONDENSE STEAM FROM PSVs.
FSAR 5.4.11
CB
P
ALTERNATE RECEPTACLE FOR MASS AND ENERGY RELEASE FROM PSV DISCHARGE.
FSAR 6.2.1
PSV
A
B
C
CLOSE AS PRESSURE DECREASES.
P_pH
S.P.: 2409 psig
3/3
FSAR 5.4.13
PORV
A
B
CLOSE AS PRESSURE DECREASE
P_pH
2/2
FSAR 5.4.13
S.P.: 2346 psia
$P_{rcs}L$
CR
1/4
BLOCK VALVE
A
B
CLOSE TO ISOLATE PORV
2/2
FSAR 5.4.13
PRIMARY SYSTEM PRESS/LEVEL CONTROL
B

15.3.5.1-1e

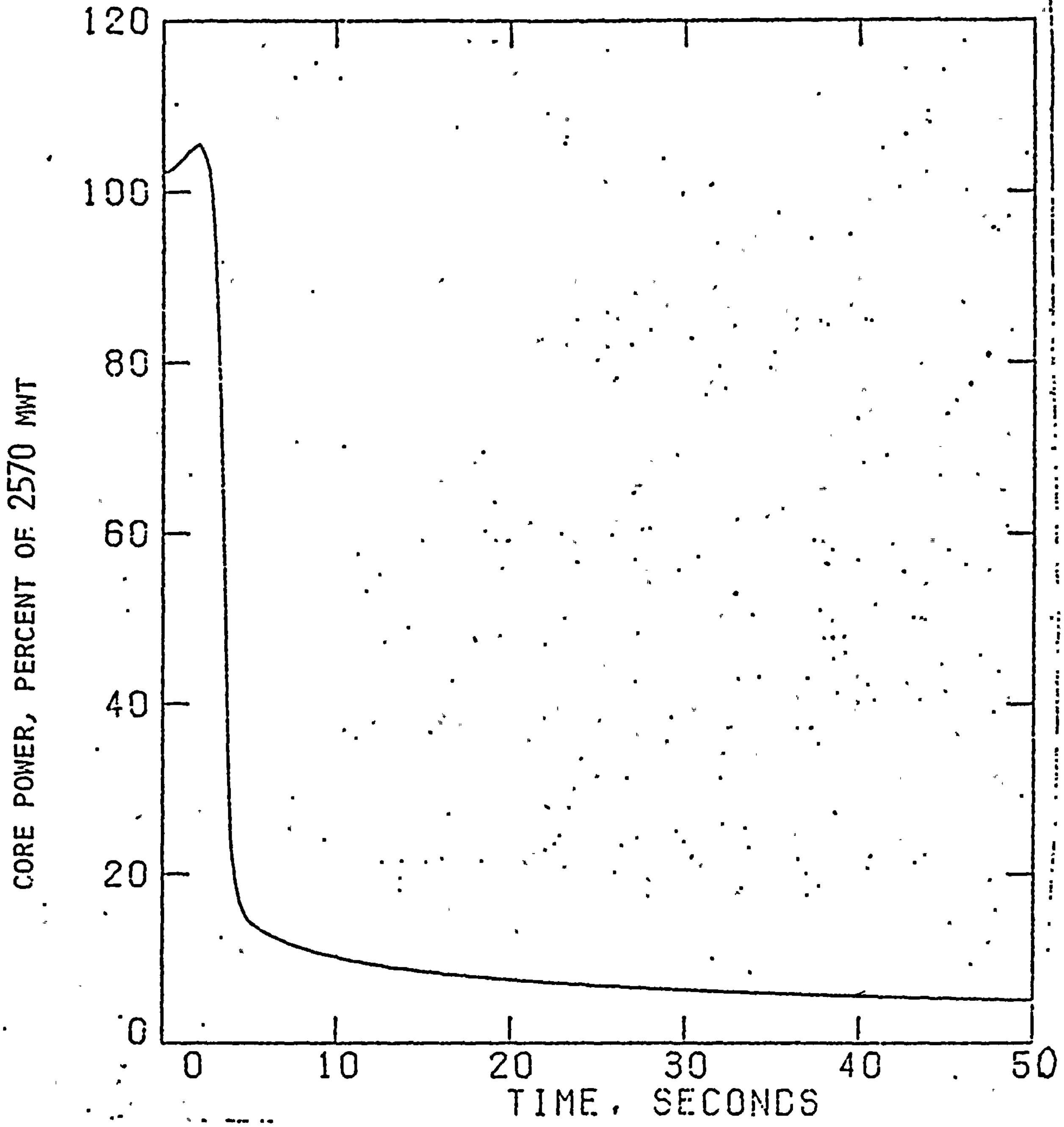

CR&L
P_p
1/4
H
AS
A
B
OPEN AND CLOSE AUXILIARY SPRAY CONTROL VALVES TO REGULATE P_p (I-SE-02-03,04).
1/3
FSAR 9.3.4
NOTE: USE OF AUXILIARY SPRAY ALSO AFFECTS RCS INVENTORY CONTROL.
HS
L_p
CR&L
1/3
P_p
L
1/4
H
CVCS (CHARGING)
A
B
C
DIVERT FLOW TO AUXILIARY SPRAY BY CLOSING CHARGING CONTROL VALVES (I-SE-02-01,02).
2/2
FSAR 9.3.4
C_b
L
1/1
CVCS
H
OPEN VALVES I-V-07-1609 (LOCAL) AND V2504 FROM RWT TO CHARGING PUMPS. CLOSE BAMT DISCHARGE VALVES (V2508 AND V2509).
S.P.: COLD SHUTDOWN BORON CONCENTRATION
1/1
FSAR 6.2
$L_{bamt}L$
CR
1/1
1/2
RWT
P
WATER SUPPLY FOR CHARGING PUMPS.
FSAR 6.3.2.2.4
P_pL
CR
1/1
1/4
H
ESFAS
A
B
C
D
PERMISSIVE BLOCK OF PRESSURIZER PRESSURE INPUT TO SIAS TO PERMIT SHUTDOWN DEPRESSURIZATION OF REACTOR COOLANT SYSTEM.
S.P.: 1650 psia
3/4
FSAR 7.3.1.1.1
NOTE: IF THE SYSTEM PRESSURE RISES ABOVE BLOCK SETPOINT THE BLOCK IS AUTOMATICALLY REMOVED.
CR&L
P_p
1/4
H
SIT
A
B
C
D
DEPRESSURIZE SITS BY DRAINING OR VENTING AND ISOLATE THEM.
4/4
FSAR 6.3.2.2.1
DEPRESSURIZING - P_p ~625 psig
ISOLATION - P_p ~278 psia
PRIM. SYS. PRESS/LEVEL CONTROL
B
HS
L_p
CR&L
1/3
H
CVCS (CHARGING)
A
B
C
START AND STOP CHARGING PUMPS TO MAKEUP RCS VOLUME SHRINKAGE.
1/3
FSAR 9.3.4
P_p
CR&L
1/4
H
PPCS (PH)
HS
PROP
BACKUP
LOAD HEATERS ON SAFETY BUS. USE HEATERS TO ADJUST RATE OF DECREASE OF PZR PRESSURE. (EITHER PROPORTIONAL OR BACKUP HEATERS MAY BE USED).
1/2
FSAR 7.7.1.1.2

15.3.5 1-1f


4
5
RADIOACTIVE EFFLUENT CONTROL
$P_{1a}L$
CCW
P
CLOSE VALVES I-HCV-14-1,2,6,7,8A,8B, 9,10 TO ISOLATE NON-ESSENTIAL CCW TO AND FROM CONTAINMENT BUILDING INCLUDING RCPs.
1/1
FSAR 9.2.2
$P_{1a}L$
CI
P
A
B
CLOSE VALVES INCLUDING THOSE IN RCP CONTROLLED BLEEDOFF LINE, VARIOUS SAMPLE LINES, INSTRUMENT AIR SUPPLY LINE; RDT DRAINLINE, PRIMARY MAKEUP WATER, CONTAINMENT PURGE, NITROGEN SUPPLY, WASTE GAS HEADER, CONTAINMENT AIR MONITORING LINE, START SIGNAL SENT TO SBVS FANS AND OPEN SIGNAL SENT TO SBVS VALVES.
1/2
FSAR 6.2.4, 7.3.1.1.4, 9.4
$P_{cbo}H$
CVCS
P
RELIEVES CONTROLLED BLEEDOFF FROM RCPs TO QT VIA V2199 UPON LOSS OF INSTRUMENT AIR.
1/1
FSAR 9.3.4
QT
P
RECEPTACLE FOR CONTROLLED BLEEDOFF FROM RCPs FOLLOWING CONTAINMENT ISOLATION.
FSAR 5.4.11
CONTAINMENT BUILDING ISOLATION
$P_{1a}L$
CVCS
P
A
B
C
CLOSE LETDOWN ISOLATION VALVES (V-2515, V-2516, V-2522).
1/3
FSAR 7.3, 9.3.4
PRIMARY SYSTEM ISOLATION
$P_{1a}L$
SGBS
P
A
B
CLOSE STEAM GENERATOR BLOWDOWN AND BLOWDOWN SAMPLING ISOLATION VALVES (I-FCV-23,3,5,7,9).
2/2
FSAR 10.4.8
SECONDARY SYSTEM ISOLATION


5
RESTORATION OF AC POWER
CR&L
V_{saf}^L
1/1
BUVR (4.16KV)
UVS
1/1
FSAR 7.4, 8.3.1.1.1.f, 8.3.1.1.h
UVS
1/1
DG
STARTS
1/1
FSAR 8.3.1.1.1f, 8.3.1.1.2.13, 9.5.6
UVS
1/1
SAFETY BUS CIRCUIT BREAKERS
SHED ALL LOADS.
1/1
FSAR 8.3.1.1.2.h
V_{dg}^L
1/1
1/1
SAFETY BUS CIRCUIT BREAKERS
CLOSE DG OUTPUT BREAKER TO CONNECT DG TO 4.16KV SAFETY BUS. (10 SECONDS FROM START OF DG).
1/1
FSAR 8.3.1.1.2.h
V_{saf}^L
1/1
LS
LOAD REQUIRED ESF LOADS FOLLOWING ISOLATION OF 4.16KV BUS AND CONNECTION OF DG.
1/1
FSAR 8.3.1.1.1f, 8.3.1.1.2.h
18 SEC. TO LOAD ALL SAFETY LOADS.
FSAR TABLE 8.3-2
NOTE: THE ABOVE PATH IS TYPICAL OF THE STARTING AND LOADING OF ONE DG.
RESTORATION
SPENT FUEL POOL HEAT REMOVAL
SFP
P
FUEL COOLING BY HEATING OF SPENT FUEL POOL WATER.
FSAR 9.1
CR
T_{sfp}^H
1/1
1/2
CR
L_{sfp}^L
1/1
1/2
FSAR 9.1.3.2.1
CCW
H
A
B
OPEN VALVE (2-IV-HV-14-19 OR 20) TO RESTORE COOLING WATER TO FPHX.
1/2
FSAR 9.2.2
PCPS
H
A
B
LOAD FUEL POOL PUMP(s) ON SAFETY BUS. CIRCULATE POOL WATER THROUGH THE FUEL POOL HEAT EXCHANGER FOR COOLING.
1/2
FSAR 9.1.3
SPENT FUEL POOL HEAT REMOVAL

IS RESTORED.



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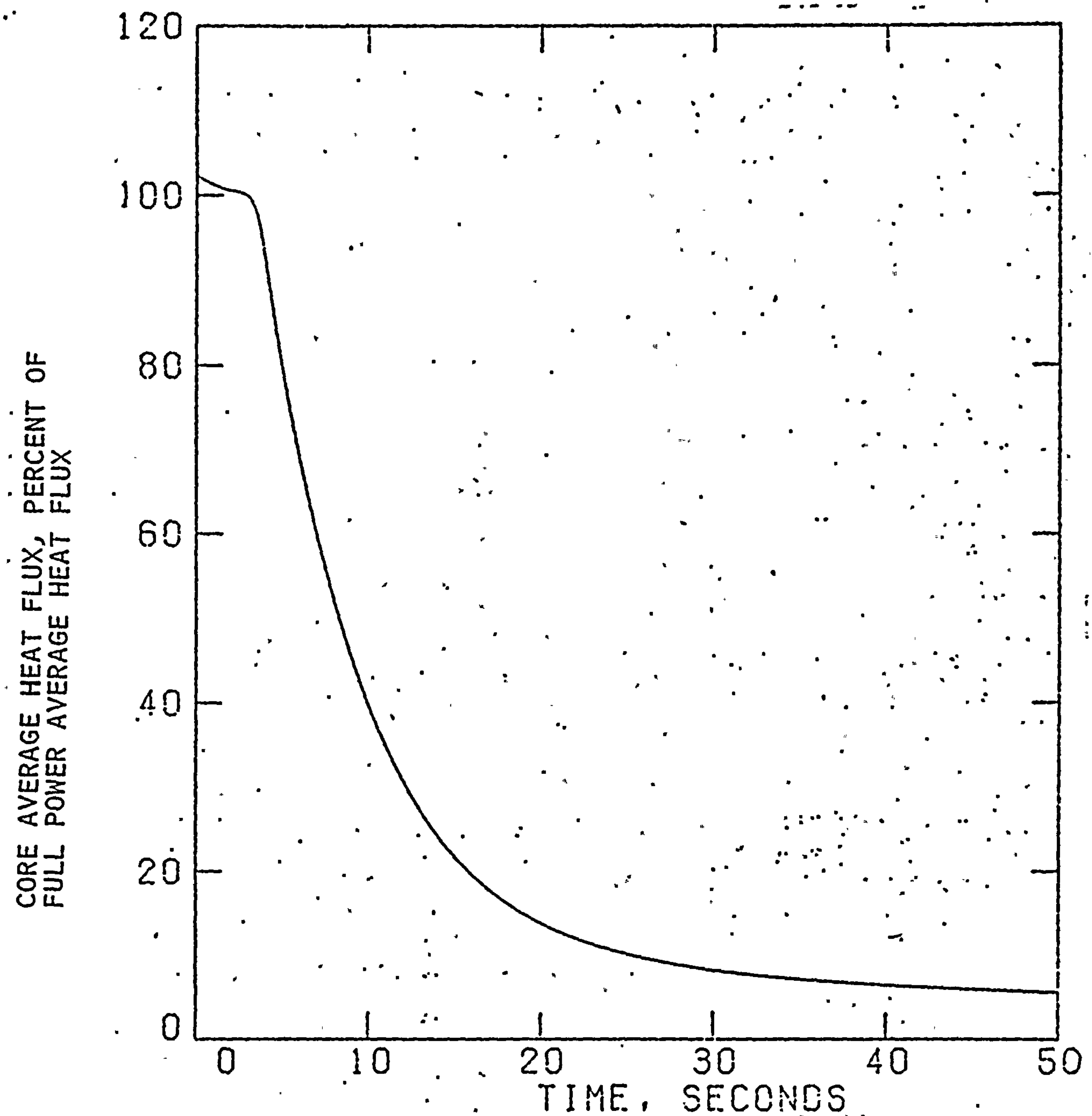
CORE POWER VS. TIME
FIGURE 15.3.5.1-2



FLORIDA POWER & LIGHT COMPA
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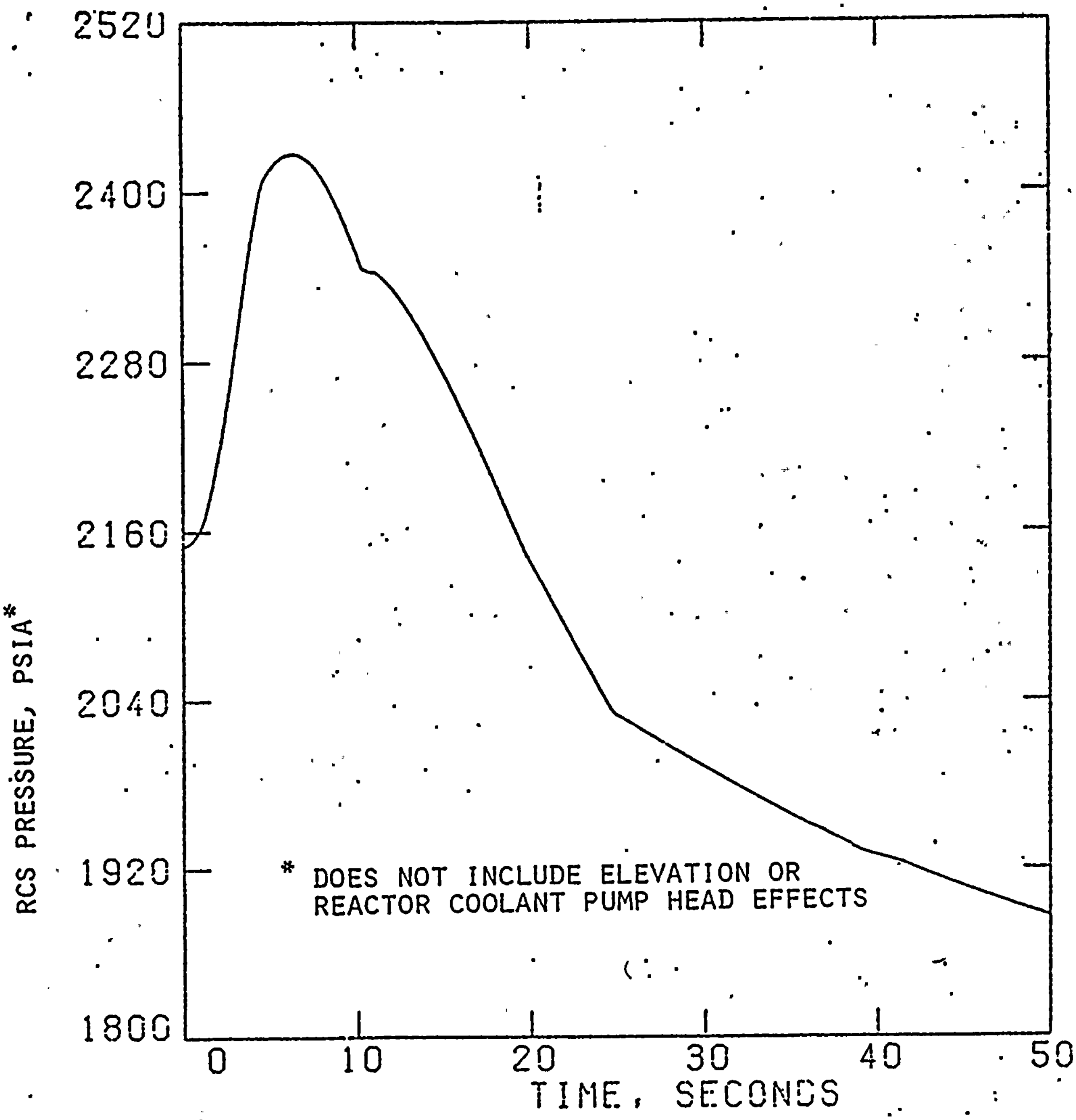
CORE AVERAGE HEAT FLUX VS. TIME

FIGURE 15.3.5.1-3



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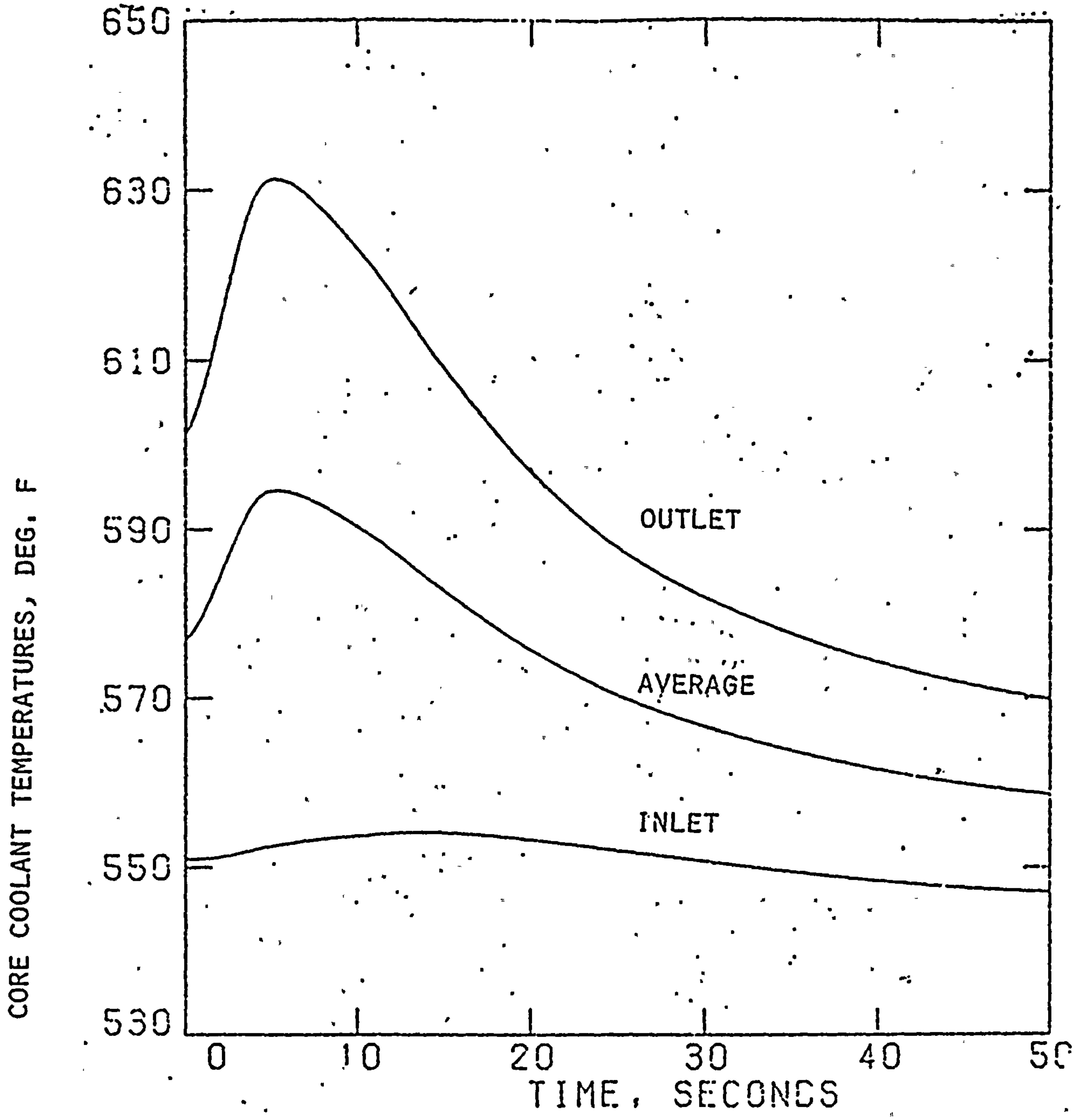
RCS PRESSURE VS. TIME

FIGURE 15.3.5.1-4



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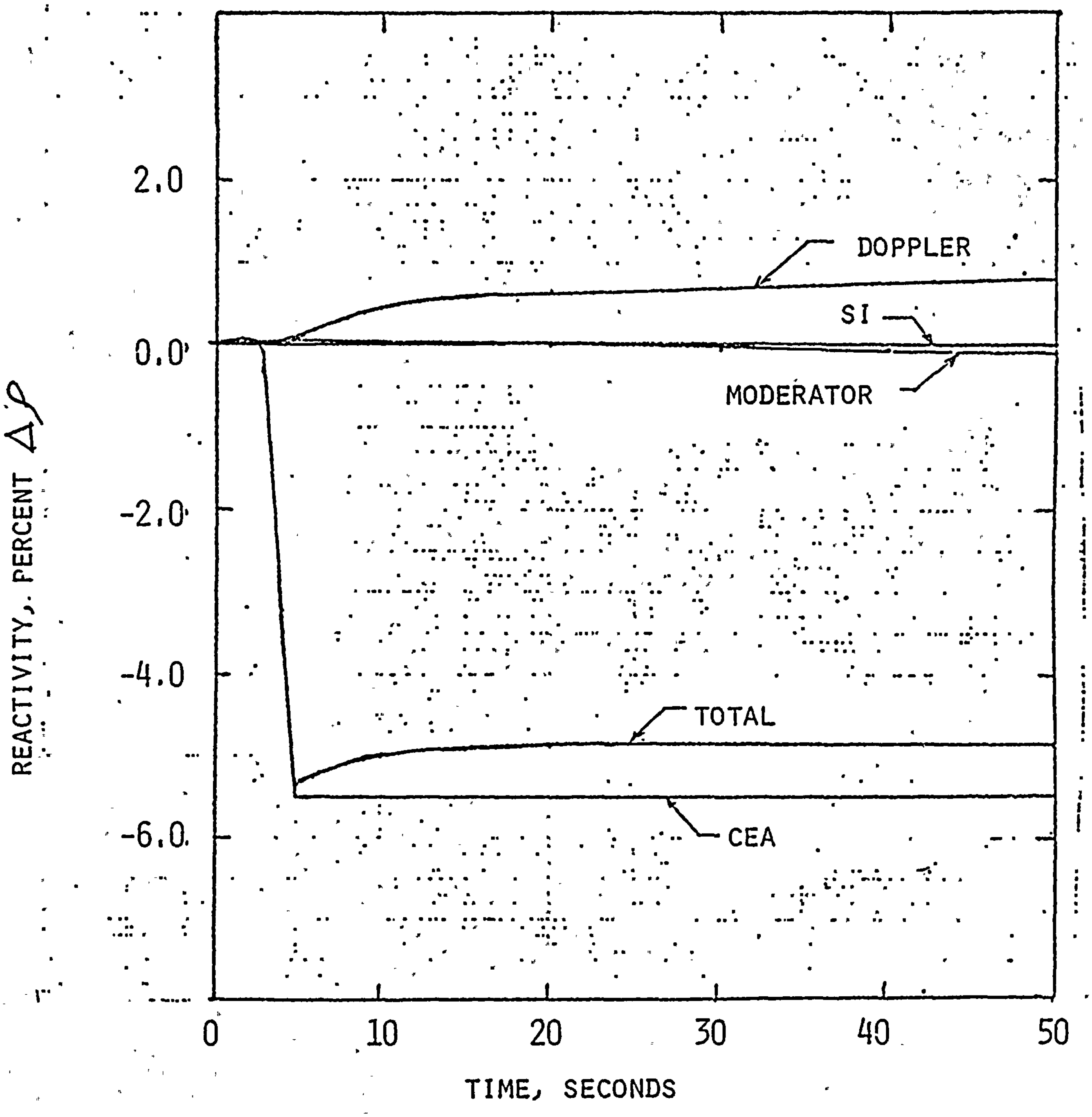
CORE COOLANT TEMPERATURE
VS. TIME
FIGURE 15.3.5.1-5



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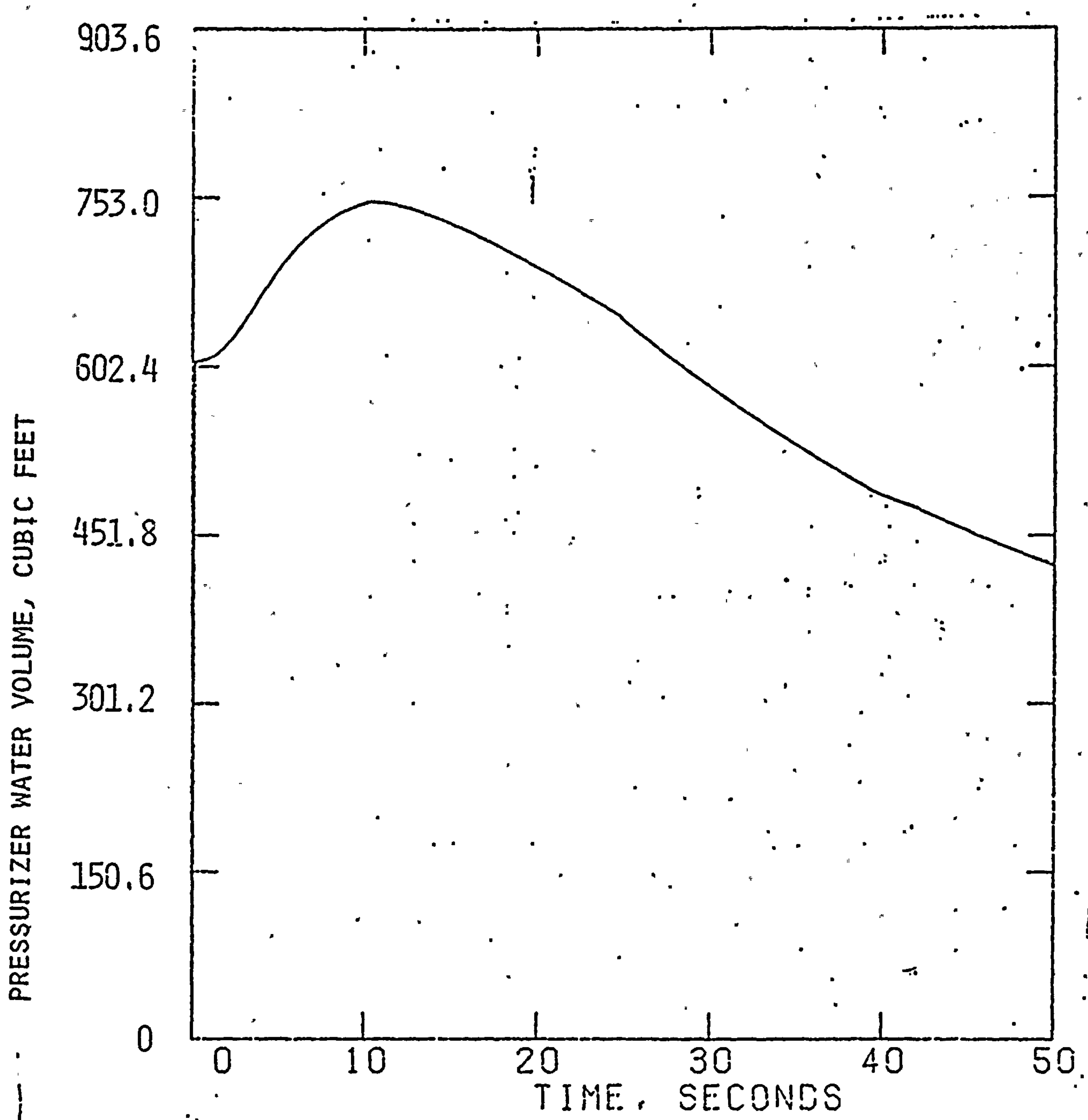
REACTIVITY VS. TIME
FIGURE 15.3.5.1-6



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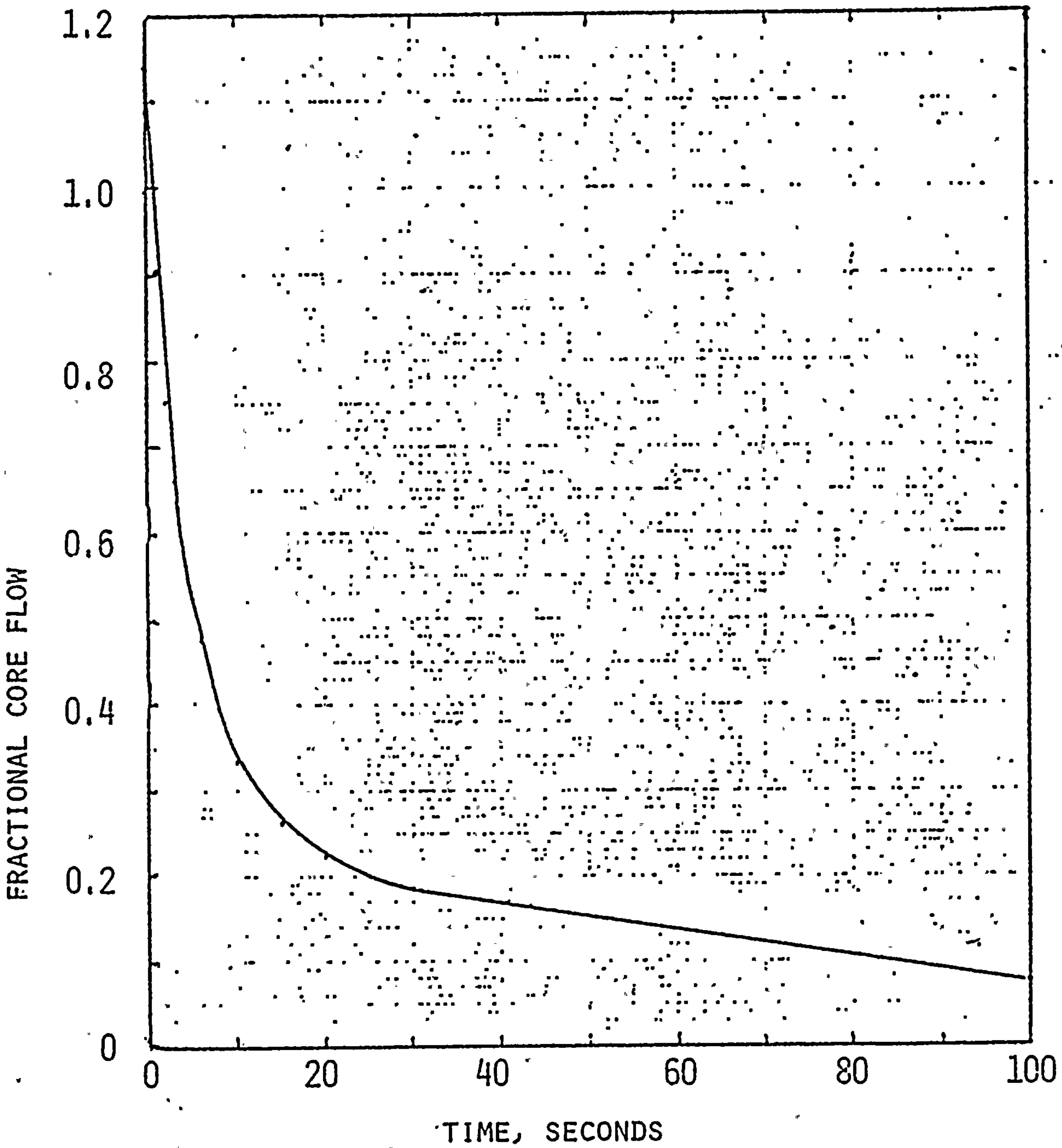
PRESSURIZER WATER VOLUME VS. TIME

FIGURE 15.3.5.1-7



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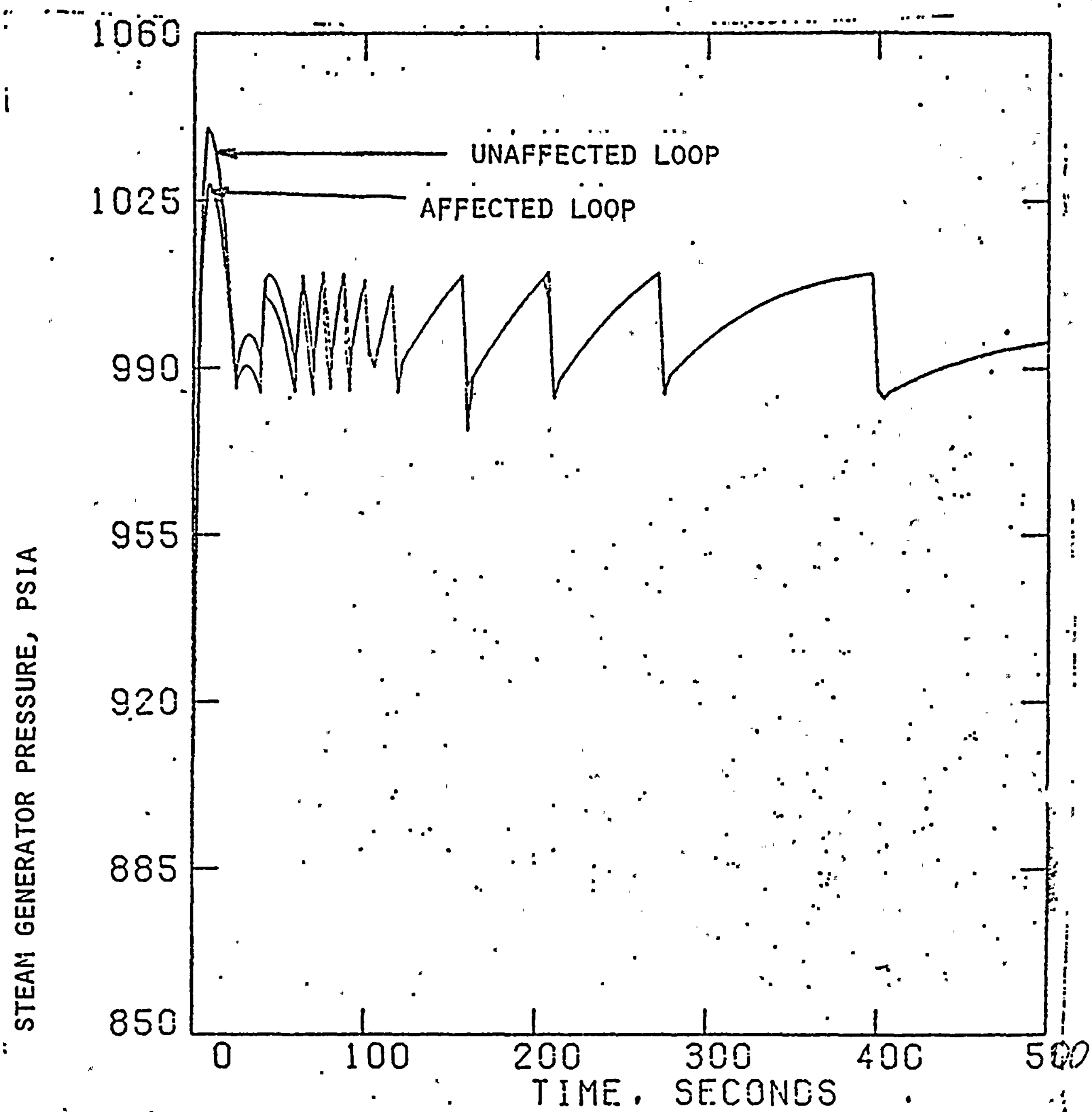
FRACTIONAL CORE FLOW
VS. TIME

FIGURE 15.3.5.1-8



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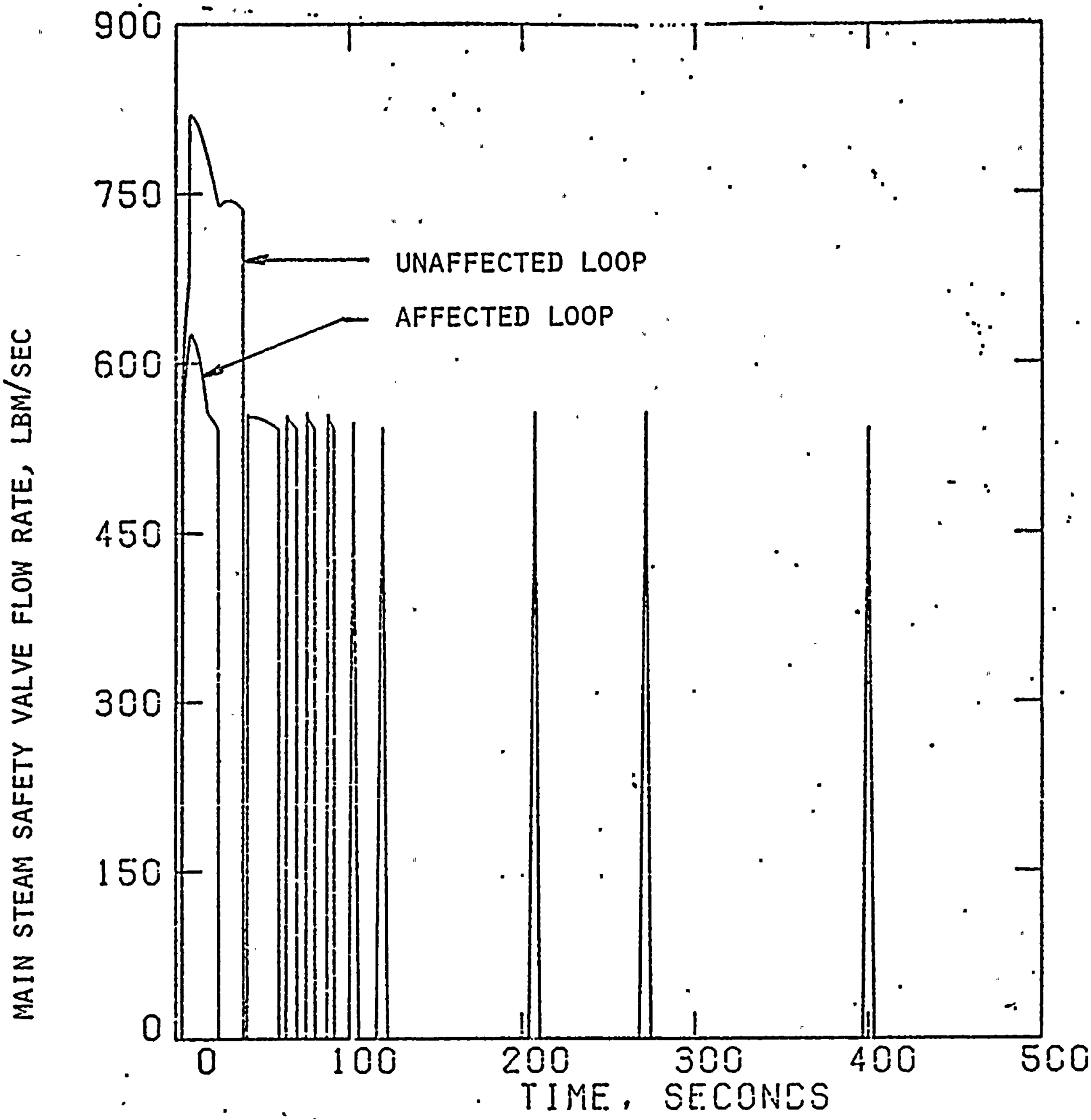
STEAM GENERATOR PRESSURE VS. TIME

FIGURE 15.3.5.1-9



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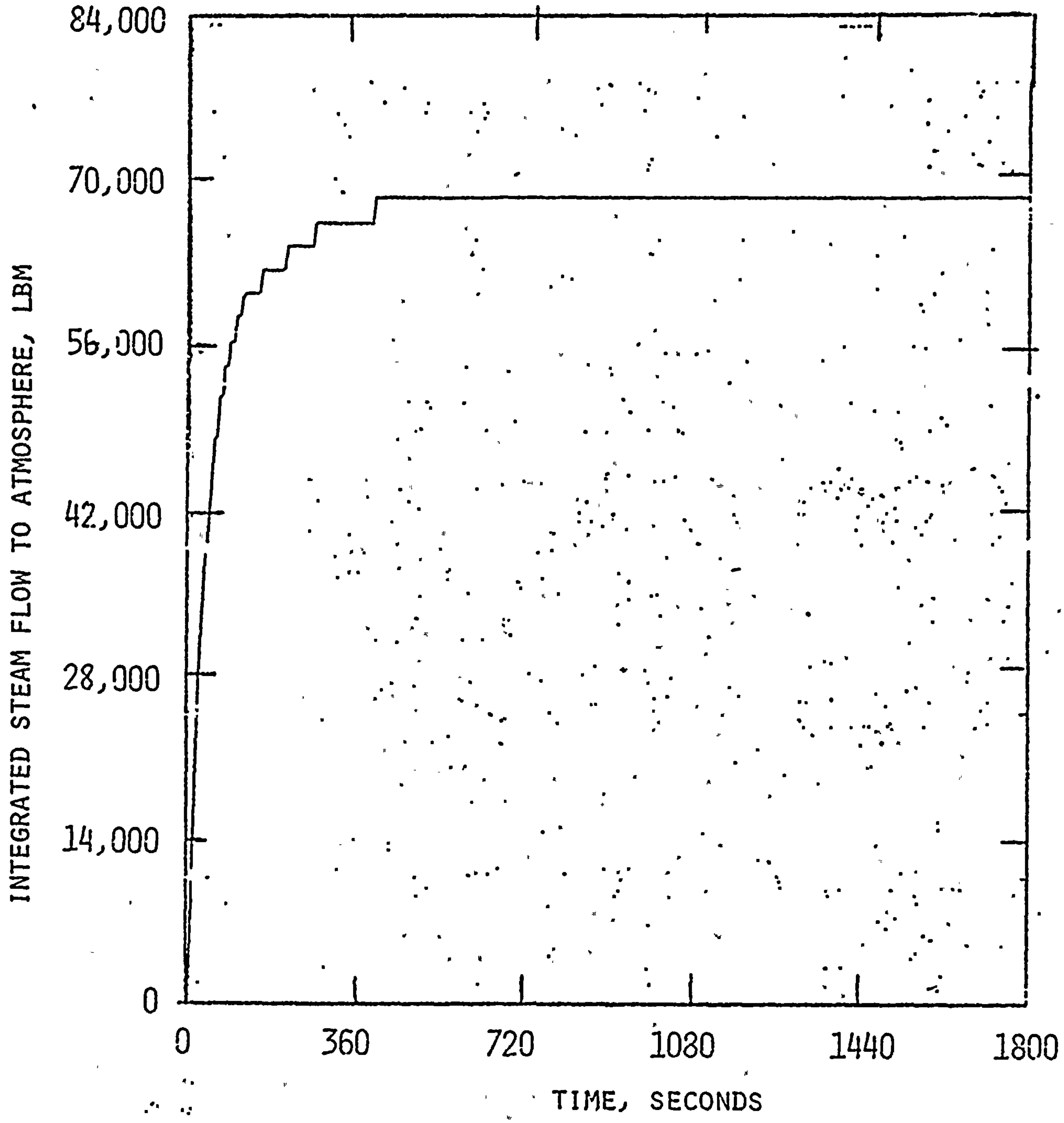
MAIN STEAM SAFETY VALVE
FLOW RATE VS. TIME
FIGURE 15.3.5.1-10



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INTEGRATED STEAM FLOW VS. TIME

FIGURE 15.3.5.1-11

Section 15.4 Revisions

RCS volume shrinkage. RCS pressure is gradually reduced by the pressurizer
spray valves. The operator may also actuate the pressurizer heaters during
cooldown, to permit using a higher spray rate and obtain better pressure
control and mixing of fluid in the pressurizer. During cooldown, the
charging pumps initially take suction from the boric acid makeup tank BAMT
until the RCS has been increased to the cold shutdown boron concentration,
at which time the charging pump suction is realigned to the refueling water
tank. As the RCS pressure is reduced, the operator blocks the safety in-
jection actuation signal to prevent its inadvertent actuation. The safety 2
injection tanks are depressurized by draining or venting and then are
isolated to permit further depressurization of the RCS. After the reactor
coolant pumps have been stopped, the operator uses the auxiliary spray to
reduce pressurizer pressure.

Maintenance of AC Power:

Upon loss of power to the unit auxiliary transformers, their loads are transferred to the startup transformers by a fast-dead bus transfer.

15.4.2.3.3 Analysis of Effects and Consequences

a) Mathematical Models

The NSSS response to the PLCEA Subgroup Drop was simulated using the 4
CESEC code described in Subsection 15.0.4. The transient minimum
DNBR values were calculated using the TORC code which uses the CE-1
CHF correlation described in Subsection 15.0.4.

b) Input Parameters and Initial Conditions

The range of initial conditions considered are given in Subsection
15.0.3. Table 15.4.2.3-4 gives the initial conditions used in this
analysis. Maximum core power, highest core inlet coolant tempera-
ture, lowest core mass flow rate, and lowest pressurizer pressure
are used since these values have the most adverse impact on DNBR.
The least negative Doppler coefficient and the smallest scram CEA 2
worth maximizes the heat flux increase after a reactor trip occurs,
giving a lower minimum DNBR. The moderator temperature coefficient
least negative
is set at the ~~most positive~~ value that is allowed by the Technical
Specifications with part length CEAs in the core. For this
analysis, the thermal margin/low pressure and high local power 2
density trips are assumed not to function.

c) Results

The dynamic behavior of important NSSS parameters following a part
length CEA Subgroup drop is presented on Figures 15.4.2.3-2 to 8. 4
Table 15.4.2.3-1 summarizes some of the important results of this
event and the times at which the minimum and maximum parameter
values discussed below occur.

TABLE 15.4.2.3-4

INPUT PARAMETERS AND INITIAL CONDITIONS
ASSUMED FOR PART LENGTH CEA SUBGROUP DROP ANALYSIS | 4

Parameter	Assumed Value
Power Level, MWt	2630
Core Inlet Coolant Temperature, F	551
Core Flowrate, gpm	370,000
RCS Pressure, psia	2150
Pressurizer Water Volume, % level	52.7
Axial Shape Index	-.30
Steam Generator Water Level, % of narrow range tap span	70
Doppler Coefficient Multiplier	0.85
Moderator Temperature Coefficient, $10^{-4}\Delta\rho/F$	-0.5
CEA Worth for Trip, $10^{-2}\Delta\rho$	-5.5
Worth of Dropped Subgroups, $10^{-2}\Delta\rho$ (90% Insertion / 100% Insertion)	0.195/0.147

2

15.4.4.4 Limiting Loss of Shutdown Margin Event

None of the Limiting Fault-2 event groups or event group combinations resulting in reactivity and power distribtuion anomalies shown in Table 15.4.4-1 result in a closer approach to loss of shutdown margin than that produced by the slow positive reactivity insertion described in Subsection 15.4.2.4. The additional plant conditions and failures considered here do not have an adverse effect on this event with respect to time to loss of 2
shutdown margin. Therefore, the conclusions of Subsection 15.4.2.4 also apply to this section.

15.4.5 LIMITING FAULT 3 EVENTS

15.4.5.1 Limiting Offsite Dose Event-Control Element Assembly Ejection with a Failure to Achieve a Fast Transfer of a 4.16 kV Bus and High Steam Generator Tube Leakage Rate

15.4.5.1.1 Identification of Event and Causes

All Limiting Fault 3 (LF-3) event groups in the Reactivity and Power Distribution Anomalies event type and the LF-3 event combinations as shown in Table 15.4.5-1 were compared to find the event resulting in the maximum offsite doses. The CEA ejection with a failure to achieve fast transfer 2
of a 4.16 kV bus and a high steam generator tube leakage rate was identified as the limiting LF-3 event.

The event groups and event combinations evaluated and the significance of the approach to acceptance guideline for offsite dose are indicated in Table 15.4.5-1. The events indicated as insignificant (I) produce offsite doses well within the acceptance guideline in Table 15.0-4. All events listed as significant (S) produce offsite doses within the acceptance 2
guideline.

This event occurs due to the rupture of a CEDM nozzle or housing, subsequent ejection of its CEA (from the core) and release of primary coolant into containment.

A failure to achieve a fast transfer to a startup transformer can cause the loss of either one 6.9 kV bus or one 4.16 kV bus. The loss of the 4.16 kV bus causes the loss of condenser vacuum while the loss of the 6.9 kV bus causes the loss of two reactor coolant pumps and one feedwater pump. 2
Without the condenser, cooldown must be performed through the atmospheric dump valves (ADVs), hence the effect on the radiation release from the CEA ejection event is more adverse with the failure to achieve a transfer of the 4.16 kV bus.

The analysis of a CEA Ejection with loss of offsite power is summarized in Appendix 15C.3.

All events listed in Table 15.4.5-1, except those involving a CEA ejection, 2
have an insignificant approach to the acceptance guideline for the offsite doses. Only the CEA ejection event releases primary coolant into containment. The CEA ejection with a loss of offsite power as a result of turbine trip also causes a loss of condenser vacuum as well as the loss of all four reactor coolant pumps. However, the failure to achieve a fast transfer of a 4.16 kV bus is more severe than the loss of offsite power as a result of 2
turbine trip, since it maintains forced Reactor Coolant System (RCS) flow,

TABLE 15.6.2.1-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR THE STEAM GENERATOR TUBE RUPTURE

Time (Sec)	Event	Analysis Set Point or Value	Success Paths: Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Maintenance of AC Power	Containment Integrity	Plant Habit Habitability	Radioactive Effluent Control
0.0	Tube rupture occurs	--								
28	PPCS energizes proportional heaters, psia	2225				X				
40	PLCS generates minimum letdown signal, inches below programmed level	4 ~~14~~				X				
	-PLCS generates maximum charging signal, inches below programmed level	14				X				
	-PPCS energizes backup heaters, psia	2310 ~~2200~~				X				
120	Low pressurizer level alarm, inches below programmed level	15								
800	Pressurizer heater de-energized, inches below programmed level	158				X				
1272	Reactor trip signal generated on TM/LP, low pressurizer pressure floor, psia	1875	X							
	-Maximum reactor power, %	102.9								
	-Turbine trip on loss of power on CEDM power supply buses	--			X					
	-Fast transfer to start-up transformers	--					X			
1280	Main steam safety valves open*, psig	975			X					
1285	Maximum SG pressure, psia	1016								
1287	Pressurizer empties	--								

* MSSVs cycle until operator actuates SBCS at 1320 seconds

CHAPTER 15

TABLE OF CONTENTS (Cont'd)

6

11

Insert A

3

INSERT A (Page 15-iv)

15C.2 ADDITIONAL INFORMATION FOR CEA MISOPERATION ANALYSES IN SUBSECTION 15.4.2.3

Analysis of the following three uncontrolled positive reactivity insertion events was performed:

1. Single part length CEA drop (SPLD)
2. Sequential rod withdrawal (high and low power)
3. Part length subgroup drop (PLSD)

The limiting fuel performance event was found to be the PLSD. The PLSD is presented in FSAR Subsection 15.4.2.3. The reasons that the other two events are less limiting are discussed below.

15C.2.1 Single Part Length CEA Drop:

Significant differences exist in the method of thermal margin protection for the SPLD as opposed to the PLSD. The PLSD will cause a reactor trip, whereas the SPLD will not. Sufficient margin exists during steady state operation such that the SPLD will not significantly approach thermal margin limits. The Technical Specifications will stipulate the appropriate time period for operator response to retrieve the rod or reduce core power to prevent a violation of the specified acceptable fuel design limit (i.e., DNBR $\geq$ 1.19).

The PLSD produces more limiting fuel performance results for the following reasons:

a) Relative to the SPLD, the PLSD results in a greater hot channel 3D power distribution increase in the region where the minimum DNBR occurs.

b) The PLSD causes a greater increase in total core power due to a greater reactivity increase than the SPLD.

The two above effects result in the part length CEA subgroup drop experiencing a larger decrease in DNBR than the single part length CEA drop. Thus, the part length CEA drop has less adverse fuel performance than the part length CEA subgroup drop which is presented in Subsection 15.4.2.3.

15C.2.2 Sequential Rod Withdrawal (high and low power):

Similarly, analysis of the sequential rod withdrawal (high power and low power) shows that it is also not as limiting as the part length CEA subgroup drop. The sequential rod withdrawal has much less of a radial and axial power distribution distortion than a part length CEA subgroup drop. The sequential rod withdrawal actually flattens the planar radial power distribution at the core heights in the areas where rods are being withdrawn. At other core heights, the radial power distribution will remain the same. At no position a[illegible]ly will the planar radial power distribution become more peaked. The change in the axial power distribution to a more top peaked shape occurs very slowly due to the slow withdrawal rate, as compared to the part length CEA subgroup drop. The concurrent increase in core power also occurs very slowly. Thus, the degradation in DNBR margin occurs slowly. Less thermal margin degradation occurs for a slower transient since the DNBR margin degradation between time of trip and time of minimum DNBR is less than that for a faster transient. 6

Therefore, the part length CEA subgroup drop produces more adverse fuel performance results relative to both the part length CEA drop and the sequential CEA withdrawal (high power and low power). Thus, the part length CEA subgroup drop was presented as the infrequent category limiting fuel performance event in FSAR Subsection 15.4.2.3.

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15C.3 CEA Ejection with Loss of Offsite Power.

The following CEA ejection cases were requested to be analyzed without offsite power:

(1) CEA ejection with control element housing rupture and subsequent rapid blowdown into containment.

(2) CEA ejection where the control element housing does not rupture and the primary system leaks to the secondary system through leaks in the steam generator tubes.

The analysis of a CEA ejection with a rapid blowdown into containment is presented in Section 15.4.5.1. This analysis also assumed a failure of the 4.16 KV bus to fast transfer following turbine trip. The main impact of this is the assumption that the condenser is unavailable for one hour. The analysis of a CEA ejection where the housing does not rupture is discussed in this section. This case was analyzed without offsite power to determine the steam released to the atmosphere.

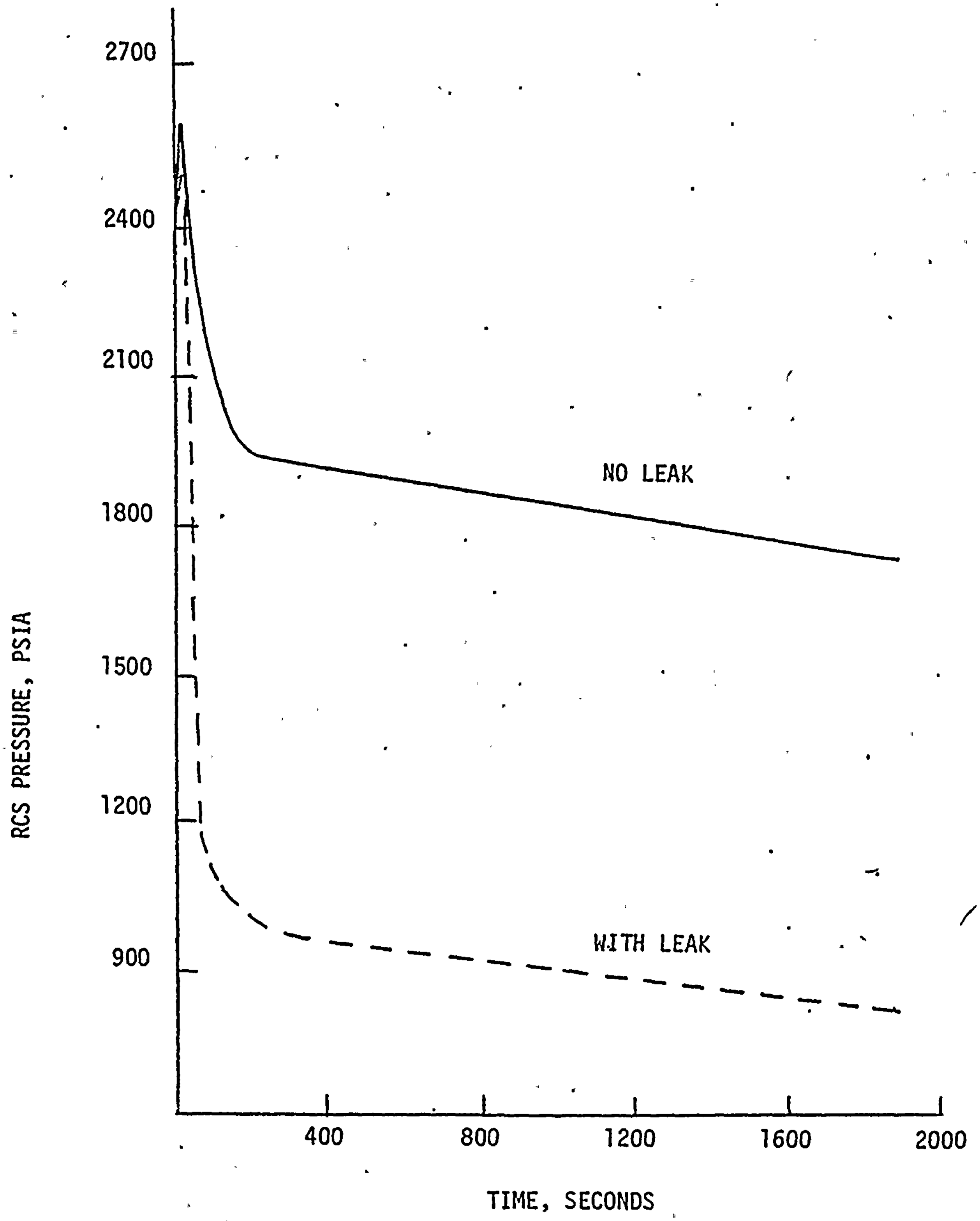
Figures 15C.3-1 and 15C.3-2 are the pressure versus time curves for primary and secondary side pressures, respectively. Table 15C.3-1 presents information associated with radiological release calculations.

The Shield Building Ventilation System (SBVS) is assumed to be actuated two minutes following the event initiation. Design basis leak rate of 0.5% by volume per day is assumed to reach the shield building annulus. The SBVS passes this material through a once-through system of charcoal absorbers. These filters are assumed to remove 95% of the elemental and organic iodine, and 99% of the particulate iodine.

Table 15C.3-1

CEA Ejection with Loss of Offsite Power
Radiological Release Information

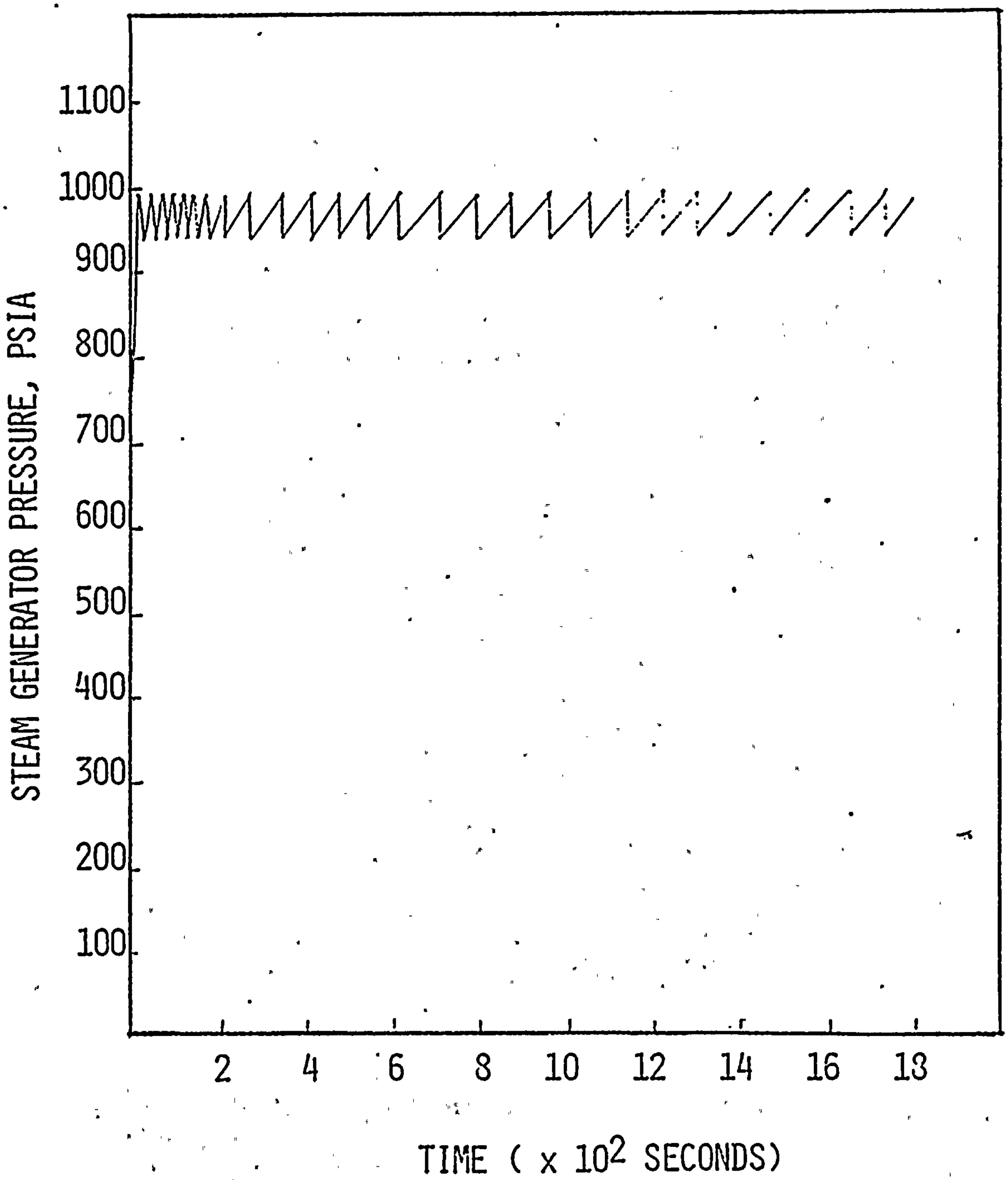
1.	Steam Released to Atmosphere During Cooldown (lbm)	
	0 - 2 hours:	
	MSSVs	74400
	ADVs	451000
	Entire Event:	
	MSSVs	74400
	ADVs	572000
2.	Fuel Pin Failure (%) (See Section 15.4.5.1)	9.5
3.	Primary Iodine Concentration Based on 9.5% Failed Fuel (μCi/gm).	8.3×10^3
4.	Secondary Iodine Concentration Based on Tech. Spec. Limits (μCi/gm).	.1
5.	Decontamination Factor for Steam Generator Iodine Transport	10
6.	Two Exclusion Boundary Thyroid Dose from Secondary Releases (Rem).	16.7



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

RCS PRESSURE vs. TIME

FIGURE 15C.3-1



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ST. LUCIE PLANT UNIT 2

STEAM GENERATOR PRESSURES VS. TIME
FIGURE 15C.3-2

APPENDIX 15C-4 9/30/81

STATION BLACKOUT ANALYSIS Final Copy, Typed

The station blackout event is outside of the design basis for St. Lucie Unit 2. Nonetheless, an analysis was performed as requested by the NRC in response to the decision of ALAB-603. This analysis shows that St. Lucie Unit 2 can successfully endure a complete loss of AC power for at least 4 hours. However, it is expected that AC power would be restored within 30 minutes to one hour as a result of either one of the following corrective actions:

1. Offsite power is restored;

2. One or both of the St. Lucie Unit 2 diesel generators are started.

Operator action at 30 minutes is credited to open the atmospheric dump valves resulting in the closure of the main steam safety valves. Operator control of the atmospheric dump valves to assure natural circulation by maintaining subcooling in the RCS occurs after 2 hours.

The results of this analysis have shown that:

1. Natural circulation and core cooling can be maintained;

2. The reactor core remains in a subcritical condition;

3. There is no fuel failure;

4. The RCS coolant pressure remains within limits; and,

5. The resulting radiological doses are within limits.

Therefore, this analysis shows that St. Lucie Unit 2 can successfully endure station blackout event. Florida Power and Light will implement operator training and emergency procedures to ensure that plant operators would take appropriate actions to assure maintenance of natural circulation.

15C.4 Total Loss of AC Power (Station Blackout)

15C.4.1 Identification of Event and Causes

The Station Blackout event results from a loss of offsite power followed by failure of both standby diesel generators to start.

For Unit 2, this event results in a loss of all onsite AC power except that supplied by inverters from the two safeguards batteries. This provides power to the 120 VAC (safeguards) instrument power and other required DC loads.

15C.4.2 Sequence of Events and Systems Operation

Table 15C.4-1 shows a chronological list of the timing of systems actions from the initiation of a station blackout event to the time that offsite power is restored (4 hours). A description of the sequence of events* is given below for each safety function:

Reactivity Control:

As a result of the loss of power to the reactor coolant pumps an automatic reactor trip signal is generated by the RPS on low reactor coolant system flow, as measured by steam generator delta-pressure (ΔP). The reactor trip signal interrupts power to the reactor trip switchgear which in turn releases the CEA's to drop into the core. The negative reactivity inserted by the CEAs is sufficient to maintain the core subcritical throughout the rest of the transient.

Reactor Heat Removal:

Following coastdown of the reactor coolant pumps, flow through the reactor is maintained by natural circulation. Heat is transferred to the secondary system through the steam generators.

Primary System Integrity:

A Power Operated Relief Valve (PORV) opens to limit the RCS pressure increase following turbine trip. Steam released from the PORV is contained in the quench tank. Letdown is isolated by the closing of the letdown control valve on loss of offsite power. Late in the transient, the Safety Injection Tanks provide borated water to the RCS increasing RCS inventory and helping to maintain subcooling in the hot leg.

Secondary System Integrity:

A turbine trip signal (TTS) is generated following the loss of offsite power and causes the turbine stop valves to close. The Main Steam Safety Valves (MSSVs) open to limit the pressure increase.

---

*Those safety actions necessary to maintain the plant in hot shutdown.

Auxiliary feedwater is automatically actuated on low steam generator level. Flow is provided by the turbine driven pump which derives all its control power from the station batteries. The operator opens the Atmospheric Dump Valves (ADVs) and regulates them from the control room to maintain steam generator pressure below the setpoint of the MSSVs and to reduce the primary system temperature to maintain subcooling in the hot leg.

Restoration of AC power:

Although the analysis which follows shows acceptable results assuming no AC power for 4 hours, in actuality AC power would be restored to the plant prior to this time (within 30 minutes to one hour) by either one of the following corrective actions.

1) Offsite power is restored and the onsite buses are manually connected to the startup transformers. Equipment is manually loaded on these buses, according to plant emergency procedures, or,

2) One (or both) Unit 2 diesel generators is started and safeguards loads are manually sequenced onto its 4.16 KV bus.

15C.4.3 Analysis of Effects and Consequences

A. Mathematical Models

The NSSS response to a Station Blackout was simulated using the CESEC-III computer program.

B. Input Parameters and Initial Conditions

The initial conditions assumed for this event are contained in Table 15C.4-2. These conditions were chosen to provide the largest and most rapid depletion of RCS inventory and shutdown margin. The highest initial pressurizer pressure, least negative Doppler coefficient and most positive moderator temperature coefficient maximize the power and RCS pressure early in the transient resulting in inventory loss through the PORV. The major contributors to the RCS depressurization are the pressurizer heat losses and RCS leakage. Maximum values of these parameters were selected based on technical specifications, plant operating data and reactor coolant pump test results. The lowest initial pressurizer water volume minimizes the available RCS inventory. Initial core inlet temperature, core mass flow rate and pressurizer pressure have a negligible impact on the primary system depressurization. The evaluation of shutdown margin depletion was performed using the most negative moderator temperature coefficient and the least negative CEA worth for trip. This minimizes the shutdown margin remaining at the end of the transient.

The disposition of normally operating systems is given on Table 15C.4-3. The utilization of safety systems is given on Table 15C.4-4.

C. Results

The dynamic behavior of important NSSS parameters following a Station Blackout is presented in Figures 15C.4-1 to 15C.4-12. Table 15C.4-1 summarizes some of the important results of this event and the times at which the minimum and maximum parameter values discussed below occur. The loss of all AC electrical power initiates, among other things, a simultaneous loss of feedwater, loss of load, and loss of forced reactor coolant flow. As indicated in Figure 15C.4-1, the core power increases initially due to positive reactivity feedback and reaches a maximum value within a few seconds. Subsequent to loss of power to the reactor coolant pumps, the primary coolant flow decreases and a low flow reactor trip occurs as indicated in Table 15C.4-1. Reactor coolant flow vs. time is shown on Figure 15C.4-7. Subsequently, due to the insertion of large negative reactivity by the scram rods, the core power decreases very rapidly and approaches the decay heat value. Departure from nucleate boiling does not occur and therefore no fuel damage is predicted. See Figure 15C.4-8.

During the initial few seconds prior to reactor trip, the reduced steam generator heat rejection capability leads to a rapid increase in both the primary and secondary fluid temperatures. The volumetric expansion due to these increases in temperature produces sharp increases in primary and secondary pressures as well as an insurge of primary coolant into the pressurizer. The variations of the primary and secondary pressures are illustrated in Figures 15C.4-3, and 15C.4.9. The initial rapid increases in both pressures are terminated by the opening of the PORV and MSSVs. The primary relief valve closes rapidly, as the primary system pressure decreases below the setpoint value within a few seconds after opening of the valve. The secondary safety valves cycle open and closed until the operator opens the atmospheric dump valves. MSSV and ADV flow vs. time are shown on Figures 15C.4-11 and 15C.4-12, respectively.

The steam generator liquid level decreases during the transient and reaches a minimum value after auxiliary feedwater flow is automatically actuated using the steam-driven auxiliary feedwater pump. Steam generator level increases until normal water level is reached. The operator subsequently controls auxiliary feedwater to maintain normal level. See Figure 15C.4-6.

The RCS pressure and temperature gradually decrease at fairly constant rates in the long term as a result of pressurizer heat loss, RCS leakage, low heat transfer rates at the steam generators, and the operator manually reducing secondary side pressure. Since the RCS pressure decreases at a higher rate than the RCS temperature, the pressure approaches the saturation pressure.

Saturation occurs in the reactor vessel head. Continued primary pressure drop without a significant decrease in primary temperatures would result in saturated conditions in the hot leg. Credit is taken for operator action to maintain at least 10°F subcooling in the hot leg. This is accomplished by further opening the atmospheric dump valves to reduce the secondary system pressure and temperature. The increased heat removal in the steam generators caused by the larger ΔT across the steam generator tubes reduces the primary system temperatures. Voiding is restricted to the vessel head and natural circulation is not adversely impacted for more than 4 hours.

The Safety Injection Tanks (SITs) provide borated water to the RCS after RCS pressure is reduced below their discharge pressure. No credit is taken for the negative reactivity added as a result of this discharge.

At 4 hours, sufficient AC power is assumed to be restored to provide power to the charging pumps and pressurizer heaters. These will be used to pressurize the RCS and to continue hot leg subcooling.

Operability of the turbine driven auxiliary feedwater pump requires at least 50 psia secondary pressure. At 4 hours after the initiation of the event, the secondary pressure will be greater than 300 psia. Less than 100,000 gallons of auxiliary feedwater are used during the event. The condensate storage tank capacity is greater than 300,000 gallons.

15C.4.4 Conclusions

The maximum RCS pressure is 2541 psia (including reactor coolant pump and elevation heads). This is well below 110% of design pressure.

Natural circulation is maintained for at least the 4 hour period that offsite AC power and diesel generator power are assumed unavailable. During this time voids are restricted to the reactor vessel head and subcooling is maintained in the hot leg.

The radiological release due to a Station Blackout results in no more than a 0.4 rem 4 hour inhalation thyroid dose at the exclusion area boundary.

The average RCS temperature at 4 hours is above 430°F. This is above the temperature at which the shutdown margin would be depleted. Therefore, the core remains subcritical following reactor trip for the duration of the event.

No fuel damage occurs during this event.

Table 15C.4-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR THE STATION BLACKOUT EVENT

Time (Sec)		Event	Setpoint or Value
0.0		Loss of all on - and off-site AC power	---
1.5		Low Primary Coolant Flow Reactor Trip, %	93
2.0		Auxiliary Feedwater Actuation Signal, % of Narrow Range Tap Span	5
2.4		Power Operated Relief Valve Opens, psig	2385
2.6		Maximum Core Power, %	104.8
5.5		Maximum RCS pressure, psia	2541
6.0		Maximum pressurizer pressure, psia	2460
6.3		Main Steam Safety Valves Open, psig	995
8.5	1.	Power Operated Relief Valve Closes, psig	2361
	2.	Total Primary Relief Valve Release, lbm	554
12.2		Maximum Secondary System Pressure, psia	1038
182.0		Auxiliary Feedwater reaches Steam Generators, gpm	500
1800.0	1.	Operator Opens and Controls Atmospheric Dump Valves, psia	900
	2.	Main Steam Safety Valves close, psig	945
	3.	Total Main Steam Safety Valve Release, lbm	116630

Table 15C.4-1 (continued)

Time (Sec)		Event	Setpoint or Value
2258.0		Voiding Occurs in Reactor Vessel Head	---
8600.0		Operator Begins to Reduce Steam Generator Pressure to Maintain Hot Leg Subcooling	---
11785.0		Main Steam Isolation Valves close, psig	435.0
12540.0		Safety Injection Tanks actuated, psia	583.0
14400.0	1.	Operator Restores AC Power	---
	2.	Total Atmospheric Dump Valve Release, lbm	363300.0

TABLE 15C.4-2

ASSUMED INITIAL CONDITIONS FOR STATION BLACKOUT ANALYSIS

PARAMETER	ASSUMED VALUE
Initial Core Power Level, MWt	2630
Core Inlet Coolant Temperature, °F	551
Core Mass Flow Rate, 10^6 lbm/hr	133.9
Pressurizer Pressure, psia	2350
Initial Pressurizer Water Volume, % Level	40
Steam Generator Water Level, % of Narrow Range Tap Span	70
Doppler Coefficient Multiplier	0.85
Moderator Temperature Coefficient, 10^{-4} $\Delta\rho$/°F	
To determine initial power transient, 0- 10 seconds	+0.4
To determine degree of shutdown margin depletion	-2.7
CEA Worth for Trip, 10^{-2} $\Delta\rho$	6.68
Pressurizer Heat Loss, 10^6 BTU/hr	0.546
Primary Coolant Leakage, gpm:	16
Identified Leakage, gpm	
a) Technical Specification Steam Generator Tube Leakage	1
b) Primary Safety Valve Leakage	3
c) Other Identified Leakage	6
Unidentified Leakage	1
RCP Controlled Bleedoff	4
RCP Seal Leakage	1
	16

TABLE 15C.4-3

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR STATION BLACKOUT

SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	MANUAL MODE THROUGH-OUT TRANSIENT	NORMAL AUTOMATIC MODE INOPERATIVE ON LOSS OF A.C.	MANUAL MODE INOPERATIVE ON LOSS OF A.C.	FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater System			X			
2. Turbine-Generator Control System	X					
3. Steam Bypass Control System				X		
4. Pressurizer Pressure Control System				X		2
5. Pressurizer Level Control System				X		
6. Control Element Drive Mechanism Control System	X					
7. Reactor Regulating System				X		
8. Reactor Coolant Pumps				X		1
9. Chemical and Volume Control System				X		2
10. Condenser Evacuation System				X		
11. Turbine Gland Sealing System				X		
12. Component Cooling Water System						2
13. Turbine Cooling Water System				X		
14. Intake Cooling Water System						2
15. Condensate Transfer System				X		
16. Circulating Water System				X		
17. Spent Fuel Pool Cooling System				X		2
18. AC Power (Non-Safety)			X			
19. AC Power (Safety)					X	3
20. D. C. Power		X				
21. Power Operated Relief Valves	X					
22. Instrument Air System			X			2
23. Waste Management-Liquid				X		

NOTES:
1. RCP bleedoff is not isolated during this event.
2. Portions of these systems, powered by the safety bus on loss of AC, are not available due to the failure of both diesel generators.
3. Only the AC power supplied through the inverters is available.

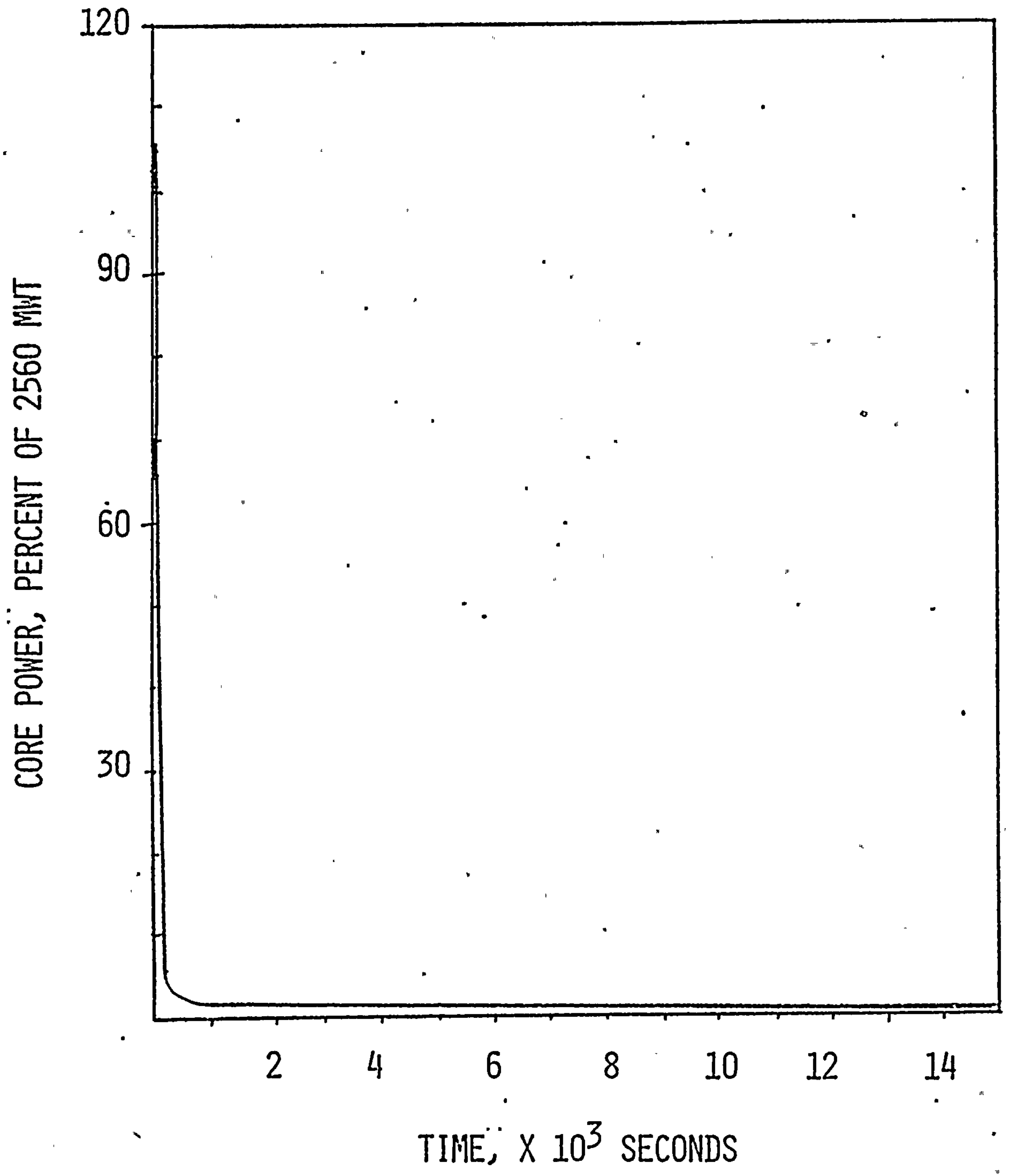
TABLE 15C.4-4

UTILIZATION OF SAFETY SYSTEMS FOR STATION BLACKOUT

	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACKUP TO NONSAFETY GRADE SYSTEM	FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	X				
2. Engineered Safety Features Actuation Systems					2
3. Diesel Generators and Support Systems				X	1
4. Reactor Trip Switch Gear	X				
5. Main Steam Safety Valves	X				
6. Pressurizer Safety Valves			X		
7. Main Steam Isolation Valves		X			2
8. Main Feedwater Isolation Valves			X		
9. Auxiliary Feedwater System	X				2,4
10. Safety Injection System		X			3
11. Shutdown Cooling System (CCW & ICW)					
12. Atmospheric Dump Valve System	X				5
13. Containment Isolation System		X			6
14. Containment Spray System					
15. Iodine Removal System					
16. Containment Combustible Gas Control System					
17. Containment Cooling System					

Notes:
1. Both diesel generators fail for this event.
2. Only those portions powered from the safeguard batteries are available.
3. Safety Injection Tanks are available.
4. Auxiliary Feedwater is automatically actuated. Only the turbine driven pump is available.
5. ADVs can be manually operated from the control room.
6. Portions of this system are actuated on loss of instrument air.

Systems not checked are not utilized during this event.



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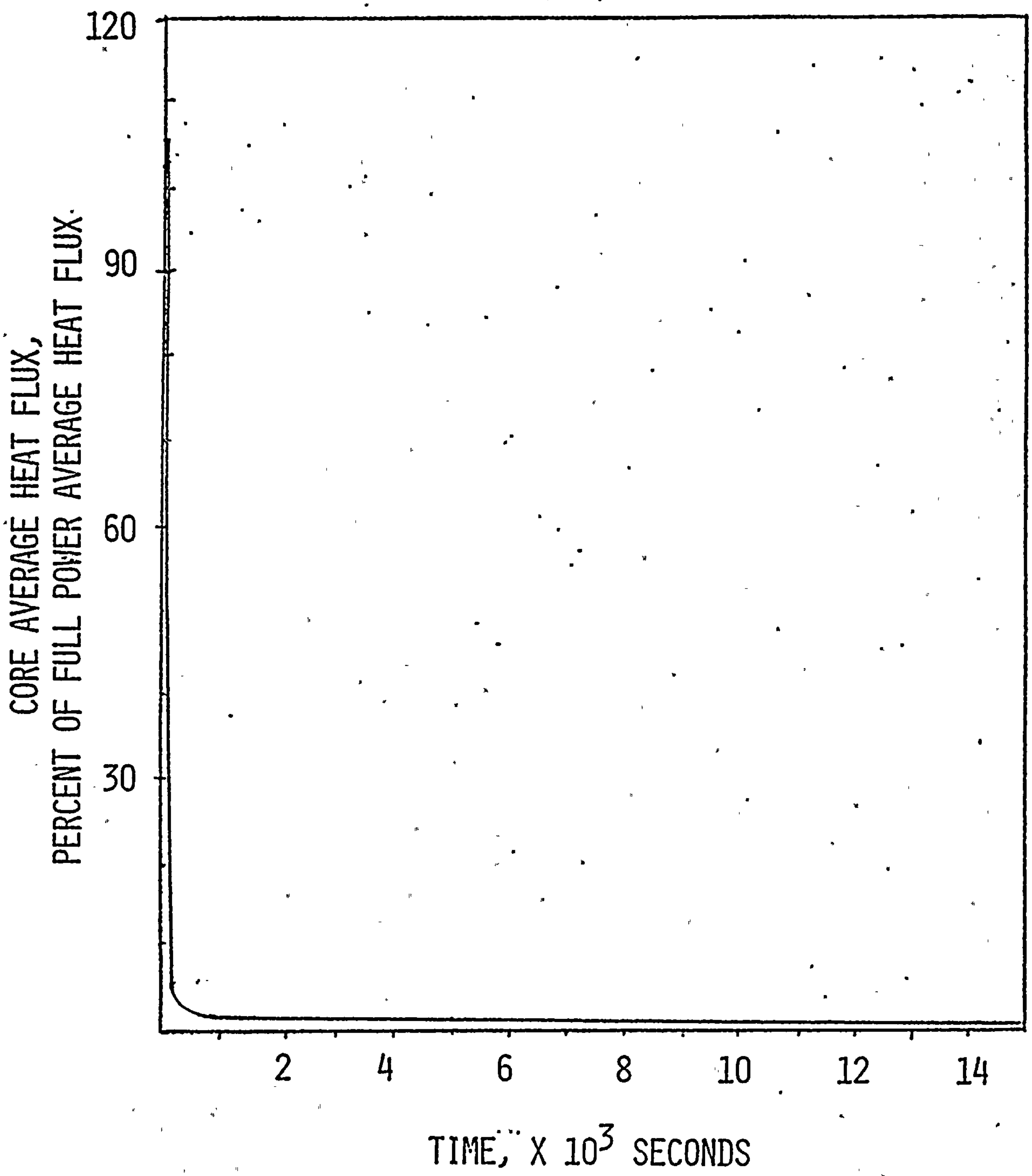
CORE POWER VS TIME

FIGURE 15C.4-1



FLORIDA POWER & LIGHT COMPANY
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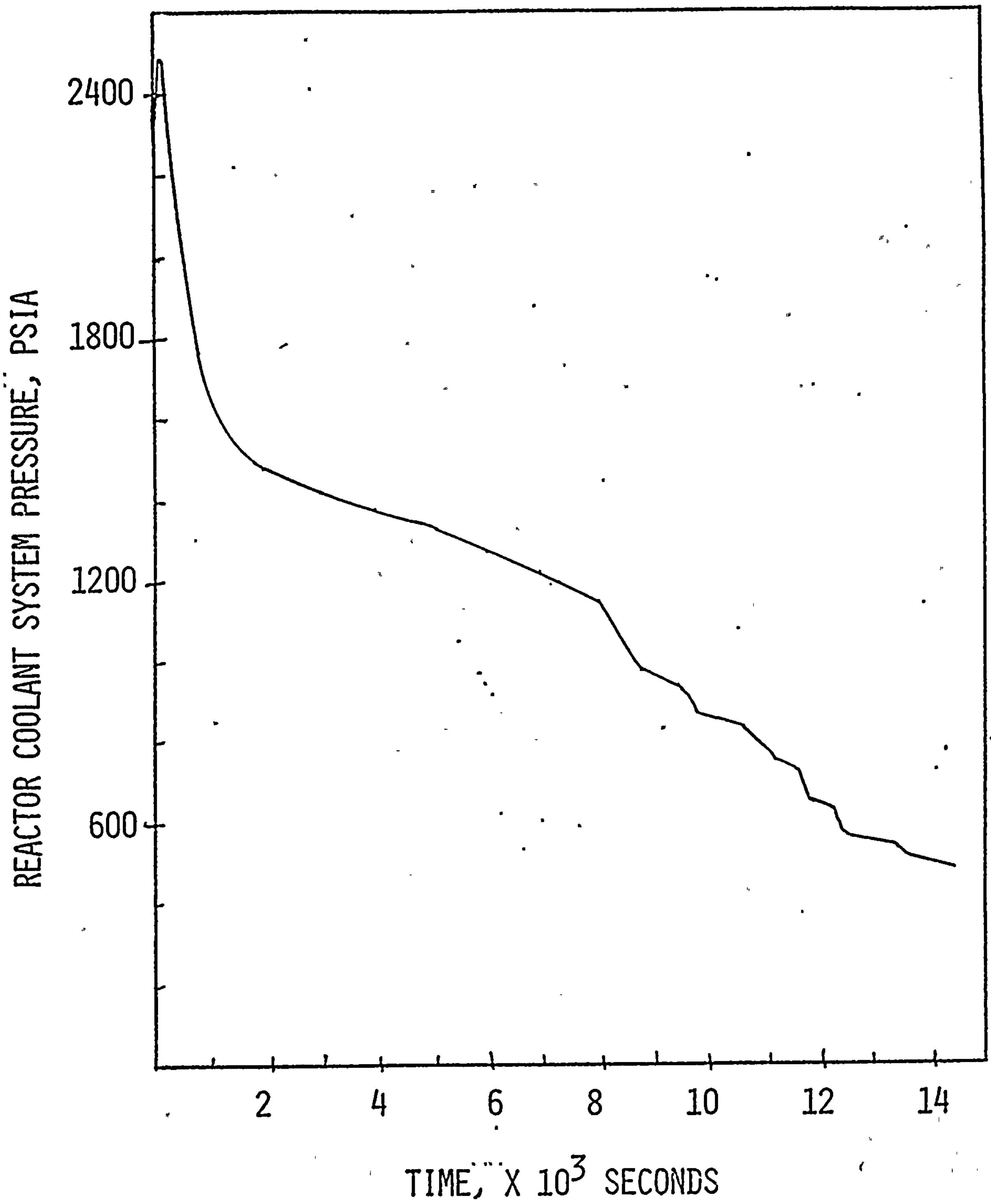
CORE AVERAGE HEAT FLUX VS TIME
FIGURE 15C.4-2



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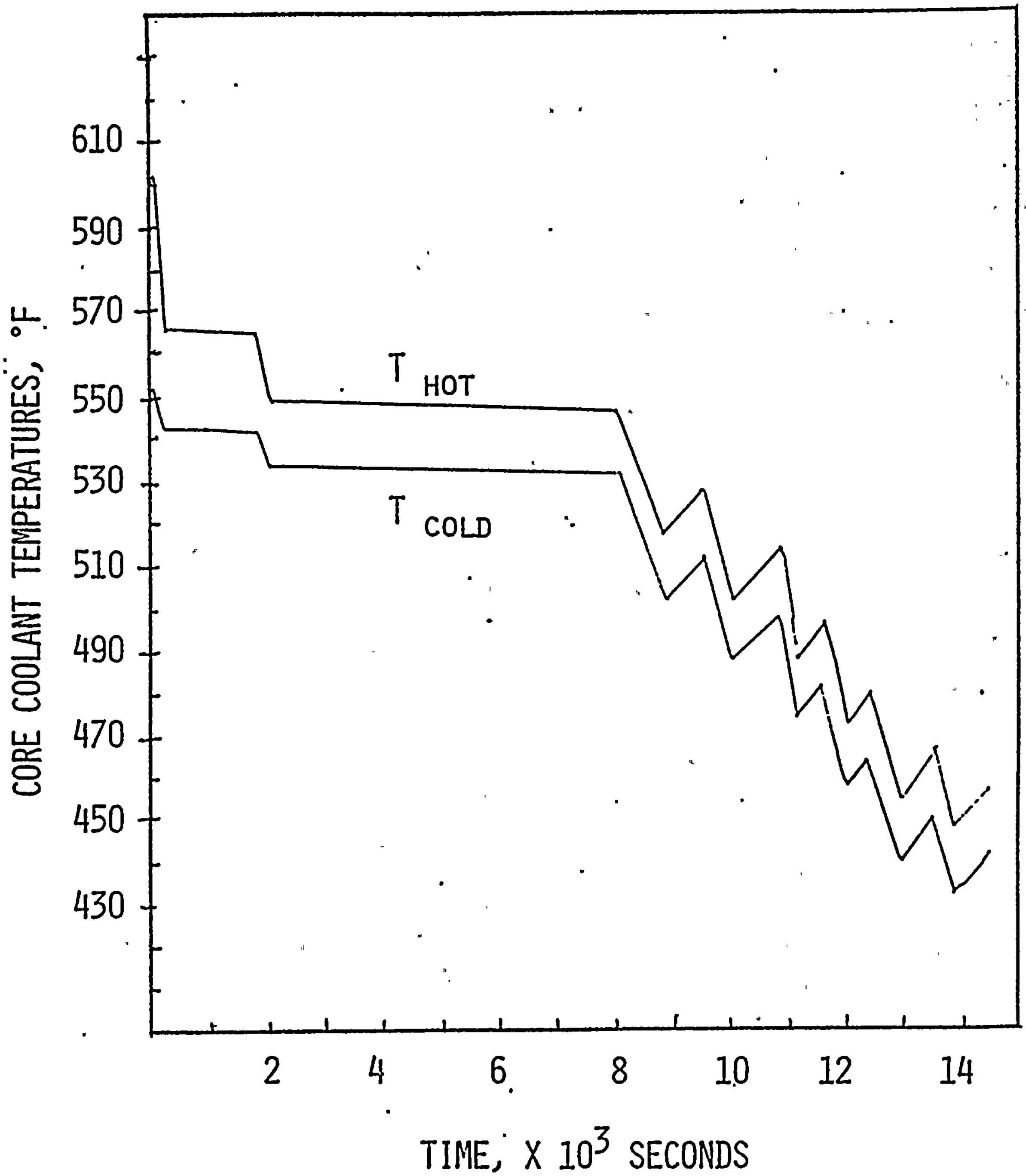
REACTOR COOLANT SYSTEM
PRESSURE VS TIME

FIGURE 15C.4-3



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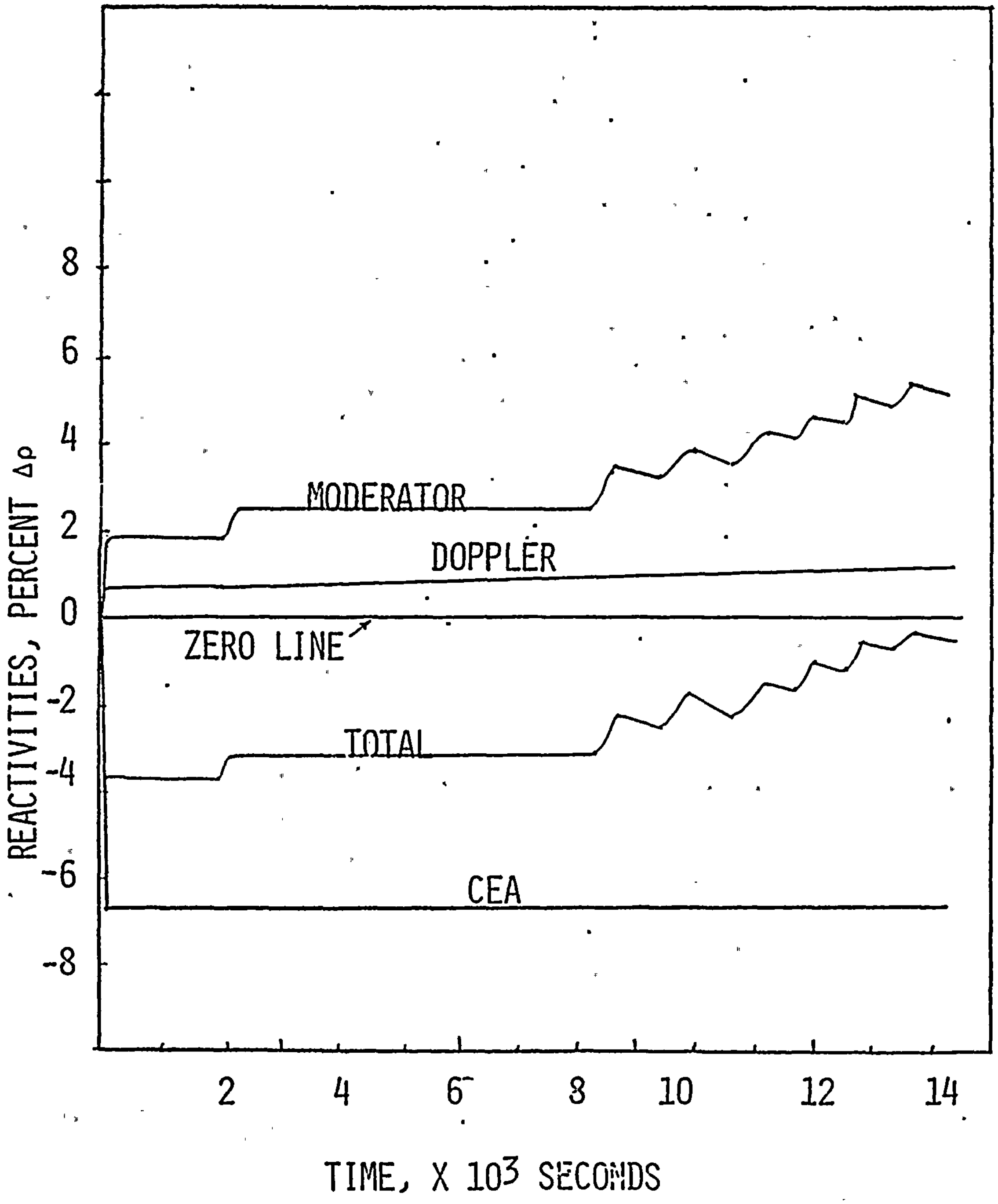
CORE COOLANT TEMPS VS TIME
FIGURE 15C.4-4



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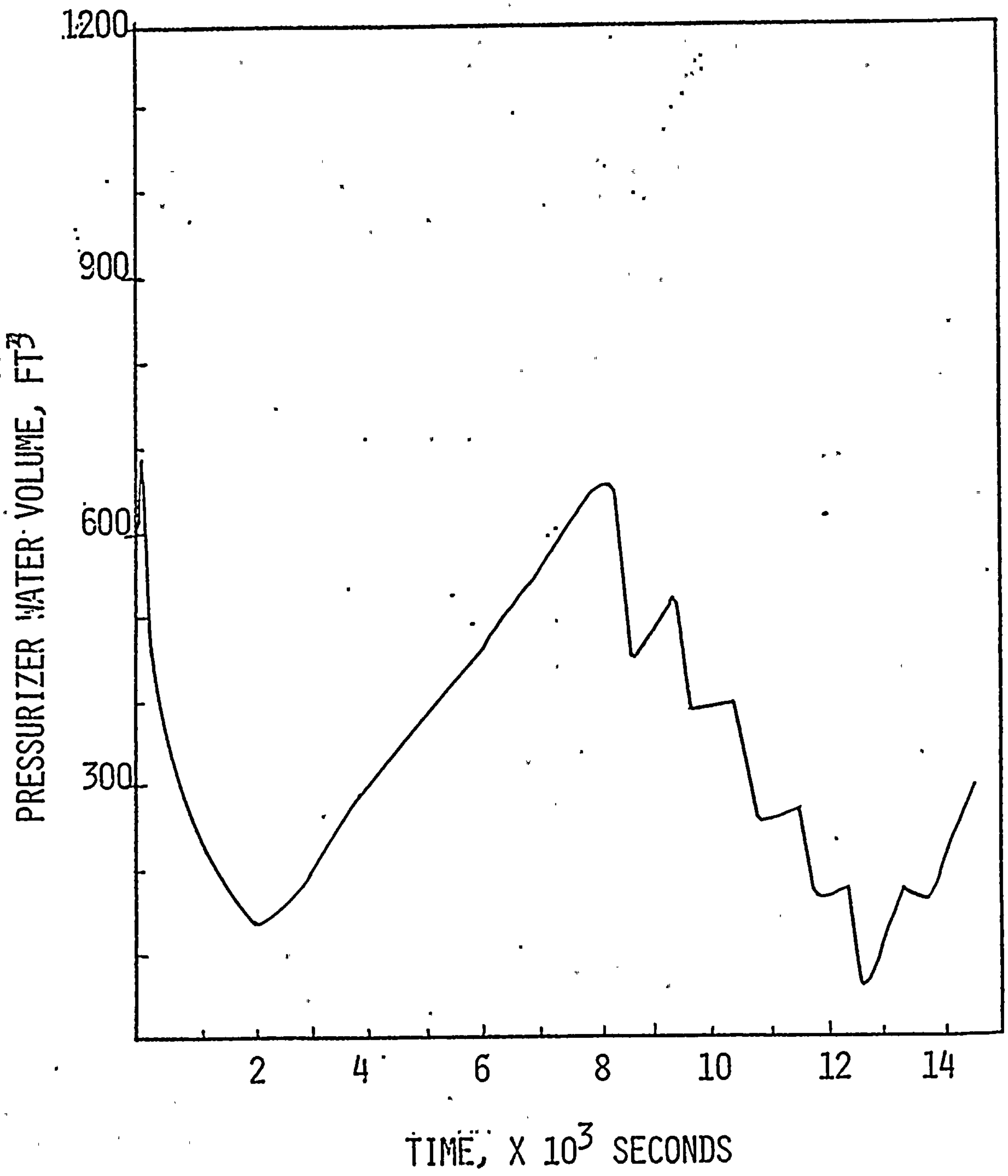
REACTIVITIES VS. TIME
FIGURE 15C.4-5



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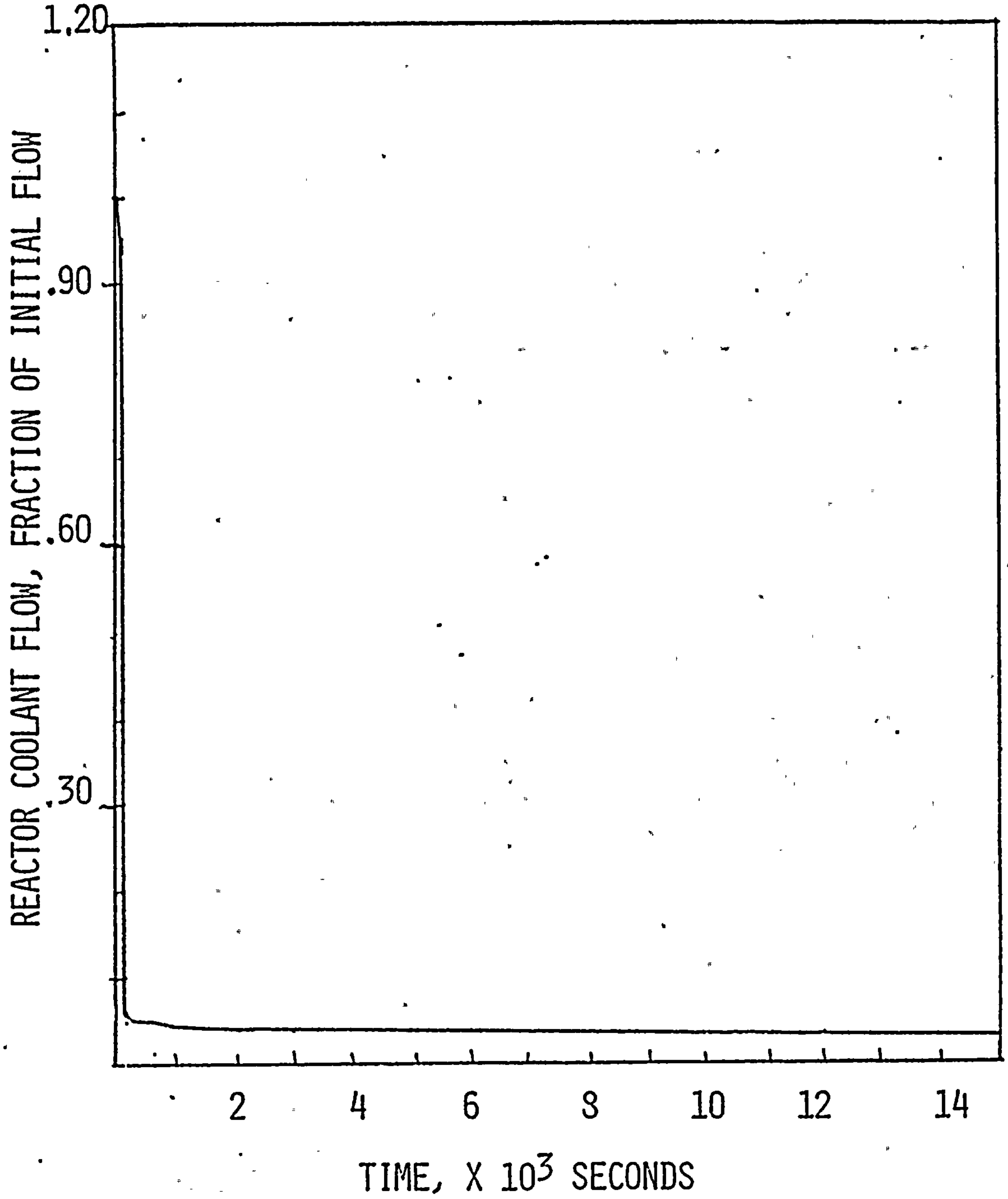
PRESSURIZER WATER VOLUME VS. TIME
FIGURE 15C.4-6



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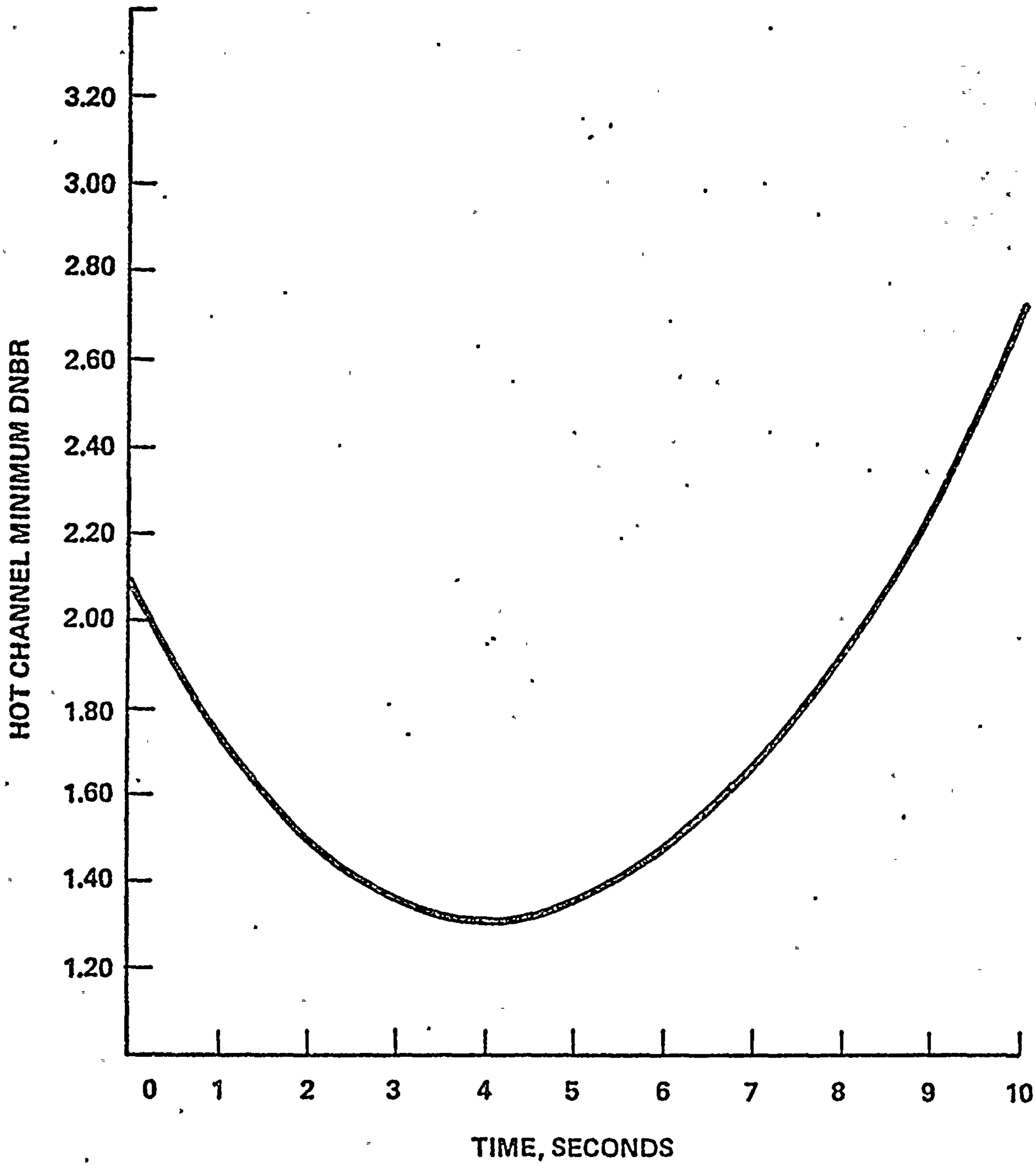
REACTOR COOLANT FLOW VS. TIME
FIGURE 15C.4-7



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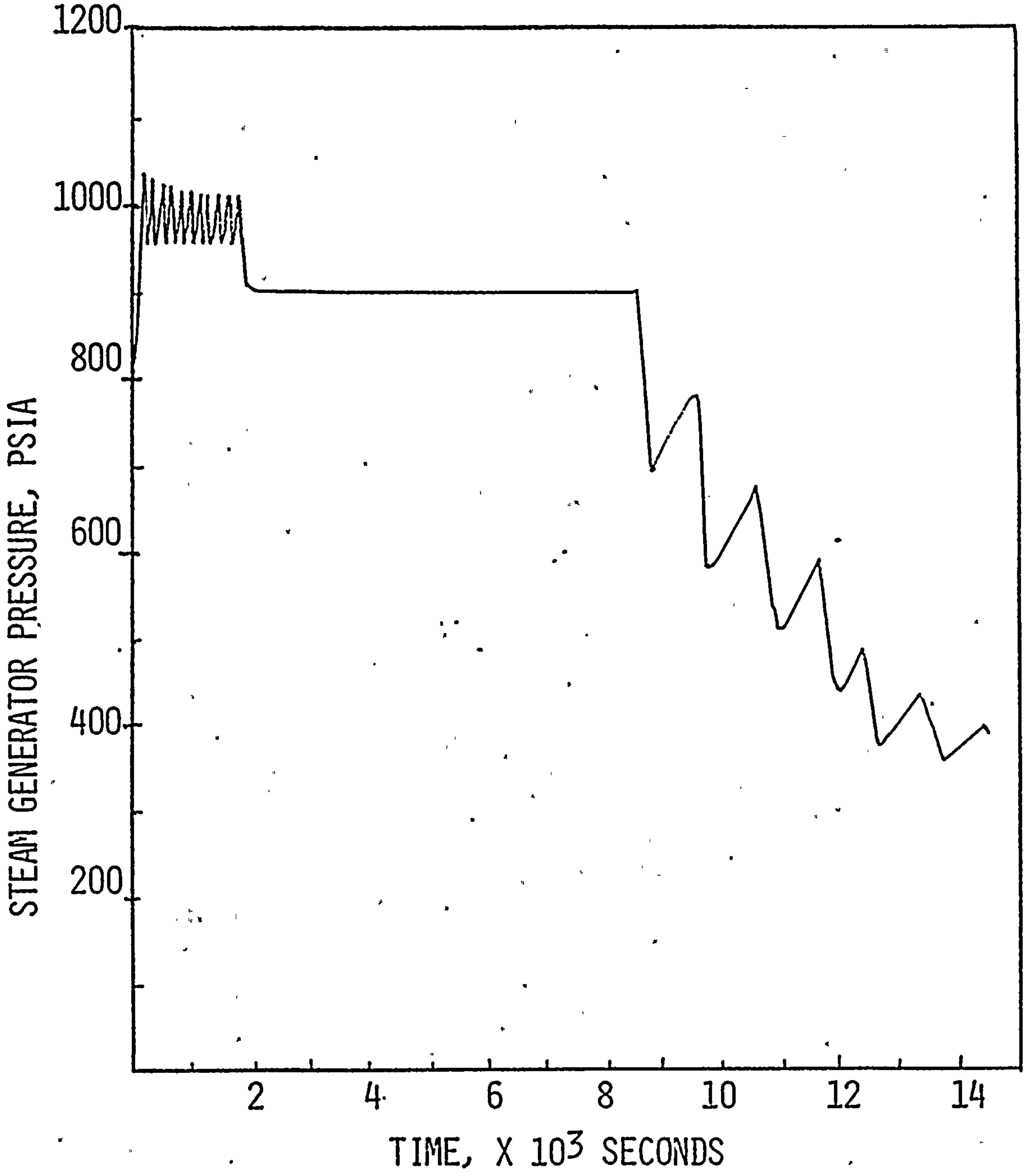
HOT CHANNEL MINIMUM DNBR
VS. TIME
FIGURE 15C.4-8



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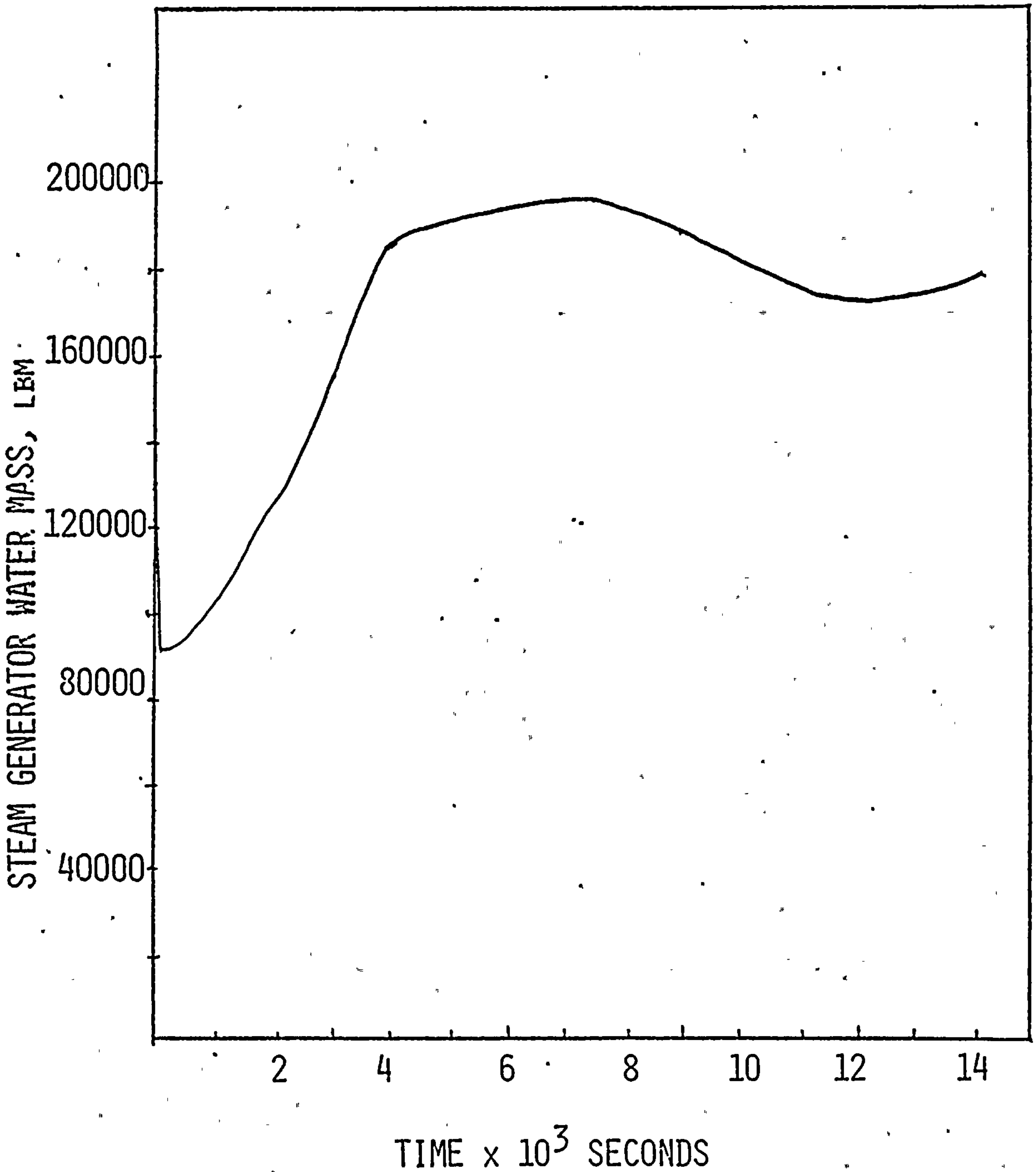
STEAM GENERATOR PRESSURE
VS. TIME
FIGURE 15C.4-9



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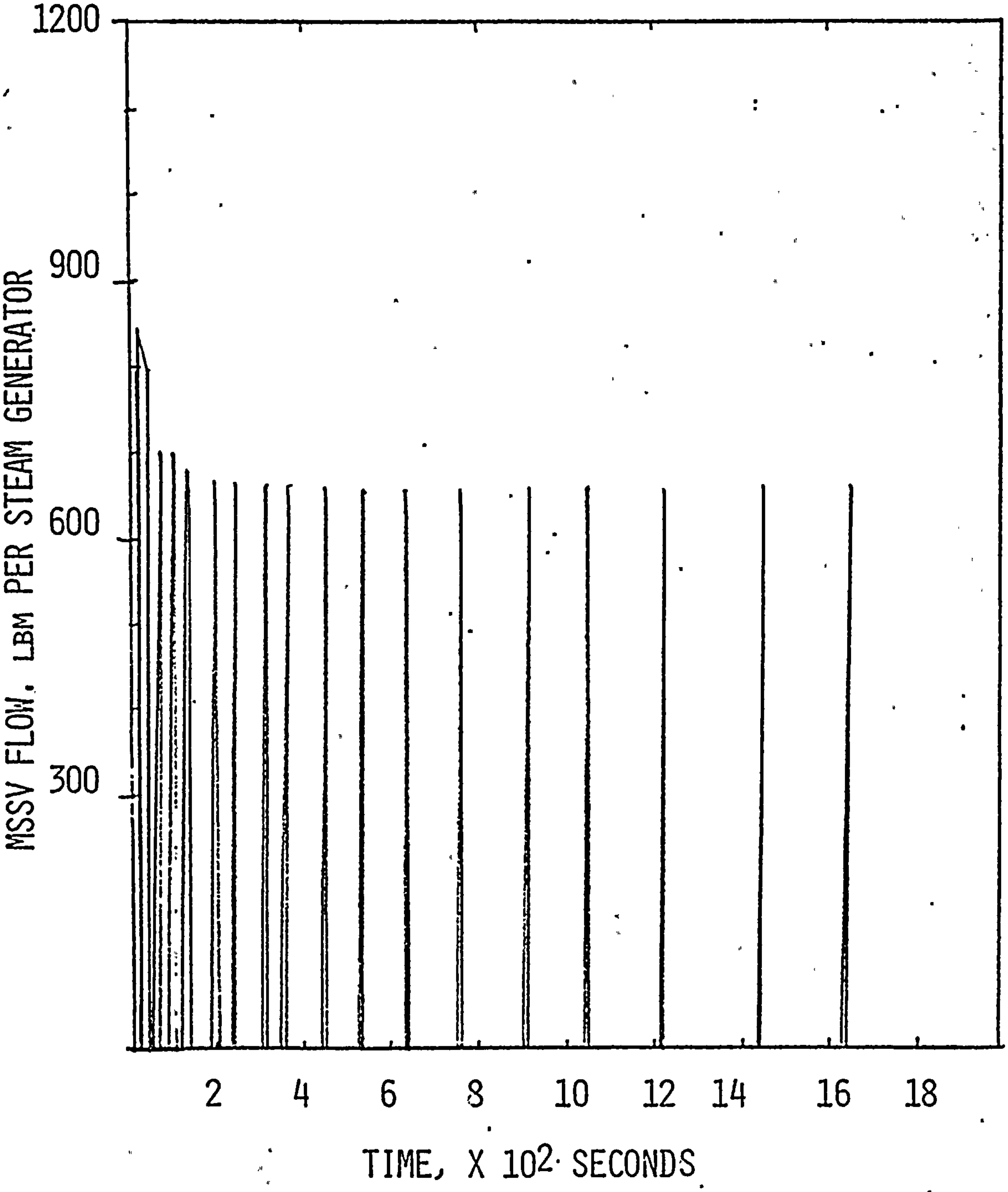
STEAM GENERATOR WATER MASS, VS. TIME
FIGURE 15C.4-10



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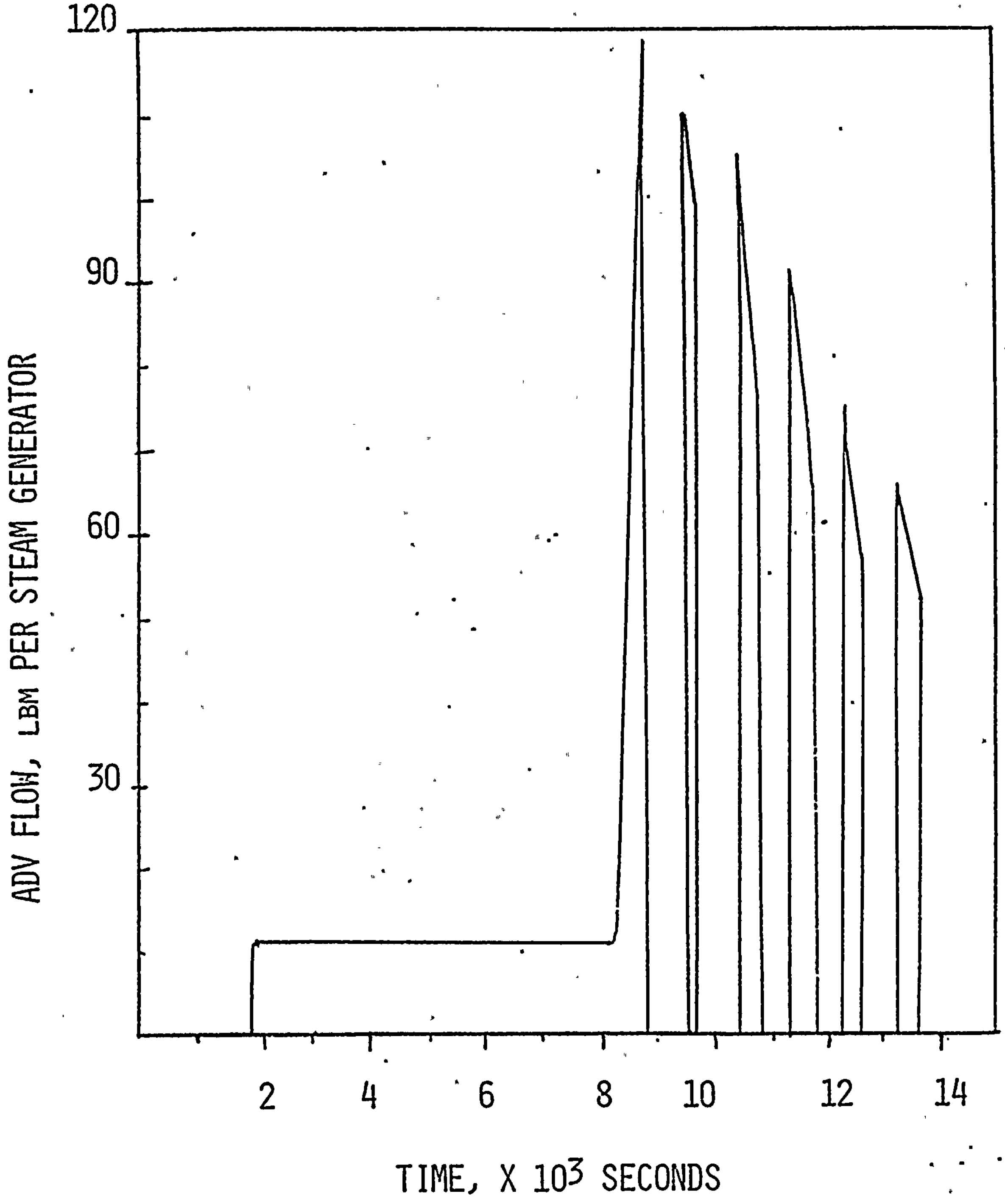
MSSV FLOW VS. TIME
FIGURE 15C.4-11



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ADV FLOW VS. TIME
FIGURE 15C.4-12

15.C.5 Steam Generator Tube Rupture With a Loss of Offsite Power As A Result of Turbine Trip.

15.C.6.1 Identification of Event and Causes

The significance of a steam generator tube rupture accident is described in Section 15.6.2. A double-ended break of a steam generator tube rupture with a loss of offsite power as a result of turbine trip event was determined to be the most limiting case with respect to radiological releases. As a result of the loss of normal AC power, electrical power would be unavailable for the station auxiliaries such as the reactor coolant pumps and the main feedwater pumps. Under such circumstances the plant would experience a loss of load, normal feedwater flow, forced reactor coolant flow, condenser vacuum, and steam generator blowdown system. The plant is operating at full power for a period of approximately 14.3 minutes, before the consequences of the primary-to-secondary leak causes the reactor trip. Thus, during this time period, the radioactivity concentration in the steam generator is allowed to increase before the main steam safety valves open, releasing radioactive materials to the atmosphere.

15.C.6.2 Sequence of Events and Systems Operation

Table 15.C.6-1 presents a chronological list of events which occur during the steam generator tubr rupture event with a loss of offsite power, from the time of the full double-ended rupture of a steam generator U-tube to the attainment of cold shutdown conditions. The corresponding success paths are also provided.

Prior to reactor trip, the systems and reactor trip operation are identical to that described in Section 15.6.2. Subsequent to reactor trip, stored and fission products decay energy must be dissipated by the reactor coolant and main steam system. In the absence of forced reactor coolant flow, convective heat transfer into and out of the reactor core is supported by natural circulation reactor coolant flow. Initially, the residual water inventory in the steam generators is used and the resultant steam is release to atmosphere via the main steam safety valves. With the availability of standby power, auxiliary feedwater is automatically initiated on a low steam generator water level signal. The operator can determine which steam generator has the tube rupture based on information from the radiation monitors prior to trip and the difference in the post-trip steam generator water levels. The operator can isolate the damaged steam generator and cool the NSSS using manual operation of the auxiliary feedwater system and the atmospheric dump valves of the unaffected steam generator any time after reactor trip occurs. The analysis presented herein conservatively assumes operator action is delayed until 30 minutes after initiation of the event.

15.C.6.3 Analysis of Effects and Consequences

15.C.6.3.1 Mathematical Model

The thermalhydraulic response of the Nuclear Steam Supply System (NSSS) to the steam generator tube rupture with a loss of offsite power as a result of turbine trip was simulated using the CESEC III computer program described in Reference 16 to Section 15.0. The thermal margin in the reactor core was determined using the TORC computer program described in Section 15.0.4 with the CE-1 CHF correlation.

15.C.6.3.2 Input Parameters and Initial Conditions

The input parameters and initial conditions used in the analysis are similar to those described in Section 15.6.2 and are listed in Table 15 C.6-2. In addition, the assumptions and conditions employed in the radiological release calculations are listed in Table 15.C.6-3.

15C .6.3.3 Results

The dynamic behavior of important NSSS parameters following a steam generator tube rupture with concurrent loss of offiste power are presented in Figures 15.C.6-1 through 15 C.6-16.

Prior to reactor trip, the dynamic behavior of the NSSS following a steam generator tube rupture with loss of offsite power is similar to that following a steam generator tube rupture without loss of offsite power which is described in Section 15.6.2. At about 863 seconds, after the initiation of the tube rupture, the reactor trips due to reaching the TM/LP low pressurizer pressure floor of 1875 psia. The reactor trip initiates a turbine/generator trip. The loss of offsite power is assumed to occur concurrent with this trip at about 863 seconds. Subsequent to the reactor trip, the RCS pressure begins to decrease rapidly, and the pressurizer empties at about 883 seconds due to the continued primary-to-secondary leak. After the pressurizer empties, the reactor vessel upper head begins to behave like a pressurizer and controls the RCS pressure response. Due to the loss of offsite power, the reactor coolant pumps begin to coast down reducing the core coolant flow rate, and the mass flow into the upper head region. This region becomes thermalhydraulically decoupled from the rest of the RCS, and due to flashing caused by the depressurization and boiloff from the metal structure to coolant heat transfer, voids form in this region at about 889 seconds. The void formation is enhanced by the decoupling effect, since the RCS pressure reduction due to primary system cooling is felt in this region, while the RCS temperature reduction is not. The significant impact of voids in the upper head region, is a slower RCS pressure decay. A safety injection actuation signal (SIAS) is generated at 888 seconds on low pressurizer pressure. The High Pressure Safety Injection (HPSI) pumps begin delivery of safety injection fluid to the RCS at about 1509 seconds and as a result, the upper head voids begin to collapse at about 1717 seconds.

Following turbine trip and loss of offsite power, the main steam system pressure increases until the main steam safety valves open at about 870 seconds to control the main steam system pressure. A maximum main steam system pressure of 1006 psia occurs at about 875 seconds. Subsequent to this peak in pressure, the main steam system pressure decreases, and the safety valves continue to open and close to control the SG pressures. Prior to turbine trip, the feedwater control system is in the automatic mode, and supplies feedwater to the steam generators to match the steam flow through the turbine. Following turbine trip and loss of offsite power, the feedwater flow ramps down to zero. Consequently, the steam generator water levels decrease due to the steam flow out through the main steam safety valves, and a low steam generator level signal is generated at about 864 seconds. Subsequently, at about 1044 seconds emergency feedwater flow is initiated, and the steam generator water levels begin to recover.

After 1800 seconds, the operator identifies and isolates the affected steam generator by closing the main steam isolation valves. The operator then initiates an orderly cooldown by means of the atmospheric dump valves and emergency feedwater flow to the unaffected steam generator. After the pressure and temperature are reduced to 275 psia and 350°F, respectively, the operator activates the shutdown cooling system and isolates the unaffected steam generator.

The reduction in primary coolant flow rate subsequent to the loss of offsite power does not result in a reduction in thermal margin to DNB. The transient minimum DNBR of 1.39 occurs immediately after the loss of offsite power. This results in no fuel pins experiencing DNB based on the methodology described in the response to Question 440.11.

The maximum RCS and secondary pressures do not exceed 110% of design pressure following a steam generator tube rupture event with a concurrent loss of offsite power, thus, assuring the integrity of the RCS and the main steam system.

At 1800 seconds, when operator action is assumed, no more than 46,420 lbm of steam from the damaged steam generator and 40,860 lbm from the intact steam generator are discharged via the main steam safety valves. Also, during the same time period approximately 69,020 lbms of primary system mass is leaked to the damaged steam generator. Subsequently, the operator begins a plant cooldown at the technical specification cooldown rate (75 °F/hr) using the intact steam generator, the atmospheric dump valves, and the emergency feedwater system. For the first two hours following the initiation of the event, a total of 2.74 x 10^6 lbms of steam flow to the condenser through the turbine (up to the time of loss of offsite power), and about 448,490 lbms of steam are released to the environment through the atmospheric dump valves. For the two to eight hour cooldown period an additional 882,180 lbms of steam are released via the atmospheric dump valves.

The two hour exclusion area boundary (EAB) and the eight hour low population zone (LPZ) boundary inhalation doses for the case of generated iodine spike (GIS) and the case of pre-existing iodine spike (PIS) are presented in Table 15.C.6-4. The calculated EAB and LPZ doses are well within the acceptance criteria.

15.C.6.4 Conclusions

The radiological releases calculated for the steam generator tube rupture event with a loss of offsite power are well within the guidelines of 10CFR100. The RCS and secondary system pressures are well below the 110% of the design pressure limits, thus, assuring the integrity of these systems. None of the fuel pins experience DNB during the transient, since the minimum

Table 15.C.6-3

List of Assumptions and Conditions for
Radiological Release Calculations
for the Steam Generator Tube Rupture with a Loss of Offsite Power

1. Accident doses are calculated for two different assumptions: (a) assumes an event generated iodine spike (GIS) coincident with the initiation of the event and (b) assumes a pre-existing iodine spike (PIS) or fuel failure with the most reactive control rod fully withdrawn.

2. Technical specification limits are employed in the dose calculations for the primary system (4.6 µCi/gm) and secondary system (0.1 µCi/gm) activity concentrations.

3. Following the accident, no additional steam and radioactivity are released to the environment when the shutdown cooling system is placed in operation.

4. Thirty minutes after the accident, the affected steam generator is isolated by the operator. No steam and fission products activities are released from the affected steam generator thereafter.

5. A spiking factor of 500 is employed for the event-generated iodine spiking (GIS) calculations.

6. For the pre-existing iodine spiking (PIS) condition, the technical specification limit (60 µCi/gm) for the primary system activity concentration is employed.

7. Technical specification limit (1 gpm) for the tube leakage in the unaffected steam generator is assumed for the duration of the transient.

8. Steam jet air ejector release is assumed throughout the transient with a decontamination factor (DF) of 100.

9. A fraction of the iodine in the primary-to-secondary leak is assumed to be immediately airborne, if a path is available, with a partition coefficient of 1 (Maximum fraction ≅ 5%).

10. A partition coefficient of 100 is assumed between the steam generator water and steam phases.

11. The total amount of primary-to-secondary leakage through the rupture is 69,020 lbm.

12. For steam release through the atmospheric dump valves, a decontamination factor (DF) of 1 is assumed.

13. The atmospheric dump dispersion factors employed in the analyses are: 1.6×10^{-4} sec/m^3 for the exclusion area boundary and 6.7×10^{-5} sec/m^3 for the low population zone.

14. The steam flow through the condenser is 2.74×10^6 lbms. The half hour to two hour steam flow through the atmospheric dump valves (ADVs) is 448,490 lbms. An additional 882,180 lbms of steam is discharged to the environment through the ADVs during the two-eight hour time period.

Table 15.C.6-4

Radiological Consequences of a Steam Generator Tube Rupture Event With a Loss of Offsite Power

Location	Offsite Doses, Rems GIS	PIS
1. Exclusion Area Boundary 0-2 hour thyroid.	0.38	0.68
2. Low Population Zone Outer Boundary 0-8 hour thyroid.	1.96	0.49

DNBR calculated is 1.39. Therefore, no fuel failure occurs.

i. Voids form in the reactor vessel upper head region during the transient due to thermalhydraulic decoupling of this region from the rest of the RCS. However, the upper head region liquid level remains well above the top of the hot legs throughout the transient. Therefore, natural circulation cooldown is not impaired. Furthermore, the upper head voids begin to collapse upon actuation of the safety injection flow, indicative of stable plant conditions. After thirty minutes the operator employs the plant Emergency Procedure for the steam generator tube rupture event to cooldown the plant to shutdown cooling entry conditions.

TABLE 15.C.6-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR THE STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP

Time (Sec)	Event	Analysis Set Point or Value	Success Paths: Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Maintenance of AC Power	Containment Integrity	Plant Habit Habitability	Radioactive Effluent Control
0.0	Tube rupture occurs	--								
[illegible]0.5	PLCS generates minimum letdown signal, inches below programmed level	4				X				
40.5	-PLCS generates maximum charging signal, inches below programmed level	14				X				
56.7	-PPCS energizes backup heaters, psia	2310				X				
-	Low pressurizer level alarm, inches below programmed level	15								
574	Pressurizer heater de-energized, inches below programmed level	158				X				
863	Reactor trip signal generated on TM/LP, low pressurizer pressure floor, psia	1875	X							
	-Maximum reactor power, %	102.7								
	-Turbine trip on loss of power on CEDM power supply buses	--			X					
	-loss of offsite power.									
864	EFAS on low SG level signal, ft. above tube sheet.	29.8			X					
870	Main steam safety valves open*, psig	975			X					
[illegible]5	Maximum SG pressure, psia	1006								
883	Pressurizer empties	--								

* MSSVs cycle until operator actuates ADVs at 1800 seconds.

Table 15.C.6-2

Assumptions and Initial Conditions for the Steam Generator Tube Rupture With a Loss of Offsite Power

Parameter	Value
Power, MWt	2630
Core Inlet Temperature, F	548
Core Average Flowrate, gpm	370,000
Pressurizer Water Level, % Level	65
Steam Generator Pressure, psia	794
Steam Flow Rate, lbm/sec	3174
Steam Generator U-tube Break Size, in^2	0.336
CEA Worth for Trip, %$\Delta\rho$(most reactive CEA fully withdrawn)	-5.5
RCS pressure, psia	2350

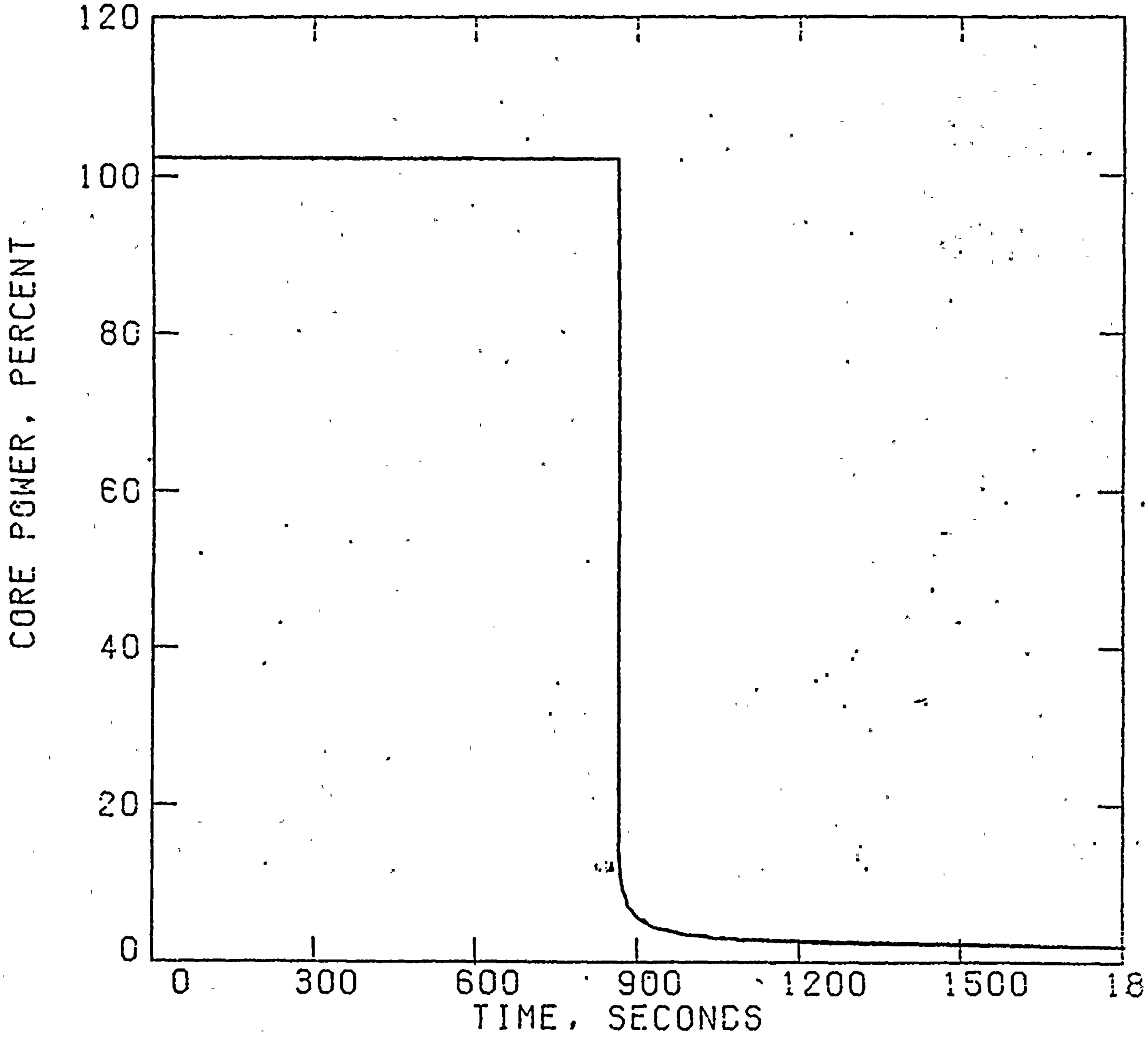

FIGURE 15.C.6-1
STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
CORE POWER VS. TIME

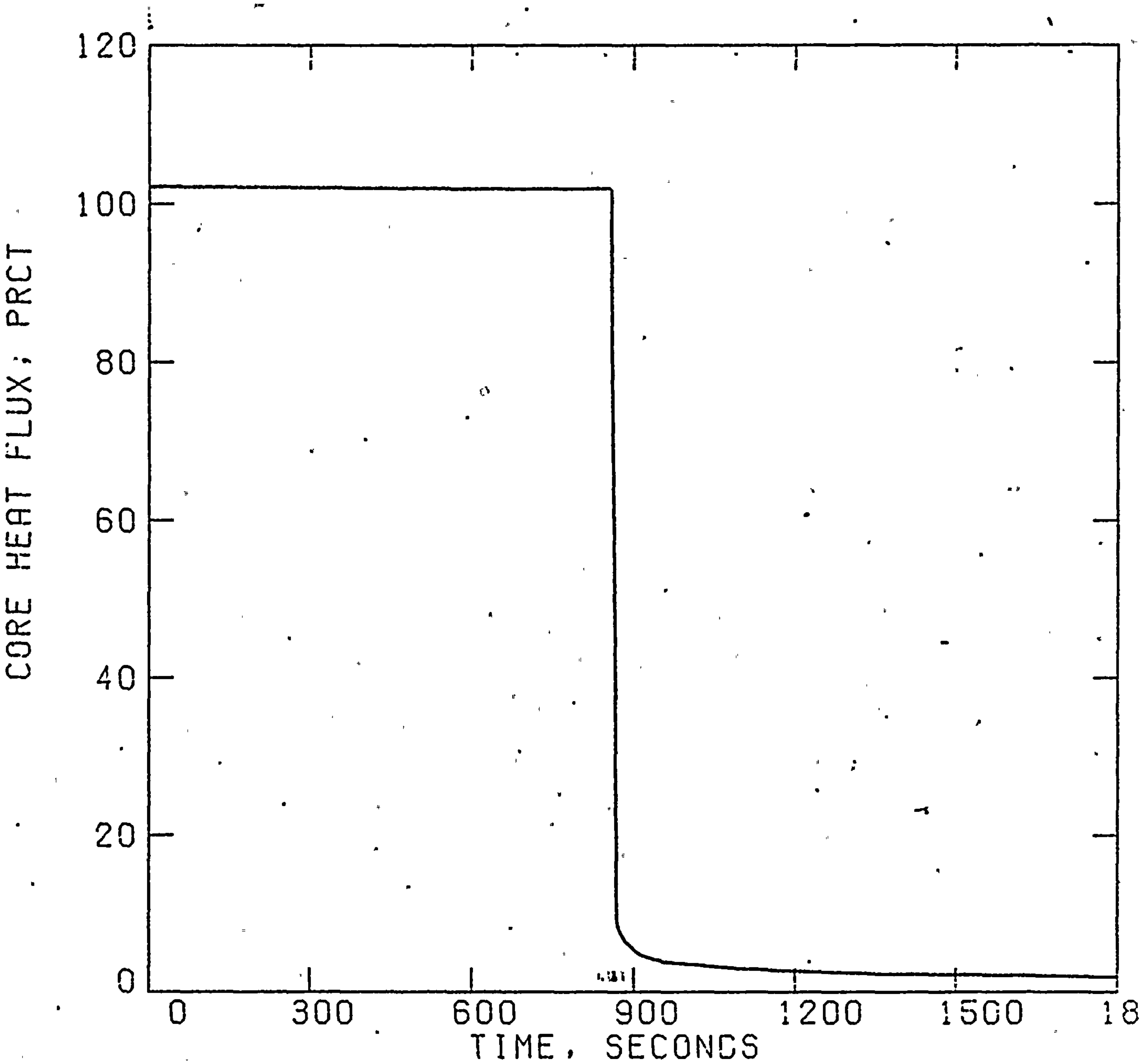

FIGURE 15.C.6-2
STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
CORE HEAT FLUX VS. TIME

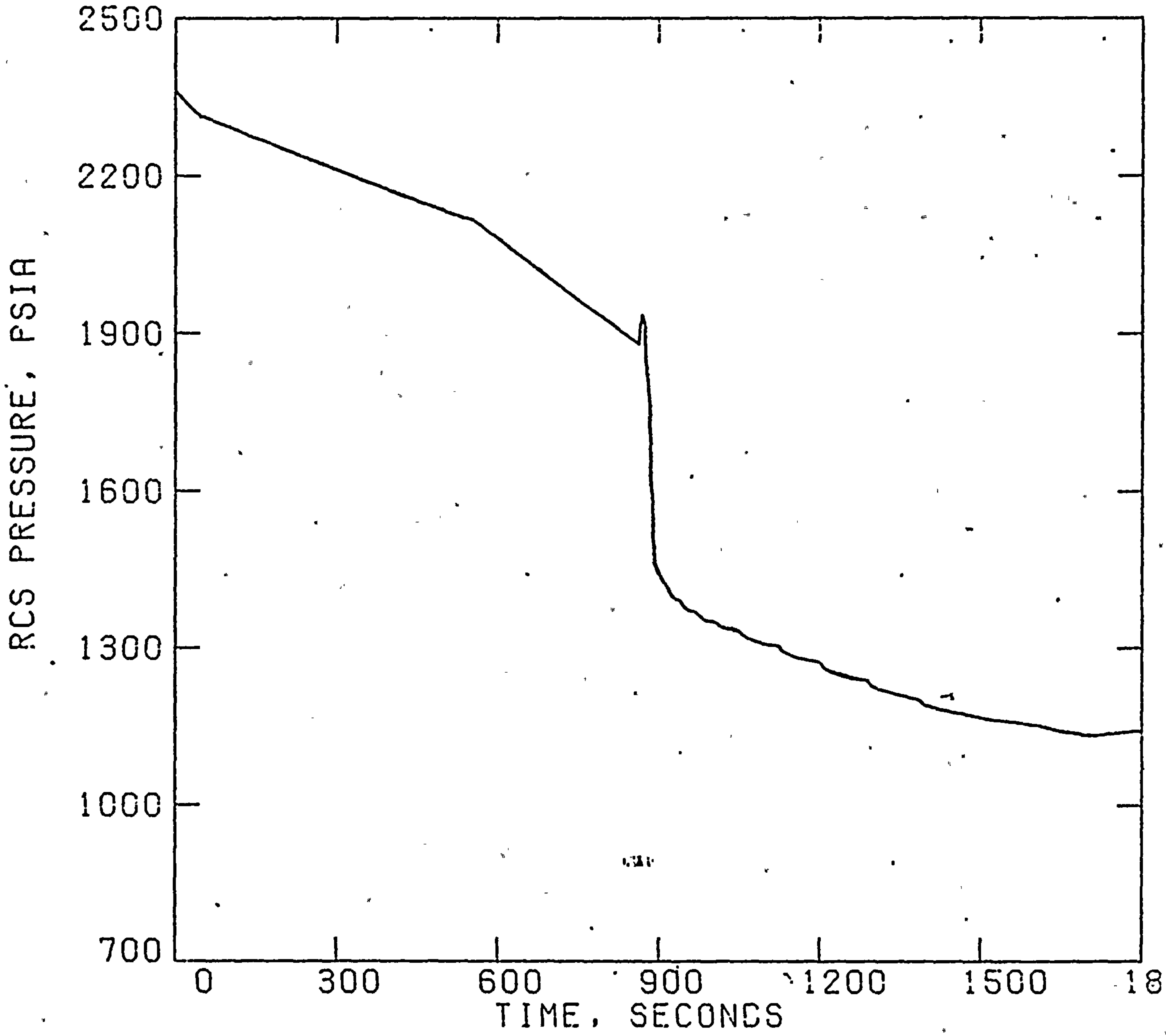

FIGURE 15.C.6-3

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
REACTOR COOLANT SYSTEM PRESSURE VS. TIME

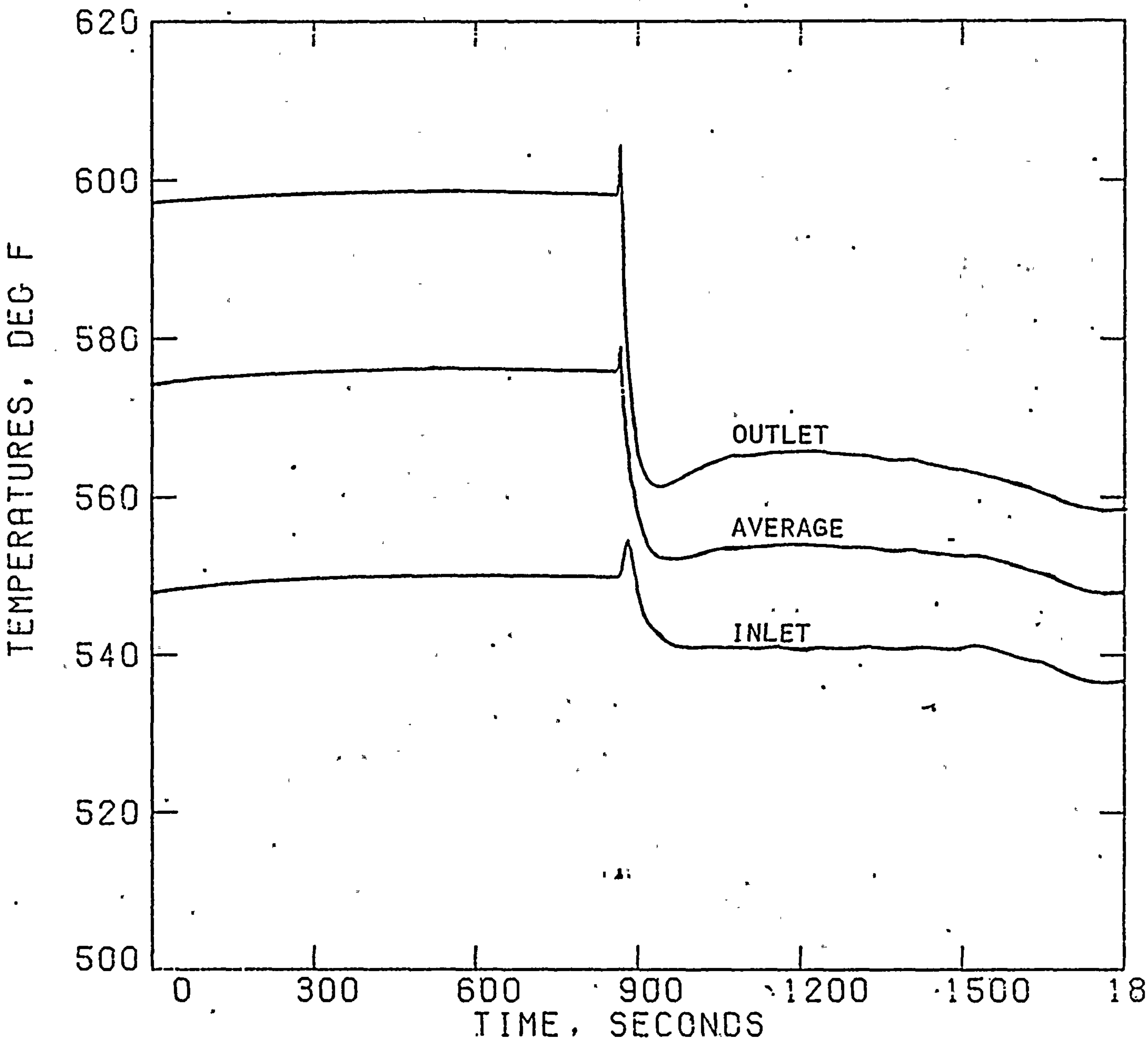

FIGURE 15.C.6-4

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
REACTOR COOLANT SYSTEM TEMPERATURES VS. TIME

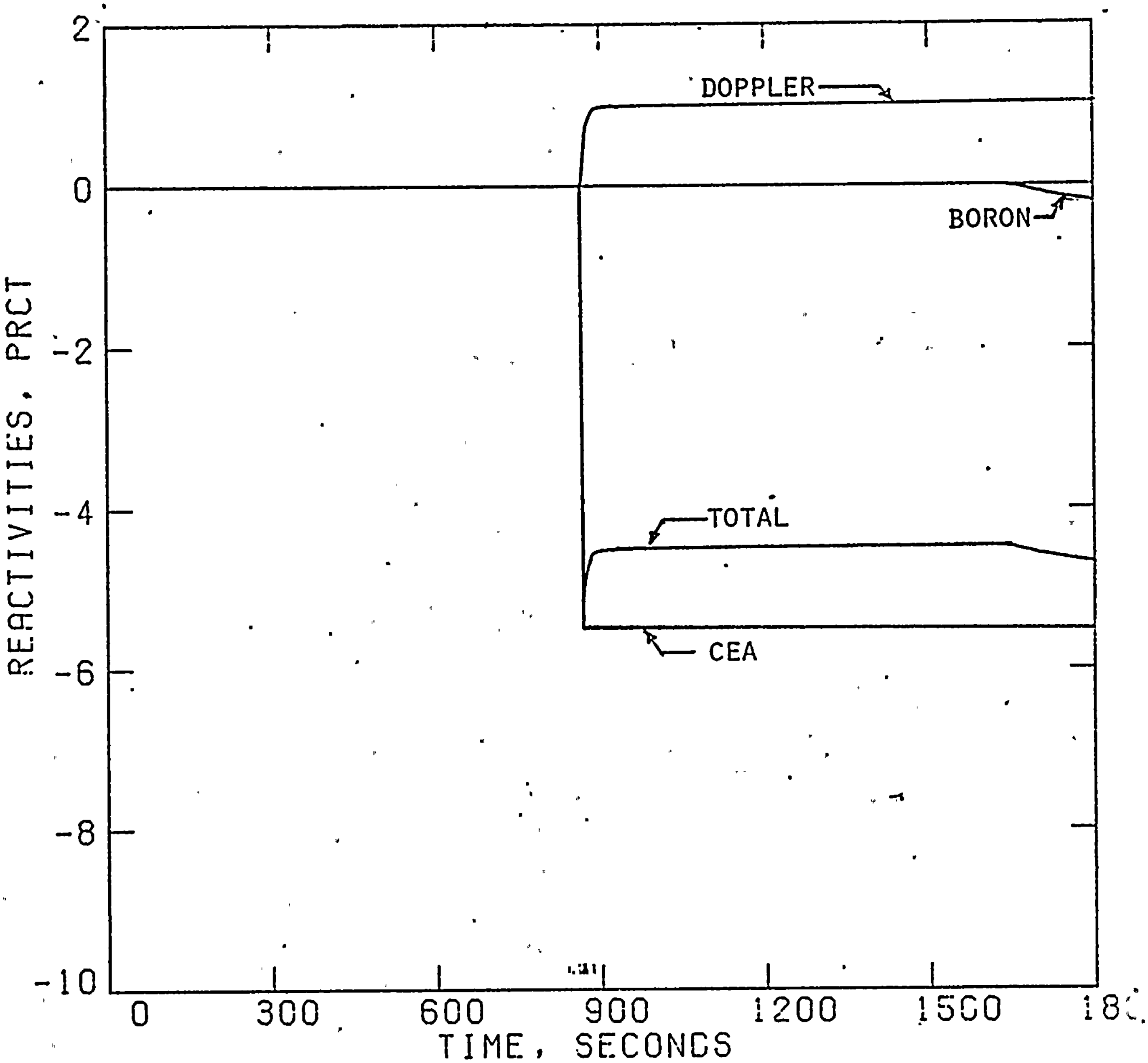

FIGURE 15.C.6-5
STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
REACTIVITIES VS. TIME

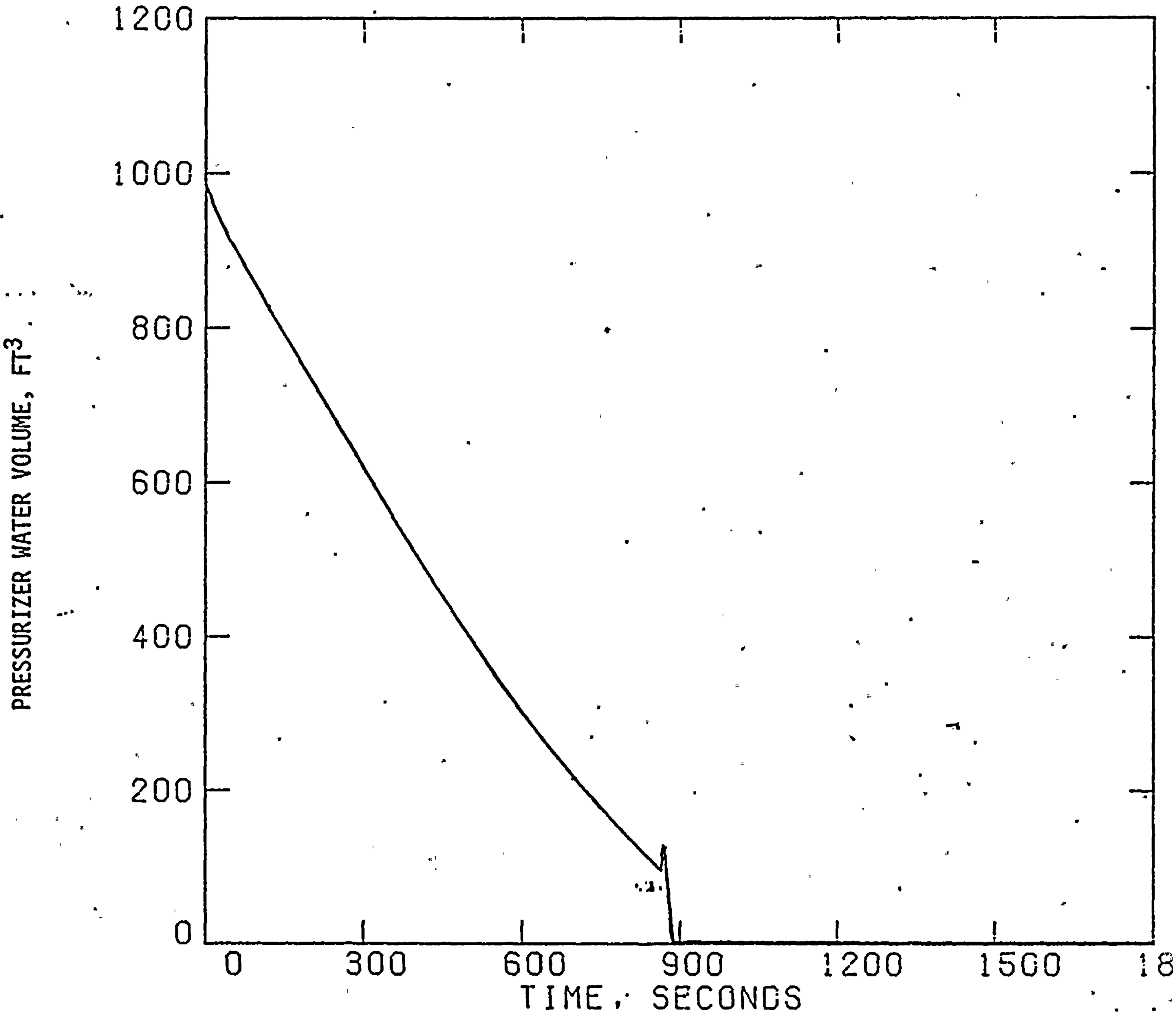

FIGURE 15.C.6-6
STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
PRESSURIZER WATER VOLUME VS. TIME

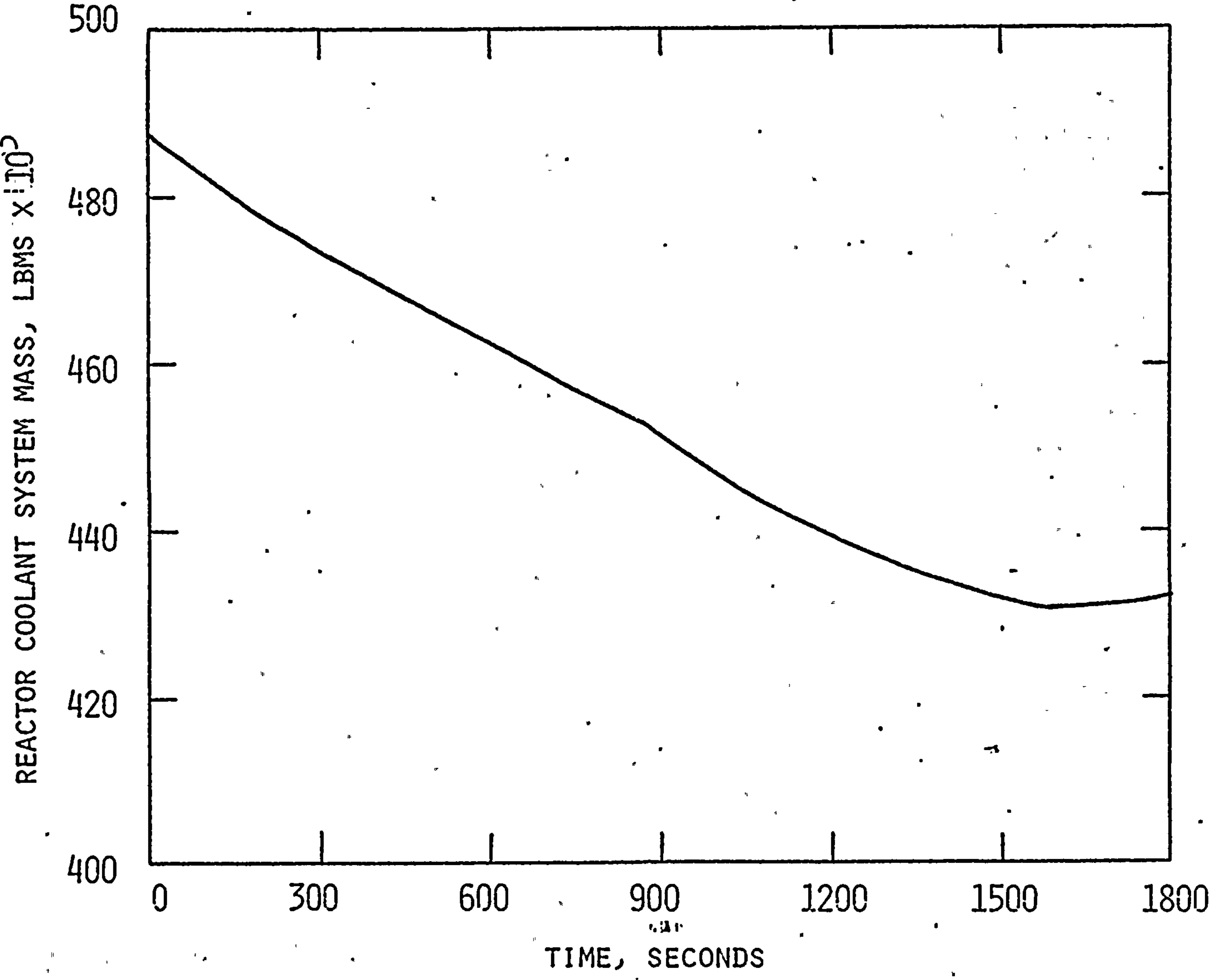

FIGURE 15.C.6-7

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
REACTOR COOLANT SYSTEM MASS VS. TIME

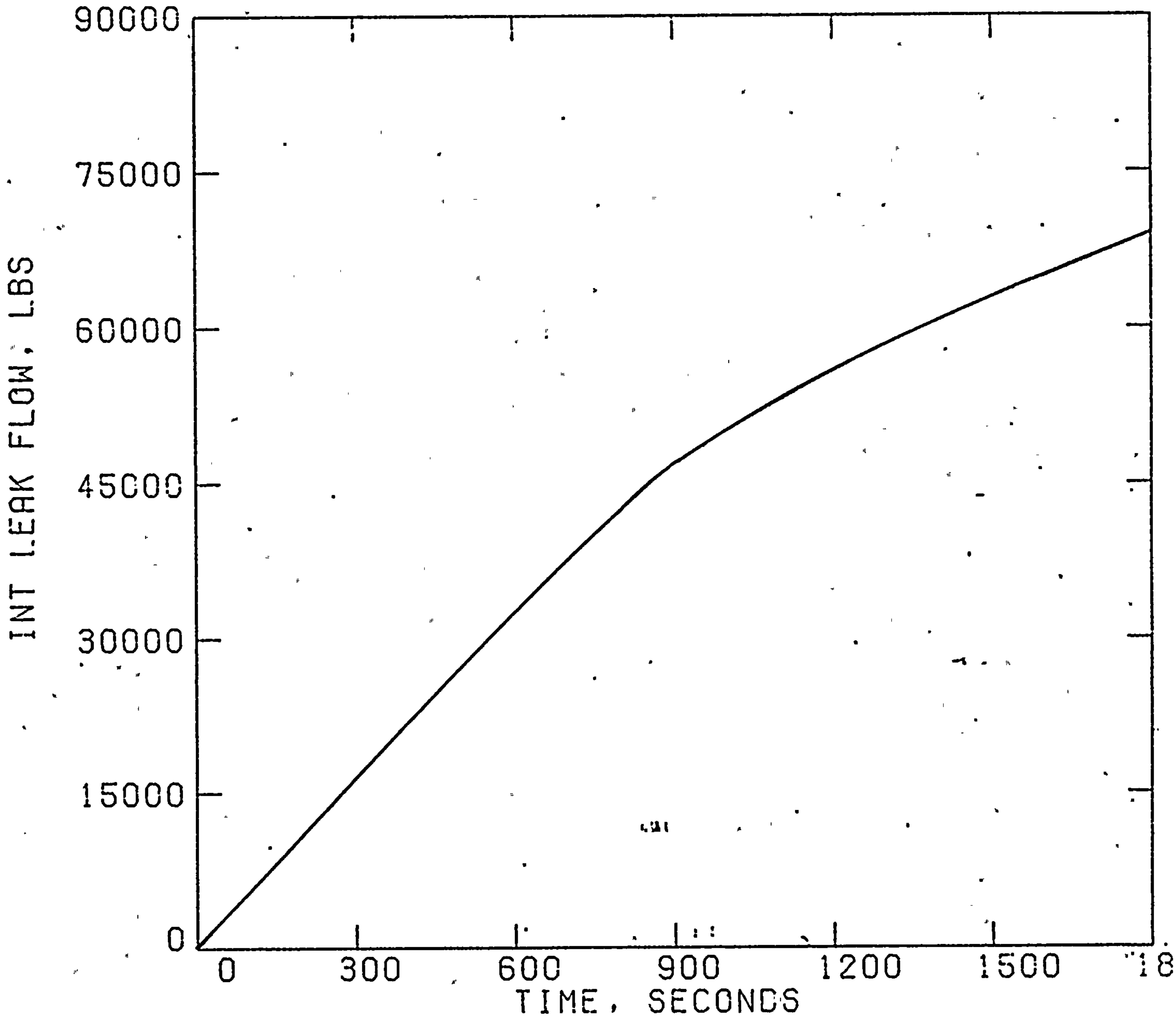

FIGURE 15.C.6-8
STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
INTEGRATED RCS LEAKAGE TO SECONDARY SYSTEM

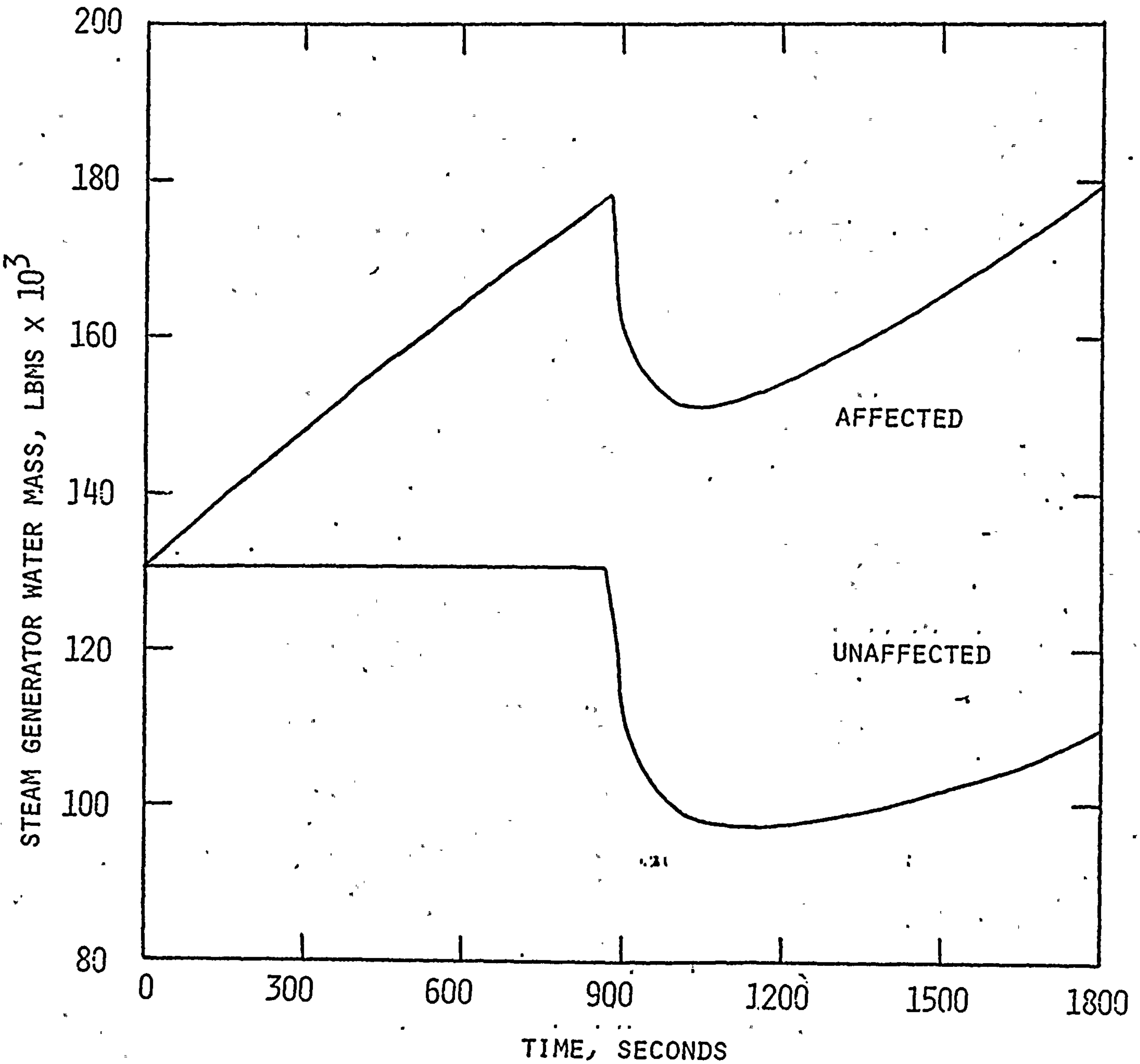

FIGURE 15.C.6-9

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
STEAM GENERATOR WATER MASS VS. TIME

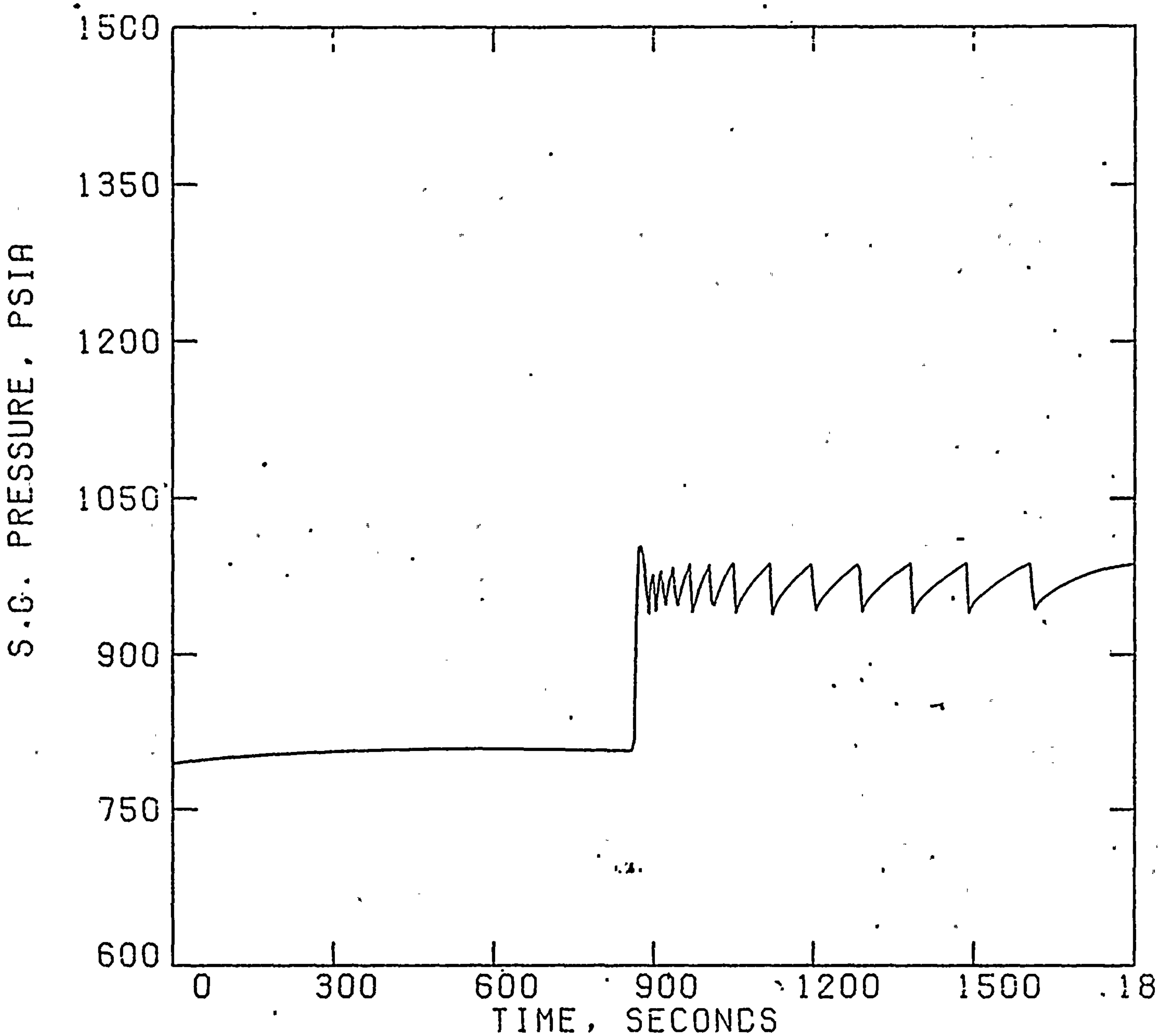

FIGURE 15.C.6-10
STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
STEAM GENERATOR PRESSURE VS. TIME

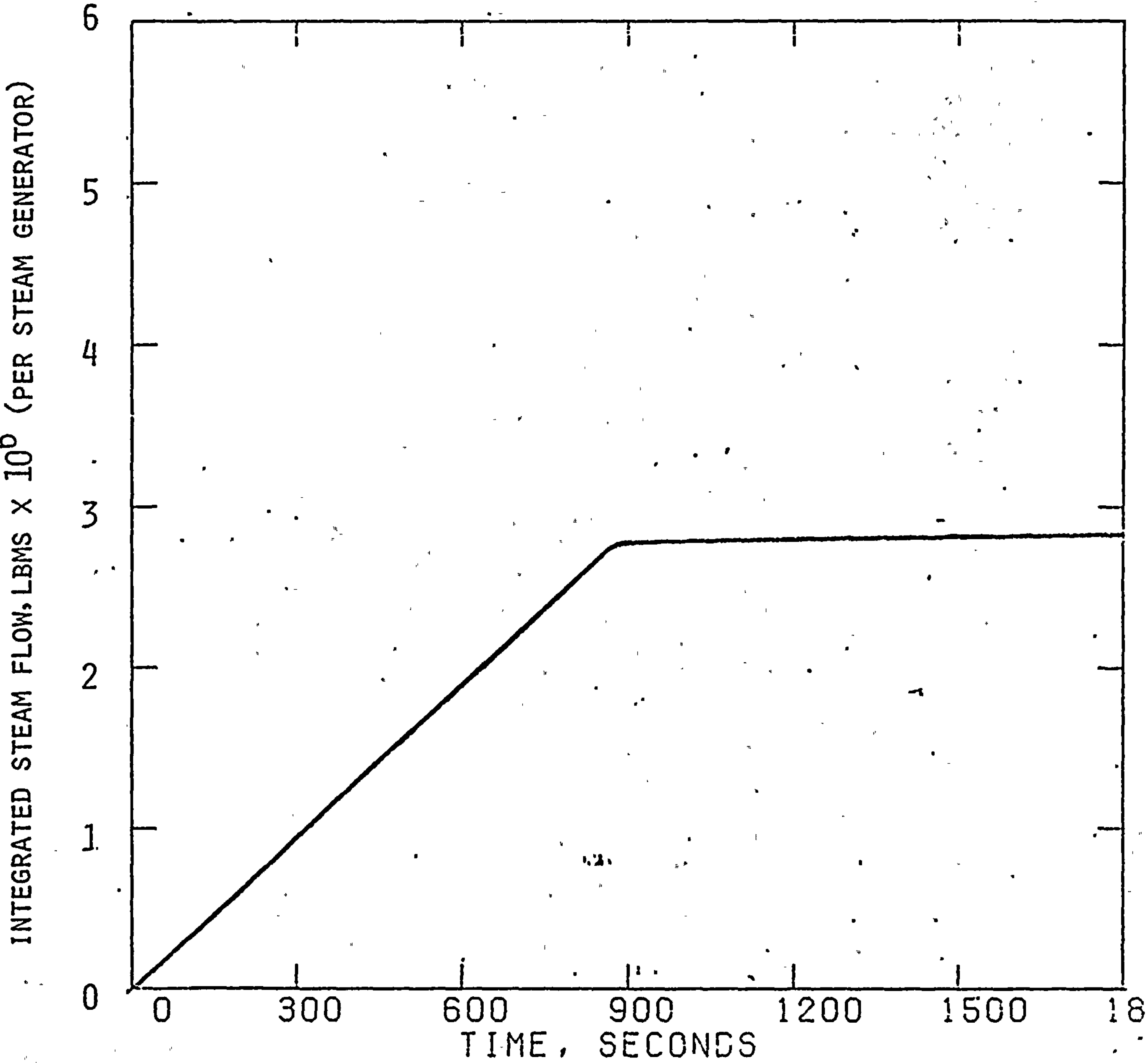

FIGURE 15 C.6-11

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
INTEGRATED STEAM FLOW PER STEAM GENERATOR VS. TIME

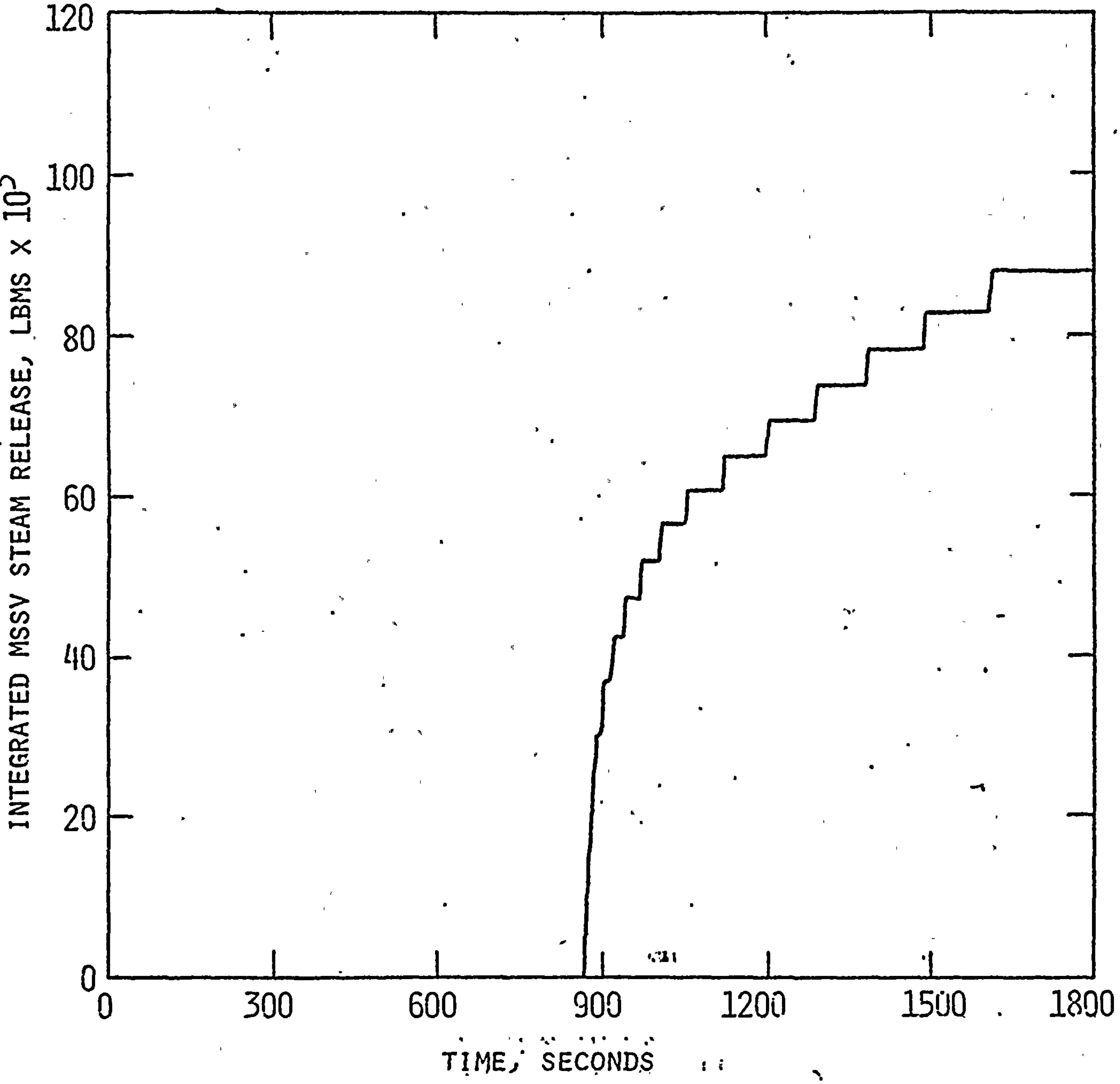

FIGURE 15.C.6-12
STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
TOTAL MSSV STEAM RELEASE VS. TIME

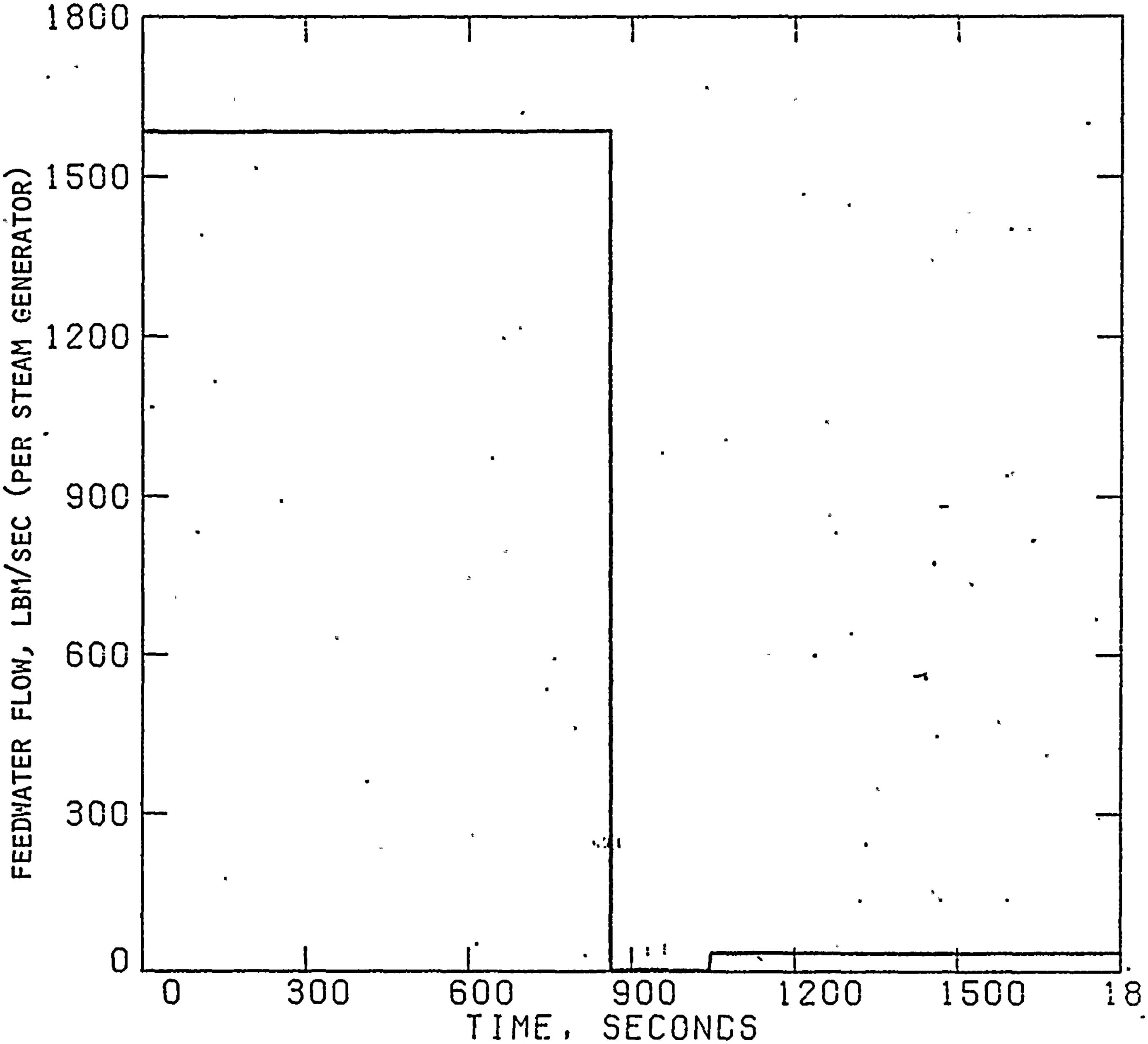

FIGURE 15.C.6-13

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
FEEDWATER FLOW VS. TIME

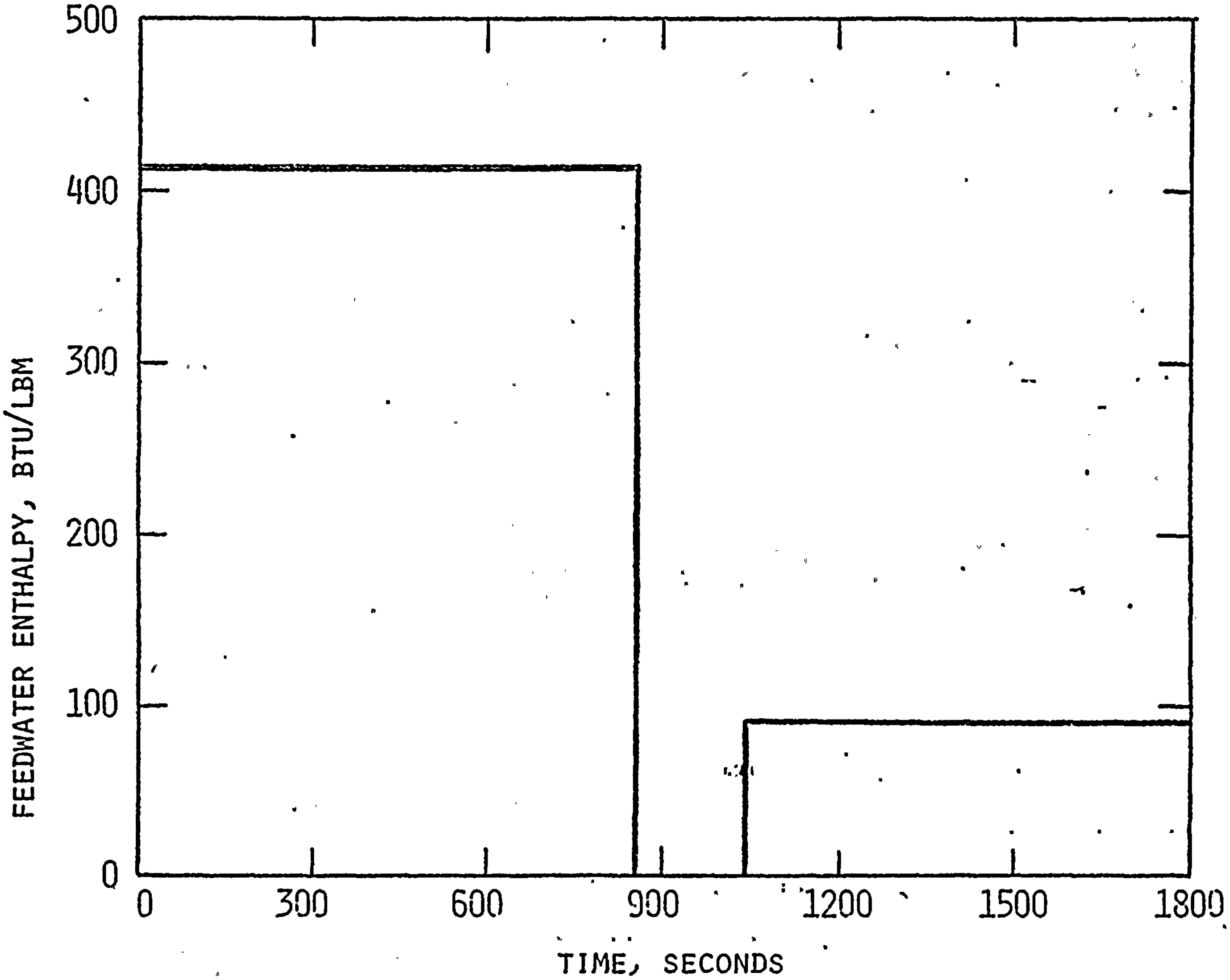

FIGURE 15 C.6-14

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
FEEDWATER ENTHALPY VS. TIME

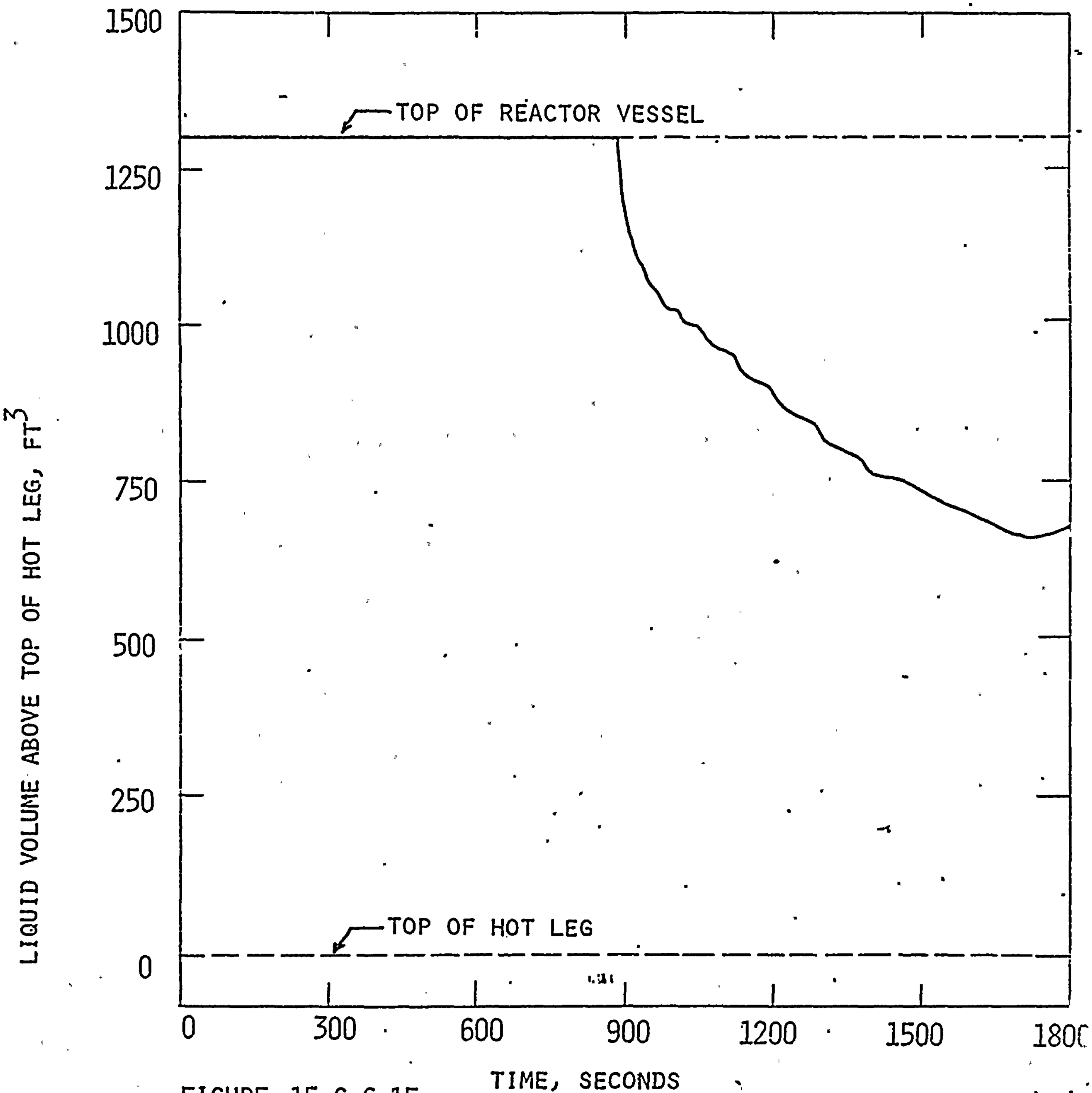

FIGURE 15 C.6-15

STEAM GENERATOR TUBE RUPTURE
WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP
LIQUID VOLUME ABOVE TOP OF HOT LEG VS. TIME

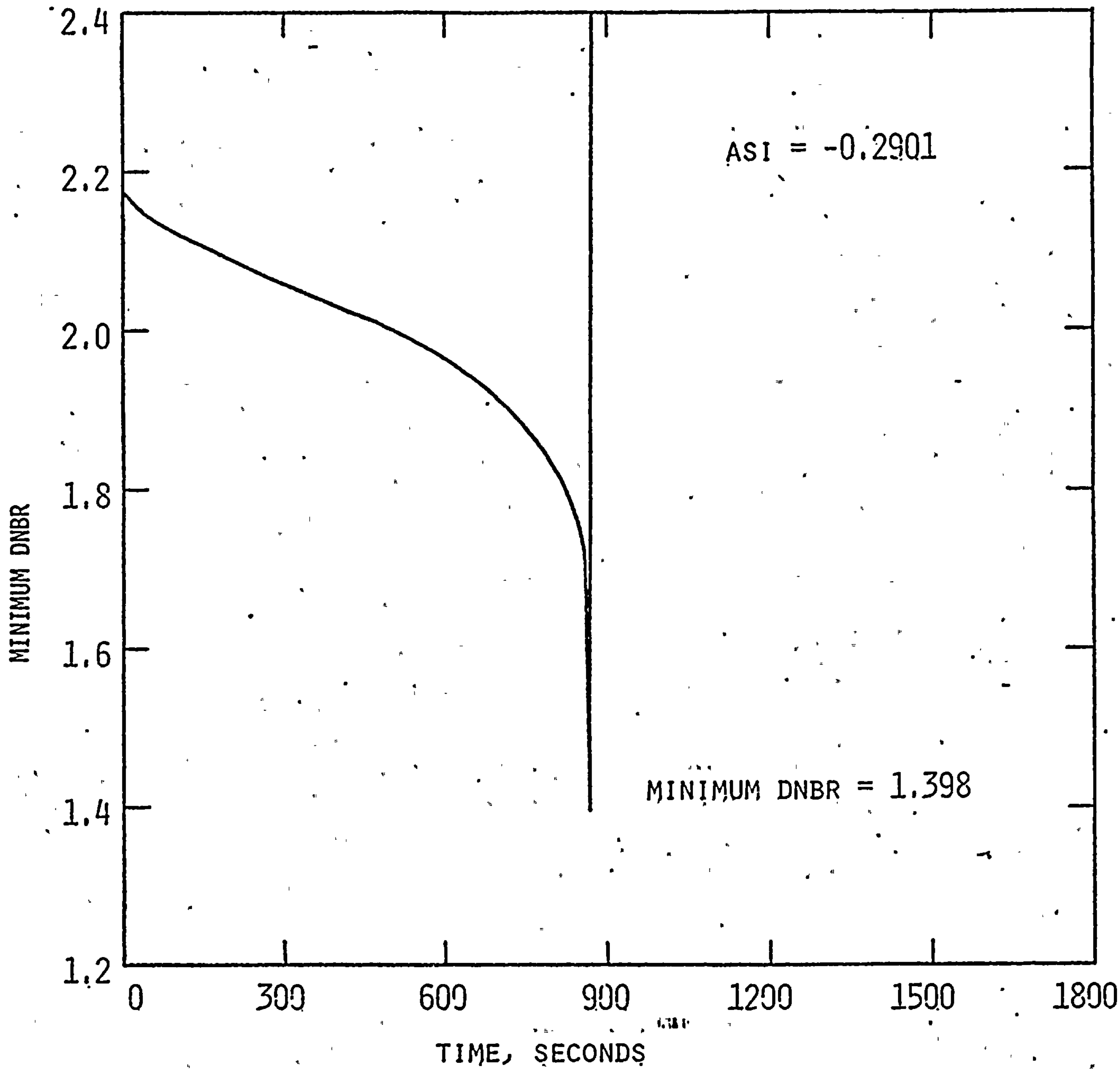

FIGURE 15.C.6-16

STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER
MINIMUM DNBR VS. TIME