AMENDMENT NUMBER 7

CESSAR-F

Docket STN-50-470F

The following sheets of CESSAR-F are to be inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Listing of Amendments	Listing of Amendments

The following sheets of CESSAR-F Chapter 1 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing (Sheets 1 and 2)

The following sheets of CESSAR-F Chapter 2 are to be inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
	Effective Page Listing

The following sheets of CESSAR-F Chapter 3 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing (Sheets 1 to 3)	Effective Page Listing (Sheets 1 to 6), Effective Page Listing Appendix 3.11A, 3.11B, Effective Page Listing Appendix 3A
Table of Contents	Table of Contents
vi, xii, xiv	vi, xii, xiv
List of Tables	List of Tables
xv	xv
Text	Text
3.2-3, 3.9-40 through 3.9-45, 3.11-1 through 3.11-7	3.2-3, 3.9-40 through 3.9-44, 3.9-44a, 3.9-44b, 3.9-44c, 3.9-45, 3.11-1 through 3.11-4, 3.11-4a, 3.11-5, 3.11-6, 3.11-7
Tables	Tables
3.2-1 (Sheets 1 to 6) 3.5-1 (Sheet 1), 3.9.3-3 (Sheets 1 to 4)	3.2-1 (Sheets 1-20) 3.5-1 (Sheet 1), 3.9.3-3 (Sheets 1 to 8)

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Title Pages (2 pages) for Appendix 3.11A)	Title Pages (2 pages) for Appendix 3.11A
Table of Contents (Appendix 3.11A)	Table of Contents (Appendix 3.11A)
i	i
List of Tables (Appendix 3.11A)	List of Tables (Appendix 3.11A)
ii	ii
List of Figures (Appendix 3.11A)	List of Figures (Appendix 3.11A)
iii	iii
Text (Appendix 3.11A)	Text (Appendix 3.11A)
3.11A-1 through 3.11A-4	3.11A-1 through 3.11A-2
Tables (Appendix 3.11A)	Tables (Appendix 3.11A)
3.11A-1 (Sheets 1 to 3)	3.11A -1 through 3.11A-14
Figures (Appendix 3.11A)	Figures (Appendix 3.11A)
3.11A-1 through 3.11A-5	3.11A-1A, 3.11A-1B, 3.11A-2 through 3.11A-5, 3.11A-6A, 3.11A-6B, 3.11A-7 through 3.11A-10
Tables (Appendix 3.11B)	Tables (Appendix 3.11B)
3.11B-1 (Sheets 1 through 6)	3.11B-1 (Sheets 1 through 7)

The following sheets of CESSAR-F Chapter 4 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing (Sheets 1 to 2), Effective Page Listing - Appendix 4C	Effective Page Listing (Sheets 1 to 7), Effective Page Listing - Appendix 4A, Effective Page Listing - Appendix 4B, Effective Page Listing - Appendix 4C
Table of Contents	Table of Contents
iii	iii

Text	Text
4.2-4, 4.2-5,4.2-15 4.2-16,4.2-26,4.2-27,4.2-30 through 4.2-32,4.2-34,4.2-37,4.2-65,4.2-70	4.2-4,4.2-4a, 4.2-5,4.2-15,4.2-16,4.2-26,4.2-27 4.2-30 through 4.2-32, 4.2-34,4.2-37,4.2-37a, 4.2-65,4.2-70
Tables	Tables
4.2-1 (Sheets 1 to 4)	4.2-1 (Sheets 1 to 4)
Figures	Figures
4.2-3 through 4.2-10	4.2-3 through 4.2-10

The following sheets of CESSAR-F Chapter 5 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing (Sheets 1 to 3)	Effective Page Listing (Sheets 1 to 4), Effective Page Listing - Appendix 5A, Effective Page Listing- Appendix 5B Effective Page Listing - Appendix 5C.
Text	Text
5.1-15, 5.2-6c,5.2-6d,5.4-29 5.4-31	5.1-15,5.2-6c,5.2-6d, 5.4-29,5.4-31,5.4-31a
Tables	Tables
5.4.7-3 (Sheet 7 of 9)	5.4.7-3 (Sheet 7 of 9)
Figures	Figures
5.1.2-1	5.1.2-1

The following sheets of CESSAR-F Chapter 6 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing (Sheets 1 and 2), Effective Page Listing - Appendix 6A, Effective Page Listing - Appendix 6B	Effective Page Listing (Sheets 1 to 6),Effective Page Listing - Appendix 6A (Sheets 1 and 2), Effective Page Listing - Appendix 6B (Sheets 1 and 2)

Text	Text
6.3-2,6.3-13	6.3-2,6.3-13
Tables	Tables
6.2.4-1 (Sheet 4 of 5)	6.2.4-1 (Sheet 4 of 5)
Figures	Figures
6.3.2-1A, 6.3.3.2-5P	6.3.2-1A, 6.3.3.2-5P

The following sheets of CESSAR-F Chapter 7 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing (Sheets 1 to 3)	Effective Page Listing (Sheets 1 to 6)
Table of Contents	Table of Contents
xii,xvi,xvii	xii, xvi, xvii
Text	Text
7.2-4, 7.7-8	7.2-4, 7.7-8, 7.7-8a, 7.7-10a
Tables	Tables
7.6-1	7.6-1
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The following sheets of CESSAR-F Chapter 8 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing

The following sheets of CESSAR-F Chapter 9 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing (Sheets 1 and 2)	Effective Page Listing (Sheets 1 to 3)
Text	Text
9.3-29	9.3-29, 9.3-29a

Tables	Tables
9.3-7 (Sheet 38 of 100), 9.3-7 (Sheet 50 of 100), 9.3-8 (2 pages)	9.3-7 (Sheet 38 of 100), 9.3-7 (Sheet 50 of 100), 9.3-8 (2 pages)
Figures	Figures
9.3-1	9.3-1

The following sheets of CESSAR-F Chapter 10 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing

The following sheets of CESSAR-F Chapter 11 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing (Sheets 1 and 2), Effective Page Listing - Appendix 11.1-A
Table of Contents	Table of Contents
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Text	Text
11.1-13	11.1-13

The following sheets of CESSAR-F Chapter 12 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing

The following sheets of CESSAR-F Chapter 13 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
	Effective Page Listing

The following sheets of CESSAR-F Chapter 14 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing (Sheets 1 to 4)

Text	Text
14.2-87,14.2-99a,14.2-100	14.2-87,14.2-99a,14.2-100

The following sheets of CESSAR-F Chapter 15 are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Every page of Chapter 15 (Volume 7) Appendices (Volume 8)	The Chapter 15 Text (Volume 7) Appendices (Volume 8)

The following sheet of CESSAR-F Chapter 17 is to be inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
	Effective Page Listing

The following sheets of CESSAR-F Appendix A are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing (Sheets 1 to 3)

The following sheets of CESSAR-F Appendix B are to be removed and inserted.

REMOVE THE FOLLOWING	INSERT THE FOLLOWING
Effective Page Listing	Effective Page Listing, (Sheets 1 and 2)

LISTING OF AMENDMENTS

Amendment No.	Date
1	February 20, 1981
2	March 12, 1981
3	May 28, 1981
4	July 16, 1981
5	October 26, 1981
6	November 20, 1981
7	March 31, 1982

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CHAPTER 3

components, such as piping and strainers are not listed; they may be found by reference to the P&ID's (Chapters 5.0, 6.0, and 9.0) where the exact boundaries are indicated.

All pressure containing components in Safety Classes 1, 2, and 3 are designed, manufactured, and tested in accordance with the rules of the ASME Boiler and Pressure Vessel Code, Section III. Components in Safety Class 4 are designed and constructed with appropriate consideration of the intended service using applicable industry codes and standards. The relationship between safety class and code class is shown in Table 3.2-2. A higher code class may be used for component without changing the safety class or affecting the balance of the system in which it is located.

Fracture toughness requirements are imposed on materials for pressure retaining parts of ASME Class 2 and 3 CESSAR system components. Test methods, acceptance, and exemption criteria are in conformance with the ASME Code, Section III.

The safety classification system is also used to identify those components to which the requirements of 10CFR50, Appendix B, are applicable. Components in Safety Classes 1, 2, and some components in Safety Class 3 are designed and manufactured under a rigorous quality assurance program reflecting the requirements of Appendix B, and are designated Quality Class 1. The Quality Class 1 quality assurance program is described in Chapter 17. Components which do not serve a safety related function are designated Quality Class 2. Quality Class 2 components will be designed and manufactured in accordance with the pertinent requirements of the Quality Assurance Program as given in Chapter 17. 7

The quality class of major mechanical and electrical components are shown in Table 3.2-1 and Section 3.11, respectively, in conjunction with the safety and seismic classifications.

The use of the above outlined safety and quality classification systems meets the intent of Regulatory Guide 1.26 and the requirements of 10CFR50 Section 50.55a.

REFERENCES FOR SECTION 3.2

1. ANSI N18.2a-1975 (ANS 51.8), "Revision and Addendum to Nuclear Safety Criteria for the Design of Stationary Pressurized WaterReactor Plants," ANSI N18.2-1973.

2. CENPD-182, Seismic Qualification of C-E Instrumentation Equipment, May 1977.

TABLE 3.2-1

(Sheet 1 of 20) 7

CLASSIFICATION OF
STRUCTURES, SYSTEMS, AND COMPONENTS

	Safety Class	Seismic Category	Quality Class	
Reactor Coolant System				
* Reactor Vessel	1	I	1	
* Steam generators (primary/secondary)	1/2 (1)	I	1	6
* Pressurizer	1	I	1	
* Reactor coolant pumps (3) (4) (10)	1	I	1	7
Piping within reactor coolant pressure boundary (6)	1/2 (5)	I	1	
Control element drive mechanisms (7)	N/A	N/A	1	
Core support structures (8)	N/A	I (2)	1	6
Fuel assemblies (9)	N/A	I	1	
Control element assemblies (9)	N/A	I	1	
Closure Head Lift Rig	4	N/A	2	7
Safety Injection System				
* Low pressure safety injection pumps	2	I	1	
* High pressure safety injection pumps	2	I	1	6
* Shutdown cooling heat exchangers	2/3 (1)	I	1	
* Safety injection tanks	2	I	1	
Chemical and Volume Control System				
* Regenerative heat exchanger	2	I	1	
* Letdown heat exchanger	2/3 (1)	I	1	
* Seal injection heat exchanger	2/3 (1)	I	1	
* Purification ion exchangers	2	I	1	
* Deborating ion exchanger	2	I	1	
* Volume control tank	2	I	1	6
* Chemical addition package	4	N/A	2	
* Boric acid batching tank	4	N/A	2	
* Charging pumps	2	I	1	
* Boric acid makeup pumps	3	I	2	
* Reactor Makeup water pumps	4	N/A	2	
* Boric acid concentrator	4	N/A	2	
* Preholdup ion exchanger	3	I	2	

N/A is Not Applicable

Footnotes to this table are given at the end of the table.

* including component supports down to (but not including) embedments. 6

CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS

	Safety Class	Seismic Category	Quality Class	
Chemical and Volume Control System (Cont'd.)				
* Boric acid condensate ion exchanger	4	N/A	2	
* Reactor drain pumps	3	I	2	
* Holdup pumps	4	N/A	2	
* Reactor drain tank	4	N/A	2	
* Holdup tank	4	N/A	2	
* Equipment drain tank	3	I	2	
* Refueling water tank	2	I	1	
* Reactor makeup water tank	4	N/A	2	
* Gas stripper	3	I	2	
* Purification filters	2	I	1	6
* Reactor drain filter	3	I	2	
* Seal injection filters	2	I	1	
* Reactor makeup filter	4	N/A	2	
* Boric acid filter	3	I	2	
Letdown Strainer	2	1	1	
Preholdup Strainer	3	1	1	
Boric Acid Condensate Ion Exchanger Strainer	4	N/A	2	
Ion Exchanger Drain Header Strainer	4	N/A	2	
Boric Acid Batching Strainer	4	N/A	2	
Chemical Addition Strainer	4	N/A	2	
Fuel Handling System				
Refueling Machine	N/A	N/A	2	
Fuel Transfer System	N/A	N/A	2	
1. Transfer Carriage	N/A	N/A	2	
2. Upending Machine	N/A	N/A	2	
3. Hydraulic Power Unit	N/A	N/A	2	
Fuel Transfer Tube, Valve	N/A	N/A	2	
CEA Change Platform	N/A	N/A	2	
Long and Short Fuel Handling Tools	N/A	N/A	2	6
Reactor Vessel Head Lifting Rig	4	N/A	2	
Upper Guide Structure Lifting Rig	N/A	N/A	2	
Core Barrel Lifting Rig	N/A	N/A	2	
Spent Fuel Handling Machine	N/A	N/A	2	
New Fuel Elevator	N/A	N/A	2	
Underwater Television	N/A	N/A	2	
Dry Sipping Equipment	N/A	N/A	2	
Refueling Pool Seal	N/A	N/A	2	
In-Core Instrumentation and CEA Cutter	N/A	N/A	2	
Extension Shaft Uncoupling Tool	N/A	N/A	2	
Fuel Transfer Tube Blind Flange	2	1	2	
CEA Handling Tools	N/A	N/A	2	

TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 3 of 20) 7

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
Reactor Coolant System (RCS) (12)				
RC-212	Reactor vessel vent	1	I	1
RC-214	Refueling level indicator	1	I	1
RC-215, 216, 232, 332, 233, 333, 234, 334, 235, 335	RCS drains	1	I	1
RC-248, 249, 252, 253, 256, 257, 260, 261	Reactor coolant pump (RCP)	2	I	1
RC-206, 207, 208, 209	Pressurizer level indicator	2	I	1
RC-204, 205	Pressurizer pressure indicator	2	I	1
RC-239	Pressurizer vent	1	I	1
RC-200, 201, 202, 203	Pressurizer safety	1	I	1
RC-240, 241, 242, 243, 236, 237	Pressurizer spray line	1	I	1
RC-100E, 100F	Pressurizer spray line control	1	I	1
RC-244	Pressurizer spray line check	1	I	1
RC-210, 213, 238	Sample System	2	I	1
RC-211	Reactor Vessel Closure Head Leakoff	2	I	1
RC-292, 293, 294, 295, 296, 297, 298, 299	RCS pressure differential	2	I	1
RC-752, 753, 754, 755	RCP Seal Housing Drain	1	I	1
RC-712, 713, 714, 715	RCP Vent	1	I	1
RC-446, 447, 448, 449, 450, 451, 452, 453	RCP HP Cooler	1	I	1
RC-772, 773, 774, 775	RCP HP Cooler vent	1	I	1
RC-868, 869, 870, 871, 700, 701, 702, 703	RCP filter drain	1	I	1
RC-724, 725, 726, 727, 736, 737, 738, 739	RCP seal cooler pressure	2	I	1
RC-430, 431, 432, 433, 344, 345, 346, 347	RCP controlled bleedoff	2	I	1
RC-380, 381, 382, 383	RCP vapor seal pressure indicator	2	I	1
Chemical and Volume Control System (CVCS) (12)				
CH-100	VCT Vent Isolation	3	I	1
CH-101	Letdown Check	2	I	1
CH-103	VCT Vent Pressure Indicator Isolation	2	I	1
CH-104	VCT Vent Isolation	2	I	1
CH-110P	Letdown Control	2	I	1
CH-110Q	Letdown Control	2	I	1
CH-112	VCT Gas Supply Line Check	2	I	1
CH-113	VCT Level Indicator Isolation	2	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 4 of 20) 7

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
CH-114	VCT Level Indicator Isolation	2	I	1
CH-115	VCT to EDT Relief	2	I	1
CH-116	VCT Local Sample Line Isolation	2	I	1
CH-117	CVT to DRDH Isolation	2	I	1
CH-118	VCT Check	2	I	1
CH-124	RWT Supply Isolation	2	I	1
CH-126	BABT Line to RWT Isolation	3	I	1
CH-127	BAC Line to RWT Check	3	I	1
CH-128	RWT Level Indicator Isolation	2	I	1
CH-129	RWT Level Indicator Isolation	2	I	1
CH-130	BAMP Recirc Isolation	3	I	1
CH-131	Boric Acid Filter D/P Indicator Isolation	3	I	1
CH-132	BAMP Discharge Filter Vent	3	I	1
CH-134	BAMP to DRDH Isolation	3	I	1
CH-135	RWT Level Indicator Isolation	2	I	1
CH-136	RWT Level Indicator Isolation	2	I	1
CH-137	RWT Level Indicator Isolation	2	I	1
CH-138	RWT Level Indicator Isolation	2	I	1
CH-139	Gas Stripper to VCT Check	2	I	1
CH-143	BAMP Suction Isolation	3	I	1
CH-144	RWT to PCPS Isolation	3	I	1
CH-145	BAMP Suction Isolation	3	I	1
CH-146	RAMP Discharge Pressure Indicator Isolation	3	I	1
CH-147	BAMP Discharge Pressure Indicator Isolation	3	I	1
CH-152	BAMP Discharge Isolation	3	I	1
CH-153	BAMP Discharge Isolation	3	I	1
CH-154	BAMP Discharge Check	3	I	1
CH-155	BAMP Discharge Check	3	I	1
CH-156	RWT Level Indicator Isolation	2	I	1
CH-157	RWT Level Indicator Isolation	2	I	1
CH-158	RWT Level Indicator Isolation	2	I	1
CH-159	RWT Level Indicator Isolation	2	I	1
CH-161	Boric Acid Makeup to VCT Check	3	I	1
CH-164	Boric Acid Filter Bypass	3	I	1
CH-165	Boric Acid Filter D/P Indicator Isolation	3	I	1
CH-166	Boric Acid Makeup to VCT Isolation	3	I	1
CH-172	Boric Acid Makeup to VCT Isolation	3	I	1
CH-174	Boric Acid Makeup Cross-connect	3	I	1
CH-176	Boric Acid Local Sample Isolation	3	I	1
CH-177	Boric Acid Line to Charging Pump Suction Check	2	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 5 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class	
CH-179	RMW Line to Charging Pump Suction Check	2	I	1	
CH-184	RMW Line to VCT Check	3	I	1	
CH-185	RMW Local Sample Isolation	3	I	1	
CH-188	VCT Check	2	I	1	
CH-190	RWT Gravity Feed Check	2	I	1	
CH-192	BAMP to RWT Recirc	3	I	1	
CH-197	Sampling System Check	2	I	1	
CH-198	RCP Controlled Bleedoff Isolation	2	I	1	
CH-199	RCP Controlled Bleedoff to RDT Relief	2	I	1	
CH-201P	Letdown Backpressure	2	I	1	
CH-201Q	Letdown Backpressure	2	I	1	
CH-203	Auxiliary Spray	1	I	1	
CH-204	PRM Flow Control	2	I	1	
CH-205	Auxiliary Spray	1	I	1	
CH-210Y	Boric Acid Makeup Control	3	I	1	7
CH-231P	Seal Injection Isolation	2	I	1	
CH-240	Charging Line Backpressure	1	I	1	
CH-241	Seal Injection Flow Control	2	I	1	
CH-242	Seal Injection Flow Control	2	I	1	
CH-243	Seal Injection Flow Control	2	I	1	
CH-244	Seal Injection Flow Control	2	I	1	
CH-255	Seal Injection Containment Isolation	2	I	1	
CH-300	RCP Controlled Bleedoff Pressure Indicator Isolation	2	I	1	
CH-305	RWT Gravity Feed Check	2	I	1	
CH-306	RWT to SIS Check	2	I	1	
CH-314	Hydrostatic Test Pump Isolation	2	I	1	
CH-315	Charging Pump to EDT Relief	2	I	1	
CH-316	Charging Pump Suction Isolation	2	I	1	
CH-317	Charging Pump Suction to DRDH Isolation	2	I	1	
CH-318	Charging Pump to EDT Relief	2	I	1	
CH-319	Charging Pump Suction Isolation	2	I	1	
CH-320	Charging Pump Suction to DRDH Isolation	2	I	1	
CH-321	Charging Pump to EDT Relief	2	I	1	
CH-322	Charging Pump Suction Isolation	2	I	1	
CH-323	Charging Pump Suction to DRDH Isolation	2	I	1	
CH-324	Charging Pump Relief	2	I	1	
CH-325	Charging Pump Relief	2	I	1	
CH-326	Charging Pump Relief	2	I	1	
CH-327	RWT Gravity Feed Isolation	2	I	1	
CH-328	Charging Pump Discharge Check	2	I	1	
CH-329	Charging Pump Discharge to DRDH Isolation	2	I	1	

TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 6 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
CH-330	BAMP Line to HT Isolation	3	I	1
CH-331	Charging Pump Discharge Check	2	I	1
CH-332	Charging Pump Discharge to DRDH Isolation	2	I	1
CH-334	Charging Pump Discharge Check	2	I	1
CH-335	Charging Pump Discharge Isolation	2	I	1
CH-336	Charging Pump Discharge to DRDH Isolation	2	I	1
CH-337	Charging Pump Discharge Isolation	2	I	1
CH-339	Charging Pump Discharge Isolation	2	I	1
CH-340	Letdown Control Valve Isolation	2	I	1
CH-341	Letdown Control Valve Isolation	2	I	1
CH-342	Letdown Control Valve Isolation	2	I	1
CH-343	Letdown Control Valve Isolation	2	I	1
CH-344	Letdown Flow Indicator Isolation	2	I	1
CH-345	Letdown to EDT Relief	2	I	1
CH-346	Letdown Pressure Control Isolation	2	I	1
CH-347	Letdown Backpressure Valve Isolation	2	I	1
CH-348	Letdown Backpressure Valve Isolation	2	I	1
CH-349	Letdown Backpressure Valve Isolation	2	I	1
CH-350	Letdown Backpressure Vavle Isolation	2	I	1
CH-351	Letdown Flow Indicator Isolation	2	I	1
CH-352	Letdown Pressure indicator Isolation	2	I	1
CH-353	Sampling System Isolation	2	I	1
CH-354	Letdown to EDT Relief	2	I	1
CH-355	Letdown Filter Bypass	2	I	1
CH-356	Letdown Filter D/P Isolation	2	I	1
CH-357	Letdown Filter D/P Isolation	2	I	1
CH-358	Letdown Filter Isolation	2	I	1
CH-359	Letdown Filter Vent	2	I	1
CH-360	Letdown Filter Isolation	2	I	1
CH-361	Letdown to DRDH Isolation	2	I	1
CH-362	Shutdown Cooling Check	2	I	1
CH-363	Shutdown Cooling Isolation	2	I	1
CH-364	PRM and Boronometer Isolation	2	I	1
CH-366	Letdown Filter Vent	2	I	1
CH-367	PRM Flow Control Valve Isolation	2	I	1
CH-368	PRM Flow Control Valve Isolation	2	I	1
CH-369	IX Isolation	2	I	1
CH-370	IX Check	2	I	1
CH-371	IX Vent to GWMS	2	I	1
CH-372	IX Resin Fill Isolation	2	I	1
CH-373	Letdown Filter Isolation	2	I	1
CH-374	IX Isolation	2	I	1
CH-375	Letdown to DRDH Isolation	2	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 7 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class	
CH-376	Letdown Filter Isolation	2	I	1	
CH-378	IX Isolation	2	I	1	
CH-379	RSSH to IX Isolation	2	I	1	
CH-380	IX to SWMS Isolation	2	I	1	
CH-381	IX Bypass	2	I	1	
CH-382	IX Isolation	2	I	1	
CH-383	IX Isolation	2	I	1	
CH-384	IX Check	2	I	1	
CH-385	IX Bypass	2	I	1	
CH-386	IX Vent to GWMS	2	I	1	
CH-387	IX Resin Fill Isolation	2	I	1	
CH-389	IX Isolation	2	I	1	
CH-390	RSSH to IX Isolation	2	I	1	
CH-391	IX to SWMS Isolation	2	I	1	
CH-392	IX Isolation	2	I	1	
CH-393	RHTX Vent	2	I	1	
CH-394	IX Bypass	2	I	1	
CH-395	IX Isolation	2	I	1	
CH-396	LPSI Check	2	I	1	7
CH-397	LPSI Isolation	2	I	1	
CH-398	IX Isolation	2	I	1	
CH-399	RSSH to IX Isolation	2	I	1	
CH-400	IX to SWMS Isolation	2	I	1	
CH-401	IX Vent to GWMS	2	I	1	
CH-402	IX Resin Fill Isolation	2	I	1	
CH-403	IX Check	2	I	1	
CH-404	IX Isolation	2	I	1	
CH-405	Charging Line Backpressure D/P Isolation	2	I	1	
CH-406	Charging Line Backpressure D/P Isolation	1	I	1	
CH-407	IX D/P Isolation	2	I	1	
CH-408	IX D/P Isolation	2	I	1	
CH-413	PRM Bypass	2	I	1	
CH-414	Letdown Strainer Bypass	2	I	1	
CH-415	IX Isolation	2	I	1	
CH-418	Letdown to VCT Isolation	2	I	1	
CH-419	Letdown Strainer to SWMS Isolation	2	I	1	
CH-420	IX Effluent Sample Isolation	2	I	1	
CH-421	Boronometer Isolation	2	I	1	
CH-422	PRM Flow Indicator Isolation	2	I	1	
CH-423	PRM Flow Control Spring Loaded Check Bypass	2	I	1	
CH-424	PRM Flow Control Bypass	2	I	1	
CH-425	Charging Line Pressure Indicator Isolation	2	I	1	

TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
CH-426	Letdown Sample Isolation	2	I	1
CH-427	Charging Line Flow Indicator Isolation	2	I	1
CH-428	Charging Line Flow Indicator Isolation	2	I	1
CH-429	Charging Line Isolation	2	I	1
CH-431	Auxiliary Spray Check	1	I	1
CH-433	Charging Line Check	1	I	1
CH-434	Charging Line Backpressure Bypass	1	I	1
CH-435	Charging Line Backpressure Spring Loaded Bypass Check	1	I	1
CH-436	Hydrogen Addition Line Isolation	2	I	1
CH-437	Charging Pump Pressure Switch Isolation	2	I	1
CH-438	Charging Pump Pressure Switch Isolation	2	I	1
CH-439	Charging Pump Pressure Switch Isolation	2	I	1
CH-440	Charging to HPSI Check	2	I	1
CH-444	Letdown Heat Exchanger Vent	3	I	1
CH-445	Letdown Line Vent	2	I	1
CH-449	PRM and Boronometer Check	2	I	1
CH-450	RDH to EDT Check	3	I	1
CH-459	EDT Line to GWMS Pressure Indicator Isolation	3	I	1
CH-460	EDT Level Indicator Isolation	3	I	1
CH-461	EDT Level Indicator Isolation	3	I	1
CH-464	EDT to RDP Check	3	I	1
CH-465	RDP Suction Isolation	3	I	1
CH-466	RDP Suction Isolation	3	I	1
CH-467	Gas Stripper to GWMS Isolation	3	I	1
CH-468	RDP Discharge Pressure Indicator Isolation	3	I	1
CH-469	RDP Discharge Pressure Indicator Isolation	3	I	1
CH-470	RDP Discharge Check	3	I	1
CH-471	RDP Discharge Check	3	I	1
CH-472	RDP Discharge Isolation	3	I	1
CH-462	EDT Drain Isolation	3	I	1
CH-473	RDP Discharge Isolation	3	I	1
CH-474	Reactor Drain Filter Bypass	3	I	1
CH-475	RDP Discharge to RDH Isolation	3	I	1
CH-476	Reactor Drain Filter D/P Isolation	3	I	1
CH-477	Reactor Drain Filter Isolation	3	I	1
CH-478	Reactor Drain Filter Isolation	3	I	1
CH-479	Reactor Drain Filter D/P Isolation	3	I	1
CH-480	IDH to EDT Check	3	I	1
CH-485	Pre-Holdup IX to RSSH Isolation	3	I	1
CH-486	Pre-Holdup IX DiDH Isolation	3	I	1

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SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 9 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
CH-488	Pre-Holdup IX D/P Isolation	3	I	1
CH-489	Pre-Holdup Strainer to SWMS Isolation	3	I	1
CH-490	Pre-Holdup IX Isolation	3	I	1
CH-491	Pre-Holdup IX Strainer Isolation	3	I	1
CH-492	Pre-Holdup IX D/P Isolation	3	I	1
CH-493	Pre-Holdup IX Effluent Sample Isolation	3	I	1
CH-494	RSSH and RDP to RDH Check	2	I	1
CH-495	Pre-Holdup IX to RWT Isolation	3	I	1
CH-496	Pre-Holdup IX to GS/EDT Isolation	3	I	1
CH-500	VCT Inlet Diverting	2	I	1
CH-501	VCT Discharge Isolation	2	I	1
CH-505	RCP Controlled Bleedoff Containment Isolation	2	I	1
CH-506	RCP Controlled Bleedoff Containment Isolation	2	I	1
CH-507	RCP Controlled Bleedoff Containment Isolation	2	I	1
CH-510	RWT Recirc	3	I	1
CH-512	VCT Makeup Supply Isolation	3	I	1
CH-513	VCT Vent	2	I	1
CH-514	Boric Acid Makeup Bypass to Charging Pumps	3	I	1
CH-515	Letdown Isolation	1	I	1
CH-516	Letdown Isolation	1	I	1
CH-520	Purification and Deborating IX Bypass	2	I	1
CH-521	PRM and Boronometer Bypass	2	I	1
CH-523	Letdown Isolation	2	I	1
CH-524	Charging Line Isolation	2	I	1
CH-526	Letdown Control Valve Bypass	2	I	1
CH-527	Load Follow Supply	3	I	1
CH-530	RWT Suction to ESFP's Isolation	2	I	1
CH-531	RWT Suction to RSFP's Isolation	2	I	1
CH-532	RWT Suction to RDP's Isolation	2	I	1
CH-536	RWT Gravity Feed to Charging Pumps Isolation	3	I	1
CH-560	RDT Suction Isolation	2	I	1
CH-561	RDT Isolation	2	I	1
CH-562	RDH Isolation	3	I	1
CH-563	EDT Discharge Isolation	3	I	1
CH-564	EDT Vent Isolation	3	I	1
CH-565	Pre-Holdup IX Bypass	3	I	1
CH-566	Gas Stripper Diversion	3	I	1
CH-567	Diversion to HT from VCT Inlet	3	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 10 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
CH-580	RMWS to RDT Isolation	2	I	1
CH-612	Seal Injection Line Vent Isolation	2	I	1
CH-613	Seal Injection Line Vent Isolation	2	I	1
CH-614	Seal Injection Vent	3	I	1
CH-639	Charging Line Check	2	I	1
CH-642	Hydrostatic Test Pump Isolation	2	I	1
CH-643	VCT Vent to GWMS Isolation	3	I	1
CH-645	Gas Addition to VCT Isolation	2	I	1
CH-646	RCP Controlled Bleedoff Line Check	2	I	1
CH-647	RWT Recirc Check	2	I	1
CH-648	RWT Recirc Sample Isolation	3	I	1
CH-649	Boric Acid Line to RWT Isolation	3	I	1
CH-653	Boric Acid Line Isolation	3	I	1
CH-654	MSH to Gas Stripper Isolation	3	I	1
CH-655	Pre-Holdup IX to Radiation Monitor Isolation	3	I	1
CH-656	Gas Stripper to HT Isolation	3	I	1
CH-657	EDT Relief to Misc Radioactive Sump	3	I	1
CH-659	Chemical Addition Line Isolation	2	I	1
CH-660	Gas Stripper Inlet Isolation	3	I	1
CH-663	Reactor Drain Filter Vent	3	I	1
CH-665	RDP Discharge Sample Isolation	3	I	1
CH-668	BAM Line to VCT Check	3	I	1
CH-686	Holdup Pump Bypass to Reactor Drain Filter Isolation	3	I	1
CH-721	Letdown to Pre-Holdup IX Isolation	3	I	1
CH-722	Letdown to Pre-Holdup IX Check	3	I	1
CH-723	Reactor Drain Line Sample Isolation	3	I	1
CH-724	Pre-Holdup IX Isolation	3	I	1
CH-725	Pre-Holdup IX Check	3	I	1
CH-726	Pre-Holdup IX Resin Fill Isolation	3	I	1
CH-727	Pre-Holdup IX D/P Isolation	3	I	1
CH-728	Pre-Holdup IX Vent Isolation	3	I	1
CH-730	Pre-Holdup IX to SWMS Isolation	3	I	1
CH-740	RCP Controlled Bleedoff Test Connection Isolation	2	I	1
CH-741	RCP Controlled Bleedoff Test Connection Isolation	2	I	1
CH-742	RCP Controlled Bleedoff Test Connection Isolation	2	I	1
CH-743	RCP Controlled Bleedoff Test Connection Isolation	2	I	1
CH-753	BAMP Recirc Isolation	3	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 11 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
CH-755	Gravity Feed to Charging Pump Isolation	2	I	1
CH-756	Gravity Feed to Charging Pump Isolation	2	I	1
CH-757	Gravity Feed to Charging Pump Isolation	2	I	1
CH-787	Seal Injection Check	1	I	1
CH-789	Seal Injection Flow Indicator Isolation	2	I	1
CH-796	Charging to HPSI Isolation	2	I	1
CH-797	Charging to HPSI Isolation	2	I	1
CH-798	Charging to HPSI Isolation	2	I	1
CH-800	Seal Injection Flow Indication Isolation	2	I	1
CH-802	Seal Injection Check	1	I	1
CH-804	Seal Injection Flow Indicator Isolation	2	I	1
CH-805	Seal Injection Flow Indicator Isolation	2	I	1
CH-807	Seal Injection Check	1	I	1
CH-809	Seal Injection Flow Indicator Isolation	2	I	1
CH-810	Seal Injection Flow Indicator Isoaltion	2	I	1
CH-812	Seal Injection Check	1	I	1
CH-814	Seal Injection Flow Indicator Isolation	2	I	1
CH-815	Seal Injection Flow Indicator Isolation	2	I	1
CH-816	Seal Injection Filter Isolation	2	I	1
CH-818	Seal Injection Filter Isolation	2	I	1
CH-819	Seal Injection Filter Isolation	2	I	1
CH-821	Seal Injection Filter Isolation	2	I	1
CH-822	Seal Injection to DRDH Isoaltion	2	I	1
CH-823	Seal Injection to DRDH Isolation	2	I	1
CH-825	Seal Injection Filter D/P Isolation	2	I	1
CH-826	Seal Injection Filter D/P Isolation	2	I	1
CH-830	Nitrogen Supply to EDT Isolation	3	I	1
CH-831	Nitrogen Supply Pressure Control	3	I	1
CH-833	Seal Injection Test Connection Isolation	2	I	1
CH-834	Seal Injection Test Connection Isolation	2	I	1
CH-835	Seal Injection Check	2	I	1
CH-836	Seal Injection Isolation	2	I	1
CH-839	Seal Injection Isolation	2	I	1
CH-843	RHTX Vent Isolation	2	I	1
CH-844	Seal Injection Filter Vent	2	I	1
CH-845	Seal Injection Filter Vent	2	I	1
CH-848	Seal Injection Test Connection Isolation	1	I	1
CH-849	Seal Injection Test Connection Isolation	1	I	1
CH-853	Letdown Line Test Connection Isolation	1	I	1
CH-854	Charging Line Test Connection Isolation	2	I	1
CH-855	Letdown Line Test Connection Isolation	2	I	1
CH-856	BAMP Suction Line Test Connection Isolation	3	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 12 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
CH-858	RSSH Line to EDT Check	3	I	1
CH-859	Seal Injection Test Connection Isolation	1	I	1
CH-860	Seal Injection Test Connection Isolation	1	I	1
CH-861	RSSH to EDT Isolation	3	I	1
CH-862	RMWT Supply to RDT Isolation	3	I	1
CH-863	Chemical Addiition Isolation	2	I	1
CH-865	Seal Injection Relief to EDT	2	I	1
CH-866	Seal Injection Check	1	I	1
CH-867	Seal Injection Check	1	I	1
CH-868	Seal Injection Check	1	I	1
CH-869	Seal Injection Check	1	I	1
Safety Injection and Shutdown Cooling Systems (SIS) (SCS) (12)				
SI-104	CSP Suction Isolation	2	I	1
SI-105	CSP Suction Isolation	2	I	1
SI-140	Sump Suction Thermal Relief	2	I	1
SI-141	PCPS Suction Thermal Relief	2	I	1
SI-150	PCPS Suction Thermal Relief	2	I	1
SI-151	Sump Suction Thermal Relief	2	I	1
SI-157	CSP Suction Check	2	I	1
SI-158	CSP Suction Check	2	I	1
SI-161	PCPS Discharge Thermal Relief	2	I	1
SI-162	PCPS Discharge Thermal Relief	2	I	1
SI-170	SDCHX Vent	2	I	1
SI-172	SDCHX Drain	2	I	1
SI-174	CS Flow Inst Isolation	2	I	1
SI-175	CS Flow Inst Isolation	2	I	1
SI-176	CS Flow Inst Isolation	2	I	1
SI-177	CS Flow Inst Isolation	2	I	1
SI-180	SDCHX Vent	2	I	1
SI-182	SDCHX Drain	2	I	1
SI-184	LPSI-CSP Interconnection	2	I	1
SI-185	LPSI-CSP Interconnection	2	I	1
SI-191	CS Header Relief	2	I	1
SI-192	PCPS Discharge Thermal Relief	2	I	1
SI-193	PCPS Discharge Thermal Relief	2	I	1
SI-194	CS Header Relief	2	I	1
SI-200	LPSI Suction Check	2	I	1
SI-201	LPSI Suction Check	2	I	1
SI-202	Sample Line Isolation	2	I	1
SI-203	Sample Line Isolation	2	I	1

TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 13 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
SI-204	PCPS Suction Isolation	2	I	1
SI-205	Sump Suction Check	2	I	1
SI-206	Sump Suction Check	2	I	1
SI-207	Sump Suction Test	2	I	1
SI-208	Sump Suction Test	2	I	1
SI-218	HPSI Orifice Bypass	2	I	1
SI-219	HPSI Orifice Bypass	2	I	1
SI-256	PCPS Suction Isolation	2	I	1
SI-257	PCPS Sample Isolation	2	I	1
SI-260	SDCHX Vent Isolation	2	I	1
SI-262	SDCHX Drain Isolation	2	I	1
SI-264	SDCHX Vent Isolation	2	I	1
SI-266	SDCHX Drain Isolation	2	I	1
SI-268	PCPS Sample Isolation	2	I	1
SI-285	RWT Recirc Line Relief	2	I	1
SI-286	RWT Recirc Line Relief	2	I	1
SI-287	SDCHX Bypass Relief	2	I	1
SI-288	RWT Return Relief	2	I	1
SI-289	SDCHX Bypass Relief	2	I	1
SI-298	RWT Line Isolation	2	I	1
SI-306	SCS Bypass Flow Control	2	I	1
SI-307	SCS Bypass Flow Control	2	I	1
SI-400	RWT Return Line Isolation	2	I	1
SI-402	HPSI Suction Isolation	2	I	1
SI-404	HPSI Discharge Check	2	I	1
SI-405	HPSI Discharge Check	2	I	1
SI-407	RWT Return Line Relief	3	I	1
SI-408	Pressure Gage Isolation	2	I	1
SI-409	HP Header Relief	2	I	1
SI-416	Pressure Gage Isolation	2	I	1
SI-417	HPSI Header Relief	2	I	1
SI-418	Shutdown Purif. Suction Isolation	2	I	1
SI-419	Shutdown Purif. Suction Isolation	2	I	1
SI-420	Shutdown Purif. Isolation	2	I	1
SI-421	Shutdown Purif. Isolation	2	I	1
SI-424	HPSI Mini-flow Check	2	I	1
SI-426	HPSI Mini-flow Check	2	I	1
SI-427	HPSI Discharge SS Isolation	2	I	1
SI-429	Shutdown Cooling Line SS Isolation	2	I	1
SI-433	LPSI Discharge Pressure Ind. Iso.	2	I	1
SI-434	LPSI Discharge Check	2	I	1
SI-435	LPSI Discharge Isolation	2	I	1
SI-436	LPSI Discharge Isolation	2	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 14 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class	
SI-437	LPSI Flow Inst. Isolation	2	I	1	
SI-438	LPSI Flow Inst. Isolation	2	I	1	
SI-439	LPSI Discharge Relief to EDT	2	I	1	
SI-440	LPSI Flow Inst. Isolation	2	I	1	
SI-441	LPSI Flow Inst. Isolation	2	I	1	
SI-442	PCPS Suction Isolation	2	I	1	
SI-443	PCPS Suction Isolation	2	I	1	
SI-445	LPSI Suction SS Isolation	2	I	1	
SI-446	LPSI Discharge Check	2	I	1	
SI-447	LPSI Discharge Check	2	I	1	
SI-448	LPSI Mini-flow Check	2	I	1	
SI-449	LPSI Discharge Relief to EDT	2	I	1	
SI-450	LPSI Discharge PCPS Isolation	2	I	1	
SI-451	LPSI Mini-flow Check	2	I	1	
SI-454	LPSI Discharge PCPS Isolation	2	I	1	
SI-455	LPSI Discharge PCPS Isolation	2	I	1	
SI-458	LPSI Discharge PCPS Isolation	2	I	1	
SI-459	RWT Return Line Isolation	2	I	1	
SI-460	RWT Return Line Isolation	2	I	1	
SI-461	SIT to EDT Isolation	3	I	1	7
SI-462	SIT Local Sample Isolation	3	I	1	
SI-463	SIT Isolation	2	I	1	
SI-464	RWT REturn Line Isolation	2	I	1	
SI-465	RWT REturn Line SS Isolation	2	I	1	
SI-470	HPSI Suction Isolation	2	I	1	
SI-473	SIT Relief to RDT	2	I	1	
SI-474	SIT Relief to RDT	2	I	1	
SI-476	HPSI Discharge Isolation	2	I	1	
SI-478	HPSI Discharge Isolation	2	I	1	
SI-482	CSP Discharge Pressure Ind. Iso.	2	I	1	
SI-483	CSP Discharge Pressure Ind. Iso.	2	I	1	
SI-484	CSP Discharge Check	2	I	1	
SI-485	CSP Discharge Check	2	I	1	
SI-486	CSP Mini-flow Check	2	I	1	
SI-487	CSP Mini-flow Check	2	I	1	
SI-508	Charging Pump Isolation	2	I	1	
SI-509	Charging Pump Isolation	2	I	1	
SI-550	LPSI Suction Test Isolation	2	I	1	
SI-551	CSP Suction Test Isolation	2	I	1	
SI-552	HPSI Suction Test Isolation	2	I	1	
SI-553	HPSI Suction Test Isolation	2	I	1	
SI-554	CSP Suction Test Isolation	2	I	1	
SI-555	LPSI Suction Test Isolation	2	I	1	
SI-604	HPSI Hot Leg Injection Isolation	2	I	1	
SI-609	HPSI Hot Leg Injection Isolation	2	I	1	

TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 15 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
SI-657	SDCHX Discharge Throttle	2	I	1
SI-658	SDCHX Discharge Throttle	2	I	1
SI-659	Mini-flow to RWT Isolation	2	I	1
SI-660	Mini-flow to RWT Isolation	2	I	1
SI-661	RDT Isolation	2	I	1
SI-664	CSP Mini-flow Isolation	2	I	1
SI-665	CSP Mini-flow Isolation	2	I	1
SI-666	HPSI Mini-flow Isolation	2	I	1
SI-667	HPSI Mini-flow Isolation	2	I	1
SI-668	LPSI Mini-flow Isolation	2	I	1
SI-669	LPSI Mini-flow Isolation	2	I	1
SI-671	CSS Isolation	2	I	1
SI-672	CSS Isolation	2	I	1
SI-673	Containment Sump Isolation	2	I	1
SI-674	Containment Sump Isolation	2	I	1
SI-675	Containment Sump Isolation	2	I	1
SI-676	Containment Sump Isolation	2	I	1
SI-678	CSP Flow Control	2	I	1
SI-679	CSP Flow Control	2	I	1
SI-682	SIT Fill Line Isolation	2	I	1
SI-683	LPSI Pump Suction Isolation	2	I	1
SI-684	CSP Discharge Isolation	2	I	1
SI-685	LPSI Disch. SDCHX Intake Cross Connect Line Isolation	2	I	1
SI-686	SDCHX Disch. LPSI Header Cross Connect Line Isolation	2	I	1
SI-687	SDCHX Disch. Isolation to CSS Header	2	I	1
SI-688	SDCHX Spray Bypass	2	I	1
SI-689	CSP Discharge Isolation	2	I	1
SI-692	LPSI Suction Isolation	2	I	1
SI-693	SDCHX Spray Bypass	2	I	1
SI-694	LPSI Disch. SDCHX Intake Cross Connect Line Isolation	2	I	1
SI-695	SDCHX Disch. Isolation to CSS Header	2	I	1
SI-696	SDCHX Disch. LPSI Header Cross Connect Line Isolation	2	I	1
SI-698	HPSIP Orifice Bypass	2	I	1
SI-699	HPSIP Orifice Bypass	2	I	1
SI-113	HP Header Check	1	I	1
SI-114	LP Header Check	1	I	1
SI-115	HP Header Flow Ind. Isolation	2	I	1
SI-116	HP Header Flow Ind. Isolation	2	I	1
SI-117	SIT Pressure Ind. Isolation	2	I	1
SI-119	SIT Pressure Ind. Isolation	2	I	1

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TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 16 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
SI-123	HP Header Check	1	I	1
SI-124	LP Header Check	1	I	1
SI-125	HP Header Flow Ind. Isolation	2	I	1
SI-126	HP Header Flow Ind. Isolation	2	I	1
SI-127	SIT Pressure Ind. Isolation	2	I	1
SI-129	SIT Pressure Ind. Isolation	2	I	1
SI-133	HP Header Check	1	I	1
SI-134	LP Header Check	1	I	1
SI-135	HP Header Flow Ind. Isolation	2	I	1
SI-136	HP Header Flow Ind. Isolation	2	I	1
SI-137	SIT Pressure Ind. Isolation	2	I	1
SI-139	SIT Pressure Ind. Isolation	2	I	1
SI-143	HP Header Check	1	I	1
SI-144	LP Header Check	1	I	1
SI-145	HP Header Flow Ind. Isolation	2	I	1
SI-146	HP Header Flow Ind. Isolation	2	I	1
SI-147	SIT Pressure Ind. Isolation	2	I	1
SI-149	SIT Pressure Ind. Isolation	2	I	1
SI-164	CS Header Check	2	I	1
SI-165	CS Header Check	2	I	1
SI-166	HP Header Relief to EDT	2	I	1
SI-169	HP Header Relief to EDT	2	I	1
SI-179	HP Header Relief to Cont. Sump	2	I	1
SI-189	HP Header Relief to Cont. Sump	2	I	1
SI-210	SIT Fill & Drain Isolation	2	I	1
SI-211	SIT Relief to Atmosphere	2	I	1
SI-212	SIT Level Ind. Isolation	2	I	1
SI-213	SIT Level Ind. Isolation	2	I	1
SI-214	SIT Local Sample Isolation	2	I	1
SI-215	SIT Check	1	I	1
SI-216	Injection Line Press. Ind. Iso.	1	I	1
SI-217	Safety Inj. Line Check	1	I	1
SI-220	SIT Fill & Drain Isolation	2	I	1
SI-221	SIT Relief to Atmosphere	2	I	1
SI-222	SIT Level Ind. Injection	2	I	1
SI-223	SIT Level Ind. Injection	2	I	1
SI-224	SIT Local Sample Isolation	2	I	1
SI-225	SIT Check	1	I	1
SI-226	Inj. Line Pressure Ind. Iso.	1	I	1
SI-227	Safety Inj. Line Check	1	I	1
SI-228	SIT Level Ind. Isolation	2	I	1
SI-229	SIT Level Ind. Isolation	2	I	1
SI-230	SIT Fill & Drain Isolation	2	I	1
SI-231	SIT Relief to Atmosphere	2	I	1

TABLE 3.2-1

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 17 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class	
SI-232	SIT Level Ind. Isolation	2	I	1	
SI-233	SIT Level Ind. Isolation	2		1	
SI-234	SIT Local Sample Isolation	2	I	1	
SI-235	SIT Check	1	I	1	
SI-236	Inj. Line Pressure Ind. Iso.	1	I	1	
SI-237	Safety Inj. Line Check	1	I	1	
SI-238	SIT Level Ind. Isolation	2	I	1	
SI-239	SIT Level Ind. Isolation	2	I	1	
SI-240	SIT Fill & Drain Isolation	2	I	1	
SI-241	SIT Relief to Atmosphere	2	I	1	
SI-242	SIT Level Ind. Isolation	2	I	1	
SI-243	SIT Level Ind. Isolation	2	I	1	
SI-244	SIT Local Sample Isolation	2	I	1	
SI-245	SIT Check	1	I	1	
SI-246	Inj. Line Pressure Ind. Iso.	1	I	1	
SI-247	Safety Injection Line Check	1	I	1	
SI-248	SIT Level Ind. Isolation	2	I	1	
SI-249	SIT Level Ind. Isolation	2	I	1	
SI-258	SIT Level Ind. Isolation	2	I	1	
SI-259	SIT Level Ind. Isolation	2	I	1	7
SI-321	HP Hot Leg Injection Isolation	2	I	1	
SI-322	Hot Leg Check Leakage Valve	1	I	1	
SI-331	HP Hot Leg Injection Isolation	2	I	1	
SI-332	Hot Leg Check Leakage Valve	1	I	1	
SI-468	HP Header Relief to EDT	2	I	1	
SI-469	SDC Line Relief to RDT	1	I	1	
SI-500	CSS Test Line Isolation	2	I	1	
SI-501	CSS Test Line Isolation	2	I	1	
SI-506	HP Header Pressure Ind. Iso.	1	I	1	
SI-510	CSS Test Line Isolation	2	I	1	
SI-511	CSS Test Line Isolation	2	I	1	
SI-516	HP Header Pressure Ind. Iso.	1	I	1	
SI-522	HP Header Check	1	I	1	
SI-523	HP Header Check	1	I	1	
SI-525	HP Header Flow Ind. Isolation	2	I	1	
SI-526	HP Header Flow Ind. Isolation	2	I	1	
SI-532	HP Header Check	1	I	1	
SI-533	HP Header Check	1	I	1	
SI-535	HP Header Flow Ind. Isolation	2	I	1	
SI-536	HP Header Flow Ind. Isolation	2	I	1	
SI-605	SIT Atmospheric Vent Isolation	2	I	1	
SI-606	SIT Atmospheric Vent Isolation	2	I	1	
SI-607	SIT ATmospheric Vent Isolation	2	I	1	
SI-608	SIT Atmospheric Vent Isolation	2	I	1	

SAFETY CLASS 1, 2 & 3 VALVES

(Sheet 18 of 20)

Component Identification	Location/Description	Safety Class	Seismic Category	Quality Class
SI-611	SIT Fill & Drain Isolation	2	I	1
SI-612	SIT N_2 Supply Isolation	2	I	1
SI-613	SIT Atmospheric Vent Isolation	2	I	1
SI-614	SIT Isolation	1	I	1
SI-615	LPSI Header Isolation	2	I	1
SI-616	HPSI Header Isolation	2	I	1
SI-617	HPSI Header Isolation	2	I	1
SI-618	Check Valve Leakage Line Iso.	1	I	1
SI-619	SIT N_2 Supply Isolation	2	I	1
SI-621	SIT Fill & Drain Isolation	2	I	1
SI-622	SIT N_2 Supply Isolation	2	I	1
SI-623	SIT Atmospheric Vent Isolation	2	I	1
SI-624	SIT Isolation	1	I	1
SI-625	LPSI Header Isolation	2	I	1
SI-626	HPSI Header Isolation	2	I	1
SI-627	HPSI Header Isolation	2	I	1
SI-628	Check Valve Leakage Line Iso.	1	I	1
SI-629	SIT N_2 Supply Isolation	2	I	1
SI-631	SIT Fill & Drain Isolation	2	I	1
SI-632	SIT N_2 Supply Isolation	2	I	1
SI-633	SIT Atmospheric Vent Isolation	2	I	1
SI-634	SIT Isolation	1	I	1
SI-635	LPSI Header Isolation	2	I	1
SI-636	HPSI Header Isolation	2	I	1
SI-637	HPSI Header Isolation	2	I	1
SI-638	Check Valve Leakage Line Iso.	1	I	1
SI-639	SIT N_2 Supply Isolation	2	I	1
SI-641	SIT Fill & Drain Isolation	2	I	1
SI-642	SIT N_2 Supply Isolation	2	I	1
SI-643	SIT Atmos. Vent Isolation	2	I	1
SI-644	SIT Isolation	1	I	1
SI-645	LPSI Header Isolation	2	I	1
SI-646	HPSI Header Isolation	2	I	1
SI-647	HPSI Header Isolation	2	I	1
SI-648	Check Valve Leakage Line Iso.	1	I	1
SI-649	SIT N_2 Supply Isolation	2	I	1
SI-651	SCS Suction Line Isolation	1	I	1
SI-652	SCS Suction Line Isolation	1	I	1
SI-653	SCS Suction Line Isolation	1	I	1
SI-654	SCS Suction Line Isolation	1	I	1
SI-655	SCS Suction Line Isolation	2	I	1
SI-656	SCS Suction Line Isolation	2	I	1
SI-690	SCS Warmup Line Isolation	2	I	1
SI-691	SCS Warmup Line Isolation	2	I	1

TABLE 3.2-1

(Sheet 19 of 20)

NOTES:

(1) Two safety classes are used for heat exchangers to distinguish primary and secondary sides where they are different.

(2) Only those core support structures necessary to support and restrain the core and to maintain safe shutdown capability are classified as Seismic Category I.

(3) Loss of cooling water and/or seal water service to the reactor coolant pumps (RCP's) may require stopping the pumps. However, the continuous operation of the pumps is not required during or following an SSE. The auxiliaries are therefore not necessarily Safety Class 3 or Seismic Category I. Provision for cooling water to the pump bearing oil cooler and pump motor air cooler will not comply with the requirements of Regulatory Guide 1.29 (see Subsection 5.4.1.3). 6

(4) Only those structural portions of the RCP's which are necessary to assure the integrity of the reactor coolant pressure boundary are Safety Class 1.

(5) Safety class of piping within the reactor coolant pressure boundary (as defined in 10CFR50) is selected in accordance with the ANSI N18.2 criteria identified in Subsection 3.2.2. For purposes of CESSAR, 6
Safety Class 1, 2, 3, 4 of ANSI-N18.2 are equivalent to Quality Groups A, B, C, D of Regulatory Guide 1.26.

(6) Flow restricting orifices are provided in the nozzles for the RCS sampling lines, the pressurizer level and pressure instruments, the RCP differential pressure instrument lines, the common SI header pressure instrument lines, the RCP seal pressure instrument lines, the charging line differential pressure instrument line, and the SI hot leg injection pressure instrument lines, to limit flow in the event of a break downstream of a nozzle. The orifice size, 7/32 inch diameter x 1 inch long, precludes exceeding fuel design limits while utilizing minimum makeup rates. This permits an orderly shutdown in the event of a downstream break in accordance with General Design Criterion 33 (see Section 3.1.29). A reduction may, therefore, be made in the safety classification of lines downstream of the orifice.

(7) The pressure boundary housing for this component is a reactor vessel appurtenance and is Safety Class 1 and Seismic Category I, as 6
described in 3.9.4.3.

(8) Core Support structures are designed to the criteria described in 3.9.5.4.

(9) CEA and fuel assemblies are designed to the criteria described in 4.2.

(10) Reactor coolant pump auxiliary components required for lubrication 7
and cooling of pump seals and thrust bearings are Quality Class 2.

TABLE 3.2-1 (Cont'd)

(Sheet 20 of 20)

(11) Safety-related instrumentation and controls (I & C) described in Sections 7.1 through 7.6 of the FSAR plus safety-related I & C for safety-related fluid systems will be subject to the pertinent requirements of the Quality Assurance Program as given in Chapter 17. 7

(12) All containment isolation values (and their operators) within C-E's scope of supply - including manual valves, check valves, and relief valves which also serve as isolation valves will be subject to the pertinent requirements of the Quality Assurance Program as given in Chapter 17.

TABLE 3.5-1

(Sheet 1 of 2)

KINETIC ENERGY OF POTENTIAL MISSILES

Item[1]	Initial Kinetic Energy (ft-lb)	Weight (lb)	Impact Section
1. Reactor Vessel			
Closure Head Nut	1,706	100	Annular Ring, OD = 10-2/16" ID = 6.9"
Closure Heat Nut and Stud	5,226	577	Solid Circle, 6-3/4" Diameter
Control Rod Drive Assembly	57,600	1100	1.875" dia. solid circle within a concentric 7" dia. by .109" wall shroud 7
2. Steam Generator			
Primary Manway Stud and Nut	71	4-1/4	Solid Circle, 1-1/2" Diameter
Secondary Handhole Stud and Nut	7	1.15	Solid Circle, 3/4" Diameter
Secondary Manway Stud	7	3.36	Solid Circle, 1-1/4" Diameter
3. Pressurizer			
Safety Valve With Flange	89,200	550	Solid Circle, 2" Diameter
Safety Valve Flange Bolt	15	3.7	Solid Circle, 1-14" Diameter
Lower Temperature Element	288	3	Edge of Solid Disk 2-3/4" Diameter and 1/2" Thick
Manway Stud and Nut	71	4-1/4	Solid Circle, 1-1/2" Diameter
4. Main Coolant Pump and Piping			
Temperature Nozzle with RTD Assembly	1,095	8	Edge of Solid Disk 2-3/4" Diameter and 1/2" Thick
Surge and Spray Piping Thermal Wells with RTD Assembly	277	3-3/4	Edge of Solid Disc 2-3/4" Diameter and 1/2" Thick

(1) All materials are steel.

(continued)

TABLE 3.5-1 (Cont'd.) (Sheet 2 of 2)

KINETIC ENERGY OF POTENTIAL MISSILES

Item	Initial Kinetic Energy (ft-lb)	Weight (lb)	Impact Section
Main Coolant Pump Thermal Well with RTD	1,095	8	Edge of Solid Disk 2-3/4" Diameter and 1/2" Thick

5

For Class 2 and 3 pressure retaining parts of active pumps, the primary membrane stress is limited to the allowable stress value S, and primary membrane plus bending stress is limited to 1.5S for each of the loading combinations associated with the upset, emergency and faulted plant operating conditions.

The stress criteria of the ASME Code, Section III are applied in the design of component supports to the same Code Class as the pressure boundary involved within the jurisdictional boundaries defined in the code for the loading conditions defined above. Those steel support structures which are considered to be an extension of the building structure, but supplied with the pump assembly (i.e. bedplates), are designed to the stress criteria of the AISC Manual of Steel Construction.

In addition, the Safeguard Pump assemblies are required to be capable of withstanding the following thermal transients:

a) HPSI and LPSI, suction temperature increases from 40°F to 300°F in 10 seconds. After each temperature change the end point is assumed to hold until temperature equilibrium is attained. Temperature returns to 40°F in several days. This transient would be applied a minimum of 10 times during the design life of the pump.

b) LPSI shutdown cooling operation applied for 500 cycles as follows:

   1. Suction temperature increases from 70°F to 350°F in about 1 minute.

   2. Suction temperature descrease from 350°F to 70°F in several hours.

3.9.3.2 Pump and Valve Operability Assurance

3.9.3.2.1 Non-NSSS Active ASME Code Class 2 and 3 Pumps and Class 1, 2, and 3 Valves

See Applicant's SAR.

3.9.3.2.2 NSSS Active ASME Code Class 2 and 3 Pumps and Class 1, 2 and 3 Valves

3.9.3.2.2.1 Operability Assurance Program

Active pumps and valves are defined in Regulatory Guide 1.48 as components that require a mechanical motion in performing a safety function. The operability (i.e., performance of this mechanical motion) of active components during and after exposure to design bases events is confirmed per the recommendations of Regulatory Guide 1.48 by:

A. Designing each component to be capable of performing all safety functions during and following design bases events. The design specification includes applicable loading combinations, and conservative design

limits for active components, consistent with the recommendations of Regulatory Guide 1.48. The specification requires that the manufacturer demonstrate operability by analysis or test (footnotes 6 and 11 of Regulatory Guide 1.48). The results are independently reviewed by the 7
NSSS Supplier considering the effects of postulated failure modes on operability.

B. Analysis and/or test demonstrating the operability of each design under the most severe postulated loadings which are combined in a manner consistent with the recommendations of Regulatory Guide 1.48. Methods/results of operability demonstration programs are detailed in 7
Sections 3.9.3.2.2.2 and 3.9.3.2.2.3.

C. Inspection of each component to assure compliance of critical parameters with specifications and drawings. This inspection confirms that specified materials and processes were used, that wall thicknesses met code requirements, and that fits and finishes met the manufacturer's requirements based on design clearance requirements. 7

D. Shop testing of each component to verify "as built" conditions as 7
defined in Sections 3.9.3.2.2.2 and 3.9.3.2.2.3.

E. Startup and periodic inservice testing in accordance with ASME Boiler and Pressure Vessel Code, Section XI to demonstrate that the active 7
pumps and valves are in operating condition throughout the life of the plant.

NSSS active pumps are listed below with a brief description of active safety function of each. NSSS active valves are listed in Table 3.9.3-3.

Active Components	Active Safety Function
High-pressure safety injection pumps	Operate at flowrates to runout
Low-pressure safety injection pumps	Operate at flowrates to runout
Charging pumps	Operate

3.9.3.2.2.2 Operability Assurance Program Results for Active Pumps

3.9.3.2.2.2.1 High- and Low-Pressure Safety Injection Pumps. Operability of the high- and low-pressure safety injection (HPSI and LPSI) pumps under faulted conditions has been demonstrated by analyses of the assemblies and by analyses and tests of the motors in accordance with the recommendations of Regulatory Guide 1.48.

Amendment No. 7
March 31, 1982

For the HPSI pumps, the manufacturer has shown that allowable stresses are not exceeded, that clearances are acceptable and that shaft and pedestal bolt deflections do not cause stresses to exceed the normal values indicated by past experience for other pumps of the same type.

For the LPSI pumps, the manufacturer has shown that allowable stresses are 7
not exceeded and that clearances remain acceptable under faulted loadings.

Where necessary, lumped mass models are used with the computer programs to determine the natural frequencies and displacements. The models are conservative (i.e., simplifications tend to make them more flexible).

Operability was demonstrated under the following loads;

	HPSI Pump	LPSI Pump
Horizontal seismic, g's	1.1	1.1
Vertical seismic, g's	1.1	1.1
Design pressure, $lb/in.^2$	2050	2050
Suction nozzle max, resultant force, lb	4000	4000
Suction nozzle max, resultant moment, ft-lb	12000	50000
Discharge nozzle max, resultant force, lb	2500	6500
Discharge nozzle max, resultant moment, ft-lb	2500	16000

To verify "as built" conditions the HPSI and LPSI pumps were hydrostatically
tested in accordance with the ASME Boiler and Pressure Vessel Code, Section
III to confirm acceptability of structural integrity of pressure retaining
parts, tested for seal leakage, and tested for performance and NPSH charac-
teristics in accordance with the Hydraulic Institute Standard to verify
operation within specified parameters. The motors were built as Class IE 7
and were tested in accordance with IEEE Standard 112A-1964 to verify opera-
tion within specified parameters. Additionally, the motors were qualified
to IEEE Standard 323-1974 and IEEE Standard 344-1975 to assure operability
during and following design basis events.

3.9.3.2.2.2.2 Charging Pumps. The charging pumps have a relatively complex geometry, which is difficult to analyze. Therefore, a simplified analysis and type test were used to confirm the charging pump operability during and following a DBE.

A sinusoidal test with simultaneous 1.5 g horizontal and vertical accelera-
tions was conducted. The test on the pump assembly, including its supports, 7
showed no significant natural frequencies in the 1 to 33 Hz range. The
fundamental linear natural frequency of the rotating parts of the pump was
shown to be greater than 73 Hz. The base of the test pump had a fundamental
natural frequency above 33 Hz. Therefore, the System 80 pumps are rigid to
postulated seismic input.

The test pump was vibration tested with 2410 psig internal pressure, 1825-
pound axial force and 610 ft-lb moment on the suction nozzle, and 1650-
pound axial force and 550 ft-lb moment on the discharge nozzle. Simultane-
ous 1.5g accelerations is applied to the horizontal and vertical axes by
driving the assembly in a 45 degree plane. The test was run with the
horizontal input parallel to the motor axis. It was repeated with the 7
horizontal input directed 90, 180, and then 270 degrees from the direction
for the first test.

The pump was subjected to two sinusoidal sweeps at 1/2 octave per minute in
each direction with 1.0g peak accelerations, limited to 12-inch double
amplitude, from 1 to 35 Hz. One of the sweeps in each direction was with
the pump operating and one with the pump idle. The test shows that no
resonances applicable to operability are in the range of concern, and the
unit is therefore rigid to the postulated seismic input. The assembly,
both operating and nonoperating, was exposed to a 1.5g horizontal and
vertical 30-second sinusoidal dwell at 2.5, 10, 12.25, 20, 23.8 and 33 Hz.
The pump was shown to operate normally, and no evidence of damage or deteri- 7
oration to critical parts exists. The 1.5g horizontal and vertical accelera-
tions exceed the applicable response spectra. The successful test on these
pumps demonstrates that the System 80 pumps operate during and following
the postulated seismic event.

To verify "as built" conditions the charging pumps were hydrostatically
tested in accordance with the ASME Boiler and Pressure Vessel Code, Section
III to confirm acceptability of structural integrity of pressure retaining
parts, tested for seal leakage, and tested for performance and NPSH charac-
teristics in accordance with the Hydraulic Institute Standards to verify
operation within specified parameters. The motors were built as Class IE 7
and were tested in accordance with IEEE Standard 112A-1964 to verify opera-
tion within specified parameters. Additionally, the motors were qualified
to IEEE Standard 323-1974 and IEEE Standard 344-1975 to assure operability
during and following design basis events.

3.9.3.2.2.3 Operability Assurance Program for Active Valves

Safety related active valves must perform their mechanical motion in times
of an accident. The qualification program assures that these valves will
operate during a seismic event. Qualification tests and/or analyses are
conducted for all active valves.

7

Class 1, 2 and 3 valves are designed/analyzed according to the rules of the
ASME Boiler and Pressure Vessel Code, Section III, Section NB-3500, NC-
3500, and ND-3500 respectively.

Procurement specifications for safety related active valves stipulate that vendor shall submit either detailed calculations and/or test data to demonstrate operability when subjected to the specification loading and stress criteria (normal through faulted conditions). The decision to accept actual or prototype test data, or analysis for operability assurance is made during the normal design and procurement process. The decision to test is based on (1) whether the component is amenable to analysis, (2) whether proven analytical methods are available, and (3) whether applicable prototype test data is available. If analysis or prototype test data is not sufficient, testing is conducted to qualify the component or to verify the analytical technique.

Where appropriate, valve stem deflection calculations are performed to determine deflections due to short term seismic and other applicable loadings. Deflections so determined are compared to allowable clearances. It must be noted that seismic events are of short duration; thus, contact (if it occurs) does not demonstrate that operability is adversely affected. Cases where contact occurs are reviewed on a case by case basis to determine acceptability.

The operability of active Code Class 1, 2 and 3 components is assured through an extensive program of design verification, qualification testing and thorough surveillance of the manufacturing, assembly and shop testing of each active component. Each aspect of the design related to pressure boundary integrity and operability is either tested or verified by calculations. Procedures for testing are developed by component manufacturers and reviewed and approved by the NSSS supplier before the tests are conducted. The design analyses of the component take into consideration environmental conditions including loadings developed from seismic, operational effects, and pipe loads. Where necessary and feasible, the conclusions of these analyses are confirmed by test. 7

On all active valves, an analysis of the extended structure is also performed for static equivalent seismic SSE loads supplied at the center of gravity of the extended structure. The maximum stress limits allowed in these analyses show that structural integrity is within the limits developed and accepted by the ASME Code.

The safety-related valves are subjected to a series of tests prior to service and during the plant life. Prior to installation, the following tests are performed; shell hydrostatic test to ASME Sections III requirements, backseat and main seat leakage tests, disc hydrostatic test, functional tests to verify that the valve will open and close within the specified time limits, operability qualification of motor operators for the environmental conditions over the installed life (i.e., aging, radiation, accident environment simulation, etc.) according to IEEE 382. Cold hydro qualification tests, hot functional qualification tests, periodic inservice inspections, and periodic inservices operation are performed insitu to verify and assure the functional ability of the valves. These tests ensure the reliability of the valve for the design life of the plant. The valves are designed using either stress analyses or the pressure containing minimum wall thickness requirements.

All the active valves shall be designed to ave a first natural frequency which is greater than 33 Hz. This is shown by suitable test or analysis.

The above outlines in general the methods used to assure valve operability. Each vendor's specific program is described in the plant specific FSAR.

In addition to the above, the following specific operability assurances are provided for the various type valves:

3.9.3.2.2.3.1 Pneumatically Operated Valves

Pneumatic operated valves are furnished by several vendors in CE System 80 Nuclear Power Plants. Methods of operability demonstration are discussed in general but will be discussed in detail in the plant specific FSAR subject to the vendor(s) utilized. Spring actuation of the valve is the required active safety function. Loss of electric power or supply air will result in venting of the actuator and return of the valve to the safe position. Each vendor provides their own method to demonstrate valve operability. The operability for these valves is demonstrated by analysis, test or by a combination of analysis and test. The vendor considers concurrent loads including seismic, design pressure and pipe loads.

The three-way solenoid valve was qualified by test to IEEE-382-1972, IEEE-323-1974 and IEEE-344-1975. Testing included thermal aging, radiation aging, wear aging, vibration endurance, seismic event simulation, and loss of coolant accident. All test results provided satisfactory evidence of air solenoid valve operability. 7

Limit switches, used to determine valve position, were qualified by testing to IEEE-323-1974, IEEE-344-1975 and IEEE-382-1972. Switches were successfully performance tested for aging simulation, wear aging, radiation exposure, seismic qualification, and design basis event environmental conditions. For valves outside of containment and utilizing EA-170 limit switches, the switches were seismically qualified to IEEE-344-1975 and were tested to sustain radiation dosages up to 2×10^8 rads.

3.9.3.2.2.3.2 Motor Operated Valves

Motor operated valves are qualified by analysis as a minimum as described above. The analysis for each valve assembly considers the effects of seismic loads, design pressure, and piping reaction forces to provide assurance of operability.

To provide full qualification of the motor operated valve actuator, environmental and seismic qualification tests were conducted to simulate the following conditions:

A. Inside Containment (LOCA)

B. Outside Containment

C. Seismic Qualification

D. Steam Line Break Accident

Mid-size valve actuators were subjected to complete environmental qualification consisting of inside containment and outside containment. Each qualification exposed the actuator to thermal and mechanical aging, radiation aging, seismic aging, environmental transient profile test, and steam line break. For the steam line break test an actuator was subjected to a very high superheated temperature to demonstrate that the electrical components of the actuator never exceeded the saturated temperature corresponding to the ambient pressure for the short duration of the test. This short term test proves the existing qualification envelopes the steam line break for superheated temperatures as high as 492°F for a few minutes.

The qualification of the mid-size valve actuator was used to generically qualify all sizes of mid-size valve actuator operators for the environmental test conditions in accordance with IEEE-382-1972. All sizes are constructed of the same materials with components designed to equivalent stress levels, and to the same clearances and tolerances with the only differnece being in physical size which varies corresponding to the differences in unit rating.

All the qualifications were conducted per IEEE 382-1972 and meet the requirements of IEEE 323-1974 and IEEE 344-1975 as they apply to valve motor actuators. Further, since the actuators performed satisfactorily without maintenance throughout the various qualifications, the valve actuators are fully qualified for use in CE Nuclear Power Generating Plants.

3.9.3.2.2.3.3 Pressurizer Safety Valves

Pressurizer Safety valves are 6 x 8 valves. Operability has been successfully demonstrated by a combination of dynamic testing and analysis or by static testing. Operability was successfully demonstrated with a 6g seismic load by one vendor or with a 7.1g seismic load by another vendor. Dynamic testing 7 has demonstrated that the natural frequency of both valves was greater than 33 Hz. A summary of the test programs follows:

A. Vendor A Safety Valves

1. Natural Frequency Demonstration

   Vibration input was in a single, horizontal direction. It was established by previous experience that the horizontal direction was more significant than the vertical direction, and that there was no material difference between teh various horizontal directions. The frequency of vibration was increased from 5 to 75 Hz at a rate of 1 octave per minute. Accelerometers were mounted on the valve assembly. The actual natural frequency under test conditions was 38 Hz.

2. Operability Demonstration

   A series of tests demonstrated that the valve would fully open and reseat during and after a seismic acceleration. Vibration input ranged from 3 to 6g and 10 to 33 Hz. The tests were

performed using saturated steam. In addition, analysis was used to establish the significance of nozzle loading. The results indicated that deformation was significantly less than the internal clearances. This loading was therefore neglected in the seismic operability tests.

B. <u>Vendor B Safety Valves</u>

1. <u>Natural Frequency Demonstration</u>

A resonance survey was performed along three orthogonal axes with one axis being the centerline of the outlet port. (Valve mounted on inlet port.) No resonant frequencies were detected in the range of 1-50 Hz on any axis.

2. <u>Operability Demonstration</u>

A series of tests demonstrated that the valve would fully open and reseat during and after applying the following loading combinations: Static seismic loads up to 7.1g were applied to the valve in the direction of least bending stiffness. In addition the maximum permissable piping loads were applied concurrently. The tests were performed using saturated steam. Valve operation was satisfactory.

C. <u>EPRI Testing of Safety Valves</u>

One manufacturer's valve was tested in the EPRI Test Program under
full pressure and full flow conditions. This testing has demonstrated
that stable valve operation under these conditions is dependent upon
the inlet pipe configuration, built up back pressure range and blow-
down setting. Prior to plant startup the inlet pipe configuration and 7
built up back pressure range for each specific plant will be examined
by CE and the applicable valve vendor. If necessary, the valves will
be adjusted to provide blowdown settings which will result in stable
valve operation. These blowdown settings will be recommended by the
vendor and approved by CE. These adjustments will be based on the
results obtained in the EPRI Test Program. Required adjustments to
the valve to assure operability will be documented in the plant spe-
cific FSAR.

3.9.3.2.2.3.4 <u>Check Valves</u>. The <u>check valves</u> are characteristically simple in design and their operation will not be affected by seismic accelerations or the maximum applied nozzle loads. The check valve design is compact and there are no extended structures or masses whose motion could cause distortions which could restrict operation of the valve. The nozzle loads due to maximum seismic excitation will not affect the functional ability of the valve since the valve disc is designed to be isolated from the casing wall. The clearance supplied by the design around the disc will prevent the disc from becoming bound or restricted due to any casing distrotions caused by nozzle load. Therefore, the design of these valves is

such that once the structural integrity of the valve is assured using standard design or analysis methods, the ability of the valve to operate is assured by the design features. In addition to these design considerations, the valve will also undergo, (1) stress analysis including the SSE loads, (2) in-shop hydrostatic tests, (3) in-shop seat leakage test, and (4) 7
periodic in-situ valve exercising and inspection to assure the functional ability of the valve.

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3.9.3.3 Design and Installation Details for Mounting of Pressure Relief Devices

See Applicant's SAR.

3.9.3.4 Component Supports

Supports for ASME Section III Code Class 1 components in the CESSAR scope are specified for design in accordance with the loads and loading combinations discussed in Section 3.9.3.1.

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In addition to the normal operating and seismic supports, component stops are employed to limit displacements for postulated pipe breaks. Where a component stop is designed solely to control movement following a postulated pipe break, only the design loading combination (d) of Section 3.9.3.1 is specified.

Component supports which are loaded during normal operation, seismic and following a pipe break are specified for design for loading combinations (a) through (d) of Section 3.9.3.1. Component stops which are loaded only following a pipe break are specified for design for loading combination (d). Design stress limits applied in evaluating loading combinations (a), (b), and (c) of Section 3.9.3.1 are consistent with the ASME Code, Section III. The design stress limits applied in evaluating loading combination (d) of Section 3.9.3.1 are in accordance with the ASME Ccde, Section III. Loads in compression members are limited to 2/3 of the critical buckling load.

For design criteria for restraints provided solely to control movement of postulated broken piping, see the Applicants SAR.

To insure that pipe restraints and component stops do function independently of the normal support system, the motions of the intact pipe due to all normal and upset plant conditions and vibratory motion of the SSE are calculated and used to specify a minimum clearance between the pipe and the restraint. Wherever possible, gaps between pipes and restraints are maximized to avoid possible contact during plant operation. Where a particular location requires minimizing a gap, special features are provided to permit adjustment of the gap size during hot functional testing in order to decrease the uncertainty in the calculated pipe motion in the vicinity of the restraint. See Applicants SAR for details of pipe restraint design.

TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 1 of 8) 7

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE	
SI 134	Safety Injection Sys. (Operate)	12	Swing Check	1	None	
SI 143	Safety Injection Sys. (Operate)	4	Swing Check	1	None	
SI 144	Safety Injection Sys. (Operate)	12	Swing Check	1	None	
SI 164	Safety Injection Sys. (Operate)	10	Swing Check	2	None	
SI 165	Safety Injection Sys. (Operate)	10	Swing Check	2	None	
SI 179	Shutdown Cooling Suction Relief	6 x 10	Relief	2	None	
SI 189	(Operate)	6 x 10	Relief	2	None	
SI 215	Safety Injection Sys. (Operate)	14	Swing Check	1	None	
SI 217	Safety Injection Sys. (Operate)	14	Swing Check	1	None	
SI 225	Safety Injection Sys. (Operate)	14	Swing Check	1	None	
SI 227	Safety Injection Sys. (Operate)	14	Swing Check	1	None	
SI 235	Safety Injection Sys. (Operate)	14	Swing Check	1	None	
SI 237	Safety Injection Sys. (Operate)	14	Swing Check	1	None	7
SI 245	Safety Injection Sys. (Operate)	14	Swing Check	1	None	
SI 247	Safety Injection Sys. (Operate)	14	Swing Check	1	None	
SI 321	Safety Injection Sys. (Operate)	3	Globe	2	Motor	
SI 322	Safety Injection Sys. (Close)	1	Globe	1	Pneumatic	
SI 331	Safety Injection Sys. (Operate)	3	Globe	2	Motor	
SI 332	Safety Injection Sys. (Close)	1	Globe	1	Pneumatic	
SI 522	Safety Injection Sys. (Operate)	3	Swing Check	1	None	
SI 523	Safety Injection Sys. (Operate)	3	Swing Check	1	None	
SI 532	Safety Injection Sys. (Operate)	3	Swing Check	1	None	
SI 533	Safety Injection Sys. (Operate)	3	Swing Check	1	None	

TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 2 of 8) 7

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 605	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 606	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 607	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 608	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 611	Safety Injection Tank Fill Valve (Close)	2	Globe	2	Pneumatic
SI 613	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 614	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor
SI 615	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor
SI 616	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 617	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 618	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 621	Safety Injection Tank Fill Valve (Close)	2	Globe	2	Pneumatic
SI 623	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid 7
SI 624	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor
SI 625	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor
SI 626	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 627	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 628	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 631	Safety Injection Tank Fill Valve (Close)	2	Globe	1	Pneumatic
SI 633	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 634	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor
SI 635	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor

TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 3 of 8) 7

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 636	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 637	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 638	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 641	Safety Injection Tank Fill Valve (Close)	2	Globe	2	Pneumatic
SI 643	Safety Injection Tank Vent (Operate)	1	Globe	2	Solenoid
SI 644	Safety Injection Tank Isolation (Operate)	14	Gate	1	Motor
SI 645	LPSI Header Isolation Valve (Operate)	12	Globe	2	Motor
SI 646	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 647	HPSI Header Valve (Operate)	2	Globe	2	Motor
SI 648	Leakage Return to RWT (Close)	1	Globe	1	Pneumatic
SI 651	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 652	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 653	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 654	Shutdown Cooling Suction (Operate)	16	Gate	1	Motor
SI 655	Shutdown Cooling Suction (Operate)	16	Gate	2	Motor
SI 656	Shutdown Cooling Suction (Operate)	16	Gate	2	Motor
SI 690	Safety Injection Sys. (Operate)	10	Globe	2	Motor
SI 691	Safety Injection Sys. (Operate)	10	Globe	2	Motor
SI 157	Safety Injection Sys. (Operate)	18	Swing Check	2	None
SI 158	Safety Injection Sys. (Operate)	18	Swing Check	2	None

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TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 4 of 8)

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VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 200	Safety Injection Sys. (Operate)	20	Swing Check	2	None
SI 201	Safety Injection Sys. (Operate)	20	Swing Check	2	None
SI 205	Safety Injection Sys. (Operate)	24	Swing Check	2	None
SI 206	Safety Injection Sys. (Operate)	24	Swing Check	2	None
SI 306	Safety Injection Sys. (Operate)	10	Globe	2	Motor
SI 307	Shutdown Cooling Sys. (Operate)	10	Globe	2	Motor
SI 404	Safety Injection Sys. (Operate)	4	Swing Check	2	None
SI 405	Safety Injection Sys. (Operate)	4	Swing Check	2	None
SI 424	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 426	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 434	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 446	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 448	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 451	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 484	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 485	Safety Injection Sys. (Operate)	10	Swing Check	2	None
SI 486	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 487	Safety Injection Sys. (Operate)	2	Lift Check	2	None
SI 604	HPSI Hot Leg Isolation (Operate)	3	Gate	2	Motor
SI 609	HPSI Hot Leg Isolation (Operate)	3	Gate	2	Motor
SI 657	Shutdown Cooling (Operate)	16	Butterfly	2	Motor
SI 658	Shutdown Cooling (Operate)	16	Butterfly	2	Motor

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TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 5 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
SI 659	Mini Flow Isolation (Operate)	4	Globe	2	Solenoid
SI 660	Mini Flow Isolation (Operate)	4	Globe	2	Solenoid
SI 664	CSP Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 665	CSP Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 666	HPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 667	HPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 668	LPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 669	LPSI Pump Mini Flow Isolation (Operate)	2	Globe	2	Motor
SI 671	Containment Spray Isolation Valve (Operate)	8	Gate	2	Motor
SI 672	Containment Spray Isolation Valve (Operate)	8	Gate	2	Motor
SI 673	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 674	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 675	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 676	Sump Suction Isolation (Operate)	24	Butterfly	2	Motor
SI 678	CSP Flow Control Valve (Operate)	10	Butterfly	2	Motor
SI 679	CSP Flow Control Valve (Operate)	10	Butterfly	2	Motor
SI 682	SIT Fill Line (Close)	2	Globe	2	Pneumatic
SI 683	LPSI Pump Suction (Operate)	20	Gate	2	Motor
SI 684	CSP Discharge (Operate)	10	Gate	2	Motor
SI 685	LPSI Discharge (Operate)	10	Gate	2	Motor
SI 686	SDCHX Discharge (Operate)	20	Gate	2	Motor
SI 687	SDCHX Discharge (Operate)	10	Gate	2	Motor

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TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 6 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE	
SI 688	SDCHX Spray Bypass (Operate)	10	Gate	2	Motor	
SI 689	CSP Discharge (Operate)	10	Gate	2	Motor	
SI 692	LPSI Pump Suction (Operate)	20	Gate	2	Motor	
SI 693	SDCHX Spray Bypass (Operate)	10	Gate	2	Motor	
SI 694	LPSI Discharge (Operate)	10	Gate	2	Motor	
SI 695	SDCHX Discharge (Operate)	10	Gate	2	Motor	
SI 696	SDCHX Discharge (Operate)	20	Gate	2	Motor	
SI 698	HPSI Pump Orifice Bypass (Operate)	4	Gate	2	Motor	
SI 699	HPSI Pump Orifice Bypass (Operate)	4	Gate	2	Motor	
SI 113	Safety Injection Sys. (Operate)	4	Check	1	None	
SI 114	Safety Injection Sys. (Operate)	12	Check	1	None	
SI 123	Safety Injection Sys. (Operate)	4	Check	1	None	
SI 124	Safety Injection Sys. (Operate)	12	Check	1	None	7
SI 133	Safety Injection Sys. (Operate)	4	Check	1	None	
CH 118	VCT Outlet Check (Operate)	4	Swing Check	2	None	
CH 190	Gravity Feedline Check (Operate)	3	Swing Check	2	None	
CH 203	Auxiliary Spray (Operate)	2	Globe	1	Solenoid	
CH 205	Auxiliary Spray (Operate)	2	Globe	1	Solenoid	
CH 240	Charging Line Backpressure (Close)	2-1/2	Globe	1	Pneumatic	
CH 255	Seal Inj. Containment Isolation (Open)	1-1/2	Globe	2	Motor	
CH 305	RWT Suction Check (Operate)	20	Swing Check	2	None	
CH 306	RWT Suction Check (Operate)	20	Swing Check	2	None	

TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 7 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE	
CH 328	Charging Line Check (Operate)	2	Lift Check	2	None	
CH 331	Charging Line Check (Operate)	2	Lift Check	2	None	
CH 334	Charging Line Check (Operate)	2	Lift Check	2	None	
CH 431	Auxiliary Spray Check (Operate)	2	Lift Check	1	None	
CH 433	Charging Line Check (Operate)	2-1/2	Lift Check	1	None	
CH 440	HPSI Header Check (Operate)	2	Lift Check	2	None	
CH 494	RMW Supply Line to RDT Check (Operate)	1-1/2	Lift Check	2	None	
CH 505	RCP Controlled Bleed-Off Containment Isolation (Close)	1	Globe	2	Pneumatic	
CH 506		1	Globe	2	Pneumatic	
CH 515	Letdown Isolation Valve (Close)	2	Globe	1	Pneumatic	
CH 516		2	Globe	1	Pneumatic	
CH 523		2	Globe	2	Pneumatic	
CH 524	Charging Line Isolation Valve (Open)	2-1/2	Globe	2	Motor	7
CH 530	RWT Suction Isolation (Operate)	20	Gate	2	Motor	
CH 531		20	Gate	2	Motor	
CH 560	RDT Suction Isolation (Close)	3	Globe	2	Pneumatic	
CH 561	RDT Suction Isolation (Close)	3	Globe	2	Pneumatic	
CH 580	RMW Supply Isolation to RDT Iso. (Close)	1-1/2	Globe	2	Pneumatic	
CH 639	Charging Line Check Valve (Operate)	2-1/2	Lift Check	2	None	
CH 787	Seal Injection Check (Operate)	1	Lift Check	1	None	
CH 802	Seal Injection Check (Operate)	1	Lift Check	1	None	
CH 807	Seal Injection Check (Operate)	1	Lift Check	1	None	

TABLE 3.9.3-3

NSSS SEISMIC I ACTIVE VALVES

(Sheet 8 of 8)

VALVE NO.	SYSTEM NAME (safety function)	LINE SIZE	VALVE TYPE	ASME SECTION III CODE CLASS	ACTUATOR TYPE
CH 812	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 835	Seal Injection Check (Operate)	1-1/2	Lift Check	2	None
CH 866	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 867	Seal Injection Check (Operate)	1	Lift Check	1	None
CH 868	Seal Injection Check (Operate)	1	Lift Check	1	None
CH-869	Seal Injection Check (Operate)	1	Lift Check	1	None
RC 200	RCS (Operate)	6 x 8	Safety	1	None
RC 201	RCS (Operate)	6 x 8	Safety	1	None
RC 202	RCS (Operate)	6 x 8	Safety	1	None
RC 203	RCS (Operate)	6 x 8	Safety	1	None
RC 244	RCS (Operate)	4	Check	1	None
IR 100	Iodine Removal Sys. (Operate)	1	Vacuum Breaker	2	None
IR 118	Iodine Removal Sys. (Operate)	1	Vacuum Breaker	2	None
IR 120	Iodine Removal Sys. (Operate)	1/2	Check	2	None
IR 130	Iodine Removal Sys. (Operate)	1/2	Check	2	None
IR 680	Iodine Removal Sys. (Operate)	1/2	Globe	2	Solenoid
IR 681	Iodine Removal Sys. (Operate)	1/2	Globe	2	Solenoid
IR 682	Iodine Removal Sys. (Operate)	1/2	Globe	2	Solenoid
IR 683	Iodine Removal Sys. (Operate)	1/2	Globe	2	Solenoid

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NOTE:

1. (Operate) is defined as valve being capable of both opening and closing.

2. (Close) is defined as valve being capable of moving to or maintaining a closed position.

3. (Open is defined as valve being capable of moving to or maintaining an open position.

3.11 ENVIRONMENTAL DESIGN OF MECHANICAL AND ELECTRICAL EQUIPMENT

The design criteria with respect to environmental effects on the electrical and mechanical equipment of the Reactor Protective System and the Engineered Safety Features System to ensure acceptable performance in all environments (normal and accident) depend upon equipment location and function. Such equipment is qualified to meet its performance requirements under the environmental and operating conditions in which it will be required to function and for the length of time for which its function is required. As far as practical, equipment for these systems is located outside the Containment Building or other areas where adverse environmental conditions could exist. Compatability of mechanical and electrical equipment with environmental conditions is provided within the following design criteria:

A. For operation under normal conditions the systems are designed and qualified to remain functional after exposures within the following ranges of environmental conditions:

   1. Design temperatures maintained at the equipment location during normal operation by the ventilating and cooling system described in Section 9.4. Temperature ranges are given in Appendix 3.11A, Table 3.11A-1 thru 3.11A-14. 7

   2. Relative humidity ranges are given in Appendix 3.11A, Table 3.11A-1 thru 3.11A-14. 7

   3. Pressure ranges are given in Appendix 3.11A, Table 3.11A-1 thru 3.11A-14. 7

   4. Maximum expected integrated radiation exposures for 40 years at the equipment location during normal operation are given in Appendix 3.11A, Table 3.11A-1 thru 3.11A-14. 7

B. In addition to the normal operation environmental requirements given in listing A above, the mechanical and electrical components required to mitigate the consequences of a design basis event (DBE) or to attain a safe shutdown of the reactor are designed to remain functional after exposure to the environmental conditions anticipated following the specific DBE which they are intended to mitigate. Anticipated environmental conditions and requirements are listed below. 7

   1. The temperature, pressure, and humidity ranges following the design bases accidents such as the loss of coolant accident (LOCA), the main steam line break (MSLB), control element assembly ejection, or feedwater line break (FWLB), "Worst Case" combined (LOCA & MSLB) are indicated in Appendix 3.11A. 7

   2. The time integrated post accident radiation doses are indicated in Appendix 3.11A. Equipment will be designed for the types and levels of radiation associated with normal operation plus the radiation associated with the limiting design basis accident (DBA). If more than one type of radiation is significant each type may be considered separately. 7

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3.11.1 EQUIPMENT IDENTIFICATION AND ENVIRONMENTAL CONDITIONS

Appendix 3.11B lists and categorizes systems required to mitigate a DBE or to attain a safe shutdown. Specific equipment and components for each system are discussed in the appropriate section of the safety analysis report as referenced in Appendix 3.11B. The major component categories, such as motor-operated valves, pump motors, instrumentation and pressure boundary equipment in each system, and the location of the components by area are also provided.

3.11.2 QUALIFICATION TESTS AND ANALYSES

Qualification tests and analyses performed in accordance with the methodologies defined in CENPD 255 Rev. 03 on NSSS instrumentation and electrical equipment (including pump and valve motors and electrical accessories) fulfill the requirements of IEEE Standard 323-1974, and "Category 1" of NUREG 0588. For mechanical equipment, environmental qualification is based on engineering, 7
evaluation, and material selection where sufficiently reliable data is available.

3.11.2.1 Component Environmental Design and Qualification for Normal Operation

Equipment listed in Appendix 3.11B is designed for 40 years of continuous operation in the temperature, pressure, humidity, and radiation environment that exists at the equipment location during normal operation, assuming proper routine preventive maintenance is performed, such a periodic replacement of seals and packing.

Appendix 3.11A provides the ranges of the design temperatures, pressure, and humidities, as well as the exposures to chemical spray and radiation for each area in which safety-related equipment listed in Appendix 3.11B is located.

7

3.11.2.2 Component Environmental Design and Qualification for Operation After a Design Basis Event

Equipment listed in Appendix 3.11B is designed to remain functional in the temperature, pressure, humidity, and chemical spray environment conditions that exist at the equipment location after the design basis LOCA. This equipment is also designed for the maximum calculated integrated radiation

exposure after the design basis LOCA, as discussed in Section 3.11.5. The temperature, pressure, and humidity environment inside the containment after a LOCA is discussed in detail in Section 6.2.1.3. The containment spray characteristics are given in Section 6.2.2.1. The integrated post-accident radiation dose for those areas at which equipment is located is given in Appendix 3.11A. The temperature, pressure, and humidity environment inside the containment after a MSLB is discussed in detail in Section 6.2.1.4.

The requirements of the General Design Criteria, Appendix A to 10CFR50, are met as follows:

- Criterion 1 - Quality Standards and Records, refer to Section 3.1.1.

- Criterion 4 - Environmental and Missile Design Basis, refer to Subsection 3.1.4.

- Criterion 23 - Protection System Failure Modes, refer to Section 3.1.19.

- Criterion 50 - Containment Design Basis, refer to Sections 3.1.43 and 6.2.1.

The requirements of the Quality Assurance Criterion III, Appendix B to 10CFR50 are met as discussed in the Design and Procurement Q.A. Program (See Chapter 17).

The recommendations contained in the documents discussed below, listings A through D, and other applicable Regulatory Guides and Standards have also been utilized.

A. Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment.

B. Regulatory Guide 1.73, Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants. A descripiton of the tests and analysis by which active NSSS valves are qualified is provided in Section 3.9.2.2.

C. The qualification methods and documentation requirements of IEEE Standard 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations and "Category 1" of NUREG 0588, are discussed in CENPD-255 Rev. 3 (Reference 1). | 7

D. Pressure boundary components inside the containment are designed for the appropriate temperature and pressure environment in accordance with the applicable code to which the component is constructed. | 7

Qualification testing is not considered necessary for such components.

RADIATION IN HARSH AND NON-HARSH ENVIRONMENT

Electrical Equipment will be designed for the types and levels of radiation associated with normal operation plus the radiation associated with the limiting Design Basis Accident (DBA). These levels are defined in Appendix 3.11A. If more than one type of radiation is significant, each type may be applied separately.

Electrical Equipment which is exposed to radiation above 10^4 Rads will be irradiated to its anticipated Total Integrated Dose (TID) prior to type testing unless determined by analysis that radiation does not effect its ability to perform its required function. Where the application of the accident dose is planned during DBA testing, it need not be included during the aging process.

Electrical Equipment which will be exposed to radiation levels 10^4 Rads or below will be analyzed to be determined whether low level radiation could impact its ability to perform its required function.

Electrical Equipment will be qualified to the typical radiation environments defined in Appendix 3.11A, as required.

Gamma

Cobalt-60 is considered an acceptable gamma radiation source. Other sources may be found acceptable, and will be justified. Electrical Equipment will be tested to typical gamma radiation levels defined in Appendix 3.11A. 7

Beta

Electrical Equipment exposed to beta radiation will be identified and an analysis will be performed to determine if the operability of the equipment is affected by beta radiation ionization and heating effects. Qualification will be performed by test unless analysis demonstrates that the safety function will not be degraded by Beta exposure. Equipment will be tested and/or analyzed to the beta radiation levels defined in Appendix 3.11A. Where testing is recommended, gamma equivalent radiation source will be used.

Neutron

Electrical Equipment exposed to neutron radiation will be identified and neutron radiation levels defined. When actual neutron dose qualification testing is not performed, an equivalent gamma radiation dose will be used for qualification testing to simulate neutron exposure. The basis for establishing an equivalent gamma radiation dose will be provided.

Paints/Radiation Effects

Electrical Equipment; an analysis will be performed addressing paint exposure to beta and gamma radiation, if required. Qualification of painted equipment will be by test if analysis indicates that the safety function of the equipment could be impaired by paint failure due to radiation.

Chemical Spray

After a postulated accident, such as the LOCA or MSLB, components located in the Containment Building may be exposed to a chemical spray from a solution used to remove iodine from the containment building atmosphere. Equipment will be environmentally tested to these conditions and performance requirements demonstrated during and after the test. The most severe spray composition will be determined by single failure analysis of the spray system. Corrosion effects due to long term exposure will be addressed, as appropriate.

Where qualification for chemical spray environment is required, the simulated spray will be initiated at the time shown in Appendix 3.11A.

Typical values of chemical spray composition, concentration and pH are defined in Appendix 3.11A, Tables 3.11A-1, 3.11A-2 and 3.11A-13.

3.11.3 QUALIFICATION TEST RESULTS

3.11.3.1 NSSS Instrumentation and Electrical Equipment

Qualification testing and analyses of NSSS Instrumentation and Electrical Equipment are discussed in Reference 1.

3.11.3.2 NSSS Mechanical Equipment

Qualification tests results and analyses of NSSS Mechanical Equipment are provided in Section 3.9.2.2 .

3.11.4 CLASS 1E INSTRUMENTATION LOSS OF VENTILATION EFFECTS

Loss of ventilation is discussed in the Applicant's SAR. Interface criteria are presented in Chapter 7. 7

Class 1E equipment which is located in the control room or similar areas includes the following:

Plant Protection System Cabinet (PPS)

Auxiliary Relay Cabinet (ARC)

Auxiliary Protective Cabinet (APC)

Main Control Panels

Process Instrument Cabinet

Other instrumentation, such as process transmitters and signal converters and the reactor trip switchgear system circuit breakers, are located in the Auxiliary Building or Containment Building. Equipment in these areas is qualified for the maximum expected temperature, radiation, humidity, and pressure under which the equipment is expected to operate.

The following are the normal and abnormal environmental conditions for which C-E Class 1E safety-related equipment is qualified to operate according to the service location of the equipment and the expected environmental condition.

Appendix 3.11A, Tables 3.11A-1 thru 3.11A-14 which define typical environmental conditions and associated environmental test profiles are defined in Figures 3.11A-6A thru 3.11A-10.

3.11.5 CHEMICAL SPRAY, RADIATION, HUMIDITY, DUST, SUBMERGENCE, AND POWERSUPPLY VOLTAGE AND FREQUENCY VARIATION

3.11.5.1 Chemical Environment

Engineered Safety Feature Systems are designed to perform their safety-related functions in the temperature, pressure, and humidity conditions described in Section 3.11.1 and Sections 6.2 and 6.3. In addition, components of ESF systems inside the containment are designed to perform their safety-related functions in the presence of the existing chemical environment, resulting from the boric acid and hydrazine solutions recirculated through the Safety Injection System (SIS) and Containment Spray Systems (CSS). The SIS is designed for both the maximum and long-term boric concentration and pH. These chemical environment conditions are given in Appendix 3.11A.

3.11.5.2 Radiation Environment

The components in the Engineered Safety Feature and Reactor Protection Systems are designed to meet their performance requirements under the environmental and operating conditions in which they will be required to function and for the length of time for which their function is required. The components are designed to ensure acceptable performance under normal operational radiation exposure in addition to the single most adverse post accident environment. The normal operational exposures are based on the design source terms provided in Section 11.1 and Section 12.2. Radiation environments for those components for which the most adverse accident conditions are post LOCA are based on the source term assumptions consistent with Regulatory Guides 1.4 and 1.7. Radiation environments for those components for which the most adverse accident condition is other than the LOCA (such as the main steam line break, feedwater line break or CEA ejection) are based on conservative estimates of the fuel assembly gas gap activities and maximum Reactor Coolant specific activities as discussed in Section 11.1. 7

HUMIDITY

Equipment not subjected to steam environments during DBE testing will be environmentally tested to short term high humidity levels prior to operation and performance requirements demonstrated during and after the test. Equipment that is subjected to steam environments will be subjected to the appropriate test profiles in Appendix 3.11A.

DUST

Dust environments will be considered when establishing service conditions and qualification requirements. The potential effects of dust exposure will be evaluated relative to effects upon equipment safety function performance.

Where dust could have a degrading effect on equipment safety function performance, it will be addressed in the qualification program through the development of a maintenance program and/or an upgrading of equipment interface requirements.

SUBMERGENCE

Equipment locations and operability requirements will be reviewed to establish whether or not specific equipment could be subject to submergency during its required operating time. Flood levels both inside and outside containment will be reviewed and potential impacts on equipment qualification appropriately addressed. Where operability during submergency is required, qualification will be demonstrated by type test and/or analysis supported by partial type test data. 7

Power Supply Voltage and Frequency Variation

Power supply voltage and frequency variation is addressed in several areas throughout the equipment design and verification process. During the design process interface requirements dictate the acceptable range of power supply variation. Equipment specifications incorporate these interface requirements into the design to ensure acceptable operation within the defined range of power supply voltage and frequency variation. Upon equipment fabrication and completion, design verification tests are performed to demonstrate design adequacy.

REFERENCES

1. "Qualification of Combustion Engineering Class 1E Instrumentation", CENPD-255 Rev. 3, Combustion Engineering, Inc., Windsor, Connecticut. | 7

2. Griess, J. C. and Bacarella, A. L., "Design Considerations of Reactor Containment Spray Solutions", CRNL-TM-2412, Part III, Oak Ridge National Laboratory, Oak Ridge, Tennessee, December, 1969.

3. Kircher, J. F., and Bowman, R. E., "Effects of Radiation on Materials and Components", Van Nostrand Reinhold, New York, 1964.

APPENDIX 3.11A

TYPICAL ENVIRONMENTAL CONDITIONS AND TEST PROFILES 7

FOR

STRUCTURES AND COMPNENTS

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APPENDIX 3.11A

TYPICAL ENVIRONMENTAL CONDITIONS AND TEST PROFILES 7

FOR

STRUCTURES AND COMPONENTS

This appendix defines the generic environmental qualification requirements for CESSAR scope structures and components. The requirements are given in categories which combine various locations and conditions of design for environmental qualification purposes.

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APPENDIX 3.11A

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3.11A-1 DEFINITION OF ENVIRONMENTAL CONDITIONS AND PROFILES

The purpose of this appendix is to define typical environmental conditions and associated environmental test profiles.

SUMMARY

Figures 3.11A-1A through 3.11A-5 provide typical post accident environmental conditions. These figures are not "test" profiles and therefore do not include margin.

Tables 3.11A-1 through 3.11A-14 provide a series of tables titled "Category "XX"" Environmental Conditions". These tables were developed for the purpose of defining a limited set of clearly established environmental conditions that could be associated with specific equipment and/or locations. Appendix 3.11A utilizes and illustrates this approach by correlating a generic piece of equipment with its corresponding environmental category designator.

These tables also do not define actual test conditions or parameters and therefore do not include margin.

Figure 3.11A-6A and 3.11A-6B are the in-containment test profiles that correspond to the post accident environmental conditions defined in Figures 3.11A-1A through 3.11A-5 and Tables 3.11A-1, 3.11A-2 and 3.11A-13. Both Figure 3.11A-6A and 3.11A-6B incorporate and illustrate required margin. For an explanation of the use of these profiles see Section 3.4.1 of CENPD 255, Rev. 03. 7

Figures 3.11A-7 through 3.11A-10 are test profiles for equipment located outside containment. These test profiles also do not incorporate margin.

The test profiles included herein represent "typical" examples of qualification test profiles and are not intended to represent the complete set of all test profiles utilized.

ENVIRONMENTAL CONDITIONS

A. Tables 3.11A-11 and 3.11A-2 list typical parameters for design basis accident conditions inside containment (Environmental Categories "A-1" and "A-2").

B. Table 3.11A-3 lists typical parameters for normal environmental conditions inside containment (Environment Category "B").

C. Tables 3.11A-4, 3.11A-11 and 3.11A-12 list typical parameters for normal environment conditions outside containment (Environment Categories "C", "J" and "K").

D. Tables 3.11A-5 through 3.11A-10 list typical parameters for abnormal environment conditons outside containment (Environment Categories "D", "E", "F", "G", "H" and "I").

E. Table 3.11A-13 lists typical "Worst Case" parameters for valves inside containment (Environment Category V-1).

F. Table 3.11A-14 lists typical "Worst Case" parameters for valves outside containment (Environment Category V-2).

G. Figures 3.11A-1A through 3.11A-5 provide profiles for typical post accident environment conditions.

H. Figures 3.11A-6A and 3.11A-6B represent simulated environmental profiles for equipment located inside containment, as appropriate (Environment Categories "A-1", "A-2" and "V-1").

I. Figures 3.11A-7 and 3.11A-8 represent simulated environmental conditions for equipment located outside containment, as appropriate (Environment Category "C").

J. Figures 3.11A-9 and 3.11A-10 will be used to simulate environment conditions for equipment located outside containment, as appropriate (Environment Categories "H" and "J").

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TABLE 3.11A-1

CATEGORY "A-1" ENVIRONMENTAL CONDITIONS
(LOCA: IN-CONTAINMENT)

ENVIRONMENTAL PARAMETERS	RANGE AND DURATION	
TEMPERATURE, °F	FIGURE 3.11A-1A	
PRESSURE, PSIG	FIGURE 3.11A-1B	
HUMIDITY	SUPERHEATED STEAM/ AIR MIXTURE	
RADIATION, RADS	FIGURES 3.11A-4 AND 3.11A-5	7
CHEMICALS	NOTE '1'	

NOTE 1 - 4400 PPM BORON AS H_3BO_3, 50-100 PPM HYDRAZINE AS N_2H_4 AND $P^{H}4$ TO 10.

TABLE 3.11A-2

CATEGORY "A-2" ENVIRONMENTAL CONDITIONS
(MSLB: IN-CONTAINMENT)

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	FIGURE 3.11A-3	0-12 MIN.
	FIGURE 3.11-1A (AFTER 12 MIN.)	
PRESSURE, PSIG	SAME AS LOCA PROFILE FIGURE 3.11A-1B	
HUMIDITY	SH STEAM/AIR MIXTURE	0-12 MIN. 7
	SAT. STEAM/AIR MIXTURE (AFTER 12 MIN.)	
RADIATION, RADS	4.5 X 10^4 γ (TID)	
CHEMICALS	NOTE '1'	

NOTE 1 - 4400 PPM BORON AS H_3BO_3, 50-100 PPM HYDRAZINE AS N_2H_4 AND $p^{H}4$ TO 10.

TABLE 3.11A-3

CATEGORY "B" ENVIRONMENTAL CONDITIONS
(NORMAL: IN-CONTAINMENT)

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	55 TO 122	CONTINUOUS
PRESSURE, PSIG	0-5	CONTINUOUS
HUMIDITY, %	20-90	CONTINUOUS
RADIATION, RADS (TID)	NOTE '1'	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - DOSE VARIES WITH COMPONENT (SEE CESSAR-F, TABLE 3.11B-2)

TABLE 3.11A-4

CATEGORY "C" ENVIRONMENTAL CONDITIONS

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	55 TO 104	CONTINUOUS
PRESSURE, PSIG	0	CONTINUOUS
HUMIDITY, %	20-90 NOTE '1'	CONTINUOUS
RADIATION, RADS (TID)	NOTE '2'	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - AT OR ABOVE 80°F, THE MOISTURE CONTENT IS THAT WHICH PRODUCES 90% RELATIVE HUMIDITY AT 80°F (DEWPOINT OF 77°F).

NOTE 2 - DOSE VARIES WITH COMPONENT (SEE CESSAR-F, TABLE 3.11B-2).

TABLE 3.11A-5

CATEGORY "D" ENVIRONMENTAL CONDITIONS

ENVIRONMENTAL PARAMETERS	RANGE OR MAXIMUM	DURATION
TEMPERATURE, °F	104-120	4 HR.
	104 TO 55	AFTER 4 HR.
PRESSURE, PSIG	0	ALL DURATION
HUMIDITY, %	20-90 NOTE '1'	NOTE '2'
RADIATION, RADS	4×10^6 γ (TID)	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - AT OR ABOVE 80°F, THE MOISTURE CONTENT IS THAT WHICH PRODUCES 90% RELATIVE HUMIDITY AT 80°F (DEWPOINT OF 77°F). AT OR ABOVE 120°F, THE MOISTURE CONTENT IS THAT WHICH PRODUCES 99% RELATIVE HUMIDITY AT 120°F (DEWPOINT OF 116°F).

NOTE 2 - LIMITED TO 8 HOURS OUTSIDE THE NORMAL RANGE OF CATEGORY "C" UNLESS OTHERWISE SPECIFIED.

TABLE 3.11A-6

CATEGORY "E" ENVIRONMENTAL CONDITIONS

ENVIRONMENTAL PARAMETERS	RANGE OR MAXIMUM	DURATION
TEMPERATURE, °F	55 TO 330	0 - 3 MIN.
	104-55	AFTER 3 MIN.
PRESSURE, PSIG	3	0-3 MIN.
	0	AFTER 3 MIN.
HUMIDITY, %	100	0-3 MIN.
	NOTE '2'	AFTER 3 MIN. (NOTE '1')
RADIATION, RADS	$<10^3$ (TID)	
CHEMICALS	NOT APPLICABLE	

NOTE 1 - LIMITED TO 8 HOURS OUTSIDE THE NORMAL RANGE OF CATEGORY "C" UNLESS OTHERWISE SPECIFIED.

NOTE 2 - AT OR ABOVE 80°F, THE MOISTURE CONTENT IS THAT WHICH PRODUCES 90% RELATIVE HUMIDITY AT 80°F (DEWPOINT OF 77°F).

7

TABLE 3.11A-7

CATEGORY "F" ENVIRONMENTAL CONDITIONS

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	FIGURE 3.11A-2 (NOTE '2')	
PRESSURE, PSIG	0	ALL DURATION
HUMIDITY	SAT. STEAM/AIR MIXTURE	NOTE '2'
RADIATION, RADS	NOTE '1'	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - FOR UNCONTROLLED ACCESS AREAS 1 X 10^4 γ (TID) AND FOR CONTROLLED ACCESS AREAS 4 X 10^6 γ (TID).

NOTE 2 - LIMITED TO 8 HOURS OUTSIDE THE NORMAL RANGE OF CATEGORY "C" UNLESS OTHERWISE SPECIFIED.

TABLE 3.11A-8

CATEGORY "G" ENVIRONMENTAL CONDITIONS

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	FIGURE 3.11A-2 (NOTE '1')	
PRESSURE, PSIG	0	ALL DURATION
HUMIDITY	SAT. STEAM/AIR MIXTURE	NOTE '1'
RADIATION, RADS	3.1×10^4 γ (TID)	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - LIMITED TO 8 HOURS OUTSIDE THE NORMAL RANGE OF CATEGORY "C" UNLESS OTHERWISE SPECIFIED.

TABLE 3.11A-9

CATEGORY "H" ENVIRONMENTAL CONDITIONS

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	55 TO 104	NOTE '2'
PRESSURE, PSIG	0	ALL DURATION
HUMIDITY, %	20-90 NOTE '1'	NOTE '2'
RADIATION, RADS	$<10^3$ (TID)	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - AT OR ABOVE 80°F, THE MOISTURE CONTENT IS THAT WHICH PRODUCES 90% RELATIVE HUMIDITY AT 80°F (DEWPOINT OF 77°F).

NOTE 2 - LIMITED TO 8 HOURS OUTSIDE THE NORMAL RANGE OF CATEGORY "J" UNLESS OTHERWISE SPECIFIED.

TABLE 3.11A-10

CATEGORY "I" ENVIRONMENTAL CONDITIONS
(OUTSIDE PLANT BUILDINGS)

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	-30 TO 122	NOTE '1'
PRESSURE, PSIG	0	ALL DURATION
HUMIDITY, %	100	NOTE '1'
RADIATION, RADS	$<10^3$ (TID)	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - LIMITED TO 8 HOURS OUTSIDE THE NORMAL RANGE OF CATEGORY "K" UNLESS OTHERWISE SPECIFIED.

TABLE 3.11A-11

CATEGORY "J" ENVIRONMENTAL CONDITIONS

ENVIRONMENTAL PARAMETERS	RANGE	DURATION	
TEMPERATURE, °F	65 TO 85	CONTINUOUS	7
PRESSURE, PSIG	0	CONTINUOUS	
HUMIDITY, %	40-60	CONTINUOUS	
RADIATION, RADS	$<10^3$ (TID)		
CHEMICALS	NOT APPLICABLE		

TABLE 3.11A-12

CATEGORY "K" ENVIRONMENTAL CONDITIONS
(OUTSIDE PLANT BUILDINGS)

ENVIRONMENTAL PARAMETERS	RANGE	DURATION
TEMPERATURE, °F	-30 TO 120	CONTINUOUS
PRESSURE, PSIG	0	CONTINUOUS
HUMIDITY, %	20-90 NOTE '1'	CONTINUOUS
RADIATION, RADS	$<10^3$ (TID)	
CHEMICALS	NOT APPLICABLE	

7

NOTE 1 - AT OR ABOVE 80°F, THE MOISTURE CONTENT IS THAT WHICH PRODUCES 90% RELATIVE HUMIDITY AT 80°F (DEWPOINT OF 77°F). AT OR ABOVE 120°F, THE MOISTURE CONTENT IS THAT WHICH PRODUCES 90% RELATIVE HUMIDITY AT 120°F (DEWPOINT OF 116°F).

TABLE 3.11A-13
CATEGORY "V-1" ENVIRONMENTAL CONDITIONS
(WORST CASE: IN-CONTAINMENT): NOTE 3

ENVIRONMENTAL PARAMETERS		RANGE	DURATION	
TEMPERATURE, °F	NORMAL	60 - 122	CONTINUOUS	
	LOCA	FIGURE 3.11A-1A		
	MSLB	FIGURE 3.11A-3	0-12 MIN.	
		FIGURE 3.11A-1A	AFTER 12 MIN.	
PRESSURE, PSIG	NORMAL	0-5	CONTINUOUS	
	LOCA	FIGURE 3.11A-1B		
	MSLB	FIGURE 3.11A-1B		
HUMIDITY, %	NORMAL	NOTE '1'		7
	LOCA	SAT. STEAM/AIR MIXTURE	ALL DURATION	
	MSLB	SH. STEAM/AIR MIXTURE	0-12 MIN.	
		SAT. STEAM/AIR MIXTURE	AFTER 12 MIN.	
RADIATION, RADS		1×10^{8} (TID)		
CHEMICALS		NOTE '2'		

NOTE 1 - 95% RELATIVE HUMIDITY (RH) AT 60 TO 80°F. FOR 80°F TO MAXIMUM TEMPERATURE FIXED MOISTURE CONTENT IS EQUIVALENT TO 95% RH AT 80°F.

NOTE 2 - 4400 PPM BORON AS H_3BO_3, 50-100 PPM HYDRAZINE AS N_2H_4 AND P^H 4 TO 10.

NOTE 3 - COMBINED "WORST CASE" CONDITION FOR NORMAL/LOCA/MSLB ENVIRONMENTS.

TABLE 3.11A-14
CATEGORY "V-2" ENVIRONMENTAL CONDITIONS
(WORST CASE: OUTSIDE CONTAINMENT): NOTE 2

ENVIRONMENTAL PARAMETERS		RANGE	DURATION
TEMPERATURE, °F	NORMAL	60-104	CONTINUOUS
	LOCA	FIGURE 3.11A-2	
	MSLB	60-330	0-3 MIN.
		FIGURE 3.11A-2	AFTER 3 MIN.
PRESSURE, PSIG	NORMAL	0	CONTINUOUS
	LOCA	0	ALL DURATION
	MSLB	3	0-3 MIN.
		0	AFTER 3 MIN.
HUMIDITY, %	NORMAL	NOTE '1'	
	LOCA	SAT. STEAM/AIR MIXTURE	ALL DURATION
	MSLB	SAT. STEAM/AIR MIXTURE	ALL DURATION
RADIATION, RADS		5×10^7 (TID)	
CHEMICALS		NOT APPLICABLE	

NOTE 1 - 95% RELATIVE HUMIDITY (RH) AT 60 TO 80°F. FOR 80°F TO MAXIMUM TEMPERATURE FIXED MOISTURE CONTENT IS EQUIVALENT TO 95% RH AT 80°F.

NOTE 2 - COMBINED "WORST CASE" CONDITION FOR NORMAL/LOCA/MSLB ENVIRONMENTS.

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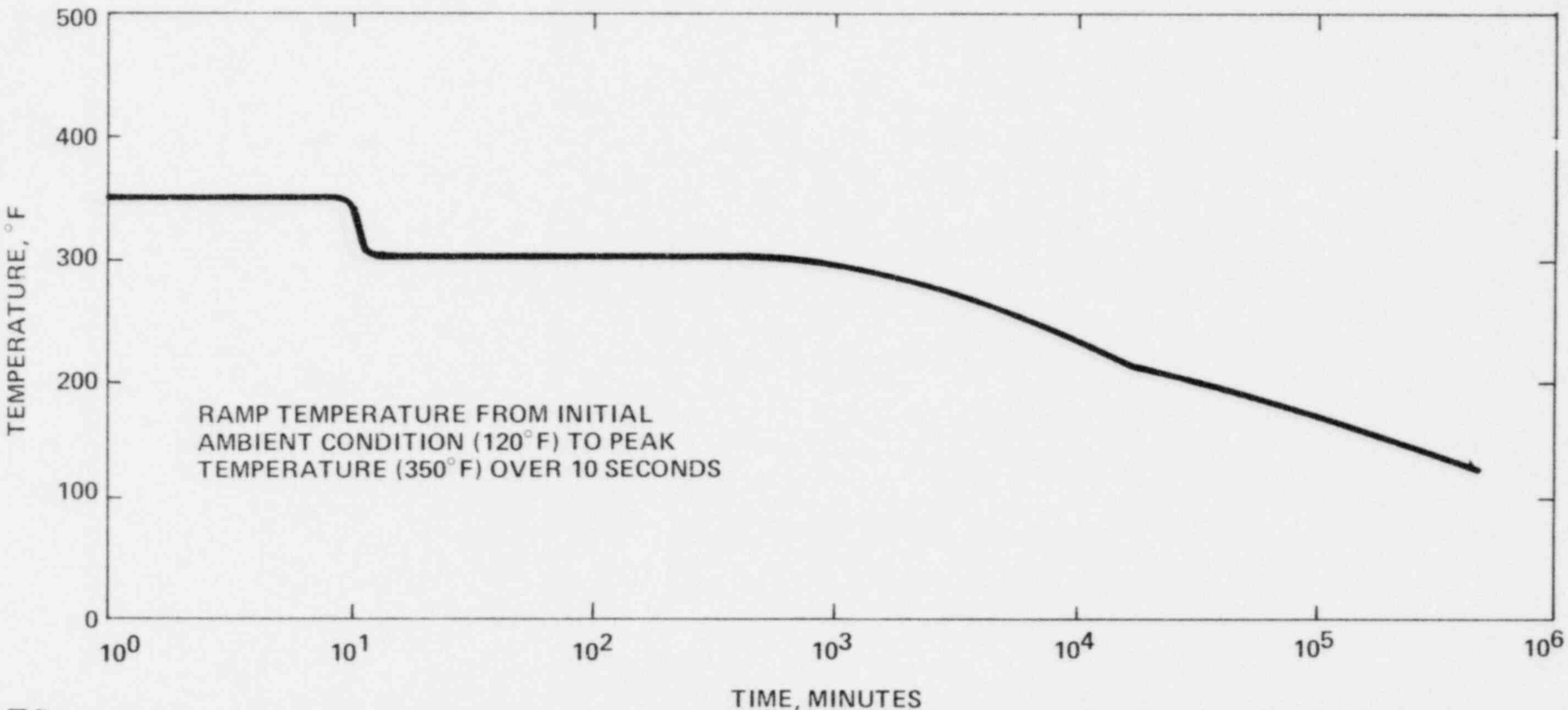

C-E SYSTEM 80

TYPICAL CONTAINMENT ATMOSPHERE TEMPERATURE CONDITION FOLLOWING LOCA

Figure 3.11A-1A

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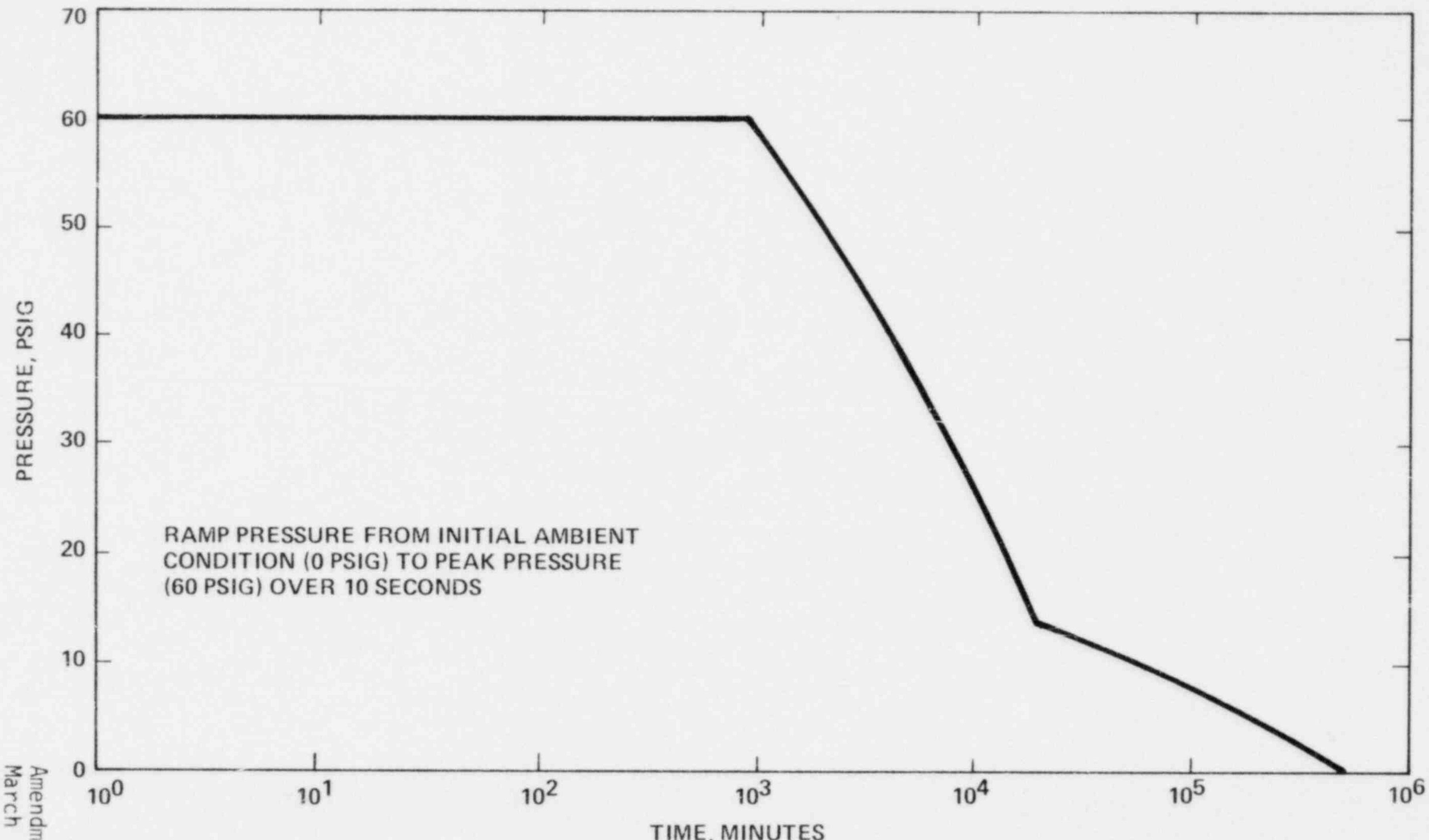

C-E SYSTEM 80

TYPICAL CONTAINMENT ATMOSPHERE PRESSURE CONDITION FOLLOWING LOCA

Figure 3.11A-1B

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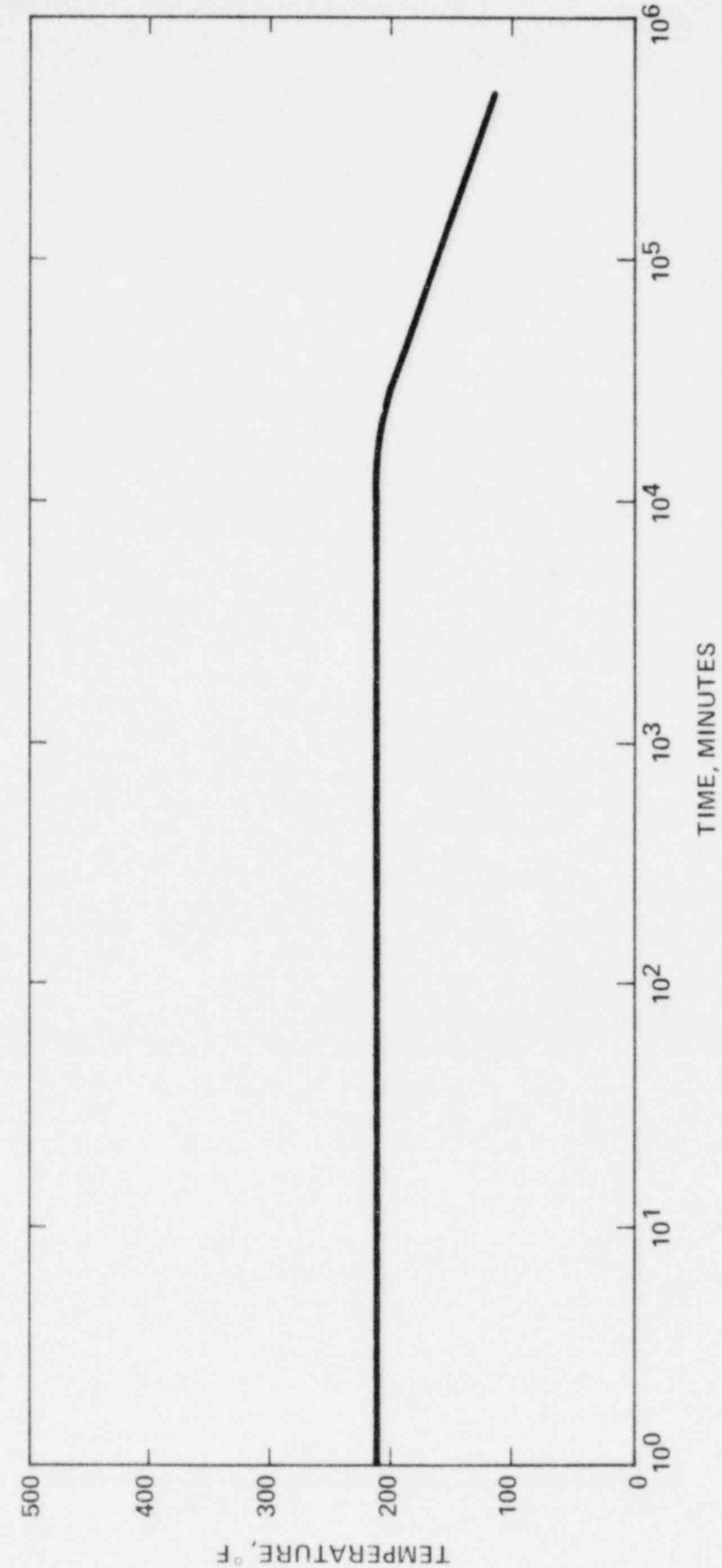
March 31, 1982



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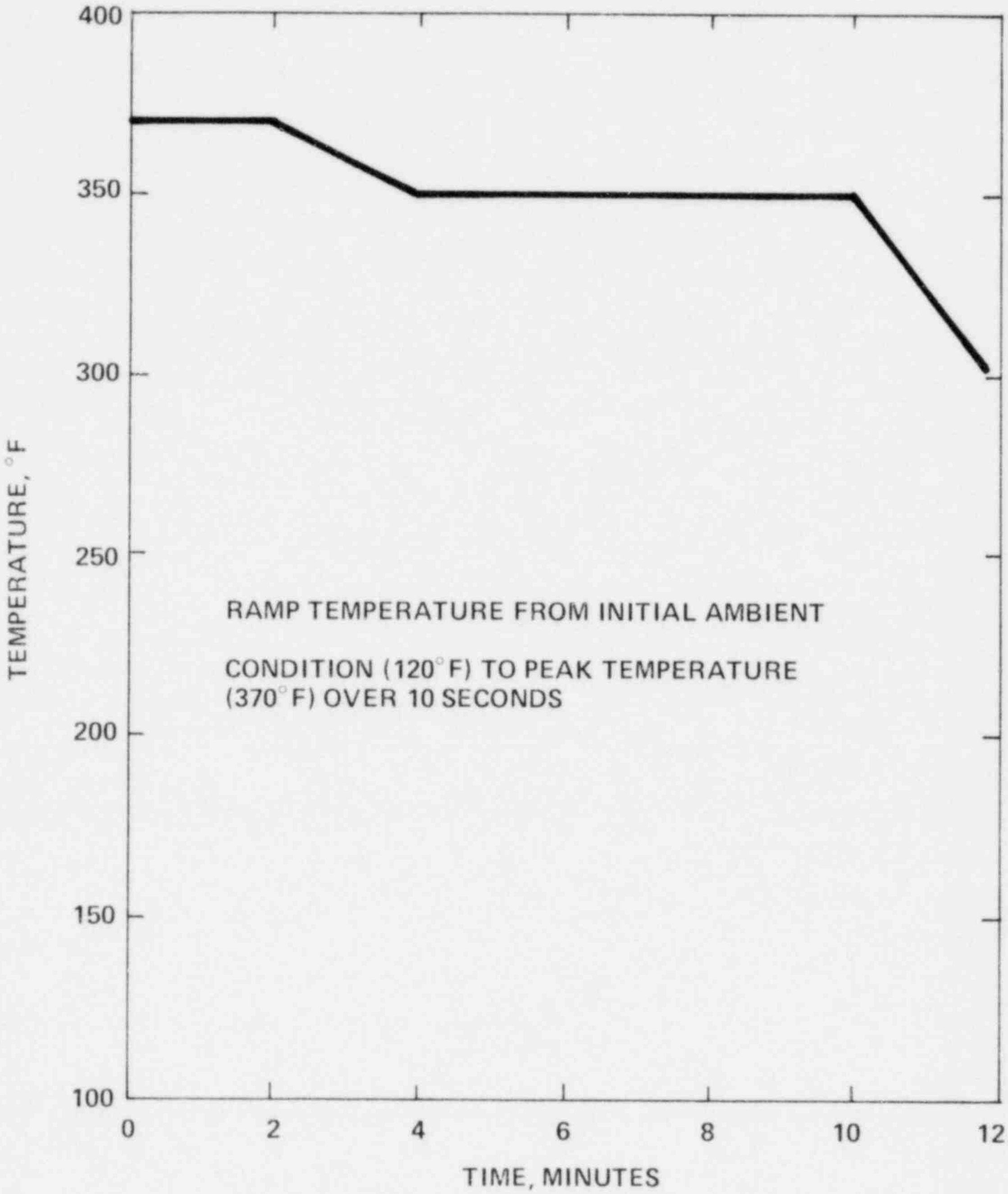
March 31, 1982

C - E SYSTEM 80	TYPICAL ANNULUS ATMOSPHERE TEMPERATURE CONDITION FOLLOWING LOCA/MSLB	Figure 3.11A-2



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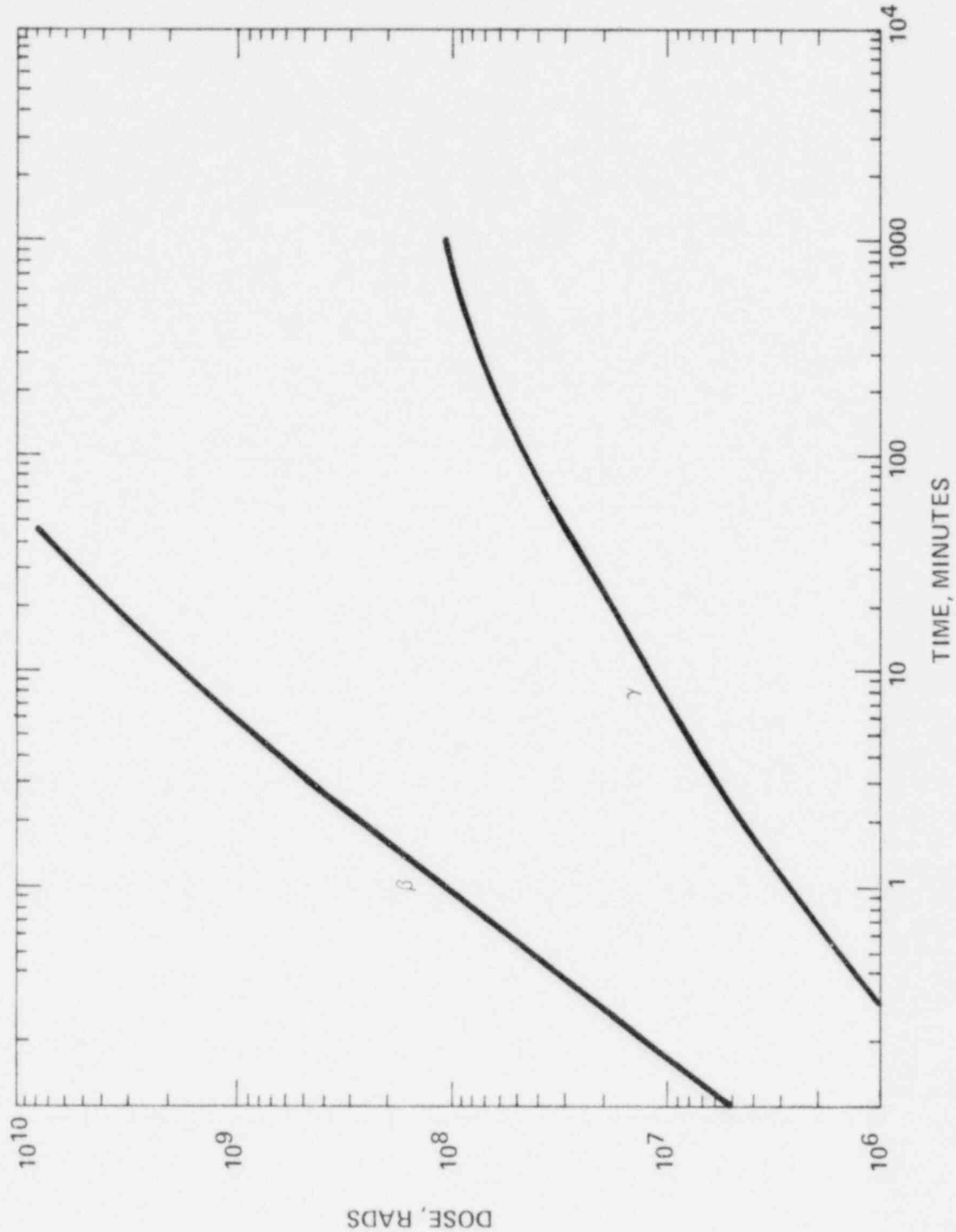
C - E SYSTEM 80	TYPICAL CONTAINMENT ATMOSPHERE TEMPERATURE CONDITION FOLLOWING MSLB	Figure 3.11A-3



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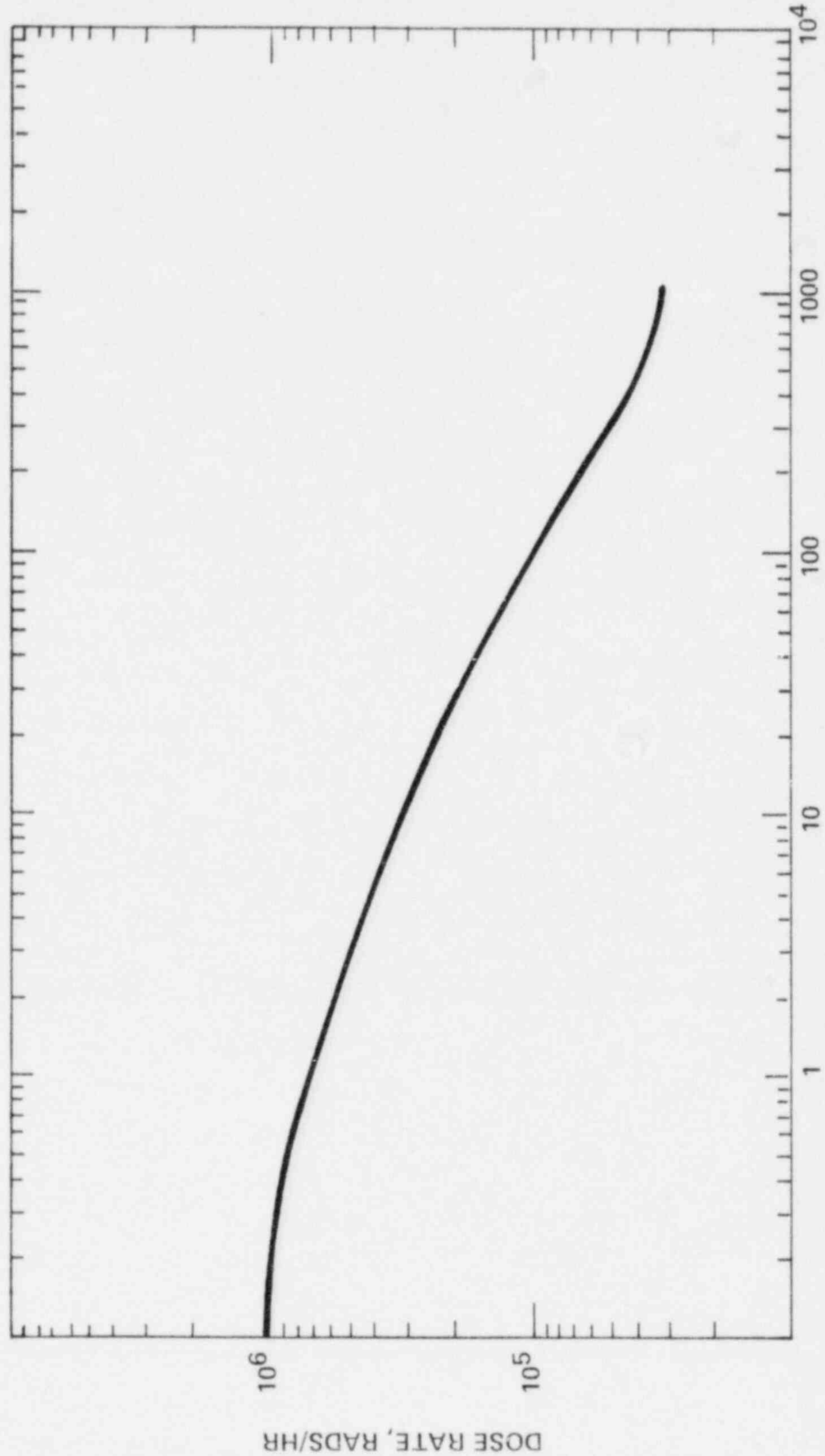
C - E SYSTEM 80	TYPICAL CONTAINMENT RADIATION DOSE FOLLOWING LOCA	Figure 3.11A-4



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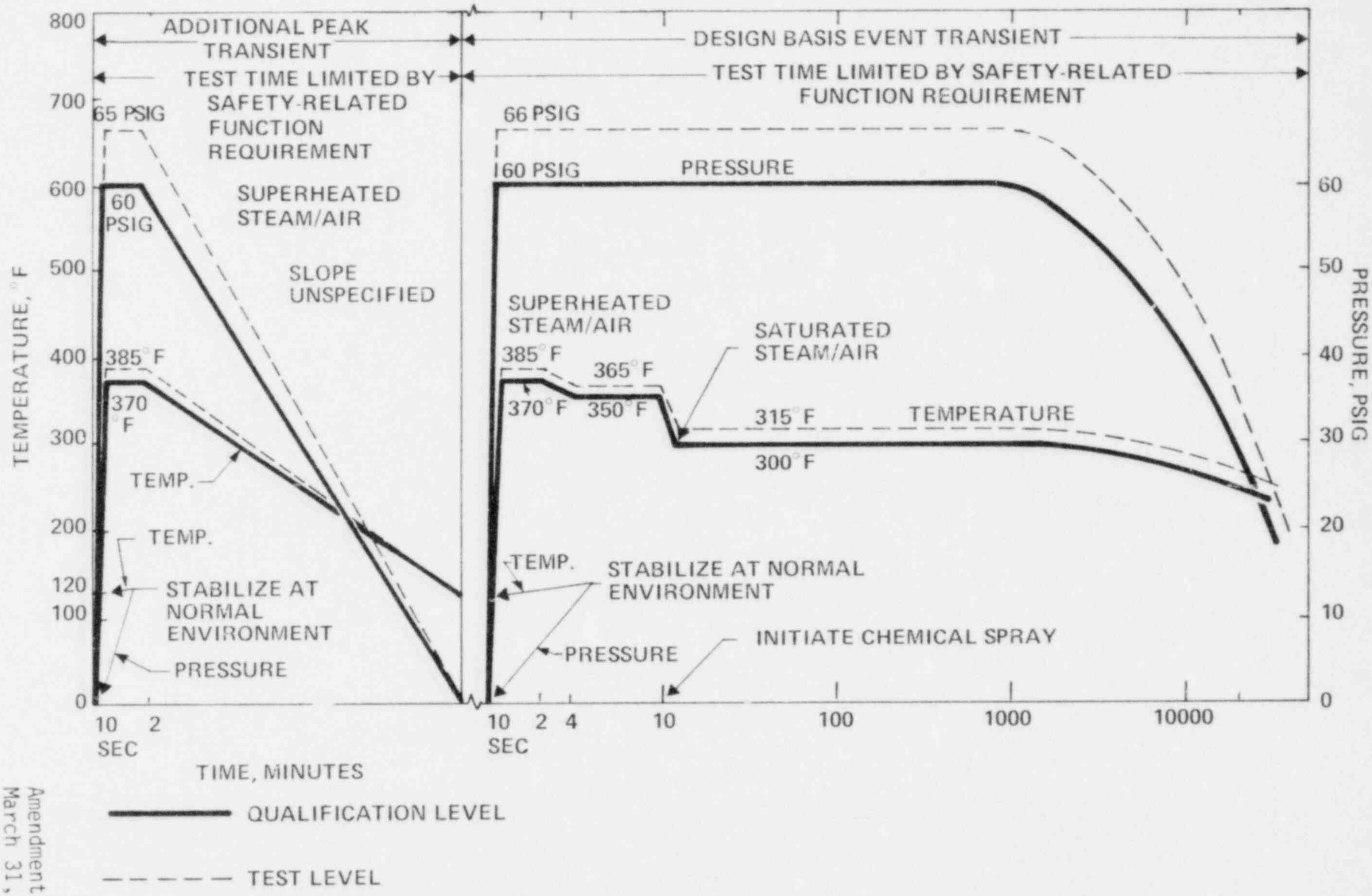
C - E SYSTEM 80	TYPICAL CONTAINMENT GAMMA DOSE RATE FOLLOWING LOCA	Figure 3.11A-5



C - E SYSTEM 80

TYPICAL CONTAINMENT BUILDING ENVIRONMENTAL TEST PROFILE FOR CATEGORY "A.1", "A.2" AND "V.1" ENVIRONMENTAL CONDITIONS

Figure 3.11A-6A

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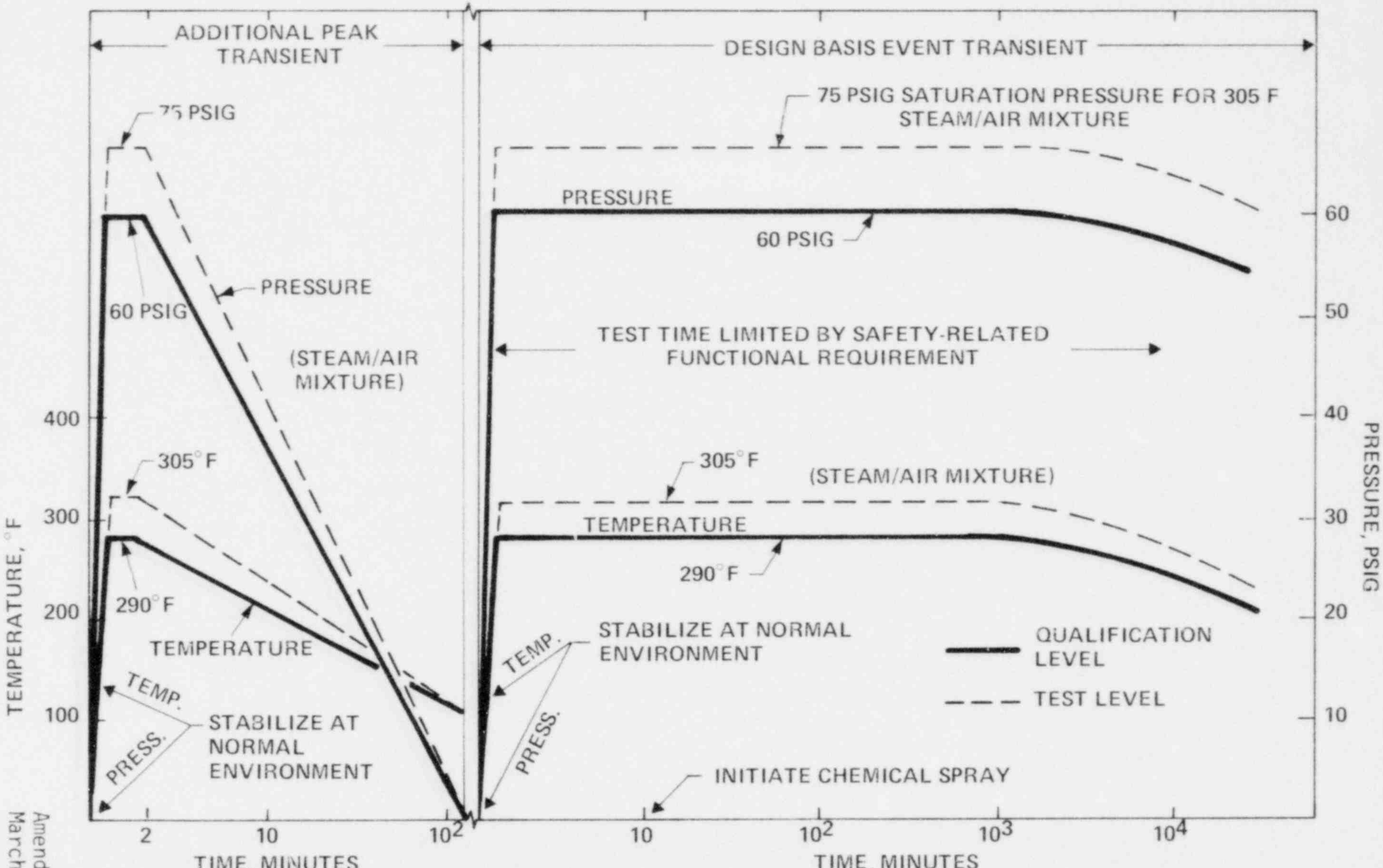
C - E



TYPICAL CONTAINMENT BUILDING ENVIRONMENTAL TEST PROFILE FOR CATEGORY "A-1", "A-2" AND "V-1" ENVIRONMENTAL CONDITIONS

Figure 3.11A-63

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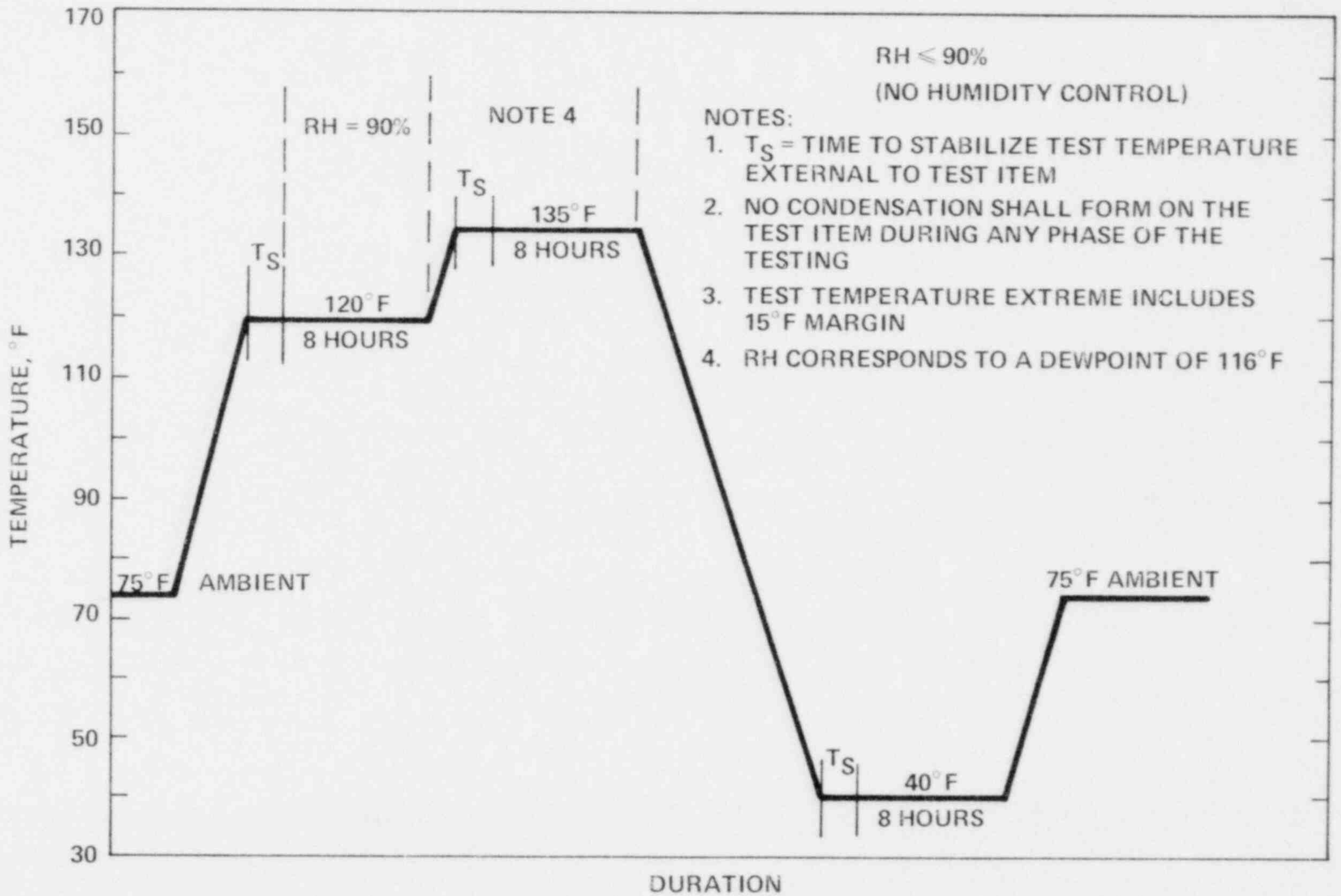

C-E SYSTEM 80

TYPICAL ENVIRONMENTAL TEST PROFILE FOR CATEGORY "C" ENVIRONMENTAL CONDITIONS

Figure 3.11A-7

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C - E SYSTEM 80

TYPICAL INSIDE CABINET ENVIRONMENTAL TEST PROFILE FOR CATEGORY "C" ENVIRONMENTAL CONDITIONS

Figure 3.11A-8

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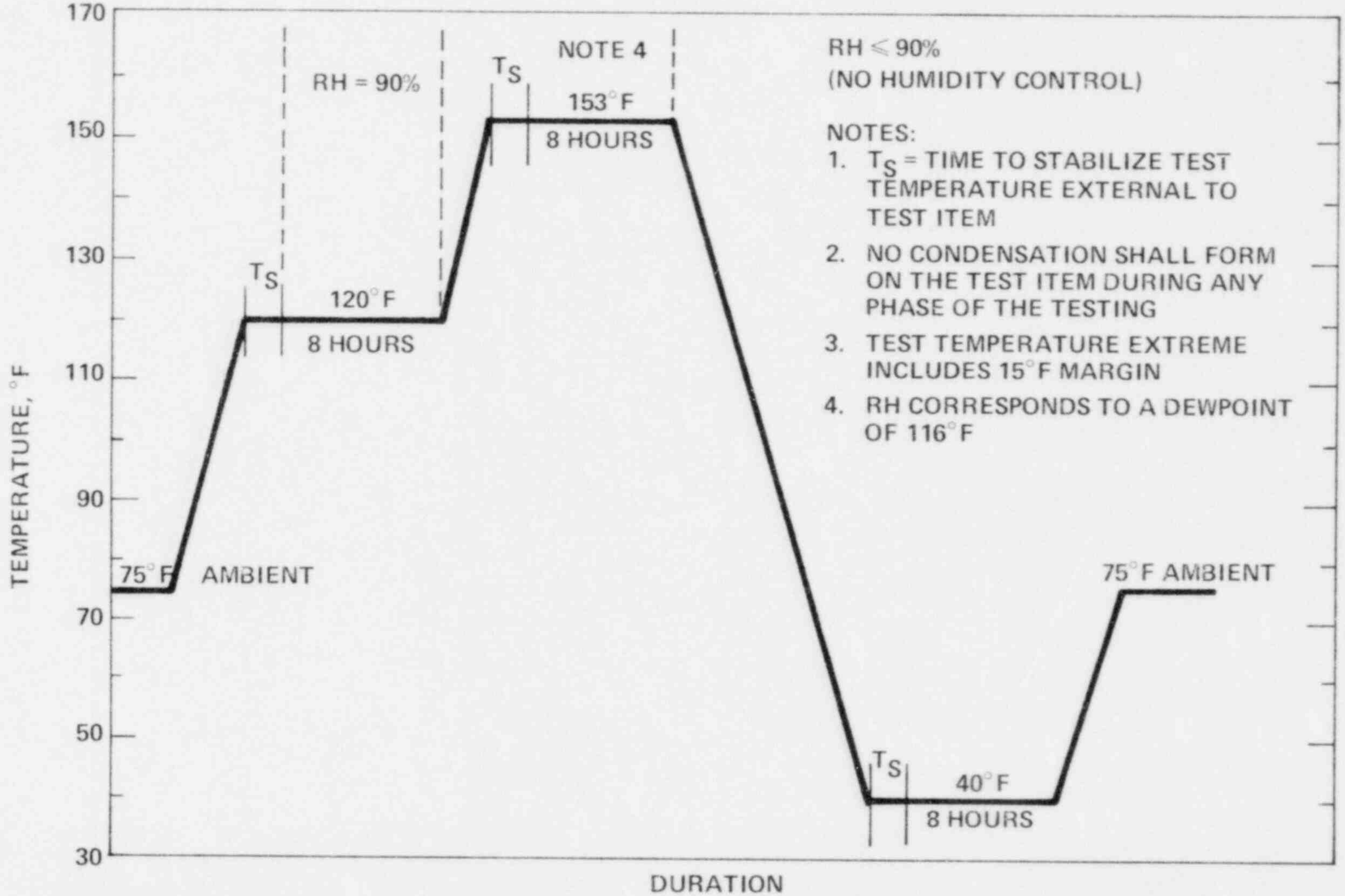

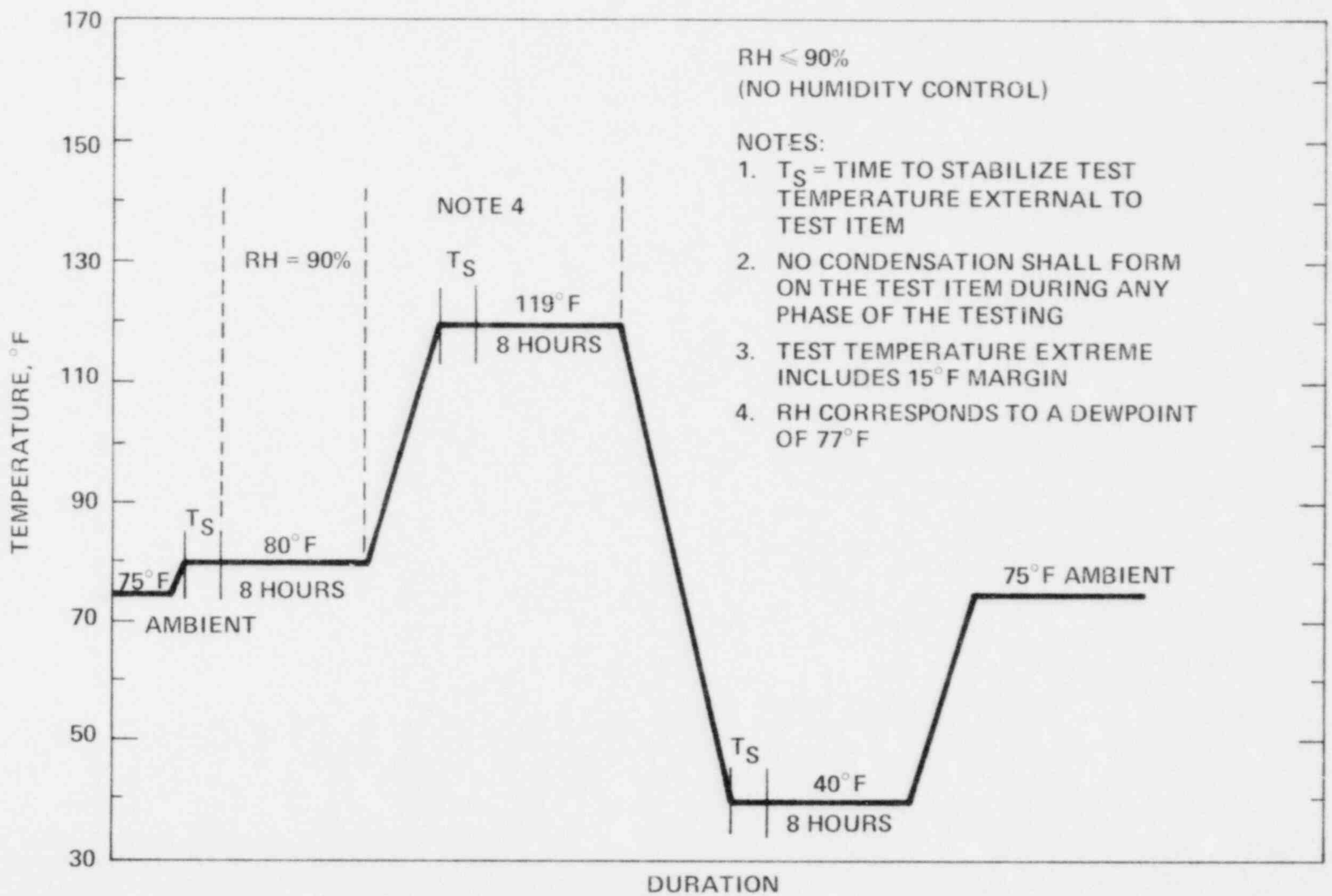

C - E SYSTEM 80

TYPICAL INSIDE CABINET ENVIRONMENTAL TEST PROFILE FOR CATEGORIES "H" AND "J" ENVIRONMENTAL CONDITIONS

Figure 3.11A-9

C - E SYSTEM 80

TYPICAL INSIDE CABINET ENVIRONMENTAL TEST PROFILE FOR CATEGORIES "H" AND "J" ENVIRONMENTAL CONDITIONS

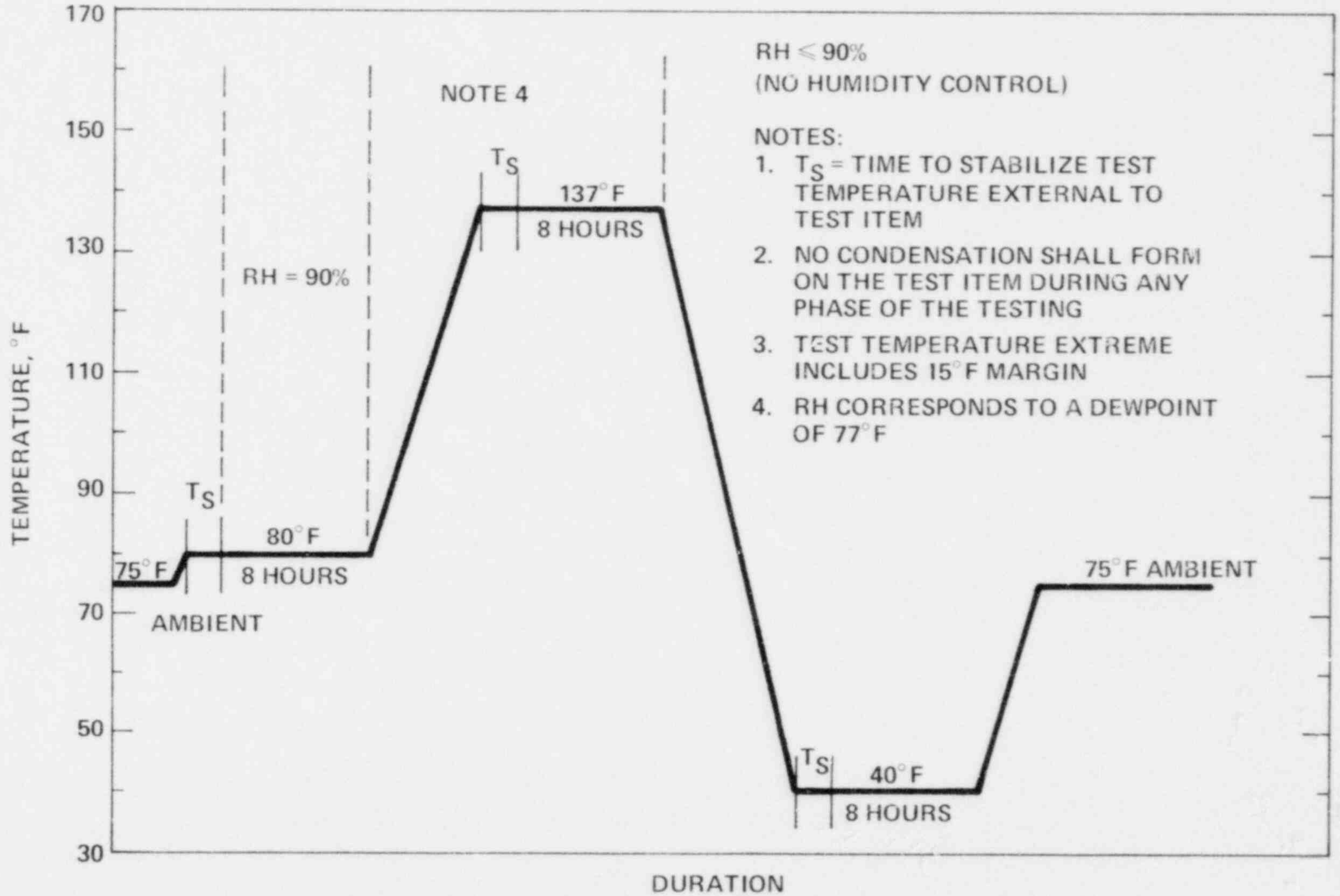

Figure 3.11A-10

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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION FOR DESIGN BASIS ACCIDENT LOCA	MSLB	SPECIFIED ENVIRONMENTAL CONDITIONS + LOCATION (SEE App. 3.11A FOR LEGEND)	EQUIPMENT AND COMPONENTS	REMARKS	DISCUSSED IN FSAR SECTION
I. Chemical + Volume Control System	Passive	Passive	C	CH-110P, CH-110Q Letdown Control Valves		9.3.4
	Passive	Passive	C	CH-201P, CH-201Q Letdown Backpressure Valves		9.3.4
	Continuous	Continuous	A-1 A-2, B	CH-203, CH-205 Auxiliary Spray Valves		9.3.4
	Passive	Passive	C	CH-204 PRM Flow Control Valve		9.3.4
	Passive	Passive	C	CH-201Y Boric Acid Control Valve		9.3.4
	Passive	Passive	C	CH-231P Seal Injection Isolation Valve		9.3.4
	Continuous	Continuous	A-1 A-2, B	CH-240 Charging Line Backpressure Valve		9.3.4
	Passive	Passive	B	CH-241, CH-242, CH-243, CH-244 Seal Injection Flow Control Valves		9.3.4
	Continuous	Continuous	C	CH-255 Seal Injection Containment Isolation Valve	C, F, G required if valve is in annulus building	9.3.4
	Passive	Passive	C	CH-500 VCT Inlet Diversion Valve		9.3.4

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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION FOR DESIGN BASIS ACCIDENT LOCA	MSLB	SPECIFIED ENVIRONMENTAL CONDITIONS + LOCATION (SEE App. 3.11A FOR LEGEND)	EQUIPMENT AND COMPONENTS	REMARKS	DISCUSSED IN FSAR SECTION
I. Chemical + Volume Control System (cont'd)	Passive	Passive	C	CH-501 VCT Discharge Isolation Valve		9.3.4
	Continuous	Continuous	C	CH-505 RCP Controlled Bleedoff Containment Isolation Valve	C, F, G required if valve is in annulus building	9.3.4
	Continuous	Continuous	A-1 A-2, B	CH-506, RCP Controlled Bleedoff Containment Isolation Valve		9.3.4
	Continuous	Continuous	B	CH-507 RCP Controlled Bleedoff Header Isolation		9.3.4
	Passive	Passive	C	CH-510 RWT Recirculation Valve		9.3.4
	Passive	Passive	C	CH-512 VCT Makeup Supply Isolation Valve		9.3.4
	Passive	Passive	C	CH-514 Boric Acid Makeup Bypass to Charging Pump Valve		9.3.4
	Continuous	Continuous	A-1, A-2, B	CH-515, CH-516, Letdown Isolation Valves		9.3.4
	Passive	Passive	C	CH-250 Purification and Deborating IX Bypass Valve		9.3.4
	Passive	Pa[illegible]	C	CH-521 PRM and Boronometer Bypass Valve		9.3.4

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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION FOR DESIGN BASIS ACCIDENT LOCA	MSLB	SPECIFIED ENVIRONMENTAL CONDITIONS + LOCATION (SEE App. 3.11A FOR LEGEND)	EQUIPMENT AND COMPONENTS	REMARKS	DISCUSSED IN FSAR SECTION
I. Chemical + Volume Control System (Cont'd)	Continuous	Continuous	C	CH-523 Letdown Isolation Valve	C, F, G required if valve is in annulus building	9.3.4
	Continuous	Continuous	C	CH-524 Charging Line Isolation Valve	C, F, G required if valve is in annulus building	9.3.4
	Passive	Passive	C	CH-526 Letdown Control Bypass Valve		9.3.4
	Passive	Passive	C	CH-527 Load Follow Supply Valve		9.3.4
	Continuous	Continuous	C, D	CH-530, CH-531 RWT Suction to ESFP's Isolation Valve	C, F, G required if valve is in annulus building	9.3.4
	Passive	Passive	C	CH-532 RWT Suction to RDP's Isolation Valve		9.3.4
	Continuous	Continuous	A-1, A-2, B	CH-560 RDT Suction Containment Isolation Valve		9.3.4
	Continuous	Continuous	C	CH-561 RDT Suction Containment Isolation Valve	C, F, G required if valve is in annulus building	9.3.4
	Passive	Passive	C	CH-562 Recycle Drain Header Isolation Valve		9.3.4
	Passive	Passive	C	CH-563 EDT Discharge Isolation Valve		9.3.4
	Passive	Passive	C	CH-564 EDT Vent Isolation Valve		9.3.4

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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION FOR DESIGN BASIS ACCIDENT LOCA	MSLB	SPECIFIED ENVIRONMENTAL CONDITIONS + LOCATION (SEE App. 3.11A FOR LEGEND)	EQUIPMENT AND COMPONENTS	REMARKS	DISCUSSED IN FSAR SECTION
I. Chemical + Volume Control System (Cont'd)	Passive	Passive	C	CH-565 Pre-Holdup IX Bypass Valve		9.3.4
	Passive	Passive	C	CH-566 Gas Stripper Diversion Valve		9.3.4
	Passive	Passive	C	CH-567 Diversion to HT from VCT Inlet Valve		9.3.4
	Continuous	Continuous	C	CH-580 RMWS to RDT Isolation Valve	C, F, G required if valve is in annulus building	9.3.4
	Passive	Passive	C	CH-686 Holdup Pump Bypass to Reactor Drain Filter Isolation Valve		9.3.4
	Continuous	Continuous	C	Charging Pumps, 1, 2, 3	C, F, G required if pumps are in annulus building	9.3.4
	Passive	Passive	C	CH-536 RWT Gravity Feed to Charging Pump Isolation Valve		9.3.4
II. Safety Injection System	Continuous	Continuous	C, D	HPSI Isolation Valves SI-616, 626, 636, 646	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	HPSI Isolation Valves SI-617, 627, 637, 647	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	LPSI Isolation Valves SI-615, 625, 635, 645	See Footnote (1)	6.3.3
	Continuous	Continuous	A-1, A-2, B	SIT Isolation Valves SI-614, 624, 634, 644		6.3.3

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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION FOR DESIGN BASIS ACCIDENT LOCA	MSLB	SPECIFIED ENVIRONMENTAL CONDITIONS + LOCATION (SEE App. 3.11A FOR LEGEND)	EQUIPMENT AND COMPONENTS	REMARKS	DISCUSSED IN FSAR SECTION
II. Safety Injection System (Cont'd)	Continuous	Continuous	A-1, A-2, B	SIT Vent Valves, SI-605, 606, 607, 608, 613, 623, 633, 643		6.3.3
	Continuous	Continuous	A-1, A-2, B	SIT Sample Valves SI-611, 621, 631, 641		6.3.3
	Continuous	Continuous	A-1, A-2, B	SIT Return Line Isolation Valve SI-682		6.3.3
	Continuous	Continuous	A-1, A-2, B	Check Valve Leakoff Isolation Valves SI-618, 628, 638, 648, SI-322, 332		6.3.3
	Continuous	Not Required	A-1, B	Containment Sump Suction Valves SI-673, 675		6.3.3
	Continuous	Not Required	C, D	Containment Sump Suction Valves SI-674, 676	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	HPSI Min. Flow Isolation Valves SI-666, 667	See Footnote (1)	6.3.3
	Continuous	Continuous	A-1, A-2, B	SDC Suction Valves SI-651, 652 653, 654		6.3.3
	Continuous	Continuous	C, D	SDC Suction Valves SI-655, 656	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	SDC Warmup Valves SI-690, 691	See Footnote (1)	6.3.3

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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION FOR DESIGN BASIS ACCIDENT LOCA	MSLB	SPECIFIED ENVIRONMENTAL CONDITIONS + LOCATION (SEE App. 3.11A FOR LEGEND)	EQUIPMENT AND COMPONENTS	REMARKS	DISCUSSED IN FSAR SECTION
II. Safety Injection System (Cont'd)	Continuous	Continuous	C, D	SDCHX Cross Connect Isolation Valves SI-685, 686, 694, 696	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	LPSI Pump Inlet Valves SI-683, 692	See Footnote (1)	6.3.3
	Continuous	Not Required	C, D	Hot Leg Injection Isolation Valves SI-321, 331, 604, 609	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	LPSI Pump Min. Flow Line Isolation Valves SI-669, 668	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	Miniflow Line Isolation Valves to RWT SI-659, 660	See Footnote (1)	6.3.3
	Continuous	Not Required	C, D	HPSI Orifice Bypass Valves SI-698, 699	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	HPSI Pumps 1 and 2	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	LPSI Pumps 1 and 2	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	Shutdown Cooling Heat Exchangers 1 and 2	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	SCS Bypass Flow Control SI-306,307	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	SDCHX Discharge Throttle SI-657,658	See Footnote (1)	6.3.3
	Not Required	Not Required	B	RDT Isolation SI-661		

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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION FOR DESIGN BASIS ACCIDENT LOCA	MSLB	SPECIFIED ENVIRONMENTAL CONDITIONS + LOCATION (SEE App. 3.11A FOR LEGEND)	EQUIPMENT AND COMPONENTS	REMARKS	DISCUSSED IN FSAR SECTION
II. Safety Injection System (Cont'd)	Continuous	Continuous	C, D	CSP Mini Flow Isolation SI-664,665	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	CSS Isolation SI-671, 672	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	CSP Flow Control SI-678, 679	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	CSP Discharge Isolation SI-684,689	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	SDCHX Discharge Isolation to CS Header SI-687, 695	See Footnote (1)	6.3.3
	Continuous	Continuous	C, D	SDCHX Spray Bypass SI-688, 693	See Footnote (1)	6.3.3.
	Not Required	Not Required	B	SIT N_2 Supply Isolation SI-612, 619 622, 629, 632, 639, 642, 649		
III. Reactor Coolant System	Intermittent	Intermittent	B	Pressurizer Spray Control Valves RC-100E, 100F		5.5.13
IV. Main Steam and Feedwater System	Continuous	Continuous	C, E	Main Steam Isolation Valves SG-170, 171, 180, 181		
	Continuous	Continuous	C, E	MSIV Bypass Valve, SG-183		
	Continuous	Continuous	C, E	Feedwater Isolation Valves, SG-130, 132, 135, 137, 172, 174, 175, 177		
	Continuous	Continuous	C, E	Atmospheric Dump Valves SG-178, 179, 184, 185		

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Footnote (1): Applicable to cylindrical shaped containments only. If spherical containment is used, See Applicant's SAR.

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D. Faulted Conditions

Condition IV incidents are postulated events whose consequences are such that integrity and operability of the nuclear energy system may be impaired. Mechanical fuel failures are permitted, but they must not impair the operation of the engineered safety features (ESF) systems to mitigate the consequences of the postulated event. Condition IV incidents are listed below:

1. Safe shutdown earthquake (SSE)

2. Loss-of-coolant accident (LOCA)

3. Combined SSE and LOCA

4. Locked coolant pump rotor

5. Major secondary system pipe rupture

6. CEA ejection

7. Major fuel handling accident (fuel assembly and grapple are disengaged)

4.2.1.1.1 Fuel Assembly Structural Integrity Criteria

For each of the design conditions, there are criteria which apply to the fuel assembly and components with the exception of fuel rods. These criteria are listed below and give the allowable stresses and functional requirements for each design condition. Criteria for fuel rods are discussed separately in Section 4.2.1.2.

A. Design Conditions I and II

$$P_m \leq S_m$$

$$P_m + P_b \leq F_s S_m$$

Under cyclic loading conditions, stresses must be such that the cumulative fatigue damage factor does not exceed 0.8. Cumulative damage factor is defined as the sum of the ratios of the number of cycles at a given cyclic stress (or strain) condition to the maximum number permitted for that condition. The selected limit of 0.8 is used in place of 1.0 (which would correspond to the absolute maximum damage factor permitted) to provide additional margin in the design.

Deflections must be such that the allowable trip time of the control element assemblies is not exceeded.

B. Design Condition III

$$P_m \leq 1.5\ S_m$$

$$P_m + P_b \leq 1.5\ F_s S_m$$

Deflections are limited to a value allowing the CEAs to trip, but not necessarily within the prescribed time.

C. Design Condition IV

$P_m \leq S'_m$

$P_m + P_b \leq F_s S'_m$

where S'_m = smaller value of 2.4 S_m or 0.7 S_u.

1. If the equivalent diameter pipe break in the LOCA does not exceed 0.5 square foot, the fuel assembly deformation shall be limited to a value not exceeding the deformation which would preclude satisfactory insertion of the CEAs.

2. For pipe break sizes greater than 0.5 square foot, deformation of structural components is limited to maintain the fuel in a coolable array. CEA insertion is not required for these events as the appropriate safety analyses do not take credit for CEA insertion.

3. For the upper and fitting springs, calculated shear stress must not exceed the minimum yield stress in shear.

4. For the spacer grids, the predicted impact loads must be less than the tested grid capability, ad defined in Reference 50. 7

D. Nomenclature

The symbols used in defining the allowable stress levels are as follows:

P_m = Calculated general primary membrane stress[a]

P_b = Calculated primary bending stress

S_m = Design stress intensity value as defined by Section III, ASME Boiler and Pressure Vessel Code[b]

S_u = Minimum unirradiated ultimate tensile strength

F_s = Shape factor corresponding to the particular crosss section being analyzed[c]

S'_m = Design stress intensity value for faulted conditions

The definition of S'_m as the lesser value of 2.4 S_m and 0.7 S_u is contained in the ASME Boiler and Pressure Vessel Code, Section III. 7

a. P_m and P_b are defined by Section III, ASME Boiler and Pressure Vessel Code.

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b. With the exception of zirconium base alloys, the design stress intensity values, S_m, of materials not tabulated by the Code are determined in the same manner as the Code. The design stress intensity of zirconium base alloys shall not exceed two-thirds of the unirradiated minimum yield strength at temperature. Basing the design stress intensity on

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the unirradiated yield strength is conservative because the yield strength of zircaloy increases with irradiation. The use of the two-thirds factor ensures 50% margin to component yielding in response to primary stresses. This 50% margin together with its application to the minimum unirradiated properties and the general conservatism applied in the establishment of design conditions is sufficient to ensure an adequate design.

c. The shape factor, F_s, is defined as the ratio of the "plastic" moment (all fibers just at the yield stress) to the initial yield amount (extreme fiber at the yield stress and all other fibers stressed in proportion to their distance from the neutral axis). The capability of cross sections loaded in bending to sustain moments considerably in excess of that required to yield the outermost fibers is discussed in Timoshenko.[1]

4.2.1.1.2 Material Selection

The fuel assembly grid cage structure consists of 10 Zircaloy-4 spacer grids, 1 Inconel 625 spacer grid (at the lower end), 5 Zircaloy-4 guide 7
tubes, 2 stainless steel end fittings, and 4 Inconel X-750 coil springs. Zircaloy-4, selected for fuel rod cladding, guide tubes and spacer grids, has a low neutron absorption cross section, and high corrosion resistance to reactor water environment. Also there is little reaction between the cladding and fuel or fission products. As described in Section 4.2.3, Zircaloy-4 has demonstrated its ability as a cladding, CEA guide tube, and spacer grid material.

The bottom spacer grid is of Inconel 625 and is welded to the lower end fitting. In this region of local inlet turbulence, Inconel 625 was selected rather than Zircaloy-4 to provide additional strength and relaxation resistance. Inconel 625 is a very strong material with good ductility, corrosion resistance and stability under irradiation at temperatures below 1000F.

The fuel assembly lower end fitting is of cast 304 stainless steel (Grade CF-8) and the upper end fitting assembly consists of two cast stainless steel plates and five Type 304 stainless steel machines alignment posts. This material was selected based on considerations of adequate strength and high-corrosion resistance. Also, Type 304 stainless steel has been used successfully in almost all pressurized water reactor environments, including all currently operating C-E reactors.

4.2.1.1.3 Control Element Assembly Guide Tubes

All CEA guide tubes are manufactured in accordance with Grade RA-2, ASTM B353-71, Wrought Zirconium and Zirconium Alloy Seamless and Welded Tubes for Nuclear Serivce, with the following exceptions and/or additions:

A. Chemical Properties

Additional limits are placed on oxygen.

B. Mechanical Properties

1. Flare

A section of annealed tube, between 2 and 4 inches in length, shall be flared with a tool having a 60-degree included angle until the outside diameter has increased by 15%. The flared tube shall show no cracking when examined with the unaided eye.

C. Dimensional Requirements

Dimension	Permissible Tolerance (in.)
OD	± 0.003
ID	± 0.005

4.2.1.1.4 Zircaloy-4 Bar Stock

All Zircaloy-4 bar stock is fabricated in accordance with Grade RA-2, ASTM B351, Hot-Rolled and Cold-Finished Zirconium and Zirconium Alloy Bars, Rod and Wire for Nuclear Application, with the following exceptions and/or additions:

A. Chemical Properties

Additional limits are placed on oxygen and silicon content,

B. Metallurgical Properties

1. Grain Size

The maximum average grain size is restricted.

4.2.1.1.5 Zircaloy-4 Strip Stock

All Zircaloy-4 strip stock is fabricated in accordance with Grade RA-2, ASTM B352, Zirconium and Zirconium Alloy Sheet, Strip and Plate for Nuclear Application, with the following exceptions and/or additions:

A. Chemical Properties

Additional limits are placed on oxygen and silicon content.

B. Metallurgical Properties

1. Grain Size

The maximum average grain size is restricted.

D. Specific Heat of UO_2

The specific heat of UO_2 is described by the following temperature dependent equations.[20]

$\underline{T < 2240F}$

$$C_p = 49.67 + 2.2784 \times 10^{-3}T - \frac{3.2432 \times 10^6}{(T + 460)^2}$$

$\underline{T \geq 2440\ F}$

$$C_p = -126.07 + 0.2621T - 1.399 \times 10^{-4}T^2 + 3.1786 \times 10^{-8}T^3 - 2.483 \times 10^{-12}T^4$$ 7

where:

C_p = specific heat, BTU/ft^3 - °F

T = temperature, °F

4.2.1.2.4.5 Mechanical Properties

A. Young's Modulus of Elasticity

The static modulus of elasticity of unirradiated fuel of 97% TD and deformed under a strain rate of 0.097 hr^{-1} is given by (Reference 21).

$$E = 14.22\ (1.6715 \times 10^6 - 924.4T)$$

where;

E = modulus of elasticity in psi,
T = temperature in °C in the range of 1000 to 1700°C.

B. Poisson's Ratio

The Poisson's Ratio of polycrystalline UO_2 has a value of 0.32 at 25°C based on Reference 66. The same reference notes a 10% decrease in value over the range of 25 to 1800°C. Assuming the decrease is linear, the temperature dependence of the Poisson's Ratio is given by

$$\nu = 0.32 - 1.8 \times 10^{-5}\ (T-25)$$

where;
ν = Poisson's Ratio
T = temperature in °C in the range of 25 to 1800°C.

At temperature above 1800°C, a constant value of 0.29 is used for Poisson's Ratio.

C. Yield Stress (not applicable)

D. Ultimate Stress (not applicable)

E. Uniform Ultimate Strain (not applicable)

4.2.1.2.5 Fuel Rod Pressurization

Fuel rods are initially pressurized with helium for two reasons:

A. Preclude clad collapse during the design life of the fuel. The internal pressurization, by reducing stresses from differential pressure, extends the time required to produce creep collapse beyond the required service life of the fuel.

B. Improve the thermal conductivity of the pellet-to-clad gap within the fuel rod. Helium has a higher coefficient of thermal conductivity than the gaseous fission products.

In unpressurized fuel, the initially good helium conductivity is eventually degraded through the addition of the fission product gases released from the pellets. The initial helium pressurization results in a high helium to fission products ratio over the design life of the fuel with a corresponding increase in the gap conductivity and heat transfer. The effect of fuel rod power level and pin burnup on fuel rod internal pressure has been studied parametrically.

The initial helium fill pressure will be 380 PSIG. This initial fill pressure will be sufficient to prevent clad collapse discussed in Section 4.2.3.2.8 and will produce a maximum EOL internal pressure consistent with the criteria of Section 4.2.1.2.1. The calculational methods employed to generate internal pressure histories are discussed in Reference 14.

4.2.1.2.5.1 Capacity for Fission Gas Inventory. The greater portion of the gaseous fission products remain either within the lattice or the microporosity of the UO_2 fuel pellets and do not contribute to the fuel rod internal pressure. However, a fraction of the fission gas is released from the pellets by diffusion and pore migration and thereafter contributes to the internal pressure.

The determination of the effect of fission gas generated in and released from the pellet column is discussed in Section 4.2.3.2.2. The rod pressure increase which results from the release of a given quantity of gas from the fuel pellets depends upon the amount of open void volume available within the fuel rod and the temperatures associated with the various void volumes. In the fuel rod design, the void volumes considered in computing internal pressure are:

- Fuel rod upper end plenum

- Fuel-clad annulus

C. Inconel Alloy 625 (Ni-Cr-Fe)

Configuration (as absorber)	Cylindrical bar
Outside diameter, inches	0.816 $\pm$0.002
Inside diameter, inches	Solid
Length of cylinder, inches	74.375 (Part length CEA)
Density, $lb/in.^3$	0.305
Ultimate tensile Strength, $lb/in.^2$	120-150
Specified minimum yield strength @ 650F, ksi	65
Elongation in 2 inches, %	30
Young's modulus, $lb/in.^2$	
at 70F	29.7×10^6
at 650F	27.0×10^6
Thermal conductivity (Btu/h-ft-°F):	
70F	5.7
600F	8.2
Linear thermal expansion (in./in.-°F)	7.4×10^{-6} (70 to 600F)

4.2.1.4.2 Compatibility of Absorber and Cladding Materials

The cladding material used for the control elements is Inconel Alloy 625. The selection of this material for use as cladding is based on consideration of strength, creep resistance, corrosion resistance, and dimensional stability under irradiation and also upon the acceptable performance of this material for this application in other C-E reactors currently in operation.

A. B_4C/Inconel 625 Compatibility

Studies have been conducted by HEDL[38] on the compatibility of Type 316 stainless steel with B_4C under irradiation for thousands of hours at temperatures between 1300 and 1600F. Carbide formation to a depth of about 0.004

inch in the 316 stainless steel was measured after 4400 hours at 1300F. Similar compound formation depths were observed after ex-reactor bench testing. After testing at 1000F, only 0.001 in./yr of penetration was measured. Since Inconel 625 is more resistant to carbide formation than 316 stainless steel, and the expected pellet/clad interfacial temperature in the standard design is below 800F, it is concluded that B_4C is compatible with Inconel 625.

4.2.1.4.3 Cladding Stress-Strain Limits

The stress limits for the Inconel Alloy 625 cladding are as follows:

Design conditions of Non-Operation, Normal Operation, and Upset Conditions:

$$P_m \le S_m$$

$$P_m + P_b \le F_s S_m$$

The net unrecoverable circumferential strain shall not exceed 1% on the cladding diameter, considering the effects of pellet swelling and cladding creep. 7

Design conditions of Emergency Conditions:

$$P_m \le 1.5\ S_m$$

$$P_m + P_b \le 1.5\ F_s S_m$$

Design conditions of Faulted Conditions:

$$P_m \le S'_m$$

$$P_m + P_b \le F_s S'_m$$

where S_m is the smaller of 2.4 S_m or $0.7S_u$

For definition of P_m, P_b, S_m, S'_m, S_u, and F_s, see Section 4.2.1.1.1. For the Inconel 625 CEA cladding, the value of S_m is two-thirds of the minimum specified yield strength at temperature.

For Inconel 625, the specified minimum yield strength is 65,000 lb/in.^{2} at 650F.

F_s = Mp/My where Mp is the bending moment required to produce a fully plastic section and My is the bending momemt which first produces yielding at the extreme fibers of the cross-section. The capability of cross-sections loaded in bending to sustain moments considerably in excess of that required to yield the outermost fiber is discussed in Reference 1. For the CEA cladding dimensions, F_s = 1.33.

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The values of uniform and total elongation of Inconel Alloy 625 cladding are estimated to be as follows:

Fluence (E >1 MeV), nvt	1×10^{22}	3×10^{22}
Uniform elongation, %	3	1
Total elongation, %	6	3

4.2.1.4.4 Irradiation Behavior of Absorber Materials

A. Boron Carbide Properties

1. Swelling. The linear swelling of B_4C increases with burnup according to the relationship:

   $\%\Delta L = (0.1)\ B^{10}$ Burnup, a/o

   This relationship was obtained from experimental irradiations on high density (>90% TD) wafers[39] and pellets with densities ranging between 71 and 98% TD.[38] [40] Dimensional changes were measured as a function of burnup, after irradiating at temperature expected in the design.

2. Thermal Conductivity. The thermal conductivity of unirradiated 73% dense B_4C decreases linearly with temperatures from 300 to 1600 F, according to the relationship:

   $$\lambda = \frac{1\ \text{cal/cm-°K-s}}{2.17\ (6.87 + 0.017\ T)}$$

   This relationship was obtained from measurements performed on pellets ranging from 70 to 98% TD.[41]

   The relationship between the thermal conductivity of irradiated 73% TD B_4C pellets and temperature given below was derived from measured values[41] on higher density pellets irradiated to fluences out to 3×10^{22} nvt (E >1 MeV).

   $$\lambda = \frac{1\ \text{cal/cm-°K-s}}{2.17\ (38 + 0.025\ T)}$$ 7

   where T = temperature, °K

   Thermal conductivity measurements of 17 B_4C specimens with densities ranging from 83 to 98% TD, irradiated at temperatures from 930 to 1600F showed that thermal conductivity decreased significantly after irradiation. The rate of decrease is high at the lower irradiation temperatures, but saturates rapidly with exposure.

3. Helium Release. Helium is formed in B_4C as B^{10} burnup progresses. The fraction of helium released from the pellets is important for determining rod internal gas pressure. The relationship between

helium release and irradiation temperature given below was developed at ORNL[42] to fit experimental data obtained from thermal reactor irradiations.

$$\%\text{He release} = e^{(C-1.85D)} e^{\frac{-Q}{RT}}$$

where:

C = Constant, 6.69 for pellets
D = Fractional density, 0.73 for C-E pellets
Q = Activation energy contant, 3600 cal/mole
R = Gas constant, 1.98 cal/mole - °K
T = Pellet temperature, °K

This expression becomes

$$\%\text{ He release} = 208\ e^{\frac{-1820}{T}} + 5$$

when the above parameters are substituted. In this form, design values for helium release as a function of temperature are generated. The 5% helium release allowance (the last term in the expression) was added to ensure that design values lie above all reported helium release data. Calculated values of helium release obtained from the recommended design expression lie above all experimental data points [38] [43] [44] obtained on B_4C pellet specimens irradiated in thermal reactors.

4. Pellet Porosity. Experimental evidence is available[45] which shows that for pellet densities below 90%, essentially all porosity is open at beginning-of-life. Irradiation-induced swelling does not change the characteristics of the porosity, but only changes the bulk volume of the specimens. Therefore, the amount of porosity available at end-of-life is the same as that present at beginning-of-life.

B. Inconel 625

1. Swelling. Available information indicates that Inconel 625 is highly resistant to radiation swelling. Exposure of Inconel 625 to a fluence of 3 x 10^{22} nvt (E>0.1 MeV) at a temperature of 400C (725F) showed no visible cavities in metallographic examinations[48] so that swelling, if any, would be very minor. Direct measurements made after exposure of Inconel 625 to a fluence 5 x 10^{22} nvt (E>0.1 MeV) as LMFBR conditions showed no evidence of swelling.[49] Further exposure to 6 to 10^{22} nvt (E>0.1 MeV) at 500°C (932°F) showed essentially no swelling as measured by immersion density, but did show small cavities. Thus, Inconel 625 after fluences of 3 x 10^{22} nvt (E>1 MeV) is not expected to swell.

2. Ductility. The ductility of Inconel 625 decreases after irradiation. Extrapolation of lower fluence data on Inconel 625 and 500 indicates that the values of uniform and total elongation of Inconel 625 after 1×10^{22} nvt (E >1 MeV) are 3 and 6%, respectively.

3. Strength. The value of yield strength of Inconel 625 increases after irradiation in the manner typical for metals. However, no credit is taken for increases in yield strength in the design analyses above the value initially specified.

4.2.1.5 Surveillance Program

4.2.1.5.1 Requirements for Surveillance and Testing of Irradiated Fuel Rods

High burnup performance experience, as described in Section 4.2.3 has provided evidence that the fuel will perform satisfactorily under the design conditions. The current core design bases do not include a specific requirement for surveillance and testing of irradiated fuel rods. C-E, however, has instituted a fuel surveillance program on each reactor core produced. Under this program, selected fuel assemblies are characterized during the fabrication process. Detailed measurements of important fuel pellet and cladding attributes, as well as dimensional characteristics of the fuel assembly structure, are made and recorded. In addition, special examination equipment is available to repeat the measurements of these characterized fuel assemblies in refueling pools. The fuel assembly design allows disassembly and reassembly to facilitate such inspections. Thus, should the need arise, irradiated fuel rod examination can be accomplished.

A fuel rod irradiation program has been developed to evaluate the performance of fuel rods designed for use in the 16 x 16 fuel assembly. The program includes the irradiation of six standard 16 x 16 assemblies, two each for 1, 2, and 3 cycles, respectively, in the Arkansas Nuclear One-Unit 2 reactor. Each assembly will contain a minimum of 50 precharacterized, removable rods distributed within the assembly to obatin a spectrum of exposure levels for evaluation purposes in interim and terminal examinations. Interim examination of all six assemblies is planned during refueling shutdowns after each cycle.

The ANO-2 fuel rods and specific components of the fuel rods have recieved a detailed pre-characterization. The program calls for substantial cladding characterization to include mechanical properties, texture, hydride orientation and out-of-reactor low strain rate behavior. In addition to the ID and OD dimensional data normally obtained on the clad tubing material, a minimum of 300 fuel rods will be measured to obtain as-loaded dimensions. Sufficient fuel rods will be profiled to obtain diameter and ovality measurements such that changes in these parameters can be tracked by similar measurements during interim inspections. Also, a random selection of approximately 100 UO_2 pellets from each lot per batch used will be characterized dimensionally and the density distribution will be determined. About one-half of these pellets will be placed in known axial locations in selected fuel rods while the remainder will be set aside as archives.

A poolside non-destructive examination will be made during each of the first three refuelings at ANO-2. The six 16 x 16 assemblies with characterized rods will be removed from the reactor at each refueling and moved to the spent fuel pool for leak testing (if failed fuel is in the core) and for visual inspection. The length of the assembly and peripheral rods will be measured. During the shutdown, a target of 20 pre-characterized rods per batch will be scheduled for examination and measurement. At some time after the refueling outage, pre-characterized rods retained in discharged assemblies will be measured. A target of 100 rods will be eddy current tested after each shutdown.

4.2.2 DESCRIPTION AND DESIGN DRAWINGS

This subsection summarizes the mechanical design characteristics of the fuel system and discusses the design parameters which are of significance to the performance of the reactor. A summary of mechanical design parameters is presented in Table 4.2-1. These data are intended to be descriptive of the design; limiting values of these and other parameters will be discussed in the appropriate sections.

4.2.2.1 Fuel Assembly

The fuel assembly (Figure 4.2-6) consists of 236 fuel and poison rods, 5 guide tubes, 11 fuel rod spacer grids, upper and lower end fittings, and a 7
holddown device. The outer guide tubes, spacer grids, and end fittings form the structural frame of the assembly.

The fuel spacer grids (Figure 4.2-7) maintain the fuel rod array by providing positive lateral restraint to the fuel rod but only frictional restraint to axial fuel rod motion. The grids are fabricated from preformed Zircaloy or Inconel strips (the bottom spacer grid material is Inconel) interlocked in an egg crate fashion and welded together. Each cell of the spacer grid contains two leaf springs and four arches. The leaf springs press the rod against the arches to restrict relative motion between the grids and the fuel rods. The perimeter strips contain features designed to prevent hangup of grids during a refueling operation.

The ten Zircaloy-4 spacer grids are fastened to the Zircaloy-4 guide tubes 7
by welding, and each grid is welded to each guide tube at eight locations, four on the upper face of the grid and four on the lower face of the grid, where the spacer strips contact the guide tube surface. The lowest spacer grid (Inconel) is not welded to the guide tubes due to material differences. It is supported by an Inconel 625 skirt which is welded to the spacer grid and to the perimeter of the lower end fitting.

The upper end fitting is an assembly consisting of two cast 304 stainless steel plates, five machined posts and four helical Inconel X-750 springs. 7 The end fitting attaches to the guide tubes to serve as an alignment and locating device for each fuel assembly and has features to permit lifting of the fuel assembly. The lower cast plate locates the top ends of the guide tubes and is designed to prevent excessive axial motion of the fuel rods.

The Inconel X-750 springs are of conventional coil design having a mean diameter of 1.856 in., a wire diameter of 0.316 in., and 16 active coils. Inconel X-750 was selected for this application because of its previous use for coil springs and good resistance to relaxation during operation.

The upper cast plate of the assembly, called the holddown plate, together with the helical compression springs, comprise the holddown device. The holddown plate is movable, acts on the underside of the tube sheet tubes and is loaded by the compression springs. Since the springs are located at the upper end of the assembly, the spring load combines with the fuel assembly weight to counteract upward hydraulic forces. The determination of upward hydraulic forces includes factors accounting for flow maldistribution, fuel assembly component tolerances, crud buildup, drag coefficient, and bypass flow. The springs are sized and the spring preload selected such that a net downward force will be maintained for all normal and anticipated transiet flow and temperature conditions. The design criteria limit the maximum stress under the most adverse tolerance conditions to below yield strength of the spring material. The maximum stress occurs during cold conditions and decreases as the reactor heats up. The reduction in stress is due to a decrease in spring deflection resulting from differential thermal expansion between the Zircaloy fuel bundles and the stainless steel internals.

During normal operation, a spring will never be compressed to its solid height. However, if the fuel assembly were loaded in an abnormal manner such that a spring were compressed to its solid height, the spring would continue to serve its function when the loading condition returned to normal.

The lower end fitting assembly is a simple stainless steel casting consisting 7 of a plate with flow holes and a support leg at each corner (total of four legs) that aligns the lower end of the fuel assembly with the core support structures alignment pins. Each alignment pin is required to position the corners of four lower end fittings. A center post is threaded into the central portion of 7 the flow plate and crimped into position.

The four outer guide tubes have a widened region at the upper end which contains an internal thread. Connection with the upper end fitting is made by passing the externally threaded end of the guide posts through holes in the lower cast flow plate and into the guide tubes. When assembled, the flow plate is secured between flanges on the guide tubes and on the guide posts. The connection with the upper end fitting is locked with a mechanical crimp. Each outer guide tube has, at its lower end, a welded Zircaloy-4 fitting. This fitting has a threaded portion which passes through a hole in the fuel assembly lower end fitting and is secured by a Zircaloy-4 nut. This joint is secured with a stainless steel locking ring tack welded to the lower end fitting in four places.

The central instrumentation guide tube inserts into a socket and a sleeve
in the upper and lower end fittings, respectively, and is thus retained 7
laterally by the relatively small clearance at these locations. The upper
end fitting socket is created by the center guide tube post which is threaded
into the lower cast flow plate and tack welded in two places. The lower end 7
fitting sleeve is an extension from the center post of the lower end fitting
assembly. There is no positive axial connection between the central guide
tube and the end fittings.

The five guide tubes have the effect of ensuring that bowing or excessive swelling of the adjacent fuel rods cannot result in obstruction of the control element pathway. This is so because:

A. There is sufficient clearance between the fuel rods and the guide tube surface to allow an adjacent fuel rod to reach rupture strain without contacting the guide tube surface.

B. The guide tube, having considerably greater diameter and wall thickness (and also, being at a lower temperature) than the fuel rod, is considerably stiffer than the fuel rods and would, therefore, remain straight, rather than be deflected by contact with the surface of an adjacent fuel rod.

Therefore, the bowing or swelling of fuel rods would not result in obstruction of the control element channels such as could hinder CEA movement.

The fuel assembly design enable reconstitution, i.e., removal and replacement of fuel and poison rods, of an irradiated fuel assembly. The fuel and poison rod lower end caps are conically shaped to ensure proper insertion within the fuel assembly grid cage structure; the upper end caps are designed to enable grappling of the fuel and poison rod for purposes of removal and handling. Threaded joints which mechanically attach the upper end fitting to the control element guide tubes will be properly torqued and locked during service, but may be removed to provide access to the fuel and poison rods.

Loading and movement of the fuel assemblies is conducted in accordance with strictly monitored administrative procedures and, at the completion of fuel loading, an independent check as to the location and orientation of each fuel assembly in the core is required.

The serial number provided on the fuel assembly upper end fitting enables verification of fuel enrichment and orientation of the fuel assembly. The serial number is also provided on the lower end fitting to ensure preservation of fuel assembly identity in the event of upper end fitting removal. Additional markings are provided on the fuel rod upper end caps as a secondary check to distinguish between fuel enrichments and burnable poison rods, if present.

During the manufacturing process, the lower end cap of each rod is marked to provide a means of identifying the pellet enrichment, pellet lot and fuel stack weight. In addition, a quality control program specification requires that measures be established for the identification and control of materials, components, and partially fabricated subassemblies. These means provide

assurance that only acceptable items are used and also provide a method of relating an item or assembly from initial receipt through fabrication, installation, repair, or modification to an applicable drawing, specification, or other pertinent technical document.

4.2.2.2 Fuel Rod

The fuel rods consist of slightly-enriched UO_2 cylindrical ceramic pellets, a round wire Type 302 stainless steel compression spring, and an alumina spacer disc located at each end of the fuel column, all encapsulated within a Zircaloy-4 tube seal welded with Zircaloy-4 end caps. The fuel rods are internally pressurized with helium during assembly. Figure 4.2-8 depicts the fuel rod design.

Each fuel rod assembly includes both a serial number and a visual identification mark. The serial number ensures traceability of the fabrication history of each fuel rod component. The identification mark provides a visual check on pellet enrichment batch during fuel bundle fabrication.

The fuel cladding is cold worked and stress relief annealed Zircaloy-4 tubing 0.025 inches thick. The actual tube forming process consists of a series of cold working and annealing operations, the details of which are selected to provide the combination of and properties discussed in Section 4.2.1.2.2.

The UO_2 pellets are dished at both ends in order to better accommodate thermal expansion and fuel swelling. The density of the UO_2 in the pellets is 10.38 g/cm^3, which corresponds to 94.75% of the 10.96 g/cm^3 theoretical density (TD) of UO_2. However, because the pellet dishes and chamfers constitute about 3% of the volume of the pellet stack, the average density of the pellet stack is reduced to 10.06 g/cm^3. This number is referred to as the "stack density".

The compression spring located at the top of the fuel pellet column maintains the column in its proper position during handling and shipping. The alumina spacer disc at the lower end of the fuel rod reduces the lower end cap temperature, while the upper spacer disc prevents UO_2 chips, if present, from entering the plenum region. The fuel rod plenum which is located above the pellet column, provides space for axial thermal differential expansion of the fuel column and accommodates the initial helium loading and evolved fission gases. (See Section 4.2.1.2.5.1 and 4.2.1.2.5.2.) The specific manner in which these factors are taken into account, including the calculation of temperatures for the gas contained within the various types of rod internal void volume, is discussed in Reference 14.

4.2.2.3 Burnable Poison Rod

Fixed burnable neutron absorber (poison) rods, Figure 4.2-9, will be included in selected fuel assemblies to reduce the beginning-of-life moderator coefficient. They will replace fuel rods at selected locations. The poison rods will be mechanically similar to fuel rods, but will contain a column of burnable poison pellets instead of fuel pellets. The poison material will

be alumina with uniformly-dispersed boron carbide particles. The balance of the column will consist of alumina pellets, with the total column length the same as the column length in fuel rods. The burnable poison rod plenum spring is desinged to produce a smaller preload on the pellet column than that in a fuel rod because of the lighter material in the poison pellets.

Each burnable poison rod assembly includes a serial number and visual identification mark. The serial number is used to record fabrication information for each component in the rod assembly. The identification mark is unique to poison rods and provides a visual check on the pellet boron content during fuel bundle fabrication.

4.2.2.4 Control Element Assembly Description and Design

The control element assemblies consist of four, and twelve neutron absorber elements arranged to engage the peripheral guide tubes of fuel assemblies. The neutron absorber elements are connected by a spider structure which couples to the control element drive mechanism (CEDM) drive shaft extension. The neutron absorber elements of a four element CEA engage the four corner guide tubes in a single fuel assembly. The four element CEAs are used for power shaping functions and make up the first control rod group to be inserted at high power. The twelve-element CEAs engage the four corner guide tubes in one fuel assembly and the two nearest corner guide tubes in adjacent fuel assemblies. The twelve element CEAs make up the balance of the control groups of CEAs and provide a bank of strong shutdown rods. The control element assemblies are shown in Figures 4.2-3 and 4.2-5. The pattern of CEAs (total of 89) is shown in Figure 4.2-10. Note that up to eight additional CEAs may be installed if desired for additional flexibility or future use.

Part-length CEAs are differentiated from full-length CEAs by using alphanumeric serialization instead of the numerical system used on the full-length CEAs. 7

The control elements of a full-length CEA consist of an Inconel 625 tube loaded with a stack of cylindrical absorber pellets. The absorber material consists of 73% TD boron carbide (B_4C) pellets, with the exception of the lower portion of the elements, which contain reduced diameter B_4C pellets wrapped in a sleeve of type 347 stainless steel felt metal.

The design objective realized by the use of felt metal and reduced B_4C pellets in the element tip zones is that as the B_4C pellets swell due to irradiation, the felt metal sleeve compresses as a result of the applied loading. This compression limits the amount of induced strain in the cladding. Therefore buffering of the CEA following scram, which occurs when the

B. Short-term axial load due to the impact of the spring loaded CEA spider against the upper guide structure support plates at the end of a CEA trip.

For trips occurring during normal power operation, solid impact is not predicted to occur due to the kinetic energy of the CEA being dissipated in the hydraulic buffer and by the CEA spring.

C. Short-term differential pressure load occurring in the hydraulic buffer regions of the outer guide tubes at the end of each trip stroke.

The buffer region slows the CEA during the last few inches of the trip stroke. the resultant differential pressure across the guide tube in this region is predicted to be 300 $lb/in.^2$, and this gives rise to circumferential stresses of 3300 $lb/in,^2$, which is less than one-quarter of the yield stress, for a very short term. The trip is assumed to be repeated daily. However the resultant stress is too small to have a significant effect on fatigue usage.

For conditions other than normal operation, the additional mechanical loads imposed on the fuel assembly by an OBE (equivalent to one-half DBE), DBE, and large break LOCA and their resultant effect on the control element guide tubes are discussed in the following paragraphs:

4.2.3.1.2.1 Operating Basis Earthquake (OBE). During the postulated OBE, the fuel assembly is subjected to lateral and axial accelerations which, in turn, cause the fuel assembly to deflect from its normal shape. The method of calculating these deflections is described in Section 3.7.3.14. The magnitude of the lateral deflections and resultant stresses are evaluated for acceptability. The method for calculating stresses from deflected shapes is described in Reference 50. The fuel assembly is designed to be capable of withstanding the axial loads without buckling and without sustaining excessive stresses.

4.2.3.1.2.2 Safe Shutdown Earthquake (SSE). The axial and lateral loads and deformation sustained by the fuel assembly during a postulated SSE have the same origin as those discussed above for the OBE, but they arise from initial ground accelerations twice those assumed for the OBE. The analytical methods used for the SSE are identical to those used for the OBE.

4.2.3.1.2.3 Loss-of-Coolant Accident (LOCA). In the event of a large break LOCA, there will occur rapid changes in pressure and flow within the reactor vessel. Associated with the transient are relatively large axial and lateral loads on the fuel assemblies. The response of a fuel assembly to the mechanical loads produced by a LOCA is considered acceptable if the fuel rods are maintained in a coolable array, i.e., acceptably low grid crushing. The methods used for analysis of combined seismic and LOCA loads and stresses is described in Reference 50.

4.2.3.1.2.4 Combined SSE and LOCA. It is not considered appropriate to combine the stresses resulting from the SSE and LOCA events. Nevertheless, for purposes of demonstrating margin in the design, the maximum stress 7

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intensities for each individual event will be combined by a square root of
sum of the squares (SRSS) method. This will be performed as a function of
fuel assembly elevation and position, e.g., the maximum stress intensities
for the center guide tube at the upper grid elevation (as determined in the 7
analysis discussed in the above paragraphs for SSE and LOCA) will be com-
bined by the SRSS method. It is expected that the results will demonstrate
that the allowable stresses described in paragraph 4.2.1.1 are not exceeded
for any position along the fuel assembly even under the added conservatism
provided by this load combination.

To qualify the complete fuel assembly, full-scale hot loop testing is being conducted. The tests are designed to evaluate fretting and wear of components, refueling procedures, fuel assembly uplift forces, holddown performance and

compatibility of the fuel assembly with interfacing reactor internals, CEAs and CEDMs under conditions of reactor water chemistry, flow velocity, temperature, and pressure. The test assembly will be identical to the 16 x 16 five guide tube design. The test will be run for approximately 2000 hours with completion scheduled to be timely for the first System 80 plant to go on-line.

Mechanical testing of the fuel assembly and its components is being performed to support analytical means of defining the assembly's structural characteristics. The test program consists of static and dynamic tests of spacer grids and static and vibratory tests of a full-size fuel assembly. These tests as well are scheduled for completion to support the first System 80 unit to go on-line.

4.2.3.1.3 Spacer Grid Evaluation

The function of the spacer grids is to provide lateral support to fuel and burnable poison rods in such a manner that the axial forces are not sufficient to buckle or bow the rods and that the wear resulting at the grid-to-clad contact points will be limited to acceptably small amounts. It is also a criterion that the grid be capable of withstanding the lateral loads imposed during the postulated seismic and LOCA events.

Fuel assemblies are designed such that the combination of fuel rod rigidity, grid spacing, and grid preload will not result in significant fuel rod deformation under axial loads, and the long-term effects of clad creep (reduction in clad OD), the reduction of grid stiffness with temperature and the partial relaxation of the grid material during operation ensure that this criterion is also satisfied during all operating conditions. Moreover, inspection of irradiated fuel assemblies from the Maine Yankee (14 x 14), Calvert Cliffs (14 x 14) Palisades (15 x 15) and Omaha (14 x 14) reactors has not shown significant bowing of the fuel rods. In view of these factors and the similarity of these design to the Standard System 80 designs, it is concluded that the axial forces applied by the grids on the cladding will not result in a significant degree of fuel rod bow. The influence of fuel rod lateral deflection is discussed further in Section 4.2.3.2.6. Additional discussion of the causes for and effects of fuel rod bowing are contained in Section 4.2.3.2.6 and in Reference 53.

The capability of the grids to support the clad without excessive clad wear is demonstrated by out-of pile flow testing, to be completed as described above, on the Standard System 80 assembly design and by the results of post-irradiation examination of grid-to-clad contact points in Maine Yankee fuel assemblies which showed only negligible clad wear (Reference 51).

The capability of the grid to withstand the lateral loads produced during the postulated seismic and LOCA events is demonstrated by impact testing the reference grid design, both at room temperature and at operating temperature, and comparing the test results with the analytical predictions of the seismic and LOCA loads.

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b. Adequate margin to criticality shall be provided for full rack loadings of fuel assemblies having a mechanical design similar to that described in Chapter 4.0 and enrichments up to 3.7 w/o U-235.

c. The degree of subcriticality provided shall be consistent with the requirements of ANSI Standard N18.2 Section 5.7.4.1.

F. Independence

Not Applicable

G. Thermal Limitations

1. Cooling air shall be provided to the CEDM's at a minimum flow rate of 700 SCFM per CEDM at a temperature in the range of 80F-120F. | 7

2. Drains, permanently connected systems, and other features of the spent fuel pool shall be designed so that neither maloperation nor failure can result in loss of coolant that would uncover the stored fuel.

3. Spent fuel pool cooling shall be capable of removing the decay heat generated from 1 complete core of spent fuel placed in the pool 7 days after shutdown in addition to 1/3 of a completed core that has been in the pool 90 days after shutdown.

H. Monitoring

1. Low water level alarms shall be provided for the refueling pool and the spent fuel pool.

2. A system shall be provided to monitor the Reactor Coolant System for internal loose parts. The system shall have the ability to detect a loose part striking the internal surface of Reactor Coolant System components with an energy level of one-half foot pound or more. The system shall have alarm and recording capability. The system design shall be suitable for the temperature and humidity environment experienced in the area where the equipment normally operates.

I. Operational/Controls

Not Applicable

J. Inspection and Testing

1. In service Inspection shall be performed in accordance with Section XI of the ASME Code.

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K. Chemistry/Sampling

Not Applicable

L. Materials

1. See Section 5.1.4.L.3

M. System/Component Arrangement

Not Applicable

N. Radiological Waste

Not Applicable

O. Overpressure Protection

Not Applicable

P. Related Services

1. For refueling operations, the containment building crane shall have a minimum capacity of 225 tons.

    a. A hoisting speed of 6 inches per minute or less shall be utilized during refueling operations.

    b. A load measuring device shall be provided for use during heavy lifts.

    c. A low inching speed is required during those portions of the lift when close tolerance surfaces are engaging each other.

2. An overhead crane shall be provided in the new fuel storage area to facilitate handling of new fuel.

    a. The crane capacity shall be at least 1 ton to accommodate the weight of a fuel assembly.

    b. A vertical hoisting speed of 6 feet/minute or less shall be provided.

    c. The crane load shall be capable of being limited to prevent the hoist load from exceeding 5000 pounds when handling fuel assemblies. | 5

3. See Section 5.1.4.P.3

Q. Environmental

Not Applicable

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45. HEDL-73-6, "Materials Technology Program Report for October, November, and December 1973," pp A-69 to A-72.

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51. "Joint C-E/EPRI Fuel Performance Evaluation Program, Task C, Evaluation of Fuel Rod Performance on Maine-Yankee Core I," Combustion Engineering, Inc., CENPD-221, December 1975.

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TABLE 4.2-1

MECHANICAL DESIGN PARAMETERS

(Sheet 1 of 4)

Core Arrangement

Number of fuel assemblies in core, total	241
Number of CEAs	89
Number of fuel rod locations	56,876
Spacing between fuel assemblies, fuel rod surface to surface, inches	0.208
Spacing, outer fuel rod surface to core shroud, inches	0.214
Hydraulic diameter, nominal channel, feet	0.0393
Total flow area (excluding guide tubes), ft^2	60.9
Total core area, ft^2	112.3
Core equivalent diameter, inches	143.6
Core circumscribed diameter, inches	152.46
Total fuel loading, Kg U (assuming all rod locations are fuel rods)	102.7×10^3
Total fuel weight, lb UO_2 (assuming all rod locations are fuel rods)	257.1×10^3 7
Total weight of Zircaloy, lb	71,758
Fuel volume (including dishes), ft^3	409.6

Fuel Assemblies

Batch	No. of Assemblies	Enrichment (wt%) U-235	No. of Poison Rods per Assembly	
A0	69	1.92	0	
B1	44	12 rods with 1.92 208 rods with 2.78	16	
B2	64	12 rods with 1.92 208 rods with 2.78	16	7
C0	40	12 rods with 2.78 224 rods with 3.30	0	
C1	24	12 rods with 2.78 208 rods with 3.30	16	
	241			

Fuel Rod array square 16 x 16

Fuel Rod Pitch, inches 0.506

Spacer Grid

Type	Leaf spring
Material	Zircaloy-4
Number per assembly	11
Weight each, lb	1.7

TABLE 4.2-1 (Cont'd.)

MECHANICAL DESIGN PARAMETERS
(Sheet 2 of 4)

Fuel Assemblies (Cont'd.)

Bottom Spacer Grid	
Type	Leaf spring
Material	Inconel 625
Number per assembly	1
Weight each, lb (with skirt)	3.2
Weight of fuel assembly, lb	1436
Outside dimensions	
Fuel rod to fuel rod, inches	7.972 x 7.972
Fuel Rod	
Fuel rod material (sintered pellet)	UO_2
Pellet diameter, inches	0.325
Pellet length, inches	0.390
Pellet density, g/cm^3	10.38
Pellet theoretical density, g/cm^3	10.96
Pellet density (% theoretical)	94.75
Stack height density, g/cm^3	10.061
Clad material	Zircaloy-4
Clad ID, inches	0.332
Clad OD, (nominal), inches	0.382
Clad thickness, (nominal), inches	0.025
Diametral grap, (cold, nominal), inches	0.007
Active length, inches	150
Plenum length, inches	9.677

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TABLE 4.2-1 (Cont'd.)

MECHANICAL DESIGN PARAMETERS

(Sheet 3 of 4)

Control Element Assemblies (CEA)	Full Length	Part Length
Number	76	13
Absorber elements, No. per assy.	12 and 4	4
Type	Cylindrical rods	Cylindrical rods
Clad material	Inconel 625	Inconel 625
Clad thickness, inches	0.035	0.035
Clad OD, inches	0.816	0.816
Diametral gap, inches	0.009	0.009
Elements		
Poison material	B_4C/Felt metal and reduced dia. B_4C	Inconel/B_4C
Poison length, inches	135-1/2/12-1/2	75/16
B_4C Pellet		
Diameter, inches	0.737/0.674	0.737
Density, % of theoretical density of 2.52 g/cm^3	73	73
Weight % boron, minimum	77.5	77.5

Burnable Poison Rod	
Absorber material	Al_2O_3-B_4C
Pellet diameter, inches	0.307
Pellet length, inches, min	0.500
Pellet density (% theoretical), min	93
Theoretical density, Al_2O_3, g/cm^3	3.94

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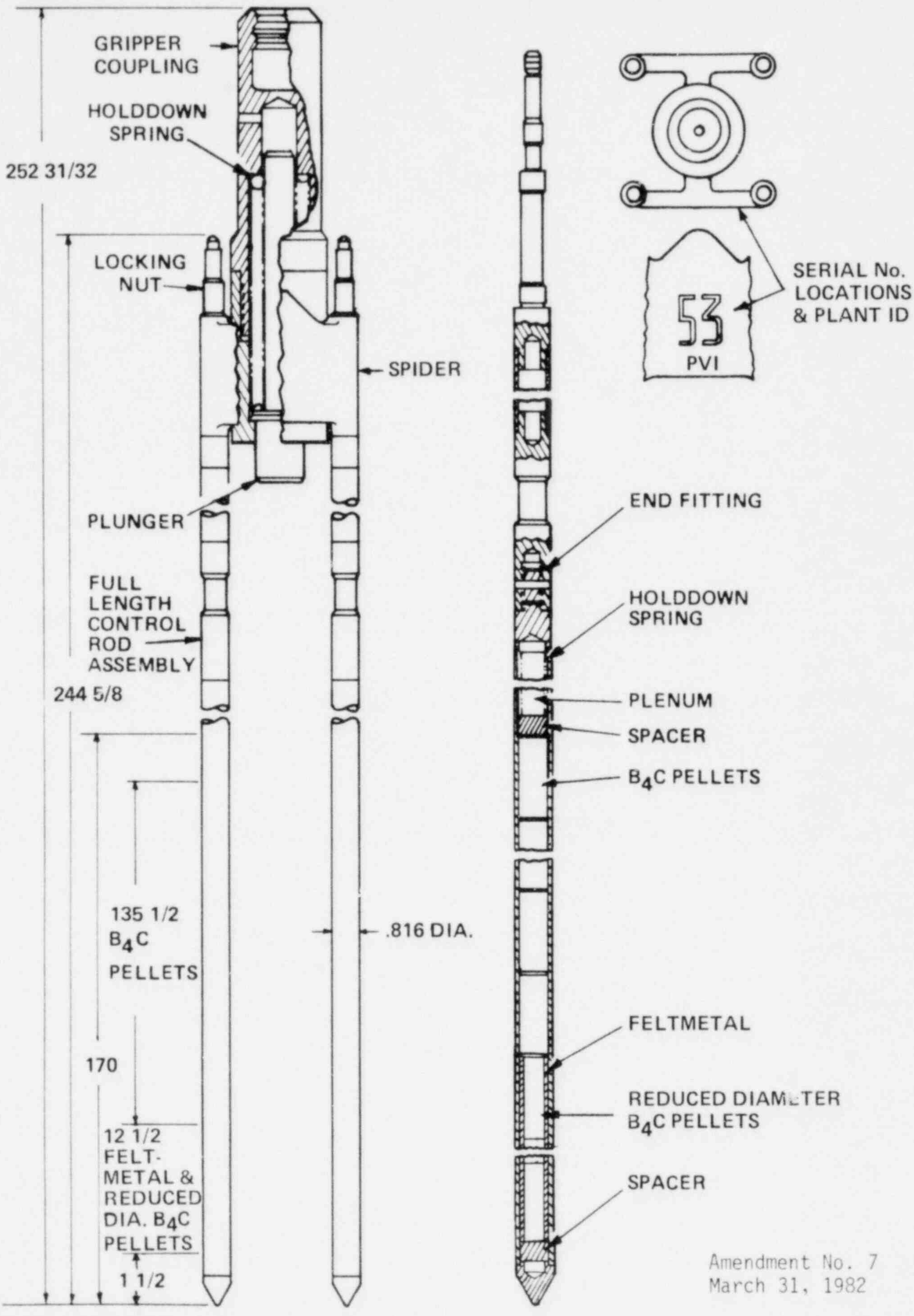
TABLE 4.2-1 (Cont'd.)

MECHANICAL DESIGN PARAMETERS
(Sheet 4 of 4)

Burnable Poison Rod (Cont'd.)	
Theoretical density, B_4C, g/cm^3	2.52
Clad material	Zircaloy-4
Clad ID, inches	0.332
Clad OD, inches	0.382
Clad thickness, (nominal), inches	0.025
Diametral gap, (cold, nominal), inches	0.025
Active length, inches	136.0
Plenum length, inches	11.090

7



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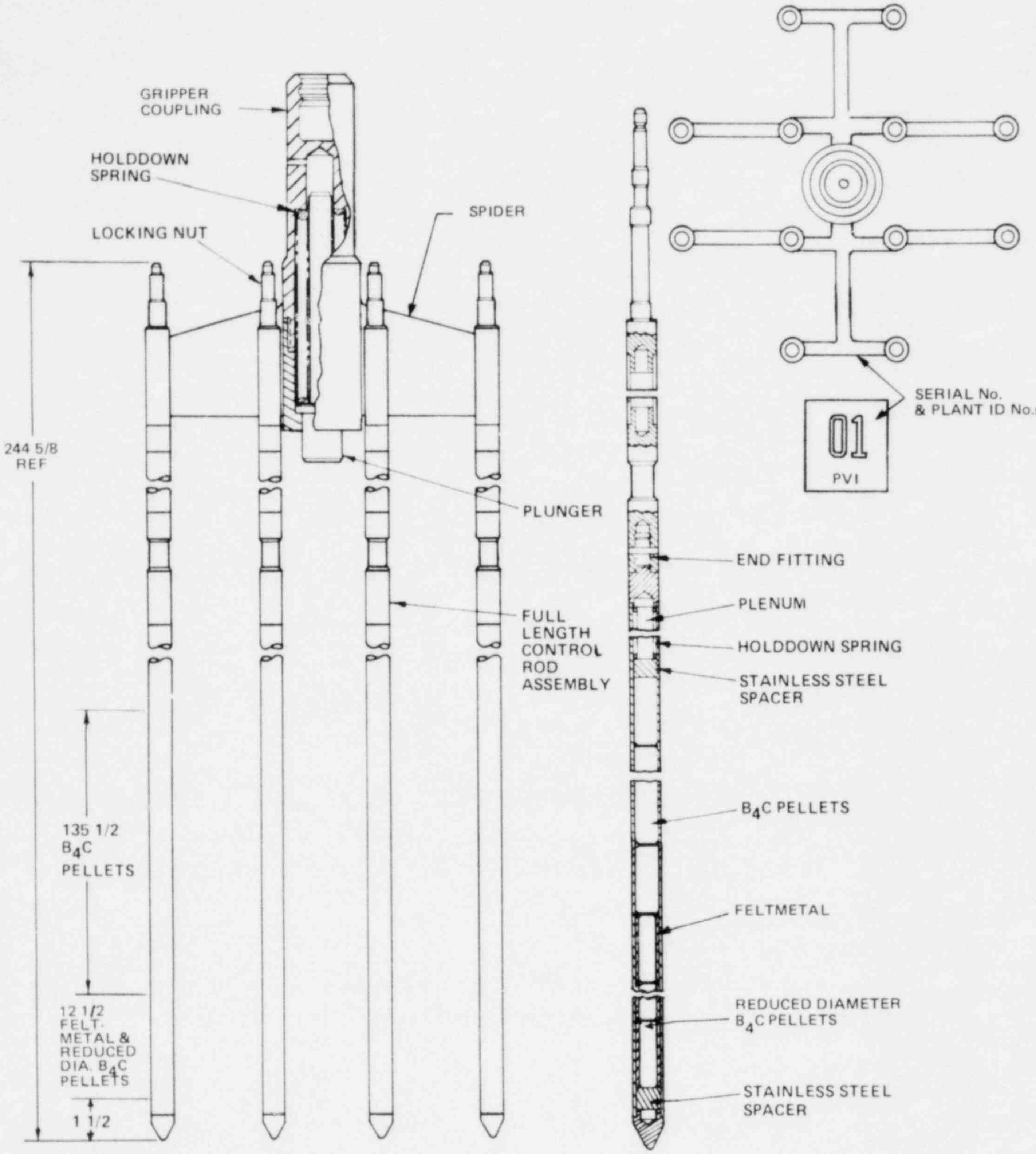
C-E SYSTEM 80	FULL LENGTH CONTROL ELEMENT ASSEMBLY (4 - ELEMENT)	Figure 4.2-3



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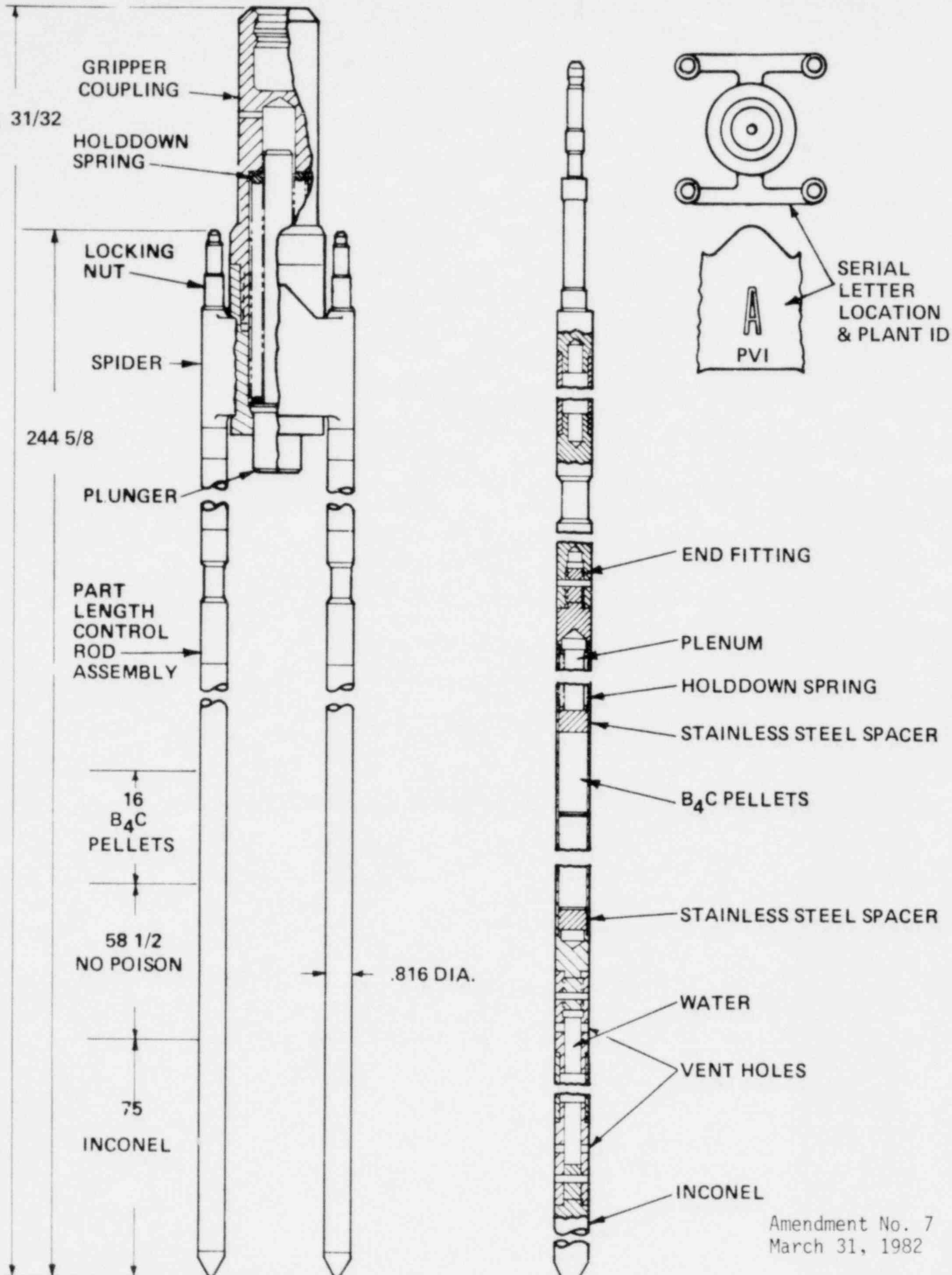
C - E SYSTEM 80	FULL LENGTH CONTROL ELEMENT ASSEMBLY (12 - ELEMENT)	Figure 4.2-4



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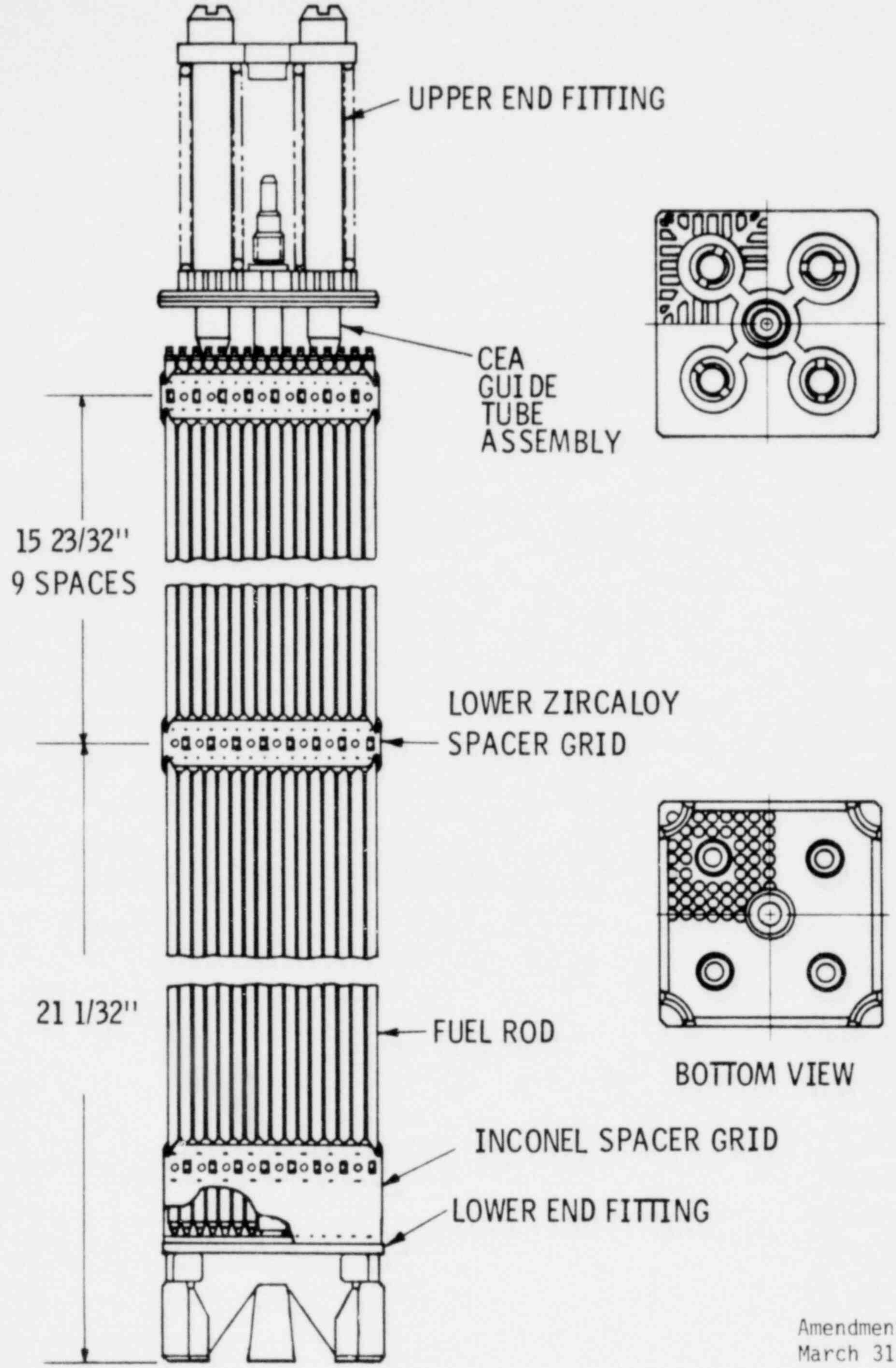
C - E SYSTEM 80	PART LENGTH CONTROL ELEMENT ASSEMBLY	Figure 4.2-5



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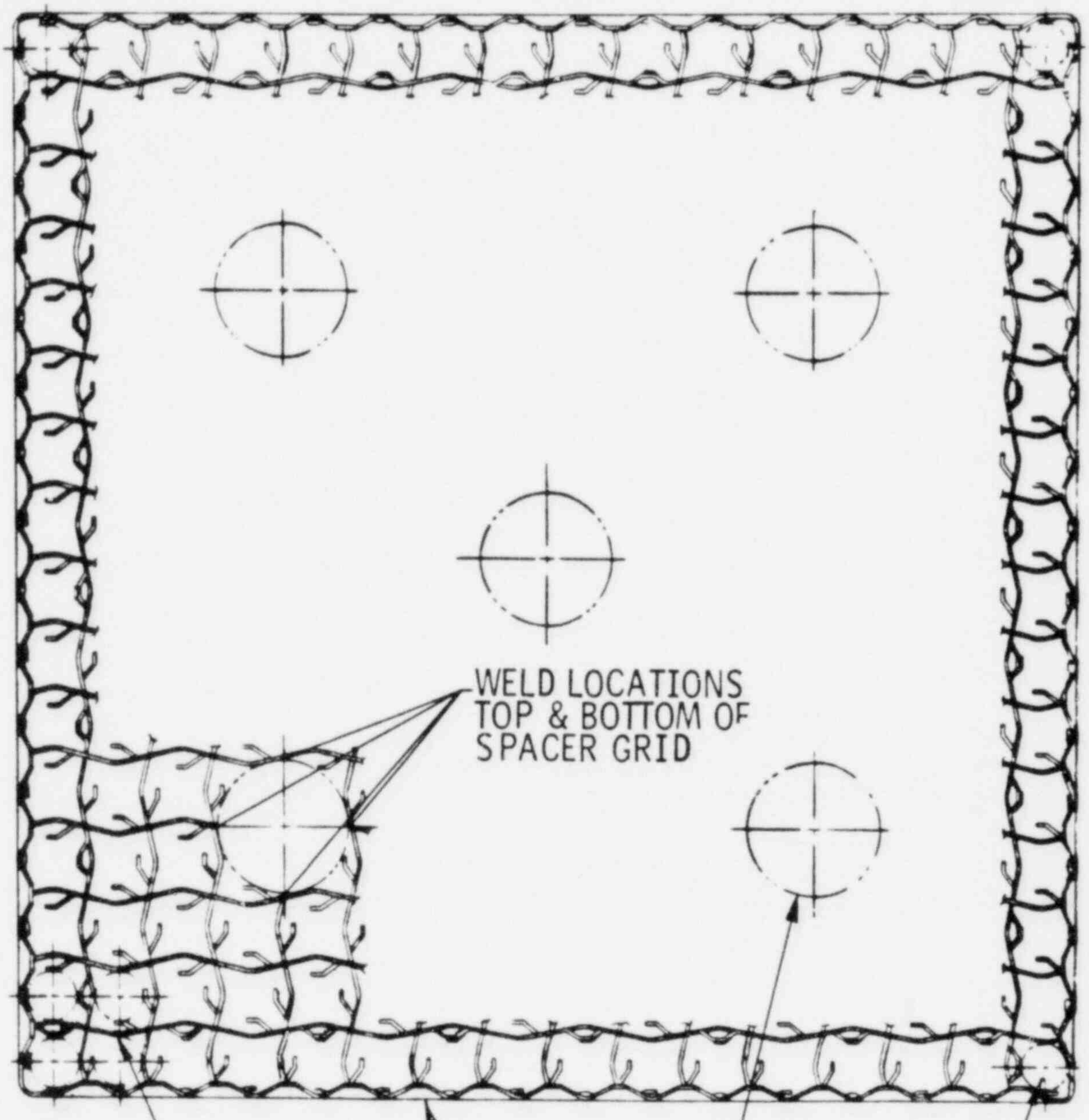
C-E SYSTEM 80	FUEL ASSEMBLY	Figure 4.2-6



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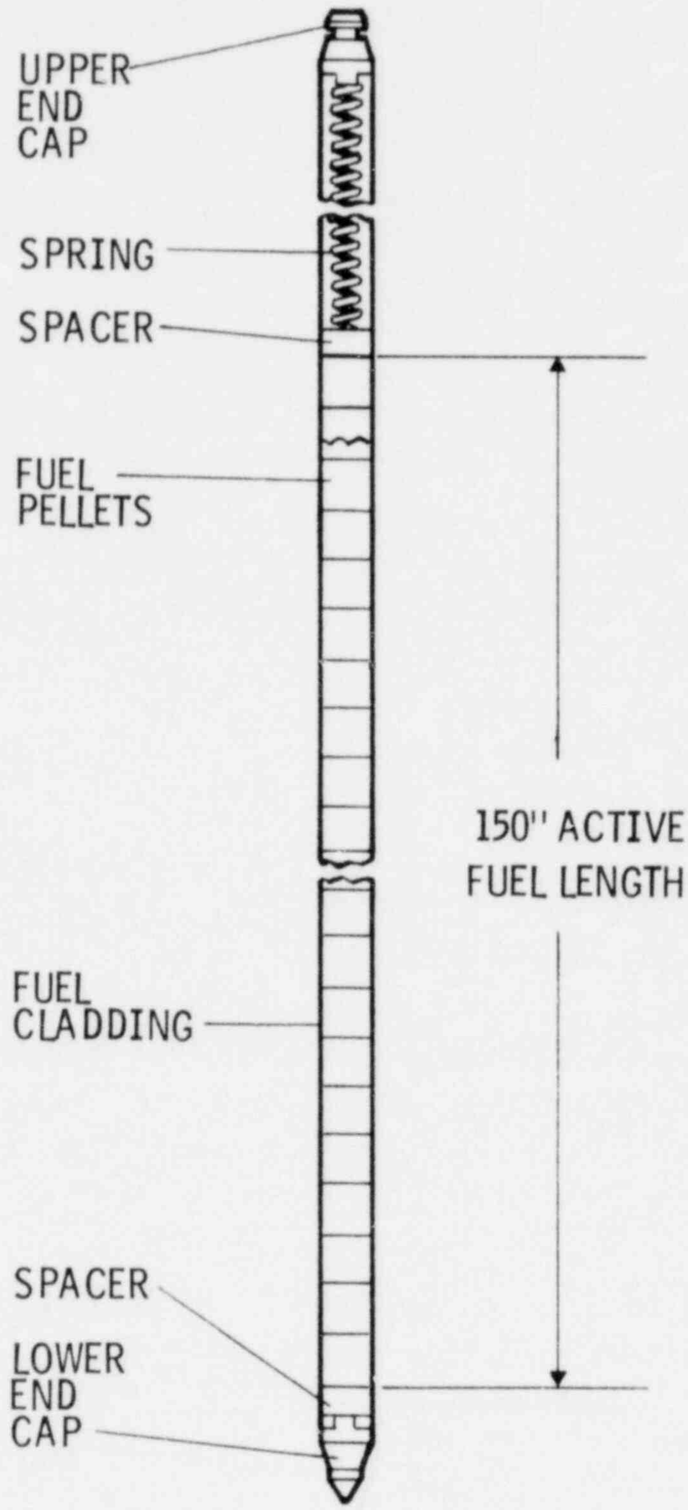
C-E SYSTEM 80	FUEL SPACER GRID	Figure 4.2-7



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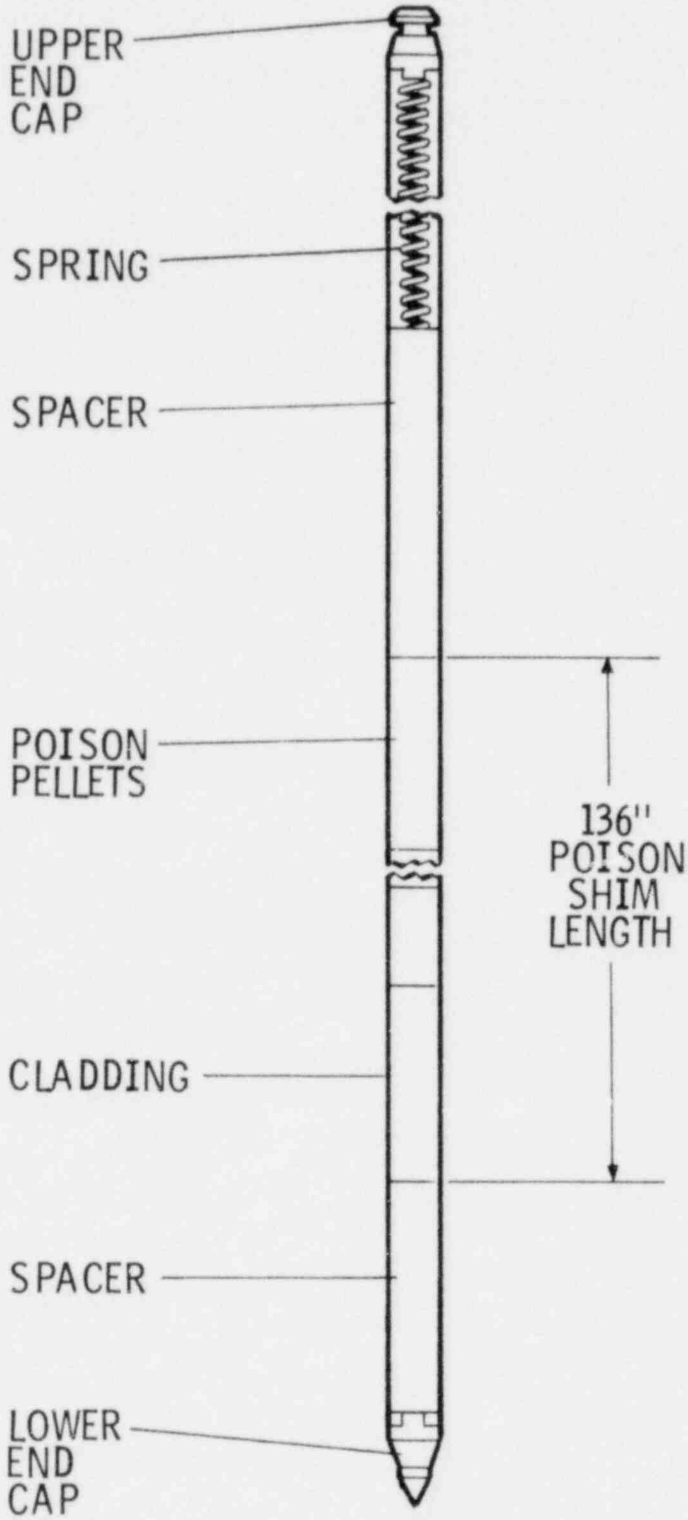
CE POWER SYSTEMS COMBUSTION ENGINEERING, INC.	FUEL ROD	Figure 4.2-8



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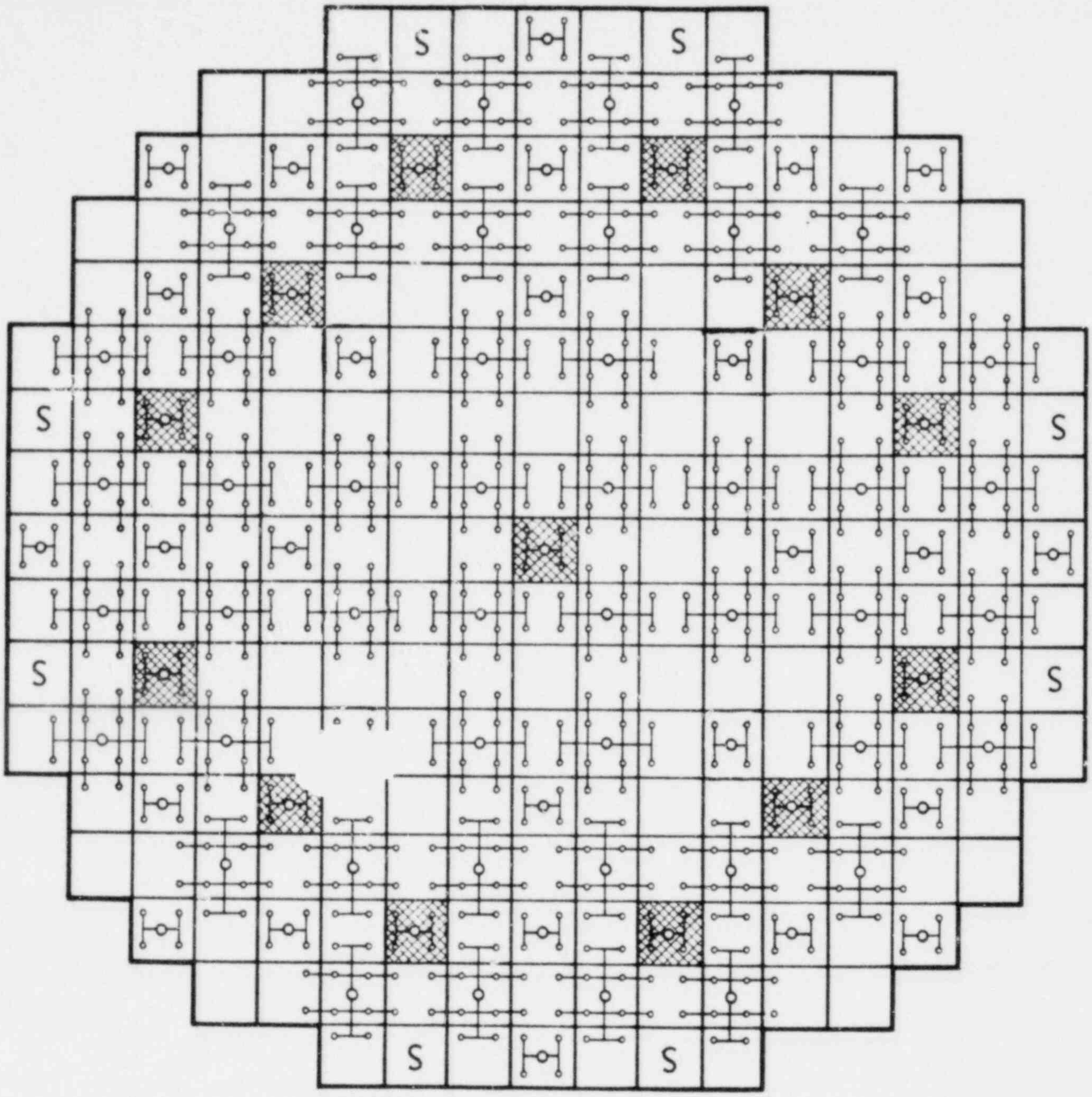
POWER SYSTEMS COMBUSTION ENGINEERING, INC.	BURNABLE POISON ROD	Figure 4.2-9



12 ELEMENT FULL LENGTH CEA's	48
4 ELEMENT FULL LENGTH CEA's	28
4 ELEMENT PART LENGTH CEA's	13
TOTAL	89 CEA's

S DENOTES SPARE CEA LOCATIONS 8

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C-E SYSTEM 80

CONTROL ELEMENT ASSEMBLY LOCATIONS

Figure 4.2-10

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7. Non-metallic insulation used on the Reactor Coolant Pressure Boundry shall conform to Regulatory Guide 1.36. The chloride and fluoride content of the non-metallic insulation shall be in the acceptable region as shown in Regulatory Guide 1.36. Tests shall be made on representative samples of the non-metallic thermal insulation shall be demineralized or distilled water.

8. No contaminants, except for cutting oils, shall be left on any RCS component surface except for the time required to perform and evaluate the particular fabrication or inspection operation.

9. Field welding of the RCS piping assemblies and components shall be done in accordance with a welding procedure or procedures by welders qualified to ASME Section IX requirements.

M. <u>System/Component Arrangement</u>

1. The pressurizer and surge line shall be located entirely above the reactor coolant loops.

2. The pressurizer surge line maximum L/D (equivalent) shall be 330 assuming 12-inch Schedule 160 piping. The L/D equivalent (Le/D) excludes entrance and exit losses but includes the height of the pressurizer above the hot leg centerline. The equivalent L/D of the height is found by use of:

$$\frac{Le}{D} = 5Z$$

where: Z is the height of the pressurizer surge nozzle above the hot leg centerline in feet.

3. The maximum acceptable pressure drop through the pressurizer spray line piping is 19 psi at a total flow rate of 375 gpm and at a water temperature of 565F. This requirement is for the piping only, allowance does not have to be made for elevation losses, the valves, or for the entrance and exit nozzles.

4. Flooding of the reactor cavity from systems other than the reactor coolant system shall be precluded to prevent immersion of the reactor vessel during operation. This is normally accomplished by routing only reactor coolant system piping inside the reactor cavity, by minimizing drainage paths to the reactor cavity, and/or providing gravity drainage paths out of the cavity below the bottom head of the vessel. The combined reactor cavity and ICI chase may be designed without gravity drainage paths below the hot and/or cold leg pipe penetrations, thereby allowing the reactor cavity to flood in the event of a breach of the reactor coolant pressure boundary inside the cavity. 7

5. The RCS sample piping shall be designed so that the overall transient time from the loop to the containment wall is approximately 90 seconds to permit the decay of short-lived radionuclides (high energy nuclides such as N-16).

6. The RCS and main steam piping, MSIV's, primary and secondary safety valves and their discharge piping and ADV's shall be arranged and supported such that the limiting loads are not exceeded for normal and relieving conditions.

7. Following a secondary line break, either all steam paths downstream of the MISV's shall be shown to be isolated by their respective control systems following a MSIS actuation signal, or the results of a blowdown through a non-isolated path shall be shown to be acceptable. An acceptable maximum steam flow from a non-isolated steam path is 10% of the main steam rate (MSR) (1.9×10^6 lb/hr @ 1000 psia saturated steam). It is not required that the control systems for downstream valves nor the downstream valves themselves be designed to IEEE 279 and IEEE 308 or ASME Code, Section III and Seismic Category I criteria respectively.

8. The MSIV's for each steam generator shall be arranged such that a maximum of 2000 cubic feet (total for two steam lines per steam generator) is contained in the piping between each steam generator and its associated MSIV's. This volume shall include all lines off of the main steam line up to their isolation valves.

9. The main steam lines shall be arranged such that a maximum of 14,000 cubic feet is contained between the MSIV's and the turbine stop valves. This volume shall include all lines off of the main steam line up to their isolation valves.

10. The main steam lines shall be headered together prior to the turbine stop valves but not upstream of the MSIV's, and a cross-connect line shall be provided which will maintain steam generator pressure differences within the following limits for all normal and upset conditions.

    a. 0-15% power operation pressure difference to be 1 psi.

    b. 15-100% power operation pressure difference to be 3 psi.

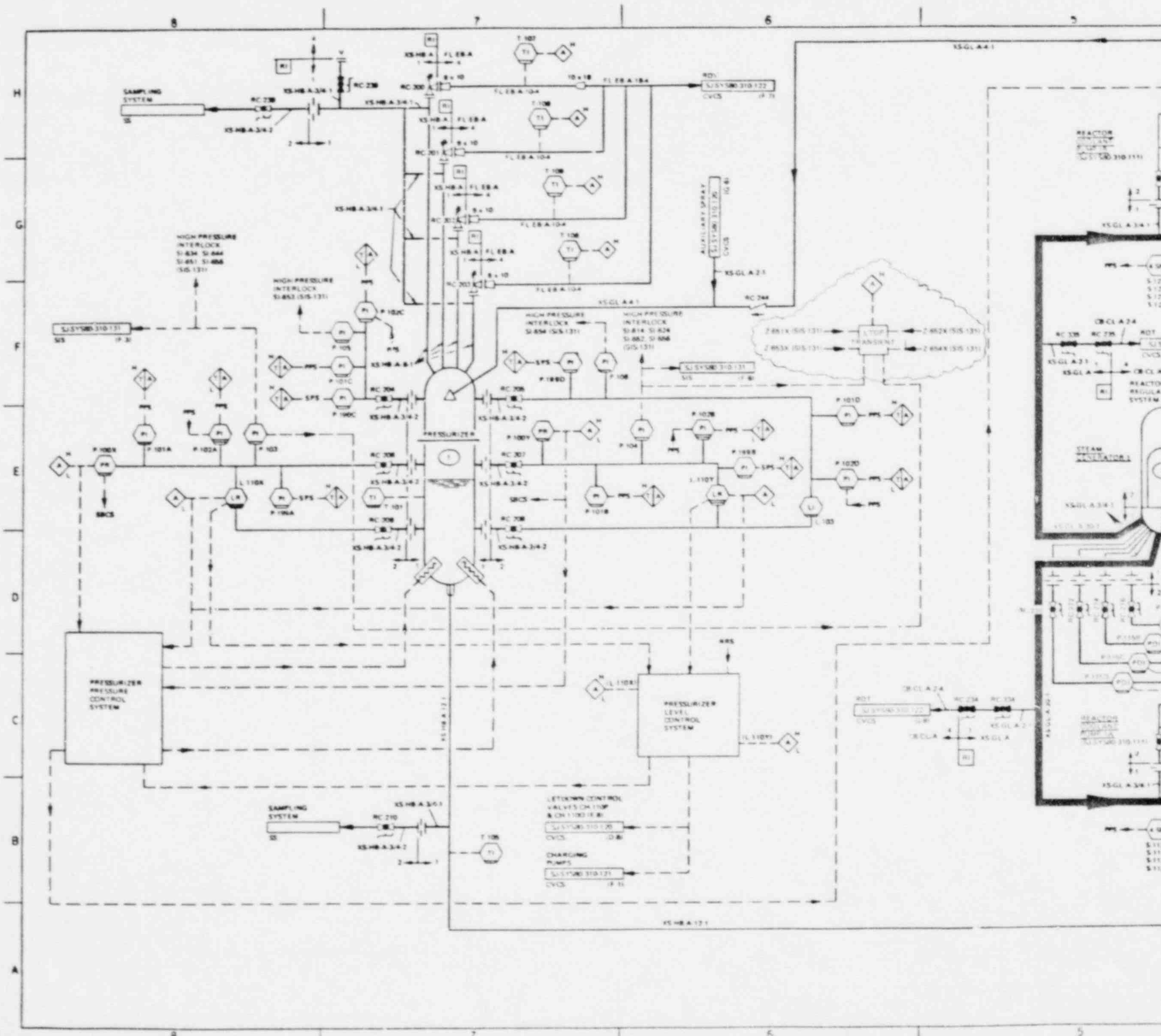
11. No automatically actuated valves shall be located upstream of the MSIV's except as required for supply to steam driven emergency feedwater pumps. Provisions shall be made to prevent blowdown of both steam generators through the emergency feedwater supply headers in the event of a steamline break. The maximum allowable flow rate per valve is 1.9×10^6 lb/hr.

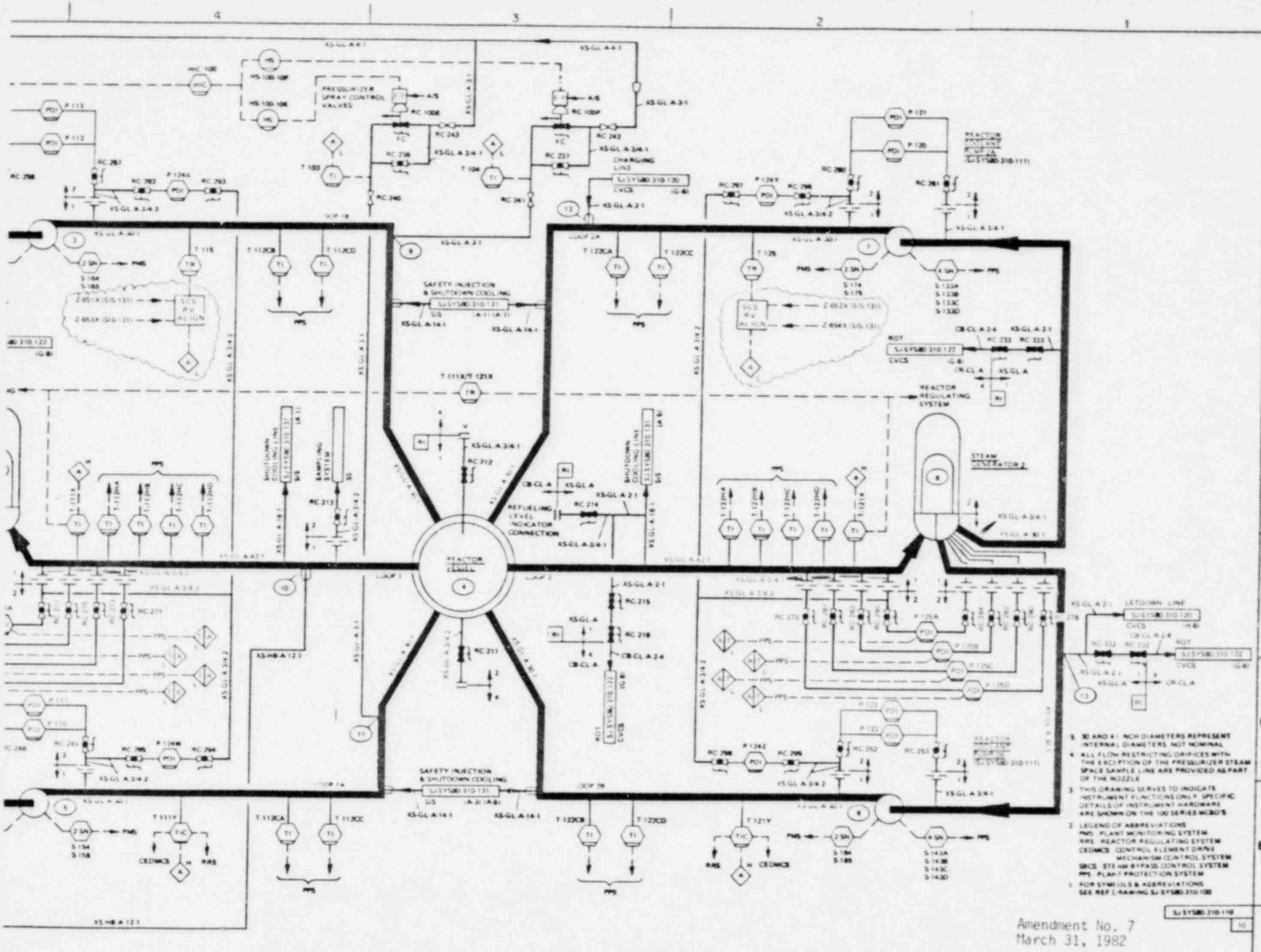
12. There shall be no isolation valves in the main steam lines between the steam generators and the secondary relief valves.

13. The main steam safety valves shall be arranged such that any condensate in the line between the safety valves and main steam line drains back to the main steam line.

14. All valves in the main steam line outside of containment up to and including the MSIV's shall be located as close as practical to the containment wall.

15. A 90° or 45° elbow facing downward shall be attached to each feedwater nozzle. Such a precaution will aid in the prevention of water hammer.


SAMPLING SYSTEM
HIGH PRESSURE INTERLOCK SI-634 SI-644 SI-651 SI-666 (SIS-131)
HIGH PRESSURE INTERLOCK SI-653 (SIS-131)
HIGH PRESSURE INTERLOCK SI-654 (SIS-131)
HIGH PRESSURE INTERLOCK SI-614 SI-624 SI-662 SI-666 (SIS-131)
PRESSURIZER
AUXILIARY SPRAY
LTOP TRANSIENT
PRESSURIZER PRESSURE CONTROL SYSTEM
PRESSURIZER LEVEL CONTROL SYSTEM
LETDOWN CONTROL VALVES CH 110P & CH 110Q
CHARGING PUMPS
STEAM GENERATOR 2
REACTOR REGULATING SYSTEM
REACTOR COOLANT PUMP



5. 30 AND 42 INCH DIAMETERS REPRESENT INTERNAL DIAMETERS, NOT NOMINAL
4. ALL FLOW RESTRICTING ORIFICES WITH THE EXCEPTION OF THE PRESSURIZER STEAM SPACE SAMPLE LINE ARE PROVIDED AS PART OF THE NOZZLE
3. THIS DRAWING SERVES TO INDICATE INSTRUMENT FUNCTIONS ONLY. SPECIFIC DETAILS OF INSTRUMENT HARDWARE ARE SHOWN ON THE 100 SERIES MCBD'S
2. LEGEND OF ABBREVIATIONS
PMS: PLANT MONITORING SYSTEM
RRS: REACTOR REGULATING SYSTEM
CEDMCS: CONTROL ELEMENT DRIVE MECHANISM CONTROL SYSTEM
SBCS: STEAM BYPASS CONTROL SYSTEM
PPS: PLANT PROTECTION SYSTEM
1. FOR SYMBOLS & ABBREVIATIONS SEE REF DRAWING SJ SYS80-310-100

SJ SYS80-310-110

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REACTOR COOLANT SYSTEM
PIPING & INSTRUMENTATION DIAGRAM

Figure 5.1.2-1

5.2.2.10.2.2 Provision for Overpressure Protection

During heatup, RCS pressure is maintained below the maximum pressure for SCS operation until RCS cold leg temperature exceeds the applicable P-T operating curve temperature corresponding to 2500 lb/in.^{2}a (see Figure 3.4-2 in the Technical Specifications). If SI-651 and 653 or SI-652 and 654 SCS suction isolation valves are open and RCS pressure exceeds the maximum pressure for SCS operation, an alarm will notify the operator that a pressurization transient is occurring during low temperature conditions. Either SCS relief valve will terminate inadvertent pressure transients occurring during RCS temperature below the applicable P-T operating curve temperature corresponding to 2500 lb/in.^{2}a. Above the maximum LTOP temperature, overpressure protection is provided by the pressurizer safety valves when the SCS relief valve is isolated from the RCS.

During cooldown whenever RCS cold leg temperature is below the applicable temperature for LTOP, the SCS relief valves provide the necessary protection. If the SCS is not aligned to the RCS before cold leg temperature is decreased
to the maximum temperature requiring LTOP, an alarm will notify the operator 7
to open the SCS suction isolation valves (SI-651, 652, 653, 654). The maximum temperature requiring LTOP is based upon the evaluation of the applicable P-T curves. However, the SCS can not be aligned to the RCS until the pressure is below the maximum pressure allowing SCS operation (see paragraph 5.4.7.2.3, item a.2).

These LTOP conditions are within the SCS operating range. Technical Specification section 16.3/4.4.9.3 requires the SCS suction line isolation valves to be open when operating in the LTOP mode. Also, this Technical Specification ensures that appropriate action is taken if one or more SCS relief valves are out of service during the LTOP mode of operation.

Either SCS relief valve will provide sufficient relief capacity to prevent any pressure transient from exceeding the isolation interlock setpoint (See figures 5.2-1 and 5.2-2).

5.2.2.10.2.3 Equipment Parameters

The SCS relief valves are spring-loaded (bellows) liquid relief valves with sufficient capacity to mitigate the most limiting overpressurization event. Pertinent valve parameters are as follows:

<u>Parameter</u>

Setpoint 450 lb/in.^{2} a 6
Accumulation 10%
Capacity 4000 (@ 10% acc) gal/min

Since each SCS relief valve is a self actuating spring-loaded liquid relief valve, control circuitry is not required. The valve will open when RCS pressure exceeds its setpoint.

The SCS relief valves are sized, based on an inadvertent safety injection actuation signal (SIAS) with full pressurizer heaters operating from a water-solid condition. The SIAS assumes simultaneous operation of two HPSI pumps and three charging pumps with letdown isolated. The resulting flow capacity requirement for water is 4000 gpm. The analysis in Section 5.2.2.10.2.1 assumed that either SCS relief valve relieved water at this rate. The design relief capacity of each of two SCS relief valves (shown in P&ID Figure 6.3.2-1B) as supplied by the valve manufacturer is 5180 gpm. This design relief capacity exceeds the minimum required relief capacity of 4000 gpm with sufficient margin in relieving capacity for even the worst transient. The SCS relief valves are Safety Class 2, designed to Section III of the ASME Code.

5.2.2.10.2.4 Administrative Controls 6

Administrative controls necessary to implement the LTOP provisions are limited to those controls that open the SCS isolation valves. Before entering the low temperature region for which overpressure protection is necessary, RCS pressure is decreased to below the maximum pressure required for SCS operation. Once the SCS is aligned, no further specific administrative procedural controls are needed to ensure proper overpressure protection. The SCS will remain aligned whenever the RCS is at low temperatures and the reactor vessel head is secured. As designated in Table 7.5-2, indication of SCS isolation valve position is provided.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specification

A list of specifications for the principal ferritic materials, austenitic stainless steels, bolting and weld materials, which are part of the reactor coolant pressure boundary is given in Table 5.2-2.

Studies have shown that the irradiation induced mechanical property changes of SA-533B materials can depend significantly upon the amount of residual elements present in the compositions, namely; copper, phosphorous, and vanadium. It has also been found that residual sulfur affects the initial toughness of SA-533B materials. Specific controls are placed on the residual chemistry of reactor vessel plates and the as-depositied welds used to join these plates to limit the maximum predicted increase in the reference temperature (RT_{NDT}, which is discussed in Section 5.3.1.6) and to limit the extent of the reactor vessel beltline. The beltline is defined by Appendix G of 10CFR50.

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5. Pumps Used During Shutdown Cooling

The LPSI pumps are used as part of the SCS. During shutdown cooling, these pumps take suction from the reactor hot leg pipes and discharge through the shutdown cooling heat exchangers. The flow is then returned to the RCS through the LPSI header to the four cold legs. One LPSI pump is aligned to each shutdown cooling heat exchanger. At the start of shutdown cooling, both of the LPSI pumps are in service. When the RCS temperature is below 200°F, the containment spray pumps may be realigned and started to provide additional flow through the heat exchangers. The LPSI pumps are described in Section 6.3.2.2.2.

5.4.7.2.3 Overpressure Prevention

a. Overpressurization of the SCS by the RCS is prevented in the following ways:

1. The shutdown cooling suction isolation valves (SI-651, 652, 653, and 654) are powered by four independent power supplies such that a fault in one power supply or valve will neither line up the RCS to either of the two SCS trains inadvertently nor prevent the initiation of shutdown cooling with at least one train when pressure permits.

2. Interlocks associated with the shutdown cooling suction isolation valves prevent the valves from being opened if RCS pressure exceeds 400 psia, and close these valves automatically if RCS pressure should rise above the accumulation pressure of the shutdown cooling suction line reliefs valves. This value is 700 psia. The instrumentation and controls which implement this are discussed in Section 7.6.

3. The SCS suction valves inside the containment are designed for full RCS pressure with the second valve forming the pressure boundary and class change.

4. Alarms on SI-651, 652, 653 and 654 annunciate when the shutdown cooling system suction isolation valves are not fully closed. Also, if SI-651 and 653 or SI-652 and 654 valves are open and RCS pressure exceeds the maximum pressure for SCS operation, an alarm will notify the operator that a pressurization transient is occurring during low temperature conditions.

5. Relief valves are provided as discussed in Section 5.4.7.2.2.

The effects of inadvertent operation are discussed in Table 5.4.7-3.

5.4.7.2.4 Applicable Codes and Classifications

a. The SCS is a Safety Class 2 System, except for that portion discussed in b. below, which is Safety Class 1.

b. The piping and valves from the RCS up to and including SI-653 and 654 are designed to ASME B&PVC Section III, Class 1.

c. The piping, valves, and components of the SCS, with the exception of those in Section 5.4.7.2.4 b. are designed to ASME B&PVC Section III, Class 2.

d. The component cooling water side of the shutdown cooling heat exchanger is designed to ASME B&PVC Section III, Class 3.

e. The power operated valves are designed to the applicable IEEE Standards.

f. The SCS is a Seismic Category 1 System.

5.4.7.2.5 System Reliability Considerations

The SCS is designed to perform its design function assuming a single failure, as described in Section 5.4.7.1.2.

To assure availability of the SCS when required, redundant components and power supplies are utilized. The RCS can be brought to refueling temperature utilizing one of the two redundant SCS trains. However, with the design heat load, the cooldown would be considerably longer than the specified 27-1/2 hour time period.

A loss of instrument air to the shutdown cooling system will not result in a loss of cooling ability.

Inadvertent overpressurization of the SCS is precluded by the use of pressure relief valves and interlocks installed on the shutdown cooling suction line isolation valves and safety injection tank isolation valves (see Section 7.6 and 5.4.7.2.3).

The instrumentation, control, and electric equipment pertaining to the SCS was designed to applicable portions of IEEE Standards 279 and 308.

In addition to normal offsite power sources, physically and electrically separated and redundant emergency power supply systems are provided to power safety-related components. See Chapter 8 for further discussion.

Since the SCS is essential for a safe shutdown of the reactor, it is a Seismic Category I system and designed to remain functional in the event of a design basis earthquake.

For long-term performance of the SCS without degradation due to corrosion, only materials compatible with the pumped fluid are used.

Environmental conditions are specified for system components to ensure acceptable performance in normal and applicable accident environments (see Section 3.11).

In the event of a limited leakage passive failure in one train of the SCS, continued core cooling is assured by the two independent train design of the SCS. Make-up of the leakage is provided by the manual alignment of the

SIS to the refueling water tank or by opening the Safety Injection Tank isolation valves. The affected SCS train can then be isolated and core cooling continued with the other train.

A limited leakage passive failure is defined as the failure of a pump seal or valve packing, whichever is greater. The maximum leakage is expected to be from a failed LPSI pump seal.

This leakage to the pump compartment will normally drain to the room sump. From there it is pumped to the water management system. The sump pumps in each room will handle expected amounts of leakage. If leakages are greater than the sump pump capacity, the room will be isolated.

5.4.7.2.6 Manual Actions

1. Plant Cooldown

   Plant cooldown is the series of manual operations which bring the reactor from hot shutdown to cold shutdown. Cooldown to approximately 350°F is accomplished by releasing steam from the secondary side of the steam generators. When the RCS pressure falls below 2150 psia, the Safety Injection Actuation Signal (SIAS) setpoint can be manually decreased as discussed in Section 7.2.1.1.1.6. When RCS pressure reaches 625 psig, the safety injection tank pressure is reduced to 400 psig. When RCS pressure reaches 400 psig, the safety injection tank isolation valves are closed.

   When RCS temperature and pressure decrease below 350°F and the maximum pressure for SCS operation, the SCS may be used. If the SCS is not aligned to the RCS before cold leg temperature is reduced to below the maximum RCS cold leg temperature requiring LTOP, an alarm will notify the operator to open the SCS isolation valves (SI-651, 652, 653, 654). The maximum temperature requiring LTOP is based upon the evaluation of the applicable P-T curves. This operator action requires that the RCS be depressurized to below the maximum pressure for SCS operation, in order to clear the permissive SCS interlock (see paragraph 5.4.7.2.3, item a.2). Interlocks associated with the six valves on the two SCS suction lines prevent overpressurization of the SCS. See Section 7.6 and 5.4.7.2.3 for details. Also, if SI-651 and 653 or Si-652 and 654 SCS suction isolation valves are open and RCS pressure exceeds the maximum pressure for SCS operation, an alarm will notify the operator that a pressurization transient is occurring during low temperature conditions. 7

   Shutdown cooling is initiated using only the LPSI pumps (LPSIP), with the CSS lined up for automatic initiation of spray, bypassing the shutdown cooling heat exchanger. The SCS is warmed up and placed in operation as follows (refer to Figures 6.3.2-1A, 1B, 1I, 1J, 1K, and 1L):

   a. The containment spray isolation valves for the shutdown cooling heat exchangers (SI-684*, 687*, 689, 695) are shut.

   b. The containment spray valves bypassing the shutdown heat exchangers (SI-688*, 693) are opened.

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c. The LPSI pump minimum flow recirculation isolation valves (SI-668, 669*) are shut.

d. The LPSI pump suction valves (SI-683*, 692) from the RWT and containment sump are shut.

e. The shutdown cooling suction line isolation valves (SI-651*, 652, 653*, 654, 655*, 656) in the two suction lines are opened.

f. The crossover valves between the LPSI pump discharge and the shutdown cooling heat exchangers (SI-685*, 694) are opened.

g. The crossover valves between the shutdown cooling heat exchanger outlet and the LPSI header (SI-686*, 696) are opened and the shutdown cooling throttle valves (SI-657*, 658) are cracked open.

h. The SCS warmup line isolation valves (SI-690, 691*) are opened and the LPSI pumps are started to induce recirculation flow through the SCS (flow is limited to 5000 gpm per pump).

i. Once flow has been induced in the SCS, the LPSI isolation valves (SI-615, 625, 635*, 645*) are cracked open to allow a small amount of flow from the RCS to heat up SCS valves and piping.

j. The LPSI header isolation valves (SI-615, 625, 635*, 645*) are then gradually opened, while the warmup line isolation valves (SI-690, 691*) are gradually closed to maintain a constant flow of 5000 gpm per pump. When the LPSI header isolation valves (SI-615, 625, 635*, 645*) are open to their preset positions and the SCS warmup line isolation valves (SI-690, 691*) are closed, the SCS is aligned in its operating mode.

k. The shutdown cooling throttle valves (SI-657*, 658) and the SCS bypass flow control valves (SI-306*, 307) are adjusted as necessary to maintain the RCS cooldown rate at 75°F/hour or less, at a SCS flow of 5000 gpm through each heat exchanger.

When reactor coolant temperature decreases below 200°F (typically 170°F), the containment spray pumps are aligned to provide additional shutdown cooling flow. The SCS is realigned to the following line-up (refer to Figure 6.3.2-1A):

a. The containment spray pump suction valves (SI-104, 105*) from the RWT and containment sump are closed.

b. The containment spray pump minimum flow recirculation line isolation valves (SI-664*, 665) are shut.

c. The containment spray bypass around the shutdown cooling heat exchanger valves (SI-688*, 693) are shut.

d. The containment spray pump suction valves (SI-184*, 185) from shutdown cooling suction lines are opened.

e. The containment spray pump discharge to the shutdown cooling heat exchanger valves (SI-684*, 689) are opened.

f. The containment spray pump discharge valves (SI-678*, 679) are opened to the position determined by preoperational testing.

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TABLE 5.4.7-3 (Cont.) (Sheet 7 of 9)

SHUTDOWN COOLING SYSTEM FMEA

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
23.	SCS Stop Valves for Suction Line SI-651 SI-652 SI-653 SI-654	a) Fails open	Elect. Malf., Mech. binding	None	Position indication in control room, Periodic testing	The redundant series valve ensures that SCS is protected from normal RCS pressure during power operation	Interlocks associated with the valves prevent overpressurization. These interlocks prevent the valves in the suction line of the SCS from being opened if RCS pressure exceeds 400 psia. These valves automatically close if RCS pressure should rise above the accumulation pressure of the SCS suction line relief valves. This pressure is 700 psia. |7
		b) Fails closed	Elect. Malf., Mech. binding	Prevention of decay heat removal from core via one SCS subsystem during normal shutdown cooling or long term cooling following a small LOCA	Position indication in control room, Periodic testing	Redundant shutdown cooling subsystem assures adequate cooling although cooling time will be extended.	
24.	SI Tank Isolation Valves SI-614 SI-624 SI-634 SI-644	a) Fails open	Elect. Malf., Mech. binding	Unable to isolate one SI tank from the RCS.	Position indication in control room, Periodic testing	None required	During shutdown cooling these valves are closed. However, if a LOCA occurs a SIAS will automatically open these valves. SCS interlock prevents initiation of shutdown cooling unless SIT pressure is reduced to a safe level. SIT pressure can be lowered by bleeding off nitrogen.

SHUTDOWN COOLING SYSTEM FMEA

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection*	Inherent Compensating Provision	Remarks and Other Effects
		b) Fails closed	Elect. Malf., Mech. binding	No effect during shutdown cooling	Valve position indications in control room, Periodic testing	None required	
25.	Shutdown Cooling Line Isolation Valves SI-655 SI-656	a) Fails open	Elect. Malf., Mech. binding	No effect on shutdown cooling	Valve position indication in control room, Periodic testing	None required during shutdown cooling operations	Valve is normally locked closed in control room
		b) Fails closed	Elect. Malf., Mech. binding	Inability to align one shutdown cooling subsystem for shutdown cooling	Valve position indication in control room, Periodic testing	Redundant shutdown cooling subsystem	
26.	PCPS Crossover Valves to SCS SI-256 SI-442 SI-455 SI-458	a) Fails open	Mech. binding	None	Periodic testing	Adjacent valve (SI-204, SI-443, SI-450, SI-454) provides back-up isolation.	Valve is normally locked closed at valve
		b) Fails closed	Mech. binding	None during shutdown cooling. Isolation of the spent fuel pool cooling system from one train of the SCS prevents use of one SDCHX to assist in cooling the spent fuel pool when it contains 1-1/3 cores.	See customer's SAR for description of PCPS. Periodic testing	PCPS connection with redundant SDCHX.	One of the shutdown cooling HX may be aligned to the PCPS when no longer needed to maintain reactor coolant at refueling temperature
27.	Shutdown Cooling Line	a) One line clogs	Contaminants	Effective loss of one shutdown cooling subsystem	Low flow indications from F-307 or F-306, Periodic testing	Redundant shutdown cooling subsystem	Periodic sampling will monitor build-up of contaminants
		b) Limited Leakage in one train	Seal failure	Release of coolant and radioactivity outside of containment.	Local leak detection. See customer's SAR	The leak can be isolated without affecting the redundant subsystem	
28.	Flow Indicator F-306, F-307 F-338, F-348	False indication	Elect. Malf.	Inability to control cooldown rate in affected train.	Comparison with redundant indicator, with all other process instrumentation and valve position indications consistent.	Redundant indicator	

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TABLE 6.2.4-1 (Cont'd.) (Sheet 3 of 5)

CONTAINMENT ISOLATION SYSTEM

Penetration Number	Applicable GDC	System(4)	Line(5) Size (in)	ESF Function	Valve(1) Arrangement	Valve Number	Valve Location Relative To Containment	Type C(8) Leakage Test	Valve(7) Type
28	55	SCS	16	No	5	SI-691	Outside	Yes	Globe
						SI-655	Outside	Yes	Gate
						SI-653	Inside	Yes	Gate
29	55	SIS	2	No	6	SI-463	Outside	Yes	Globe
						SI-682	Inside	Yes	Globe
40	55	CVCS	2	No	7	CH-523	Outside	Yes	Globe
						CH-516	Inside	Yes	Globe
41	55/56	CVCS	2-1/2	No	8	CH-524	Outside	Yes	Globe
						CH-431	Inside	Yes	Check
						CH-433	Inside	Yes	Check
						CH-854	Outside	Yes	Globe
						CH-393	Inside	Yes	Globe
43	55	CVCS	1	No	9	CH-505	Outside	Yes	Globe
						CH-506	Inside	Yes	Globe
44	55	CVCS	3	No	10	CH-560	Inside	Yes	Globe
						CH-561	Outside	Yes	Globe
45	55	CVCS	1-1/2	No	11	CH-494	Inside	Yes	Check
						CH-580	Outside	Yes	Globe
57	55	CVCS	1-1/2	No	12	CH-255	Outside	Yes	Globe
						CH-835	Inside	Yes	Check

TABLE 6.2.4-1 (Cont'd.) (Sheet 4 of 5)

CONTAINMENT ISOLATION SYSTEM

Penetration Number	Applicable GDC	System(4)	Valve Operator	Primary(2) Actuation Mode	Secondary(2) Actuation Mode	Valve Position: Normal	Valve Position: Shut-down	Valve Position: Post-Accident	Valve Position: Failure	ESF(3) Actuation Signal	Closure Time (Sec)	Power Source	
28	55	SCS	Motor	R	M	C	O or C	O or C	FAI	None	30	EA	
			Motor	R	M	C	O	O or C	FAI	None	80	EA	
			Motor	R	R	C	O	O or C	FAI	None	80	EC	
29	55	SIS	None	M	M	C	O or C	C	FAI	None	N.A.	N.A.	
			Air	A	R	C	O or C	C	FC	SIAS	5	EA	
40	55	CVCS	Air	A	R, M	O	C	C	FC	CIAS/SIAS	5	EB	
			Air	A	R	O	C	C	FC	CIAS	5	EA	
41	55/56	CVCS	Motor	R	M	O	O	O	FAI	None	5	EB	7
			None	A	A	C	O or C	O or C	N.A.	None	N.A.	N.A.	
			None	A	A	O	O or C	O or C	N.A.	None	N.A.	N.A.	
			Hand	M	M	C	C	C	N.A.	None	N.A.	N.A.	
			Hand	M	M	C	C	C	N.A.	None	N.A.	N.A.	
43	55	CVCS	Air	A	R,M	O	O or C	C	FC	CIAS	5	EB	
			Air	A	R	O	O or C	C	FC	CIAS	5	EA	
44	55	CVCS	Air	A	R	O or C	C	C	FC	CIAS	5	EA	
			Air	A	R, M	O or C	C	C	FC	CIAS	5	EB	
45	55	CVCS	None	A	A	O or C	C	C	N.A.	None	N.A.	N.A.	
			Air	A	R, M	O or C	C	C	FC	CIAS	5	EA	
57	55	CVCS	Motor	R	M	O	O	O or C	FAI	None	5	EA	7
			None	A	A	O	O	O or C	N.A.	None	N.A.	N.A.	

6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 DESIGN BASES

6.3.1.1 Summary Description

The Emergency Core Cooling System (ECCS) or Safety Injection System (SIS) is designed to provide core cooling in the unlikely event of a Loss-of-Coolant Accident (LOCA). The ECCS prevents significant alteration of core geometry, Precludes fuel melting, limits the cladding metal-water reaction, removes the energy generated in the core and maintains the core subcritical during the extended period of time following a LOCA.

The SIS accomplishes these functional requirements by use of redundant active and passive injection subsystems. The active portion of the SIS consists of high and low pressure Safety Injection pumps and associated valves. The passive portion consists of pressurized Safety Injection Tanks (SIT).

In addition, the Safety Injection System functions to inject borated water into the Reactor Coolant System to add negative reactivity to the core in the unlikely event of a steam line rupture. Safety Injection is also initiated in the event of a Steam Generator Tube Rupture or a CEA Ejection incident. The system is actuated automatically.

6.3.1.2 Criteria

6.3.1.2.1 Functional Design Bases

a. The shutoff head and flowrates of the High Pressure Safety Injection Pump (HPSIP) and Low Pressure Safety Injection Pump (LPSIP) were selected to insure that adequate flow is delivered to the RCS to accomplish the functional requirements of Section 6.3.1.1.

b. Storage of fluid for the SIS is accomplished by the Refueling Water Tank (RWT) which contains a sufficient amount of borated fluid to accomplish the functional requirements of Section 6.3.1.1.

c. The SIS is designed such that equal flows are delivered to each injection point, regardless of break location.

6.3.1.2.2 Reliability Design Bases

a. The safety function defined in Section 6.3.1.1 can be accomplished assuming the failure of a single active component during the injection mode of operation or a single active or limited leakage passive failure of a component during the recirculation mode of operation. For failure analysis, all necessary supporting systems including the onsite electrical power system are considered a part of the Safety Injection System. A Failure Modes and Effects Analysis is presented in Table 6.3.2-2.

b. Components of the Safety Injection System and instrumentation which must operate following a LOCA are designed to operate in the environment of Section 3.11.

c. The Safety Injection System is designed to perform the functions of Section 6.3.1.1 for the entire duration of a LOCA.

d. The Safety Injection System is designed to Seismic Category I requirements.

6.3.1.3 Interface Requirements

Below are detailed the interface requirements that the SIS places on certain aspects of the BOP, listed by categories. In addition, applicable GDC and Regulatory Guides, which C-E utilizes in its design of the SIS, are presented. These GDC and Regulatory Guides are listed only to show what C-E considers to be relevant, and are not imposed as interface requirements, unless specifically called out as such in a particular interface requirement.

Relevant GDC - 1, 2, 3, 4, 13, 18, 20, 21, 22, 23, 35, 36, 37, 54, 57

Relevant Reg. Guides - 1.1, 1.26, 1.28, 1.29, 1.31, 1.36, 1.38, 1.44, 1.46, 1.48, 1.53, 1.64, 1.68, 1.75, 1.79, 1.82

A. Power

1. The Safety Injection System pumps and valves shall be capable of being powered from the plant turbine generator (onsite power source), and/or plant startup power source (offsite power), and the emergency generators (emergency power). 7

2. Power connections shall be through a minimum of two independent buses so that in the event of a LOCA in conjunction with a single failure in the electrical supply, the flow from one high-pressure and one low-pressure safety injection train shall be available for core protection.

3. Each electrical bus of the above shall be connected to one high-pressure safety injection pump and associated valves and one low-pressure safety injection pump and associated valves.

4. Each emergency generator and the automatic sequencers necessary for generator loading shall be designed such that flow to the core is attained within a maximum of 30 seconds. The emergency generator interface requirements are described in Section 8.3.1 and shall be complied with.

5. Instrument power supplies shall be provided as stated in Chapter 8.

6. The SIS hot leg injection valves shall be powered such that a single electrical failure cannot cause spurious initiation of hot leg injection flow through either hot leg injection line, nor

The high-pressure safety injection pumps are sized such that one HPSI pump (after consideration of spillage directly out the break) will supply adequate water to the core to match decay heat boiloff rates soon enough to minimize core uncovery and allow small break LOCA's to meet the performance criteria of 10CFR50.46. A typical pump characteristic curve is shown in Figure 6.3.2-3. The effectiveness of the pump during a steam line break is also analyzed to assure that the pumps are adequately sized.

Mechanical shaft seals are used and are provided with leakoffs which collect any leakage past the seals. The seals are designed for operation with a pumped fluid temperature of 350°F.

The pump motors are specified to have the capability of starting and accelerating the driven equipment, under load, to design point running speed within 5 seconds based on an initial voltage of 75% of the rated voltage at the motor terminals, increasing linearly with time to 90% voltage in the first 2 seconds, and increasing to 100% voltage in the next 2 seconds.

The pumps are provided with drain and flushing connections to permit reduction of radiation before maintenance. The pressure containing parts of the pump are stainless steel with internals selected for compatibility with boric acid solutions. The materials selected are analyzed to ensure that differential expansion during design transients can be accommodated.

The pumps are provided with minimum flow protection to prevent damage resulting from operation against a close discharge. Also, individual HPSI pump ultrasonic flow meters provide low flow alarming. 7

The design temperature is based on the saturation temperature of the reactor coolant at the containment design pressure plus a design tolerance. The design pressure for the high pressure pumps is based on the shutoff head plus maximum containment pressure plus a design tolerance. The High-Pressure Pump Data is summarized in Table 6.3.2-1.

6.3.2.2.4 Piping

Piping is specified to deliver borated safety injection water from the safety injection tanks and from the refueling water tank via the safety injection pumps, to the safety injection nozzles in the RCS. The major piping sections are (refer to Figures 6.3.2-1A & 1B):

a. From each safety injection tank to its respective RCS cold leg safety injection nozzle;

b. Redundant piping from the refueling water tank and containment sump to the suction of the high- and low-pressure safety injection pumps;

c. Redundant piping from the high-pressure safety injection pumps discharge to redundant high-pressure injection headers each of which serves the four safety injection nozzles on the cold legs and one nozzle on each shutdown cooling suction line;

d. Redundant piping from the low-pressure safety injection pump discharge to each low-pressure injection header which serves two of the four safety injection nozzles.

The Safety Injection System piping is fabricated of austenitic stainless steel and is designed to ASME Code Section III. Flexibility and seismic loading analyses are performed by each Applicant to confirm the structural adequacy of the system piping.

6.3.2.2.5 Valves

The location, type and size, type of operator, position (during the normal operating mode of the plant) and failure position of the SIS valves, is shown in Figures 6.3.2-1A and 6.3.2-1B. Pressure design rating and code design classification are also shown. A valve list is given in Table 6.3.2-6.

a. Relief Valves

Protection against overpressure of components within the Safety Injection System is provided by conservative design of the system piping, appropriate valving between high-pressure sources and low-pressure piping, and by relief valves. All lines within the high- and low-pressure systems from the RCS up to and including the safety injection valves are designed for full Reactor Coolant System pressure. In addition, the high-pressure header to which the charging pumps discharge is designed for full Reactor Coolant System pressure up to and including the header check valve. Relief valves are provided as required by applicable codes. All relief valves are of the totally enclosed, pressure tight-type with suitable provisions for gagging.

A tabulation of Safety Injection System relief valves is provided below.

1. SI-211, 221, 231, and 241, Safety Injection Tank relief valves.

The relief valves on the safety injection tanks are sized to protect the tanks against the maximum fill rate of liquid or gas into the safety injection tanks. They discharge into the containment. The set pressure is 700 psig with a capacity of 6000 SCFM of gas or 230 gpm of liquid.

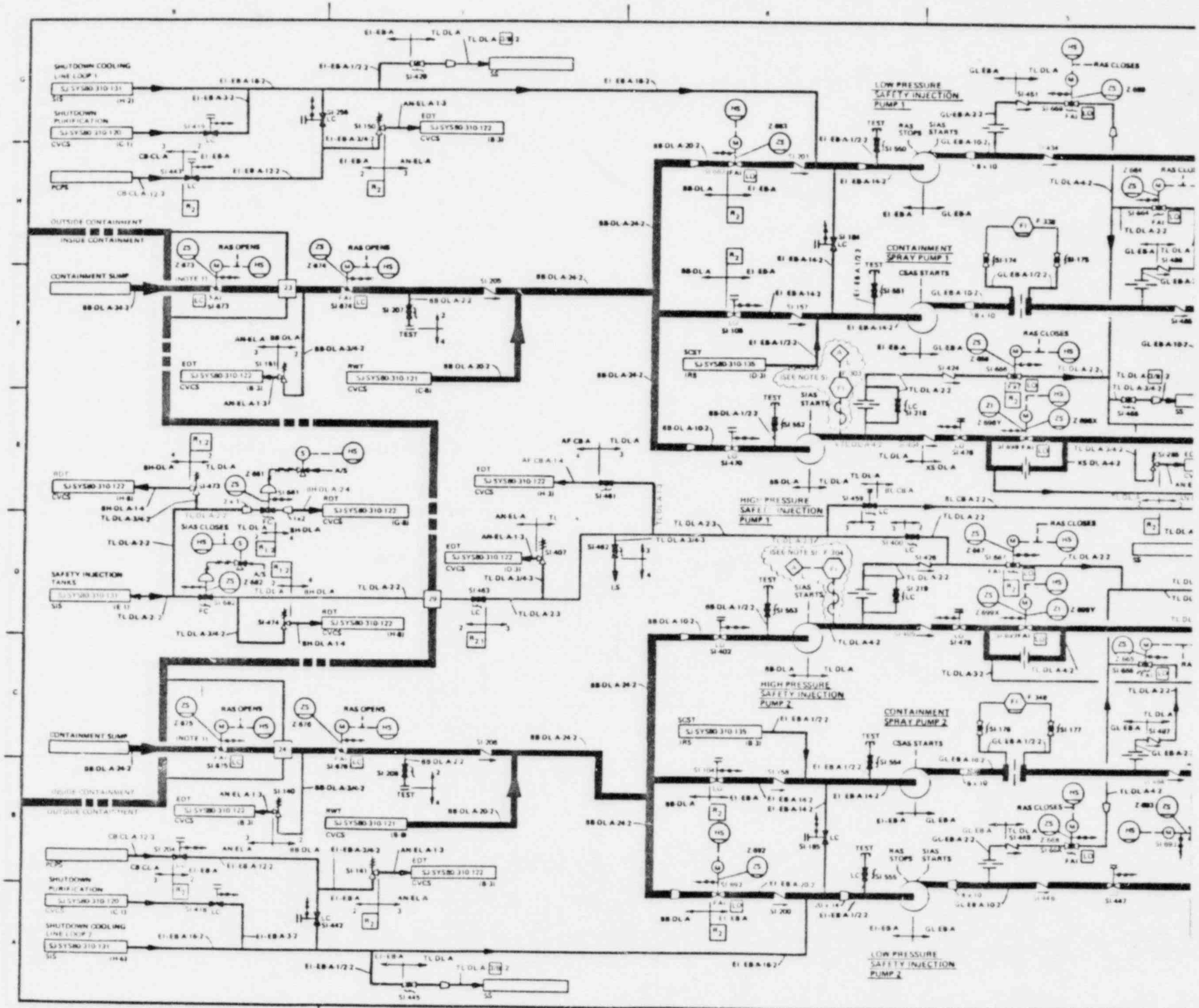
2. SI-473, Check Valve Leakage Relief Valve.

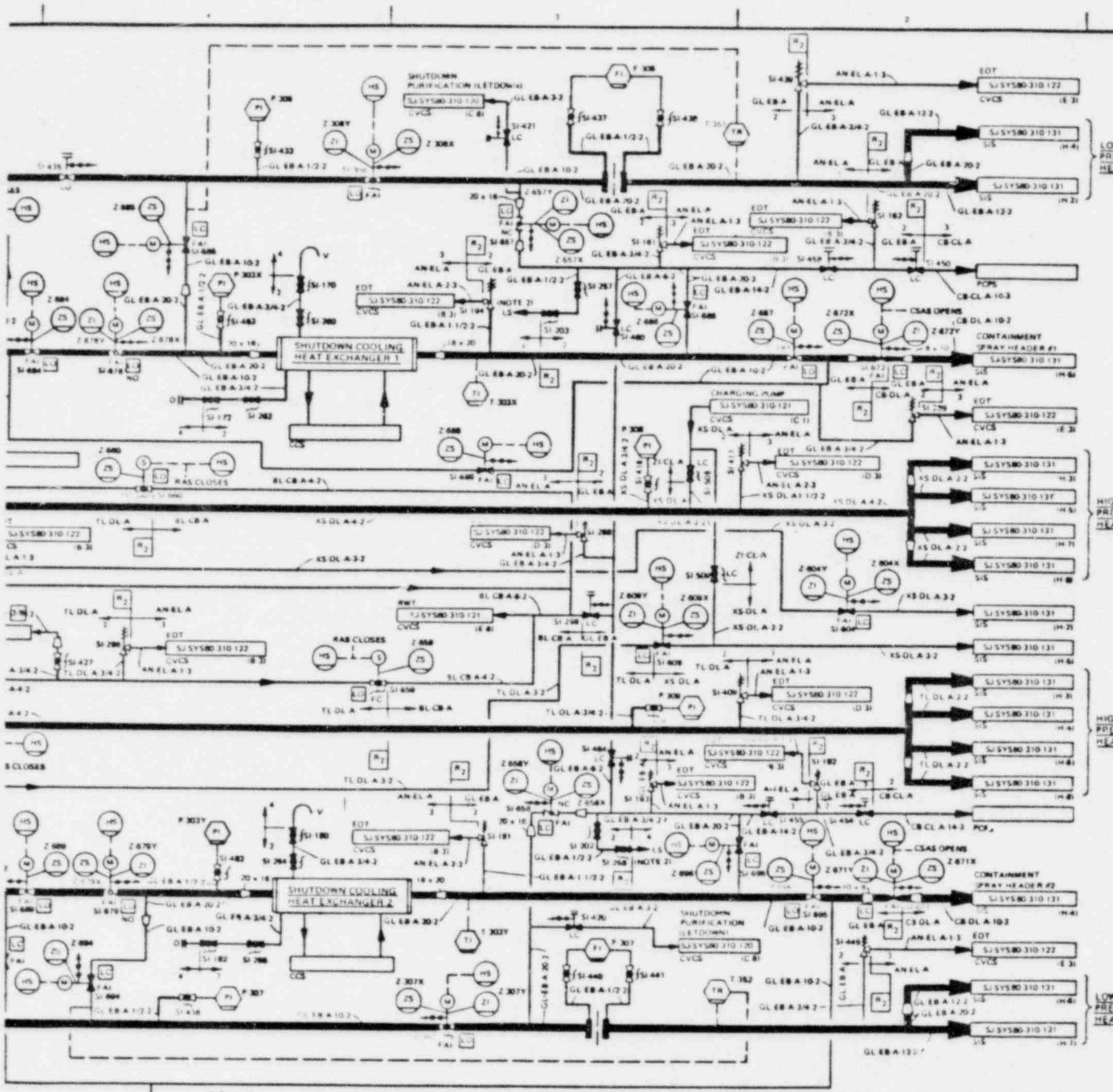
A relief valve is provided on the safety injection test and leakage return line.

This relief valve is sized to protect against overpressure of the line when relieving injection line pressure following check valve testing or during normal operation. It discharges into the reactor drain tank. The set pressure is 2050 psig with a capacity of 35 gpm.

3. SI-474 and SI-407, Safety Injection Tank Fill Line Relief Valves.

Relief valves are located on the Safety Injection Tank fill line to protect against overpressure due to a temperature increase. SI-474 discharges to


SHUTDOWN COOLING LINE LOOP 1
SHUTDOWN PURIFICATION
PCPS
OUTSIDE CONTAINMENT
INSIDE CONTAINMENT
CONTAINMENT SUMP
RAS OPENS
SAFETY INJECTION TANKS
SIAS CLOSES
LOW PRESSURE SAFETY INJECTION PUMP 1
CONTAINMENT SPRAY PUMP 1
CSAS STARTS
RAS STOPS
SIAS STARTS
RAS CLOSES
HIGH PRESSURE SAFETY INJECTION PUMP 1
(SEE NOTE 5)
HIGH PRESSURE SAFETY INJECTION PUMP 2
CONTAINMENT SPRAY PUMP 2
LOW PRESSURE SAFETY INJECTION PUMP 2
SHUTDOWN COOLING LINE LOOP 2



5. BROKEN LINE INDICATES CLAMP-ON TYPE SONIC SENSOR. PIPE INTEGRITY NOT BROKEN.

4. NOMINAL SIZES OF C-E SUPPLIED COMPONENTS ARE SHOWN ON THE P&ID. FOR DETAILED EQUIPMENT PARAMETERS SEE THE EQUIPMENT SPECIFICATION. PIPE SIZES ARE TYPICAL. HEAD LOSS/ΔP REQUIREMENTS ARE FOUND IN THE INTERFACE DOCUMENT. DUE TO BUILDING ARRANGEMENTS, PIPE SIZES MAY HAVE TO DIFFER FROM THOSE SHOWN.

3. FOR SYMBOLS & ABBREVIATIONS SEE DRAWING SJ SYS80 310 100 SEE FIGURE (1.1.1)

2. THIS LINE MUST BE LEAD OUT OF SAFEGUARDS ROOM.

1. ENCAPSULATED VALVES OR EQUIVALENT CONTAINMENT PENETRATION SATISFYING GENERAL DESIGN CRITERIA 54 AND 55.

SJ SYS80 310 130

Amendment No. 7
March 31, 1982

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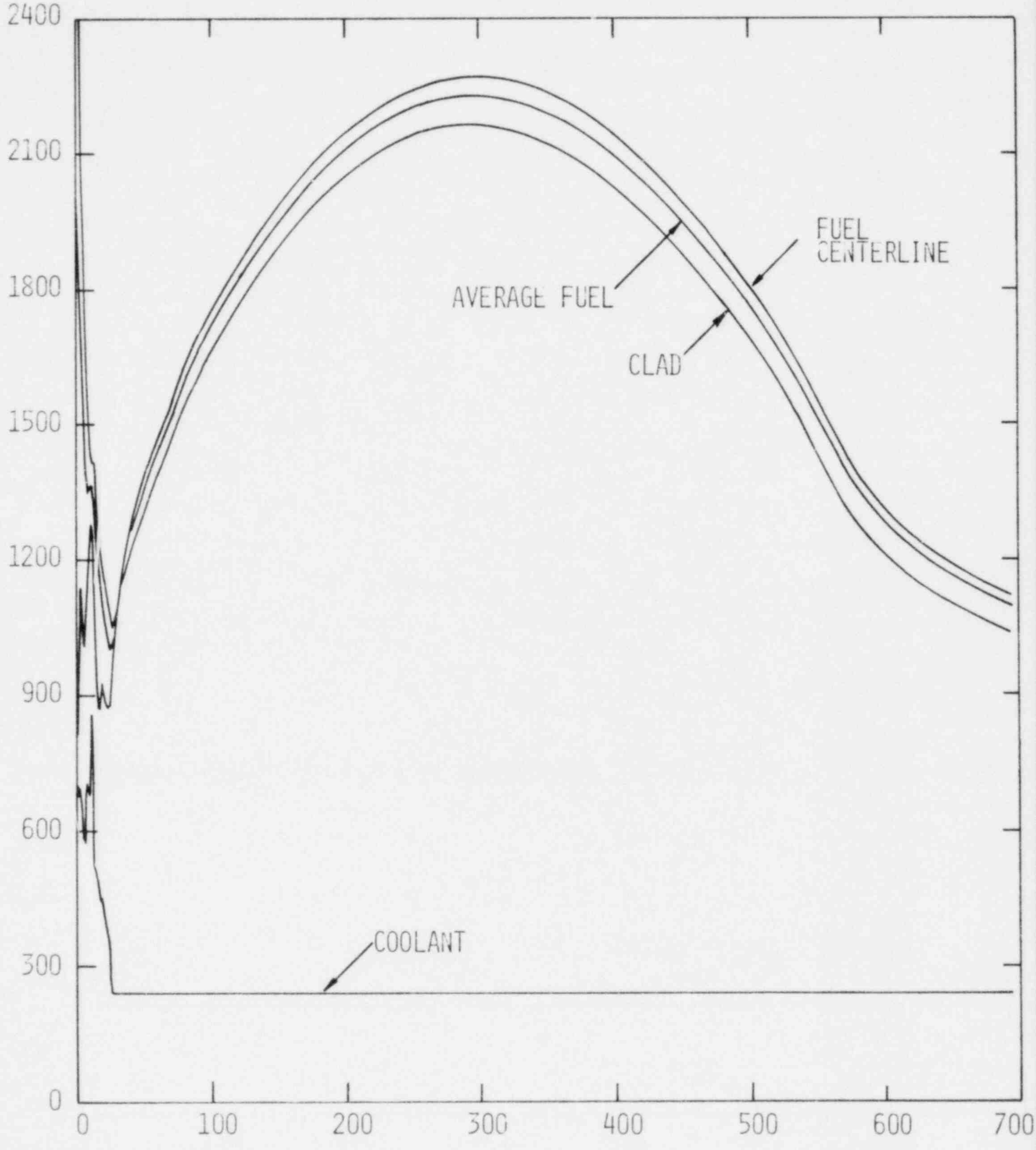
C-E SYSTEM 80

SAFETY INJECTION SYSTEM
PIPING AND INSTRUMENTATION DIAGRAM

Figure 6.3.2-1A



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	1.0 x DOUBLE ENDED GUILLOTINE BREAK IN PUMP DISCHARGE LEG CLAD, CENTERLINE, AVERAGE FUEL AND COOLANT TEMPERATURE FOR HOTTEST NODE	Figure 6.3.3.2-5P

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*See Applicant's SAR

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Pretrip alarms are initiated above the trip setpoint to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.7 Low Steam Generator Water Level. The low steam generator water level trip is provided to trip the reactor when measured steam generator water level falls to a low preset value. Separate trips are provided from each steam generator. The nominal trip setpoint is provided in Table 7.2-4.

Pretrip alarms are initiated above the trip setpoint to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.8 Low Steam Generator Pressure. The low steam generator pressure trip is provided to trip the reactor when the measured steam generator pressure falls to a low preset value. Separate trips are provided from each steam generator. The nominal trip setpoint during normal operation 6
is provided in Table 7.2-4. At steam generator pressures below normal, the operator has the ability to manually decrease the setpoint to a fixed increment below existing system pressure. This is used during plant cooldown. During startup, this setpoint is automatically increased and remains at the fixed increment below generator pressure. This fixed increment is provided in Table 7.2-4.

Pretrip alarms are initiated to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.9 High Containment Pressure. The high containment pressure trip is provided to trip the reactor when measured containment pressure reaches a high preset value. The nominal trip setpoint is provided in Table 7.2-4. The trip is provided as additional design conservatism (i.e., additional means of providing a reactor trip). The high containment pressure trip setpoint is selected in conjunction with the high-high containment pressure setpoint to prevent exceeding the containment design pressure during a design basis LOCA or main steam line break accident.

Pretrip alarms are initiated to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.10 High Steam Generator Water Level. A high steam generator water level trip is provided to trip the reactor when measured steam generator water level rises to a high preset value. Separate trips are provided from each steam generator. The nominal trip setpoint is provided in Table 7.2-4.

Pretrip alarms are initiated to provide audible and visible indication of approach to a trip condition.

7.2.1.1.1.11 Manual Trip. A manual reactor trip is provided to permit the operator to trip the reactor. Actuation of two adjacent pushbutton switches in the main control room will cause interruption of the ac power to the CEDMs. Two independent sets of trip pushbuttons are provided; either one of which will cause a reactor trip. There are also manual reactor trip switches at the reactor trip switchgear.

The remote manual initiation portion of the Reactor Trip System is designed as an input to the RTSS. This design is consistent with the recommendations of NRC Regulatory Guide 1.62. The amount of equipment common to both automatic and manual initiation is kept to a minimum. Once initiated, the manual trip will go to completion as required in Section 4.16 of IEEE Standard 279-1971.

7.2.1.1.1.12 <u>Low Reactor Coolant Flow</u>. The low reactor coolant flow trip is provided to trip the reactor when the pressure differential across the primary side of either steam generator decreases below a rate limited variable setpoint, as shown in Figure 7.2-17. A separate trip is provided for each steam generator. This function is used to provide a reactor trip 5
for a reactor coolant pump sheared shaft event.

Pretrip alarms are provided.

7.2.1.1.2 Initiating Circuits

7.2.1.1.2.1 <u>Process Measurements</u>. Various pressures, levels, and temperatures associated with the NSSS and the containment building are continuously monitored to provide signals to the RPS trip bistables. All protective parameters are measured with four independent process instrument channels. A detailed listing of the parameters measured is contained in Table 7.2-3.

A typical protective channel, as shown in Figure 7.2-1, consists of a sensor/transmitter, converter/power supply, current loop resistors, indicating meter or recorder, trip bistable/calculator inputs, and outputs for the Plant Monitoring System (PMS).

The piping, wiring, and components of each channel are physically separated from that of other like protective channels to provide independence. The output of each transmitter is an ungrounded current loop. Exceptions are (1) the nuclear instruments, and (2) the reactor coolant pump speed sensors which provide a pulsed voltage signal. Signal isolation is provided for computer inputs. Each redundant channel is powered from a separate vital ac bus.

7.2.1.1.2.2 <u>CEA Position Measurements</u>. The position of each CEA is an input to the RPS. These positions are measured by means of two reed switch assemblies on each CEA.

Each reed switch assembly consists of a series of magnetically actuated reed switches spaced at intervals along the CEA housing and wired with precision resistors in a voltage divider network (see Figure 7.2-2). A magnet attached to the CEA extension actuates the adjacent reed switches, causing voltages proportional to position to be transmitted for each assembly. The two assemblies and wiring are physically and electrically separated
from each other (see Figure 7.2-3). 5

One set of the redundant signals for all CEA's is monitored by one CEA Calculator and the other set of signals by the redundant CEA Calculator.

TABLE 7.6-1

SHUTDOWN COOLING SYSTEM AND SAFETY INJECTION TANK INTERLOCKS

SYSTEM	SETPOINT	FUNCTION
Shutdown Cooling System		
Suction Line Valves	≤ 400 psia	Permits valves to be opened by operator.
	≥ 700 psia	Valves are automatically closed. 7
Safety Injection Tank		
Isolation Valves	≥ 500 psig	Valves are automatically opened.
	≤ 415 psig	Permits valves to be closed by operator.
	SIAS	Automatically opens the valves, if the valves are closed. Sends an open signal if valves are open that overrides a closing signal.
Shutdown Cooling Relief Valves	435 psig	Prevents or mitigates overpressurization of the SCS.

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prescribed boron concentration either manually or automatically. To assist the operator in maintaining the proper boric acid concentration in the Reactor Coolant System, indications of boron concentration, in parts per million (ppm), are provided on a digital readout and on a recorder. These signals are supplied by the Boronometer. Additional recorders indicate reactor makeup water flow and boric acid makeup flow, which can be used to determine whether boration or dilution is occurring.

The Boronometer detects the boron concentration by passing reactor coolant around a neutron source. Refer to Figure 7.7-8 for the Boronometer block diagram. Around the source are BF_3 neutron detectors. As the boron concentration decreases the neutron flux detected will increase. The circuitry converts this flux signal, corrected for sample temperature, to a ppm boron signal in the signal processing drawer. These processed signals are sent to the PMS, the control room and to an annunciator.

The information supplied by the Boronometer system is used in addition to regular sampling of the reactor coolant to determine boron concentration.

At power, the boron concentration, in addition to CEA position determines reactor coolant temperature. Because of the long time required to change the boron concentration, the boron is used for long term effects such as fuel burnup and fission product build up. Boron concentration control can also be used for load following. By adjusting the boron concentration, the CEAs can be withdrawn to provide an adequate shutdown margin.

7.7.1.1.8 In-Core Instrumentation System

The in-core instrumentation system is used to monitor the core power distribution.

There are 61 in-core monitoring assemblies with five self-powered Rhodium detectors in each location. The 61 assemblies are strategically distributed about the reactor core, and the five detectors are axially distributed along the length of the core at 10, 30, 50, 70 and 90% of core height. This permits representative three diminsional flux mapping of the core. The Rhodium detectors produce a delayed beta current proportional to the neutron activation of the detectors which is proportional to the neutron flux in the detector region.

The signals from the in-core detectors are converted to usable voltage signals by the In-Core Amplifier System which sends these signals to the Plant Monitoring Computer (PMC) portion of the PMS by way of a multiplexer. The PMS converts these analog voltages to equivalent digital signals and performs the background, beta decay delay and Rhodium depletion compensation using digital signal processing routines.

In addition to the fixed system described above there is a movable in-core monitoring system. The movable system consists of two movable detectors and associated hardware to position either probe at any core locations. The movable detector system provides a flux map independent of the fixed detector system. The movable in-core system is controlled by the PMS and provides for fully automatic mapping of the total core.

The fixed and movable in-core instrumentation systems are designed to perform the following functions:

a. To determine the gross power distribution in the core during different operating conditions from 20% to 100% power;

b. To provide data to estimate fuel burn-up in each fuel assembly;

c. To provide data for the evaluation of thermal margins in the core;

The fixed and movable in-core detectors can be used to assist in the calibration of the ex-core detectors by providing azimuthal and axial power distribution information. The ex-core system is used to provide indication of the flux power and axial distribution for the Reactor Protective System.

7.7.1.1.9 Ex-Core Neutron Flux Monitoring System (Non-Safety Channels)

The ex-core neutron flux monitoring system includes neutron detectors located around the reactor core and signal conditioning equipment located in the control room area. Neutron flux is monitored from source levels through full power operation and signal outputs are provided for reactor control and for information display.

Two startup channels provide source level neutron flux information to the reactor operator for use during extended shutdown periods, initial reactor 5
startup, startups after extended shutdown periods, and following reactor refueling operations. Each channel consists of a dual section proportional counter assembly, with each section having multiple BF_3 proportional counters, one preamplifier located outside the reactor shield, and a signal processing drawer containing power supplies, a logarithmic amplifier, and test circuitry. High voltage power to the proportional counters is terminated several decades of neutron flux above the source level to extend detector life. These channels provide readout and audio count rate information but have no direct control or protective functions.

Two control channels provide neutron flux information, in the power operating range of 1% to 125%, to the Reactor Regulating System for use during automatic turbine load-following operation (see Section 7.7.1.1.1). Each control channel consists of a dual section uncompensated ionization chamber detector and a signal conditioning drawer containing power supplies, a linear amplifier, and test circuitry. The detector is operated in the current mode only. These channels are completely independent of the safety channels.

7.7.1.1.10 Boron Dilution Alarm System

Reactivity control in the reactor core is effected, in part, by soluble boron in reactor coolant system. The Boron Dilution Alarm System (Figure 7.7-10) utilizes the startup channel nuclear instrumentation signals to detect a possible inadvertent boron diultion event while in Modes 3-6. There are 7
two redundant and independent channels in the Boron Dilution Alarm System (BDAS) to ensure detection and alarming of the event.

The BDAS contains logic which will detect a possible inadverent boron dilution event by monitoring the startup channel neutron flux indications. When these neutron flux signals increase (during shutdown) to equal or greater than the calculated alarm setpoint, alarm signals are initiated to the Plant Annunciation System. The alarm setpoint is periodically, automatically lowered to be a fixed amount above the current neutron flux signal. The alarm setpoint will only follow decreasing or steady flux levels, not an increasing signal. The current neutron flux indication and alarm setpoint (per channel) are displayed. There is also a reset capability to allow the operator to acknowledge the alarm and initialize the system. 7

7.7.1.2 Design Comparison

The functional design of the following, non-safety, control systems was performed by Combustion Engineering. The design differences between the control systems in the CESSAR Licensing scope and the control systems provided for the reference plant (Arkansas Nuclear One - Unit 2 - (ANO-2) NRC Docket No. 50-368) are discussed in this section.

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7.7.1.2.10 Boron Dilution Alarm System

The Boron Dilution Alarm System is an addition to the CESSAR design. There is no functional comparison to the reference plant. 7

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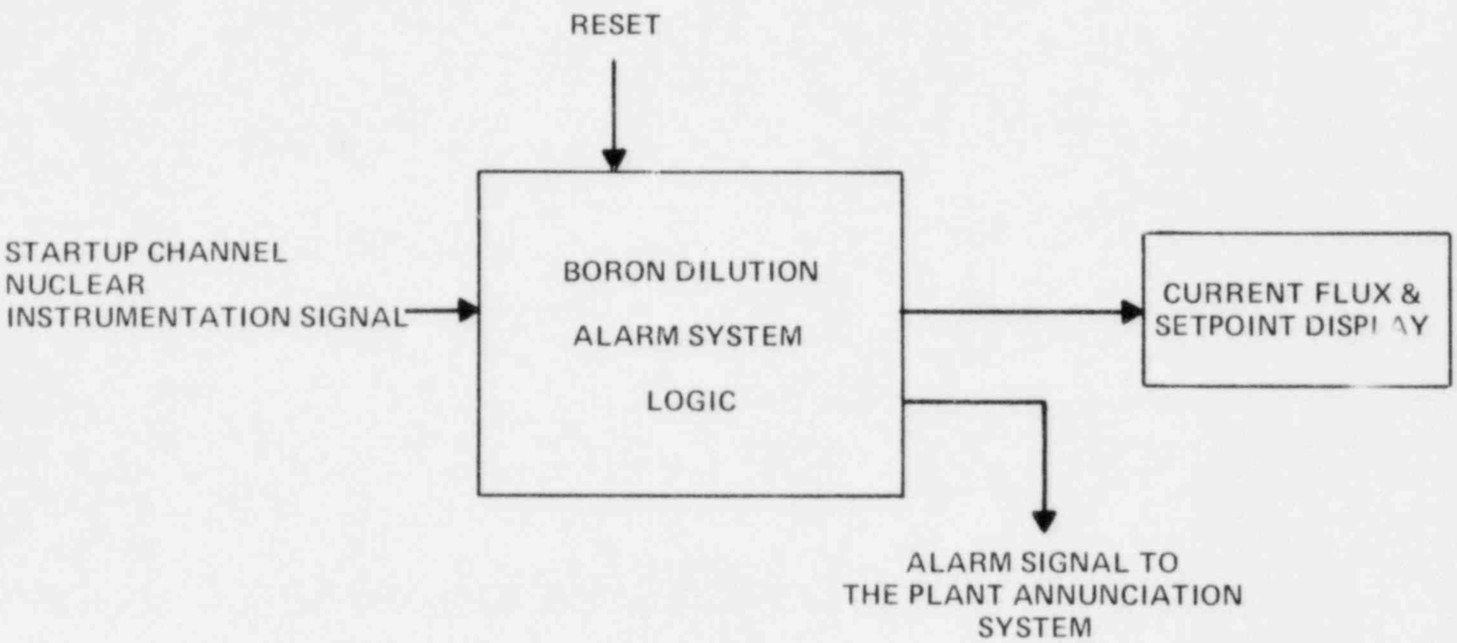

NOTE: ONLY ONE OF TWO IDENTICAL CHANNELS IS SHOWN.

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C - E SYSTEM 80	BORON DILUTION ALARM SYSTEM SIMPLIFIED BLOCK DIAGRAM	Figure 7.7-10

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c. In the event of a failure of a bus, standby equipment connected to other buses shall be capable of being placed in operation.

2. Emergency Power Requirements

a. Charging Pumps - Each emergency power bus shall supply one pump. Additionally, the third charging pump shall be capable of receiving power from either emergency power bus. The charging pumps shall not be automatically sequenced on the emergency power busses.

b. The following are emergency power supply requirements for CVCS instrumentation:

Instrument	Control Location(1)	Emergency Bus
L-200 (RWT level)	A/C	A
L-201 (RWT level)	A/C	B
F-212 (Charging flow)	A/C	B
P-212 (Charging pressure)	A/C	A
L-203A (RWT RAS level)	A	A
L-203B (RWT RAS level)	A	B
L-203C (RWT RAS level)	A	C
L-203D (RWT RAS level)	A	D

c) The following are emergency power supply requirements for CVCS valves:

Valve	Emergency Bus	Control Location(1)
CH-515 (receives SIAS)	B	A/C
CH-516 (receives SIAS & CIAS)	A	A/C
CH-560 (receives CIAS)	A	A
CH-561 (receives CIAS)	B	A
CH-580 (receives CIAS)	A	A
CH-506 (receives CIAS)	A	A/C
CH-505 (receives CIAS)	B	A/C
CH-523 (receives CIAS)	B	A
CH-507	A	A/C
CH-530	B	A
CH-531	A	A
CH-203	B	A/C
CH-205	A	A/C
CH-255	A	A
CH-501	A	A
CH-524	B	A
CH-536	A	A

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Note (1): Location code is as follows; A-Control Room, B-Local, C-Remote Shutdown Panel, D-Location outside Control Room.

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B. Protection from Natural Phenomena

1. The location, arrangement, and installation of the RWT, charging pump gravity feed piping, charging pumps, charging pump discharge piping, the letdown line between the RCS and letdown containment

isolation valves, and Safety Injection Systems (SIS) trains suction piping shall be such that floods (and tsunami and seiches for applicable sites) or the effects thereof will not prevent them from performing their functions. The severity of the above natural phenomena to be considered, as well as the combination of the effects of these natural phenomena with the design conditions of ANSI N18.2-1973, shall meet the requirements of Criterion 2 of 10CFR50, Appendix A.

2. The location, arrangement and installation of the RWT, charging pump gravity feed piping, charging pumps, charging pump discharge piping, the letdown line between the RCS and letdown containment isolation valves, and SIS trains suction piping shall be such that winds and tornadoes or the effects thereof will not prevent them from performing their functions. The severity of the winds and tornadoes to be considered, as well as the combination of the effects of these natural phenomena with the design conditions of ANSI N18.2-1973, shall meet the requirements of Criterion 2 of 10CFR50, Appendix A.

3. The location, arrangement, and installation of the RWT, charging pump gravity feed piping, charging pumps, charging pump discharge piping, the letdown line between the RCS and letdown containment isolation valves, and SIS trains suction piping shall be such that they will withstand the effects of earthquakes without loss of the capability to perform their functions. The severity of The severity of the earthquakes considered, as well as the combination of these natural phenomena with the design conditions of ANSI N.18.2-1973, shall meet the requirements of Appendix A of 10CFR50, Appendix A of 10CFR100, and NRC Regulatory Guide 1.48. Failure of non-seismic systems and structures shall not cause loss of either SIS train.

C. Protection from Pipe Failure

The letdown subsystem (from the RCS coolant system), charging system (from valve CH-118 through the charging pumps to RCS to CH523), auxiliary spray, high pressure safety injection header, and drain header isolation valves (CH-329, 332, 3367) and boric acid addition system (including both of the Refueling Water Tank gravity feed connections to the charging pump suction header) the connections from the refueling water tank to the suction of the safety injection system pumps, and the Refueling Water Tank and spent fuel pool connections to the charging pump suction header via the Boric Acid Makeup Pumps and valve CH-514 shall be protected from loss of function from the effects of pipe rupture, such as pipe whip, jet impingement, jet reaction, pressurization, or flooding.

D. Missiles

The portion of the CVCS protected from pipe failure (see 9.3.4.6.C) shall also be protected from loss of function from the effects of missiles in accordance with the missile barrier design interface requirement of Section 3.5.3.1.

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TABLE 9.3-7 (Continued) (Sheet 37 of 100)

CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)

FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
120)	Charging Line Manual Isolation Valve; CH-429	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate charging line for maint. or for alternate path charging thru HPSI header	Operator	Valve, CH-524 can be closed	
		b) fails closed	Mech. binding	Unable to reestablish charging flow thru normal path	Operator	Alternate charging path thru HPSI header	
121)	Charging Line Isolation Valve; CH-524	a) fails open	Mech. binding, valve operator failure, loss of power	No impact on normal operation. Unable to isolate charging line for maint. or alternate path charging thru HPSI header	Valve position indicator in control room, flow indicator, FI-212	Manual isolation valve, CH-429	Handwheel on valve can be used to close valve if operator malfunction.
		b) fails closed	Mech. binding, valve operator failure	Unable to reestablish charging thru normal path; if this occurs during normal operation the chg. pump disch. relief will lift.	Valve position indicator in control room, flow indicator, FI-212	Alternate path charging thru HPSI header	
122)	Test Connection CH-854	a) fails closed	Mech. binding	No impact on normal operation. Unable to test charging line isolation valves IAW ASME XI.	Operator	None	
		b) seat leakage	Contamination, mech. damage	Minor loss of primary coolant outside containment	Local leak detectors	Drain line is blind flanged	
123)	Temperature Indicator, TI-229	erroneous temperature indications	Elect. or mech. malfunct., setpoint drift	No impact on system operation. TI-229 has no control function	Periodic test	None	
124)	Auxiliary Spray Valves; CH-203, CH-205	a) fails closed	Mech. binding, valve operator failure, loss of power	No impact on normal operation. Unable to use the charging pumps to provide aux. PZR spray for PZR pres. control during plant shutdown	Valve position indication in control room	Redundant valves from separate power supplies.	Cold shutdown can be achieved without auxiliary spray.

CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)

FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
		b) fails open	spurious signal, operator error	Excess PZR spray flow, resulting in reduction of RCS pres.	Valve position indicators in control room	None	PZR heaters will come on to maintain PZR pres.
125)	Charging Line Pressure Control Valve, CH-240	a) fails closed	Mech. failure, Spurious signal	Sudden loss of charging flow, VCT level increases, PZR level decreases. Pressure increases in charging line	VCT and PZR level indications, Lo flow alarms from FI-212, Hi pres. indic. from PI-212	Alternate charging path through HPSI header. Spring check valve CH-435 will open to maintain charging flow	
		b) regulates back pressure too low	Valve operator malfunction, mech. binding	Short term decrease in RCP seal injection flow and increase in charging flow	Lo flow indications or alarms from seal injection flow indicators. Lo delta pres. indication or alarm from PDIC-240	Seal injection flow control valves will open to increase flow, thereby reestablishing flow balance	
		c) regulates back pressure too high	Valve operator malfunction, mech. binding partial blockage	Short term increase in RCP seal injection flow and decrease in charging flow. Increase in charging line pres.	Hi flow indications or alarm from seal injection flow indicators. Hi delta pres. indication or alarm from PDIC-240	Seal injection flow control valves will close to limit flow. Spring check valve CH-435 will open to maintain charging flow if necessary.	7
126)	Auxiliary Spray Line Check Valve; CH-431	a) fails closed	Mech. binding, blockage	No impact on normal operation. Unable to provide aux. PZR spray for PZR pressure control during plant shutdown	Lo flow indication from FI-212, PZR pres., not decreasing.	None	Plant can be brought to cold shutdown without auxiliary spray.
		b) fails open	Mech. failure	Diversion of PZR spray flow to charging line. Possible PZR pres. increase	PZR pres. indicators	Aux. spray valves CH-203 and CH-205 are closed during normal operation	
127)	Differential Pressure Indicator/ Controller; PDIC-240	a) spurious Lo diff. pres readings	Elect. or mech. malfunct., setpoint drift	PDIC-240 will drive CH-240 closed trying to maintain a DP of 30 lbs. seal injection flow will increase, charging line pressure will increase	Hi flow alarms from seal injection flow indicators, Hi pres indic. from PI-212, CH-240 position indicator	Seal injection flow control valves will maintain seal inject. flow. Spring check valve, CH-435 will open to maintain charging flow if necessary.	

CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)

FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
165)	BAMP Recirculation Valves; CH-192, CH-130	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate recirculalation line for maint. on BAMP	Operator	Valves CH-510 and CH-647 provide adequate isolation	
		b) fails closed	Mech. failure	Unable to establish recirculation flow path for one BAMP. Possible damage to pump if it is dead headed into a closed makeup line	Operator	Redundant BAMP available	This valve would be repaired before starting affected pump. Valves closed only for pump maint.
166)	BAMP Suction to Pool Cooling and Purification System (PCPS) Isolation Valve; CH-144	a) fails closed	Mech. binding, blockage	No impact on normal operation unable to obtain borated makeup water from PCPS	Operator	RWT is normal source of borated makeup water	
		b) seat leakage	Contamination, mech. damage	BAMP will draw suction on spent fuel pool, gradually reducing its level. Reduced shielding and cooling for spent fuel	Spent fuel pool level indicators	Redundant isolation valve in PCPS	
167)	BAMP Discharge to PCPS Isolation Valve, CH-753	a) fails closed	Mech. failure, blockage	No impact on normal operation. Unable to supply borated water to spent fuel pool from RWT	Operator	None	
		b) seat leakage	Contamination, mech. damage	Minor diversion of makeup flow to spent fuel pool (SFP). Gradual SFP level increase	SFP Level indicators. Possibly Lo flow indic. from FQRC-210Y	None	

CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)

FAILURE MODE AND EFFECTS ANALYSIS

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remarks and Other Effects
168)	RWT Gravity Feed to Charging Pump Suction Isolation Valve; CH-536	a) fails closed	Mech. failure, blockage, loss of power.	No impact on normal operation. Unable to supply boric acid solution from RWT via one gravity feed line to charging pump suction header without the BAMPs	Valve position indication in control room.	Alternate gravity feed path to individual charging pump suction lines	
		b) seat leakage	Contamination mech. damage	Diversion of boric acid solution from RWT to RCS via charging pumps. Possible over boration of RCS	Boronometer indications, sample analysis. Decreasing reactor power	None	
		c) fails open	Mech. failure	Diversion of boric acid solution from RWT to RCS via charging pumps. Possible over boration of RCS.	Boronometer indications, sample analysis. Decreasing reactor power.	None	
169)	RWT Gravity Feed to Charging Pump Suction Header Check Valve, CH-190	a) fails closed	Mech. failure, blockage	Same as 168 a)	None	Same as 168 a)	
		b) fails open	Mech. failure, seat leakage	No impact on normal operation	None	Isolation valve, CH-141	
170)	Boric Acid Filter (BAF) Isolation Valves; CH-161, CH-166	a) fails open	Mech. binding	No impact on normal operation. Unable to isolate BAF for element replacement	Operator	None	
		b) fails closed	Mech binding	Unable to place BAF back in service after maint.	Operator	Boric acid makeup can continue through diversion valve CH-164	
171)	BAF Diversion Valve, CH-164	a) fails closed	Mechanical binding, blockage	No impact on normal operation. Unable to divert boric acid makeup flow past BAF when BAF element replacement needed	Operator	None	

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TABLE 9.3-8

CHEMISTRY AND VOLUME CONTROL SYSTEM LIST OF ACTIVE VALVES

Reference: Figure 9.3-1, P&ID

Task Number	P+ID Coordinates	Valve* Type	Line Size (in)	Actuator* Type	Environmental* Design Criteria
CH 118	C3	C	4.00	N	C(1)
CH-190	B3	C	3.00	N	C(1)
CH-305	B8	C	20.00	N	C, D
CH-306	C7	C	20.00	N	C, D
CH-328	B2	C	2.00	N	C(1)
CH-331	E2	C	2.00	N	C(1)
CH-334	G2	C	2.00	N	C(1)
CH-440	C2	C	2.00	N	C(1)
CH-505	G7	D	1.00	N	C(1)
CH-506	G7	D	1.00	N	A-1, A-2, B
CH-530	B8	T	20.00	M	C, D
CH-531	C8	T	20.00	M	C, D

Reference: Figure 9.3-2, P&ID 7

Task Number	P+ID Coordinates	Valve* Type	Line Size (in)	Actuator* Type	Environmental* Design Criteria
CH-494	H7	C	1.50	N	A-1, A-2, B
CH-560	D7	G	3.00	D	A-1, A-2, B
CH-561	D7	G	3.00	D	C(1)
CH-580	H6	G	1.50	D	C(1)

Reference: Figure 9.3-4, P&ID

Task Number	P+ID Coordinates	Valve* Type	Line Size (in)	Actuator* Type	Environmental* Design Criteria
CH-203	H7	G	2.00	S	A-1, A-2, B
CH-205	G7	G	2.00	S	A-1, A-2, B
CH-240	G6	G	2.50	D	A-1, A-2, B
CH-255	F3	G	1.50	M	C(1)
CH-431	G6	C	2.00	N	A-1, A-2, B
CH-433	G6	C	2.50	N	A-1, A-2, B
CH-515	H8	G	2.00	D	A-1, A-2, B
CH-516	H8	G	2.00	D	A-1, A-2, B

TABLE 9.3-8 (Cont'd)

Reference: Figure 9.3-4, P&ID (Cont'd)

Task Number	P+ID Coordinates	Valve* Type	Line Size (in)	Actuator* Type	Environmental* Design Criteria
CH-523	E8	G	2.00	D	C(1)
CH-524	E8	G	2.50	M	C(1)
CH-639	D8	C	2.50	N	C(1)
CH-787	H1	C	1.00	N	A-1, A-2, B
CH-802	G1	C	1.00	N	A-1, A-2, B
CH-807	F1	C	1.00	N	A-1, A-2, B
CH-812	E1	C	1.00	N	A-1, A-2, B
CH-835	F2	C	1.50	N	A-1, A-2, B
CH-866	H1	C	1.00	N	A-1, A-2, B
CH-867	G1	C	1.00	N	A-1, A-2, B
CH-868	F1	C	1.00	N	A-1, A-2, B
CH-869	E1	C	1.00	N	A-1, A-2, B

7

* Refer to Table 1.1-1 for definition of Symbols; Appendix 3.11A for Environmental Design Criteria Legend

Note (1): C, F, G required if valve in annulus building

(2): See Section 3.11 for the extent of environmental qualification testing.

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PRESSURIZER LEVEL CONTROL SYSTEM

24. Backup Charging Pump Fails to Turn On
25. Backup Charging Pump Fails to Turn Off
26. Letdown Flow Control Valve Fails to Close
27. Letdown Flow Control Valve Fails to Open

MAIN FEEDWATER SYSTEM

28. One MFIV Fails to Close
29. One Back-flow Check Valve Fails to Close

MAIN STEAM SYSTEM

30. One MSIV Fails to Close
31. One Atmospheric Dump Valve Fails to Open
32. One MSSV Fails to Reclose

EMERGENCY FEEDWATER SYSTEM

33. Failure of Any One Emergency Feed Pump to Start

EMERGENCY CORE COOLING SYSTEM

34. Failure of One HPSI or LPSI Pump

ELECTRICAL POWER SOURCES

35. Loss of Offsite Power After Turbine Trip
36. Failure of One Emergency Generator to Start, Run, or Load
37. Failure of One Breaker to Achieve Fast Transfer to Backup Power Supply

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February 20, 1981

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6

Amendment No. 6
November 20, 1981

11.1.8 STEAM GENERATOR ACTIVITY MODEL

The specific activities in the steam generator and secondary systems are to be discussed in the Applicant's SAR. The bases data for these activities are supplied in Table 11.1.8-1.

11.1.9 RADWASTE SYSTEMS

Detailed information, including references to P&IDs pressures, temperatures, flow rates, and expected volumes of waste input to each of the radwaste systems is provided below.

<u>Liquid Waste Management System (LWMS)</u>

1. Chemical addition package strainer drain (Zone G-5 of Figure 9.3-1).

Flow	0-10 gpm
Chemical Nature	Primary grade water and 2060 ppm LiOH(max)
Pressure	25 psig
Temperature	40-120°F

2. Supply to LWMS waste condensate tank (Zone D-5 of Figure 9.3-3).

Flow	0-20 gpm 1
Chemical Nature	Primary grade makeup water
Temperature	120-130°F
Pressure	55 psig

3. Supply to LWMS waste concentrator (Zone G-7 of Figure 9.3-3).

Flow	0-20 gpm
Chemical Nature	Primary water
Temperature	40-90°F
Pressure	60 psig

4. BAC Drains (Zone D-5 of Figure 9.3-3).

Flow	0-20 gpm
Chemical Nature	Primary water and component cooling water
Temperature	40-200°F
Pressure	ATM

<u>Solid Waste Management System (SWMS)</u>

1. Ion exchanger resin sluicing lines (Zones A-1, C-4, and G-5 of Figures 9.3-4, 9.3-2, and 9.3-3, respectively).

Flow	100 gpm (max) water and 100 SCFM (max) air
Chemical Nature	Resin, air, reactor makeup water
Pressure	75 psig
Temperature	40-120°F
Volume of dewatered resin	36 ft^3/ion exchanger sluicing operation
Volume of resin discharged per year (based on one replacement per resin bed per year)	180 ft^3
Spent resin activity input to SWMS per year	Table 11.1.9-1

| 6

2. Strainer blowdown lines (Zones A-1, F-4, and G-5 of Figures 9.3-4, 9.3-2 and 9.3-3, respectively)

Flow	10 gpm
Chemical Nature	Resin slurry
Pressure	50 psig
Temperature	40-120°F

3. Boric acid concentrator concentrate discharge to SWMS (Zone B-5 of Figure 9.3-3).

Continuous:	Flow	0-20 gpm 12 wt % boric acid (max)
	Temperature	160-180°F
	Pressure	55 psig
Batch:	Flow	20 gpm 12 wt % boric acid (max)
	Temperature	160-180°F
	Pressure	55 psig
	Volume	2000 gallons (max)

4. The Solid Waste Management System shall be capable of receiving the following quantities of spent filter cartridges or equivalent each year:

	Replacement Frequency	Waste Volume
Seal injection filters	2	4.18 ft^3
Purification filters	4	16.72 ft^3
Boric acid filters	1	2.09 ft^3
Reactor drain filters	1	2.09 ft^3
Reactor makeup filters	1	2.09 ft^3

| 6

Gas Waste Management System (GWMS)* | 6

1. Purification and deborating ion exchanger vent (Zone D-1 of Figure 9.3-4; one ion exchanger vent rate/year).

Flow	0-20 scfm
Chemical Nature	Air
Temperature	40-120°F
Pressure	0 psig
Volume	170 scf/year

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2.2 The RRS, FWCS, SBCS, RPCS, and the pressurizer level and pressure control systems are in automatic operation.

3.0 TEST METHOD

3.1 Load increases and decreases (steps and ramps) in accordance with the C-E Fuel Pre-conditioning Guidelines will be performed at power levels in the 90 to 100% range and with swings in the 50 to 25 to 6
50% power level.

4.0 DATA REQUIRED

4.1 Time dependent data.

4.1.1 Pressurizer level and pressure.

4.1.2 RCS temperatures.

4.1.3 CEA position.

4.1.4 Power level and demand.

4.1.5 Steam generator levels and pressures.

4.1.6 Feedwater and steam flow.

5.0 ACCEPTANCE CRITERIA

5.1 The step and ramp transients demonstrate that the plant performs load changes allowed by C-E's Fuel Pre-conditioning Guidelines and data has been taken that will demonstrate the plant's ability to 6
meet unit load swing design transients.

5.2 That no audible noise or significant vibration is observed in the economizer or in the rest of the Feedwater and Emergency Feedwater 7
systems, due to water hammer.

14.2.12.5.4 Control Systems Checkout Test

1.0 OBJECTIVE

1.1 To demonstrate that the automatic control systems operate satisfactorily during steady-state and transient conditions.

2.0 PREREQUISITES

2.1 The reactor is operating at the desired conditions.

2.2 The RRS, FWCS, SBCS, RPCS, and the pressurizer level and pressure controls are in automatic operation.

3.0 TEST METHOD

3.1 The performance of the control systems during normal operations, transients and trips will be monitored to demonstrate that the systems are operating satisfactorily.

4.0 DATA REQUIRED

4.1 Time dependent data.

4.1.1 Pressurizer level and pressure.

4.1.2 RCS temperatures.

4.1.3 CEA position.

4.1.4 Power level and demand.

4.1.5 Steam generator levels and pressures.

4.1.6 Feedwater and steam flow.

5.0 ACCEPTANCE CRITERIA

5.1 The control systems maintain the reactor power, RCS temperature, pressurizer pressure and level, and steam generator levels and pressures within their control bands during both steady state and transient operation. | 6

14.2.12.5.5 Reactor Coolant and Secondary Chemistry and Radiochemistry Test

1.0 OBJECTIVE

1.1 To conduct chemistry tests at various power levels with the intent of gathering corrosion data and determining activity buildup.

1.2 To verify proper operation of the process radiation monitor.

1.3 To verify the adequacy of sampling and analysis procedures.

2.0 PREREQUISITES

2.1 The reactor is stable at the desired power level.

2.2 Sampling systems for the RCS and CVCS are operable.

3.0 TEST METHOD

3.1 Samples will be collected from the RCS and secondary system at various power levels and analyzed in the laboratory using applicable sampling and analysis procedures.

3.2 Samples will be collected at the process radiation monitor at various power levels, analyzed in the laboratory, and compared with the process radiation monitor to verify proper operation.

3.0 TEST METHOD

3.1 Planar radial peaking factors are verified for various CEA configurations by comparison of the CPC values with values measured with the incore detector system. 6

3.2 The CEA shadowing factors are verified by comparing excore detector responses for various CEA configurations with the unrodded excore responses. 6

3.3 The shape annealing factors are measured by comparing incore power distributions and excore detector responses during a free Xe oscillation.

*3.4 The temperature annealing factors are verified by comparing core power and excore detector responses for various RCS temperatures.

4.0 DATA REQUIRED

4.1 Conditions of the measurement.

4.1.1 Power.

4.1.2 Burnup.

4.2 Time dependent data.

4.2.1 Incore and excore detector readings.

4.2.2 CEA position.

4.2.3 RCS temperatures.

5.0 ACCEPTANCE CRITERIA

5.1 Measured radial peaking factors determined from incore flux maps are no higher than the corresponding values used in the CPCs.

5.2 The CEA shadowing factors, and temperature annealing factors used in the CPCs agree within the acceptance criteria specified in the CPC test requirements. 6

5.3 The shape annealing matrix have been measured and the boundary point power correlation constants used in the CPCs are within the limits specified by the test requirements.** 6

*This test will be performed only on the "first-of-a-kind" plant.

**As specified in the appropriate revisions or supplements of CEN 63A. 6

14.2.12.5.17 Main and Emergency Feedwater Systems Test

1.0 OBJECTIVE

1.1 To demonstrate that the operation of the main feedwater and emergency feedwater systems during Hot Standby, Startup and other normal operations, transients, and plant trips is satisfactory. 7

Amendment No. 7
March 31, 1982

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2.0 PREREQUISITES

2.1 The SBCS, FWCS, RRS, RPCS, and pressurizer pressure and level controls are operable in either manual or automatic modes. 7

3.0 TEST METHOD

3.1 Performance of the feedwater systems will be monitored during normal operation, transients, and trips.

4.0 DATA REQUIRED

4.1.1 Reactor power

4.1.2 RCS temperatures

4.1.3 Pressurizer pressure

4.1.4 Steam generator levels and pressures

4.1.5 Steam and feedwater flows

5.0 ACCEPTANCE CRITERIA

5.1 The main and emergency feedwater systems perform as designated by the system description.

5.2 No audible noise or vibration is observed during design operation, due to water hammer. 7

14.2.12.5.18 CPC Verification

1.0 OBJECTIVE

To verify DNBR and Local Power Density (LPD) calculations of the CPCs.

2.0 PREREQUISITES

2.1 The reactor is at the desired power level and CEA configuration with equilbrium Xe.

2.2 The CPCs are operational.

2.3 The incore detector system is operational.

3.0 TEST METHOD

3.1 Specified values are recorded from the CPCs.

3.2 The values for LPD and DNBR obtained from the CPCs are compared with the values calculated for the same conditions using the CPC FORTRAN Simulator.

CHAPTER 15

ACCIDENT ANLAYSES

* Chapter 15 and its appendices are completely replaced in Amendemnt No. 7. Due to the effort required to revise the format from the original submittal, previous amendments were submitted as interim documents. Therefore, revision lines are not shown on the revised pages.

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15. ACCIDENT ANALYSES

15.0 ORGANIZATION AND METHODOLOGY

This chapter presents analytical evaluations of the Nuclear Steam Supply System (NSSS) response to postulated disturbances in process variables and to postulated malfunctions or failures of equipment. Such incidents (or events) are postulated and their consequences analyzed despite the many precautions which are taken in the design, construction, quality assurance, and plant operation to prevent their occurrence. The effects of these incidents are examined to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations.

15.0.1 CLASSIFICATION OF TRANSIENTS AND ACCIDENTS

15.0.1.1 Format and Content

This chapter is structured according to the format and content suggested by Reference 1 and required by Reference 26.

15.0.1.2 Event Categories

Each postulated initiating event has been assigned to one of the following categories;

a. Increased Heat Removal by Secondary System,

b. Decreased Heat Removal by Secondary System,

c. Decreased Reactor Coolant Flow,

d. Reactivity and Power Distribution Anomalies,

e. Increase in RCS Inventory,

f. Decrease in RCS Inventory,

g. Radioactive Release from a Subsystem or Component, or

h. Anticipated Transients Without Scram (ATWS).

Definition of an appropriate evaluation basis and acceptance criteria does not presently exist for ATWS, therefore, these events are not addressed in this chapter. The assignment of an initiating event to one of these eight categories is made according to Reference 26.

15.0.1.3 Event Frequencies

Reference 26 subjectively classifies initiating events in the following qualitative frequency groups:

A. Moderate Frequency Events

B. Infrequent Events

C. Accidents

15.0.1.4 Events and Event Combinations

The events and event combinations in this chapter are those identified by Reference 26, and are presented with respect to the event specific acceptance criteria specified therein. For each applicable acceptance criterion in an event category, only the limiting event or event combination is presented in analytical detail. Qualitative discussions are provided for all other events or event combinations explaining why they are not limiting.

For event combinations which require consideration of a single failure, the limiting failure is selected from those listed in Table 15.0-6. Only low probability dependent failures (e.g., loss of offsite power following turbine trip) and independent pre-existing failures are considered credible and included in the table. Pre-existing failures are equipment failures existing prior to the event initiation which are not revealed until called upon during the event (e.g., a failure of an emergency feedwater pump). High probability dependent occurrences are always included in the event analysis, if they have an adverse impact (e.g., loss of main feedwater pumps following a loss of electric power).

15.0.1.5 Section Numbering

The incidents analyzed in this chapter are presented in sections in accordance with Reference 26 and are numbered as described in Table 15.0-2.

15.0.1.6 Sequence of Events Analysis

The purpose of the Sequence of Events and Systems Operation section provided for each limiting event in this chapter is to provide:

1. "The step-by-step sequence of events from event initiation to the final stabilized condition,

2. The extent to which normally operating plant instrumentation and controls are assumed to function,

3. The extent to which plant and reactor protection systems are required to function,

4. The credit taken for the functioning of normally operating plant systems, (and)

5. The operation of engineered safety systems that is required, (1)" as well as

6. "A summary of a systematic functional analysis of components required for each event analyzed in Chapter 15. The summary should be shown in the form of simple block diagrams beginning with the event, branching out to the various possible protection sequences for each safety action required to mitigate the consequences of the event (e.g., core cooling, containment isolaion, pressure relief, scram, etc.), and ending with an identification of the specific safety actions being provided. (24)"

A detailed Sequence of Events Analysis (SEA) has been performed for each limiting event for which detailed results are presented in this chapter. SEA has been specifically omitted for those events which, though representing limiting events for their category do not result in the actuation of safety systems or for which a detailed, quantitative analysis was not presented. The results of the analysis are presented in the form of three tables and a figure for each event. The first table in each Sequence of Events and Systems Operation section (15.X.Y-1) presents a chronological list of events which occur during the transient and the time at which they occur, from the initiation of the event to the achievement of cold shutdown conditions. The second table (15.X.Y-2) is a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient. The results of the SEA are summarized in the Sequence of Events Diagram (SED) and in a third table (15.X.Y-3) which specifies the reactor protection and engineered safety feature systems which are actuated, to accomplish safety functions, during the course of the transient.

The SED together with the chronological list of events and the SEA symbol and acronym drawing (Figure 15.0.-1) may be used to trace the actuation and interaction of the systems used to mitigate the consequences of each event. The SED is a block diagram, composed of several success paths which define a set of safety actions leading from the initiating event to the accomplishment of a specific safety function. All of the safety functions used in the SED's are defined in Figure 15.0-1. A success path may be composed of two branches, one indicated by a solid line, describing the Sequence of Events which occur in the transient analysis and the other, indicated by a dotted line, describing an alternative or back-up path to a given means of accomplishing a safety function. An alternate dotted path is specified if the analysis assumed the action of a non-safety system in achieving a particular safety function. Non-safety systems are indicated by an "NS" in the upper right-hand corner of the system block.

The redundancy of a system or component is indicated by a fraction (e.g., 1/2, 2/4) placed beneath the system block. The numerator specifies the number of trains or components required to perform the action and the denominator specifies the number of trains or components available. In cases where no alternate path exists and a single system or component is included in a success path, the symbol "S.F." will be used to indicate that no single active failure will prevent the accomplishment of the safety action.

Components or systems which require no active initiation or actuation to perform their function are considered to be passive and are marked as such with a "P" in the lower left-hand corner of the system block. The absence of a passive label implies that a component is considered to be active and must be actively initiated to perform its function.

Manual operations performed on a given system or component are indicated by placing an "M" in the lower left-hand corner of the system block. When a manual action is required, the sensed variables necessary to perform the action are shown as inputs and the location of the input signal is shown above the input signal circle.

The system setpoint values assumed in the transient analysis, e.g., trip signal setpoints, will be noted along the success path. Time delays or the time required to perform an action are shown as a number with square brackets.

All events presented in Sequence of Events Diagrams (SED) in this chapter are shown from event initiation to achievement of the Cold Shutdown operating mode (see Chapter 16). Not all events require that the plant be taken to Cold Shutdown. The SED's only demonstrate that for any event presented here it is possible to take them to Cold Shutdown by means of the safety actions indicated.

15.0.2 SYSTEMS OPERATION

During the course of any event various systems may be called upon to function. Some of these systems are described in Chapter 7 and include those electrical, instrumentation, and control systems designed to perform a safety function (i.e., those systems which must operate during an event to mitigate the consequences) and those systems not required to perform a safety function (see Sections 7.2 through 7.6 and 7.7, respectively).

The Reactor Protection System (RPS) is described in Section 7.2. Table 15.0-4 lists the RPS trips for which credit is taken in the analyses discussed in this section, including the setpoints and the trip delay times associated with each trip. The analyses take into consideration the response times of actuated devices after the trip setting is reached.

The reactor trip delay times shown in Table 15.0-4 are defined as the elapsed time from the time the sensor output reaches the trip setpoint to the time the trip breakers open. The sensor response is modeled by using the transfer function for the particular sensor used.

The interval between trip breaker opening and the time at which the magnetic flux of the Control Element Assembly (CEA) holding coils has decayed enough to allow CEA motion is conservatively assumed to be 0.34 seconds. Finally, a conservative value of 3.66 seconds is assumed for CEA insertion, defined as the elapsed time from the beginning of CEA motion to the time of 90% insertion of the CEAs in the reactor core.

The Engineered Safety Feature Actuation Systems (ESFAS) and electrical, instrumentation, and control systems required for safe shutdown are described in Sections 7.3 and 7.4, respectively. The manner in which these systems function during events is discussed in each event description. The instrumentation which is required to be available to the operator in order to assist him in evaluating the nature of the event and determining required action is described in Section 7.5. The use of this instrumentation by the operator is discussed in each event description.

Other systems called upon to function are described in Chapters 6, 9, and in the Applicants SAR. The utilization of these systems is described in the Sequence of Events section of each presentation.

Systems which may but are not required to perform safety functions are described in Section 7.7. These include various control systems and the Core Operating Limit Supervisory System (COLSS). In general, normal automatic operation of these control systems is assumed unless lack of operation would make the consequences of the event more adverse. In such cases, the particular control system is assumed to be inoperative, in the manual mode, until the time of operator action.

15.0.3 CORE AND SYSTEM PERFORMANCE

15.0.3.1 Mathematical Model

The Nuclear Steam Supply System (NSSS) response to various events was simulated using digital computer programs and analytical methods most of which are documented in Reference 2 and have been approved for use by the NRC by Reference 3.

15.0.3.1.1 Loss of Flow Analysis Method

The method used to analyze events which are initiated by failures which cause a decrease in reactor coolant flowrate is discussed in Appendix 15A.

15.0.3.1.2 CEA Ejection Analysis Method

The method used for analysis of the reactivity and power distribution anomalies initiated by a CEA ejection (Section 15.4.5) is documented in Reference 16, Topical Report CENPD-190A, which was approved by the NRC for reference in license applications on June 10, 1976.

15.0.3.1.3 CESEC Computer Program

The CESEC II computer program is used to simulate the NSSS (unless specified otherwise for an event). CESEC II is a version of CESEC which incorporates the ATWS model modifications documented in Reference 8 through 12 and includes additional improvements which extend the range of applicability of the models. The CESEC computer code is documented in Reference 7.

CESEC II computes key system parameters during a transient including core heat flux, pressures, temperatures, and valve actions. A partial list of the dynamic functions included in this NSSS simulation includes: point kinetics neutron behavior, Doppler and moderator reactivity feedback, boron and CEA reactivity effects, multi-node average and hot channel reactor core thermal hydraulics, reactor coolant pressurization and mass transport, reactor coolant system safety valve behavior, steam generation, steam generator water level, turbine bypass, main steam safety and turbine admission valve behavior, as well as alarm, control, protection, and engineered safety feature systems. The steam turbines, condensers and their associated controls are not included in the simulation. Steam generator feedwater enthalpy and flowrate are provided as input to CESEC II.

During the course of execution, CESEC II obtains steady-state and transient solutions to the set of equations that mathematically describe the physical models of the subsystems mentioned above. Simultaneous numerical integration of a set of nonlinear, first-order differential equations with time-varying coefficients is carried out by means of a simultaneous solution. As the time variable evolves, edits of the principal systems parameters are printed at prespecified intervals. An extensive library of the thermodynamic properties of uranium dioxide, water, and zircaloy is incorporated into this program. Through the use of CESEC-II, symmetric and asymmetric plant response over a wide range of operating conditions can be determined.

The CESEC-III version of CESEC used in some of the analyses explicitly models the steam void formation and collapse in the upper head region of the reactor vessel and is documented in Reference 27. Other improvements to this version of CESEC include: a more detailed thermalhydraulic model which explicitly simulates the mixing in the reactor vessel from asymmetric transients, an RCS flow model which calculates the time dependent reactor coolant mass flow rate in each loop, a wall heat model, 3-D reactivity feedback model, a safety injection tank model, and a primary-to-secondary heat transfer model which calculates the heat transfer for each generator node rather than for a steam generator as a whole.

15.0.3.1.4 COAST Computer Program

The COAST computer program is used to calculate the reactor coolant flow coastdown transient for any combination of active and inactive pumps and forward or reverse flow in hot or cold legs. The program is described in Reference 13 and was referenced in Reference 2.

The equations of conservation of momentum are written for each of the flow paths of the COAST model assuming unsteady one-dimensional flow of an incompressible fluid. The equation of conservation of mass is written for the appropriate nodal points. Pressure losses due to friction, and geometric losses are assumed proportional to the flow velocity squared. Pump dynamics are modeled using a head-flow curve for a pump at full speed and using four-quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

15.0.3.1.5 STRIKIN-II Computer Program

The STRIKIN-II computer program is used to simulate the heat conduction within reactor fuel rods and its associated surface heat transfer. The STRIKIN-II program is described in Reference 14.

The STRIKIN-II computer program provides a single, or dual, closed channel model of a core flow channel to calculate the clad and fuel temperatures for an average or hot fuel rod, and the extent of the zirconium water reaction for a cylindrical geometry fuel rod. STRIKIN-II includes:

A. Incorporation of all major reactivity feedback mechanisms

B. A maximum of six delayed neutron groups

C. Both axial (maximum of 20) and radial (maximum of 20) segmentation of the fuel element

D. Control rod scram initiation on high neutron power.

15.0.3.1.6 TORC Computer Program

The TORC computer program is used to simulate the fluid conditions within the reactor core and to calculate fuel pin DNBR. The TORC program is described in References 18 and 21 and was referenced in Reference 2.

15.0.3.1.7 Reactor Physics Computer Programs

Numerous computer programs are used to produce the input reactor physics parameters required by the NSSS simulation and reactor core programs previously described. These reactor physics computer programs are described in Chapter 4.

15.0.3.2 Initial Conditions

The events discussed in this chapter have been analyzed over a range of initial values for the principal process variables. The ranges were chosen to encompass all steady state operational configurations (with the exception of part loop operation).

Analysis over a range of initial conditions is compatible with the monitoring function performed by the COLSS which is described in Section 7.7 and the flexibility of plant operation which the COLSS allows. This flexibility is produced by allowing parameter trade-offs by monitoring the prinicipal process variables, synthesizing the margin to fuel thermal design limits, and displaying to the reactor operator the core power operating limit. The required margin to DNB incorporated in COLSS is currently established by the total loss of forced reactor coolant flow as described in Appendix 15A. The required margin to DNB is based on the total loss of forced reactor coolant flow since this initiating event produces the most rapid loss of margin to DNB before reactor trip and the maximum loss of margin to DNB after reactor trip. The peak linear heat generation rate incorporated in COLSS is established by the loss of coolant accident (LOCA). The range of values of each of the prinicipal process variables that was considered in analyses of events discussed in this chapter is listed in Table 15.0-5.

15.0.3.3 Input Parameters

The parameters used in the analyses are consistent with those listed in the preceding section and are primarily based on first-core values.

15.0.3.3.1 Doppler Coefficient

The effective fuel temperature coefficient of reactivity (Doppler Coefficient) as shown in Section 4.3 is multiplied by a weighting factor to conservatively account for higher feedback effects in the higher power density portions of the core and to account for uncertainties in determining the actual fuel temperature reactivity effects. The Doppler weighting factor, which is

specified for each analysis, is 0.85 for cases where a less negative Doppler feedback produces more adverse results and 1.15 for cases where a more negative Doppler feedback produces more adverse results.

The effective fuel temperature correlation is discussed in Section 4.3. This correlation relates the effective fuel temperature, which is used to correlate Doppler reactivity, to the core power.

15.0.3.3.2 Moderator Temperature Coefficient

The events analyzed in this Chapter model moderator reactivity as a function of moderator temperature instead of a moderator temperature coefficient. This method is used in order to more accurately calculate reactivity feedbacks due to the large moderator temperature variations which may occur during these events.

The moderator temperature coefficients corresponding to these moderator reactivity functions at nominal full power conditions (T_{ave}=594°F) range from $0.0*10^{-4}\Delta\rho$ /F to $-3.5*10^{-4}\Delta\rho$ /F. These values include all uncertainties, and bound the expected moderator temperature coefficients for all first cycle burnups, power levels, CEA configurations, and boron concentrations.

The most conservative, allowable value for the moderator temperature coefficient is assumed for each individual analysis.

15.0.3.3.3 Shutdown CEA Reactivity

The shutdown reactivity is dependent on the CEA worth available on reactor trip, the axial power distribution, the position of the regulating CEAs, and the time in core life. For transient analyses other than CEA ejection and Increase in Heat Removal (Sections 15.1), conservative. CEA worths of 10.0 percent and 6.4 percent $\Delta\rho$ were used for hot full power (HFP) and hot zero power (HZP), respectively. For CEA ejection events a conservative value of 3.81 percent $\Delta\rho$ was used for HFP and conditions. The foregoing values include uncertainties, the most reactive CEA stuck in the fully withdrawn position, and the effect of cooldown to HZP temperature conditions (Sub-section 4.3.2.4.3).

For Section 15.1 analyses at full power, a conservative CEA worth of 8.8 percent was used. This value is appropriate for end of equilibrium core, self-generated plutonium re-cycle (SGR) and includes uncertainties and the penalties appropriate to HFP as indicated in Table 4.3-7. For Section 15.1 events initiated from HZP, a conservative CEA worth of 6.0 percent was sufficient to preclude significant post-trip return-to-power. This value covers uncertainties, the most reactive CEA stuck in the fully withdrawn position, and the penalties appropriate to HZP as indicated in Table 4.3.6. The power dependent insertion limit (PDIL) which will be included in the Technical Specifications assures that these worths are available upon reactor trip.

The shutdown reactivity worth versus position curve which is employed in the Chapter 15 analyses, except where noted in individual discussions of events, is shown in Figure 15.0-2. This shutdown worth versus position curve was calculated assuming a more conservative rate of negative reactivity insertion than is expected to occur during the majority of operations, including power

maneuvering. Accordingly, it is a conservative representation of shutdown reactivity insertion rates for reactor trips which occur as a result of the events analyzed.

15.0.3.3.4 Effective Delayed Neutron Fraction

The effective neutron lifetime and delayed neutron fraction are functions of fuel burnup. For each analysis, the values of the neutron lifetime and the delayed neutron fraction are selected consistent with the time in life analyzed.

15.0.3.3.5 Decay Heat Generation Rate

Analyses assume decay heat generation based upon an infinite reactor operation at the initial core power level identified for each event.

15.0.4 RADIOLOGICAL CONSEQUENCES

Several of the events discussed are accompanied by the release of steam or liquid from the reactor coolant system or main steam system. The methodology and important input parameters used to assess the radiological consequences of these releases are discussed below.

The CESEC computer code (described in Section 15.0.3.1.3), in combination with hand calculations, were used to determine the mass and energy releases as a function of time. These data are then used as input to the calculation of radiological release to the atmosphere for determining thyroid and whole body doses at the exclusion area boundry.

The assumptions used for calculating radiological releases to the atmosphere follow.

1. The initial primary system activity level is based on the maximum activity in the reactor coolant due to continuous full power operation with 1% failed fuel. This activity level corresponds to a concentration of 2.09×10^{-3} Curies/lbm dose equivalent I-131.

2. The initial secondary system activity level is equal to 4.54×10^{-5} Ci/lbm dose equivalent I-131.

3. Primary-to-secondary steam generator tube leakage is included in the calculation of activity releases to atmosphere from the steam generators. The "technical specification leakage" discussed in the analyses of Chapter 15 is a 1 gpm primary-to-secondary tube leak.

4. Events for which Reference 26 requires consideration of "iodine spiking" the following are used:

   A. For iodine spiking generated by the event, the iodine appearance rate is increased by a factor of 500.

   B. For an abnormally high iodine concentration due to a previous iodine spike, a reactor coolant activity of 2.72×10^{-2} Ci/lbm dose equivalent I-131 is assumed.

The dose at the site exclusion area boundary (EAB) is calculated as follows:

1. Multiply the total primary system mass release by the primary system activity level and divide by the appropriate Decontamination Factor (DF). This gives the total number of dose equivalent I-131 curies released from the primary system.

2. For the applicable secondary system releases, multiply the total secondary system mass release by the secondary system activity level and divide by the appropriate DF to obtain the equivalent I-131 curies released to the environment.

3. The curies of dose equivalent I-131 released to the environment can be converted to a thyroid dose by multiplying by the following factors:

   a. Breathing rate = 0.347×10^{-3} m^3/sec(Reference 2)

   b. Atmospheric dispersion factor (X/Q) = 2.00×10^{-3} sec/m^3

   c. I-131 dose conversion factor = 1.48×10^6 rem/Ci

   Combining these parameters gives an effective dose conversion factor equal to 1.027 rem/Ci. Thus, the total thyroid dose is calculated by multiplying the total activity release (dose equivalent I-131 curies) by the effective dose conversion factor (1.027 rem/Ci).

4. Additional assumptions used in the determination of radiological releases to the atmosphere for certain events are:

   a. For pipe breaks outside containment in piping connected to the reactor coolant system, the release to atmosphere accounts for the formation of steam resulting from depressurization of the reactor coolant.

   b. For pipe breaks or valve malfunctions outside containment in the main steam system which result in eventual dry-out of a steam generator, radioactive nuclides within the steam generator are assumed to be released to atmosphere with a decontamination factor (DF) equal to 1.

REFERENCES FOR SECTION 15.0

1. NRC Regulatory Guide 1.70, Revision 2, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," September 1975.

2. "Combustion Engineering Standard Safety Analysis Report," CESSAR Docket No. STN-50-470, December 1975.

3. Combustion Engineering Standard Safety Analysis Report (CESSAR) "System 80 Nuclear Steam Supply System Standard Nuclear Design Preliminary Design Approval," PDA-2, Docket No. STN 50-470, NRC, December 31, 1975.

4. "C-E Methods for Loss of Flow Analysis," CENPD-183, July 1975.

5. Typical Balance of Plant Design. See Applicants SAR

6. Revision 1, "Analyses of Anticipated Transients Without Reactor Scram in Combustion Engineering NSSSs," CENPD-158, May 1976.

7. "CESEC Digital Simulation of a Combustion Engineering Nuclear Steam Supply System," CENPD-107, April 1974, Proprietary Information.

8. "ATWS Model Modifications to CESEC," CENPD-107, Supplement 1, September 1974, Proprietary Information.

9. "ATWS Models Modification to CESEC" CENPD-107, Supplement 1, Amendment 1-P, November 1975, Proprietary Information.

10. "ATWS Model for Reactivity Feedback and Effect of Pressure on Fuel," CENPD-107, Supplement 2, September 1974, Proprietary Information.

11. "ATWS Model Modifications to CESEC," CENPD-107, Supplement 3, August 1975.

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13. "COAST Code Description," CENPD-98, April 1973, Proprietary Information.

14. "STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program,"CENPD-135, April 1974 (Proprietary).

    "STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program (Modification)," CENPD-135, Supplement 2, December 1974 (Proprietary).

    "STRIKIN-II, A Cylindrical Geometry Fuel Rod Heat Transfer Program," CENPD-135, Supplement 4, August 1976 (Proprietary).

15. "Calculative Methods for the C-E Large Break LOCA Evaluation Model," CENPD-132, Supplement 1, December 1974 (Proprietary).

16. "C-E Method for Control Element Assembly Ejection Analysis," CENPD-190-A, January 1976.

17. "HERMITE A Multi-Dimensional Space-Time Kinetics Code for PWR Transients," CENPD-188, March 1976, Proprietary Information.

18. "TORC Code - A Computer Code for Determining the Thermal Margin of a Reactor Core," CENPD-161-P, July 1975, Proprietary Information.

19. "CE Critical Heat Flux - Critical Heat Flux Correlation for CE Fuel Assemblies with Standard Space Grids," CENPD-162-P, April 1975, Proprietary Information.

20. "Loss of Flow - CE Methods for Loss of Flow Analysis," CENPD-183, July 1975, Proprietary Information.

21. "TORC Code-- Verification and Simplified Modeling Methods," CENPD-206-P, January 1977, Propietary Information.

22. "Iodine Spiking," CENPD-180, March 1977.

23. "Radioactive Behavior in the RCS During Transients Operations," Supplement 1 to CENPD-180 March 1977.

24. "RESAR 3-S Round 1 Questions"

25. Wash - 1400, "Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," October, 1975.

26. NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," as revised through December 31, 1978.

27. LD-82-001 (dated 1/6/82), "CESEC Digital Simulation of a Combustion Engineering Nuclear Steam Supply System", Enclosure 1-P to letter from A. E. Scherer to D. G. Eisenhut, December, 1981.

TABLE 15.0-1

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TABLE 15.0-2

CHAPTER 15 SUBSECTION DESIGNATION

Each subsection is identified as 15.W.X.Y. With trailing zeros omitted where:

W = 1 Increase in heat removal by the secondary system
    2 Decrease in heat removal by the secondary system
    3 Decrease in reactor coolant system flowrate
    4 Reactivity and power distribution anomalies
    5 Increase in reactor coolant inventory
    6 Decrease in reactor coolant inventory
    7 Radioactive release from a subsystem or component

X = 1,2, etc. Event Title from Ref. 26

Y = 1 Identification of causes and frequency classifications
    2 Sequence of events and systems operation
    3 Analysis of effects and consequences
    4 Conclusions

TABLE 15.0-3

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TABLE 15.0-4

REACTOR PROTECTION SYSTEM TRIPS USED IN THE SAFETY ANALYSIS

Event	RPS	Analysis Setpoint	Trip Delay Time
Events not Mentioned Below	High logarithmic Power Level	2%	550 ms
	Variable Overpower	17% or 130%[a]	
	High Pressurizer Pressure	2450 psia	550 ms
	Low Pressurizer Pressure	1580 psia	550 ms
	Low Steam Generator Pressure	820 psia	550 ms
	Low Steam Generator Water Level	40% wide range[b]	550 ms
	High Steam Generator Water Level	99% narrow range[e]	550 ms
	Low DNBR	1.19	150 ms
	High Local Power Density	21 kw/ft[d]	150 ms
Feedwater and Steam Line Breaks	Variable Overpower	17% or 130%[a]	
	High Pressurizer Pressure	2475 psia	550 ms
	Low Pressurizer Pressure	1600 psia	550 ms
	Low Steam Generator Pressure	810 psia	550 ms
	Low Steam Generator Water Level	35% wide range[b]	550 ms
	High Steam Generator Water Level	99% narrow range[e]	550 ms
	Low DNBR	1.19	150 ms
	High Local Power Density	21 kw/ft[d]	150 ms

a. See discussion in Section 7.2.

b. Percent of distance between the wide range instrument taps above the lower tap. See Chapter 5 for details.

c. The trip delay times are discussed in Section 7.2 and include signal and sensor delay.

d. Setpoint value is set below the value at which fuel centerline melting would occur. See Section 4.4.

e. Percent of distance between the narrow range instrument taps above the lower tap. See Chapter 5 for details.

TABLE 15.0-5

INITIAL CONDITIONS

Parameter	Units	Range
Core Power	% of 3800 Mwt	0 - 102
Radial 1-pin peaking factor (with uncertainty)	-	1.40 to 1.63
Axial Shape Index		$-0.3 \leq \text{ASI} \leq +0.3$
Reactor Vessel Inlet Coolant Flowrate	% of 445600 gpm	95 - 116
Pressurizer Water Level	% distance between upper tap and lower tap above lower tap	26 to 60
Core Inlet Coolant Temperature	F	500 - 580 (2)
Reactor Coolant System Pressure	psia	1785 - 2400
Steam Generator Water Level	% distance between upper tap and lower tap above lower tap	40 - 88

(1) $$\text{ASI} = \frac{\text{area under axial shape in lower half of core} - \text{area under axial shape in upper half of core}}{\text{total area under axial shape}}$$

(2) Additional restrictions were applied to: Section 15.2.3, minimum core inlet coolant temperature equals 560°F; and Section 15.1.5, maximum core inlet coolant temperature equals 570°F.

TABLE 15.0-6

SINGLE FAILURES

STEAM BYPASS CONTROL SYSTEM

1. Failure to Modulate Open
2. Failure to Quick Open
3. One Bypass Valve Fails to Quick Close
4. Excessive Steam Bypass Flow
5. Failure to Generate Automatic Withdrawal Prohibit Signal During Steam Bypass Operation
6. Failure to Generate the Reactor Power Cutback Signal

REACTIVITY CONTROL SYSTEMS

7. Regulating Group(s) Fail(s) to Insert or Withdraw
8. A Single CEA Stuck*
9. A CEA Subgroup Stuck*
10. Failure to Initiate or Execute the Reactor Power Cutback
11. CEA's Withdraw upon Automatic Withdrawal Prohibit and/or CEA Withdrawal Prohibit

FEEDWATER CONTROL SYSTEM

12. Failure of Reactor Trip Override
13. Failure of High Level Override

TURBINE-GENERATOR CONTROL SYSTEM

14. Setback w/o Cutback
15. Failure to Modulate the Turbine Control Valves
16. Failure to Setback Given a Cutback
    (100% $\geq$ Initial Power > 75%)
17. Failure to Setback
    (75% $\geq$ Initial Power $\geq$ 60%)
18. Failure to Runback
    (60% > Initial Power)
19. Failure to Trip the Turbine

PRESSURIZER PRESSURE CONTROL SYSTEM (PPCS)

20. Failure of Spray Control Valves to Open
21. Failure of Spray Control Valves to Close
22. Failure of Backup Heaters to Turn On
23. Failure of Backup Heaters to Turn Off

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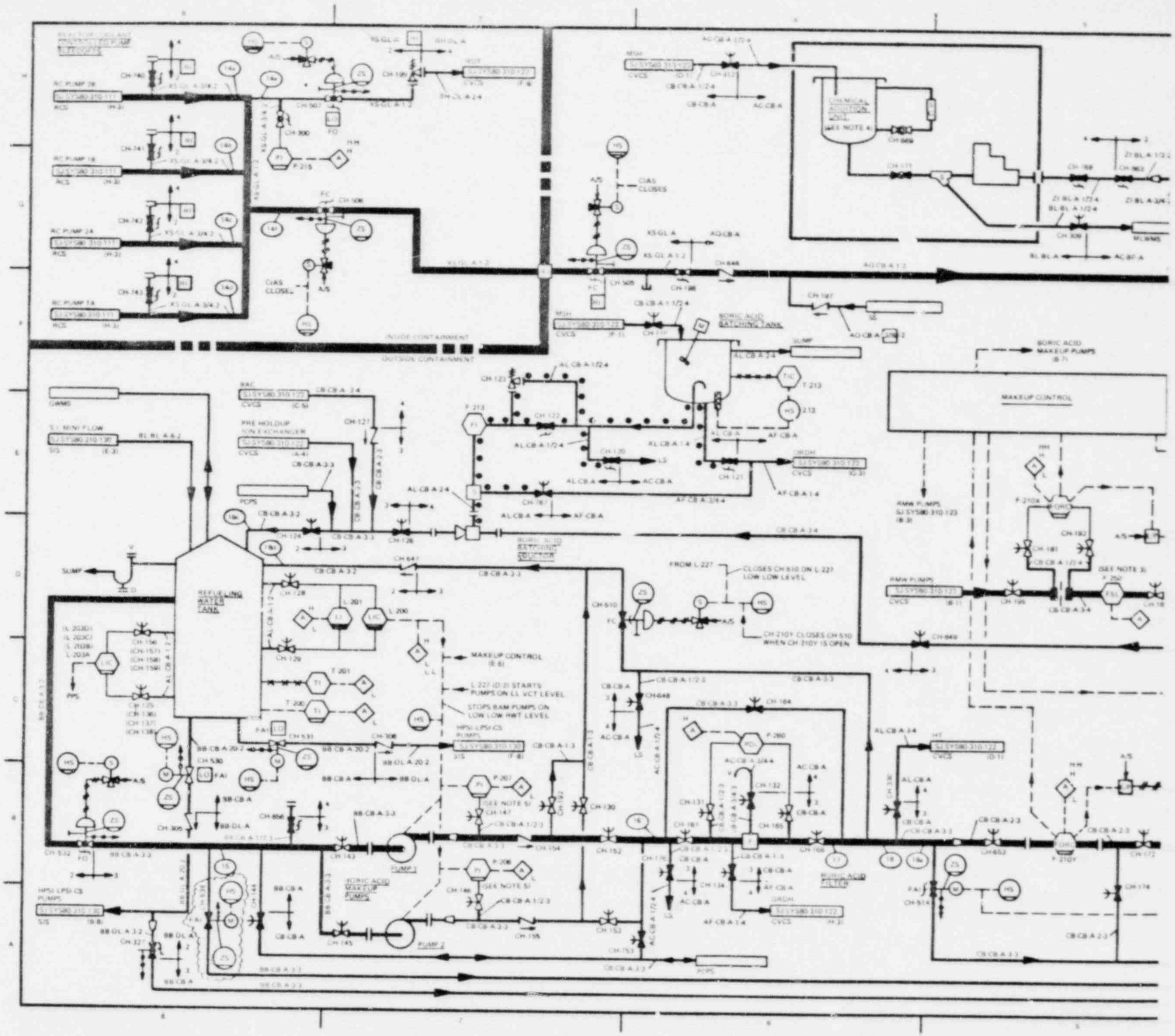
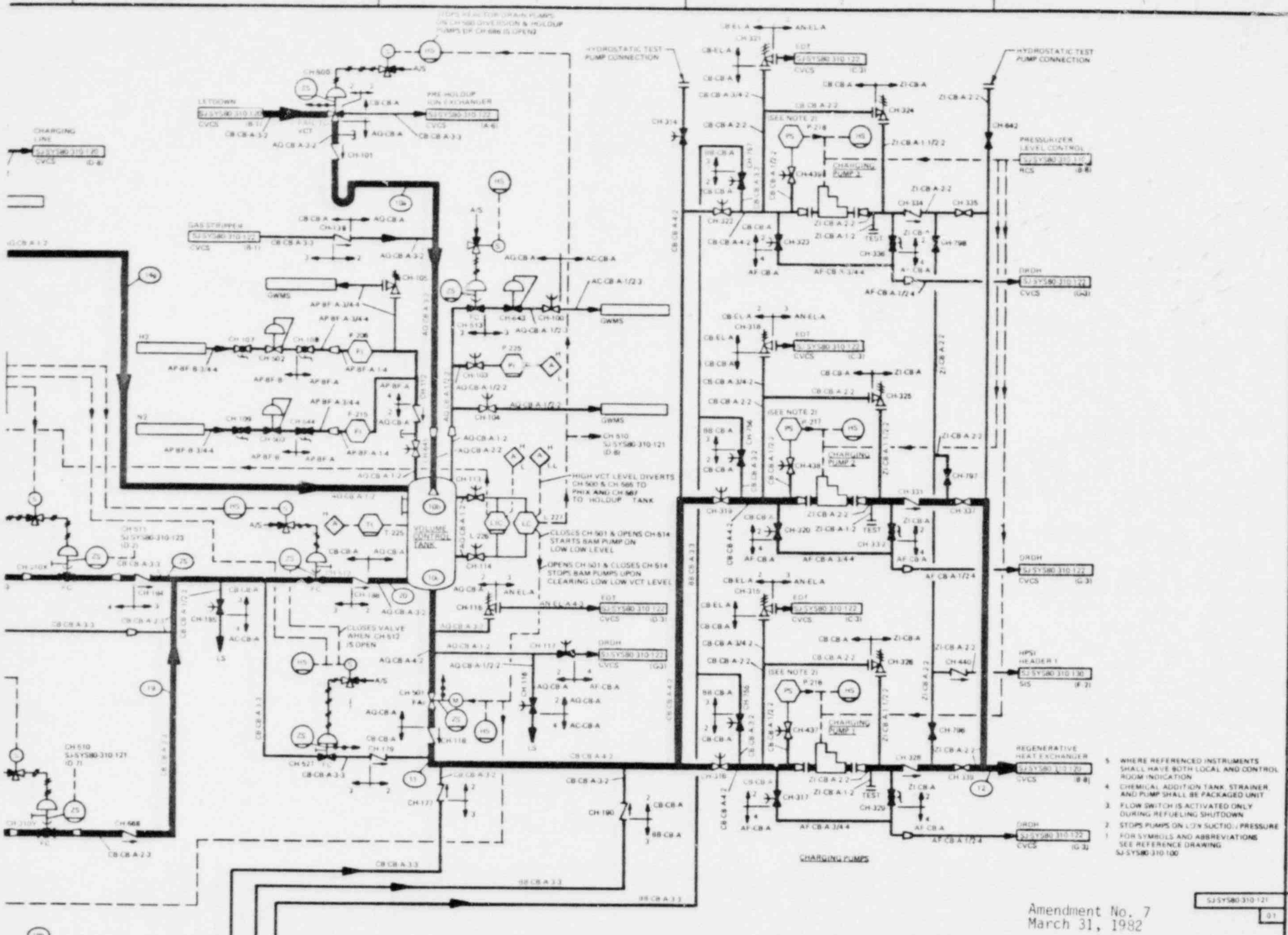
* Control Element Drive Mechanism does not respond to control signal. Release of CEA(s) on trip is not inhibited.


INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
RC PUMP 2B
RC PUMP 1B
RC PUMP 2A
RC PUMP 1A
CHEMICAL ADDITION TANK
(SEE NOTE 4)
BORIC ACID BATCHING TANK
MAKEUP CONTROL
BORIC ACID MAKEUP PUMPS
RMW PUMPS
REFUELING WATER TANK
BORIC ACID MAKEUP PUMPS
PUMP 1
PUMP 2
BORIC ACID FILTER
PRE HOLDUP ION EXCHANGER
SI MINI FLOW
GWMS
SUMP
FROM L-227
CLOSES CH 510 ON L-227 LOW LOW LEVEL
CH-210Y CLOSES CH 510 WHEN CH 210Y IS OPEN
L-227 (D-2) STARTS PUMPS ON LL VCT LEVEL
STOPS BAM PUMPS ON LOW LOW RWT LEVEL
HPSI LPSI CS PUMPS
CIAS CLOSES



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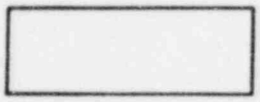
C - E SYSTEM 80

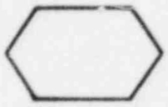
CHEMICAL & VOLUME CONTROL SYSTEM
PIPING & INSTRUMENTATION DIAGRAM

Figure 9.3-1

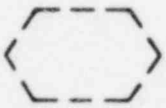
SEA SYMBOLS



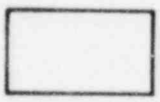
IDENTIFIES EVENT GROUP TO BE EVALUATED.



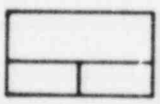
IDENTIFIES SAFETY FUNCTION WHICH IS REQUIRED TO MITIGATE THE EFFECTS OF THE TRANSIENT.



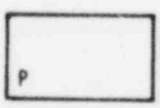
IDENTIFIES A FUNCTION WHICH OCCURS BUT WHICH IS NOT REQUIRED TO MITIGATE THE EFFECTS OF THE TRANSIENT.



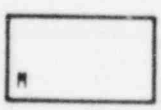
IDENTIFIES A SYSTEM OR COMPONENT



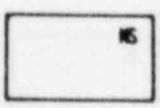
IDENTIFIES A SYSTEM HAVING TWO INDEPENDENT "TRAINS" OF EQUIPMENT OR CHANNELS.



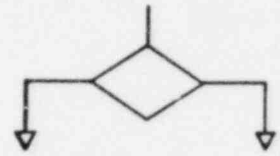
INDICATES THAT THE SAFETY ACTION OF THE SYSTEM IS PASSIVE.



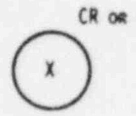
INDICATES THAT OPERATOR ACTION IS REQUIRED IN THE OPERATION OF THE SYSTEM.



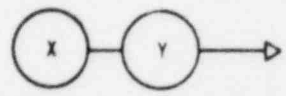
INDICATES THAT THE SYSTEM OR COMPONENTS OF THE SYSTEM, PERFORMING THE SPECIFIED ACTION, IS NOT A SAFETY SYSTEM.



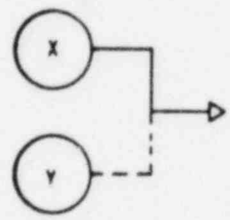
BRANCHED PATH INDICATING A D
SUCCESS PATH FOR A GIVEN SET
PLANT OR EVENT CONDITIONS.



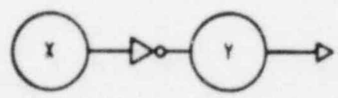
SINGLE SENSED VARIABLE "X" I
AUTOMATIC ACTION, MANUAL ACT
POST-EVENT TRACKING. CR OR
THE LOCATION (CR • CONTROL R
LOCAL) OF THE SIGNAL OR INDI
FOR MANUAL ACTIONS ONLY.



ALL OF THE SENSED VARIABLES
REQUIRED TO INITIATE THE SYS
ACTION.



ANY ONE OF THE MULTIPLE SENS
VARIABLES IS REQUIRED TO INIT
ACTION. THE SOLID LINE INDIC
THE FIRST OR MOST LIKELY METH
OF INITIATING THE ACTION.



SENSED VARIABLE "Y" INITIATES
ACTION, ONLY IF "X" IS NOT A
SETPOINT.

IDENTIFIES THE SENSED VARIABL
IF DIRECTED TOWARDS A SYSTEM,
ACTION IF DIRECTED AWAY FROM A
SYMBOL.

VERTICAL SOLID PATH INDICATES
PATH WHICH CONNECTS THE SAFETY
REQUIRED IN ORDER TO ATTAIN EA
ACCEPTABLE INCIDENT TERMINATIO

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SYSTEM

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ACTIONS
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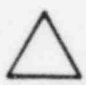
S.

A DOTTED VERTICAL LINE INDICATES AN ALTERNATIVE OR REDUNDANT PATH TO ATTAIN A SAFETY FUNCTION.

X
Y
Z

MULTIPLE SENSED VARIABLES ARE COMBINED TO PRODUCE AUTOMATIC ACTION, MANUAL ACTION OR POST EVENT TRACKING. USED PRIMARILY FOR CONTROL SYSTEMS.

INDICATES CONNECTION WITH ANOTHER DRAWING. ALLOWS TRANSFER BETWEEN SHEETS OF ONE DRAWING.



COMMENT NUMBER.

S.F.

WHEN PLACED BENEATH A SYSTEM BLOCK, INDICATES THAT THE ASSOCIATED SYSTEM IS SINGLE ACTIVE FAILURE PROOF

WHEN PLACED BENEATH A MAIN PATH - ALTERNATE PATH COMBINATION, INDICATES THAT THE COMBINATION IS SINGLE ACTIVE FAILURE PROOF

IDENTIFIES SYSTEM AS A BALANCE-OF-PLANT (BOP) SYSTEM, NOT WITHIN THE DESIGN SCOPE OF COMBUSTION ENGINEERING.

X/Y

INDICATES THE ACTUATION LOGIC OF A SYSTEM WHEN LOCATED NEAR THE INPUT SIGNAL:

X=NO. OF INPUTS REQUIRED TO GENERATE AN OUTPUT
Y=TOTAL NO. OF INPUTS

OR

INDICATES THE REDUNDANCY OF A SYSTEM WHEN LOCATED BENEATH THE SYSTEM BOX:

X=NO. OF TRAINS OR COMPONENTS REQUIRED TO PERFORM THE FUNCTION
Y=TOTAL NO. OF TRAINS OR COMPONENTS AVAILABLE

SENSED VARIABLES OR ENVIRONMENTAL CONDITIONS

Symbol	Meaning
C	CONCENTRATION
F	FLOW
ΔF	DIFFERENTIAL FLOW
ω or FREQ	FREQUENCY
G	CEA POSITIONS
H	HUMIDITY
H_2	HYDROGEN
l	LEVEL
ϕ	NEUTRON FLUX
P	PRESSURE
ΔP	DIFFERENTIAL PRESSURE
PF	CEA GROUP DEVIATION PENALTY FACTOR
Z	VALVE OR DAMPER POSITION INDICATION
Q	POWER
RE	RADIATION
S	SPEED
T	TEMPERATURE
ΔT	TEMPERATURE DIFFERENCE
TD	TIME DELAY
V	VOLTAGE
VAC	VACUUM

POINT OF ACTUATION SYMBOLS

Symbol	Meaning
C	CLOSED
H	HIGH
HH	HIGH-HIGH
L	LOW
LL	LOW-LOW
N	NORMAL
O	OPEN

EXAMPLES:

System	Meaning
$RE_{sgs}H$	HIGH STEAM GENERATOR SAMPLE LINE RADIATION
$P_{cb}HH$	HIGH-HIGH CONTAINMENT PRESSURE
$L_{sg}L$	STEAM GENERATOR LOW LEVEL

C - E SYSTEM 80	SEQUENCE OF EVENTS - SYMBOLS, ACRONYMS AND DEFINITIONS	Figure 15.0 - 1A

SPECIAL SYMBOLS

Symbol	Meaning
DNBR	DEPARTURE FROM NUCLEATE BOILING RATIO
LOP	LOSS OF POWER
ΔP_{sg}	DIFFERENTIAL PRESSURE (ACROSS A SINGLE SG)
ΔP_{sg}^{x-y}	DIFFERENTIAL PRESSURE (BETWEEN sgx & sgy, $\Delta P_{sg}^{1-2} = P_{sg1} - P_{sg2}$)
QD	LOCAL POWER DENSITY
QL	LOGARITHMIC POWER LEVEL
QO	OVER-POWER LEVEL
QS	STARTUP POWER LEVEL
RIA	ROD INSERTION ALARM
RII	ROD INSERTION INHIBIT

EXAMPLES:

Symbol	Meaning
$QL_r H$	HIGH REACTOR LOGARITHMIC POWER LEVEL

[ ] INDICATES A DELAY TIME,
E.G., CLOSING TIME FOR TSV'S

SYSTEM OR SENSED POINT SYMBOLS

Symbol	Meaning
a	AREA
ae	AIR EJECTOR
b	BORON
cb	CONTAINMENT BUILDING
cd	CONDENSER
ch	CONDENSER HOTWELL
cl	COLD LEG (REACTOR COOLANT SYSTEM)
cst	CONDENSATE STORAGE TANK
dg	DIESEL GENERATOR
eb	ELECTRIC BUS
f	FEEDWATER (TOTAL)
fd	FEEDWATER (DOWNCOMER)
fe	FEEDWATER (ECONOMIZER)
h	HYDROGEN
hl	HOT LEG (REACTOR COOLANT SYSTEM)
m	SUMP
p	PRESSURIZER
pc	PRIMARY COOLANT
r	REACTOR
rcp	REACTOR COOLANT PUMP
rcs	REACTOR COOLANT SYSTEM
rwt	REFUELING WATER STORAGE TANK
s	STEAM
sct	SPRAY CHEMICAL STORAGE TANK (N_2H_4)
sfp	SPENT FUEL POOL
sg	STEAM GENERATOR
sgb	STEAM GENERATOR BLOWDOWN LINE
sg1	STEAM GENERATOR 1
sg2	STEAM GENERATOR 2
sh	STEAM HEADER
suc	SUCTION OF PUMP
t	TURBINE
tb	TURBINE BUILDING
teh	TURBINE EXHAUST HOOD
wgt	WASTE GAS TANK

ASDS	ATMOSPHERIC STEAM
AFWS	AUXILIARY FEEDWATE
	(THIS SYSTEM MAY N BUT MAY BE COMPOS COMPONENTS WITHIN
BAMT	BORIC ACID MAKE-UP
BD	STEAM GENERATOR BL
BUVR	BUS UNDERVOLTAGE R
CB	CONTAINMENT BUILDI
CCGC	CONTAINMENT COMBUS
CCW	COMPONENT COOLING
CD	CONDENSER
CEA	CONTROL ELEMENT AS
CFDM	CONTROL ELEMENT DR
CEDMCS	CONTROL ELEMENT DR
CES	CONDENSER EVACUATI
CH	CONDENSER HOTWELLS
CHRS	CONTAINMENT HYDROG
CIAS	CONTAINMENT ISOLAT
CIS	CONTAINMENT ISOLAT
	(COLLECTION OF COM
COLSS	CORE OPERATING LIM
CPC	CORE PROTECTION CA
CS	CONTAINMENT SUMP
CSS	CONTAINMENT SPRAY
CSAS	CONTAINMENT SPRAY
CST	CONDENSATE STORAGE
CVCS	CHEMICAL AND VOLUM
CW	CIRCULATING WATER
CWP	CONTROL ROD WITHDRA
DFCV	DOWNCOMER FEEDWATER
DFIV	DOWNCOMER FEEDWATER
DLCS	DNBR/LPD CALCULATOR
ECCS	EMERGENCY CORE COOL
EFAS-1, -2	EMERGENCY FEEDWATER
EFCV	ECONOMIZER FEEDWATE
EFIV	ECONOMIZER FEEDWATE
EFWS	EMERGENCY FEEDWATER
ESFAS	ENGINEERED SAFETY F
FTB	FAST TRANSFER BREAK
FWCS	MAIN FEEDWATER CONT
HLO	HIGH LEVEL OVERRIDE
HPS	HYDROGEN PURGE SYST
HPSI	HIGH PRESSURE SAFET
IRS	IODINE REMOVAL SYST
LPSI	LOW PRESSURE SAFETY
LS	STANDBY GENERATOR L
MFW	MAIN FEEDWATER SYST
MFWBV	MAIN FEEDWATER BYPA
MSBV	MAIN STEAM BYPASS V
MSI	MAIN STEAM ISOLATIO
	(COLLECTION OF COMP

ABBREVIATIONS

DUMP SYSTEM
R SYSTEM
OT BE A SEPARATE SYSTEM
ED OF DESIGNATED
THE EFWS)
TANK
WDOWN SYSTEM
LAYS
G
TIBLE GAS CONTROL SYSTEM
ATER SYSTEM

EMBLIES
VE MECHANISM
VE MECHANISM CONTROL SYSTEM
N SYSTEM

N RECOMBINER SYSTEM
ON ACTUATION SIGNAL
ON SYSTEM
ONENTS WHICH RECEIVE CIAS .IGNAL)
T SUPERVISORY SYSTEM
CULATOR

YSTEM
CTUATION SIGNAL
TANK
CONTROL SYSTEM
YSTEM
AL PROHIBIT SIGNAL
CONTROL VALVE
ISOLATION VALVE
SYSTEM
ING SYSTEM
ACTUATION SIGNAL -SG1, -SG2
R CONTROL VALVE
R ISOLATION VALVE
SYSTEM
EATURES ACTUATION SYSTEM
ER
ROL SYSTEM

EM
Y INJECTION PUMP
EM
INJECTION PUMP
OAD SEQUENCER
EM
SS VALVE
ALVE
N SYSTEM
ONENTS WHICH RECEIVE MSIS SIGNALS)

MSIS	MAIN STEAM ISOLATION SIGNAL
MSIV	MAIN STEAM ISOLATION VALVES
MSSV	MAIN STFAM SAFETY VALVES
PH	PRESSURIZER HEATERS
PLCS	PRESSURIZER LEVEL CONTROL SYSTEM
PPCS	PRESSURIZER PRESSURE CONTROL SYSTEM
PPS	PLANT PROTECTION SYSTEM
PSV	PRESSURIZER SAFETY VALVES
PZR	PRESSURIZER
RAS	RECIRCULATION ACTUATION SIGNAL
RC	REACTOR COOLANT SYSTEM
RCP	REACTOR COOLANT PUMP
RDT	REACTOR DRAIN TANK
RPCS	REACTOR POWER CUTBACK SYSTEM
RPS	REACTOR PROTECTION SYSTEM
RRS	REACTOR REGULATING SYSTEM
RTSS	REACTOR TRIP SWITCHGEAR SYSTEM
RTS	REACTOR TRIP SIGNAL
RTO	REACTOR TRIP OVERRIDE (MFWCS)
RWT	REFUELING WATER TANK
SBS	STEAM BYPASS SYSTEM
SBCS	STEAM BYPASS CONTROL SYSTEM
SBG	STANDBY GENERATOR
SCCS	SECONDARY CHEMISTRY CONTROL SYSTEM
SCST	SPRAY CHEMICAL STORAGE TANK (HYDRAZINE)
SCS	SHUTDOWN COOLING SYSTEM
SFPC	SPENT FUEL POOL COOLING SYSTEM
SFP	SPENT FUEL POOL
SG	STEAM GENERATOR
SGSS	STANDBY GENERATOR STARTING SYSTEM
SIS	SAFETY INJECTION SYSTEM
SIAS	SAFETY INJECTION ACTUATION SIGNAL
SIT	SAFETY INJECTION TANK
SPS	SUPPLEMENTARY PROTECTION SYSTEM
SSS	STANDBY GENERATOR STARTING SIGNAL
TCV	TURBINE CONTROL VALVE
TGCS	TURBINE-GENERATOR CONTROL SYSTEM
TSV	TURBINE STOP VALVES
TTS	TURBINE TRIP SIGNAL
VCT	VOLUME CONTROL TANK

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C - E SYSTEM 80	SEQUENCE OF EVENTS - SYMBOLS, ACRONYMS AND DEFINITIONS	Figure 15.0 - 1B

SAFETY FUNCTION DEFINITIONS

Safety Function	Function Description
1. REACTIVITY CONTROL	
Reactivity Control (Trip)	Rapid insertion of negative reactivity into the core to produce subcriticality immediately following an initiating event.
Reactivity Control (Boron)	Establishment of sufficient boron concentration in the core to maintain subcriticality following the event using safety injection.
Reactivity Control (Shutdown)	Establishment of cold shutdown boron concentration prior to cooldown of the plant. Appears and is necessary only if safety injection has not occurred.
Reactivity Control (Long Term)	Switching of safety injection system from injection to recirculation mode.
2. REACTOR HEAT REMOVAL	
Natural Convective Heat Removal	Maintenance of core cooling by natural circulation in the primary loop, including natural convection in the core sufficient to prevent violation of the fuel performance limits specified in Table 15.0-3.
Non-4 Pump Heat Removal	Maintenance of core cooling by means of forced flow (other than normal four pump flow) sufficient to prevent violation of the fuel limits specified in Table 15.0-3. Specifically not considered as part of this safety function are those actions performed to accomplish the emergency core cooling safety functions.
ECC Injection Phase	Provision of coolant to the RCS sufficient to maintain a coolable reactor geometry before low refueling water tank level signal.
ECC Recirculation (Short Term)	Provision of adequate coolant to the RCS following low refueling water tank level signal and automatic switchover. Core coolant is recirculated back into the primary system after it leaks out.
ECC Recirculation (Long Term)	Provision of coolant to the RCS to achieve cold shutdown conditions following safety injection. Establishment of hot & cold leg recirculation.
Reactor Heat Removal (Shutdown)	Provision of coolant to the RCS to achieve cold shutdown conditions, using the shutdown cooling system.
3. SECONDARY SYSTEM INTEGRITY	
Secondary System Pressure/Level/Heat Sink Control	Maintenance of secondary system pressure and steam generator water level within limits such that the secondary system does not overpressurize and can be used to remove heat from the primary system.
Secondary System Pressure/Level/Heat Sink Control (Long Term)	Maintenance of secondary system pressure and steam generator water level within limits such that a heat sink is maintained for the primary system and is not overpressurized.
4. PRIMARY SYSTEM INTEGRITY	
Primary System Pressure/Level Control	Maintenance of primary system pressure and level within limits such that the primary system pressure does not exceed the acceptance guidelines given in Table 15.0-3.
Primary System Pressure/Level Control (Long Term)	Control of primary system pressure and level, and required associated actions, during cooldown from hot shutdown or standby to cold shutdown conditions to prevent exceeding pressure-temperature guidelines during the cooldown process.

Safety Func
5. CONTAINMENT
Containment Pressure/Tem Control
Containment Pressure/Tem Control (Recirculati
6. COMBUSTIBLE
Combustible
7. CONTROL ROOM
Control Room Habitability
8. FUEL HANDLIN HABITABIL
Fuel Handlin Habitabil
9. RADIOACTIVE CONTROL
Containment
Primary Syst
Secondary Sy Isolation
Radioactive Treatment
Radioactive Treatment (Long Term)
10. RESTORATION
Restoration
Restoration Power
11. SPENT FUEL PO REMOVAL
Spent Fuel Po Removal

ion	Function Description
INTEGRITY	
perature	Maintenance of containment pressure and temperature within limits such that the containment integrity is maintained.
perature on)	Maintenance of containment pressure and temperature within limits following exhaustion of the RWT by switching the containment spray system to the recirculation mode following generation of a low refueling water tank level signal.
GAS CONTROL	
Gas Control	Identification of, and conditioning of post-event containment atmosphere or treatment of event generated flammables, to prevent formation of flammable or explosive mixtures.
HABITABILITY	
	Conditioning of the post-event control room atmosphere to ensure habitability and control of personnel radiation exposure.
G BUILDING ITY	
Building ty	Conditioning of the post-event fuel handling building atmosphere to ensure habitability and control of personnel radiation exposure.
EFFLUENT	
Isolation	Isolation of containment building to prevent escape of radioactivity to the environs.
Isolation	Isolation of primary system to prevent coolant loss or escape of radioactivity to the environs.
tem	Isolation of all or part of the secondary system to prevent coolant loss or escape of radioactivity to the environs.
aterial	Mechanical and/or chemical treatment of radioactive materials to reduce the quantity that escapes or is discharged to the environs.
aterial	See above - and add switching to recirculation mode.
F A.C. POWER	
f ESF Power	Starting and loading of on-site, standby A.C. power supply.
f Non-ESF	Transfer of loads from auxiliary transformer to the start-up transformer, either automatically or as a manual operator action.
OL HEAT	
ol Heat	Cooling of the spent fuel pool following a loss of A.C. power.

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March 31, 1982

C - E SYSTEM 80	SEQUENCE OF EVENTS - SYMBOLS, ACRONYMS AND DEFINITIONS	Figure 15.0 - 1C

15.1 INCREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

15.1.1 DECREASE IN FEEDWATER TEMPERATURE

15.1.1.1 Identification of Event and Causes

A decrease in feedwater temperature may result from a loss of high pressure feedwater heaters. Loss of one of two high pressure feedwater heater drain tank pumps interrupts the steam extraction from the high pressure turbine to one of two parallel feedwater trains and results in the loss of three of six high pressure heaters. No other single failure would result in the loss of more heaters. Since each of the two feedwater heater trains increases the enthalpy of the feedwater by about 100 Btu/lbm, the loss of one train (three heaters) would cause an overall reduction in the feedwater enthalpy of approximately 50 Btu/lbm.

15.1.1.2 Sequence of Events and System Operations

A decrease in feedwater temperature causes a decrease in the temperature of the reactor coolant, an increase in reactor power due to the negative moderator temperature coefficient, and a decrease in the reactor coolant system (RCS) and steam generator pressures. Detection of these conditions is accomplished by the RCS and steam generator low pressure alarms and the high linear power alarm. If the transient were to result in an approach to specified acceptable fuel design limits, trip signals generated by the core protection calculators would assure that low departure from nucleate boiling ratio (DNBR) or high local power density limits are not exceeded.

15.1.1.3 Analysis of Effects and Consequences

A comparison of the RCS temperatures shows that the maximum RCS temperature decrease for the decrease in feedwater temperature event is less than that for the inadvertent opening of a steam generator atmospheric dump valve (IOSGADV). The smaller cooldown results in less power increase and, consequently, in less DNBR decrease during the transient. Therefore, the systems operation described above and the resulting sequence of events would produce a DNBR transient less adverse than that associated with the IOSGADV event presented in Section 15.1.4. The limiting single failure with respect to fuel performance is the loss of offsite power on turbine trip for the same reasons as given in Section 15.1.4. This event in combination with a loss of offsite power results in an event similar to the IOSGADV event in combination with a loss of offsite power which is also presented in Section 15.1.4.

All increased heat removal events analyzed in this section are characterized by decreasing RCS pressure due to the cooldown of the primary system. Thus, this event, or this event plus a single failure, will result in an insignificant increase in RCS pressure.

15.1.1.4 Conclusions

The decreased feedwater temperature event results in a DNBR greater than 1.19 throughout the transient. The event in combination with a loss of offsite power results in only a limited number of fuel pins in DNB. For both cases, the RCS pressure remains well below 2750 psia.

15.1.2 INCREASE IN FEEDWATER FLOW

15.1.2.1 Identification of Event and Causes

An increase in feedwater flow is caused by the further opening of a feedwater control valve or an increase in feedwater pump speed. The maximum increase at full power is approximately 10% above nominal for the normal feedwater system.

15.1.2.2 Sequence of Events and System Operations

An increase in feedwater flow causes a decrease in the temperature of the reactor coolant, an increase in reactor power due to the negative moderator temperature coefficient, a decrease in the RCS and steam generator pressures and an increase in steam generator water level. Detection of these conditions is accomplished by the RCS low pressure alarm and steam generator low pressure and high water level alarms. Protection against the violation of specified acceptable fuel design limits, as a consequence of an increase in feedwater flow, is provided by the low DNBR and high local power density trips. Protection against high steam generator water level is provided by the high steam generator water level trip.

15.1.2.3 Analysis of Effects and Consequences

A comparison of RCS temperatures shows that the maximum RCS temperature decrease for the increase in feedwater flow event is less than that for the inadvertant opening of a steam generator atmospheric dump valve (IOSGADV) event. The smaller cooldown results in less power increase and, consequently, in less DNBR decrease during the transient. Therefore, the systems operation described above and the resulting sequence of events would produce a DNBR transient no more adverse than that associated with the IOSGADV event presented in Section 15.1.4. The limiting single failure with respect to fuel performance is the loss of offsite power on turbine trip for the same reasons as given in Section 15.1.4. This event in combination with a loss of offsite power results in an event similar to, but less severe than, the IOSGADV event in combination with a loss of offsite power which is also presented in Section 15.1.4.

All increased heat removal events analyzed in this section are characterized by decreasing RCS pressure due to the primary system cooldown. Thus, this event, or this event plus a single failure, will result in an insignificant increase in RCS pressure.

15.1.2.4 Conclusions

The increased feedwater flow event results in a DNBR greater than 1.19 throughout the transient. The event in combination with a loss of offsite power results in only a limited number of fuel pins in DNB. For both cases, the RCS pressure remains below 2750 psia.

15.1.3 INCREASED MAIN STEAM FLOW

15.1.3.1 Identification of Event and Causes

An increase in main steam flow is caused by an inadvertent increased opening of the turbine admission valves. This may be caused by operator error or turbine load limit malfunctions and will result in no more than an 11% increase over the nominal full power steam flow rate. An increase in main steam flow can also result from the inadvertent opening of a turbine bypass valve or an atmospheric dump valve; however, these events are discussed separately in Section 15.1.4.

15.1.3.2 Sequence of Events and System Operations

An increase in main steam flow causes a decrease in the temperture of the reactor coolant, an increase in core power and heat flux, and a decrease in reactor coolant system and steam generator pressures. Detection of these conditions is accomplished by the RCS and steam generator low pressure alarms and the high reactor power alarm. If the transient were to result in an approach to specified acceptable fuel design limits, trip signals generated by the core protection calculators would assure that low departure from nucleate boiling ratio (DNBR) or high local power density limits are not exceeded.

15.1.3.3 Analysis of Effects and Consequences

A comparison of the RCS temperatures shows that the maximum RCS temperature decrease for the increased main steam flow event is identical to that for the inadvertent opening of a steam generator atmospheric dump valve (IOSGADV) event. This is due to the fact that both events cause an increase in main steam flow of 11%. Thus, the resultant power increase and the subsequent DNBR transient are also identical. Therefore, the systems operation described above and the resulting sequence of events for the increased main steam flow event will be similar to the IOSGADV event presented in Section 15.1.4. The limiting single failure with respect to fuel performance is the loss of off-site power at the time of turbine trip for the same reasons as given in Section 15.1.4. This event in combination with a loss of offsite power is similar to, but no more severe than, the IOSGADV event combined with a loss of off-site power which is also presented in Section 15.1.4.

All increased heat removal events analyzed in this section are characterized by decreasing RCS pressure due to the cooldown of the primary system. Thus, this event, or this event plus a single failure, will show an insignificant increase in RCS pressure.

15.1.3.4 Conclusions

The increased main steam flow event results in a DNBR greater than 1.19 throughout the transient. The event in combination with a loss of off-site power results in only a limited number of fuel pins in DNB. For both cases, the RCS pressure remains well below 2750 psia.

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15.1.4 INADVERTENT OPENING OF A STEAM GENERATOR RELIEF OR SAFETY VALVE

15.1.4.1 Identification of Event and Causes

Case 1: Event (IOSGADV)

An atmospheric dump valve (ADV) or a turbine bypass valve may be inadvertently opened by the operator or may open due to a failure of the control system which operates the valve. A steam generator safety valve will remain open only as a result of a valve failure. The opening of any of these valves will result in similar consequences because they relieve steam at the same maximum flow rate (11% of full power turbine flow rate). The inadvertent opening of a steam generator atmosperic dump valve (IOSGADV) is presented here to illustrate these events.

Case 2: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve plus a single failure (IOSGADV + LOP)

For the events of this section, the major parameter of concern is the minimum hot channel DNBR. This parameter establishes whether a fuel design limit has been violated and thus whether fuel cladding degradation might be anticipated. Those factors which cause a decrease in local DNBR are:

a. increasing coolant temperature
b. decreasing coolant pressure
c. increasing local heat flux (including radial and axial power distribution effects)
d. decreasing coolant flow

The single failure (SF) which yields the minimum transient hot channel DNBR is the SF which combines the greatest decrease in DNBR after initiation of a reactor trip signal with the lowest possible pre-trip DNBR. An evaluation of the SFs listed in Table 15.0.6 shows that the limiting SF for the event of this section is the loss of offsite power concurrent with a turbine trip (LOP) which is assumed to occur at a point in the transient at which the minimum hot channel DNBR is just above that which would cause the core protection calculators (CPCs) to initiate a reactor trip signal on low DNBR. The DNBR is thus at the lowest possible pre-trip value. The loss of flow due to the four pump coast down which results from the assumption of LOP following turbine trip causes a greater decrease in DNBR after reactor trip than other possible SFs. None of the other SFs can cause a significant change in DNBR in the time interval between the start of the flow coastdown and the time at which core heat flux begins to decrease due to CEA insertion. Therefore the event plus single failure presented in this section is the IOSGADV + LOP. In addition to the assumed single failure of loss of offsite power it is assumed that the most reactive CEA is held in the fully withdrawn position following reactor trip.

15.1.4.2 Sequence of Events and Systems Operation

Case 1: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (IOSGADV).

The opening of a steam generator ADV increases the rate of heat removal by the steam generators, causing cooldown of the RCS. Due to the negative moderator

temperature coefficient, core power increases from the initial value of 102% of rated core power, reaching a new stabilized value of 113%. The feedwater control system, which is assumed to be in the automatic mode, supplies feedwater to the steam generators such that steam generator water levels are maintained. Acting upon the large power mismatch between the reactor and turbine and the audible indication of steam blowdown, the reactor operator recognizes that the plant is in an abnormal state and manually trips the reactor. The analysis presented herein assumes this initial operator action is delayed until after 30 minutes following the first indication of the event.

Following the generation of a turbine trip on reactor trip the feedwater control system enters the reactor trip override mode and reduces feedwater flow to 5% of nominal, full power flow. Since the steam bypass control system is assumed to be in the manual mode with all bypass valves closed, the main steam safety valves (MSSVs) open to limit secondary system pressure and remove heat stored in the core and RCS. The secondary system pressure then decreases due to the cooldown caused by flow through the MSSVs and the ADV and the MSSVs close. The secondary system pressure continues to decrease to the point where a main steam isolation signal (MSIS) is generated. This causes one steam generator to be isolated from the flow path through the open ADV and causes main feedwater flow to be terminated. The affected steam generator continues to blow down and the level falls below the emergency feedwater actuation signal (EFAS) setpoint. However, the EFAS logic, acting upon the fact that the pressure in the affected steam generator is much lower than in the intact steam generator, prevents actuation of emergency feedwater flow. As a result the affected steam generator eventually boils dry. During the period of blowdown following reactor trip, reactor coolant temperatures and pressure decrease slowly. After dryout of the affected steam generator, decay heat and heat addition from the walls and structure of the primary coolant system cause a gradual increase in reactor coolant temperatures and pressure. Relief of steam by the safety valves on the unaffected steam generator provides cooling which limits reactor coolant temperatures. Reactor coolant pressure is limited by the pressurizer safety valves.

Subsequent to tripping the reactor, the operator manually closes the ADV which had been inadvertently opened, terminating steam release to the atmosphere from the affected steam generator. In the analysis presented herein it is conservatively assumed that this action to close the ADV is delayed 20 minutes beyond the operator's initial action to trip the reactor, or a total of 50 minutes after event initiation. RCS heat removal for plant stabilization and cooldown is accomplished by using the turbine bypass valves. The operator is assumed to initiate plant cooldown 30 minutes after he manually trips the reactor.

Case 2: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve with Loss of Offsite Power Following Turbine Trip (IOSGADV + LOP).

Up until the time of the assumed turbine trip the transient due to the IOSGADV is identical with or without the loss of offsite power. For the IOSGADV + LOP event the turbine is assumed to trip at 45 seconds into the transient, with the minimum hot channel DNBR stabilized at a value just above that which would cause the CPCs to initiate a low DNBR reactor trip. Credit is not taken for the control grade reactor trip that would occur upon turbine trip. A loss of

offsite power is assumed to occur immediately following turbine trip. The resultant coastdown of all four reactor coolant pumps causes the initiation of a low DNBR reactor trip via the action of the CPC's after detection of decreasing pump speed. Following turbine trip the feedwater control system enters the reactor trip override mode and reduces feedwater flow to 5% of nominal full power flow. Since the steam bypass control system is assumed to be in the manual mode with all bypass values closed, the MSSVs open to limit secondary system pressure and remove heat stored in the core and RCS. The secondary system pressure then decreases, due to the cooldown caused by the flow through the MSSVs and the ADV; and the MSSVs close. The secondary system pressure continues to decrease to the point where a MSIS is generated. This causes one steam generator to be isolated from the flowpath through the open ADV and causes main feedwater flow to be terminated. The affected steam generator continues to blow down and the level falls below the EFAS setpoint. However, the EFAS logic, acting upon the fact that the pressure in the affected steam generator is much lower than that in the intact steam generator prevents actuation of emergency feedwater flow. As a result the affected steam generator eventually boils dry. During the period of blowdown following reactor trip, reactor coolant temperatures and pressure decrease slowly. After dryout of the affected steam generator, decay heat and heat addition from the walls and structure of the primary coolant system cause a gradual increase in reactor coolant temperatures and pressure. Relief of steam by the safety valves on the unaffected steam generator provides cooling which in turn maintains natural circulation flow through the core and limits reactor coolant temperatures. Reactor coolant pressure is limited by the pressurizer safety valves.

Acting upon a variety of indications--including the initial large power mismatch between the reactor and turbine, the steady decrease in steam generator pressures and water levels after reactor trip, the continued decrease in pressure and level in the affected steam generator after MSIS, the low steam generator pressure and water level alarms, and the audible indication of steam blowdown--the reactor operator diagnoses the incident and manually closes the ADV which had been inadvertently opened, terminating steam release to the atmosphere from the affected steam generator. The analysis presented herein assumes that this initial operator action to close the open ADV is delayed until 30 minutes following the first indication of the event. RCS heat removal for plant stabilization and cooldown is accomplished by manual control of the ADVs on the unaffected steam generator. The operator is assumed to initiate plant cooldown 30 minutes after he manually closes the ADV which had been inadvertently opened.

15.1.4.3 Analysis of Effects and Consequences

A. Mathematical Model

The nuclear steam supply steam (NSSS) response to the IOSGADV and the IOSGADV + LOP was simulated using the CESEC-III computer program described in section 15.0.3. The time-dependent thermal margin on DNBR in the reactor core was calculated using the TORC computer program which uses the CE-1 critical heat flux correlation described in Chapter 4.

B. Input Parameters and Initial Conditions

Table 15.1.4-3 lists the assumptions and initial conditions used for these analyses in addition to those discussed in section 15.0. Conditions were chosen such that the overpower condition caused by the increase in steam flow results in the closest approach to the specified acceptable fuel design limits (SAFDL) without causing a reactor trip. If core power increases more than the 11% due to the increasing steam flow, the Core Protection Calculators (CPC) will initiate a reactor trip and there will be no further degradation in thermal margin. For transients initiated at other sets of initial conditions, a trip may or may not be required depending on whether the initial thermal margin is as low as for the combination of conditions used in these analyses.

C. Results

Case 1: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (IOSGADV)

The dynamic behavior of the salient NSSS parameters following the IOSGADV is presented in Figures 15.1.4-1.1 to 15.1.4-1.15. Table 15.1.4-1 summarizes the major events, times and results for this transient.

The opening of an ADV increases the rate of heat removal by the steam generators causing cooldown of the RCS. Due to the negative moderator reactivity coefficient, core power increases from 102% of rated core power,reaching a new, stabilized value of 113% after approximately 30 seconds. The feedwater control system, which is assumed to be in the automatic mode supplies feedwater to the steam generators such that the steam generator water levels are maintained.

During the IOSGADV transient the minimum transient DNBR of 1.19 first occurs at approximately 30 seconds and remains there until 1850 seconds when the operator manually trips the reactor. At 1850.55 seconds the trip breakers open. After a 0.34 second coil decay delay the CEA's begin to drop into the core at 1850.89 seconds. At this point, both the local and core average power decrease rapidly and DNBR increases. From 1858 seconds to 1886 seconds the MSSV's release steam.

At 2150 seconds the steam generator pressure drops below the MSIS setpoint of 820 psia. The MSIS initiates closure of the MSIV's and MFIV's. The MFIV's and MSIV's close by 2155 seconds. The affected steam generator dries out at 2650 seconds. At 3000 seconds the operator manually closes the open ADV. The operator initiates plant cooldown at 3600 seconds.

Case 2: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve with Loss of Offsite Power after Turbine Trip (IOSGADV + LOP)

The dynamic behavior of the salient NSSS parameters following IOSGADV with loss of offsite power is presented in Figures 15.1.4-2.1 to 15.1.4-2.15. Table 15.1.4-2 summarizes the major events, times and results for this transient.

The opening of an ADV increases the rate of heat removal by the steam generators causing cooldown of the RCS. Due to the negative moderator reactivity coefficient core power increases from 102% of rated core

power,reaching a new, stabilized value of 113% after approximately 30 seconds. The feedwater control system, which is assumed to be in the automatic mode, supplies feedwater to the steam generators such that the steam generator water levels are maintained until the time of loss offsite power.

During the IOSGADV + LOP transient the minimum transient DNBR of 1.195 first occurs at approximately 30 seconds and remains there until the assumed turbinetrip followed by loss of offsite power at 45 seconds. Due to decreasing core flow following the loss of power to the reactor coolant pumps, conditions existfor a low DNBR trip. At 45.6 seconds a low DNBR trip signal is initiated by the core protection calculators. The reactor trip breakers open at 45.75 seconds and after a 0.34 second coil decay delay the CEA's begin to drop into the core at 46.09 seconds. At 46.1 seconds the minimum transient DNBR of 1.05 is calculated to occur, after which DNBR rapidly increases as shown by Figure 15.1.4-2.15. By 50.5 seconds the CEA's are fully inserted. At 52 seconds the MSSV's open and release steam until 81 seconds. Voids begin to form in the upper head of the reactor vessel at 74 seconds.

At 313 seconds the steam generator pressure drops below the MSIS setpoint of 820 psia. The MSIS initiates closure of the MSIV's and MFIV's. The MFIV's and the MSIV's close by 318 seconds. At 1150 seconds the affected steam generator dries out.

At 1800 seconds the operator manually closes the open ADV. The operator initiates plant cooldown at 3600 seconds.

Due to the coastdown of the reactor coolant flow a reduction of DNBR below 1.19 is calculated to occur. Approximately 8% of the fuel pins are predicted to experience DNB. However, within 3 seconds of reactor trip, the local and average core heat flux have decreased enough such that no pins remain in DNB.

15.1.4.4 Conclusions

The IOSGADV event results in a DNBR greater than 1.19 throughout the transient. The event in combination with a loss of off-site power (IOSGADV + LOP) results in a small fraction of the fuel pins being predicted to be in DNB for a few seconds. Thus at the most a limited number of fuel rod cladding perforations could occur for the IOSGADV + LOP event. For both cases, the RCS pressure remains well below 2750 psia, ensuring that the integrity of the RCS is maintained.

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TABLE 15.1.4-1
SEQUENCE OF EVENTS FOR FULL POWER
INADVERTENT OPENING OF A STEAM GENERATOR
ATMOSPHERIC DUMP VALVE (IOSGADV)

Time (sec)	Event	Setpoint or Value
1.0	One atmospheric dump valve opens fully	--
30.0	Steady-state hot channel DNBR achieved	1.19
1850	Operator initiates manual trip signal	--
1850.55	Trip breakers open	--
1850.89	CEA's begin to drop	--
1858	Main steam safety valves open, psia	1282
1886	Main steam safety valves close, psia	1218
1872	Void begins to form in RV upper head	--
2150	Main steam isolation signal, psia	820
2155	MFIV's close completely	--
2155	MSIV's close completely	--
2650	Affected steam generator dries out	--
3000	Operator manually closes ADV	--
3600	Operator initiates plants cooldown	--

TABLE 15.1.4-2
SEQUENCE OF EVENTS FOR FULL POWER INADVERTENT OPENING OF A STEAM GENERATOR ATMOSPHERIC DUMP VALVE WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP

Time (sec)	Event	Setpoint or Value
0.0	One atmospheric dump valve opens fully	--
30.0	Steady state hot channel DNBR achieved	1.19
45.0	Turbine trips	--
45.0	Loss of offsite power occurs	--
45.6	Low DNBR trip occurs	--
45.75	Trip breakers open	--
46.09	CEA's begin to drop	--
46.1	Minimum transient DNBR	1.05
48	Hot channel DNBR increases above 1.195	--
50.5	CEA's fully inserted	--
52	Main steam safety valves open, psia	1282
81	Main steam safety valves close, psia	1218
74	Void begin to form in RV upper head	--
313	Main steam isolation signal, psia	820
318	MFIV's close completely	--
318	MSIV's close completely	--
1150	Affected steam generator dries out	--
1800	Operator manually closes ADV	
3600	Operator initiates plant cooldown	--

TABLE 15.1.4-3
ASSUMPTIONS AND INITIAL CONDITION FOR FULL POWER
INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE
(IOSGADV AND IOSGADV + LOP

Parameter	Value
Initial Core Power Level, MWt	3876
Initial Core Inlet Coolant Temperature, F	575
Initial Core Mass Flow rate, 10^6 lbm/hr	146.8
Initial Pressurizer Pressure, psia	2120
Initial Pressurizer Water Volume, ft^3	1100
Initial Steam Generator Pressure, psia	1175
Initial Steam Generator Inventory, lbm per SG	182,000
CEA Worth on Trip, $10^{-2}\ \Delta\rho$	-8.8
Core Burnup	End of cycle
ASI	-.3
Max. Radial Peaking Factor	1.4

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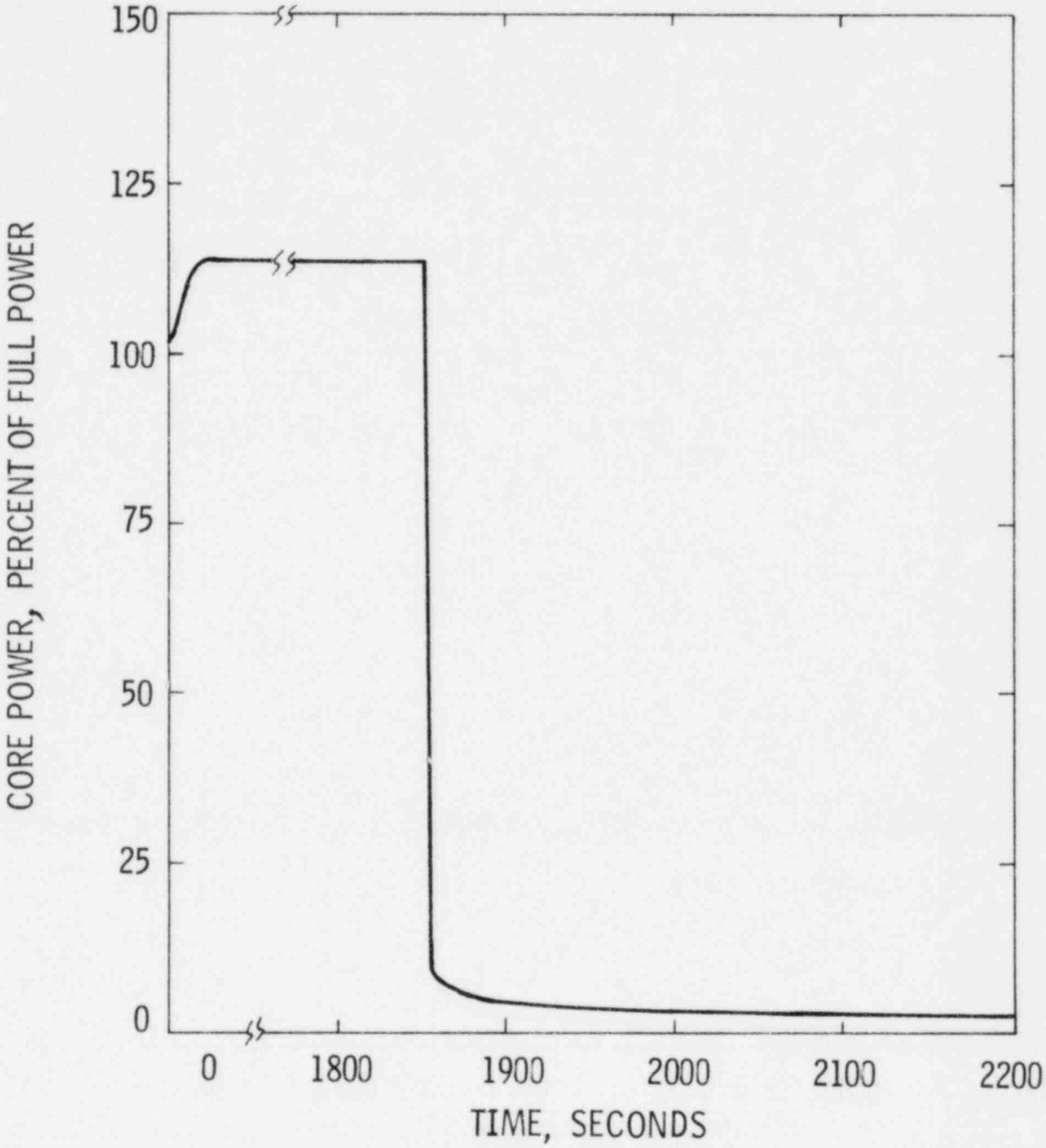

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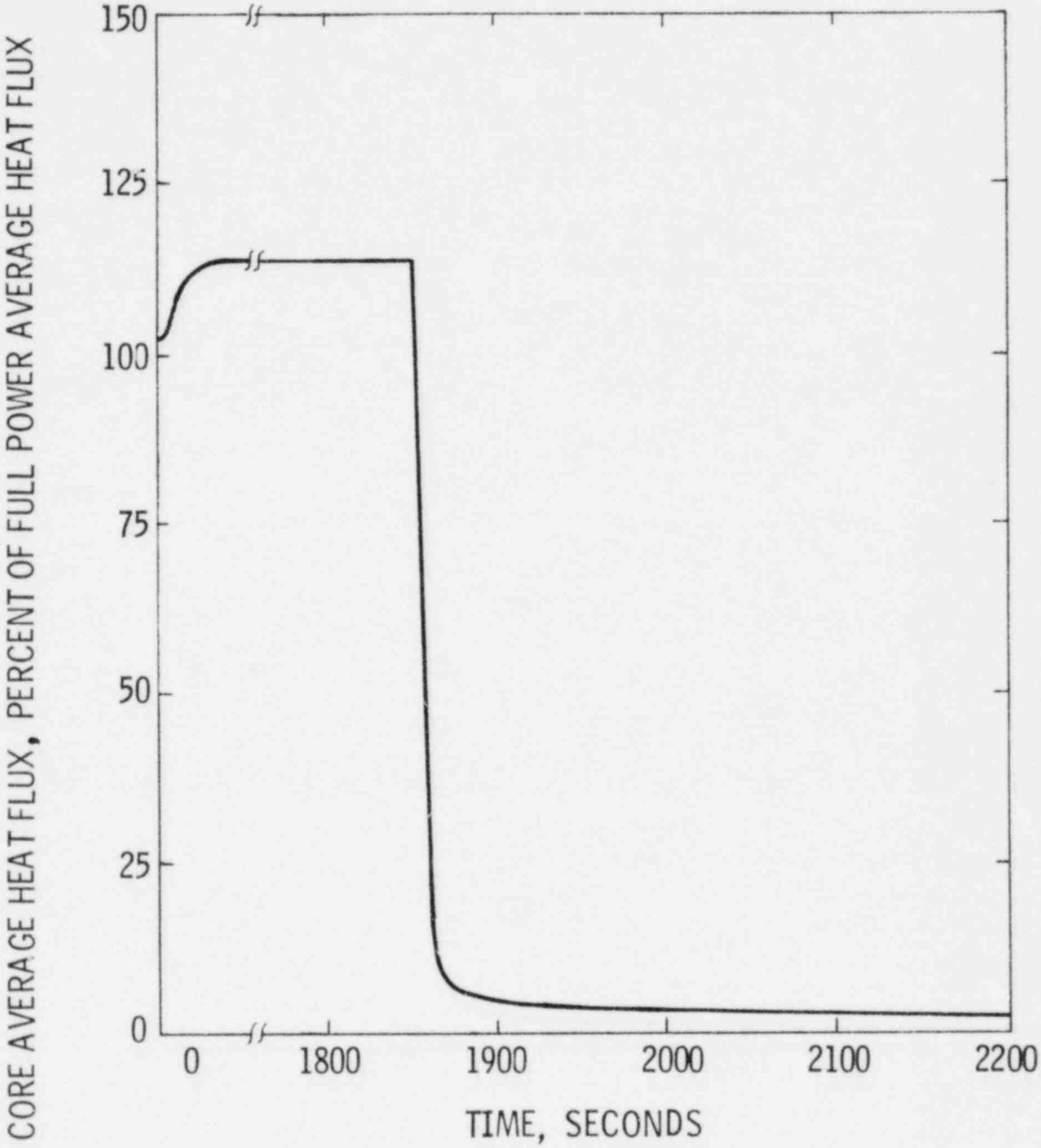
C-E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) CORE POWER VS TIME	Figure 15.1.4-1.1



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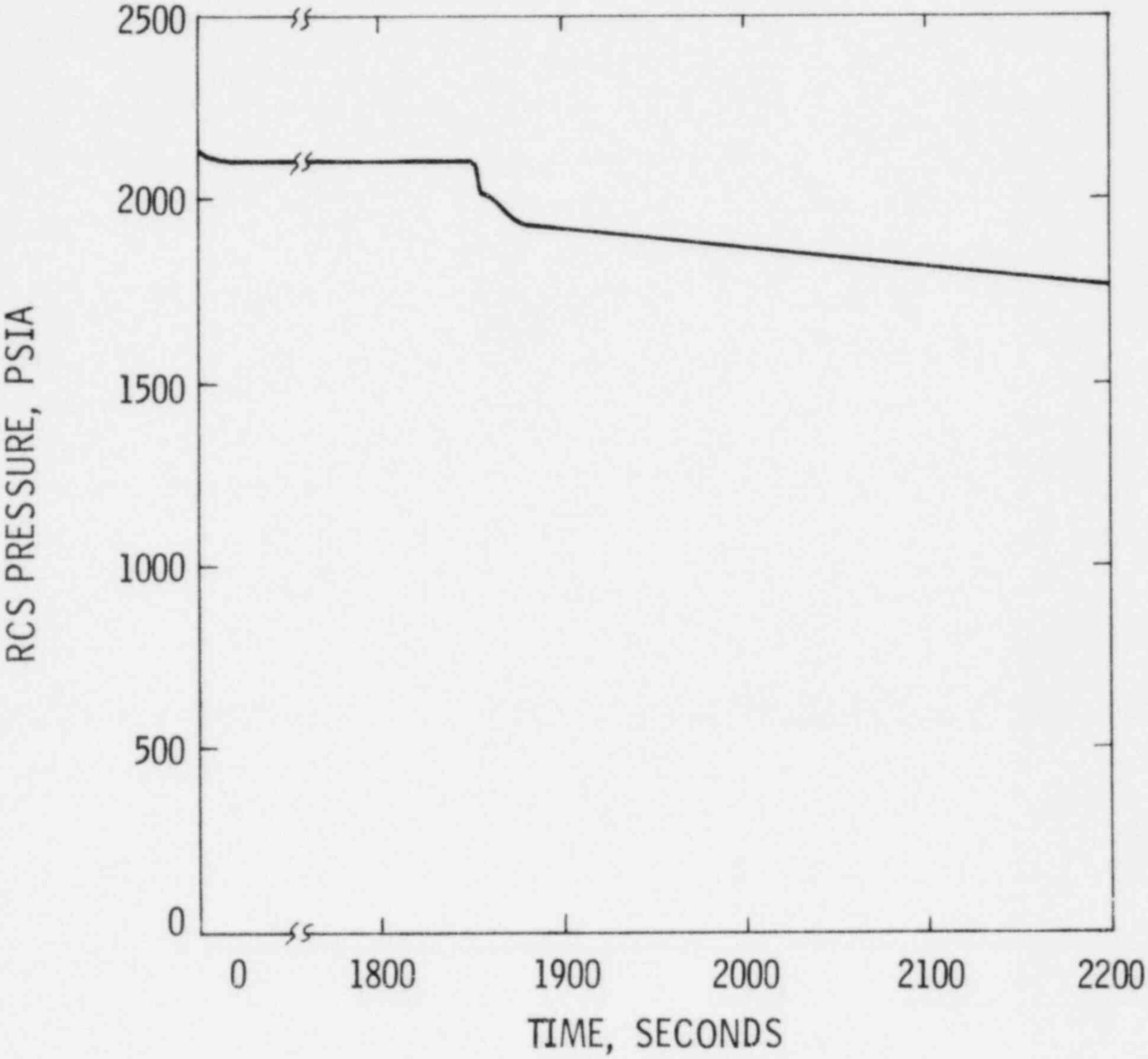
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) CORE AVERAGE HEAT FLUX VS TIME	Figure 15.1.4-1.2



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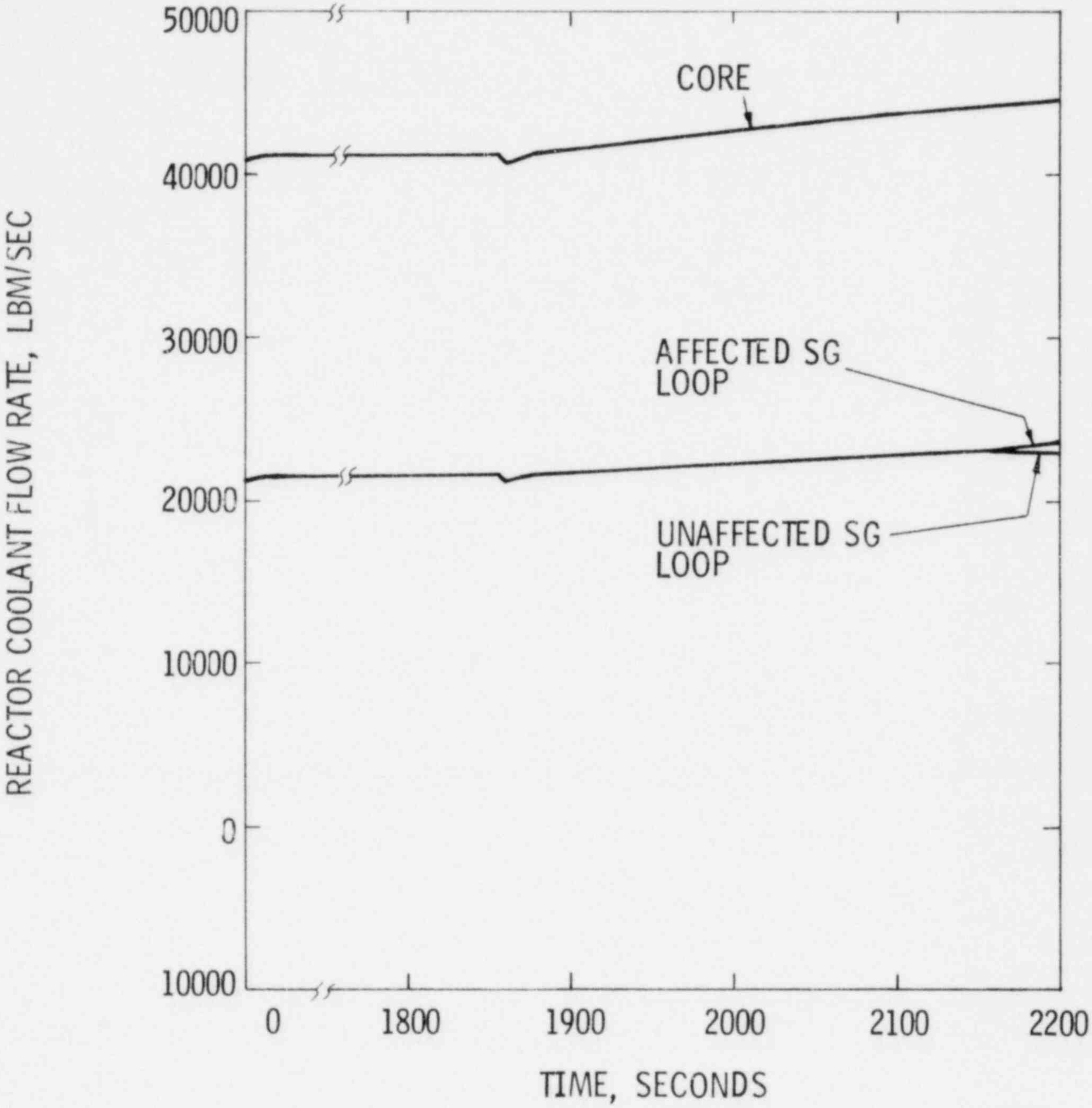
C-E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) RCS PRESSURE VS TIME	Figure 15.1.4-1.3



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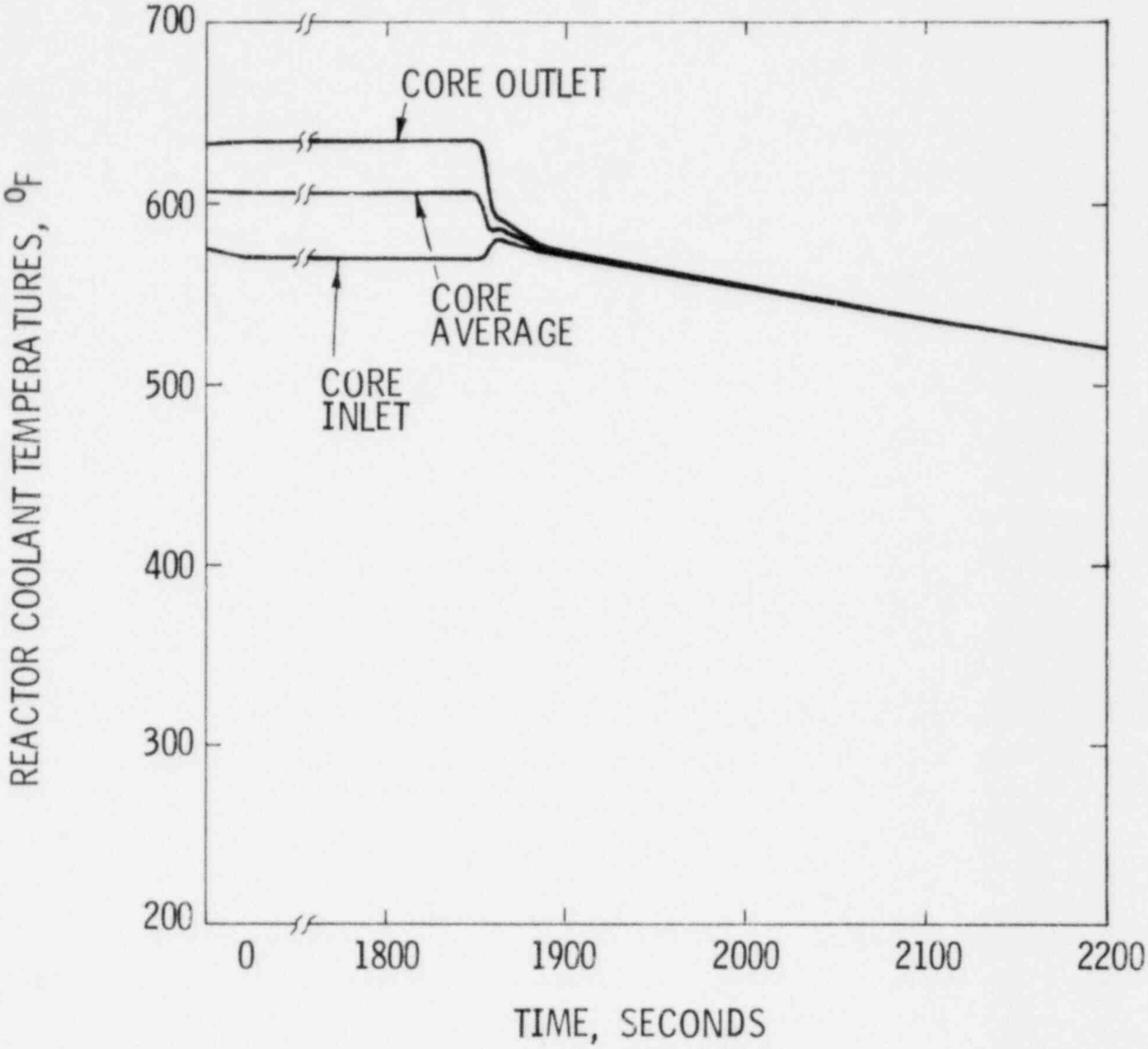
C-E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) REACTOR COOLANT FLOW RATE VS TIME	Figure 15.1.4-1.4



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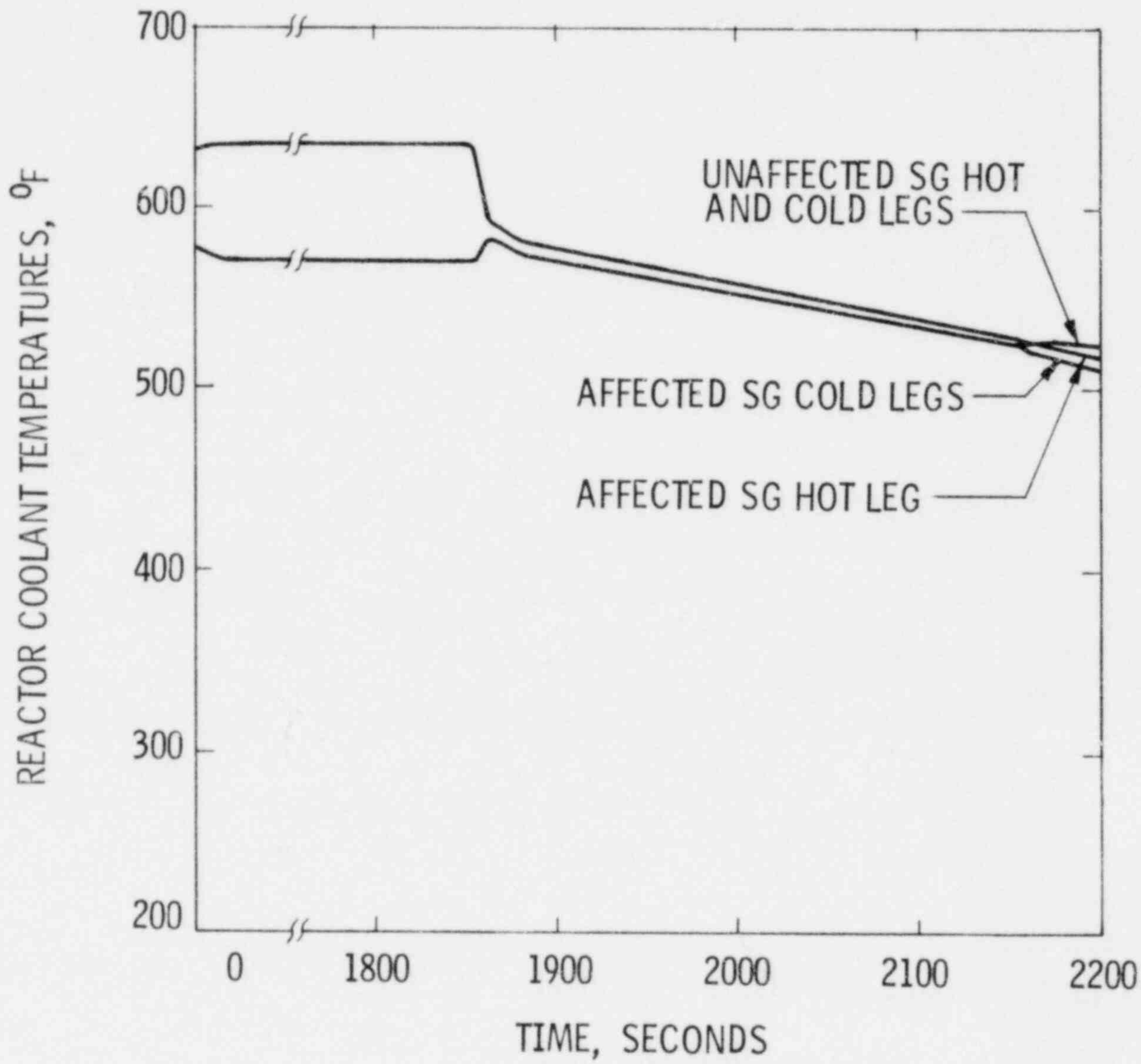
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) REACTOR COOLANT TEMPERATURES (A) VS TIME	Figure 15.1.4-1.5A



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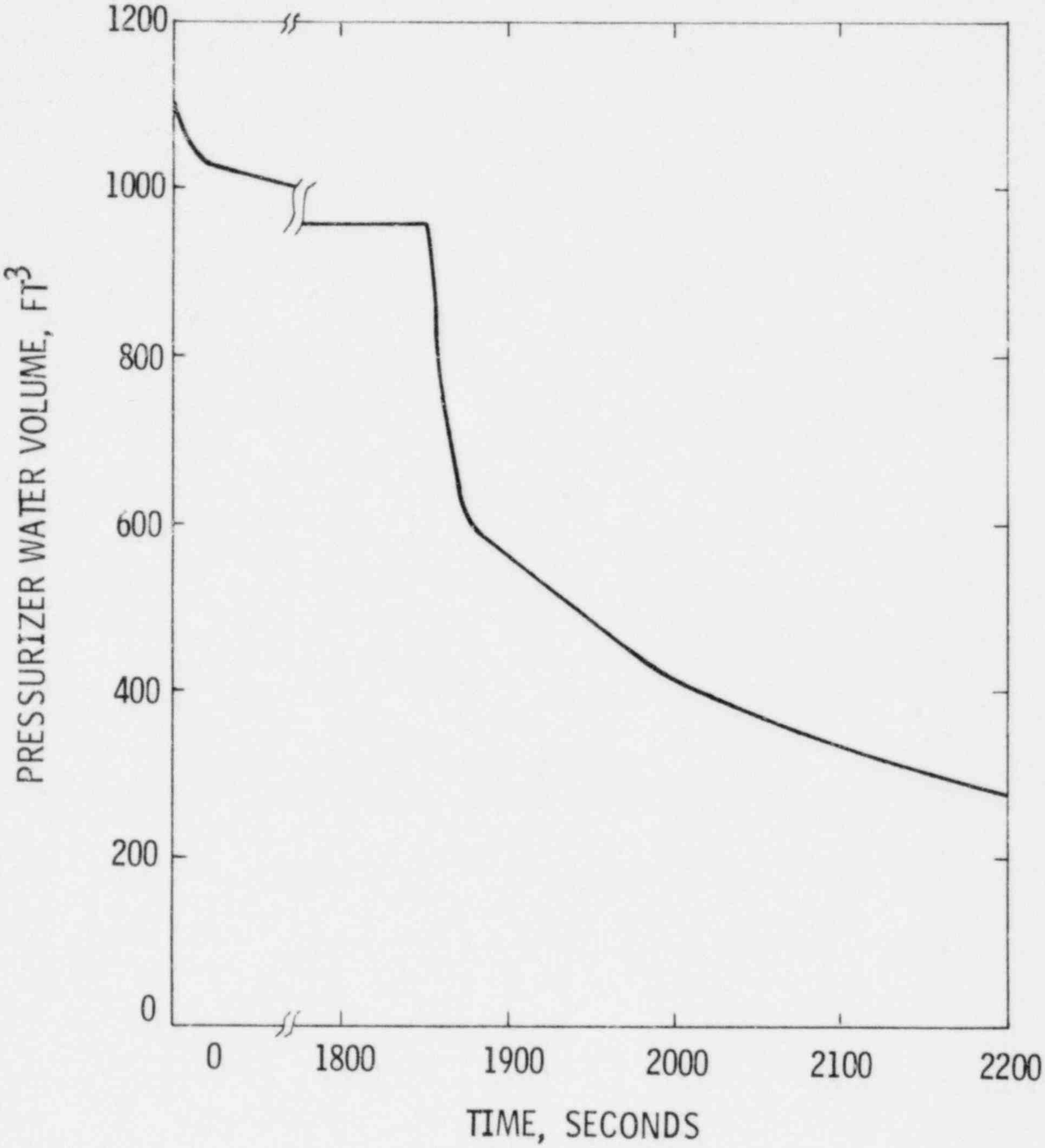
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) REACTOR COOLANT TEMPERATURES (B) VS TIME	Figure 15.1.4-1.5B



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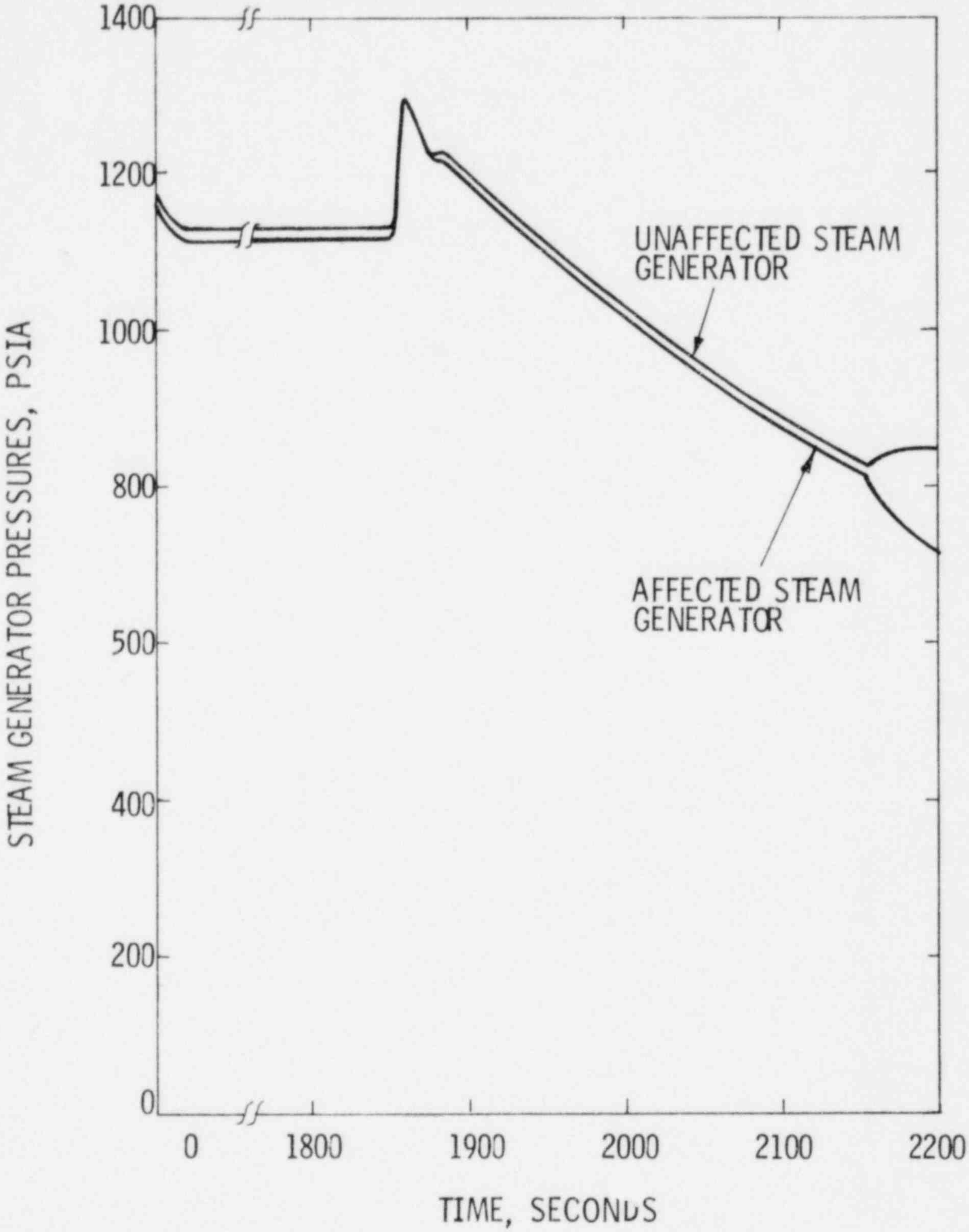
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) PRESSURIZER WATER VOLUME VS TIME	Figure 15.1.4-1.6



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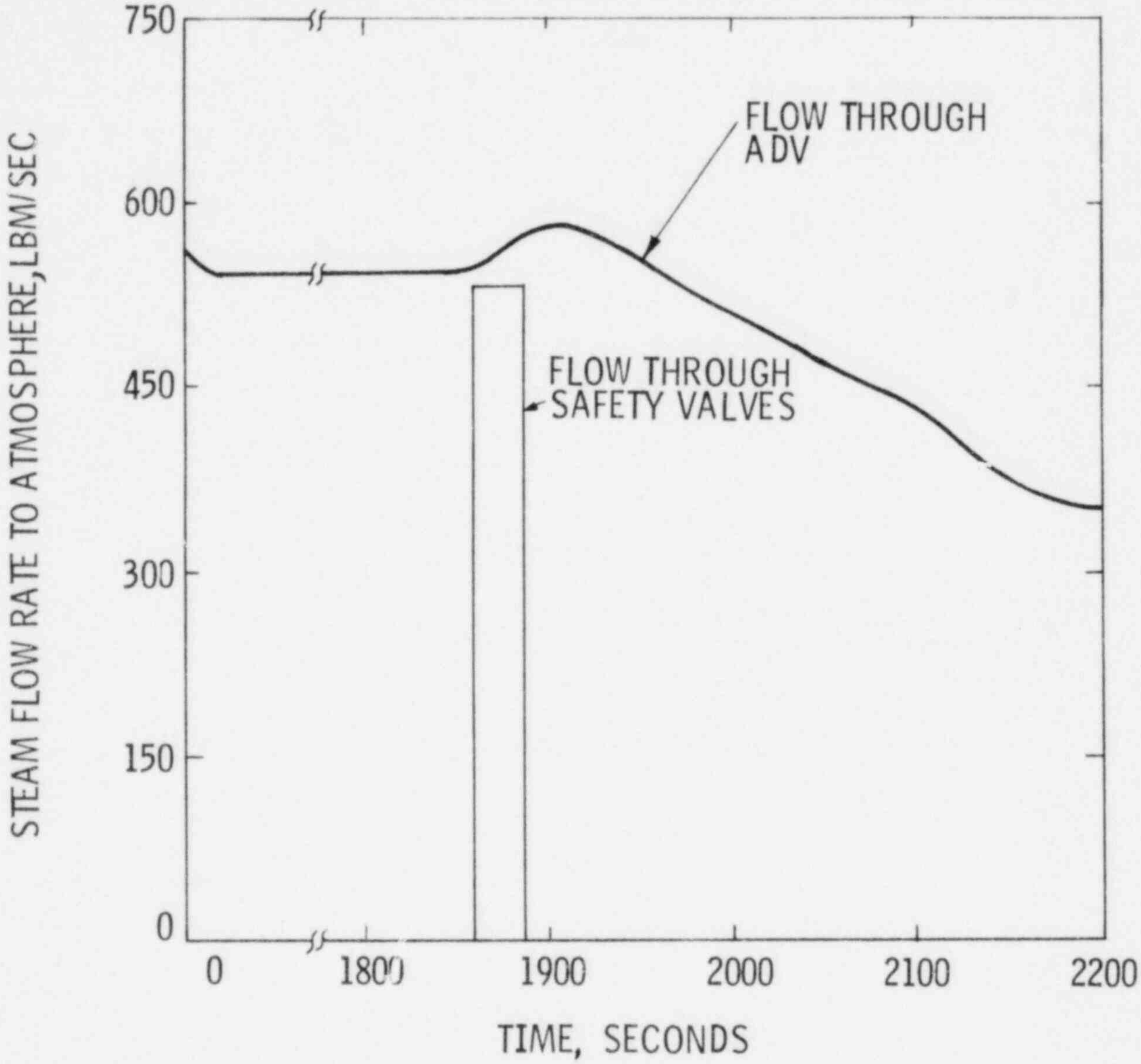
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) STEAM GENERATOR PRESSURES VS TIME	Figure 15.1.4-1.7



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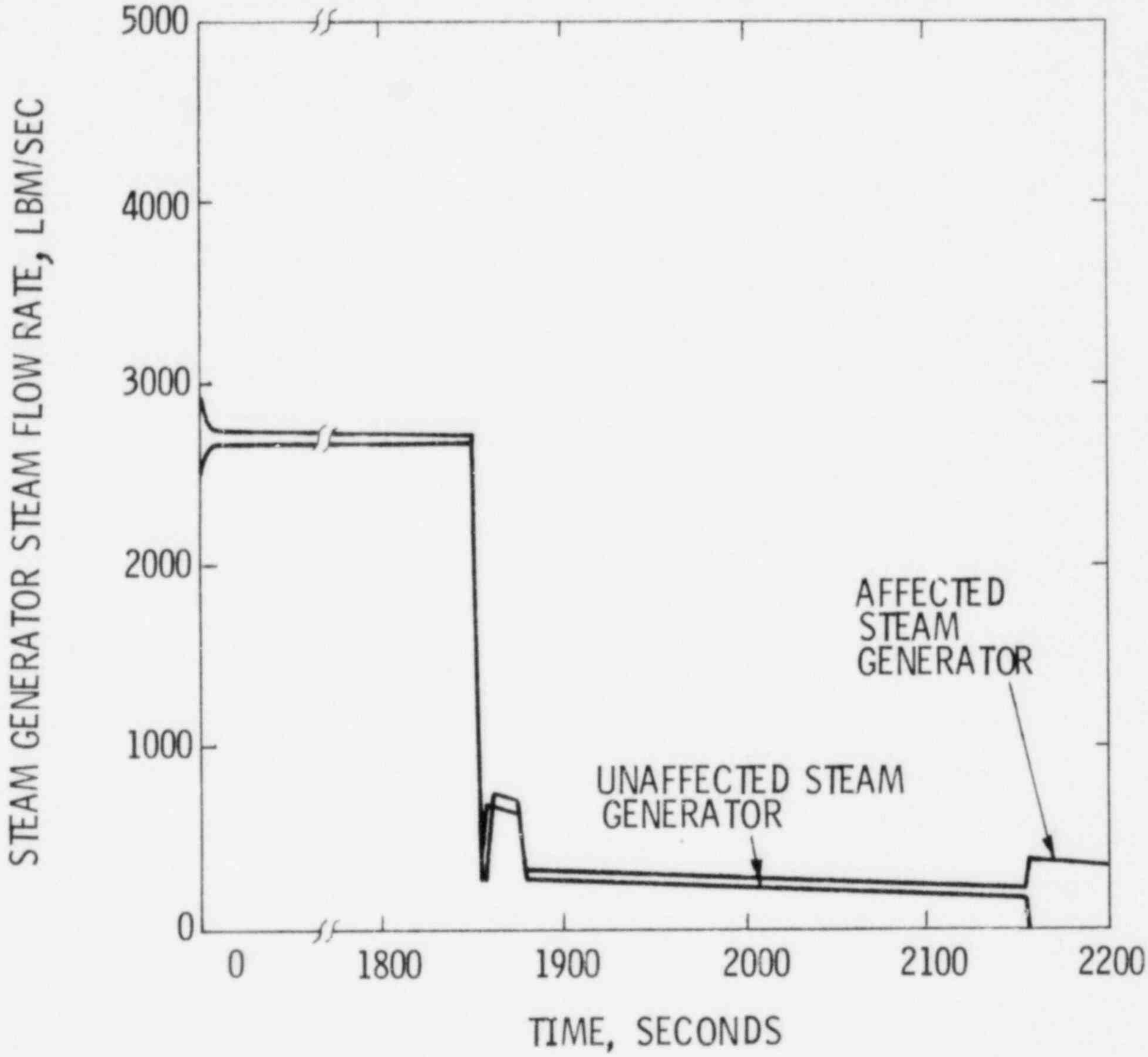
C-E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) STEAM FLOW RATE TO ATMOSPHERE VS TIME	Figure 15.1.4-1.8



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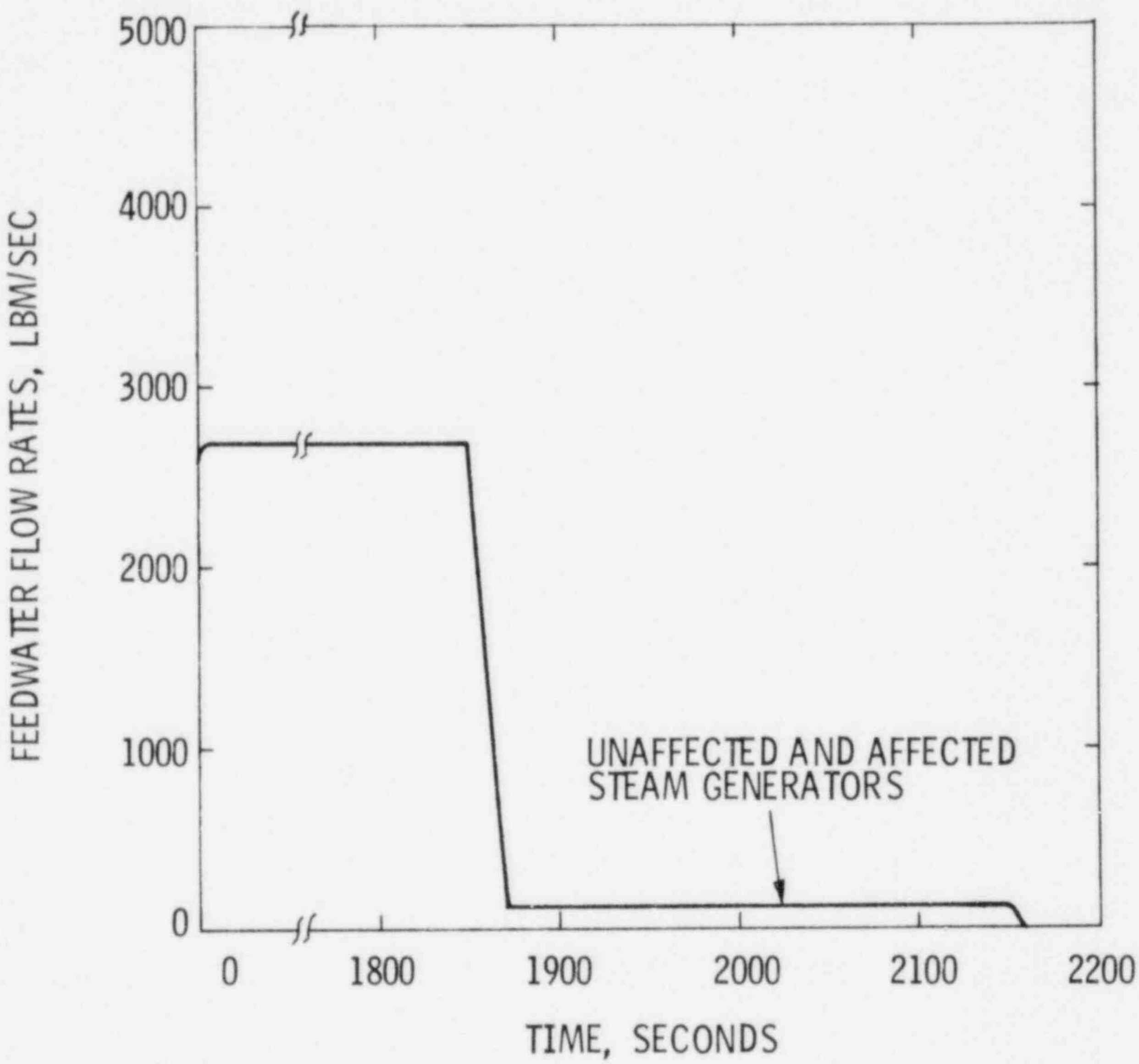
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) STEAM GENERATOR STEAM FLOW RATE VS TIME	Figure 15.1.4-1.9



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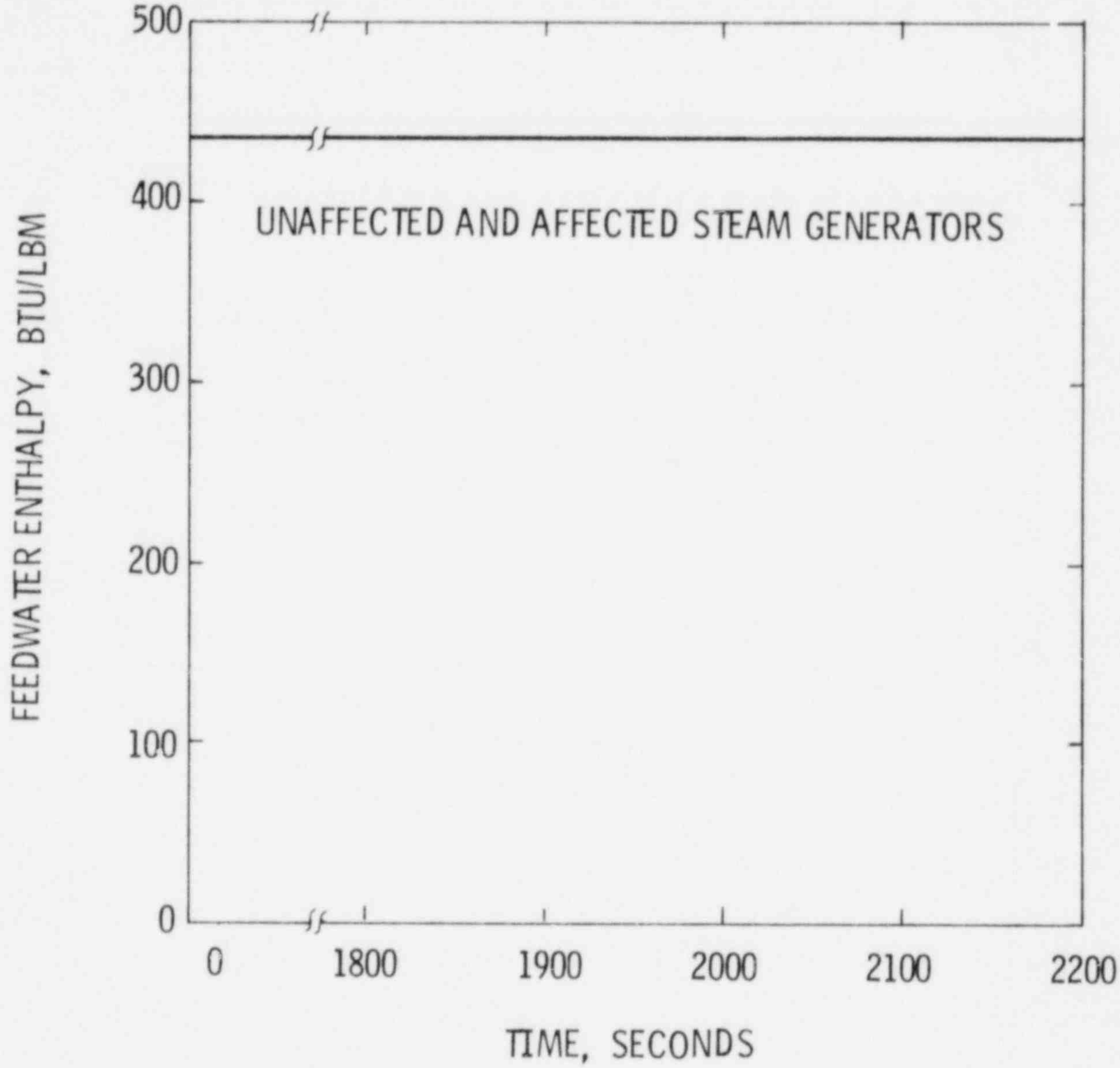
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) FEEDWATER FLOW RATES VS TIME	Figure 15.1.4-1.10



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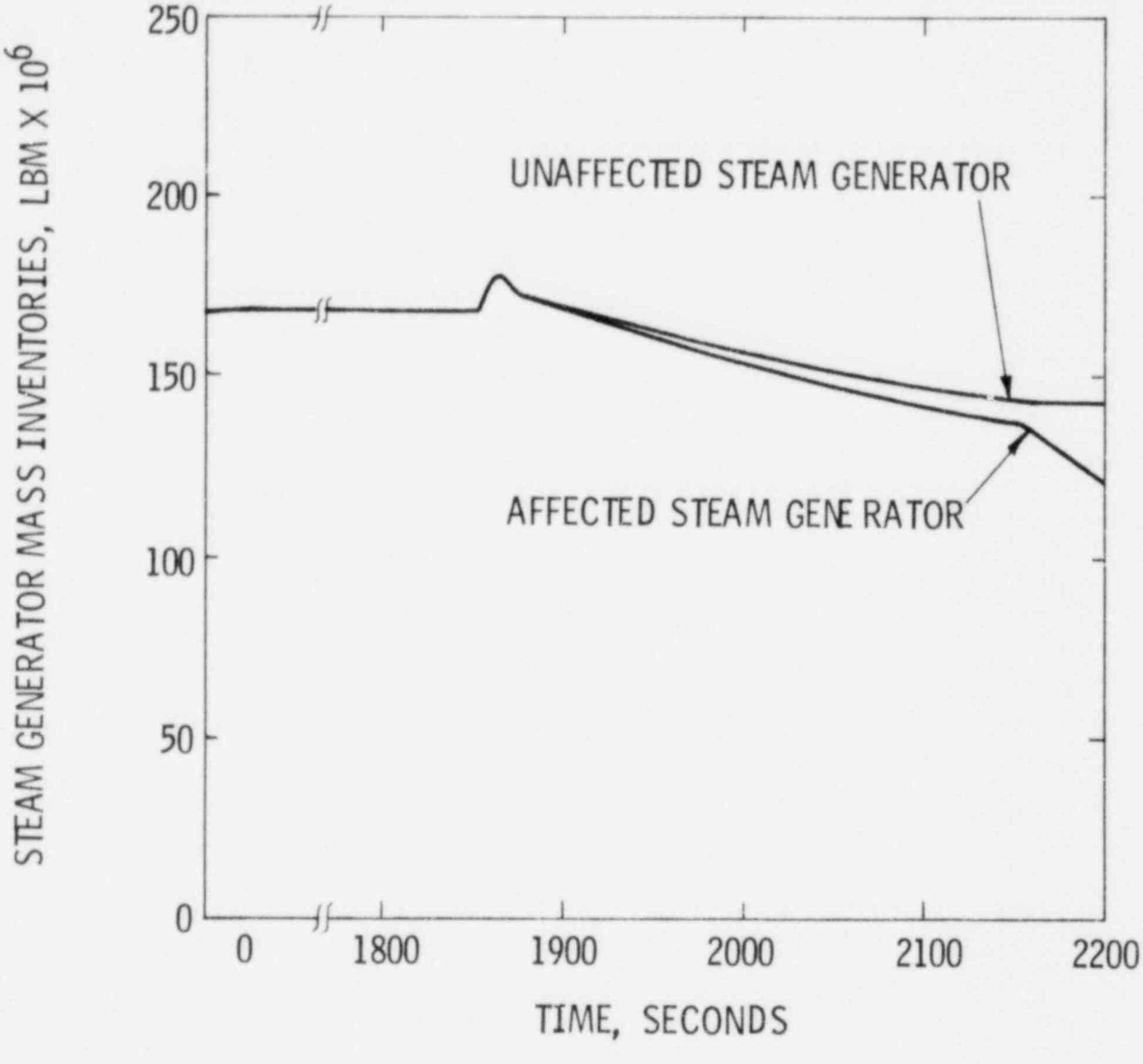
C-E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE FEEDWATER ENTHALPY VS TIME	Figure 15.1.4-1.11



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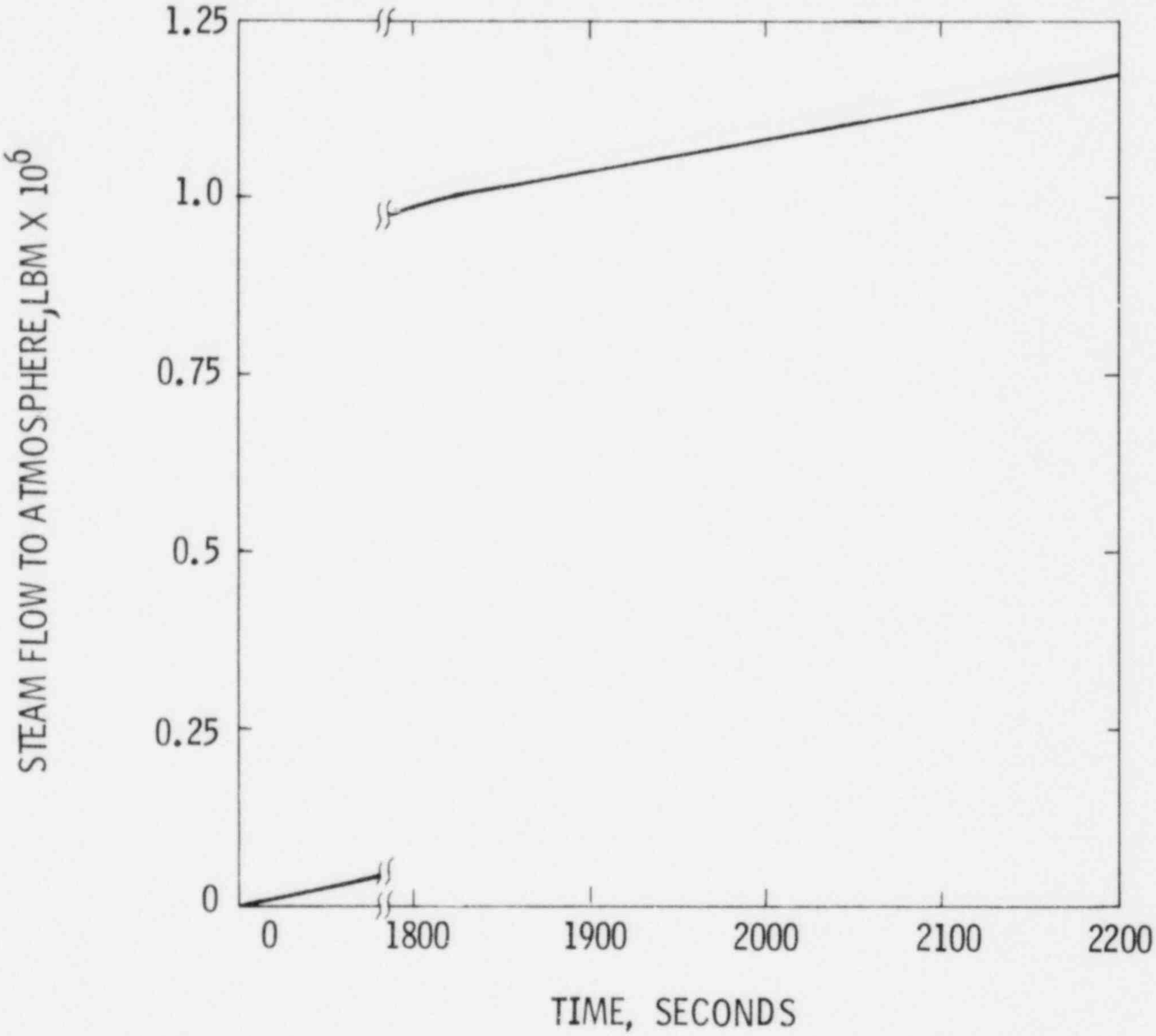
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) STEAM GENERATOR MASS INVENTORIES VS TIME	Figure 15.1.4-1.12



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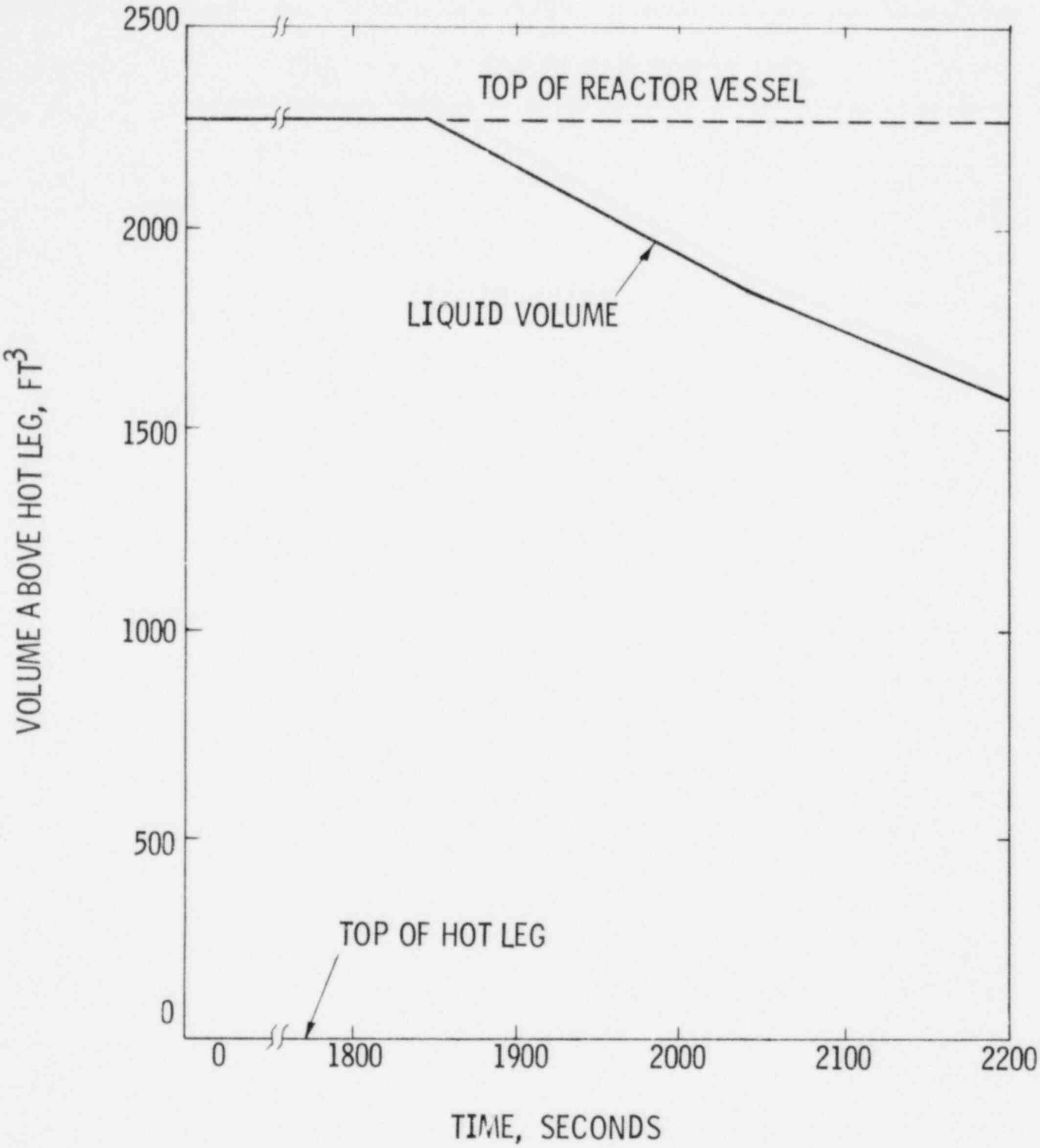
C-E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) STEAM FLOW TO ATMOSPHERE VS TIME	Figure 15.1.4-1.13



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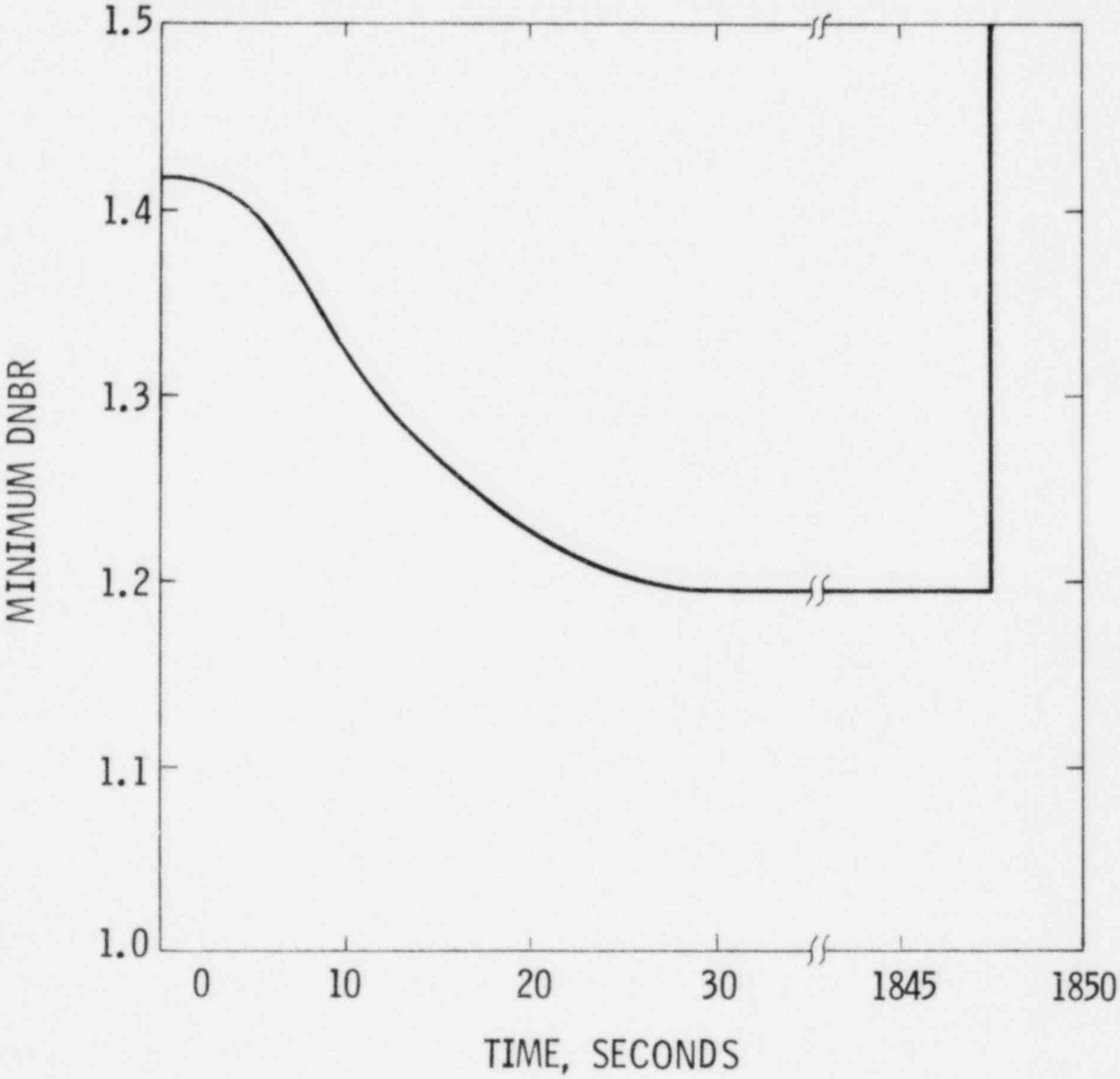
C-E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) VOLUME ABOVE HOT LEG vs TIME	Figure 15.1.4-1.14



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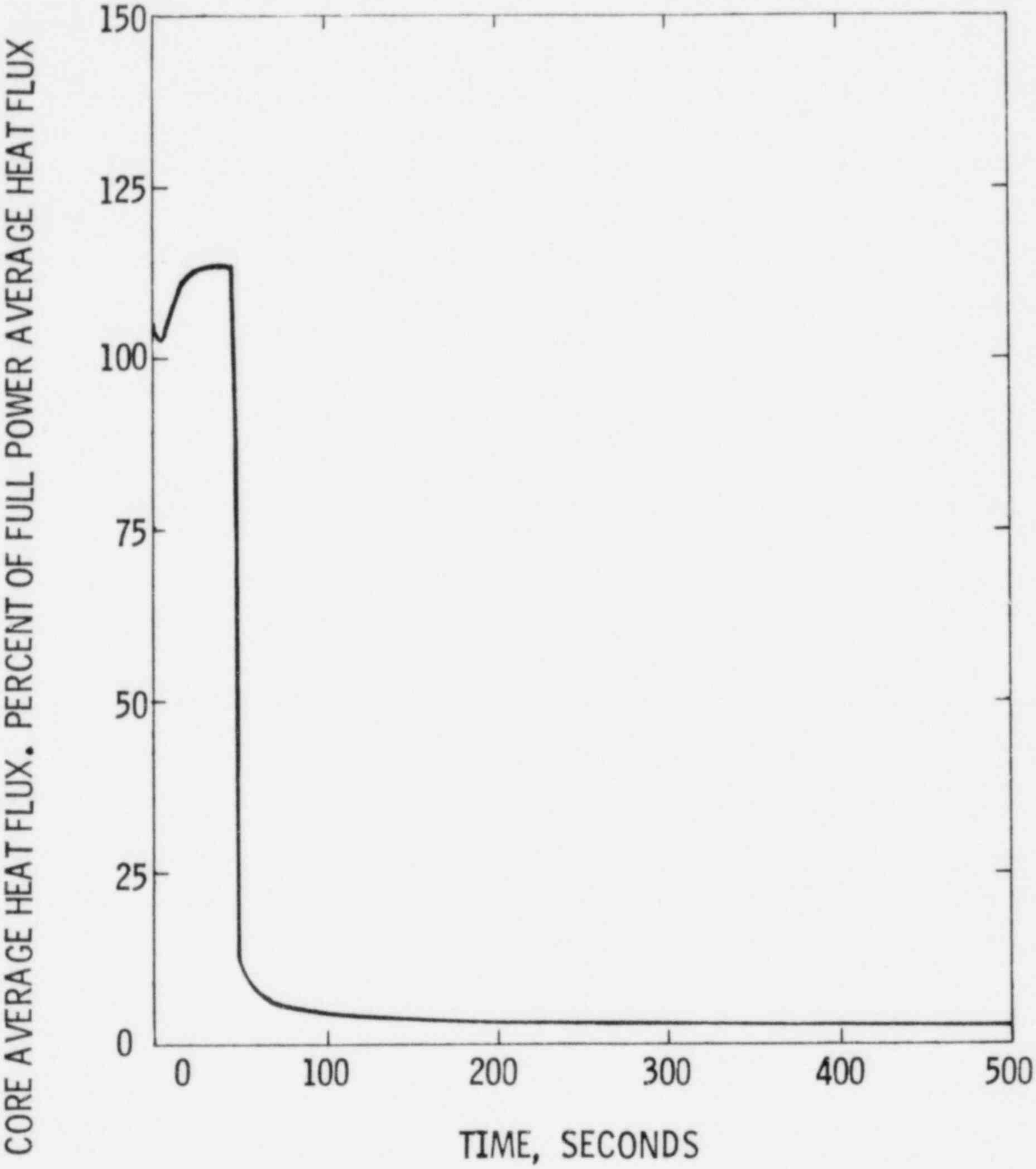
C - E SYSTEM 80	INADVERTENT OPENING OF AN ATMOSPHERIC DUMP VALVE (IOSGADV) MINIMUM DNBR VS TIME	Figure 15.1.4-1.15



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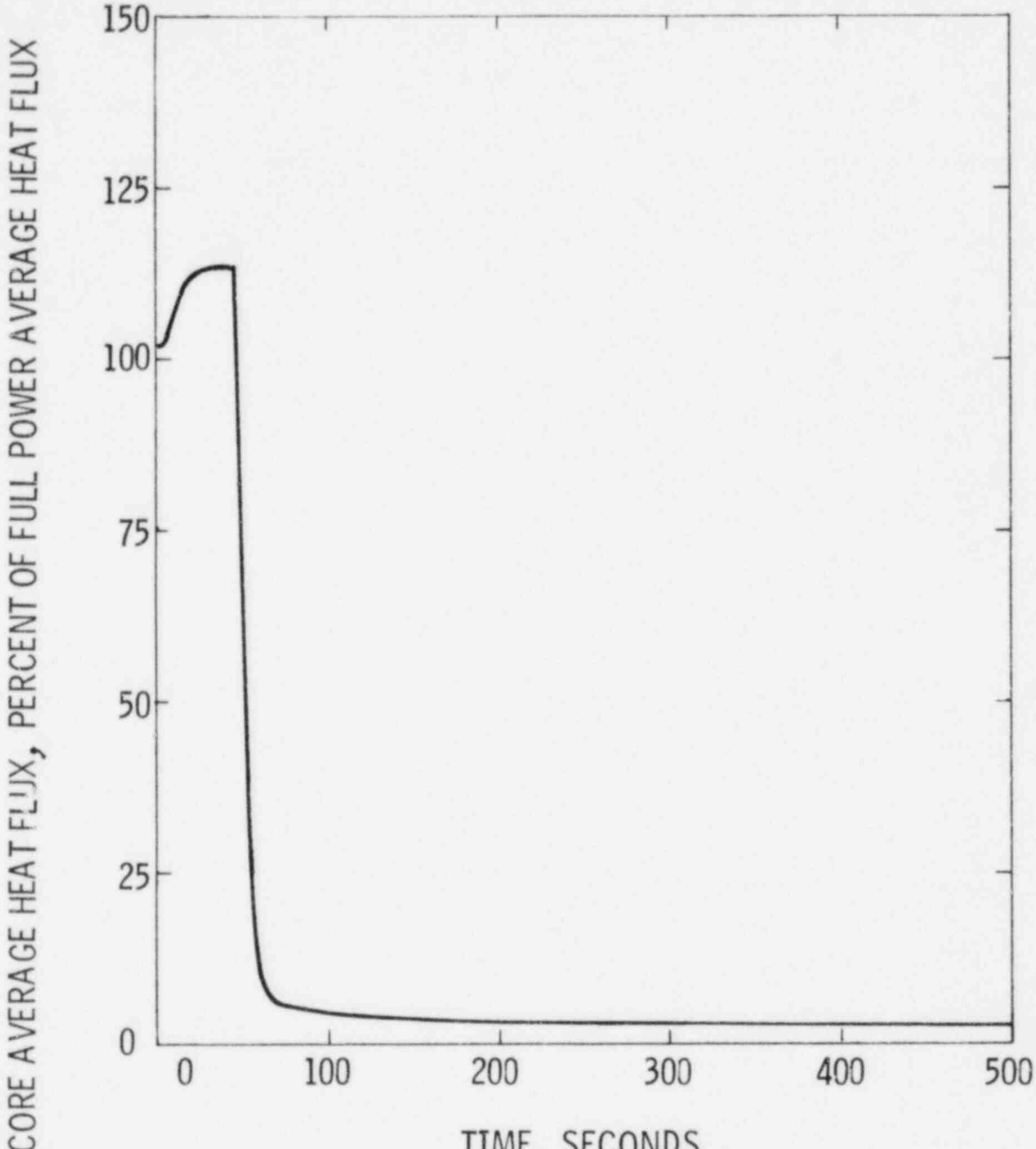
C-E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP CORE POWER VS TIME	Figure 15.1.4-2.1



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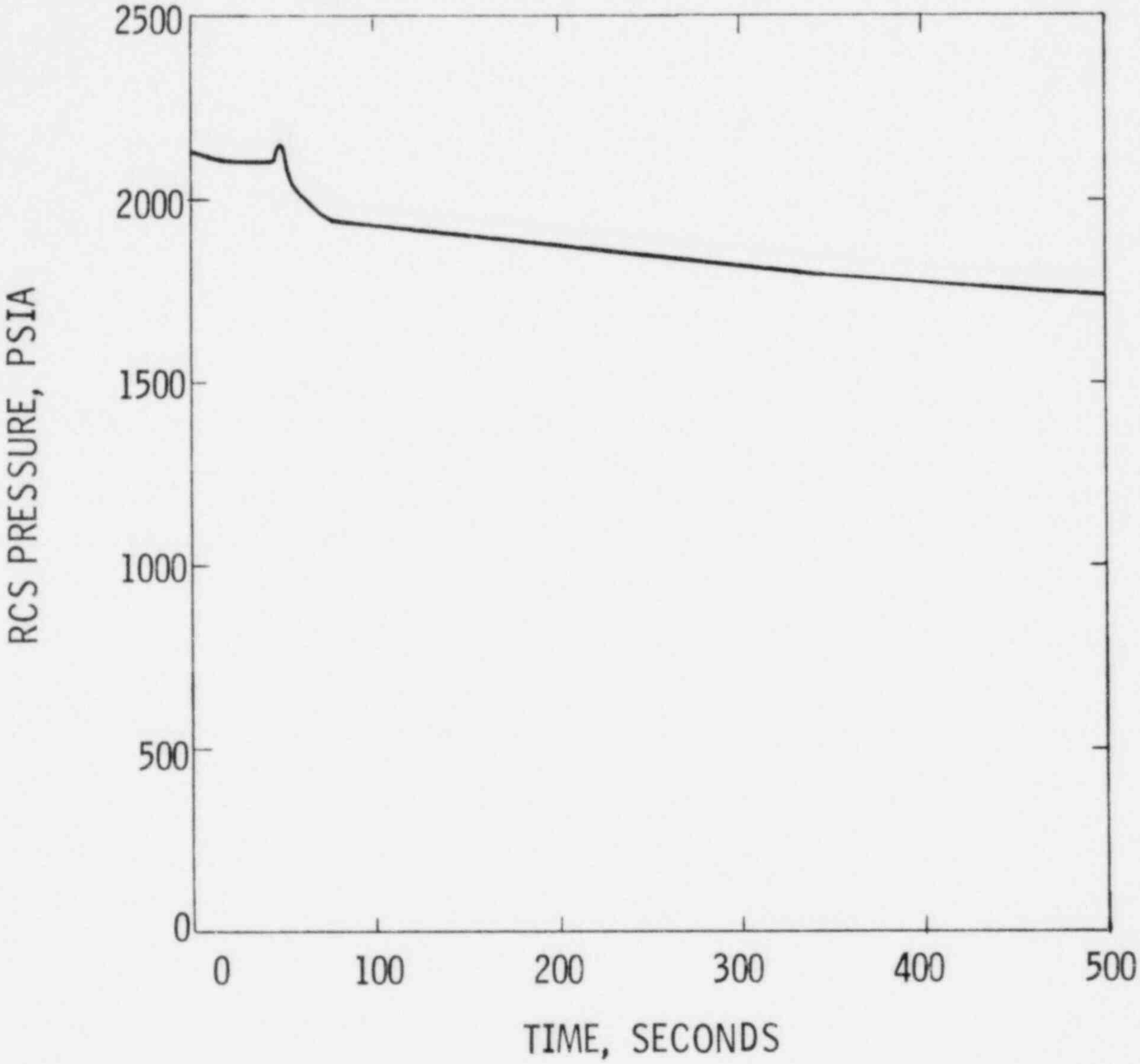
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP CORE AVERAGE HEAT FLUX VS TIME	Figure 15.1.4-2.2



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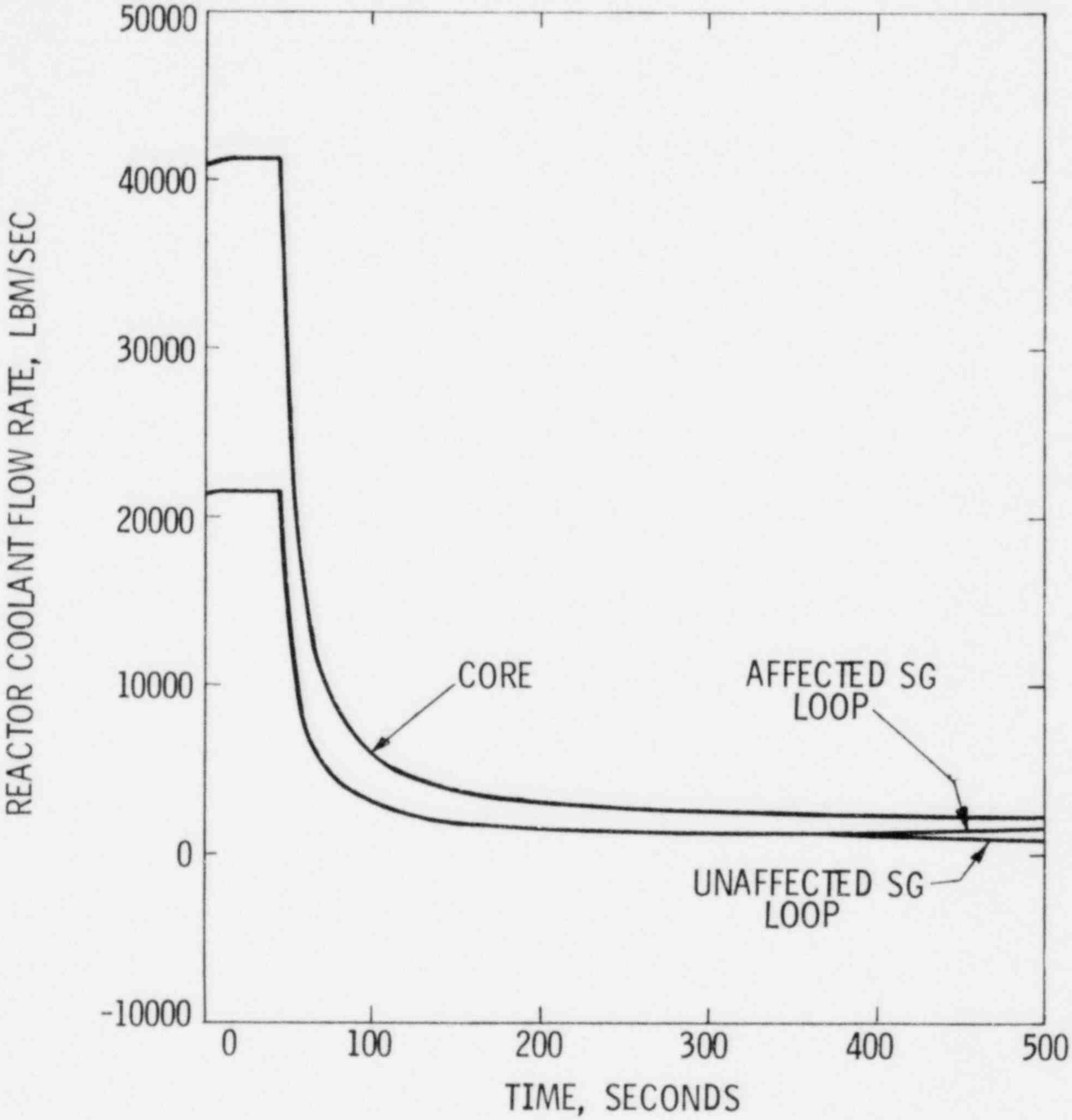
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP RCS PRESSURE VS TIME	Figure 15.1.4-2.3



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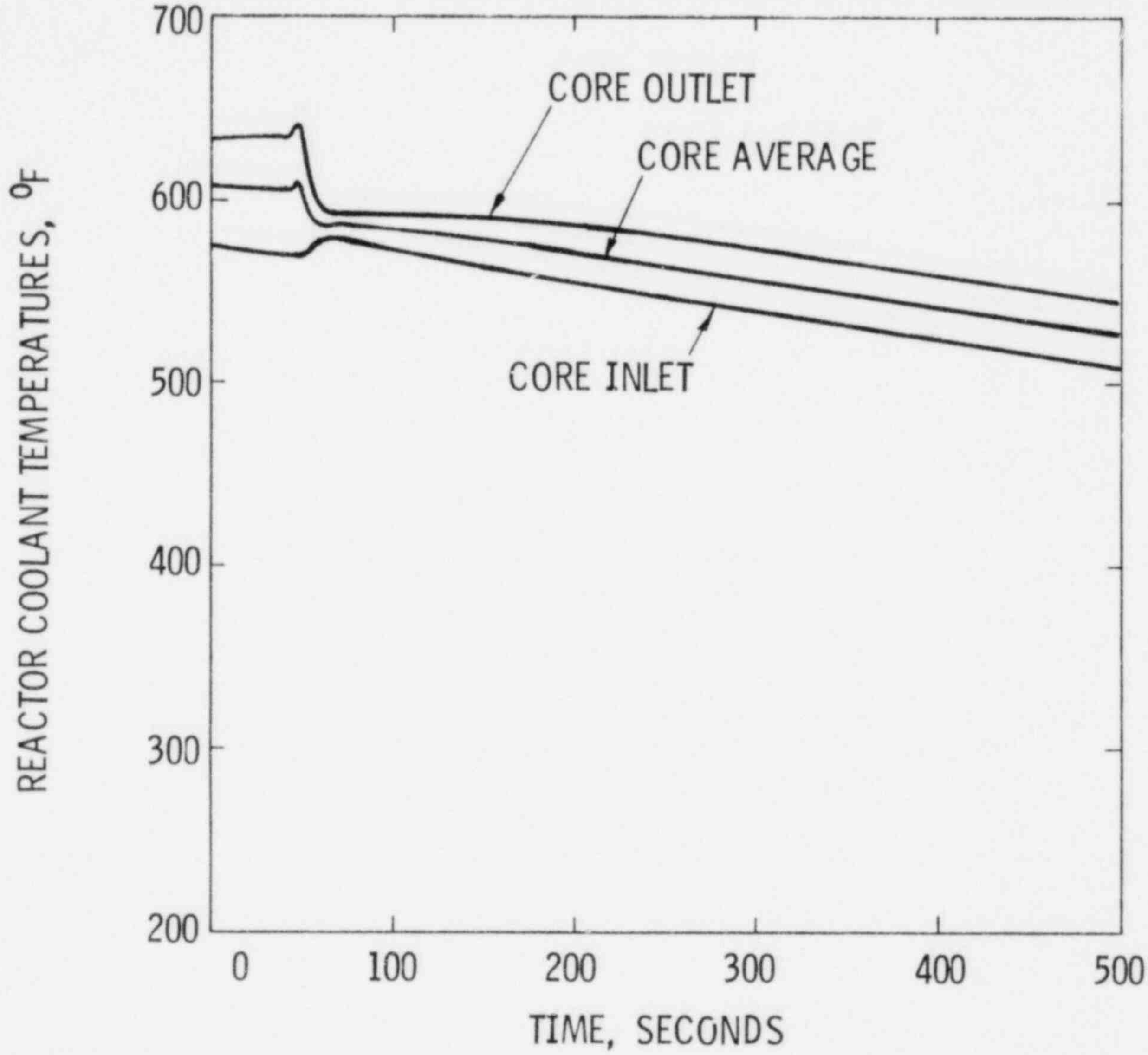
C-E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP REACTOR COOLANT FLOW RATE VS TIME	Figure 15.1.4-2.4



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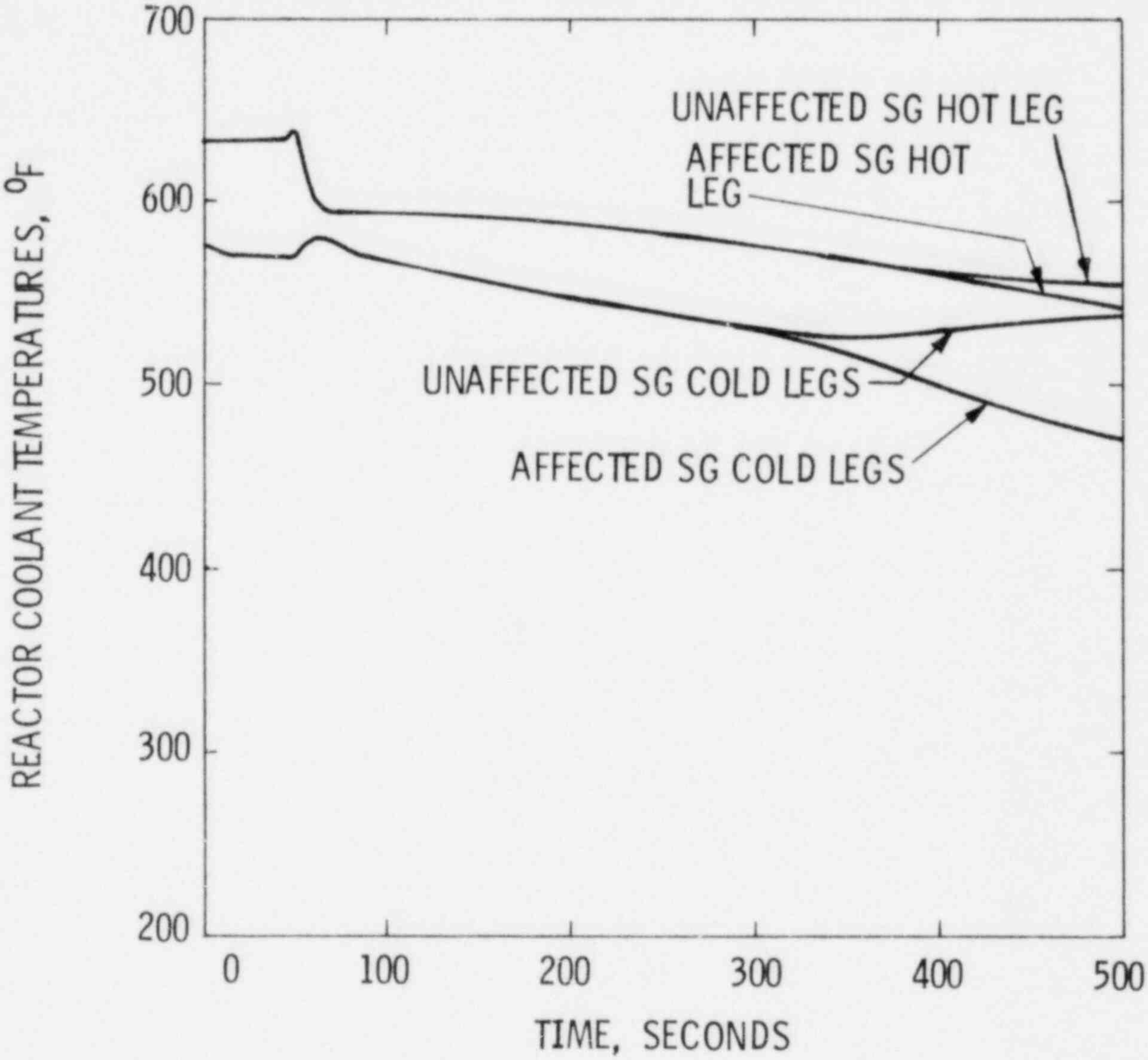
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP REACTOR COOLANT TEMPERATURES (A) VS TIME	Figure 15.1.4-2.5A



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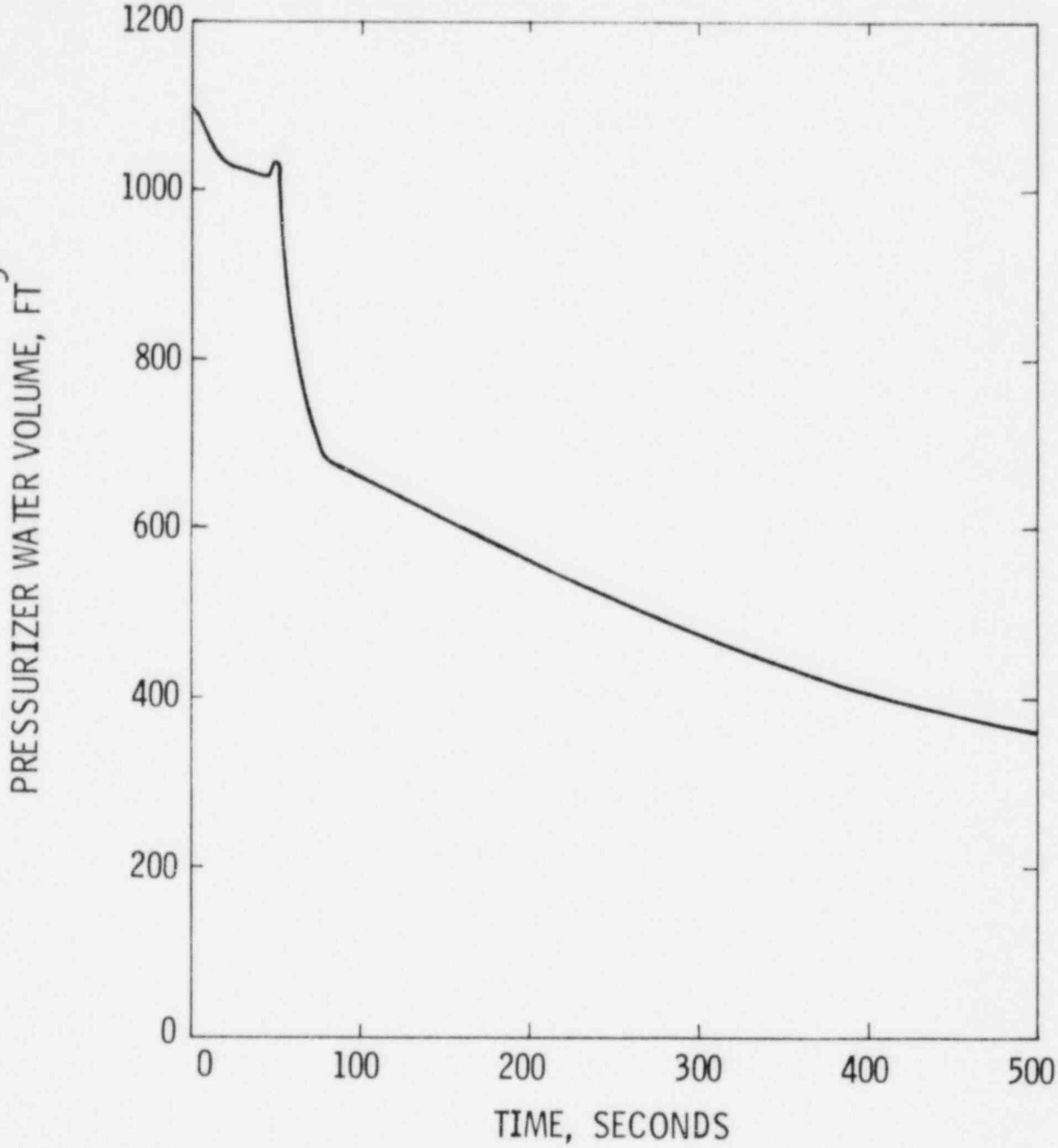
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP REACTOR COOLANT TEMPERATURES (B) VS TIME	Figure 15.1.4-2.5 B



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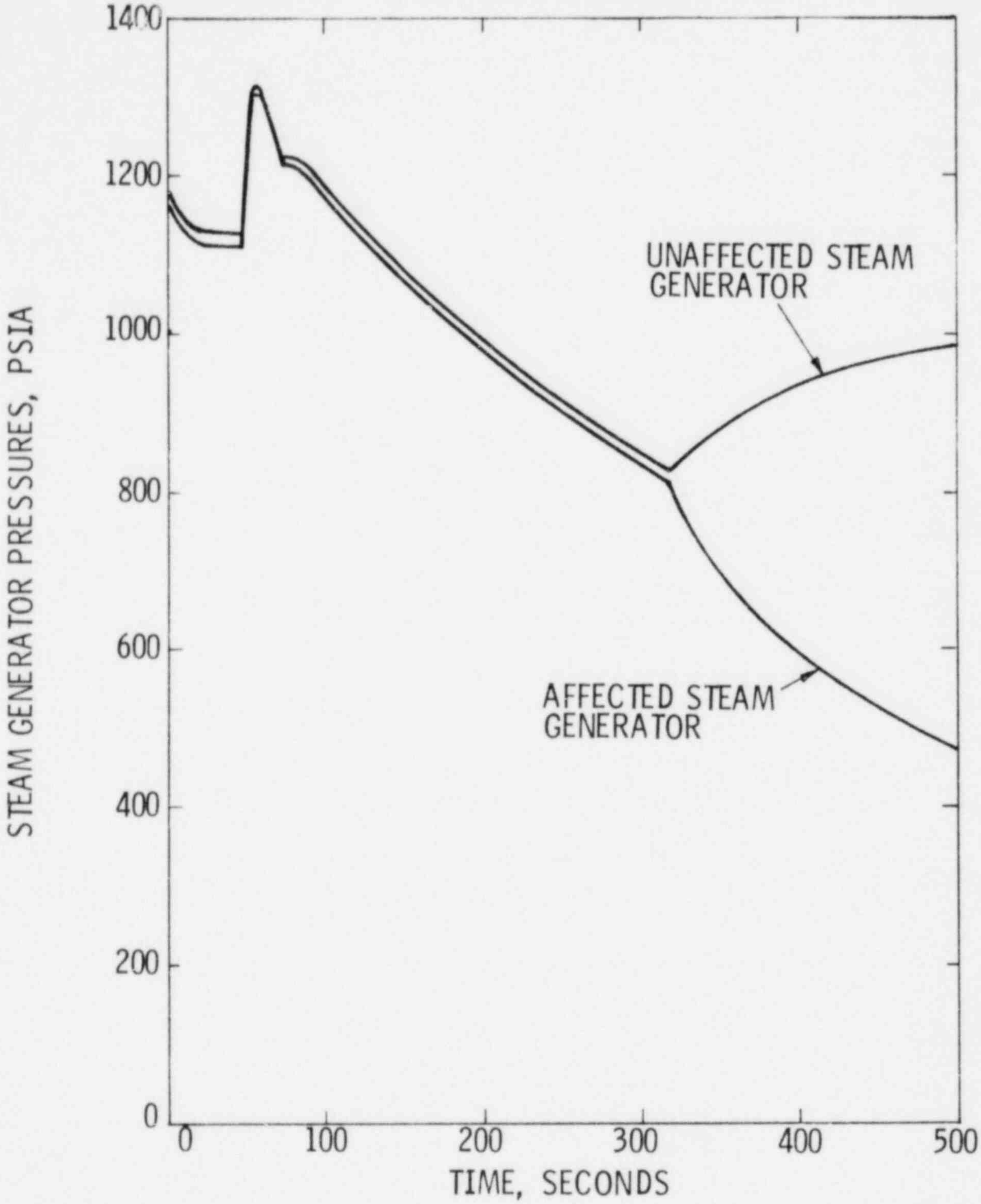
C-E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP PRESSURIZER WATER VOLUME VS TIME	Figure 15.1.4-2.6



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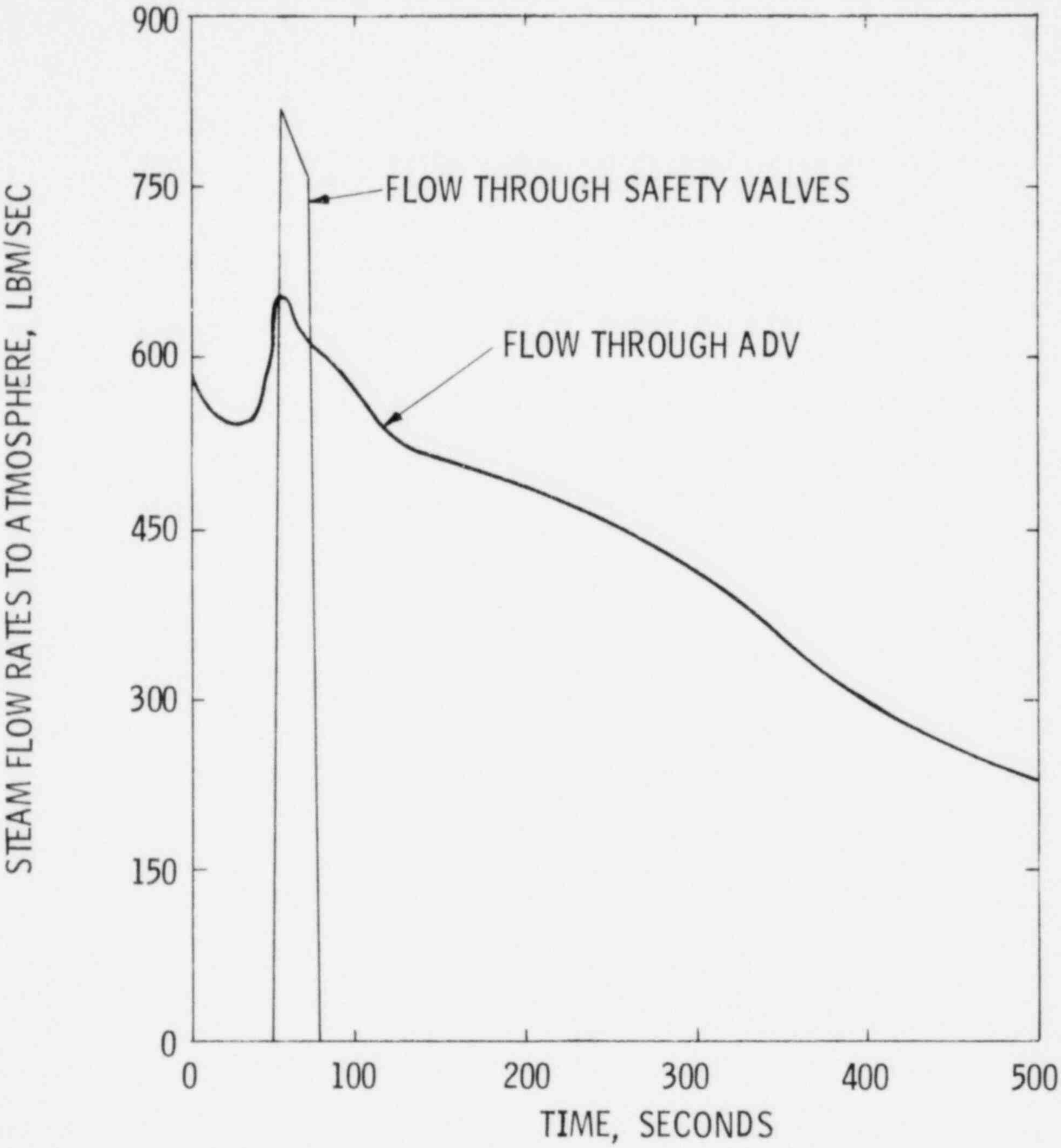
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP STEAM GENERATOR PRESSURES VS TIME	Figure 15.1.4-2.7



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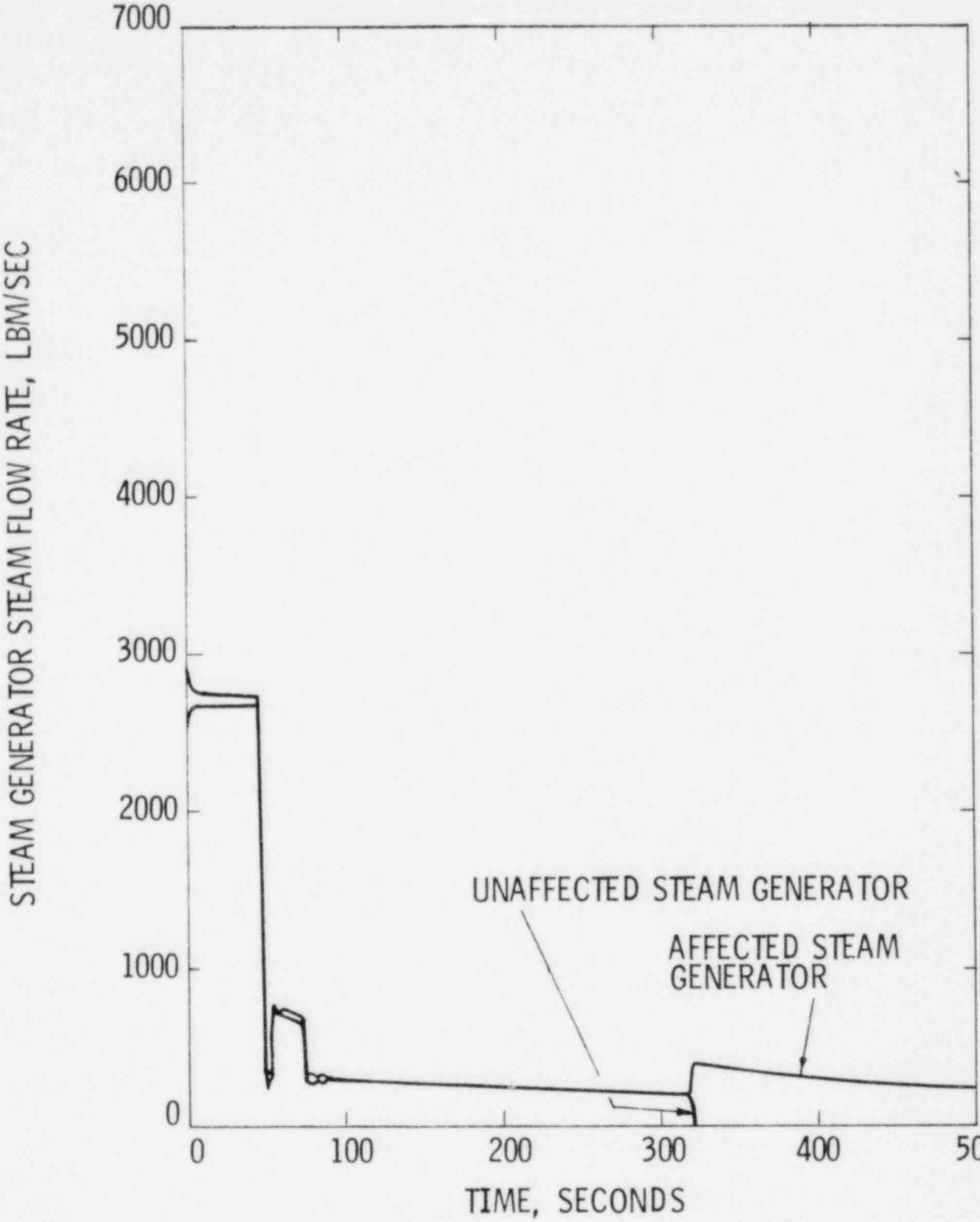
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP STEAMFLOW TO ATMOSPHERE VS TIME	Figure 15.1.4-2.8



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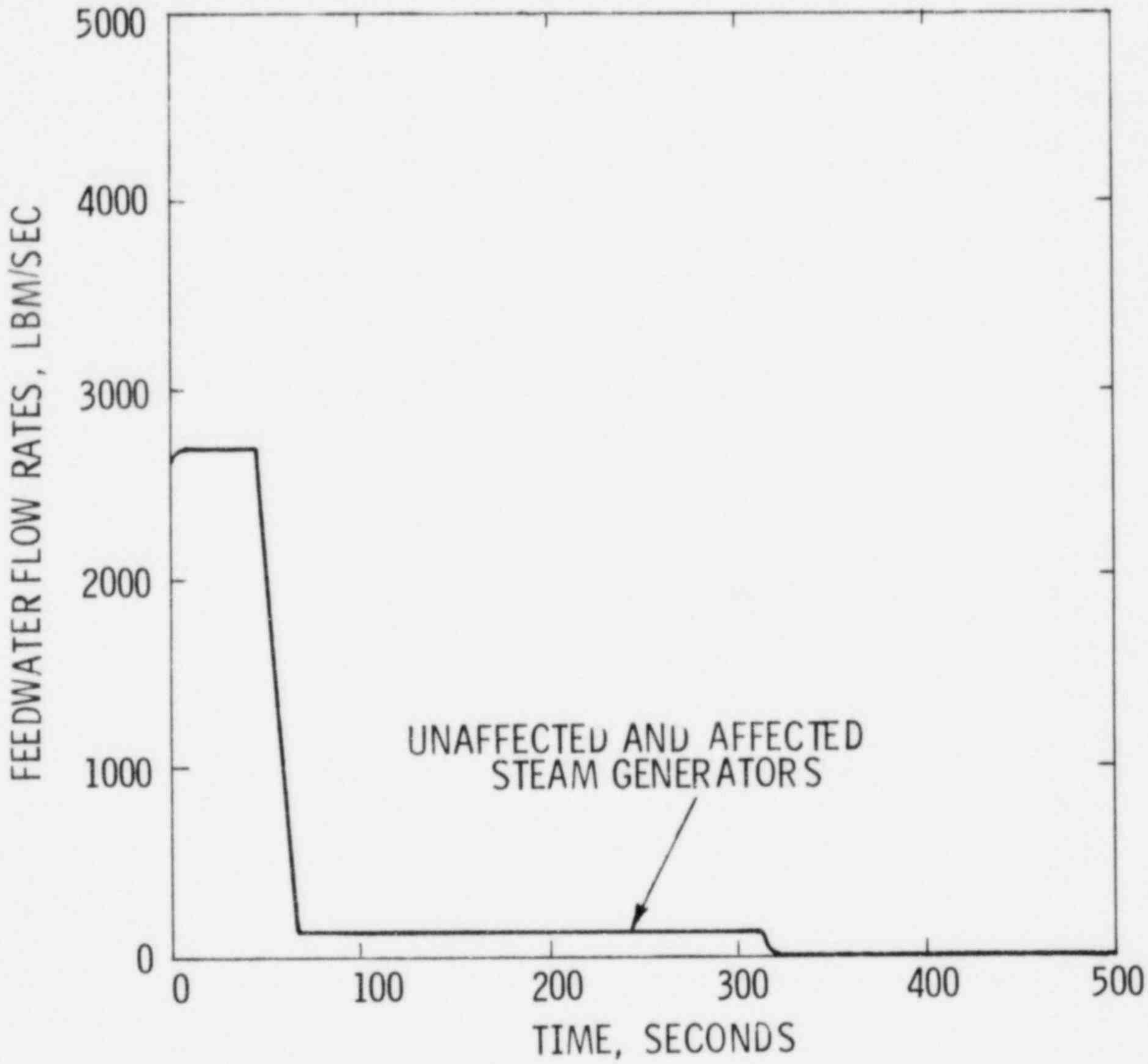
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP STEAM GENERATOR STEAM FLOW RATE VS TIME	Figure 15.1.4-2.9



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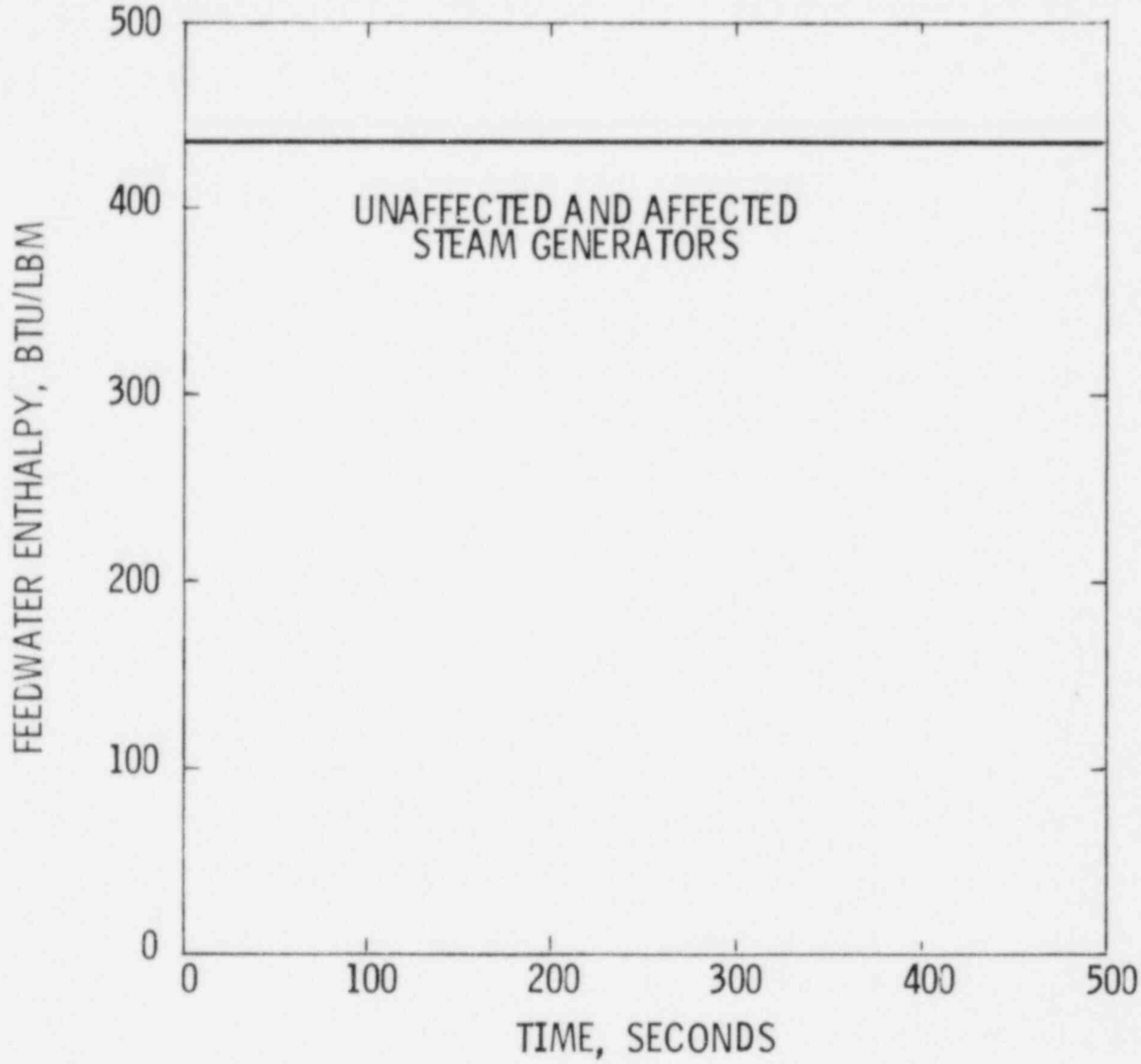
C - E SYSTEM 80	10SGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP FEEDWATER FLOW RATES vs TIME	Figure 15.1.4-2.10



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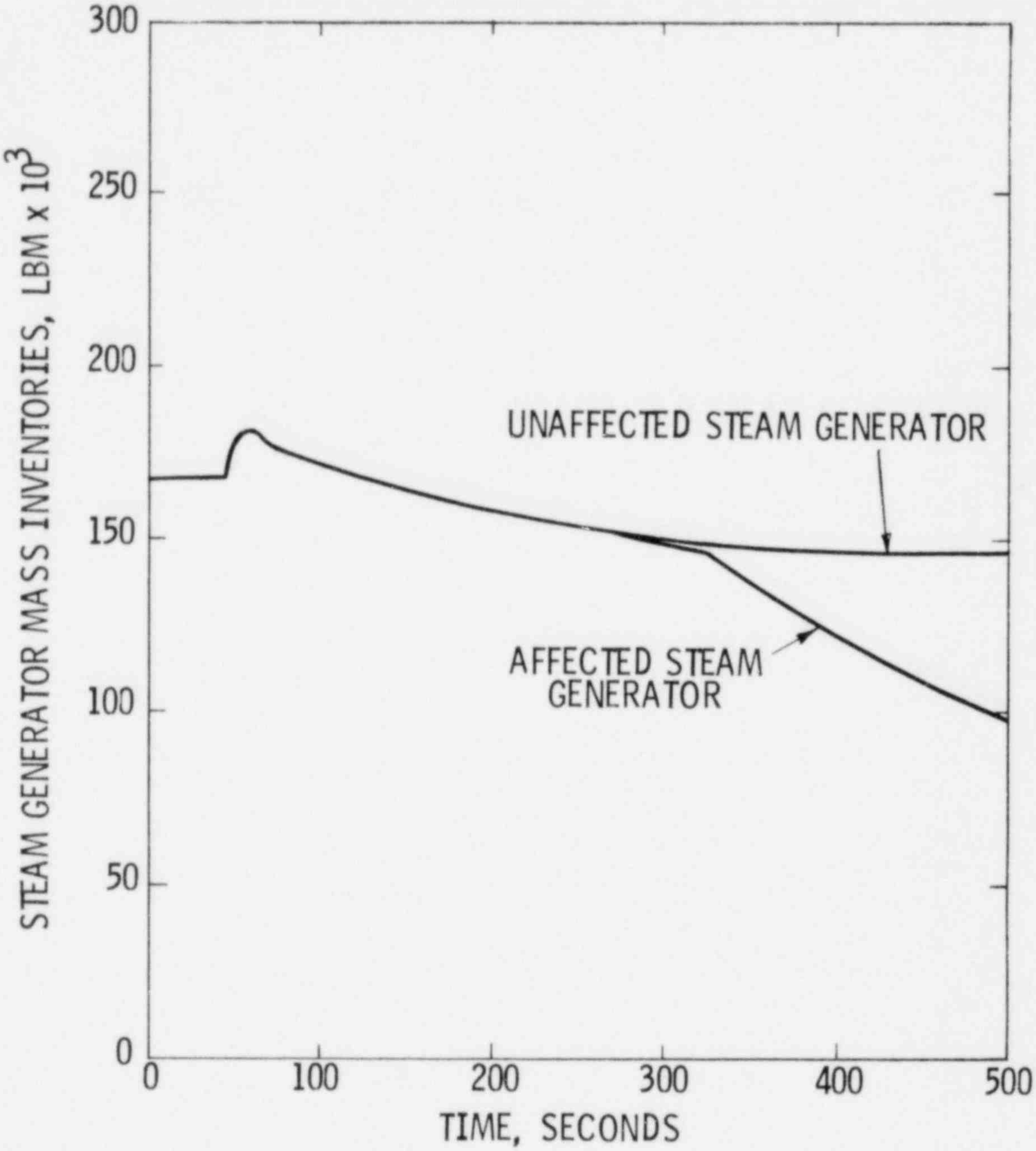
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP FEEDWATER ENTHALPY vs TIME	Figure 15.1.4-2.11



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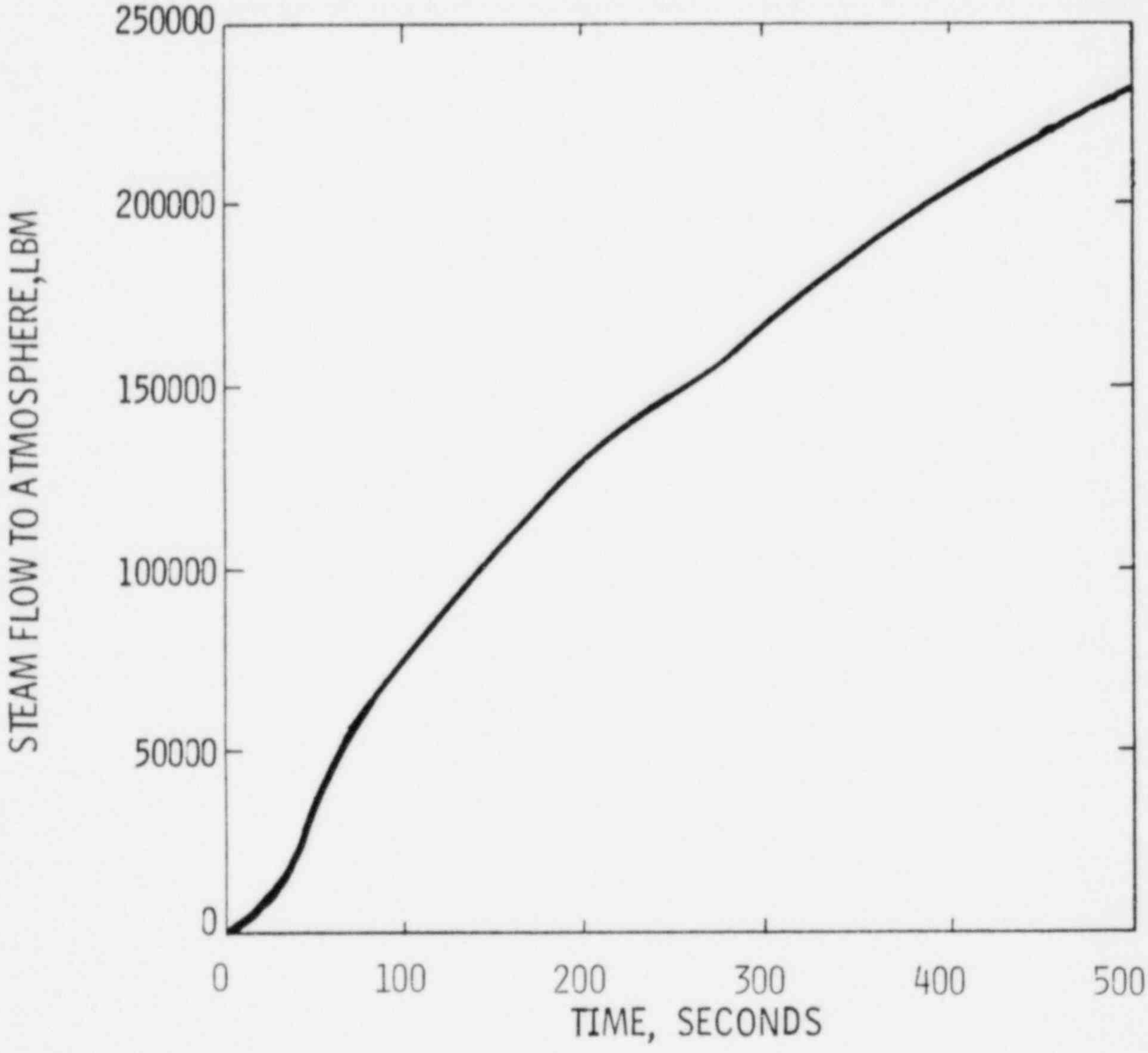
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP STEAM GENERATOR MASS INVENTORIES vs TIME	Figure 15.1.4-2.12



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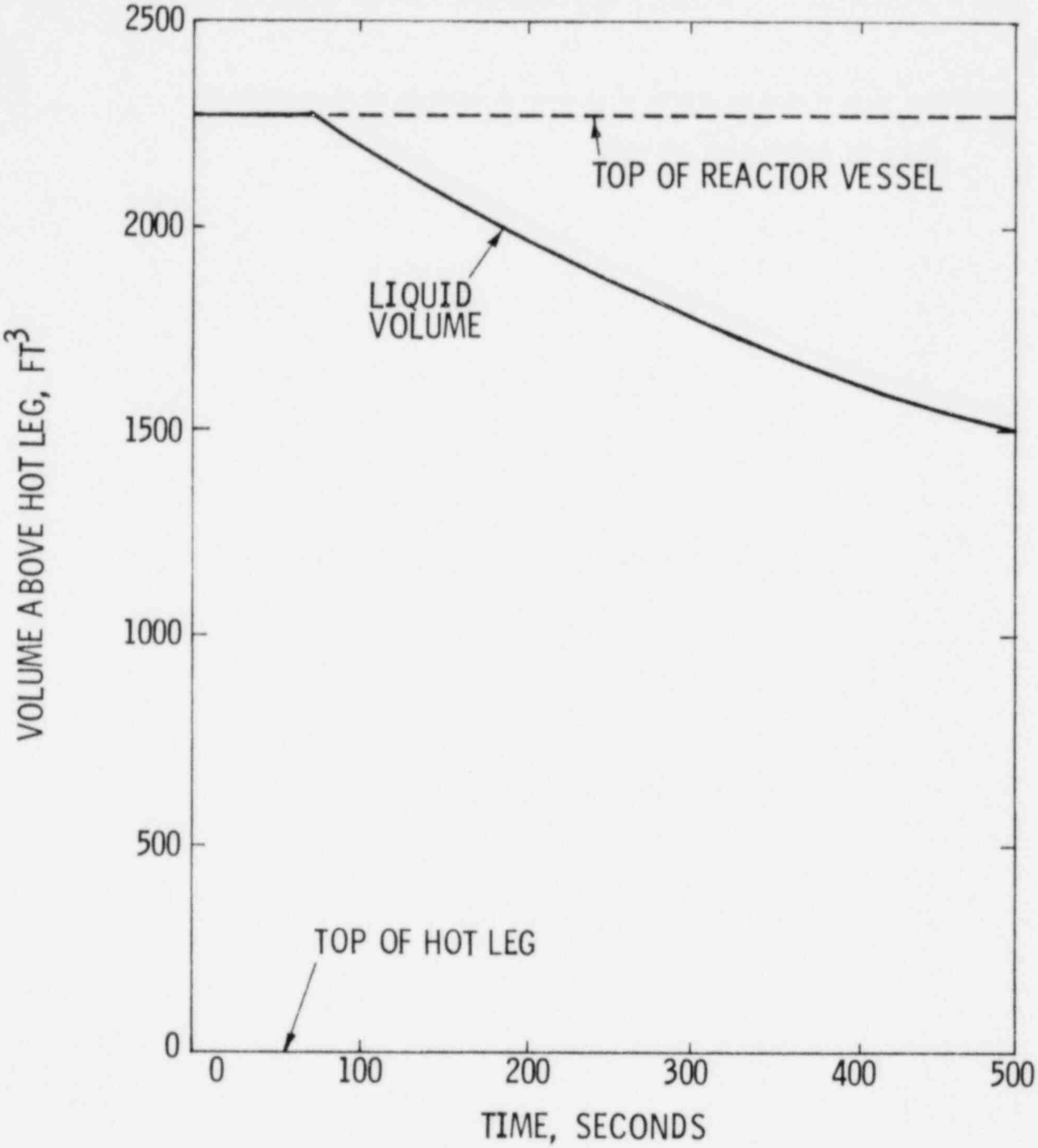
C-E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP STEAM FLOW TO ATMOSPHERE VS TIME	Figure 15.1.4-2.13



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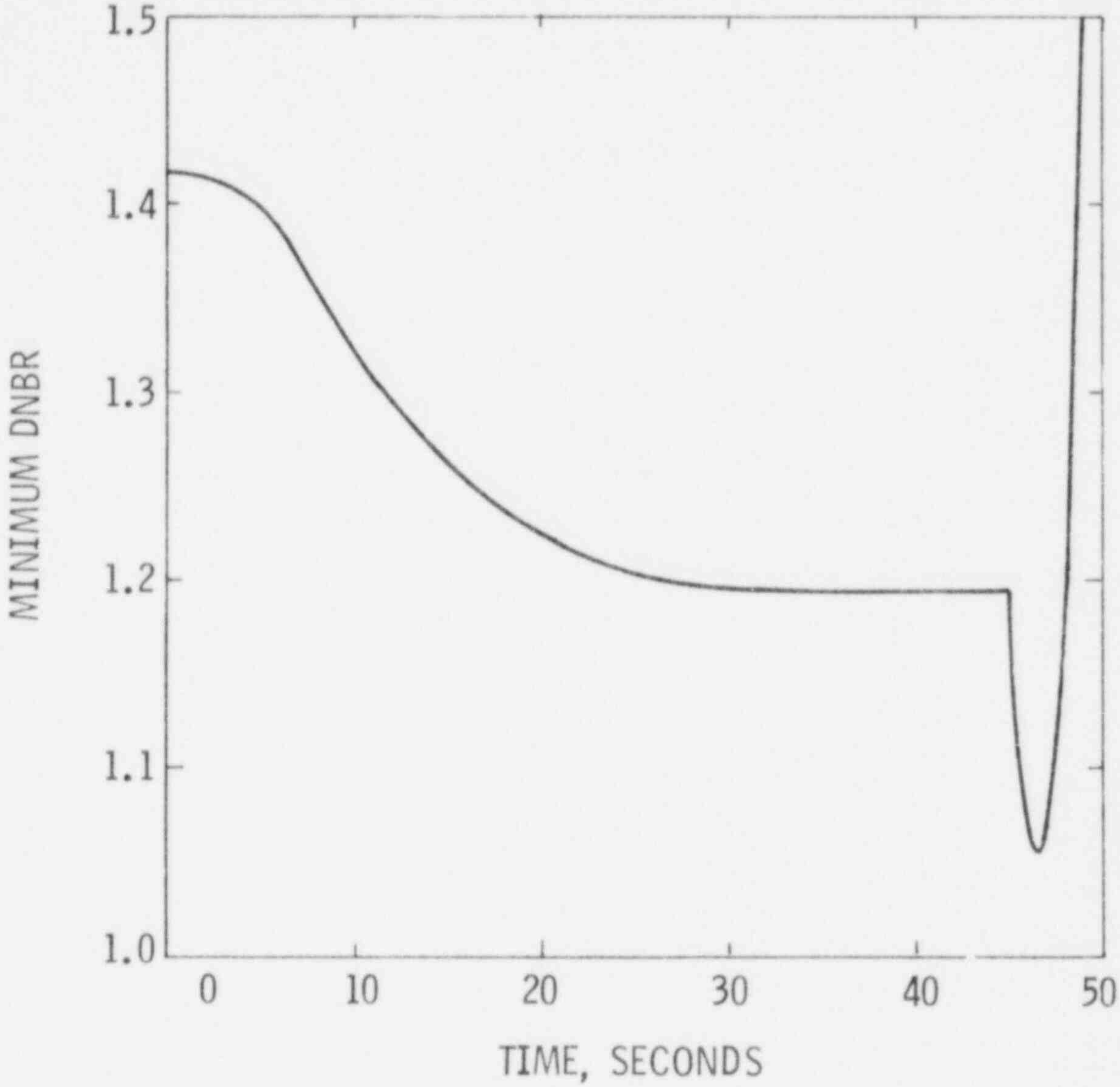
C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP REACTOR VESSEL LIQUID VOLUME vs TIME	Figure 15.1.4-2.14



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C - E SYSTEM 80	IOSGADV WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP MINIMUM DNBR VS TIME	Figure 15.1.4-2.15

15.1.5 STEAM SYSTEM PIPING FAILURES INSIDE AND OUTSIDE CONTAINMENT

15.1.5.1 Identification of Event and Causes

A steam line break (SLB) is defined as a pipe break in the main steam system. SLB cases are chosen to maximize potential for a post-trip return to power, to maximize potential for degradation in fuel cladding performance, and to maximize dose at the site Exclusion Area Boundary. The results show that fission power levels remain sufficiently low following reactor trip to preclude degradation in fuel performance as a result of post-trip return to power, that degradation in fuel performance prior to trip is of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability, and that doses are within 10CFR100 guidelines. The steam line breaks presented are:

A. Cases chosen to maximize potential for a post-trip return to power:

1. A large steam line break inside containment during full power operation with concurrent loss of offsite power in combination with a single failure, and a stuck CEA (SLBFPLOP).

2. A large steam line break inside containment during full power operation with offsite power available in combination with a single failure and a stuck CEA (SLBFP).

3. A large steam line break inside containment during zero power operation with concurrent loss of offsite power in combination with a single failure, and a stuck CEA (SLBZPLOP).

4. A large steam line break inside containment during zero power operation with offsite power available in combination with a single failure and a stuck CEA (SLBZP).

B. Cases chosen to maximize potential for degradation in fuel performance and dose at the site Exclusion Area Boundary:

5. A small steam line break outside of containment upstream of the main steam isolation valve (MSIV) during full power operation with offsite power available in combination with a single failure, technical specification steam generator tube leakage, and a stuck CEA (SSLBFP).

6. A large steam line break outside of containment upstream of the MSIV during zero power operation with concurrent loss of offsite power in combination with a single failure, technical specification steam generator tube leakage, iodine spike, and a stuck CEA (SLBZPLOPD).

The largest possible steam line break size is the double ended rupture of a steam line upstream of the MSIV. In the System 80 design, an integral flow restrictor exists in each steam generator outlet nozzle. The largest effective steam blowdown area for each steam line, which is limited by the flow restrictor throat area, is approximately 30% of the steam line cross-section area, or 1.28 square feet.

Results are presented in Appendix C which demonstrate that the cases listed above bound the results obtained for a spectrum of break sizes, loss of offsite power times, and single failures.

15.1.5.2 Sequence of Events and Systems Operation

Steam line breaks are characterized as cooldown events due to the increased steam flow rate, which causes excessive energy removal from the steam generators and the reactor coolant system (RCS). This results in a decrease in reactor coolant temperatures and in RCS and steam generator pressure. The cooldown causes an increase in core reactivity due to the negative moderator and Doppler reactivity coefficients.

Detection of the cooldown is accomplished by the pressurizer and steam generator low pressure alarms, by the high reactor power alarm and by the low steam generator water level alarm. Reactor trip as a consequence of a steam line break is provided by one of several available reactor trip signals including low steam generator pressure, low RCS pressure, low steam generator water level, high reactor power, low DNBR trip initiated by the core protection calculators and, for inside containment breaks, high containment pressure. For a SLB that occurs with a concurrent loss of offsite power, the events of turbine stop valve closure, termination of feedwater to both steam generators and coastdown of the reactor coolant pumps are assumed to be initiated simultaneously. Following reactor trip the most reactive control rod is conservatively assumed to be held in the fully withdrawn position. The depressurization of the affected steam generator results in the actuation of a main steam isolation signal (MSIS). This closes the MSIVs, isolating the unaffected steam generator from blowdown and closes the main feedwater isolation valves (MFIVS), terminating main feedwater flow to both steam generators. After the reduction of steam flow that occurs with MSIV closure, the level in the intact steam generator falls below the emergency feedwater actuation signal (EFAS) setpoint. The resulting EFAS causes emergency feedwater (EFW) flow to be initiated to the intact steam generator. The EFAS logic prevents feeding the affected steam generator. The pressurizer pressure decreases to the point where a safety injection actuation signal (SIAS) is initiated. The isolation of the unaffected steam generator and subsequent emptying of the affected steam generator terminate the cooldown. The introduction of safety injection boron upon SIAS causes core reactivity to decrease. The operator, via the appropriate emergency procedures, may initiate plant cooldown by manual control of the atmospheric steam dump valves, or, in the event that offsite power is available, by using the MSIV bypass valves associated with the unaffected steam generator and the turbine bypass valves, any time after the affected steam generator empties. The analysis presented herein conservatively assumes operator action is delayed until 30 minutes after first indication of the event. The plant is then cooled to 350 F and 400 psia, at which point shutdown cooling is initiated.

A parametric study of single failures (See Appendix C) that would have an adverse impact on the SLB has determined that the failure of one of the high pressure safety injection (HPSI) pumps to start following SIAS has the most adverse effect for the full power case with concurrent loss of offsite power and all zero power cases (Cases 1,3,4, and 6). Consequently, one HPSI pump is conservatively assumed to fail for these cases. The evaluation shows that for the full power SLB without loss

of offsite power (Case 2) the most adverse effect is caused by failure of a MSIV on one of the steam lines on the intact generator to close following MSIS. Consequently for this case steam is assumed to continue to be released from the intact steam generator after MSIS at a rate consistent with the interface requirement of a maximum of 11% design steam flow rate non-isolable steam flow. This open flow path is represented by an effective flow area for steam blowdown from the intact steam generator of 0.2556 square feet. For case 5 (SSLBFP) there is no single failure which increases the potential for degradation in fuel cladding performance or which increases the offsite dose.

The sequence of events for Cases 1 through 5 above are presented in Tables 15.1.5-1 through 5, respectively. The sequence of events for Case 6 is the same as for Case 3.

15.1.5.3 Analysis of Effects and Consequences

A. Mathematical Models

The mathematical models and data transfer between codes used in the SLB analysis are presented in Appendix C.

B. Input Parameters and Initial Conditions

The initial conditions assumed in the analysis of the NSSS response to Cases 1 through 5 are presented in Tables 15.1.5-6 through 10, respectively. The initial conditions for Case 6 are the same as those for Case 3. Justification of the selection of initial conditions and input parameters is presented in Appendix C.

C. Results

Case 1: Large Steam Line Break During Full Power Operation with Concurrent Loss of Offsite Power (SLBFPLOP)

The dynamic behavior of the salient NSSS parameters following the SLBFPLOP is presented in Figures 15.1.5-1.1 through 15.1.5-1.16. Table 15.1.5-1 summarizes the major events, times, and results for this transient.

Concurrent with the steam line break, a loss of offsite power occurs. At this time an actuation signal for the emergency diesel generators is initiated. Due to decreasing core flow following loss of power to the reactor coolant pumps, conditions exist for a low DNBR trip. At 0.6 second a low DNBR trip signal is initiated by the core protection calculators. At 0.75 second the reactor trip breakers open. After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 1.09 seconds. At 8.0 seconds voids begin to form in the upper head of the reactor vessel. At 8.3 seconds the steam generator pressure drops below the MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and MSIVs close by 13.3 seconds. EFW is automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at 13.3 seconds. At 120 seconds the pressurizer empties. At 178 seconds the pressurizer pressure has dropped below 1600 psia and initiates a SIAS. Within 30 seconds of SIAS the operable HPSI pump is loaded on the diesels and reaches full speed and the HPSI valves are fully open. At 237 seconds the affected steam generator empties.

At 259 seconds the maximum core reactivity (+ 0.09 $\% \Delta\rho$) occurs. Safety injection boron begins to reach the core at 280 seconds. As shown by Figure 15.1.5-1.16, the values of DNBR remain above those for which fuel damage would be indicated. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves, assuming that offsite power has not been restored. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

Case 2: Large Steam Line Break During Full Power Operation with Offsite Power Available (SLBFP)

The dynamic behavior of the salient NSSS parameters following the SLBFP is presented in Figures 15.1.5-2.1 through 15.1.5-2.15. Table 15.1.5-2 summarizes the major events, times, and results for this transient.

At 6.95 seconds after the initiation of the steam line break a trip signal is initiated by the core protection calculators on a projected DNBR of 1.19. At 7.1 seconds the reactor trip breakers open. After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 7.44 seconds. At 11.9 seconds voids begin to form in the upper head of the reactor vessel. At 13.5 seconds the steam generator pressure drops below the MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and the operable MSIVs close by 18.5 seconds. EFW is automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at 18.5 seconds. At 67 seconds the pressurizer empties. At 90 seconds the pressurizer pressure drops below 1600 psia and initiates a SIAS. Within 30 seconds of SIAS the HPSI pumps reach full speed and the HPSI valves are fully open. At 149 seconds the affected steam generator empties. At 151 seconds the maximum core reactivity (-0.18$\% \Delta\rho$) occurs. Safety injection boron begins to reach the core at 160 seconds. The values of DNBR remain above 10 during the post-trip approach-to-criticality portion of this transient. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the turbine bypass valves. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

Case 3: Large Steam Line Break During Zero Power Operation with Concurrent Loss of Offsite Power

The dynamic behavior of the salient NSSS parameters following the SLBZPLOP is presented in Figures 15.1.5-3.1 through 15.1.5-3.15. Table 15.1.5-3 summarizes the major events, times, and results for this transient.

Concurrent with the steam line break, a loss of offsite power occurs. At this time an actuation signal for the emergency diesel generators is initiated. Due to decreasing core flow following loss of power to the reactor coolant pumps, conditions exist for a low DNBR trip. At 0.6 second a low DNBR trip signal is initiated by the core protection calculators. At 0.75 second the reactor trip breakers open. After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 1.09 seconds. At 5.7 seconds the steam generator pressure drops below the MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and MSIVs close by 10.7 seconds. EFW is automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at 10.7 seconds.

At 45 seconds the pressurizer pressure drops below 1600 psia and initiates a SIAS. Within 30 seconds of SIAS the operable HPSI pump is loaded on the diesels and reaches full speed and the HPSI valves are fully open. At 55 seconds voids begin to form in the upper head of the reactor vessel. At 59 seconds the pressurizer empties. Safety injection boron begins to reach the core at 120 seconds. At 189 seconds the maximum core reactivity ($-0.06\%\Delta\rho$) occurs. At 1240 seconds the affected steam generator empties. The values of DNBR remain above 10 during this transient. At a maximum of 30 minutes the operator, via the the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves, assuming that offsite power has not been restored. Shutdown cooling is initiated when the RCS reaches $350^{o}F$ and 400 psia.

Case 4: Large Steam Line Break Zero Power Operation with Offsite Power Available (SLBZP)

The dynamic behavior of the salient NSSS parameters following the SLBZP is presented in Figures 15.1.5-4.1 through 15.1.5-4.15. Table 15.1.5-4 summarizes the major events, times, and results of this transient.

At 6.24 seconds after initiation of the steam line break, the steam generator pressure drops below the low steam generator pressure trip and MSIS setpoint of 810 psia. At 6.79 seconds the reactor trip breakers open. After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 7.13 seconds. The MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and MSIVs close by 11.3 seconds. EFW is automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at 11.3 seconds. At 41 seconds the pressurizer pressure drops below 1600 psia and initiates a SIAS. Within 30 seconds of SIAS the operable HPSI pump reaches full speed and the HPSI valves are fully open. At 48 seconds voids begin to form in the upper head of the reactor vessel. At 52 seconds the pressurizer empties. Safety injection boron begins to reach the core at 110 seconds. At 310 seconds the maximum core reactivity ($-0.02\%\Delta\rho$) occurs. At 418 seconds the affected steam generator empties. The values of DNBR remain above 10 for this transient. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the MSIV bypass valves associated with the unaffected steam generator and turbine bypass valves. Shutdown cooling is initiated when the RCS reaches $350^{o}F$ and 400 psia.

Case 5: Small Steam Line Break Outside Containment During Full Power Operation with Offsite Power available (SSLBFP)

The dynamic behavior of the salient NSSS parameters following a typical limiting SSLBFP is presented in Figures 15.1.5-5.1 through 15.1.5-5.8. Table 15.1.5-5 summarizes the major events, times and results for this transient.

The consequences of this transient -- fraction of fuel rods predicted to experience DNB -- are the same as those for SSLBFPs for a spectrum of break sizes, due to the protective action of the core protection calculators (CPCs). The break size assumed for the transient presented here was 1.0 square foot.

Not later than 28.4 seconds after initiation of the steam line break, a trip signal is initiated by the CPCs on a projected DNBR of 1.19. At 28.55 seconds

the reactor trip breakers open. After a 0.34 second coil decay delay, the CEAs begins to drop into the core at 28.89 seconds. At 29 seconds a minimum transient DNBR of 1.10 is calculated to occur, after which DNBR rapidly increases, as shown in Figure 15.1.5-5.9. At 60 seconds voids begin to form in the upper head of the reactor vessel. At 84 seconds the steam generator pressure drops below the MSIS setpoint of 810 psia.The MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and the operable MSIVs close by 89 seconds.

Subsequently, the events of this transient follow a sequence similar to those of the SLBFP (Case 2). Since the cooldown is less rapid, the potential for post-trip degradation in fuel cladding performance is less for this case (SSLBFP) than for Case 2 (SLBFP). At a maximum of 30 minutes the operator, using the appropriate emergency procedure, initiates plant cooldown by manual control of the turbine bypass valves. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

At the point of the minimum transient DNBR no more than 0.4% of the fuel rods are predicted to experience DNB. However, as a bounding assumption, 0.7% of the fuel pins are assumed to fail. All of the activity in the fuel gap for fuel rods that are assumed to fail is assumed to be uniformly mixed with the reactor coolant. The activity in the fuel clad gap is assumed to be 10% of the iodines and 10% of the noble gases accumulated in the fuel at the end of core life, assuming continuous full power operation. This results in a primary coolant activity of 617 μCi/gm. Assuming one gpm steam generator tube leakage, during a period of two hours after initiation of the SSLBFP, the integral leakage from the RCS through the affected steam generator is 720 lbm, which is assumed to be released to the atmosphere with a DF of 1. This mass release results in a contribution to the inhalation thyroid dose at the Exclusion Area Boundary (EAB) of 220 rem.

The total steam released from the affected steam generator is 210,000 lbm. The affected steam generator will empty in two hours; therefore all the mass release from the affected steam generator to the atmosphere has a DF of 1. The calculated inhalation thyroid dose is 9.8 rem for the blowdown originating from the secondary system fluid discharge from the affected steam generator.

Less than 89,000 lbm of steam from the unaffected steam generator will be released trough the steam line break. During the SSLBFP the MSIVs will isolate the unaffected steam generator and prevent it from emptying. Therefore, a DF of 100 is assumed in calculating iodine activity released from the unaffected steam generator. The resulting contribution to the inhalation thyroid dose at the EAB is less than 0.1 rem. Should condensor vacuum be lost during this transient, up to an additional 750,000 lbm of steam from the unaffected steam generator would be released to the atmosphere through the atmospheric steam dump valves. This would result in an additional contribution to the dose of not more than 0.4 rem.

The foregoingg doses are calculated by the methods outlined in Section 15.0.4. Table 15.1.5-11 presents the major assumptions, parameters, and radiological consequences for this transient.

In summary, the total two-hour inhalation thyroid dose at the EAB as a consequence of the SSLBFP is no more than 231 rem.

Case 6: Large Steam Line Break Outside Containment from Zero Power Operation with Loss of Offsite Power (SLBZPLOPD)

Case 6 is included in Case 3, since the break of the latter can be either inside or outside of containment. The Figures, Tables, and Discussion for Case 3 apply to Case 6.

Assuming one gpm steam generator tube leakage, during a period of two hours after initiation of the SLBZPLOPD the integral leakage from the RCS through the affected steam generator is 720 lbm, which is assumed to be released to the atmosphere with a DF of 1. This mass release results in a contribution to the inhalation thyroid doses at the EAB of:

(a) 1.6 rem, assuming technical specification primary coolant activity;
(b) 20.1 rem, assuming a pre-existing iodine spike; or
(c) 41.5 rem, assuming an event-induced iodine spike.

The total steam released from the affected steam generator is 300,000 lbm, which is the total initial mass inventory. The affected steam generator will empty in two hours; therefore all the mass release from the affected steam generator to atmosphere has a DF of 1. The calculated inhalation thyroid dose is 14.0 rem for the blowdown steam originating from the initial steam generator mass inventory.

Less than 850,000 lbm of steam from the unaffected steam generator will be released through the atmospheric steam dump valves and through the steam line break within two hours. During the SLBZPLOPD the MSIVs will isolate the unaffected steam generator and prevent it from emptying. Therefore, a DF of 100 is assumed in calculating iodine activity released from the unaffected steam generator. The resulting contribution to the inhalation thyroid dose at the EAB is 0.4 rem.

The foregoing doses are calculated by the methods outlined in Section 15.0.4. Table 15.1.5-11 presents the major assumptions, parameters, and radiological consequences for this transient.

In summary, the total two-hour inhalation thyroid dose at the EAB as a consequence of the SLBZPLOPD is no more than 56 rem.

15.1.5.4 Conclusion

For the large steam line break in combination with a single failure and stuck CEA, with or without a loss of offsite power, fission power remains sufficiently low following reactor trip to preclude fuel damage as a result of post-trip return to power.

For a large steam line break during zero power operation in combination with a loss of offsite power and technical specification tube leakage the two-hour inhalation thyroid dose at the EAB is well within 10CFR100 guidelines:

(a) 16 rem, assuming technical specification primary coolant activity;
(b) 35 rem, assuming a pre-existing iodine spike; or
(c) 56 rem, assuming an event-induced iodine spike.

The maximum potential for radiological releases due to fuel failure occurs for small steam line breaks outside containment in combination with a stuck CEA. For these cases the maximum potential for degradation in fuel cladding performance occurs prior to and during reactor trip. The fraction of fuel predicted to experience DNB for these events is no more than 0.4%. With the assumption of one gallon per minute steam generator tube leakage and a bounding assumption of 0.7% fuel failure the two-hour inhalation thyroid dose at the EAB is calculated to be no more than 231 rem, which is within the 10 CFR100 guidelines.

Potential fuel failure is sufficiently limited to ensure that the core will remain in place and intact with no loss of core cooling capabilities.

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TABLE 15.1.5-1

SEQUENCE OF EVENTS FOR A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH CONCURRENT LOSS OF OFFSITE POWER (SLBFPLOP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break and Loss of Offsite Power Occur	--
0.6	Low DNBR Trip Condition Occurs, Projected DNBR	1.19
0.75	Trip Breakers Open	--
1.09	CEAs Begin to Drop	--
8.0	Voids Begin to Form in RV Upper Head	--
8.3	Main Steam Isolation Signal, psia	810
13.3	MFIVs Close Completely	--
13.3	MSIVs close completely	--
13.3	EFW Initiated to Intact Steam Generator	--
120	Pressurizer Empties	--
178	Safety Injection Actuation Signal, psia	1600
208	Safety Injection Flow Begins	--
237	Affected Steam Generator Empties	--
259	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	+0.09
277	Minimum Post-Trip DNBR	2.7
280	Safety Injection Boron Begins to Reach Reactor Core	--
1800	Operator Initiates Cooldown	--

TABLE 15.1.5-2

SEQUENCE OF EVENTS FOR A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBFP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
6.95	Low DNBR Trip Condition Occurs, Projected DNBR	1.19
7.10	Trip Breakers Open	--
7.44	CEAs Begin to Drop	--
11.9	Voids Begin to Form in RV Upper Head	--
13.5	Main Steam Isolation Signal, psia	810
18.5	MFIVs Close Completely	--
18.5	MSIVs Close Completely	--
18.5	EFW Initiated to Intact Steam Generator	--
67	Pressurizer Empties	--
90	Safety Injection Actuation Signal, psia	1600
120	Safety Injection Flow Begins	--
149	Affected Steam Generator Empties	--
151	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-0.18
151	Minimum Post-Trip DNBR	26
160	Safety Injection Boron Begins to Reach Reactor Core	--
1800	Operator Initiates Cooldown	--

TABLE 15.1.5-3

SEQUENCE OF EVENTS FOR A LARGE STEAM LINE BREAK DURING ZERO POWER OPERATION WITH CONCURRENT LOSS OF OFFSITE POWER (SLBZPLOP AND SLBZPLOPD)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break and Loss of Offsite Power Occur	--
0.6	Low DNBR Trip Condition Occurs, Projected DNBR	1.19
0.75	Trip Breakers Open	--
1.09	CEAs Begin to Drop	--
5.7	Main Steam Isolation Signal, psia	810
10.7	MFIVs Close Completely	--
10.7	MSIVs Close Completety	--
10.7	EFW Initiated to Intact Steam Generator	--
45	Safety Injection Actuation Signal, psia	1600
55	Voids Begin to Form in RV Upper Head	--
59	Pressurizer Empties	
75	Safety Injection Flow Begins	--
120	Safety Injection Boron Begins to Reach Reactor core	--
189	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-0.06
1240	Affected Steam Generator Empties	--
1800	Operator Initiates Cooldown	--

TABLE 15.1.5-4

SEQUENCE OF EVENTS FOR A LARGE STEAM LINE BREAK DURING ZERO POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBZP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
6.24	Low Steam Generator Pressure Trip and Main Steam Isolation Signal, psia	810
6.79	Trip Breakers Open	--
7.13	CEAs Begin to Drop	--
11.3	MFIVs Close Completely	--
11.3	MSIVs Close Completely	--
11.3	EFW Initiated to Intact Steam Generator	--
41	Safety Injection Actuation Signal, psia	1600
48	Voids Begin to Form in RV Upper Head	--
52	Pressurizer Empties	--
71	Safety Injection Flow Begins	
110	Safety Injection Boron Begins to Reach Reactor Core	--
310	Maximum Transient Reactivity, $10^{-2}\ \Delta\rho$	-0.02
418	Affected Steam Generator Empties	--
1800	Operator Initiates Cooldown	--

TABLE 15.1.5-5

SEQUENCE OF EVENTS FOR A SMALL STEAM LINE BREAK OUTSIDE CONTAINMENT DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SSLBFP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
28.4	Low DNBR Trip Condition Occurs, Projected DNBR	1.19
28.55	Trip Breakers Open	--
28.89	CEAs Begin to Drop	--
29	Minimum Transient DNBR	1.10
60	Voids Begin to Form in RV Upper Head	--
84	Main Steam Isolation Signal, psia	810
89	MFIVs Close Completely	--
89	MSIVs Close Completely	--
1800	Operator Initiates Cooldown	--

TABLE 5.1.5-6

ASSUMPTIONS AND INITIAL CONDITIONS FOR A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH CONCURRENT LOSS OF OFFSITE POWER (SLBFPLOP)

Parameter	Assumed Value
Initial Core Power Level, MWt	3876
Initial Core Inlet Coolant Temperature, F	570
Initial Core Mass Flow Rate, 10^6 lbm/hr	148.8
Initial Pressurizer Pressure, psia	2400
Initial Pressurizer Water Volume, ft^3	1100
Doppler Coefficient Multiplier	1.15
Moderator Coefficient Multiplier	1.10
Axial Shape Index	+.3
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-8.8
Initial Steam Generator Inventory, lbm, affected intact	182000 148000
One High Pressure Safety Injection Pump	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

TABLE 15.1.5-7

ASSUMPTIONS AND INITIAL CONDITIONS FOR A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBFP)

Parameter	Assumed Value
Initial Core Power Level, MWt	3876
Initial Core Inlet Coolant Temperature, F	570
Initial Core Mass Flow Rate, 10^6 lbm/hr	148.8
Initial Pressurizer Pressure, psia	2400
Initial Pressurizer Water Volume, ft^3	1100
Doppler Coefficient Multiplier	1.15
Moderator Coefficient Multiplier	1.10
Axial Shape Index	+.3
CEA Worth for Trip, $10^{-2}\ \Delta\rho$	-8.8
Initial Steam Generator Inventory, lbm, affected intact	182000 148000
One Main Steam Isolation Valve on Intact Steam Generator	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

TABLE 15.1.5-8

ASSUMPTIONS AND INITIAL CONDITIONS FOR A LARGE STEAM LINE BREAK DURING ZERO POWER OPERATION WITH CONCURRENT LOSS OF OFFSITE POWER (SLBZPLOP AND SLBZPLOPD)

Parameters	Assumed Value
Initial Core Power Level, MWt	10
Initial Core Inlet Coolant Temperature, F	575
Initial Core Mass Flow Rate, 10^6 lbm/hr	147.6
Initial Pressurizer Pressure, psia	2400
Initial Pressurizer Water Volume, ft^3	1100
Doppler Coefficient Multiplier	1.15
Moderator Coefficient Multiplier	1.10
Axial Shape Index	+.3
CEA Worth for Trip, $10^{-2}\Delta\rho$	-6.0
Initial Steam Generator Inventory, lbm, affected	279000
intact	143000
One High Pressure Safety Injection Pump	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

TABLE 15.1.5-9

ASSUMPTIONS AND INITIAL CONDITIONS FOR A LARGE STEAM LINE BREAK DURING ZERO POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBZP)

Parameter	Assumed Value
Initial Core Power Level, MWt	10
Initial Core Inlet Coolant Temperature, F	575
Initial Core Mass Flow Rate, 10^6 lbm/hr	147.6
Initial Pressurizer Pressure, psia	2400
Initial Pressurizer Water Volume, ft^3	1100
Doppler Coefficient Multiplier	1.15
Moderator Coefficient Multiplier	1.10
Axial Shape Index	+.3
CEA Worth for Trip, $10^{-2}\ \Delta\rho$	-6.0
Initial Steam Generator Inventory, lbm, affected intact	279000 163000
One High Pressure Safety Injection Pump	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283

TABLE 15.1.5-10

ASSUMPTIONS AND INITIAL CONDITIONS FOR A SMALL LINE BREAK OUTSIDE CONTAINMENT DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SSLBFP)

Parameter	Assumptions
Initial Core Power Level, MWt	3876
Initial Core Inlet Coolant Temperature, F	570
Initial Core Mass Flow Rate, 10^6 lbm/hr	148.4
Initial Pressurizer Pressure, psia	2250
Initial Pressurizer Water Volume, ft^3	1100
Doppler Coefficient Multiplier	1.15
Moderate Coefficient Multiplier	1.10
Axial Shape Index	-0.359
Radial Peaking Factor, F_R	1.4
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-8.8
Initial Steam Generator Inventory, lbm, affected	182000
intact	148000
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown area for each steam line, ft^2	1

TABLE 15.1.5-11
(Sheet 1 of 3)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES
OF STEAM LINE BREAKS OUTSIDE CONTAINMENT
UPSTREAM OF MSIV

Parameter	Value SSLBFP (Case 5)	Value SLBZPLOPD (Case 6)
A. Data and Assumptions Used to Evaluate the Radioactive Source Term		
a. Power Level, Mwt	3876	10
b. Burnup, years	2	2
c. Percent of Fuel Assumed to Experience DNB, %	0.7	0
d. Reactor Coolant Activity Before Event (based on 3876 MWt), μCi/gm	4.6 Table 11.1.1-2	4.6* Table 11.1.1-2
e. Secondary System Activity Before Event	Section 15.0.4	Section 15.0.4
f. Primary System Liquid Inventory, lbm	525,600	525,600
g. Steam Generator Inventory, lbm		
- Affected Steam Generator	182,000	300,000
- Intact Steam Generator	148,000	143,000
B. Data and Assumptions Used to Estimate Activity Released from the Secondary System		
a. Primary to Secondary Leak Rate, gpm	1.0 (total)	1.0 (total)
b. Total Mass Release from the Affected Steam Generator	210,000	300,000

*Except for case assuming pre-existing iodine spike (see footnote on next page).

TABLE 15.1.5-11 (Cont'd.) (Sheet 2 of 3)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A STEAM LINE BREAKS OUTSIDE CONTAINMENT UPSTREAM OF MSIV

Parameters		Value SSLBAP (Case 5)	Value SLBZPLOPD (Case 6)
c.	Total Mass Release from the Intact Steam Generator	840,000	850,000
d.	Reactor Coolant System Activity After Event, Ci		
	Isotope		
	I-131	8.568(+4)*	
	I-132	1.217(+5)	
	I-133	1.605(+5)	
	I-134	1.680(+5)	
	I-135	1.469(+5)	
	Kr-85M	1.421(+4)	**
	Kr-85	3.903(+2)	
	Kr-87	2.400(+4)	
	Kr-88	3.475(+4)	
	Xe-131M	6.018(+2)	
	Xe-133	1.618(+5)	
	Xe-135	9.724(+4)	
	Xe-138	2.557(+4)	
e.	Percent of Core Fission Products Assumed Released to Reactor Coolant	10	**
f.	Iodine Decontamination Factor in the Affected Steam Generator	1.0	1.0
g.	Iodine Decontamination Factor in the Intact Steam Generator	100	100
h.	Credit for Radioactive Decay in Transit to Dose Point	No	No
i.	Loss of Offsite Power	No	Yes

*Numbers in parenthesis refer to the power of ten; e.g. 8.568(+4)=8.568×10^4

**Three sub-cases are presented

sub-case	RCS activity after event, μCi/gm
a) technical specification activity	4.6
b) pre-existing iodine spike	60
c) event-induced iodine spike	124

TABLE 15.1.5-11 (Cont'd.) (Sheet 3 of 3)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A STEAM LINE BREAKS OUTSIDE CONTAINMENT UPSTREAM OF MSIV

	Parameter	Value SSLBFP (Case 5)	Value SLBZPLOPD (Case 6)
C.	Dispersion Data		
1.	Distance to Exclusion Area Boundary, m	500	500
2.	Distance to Low Population Zone Outer Boundary, m	3000	3000
3.	Atmospheric Dispersion Factor, sec/m^3	2.00×10^{-3}	2.00×10^{-3}
D.	Dose Data		
1.	Method of Dose Calculation	Section 15.0.4	Section 15.0.4
2.	Dose Conversion Assumptions	Section 15.0.4	Section 15.0.4
3.	Control Room Design Parameters	See Applicant's SAR	See Applicant's SAR

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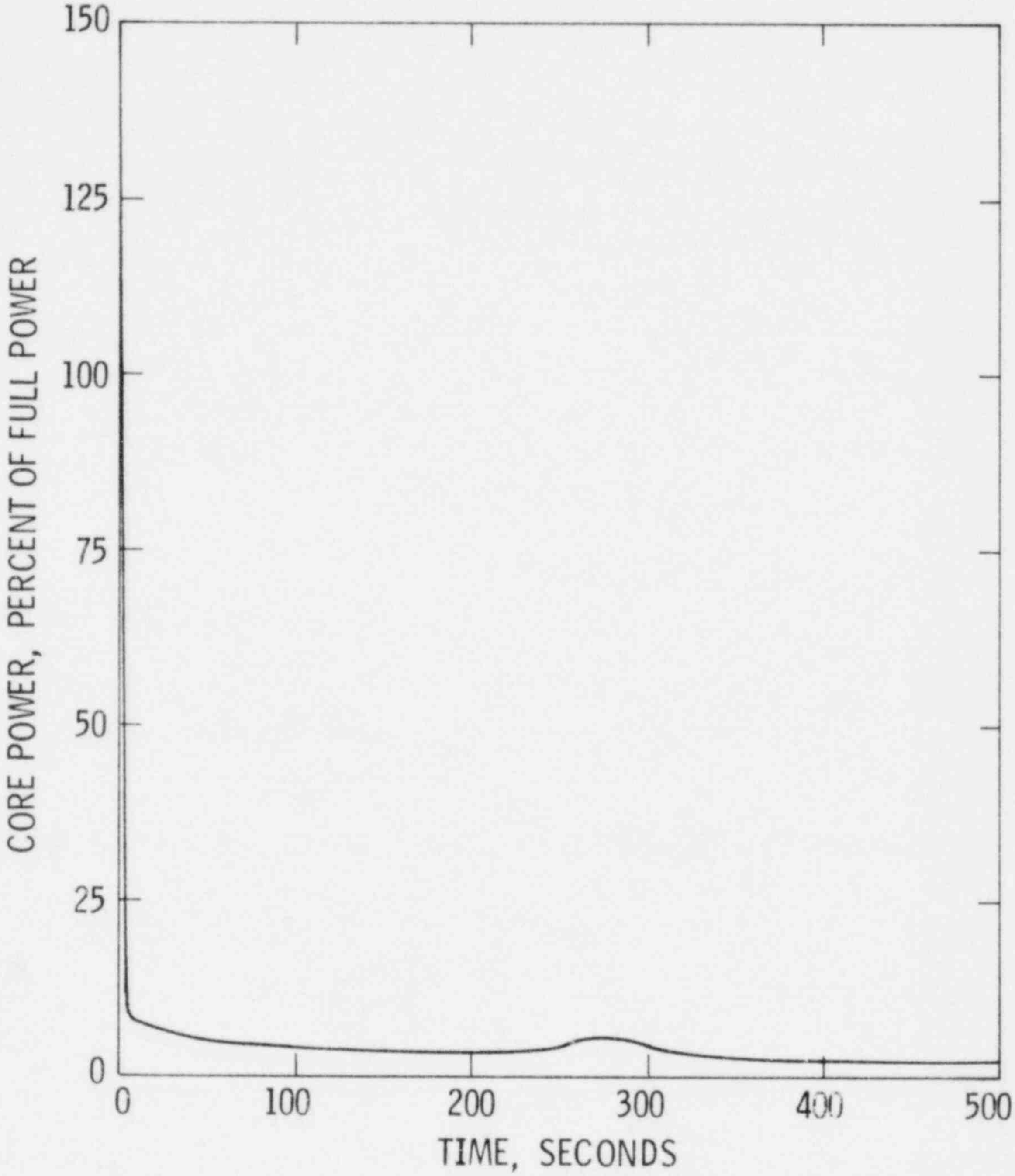
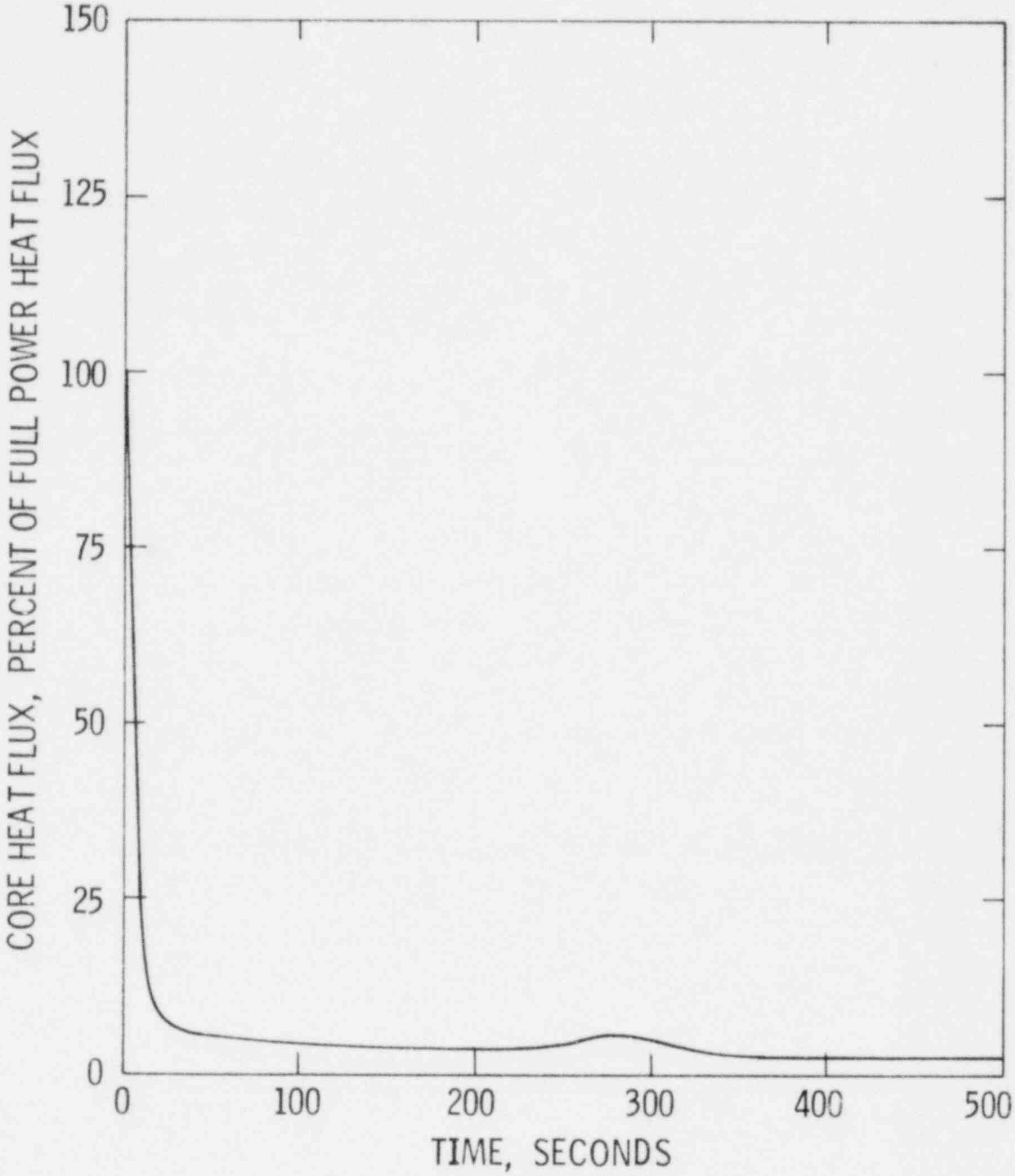
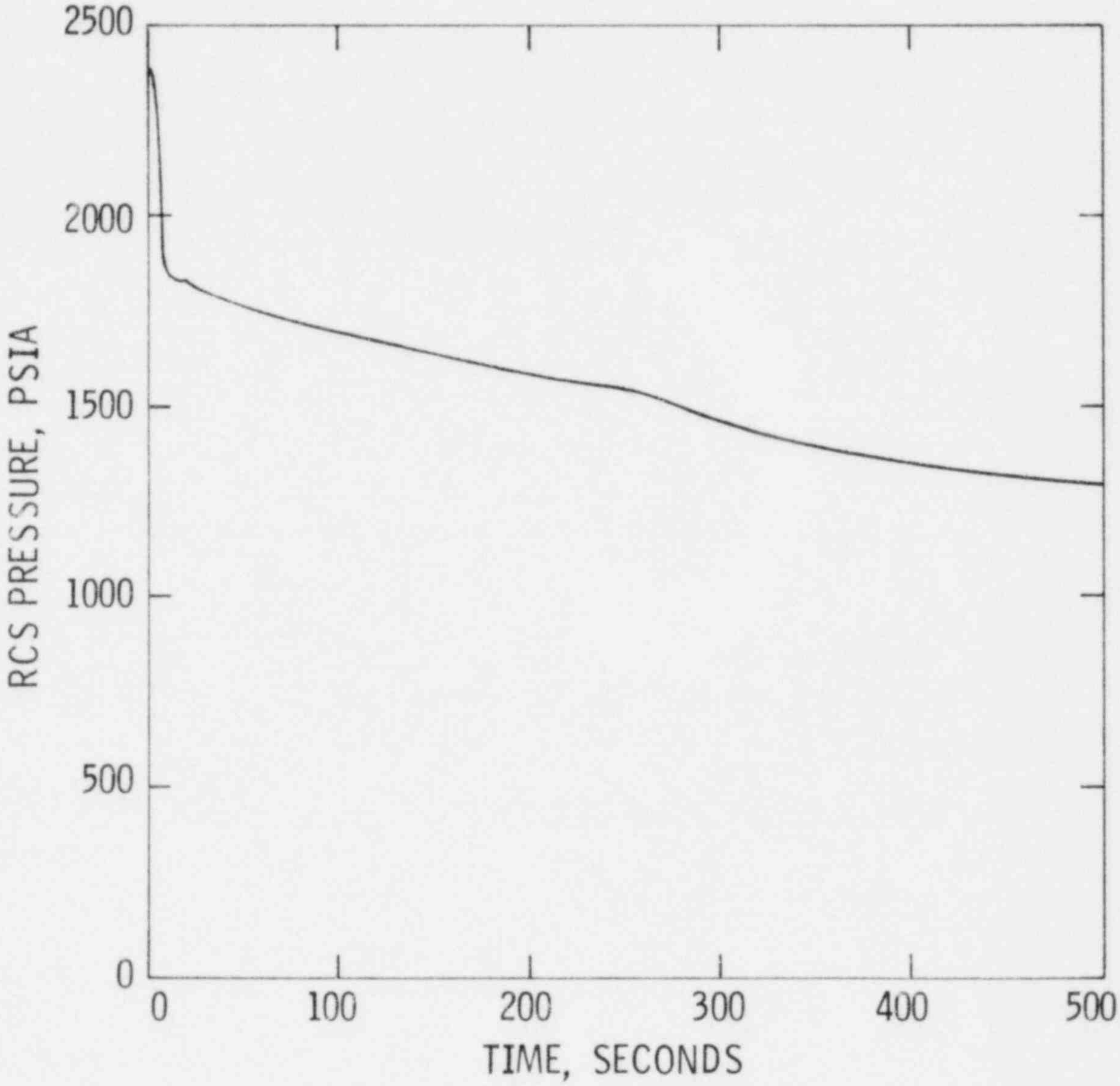


Amendment No. 7
March 31, 1982

C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER CORE POWER vs TIME	Figure 15.1.5-1.1

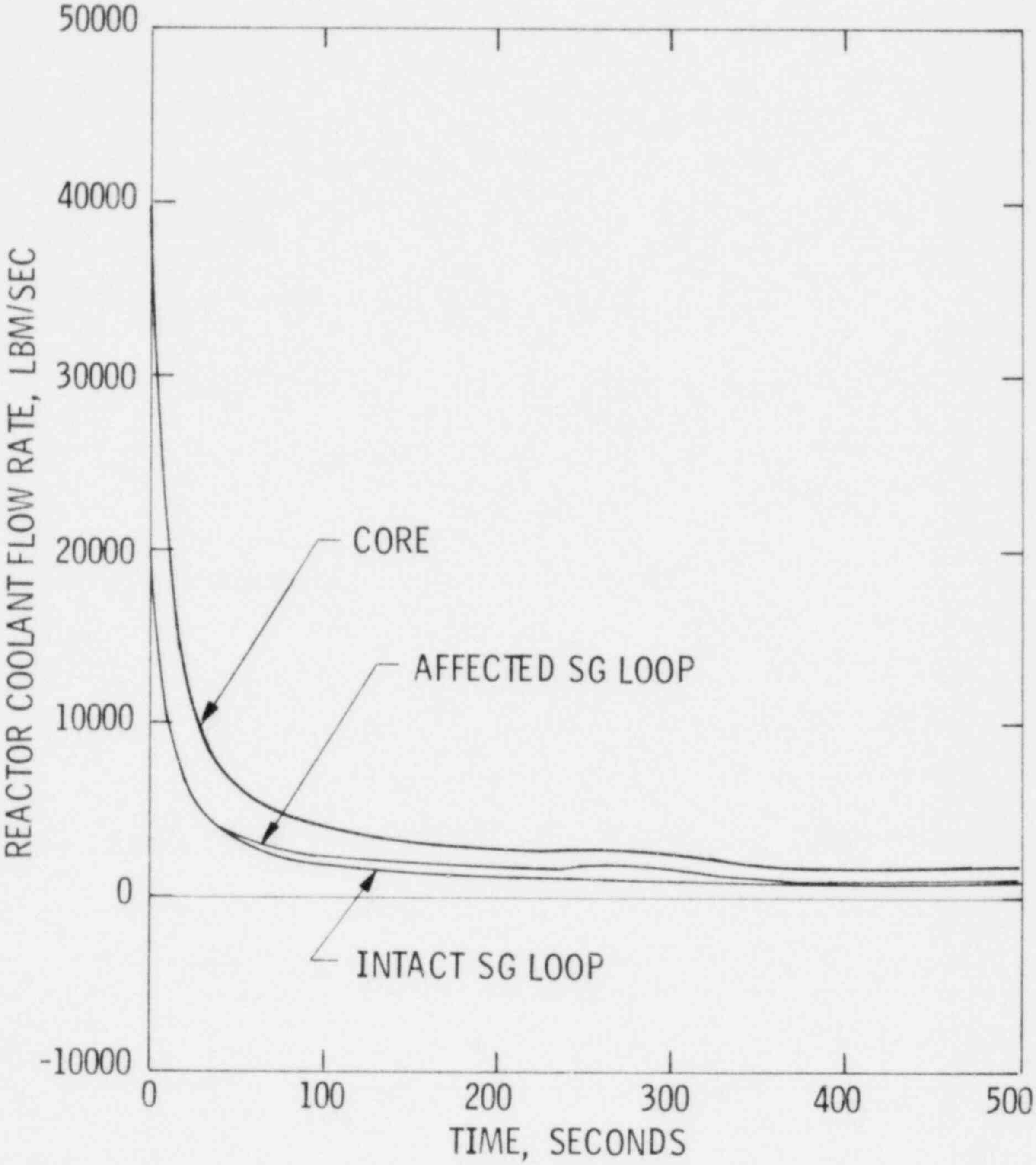


C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER CORE HEAT FLUX vs TIME	Figure 15.1.5-1.2



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER RCS PRESSURE vs TIME	Figure 15.1.5-1.3



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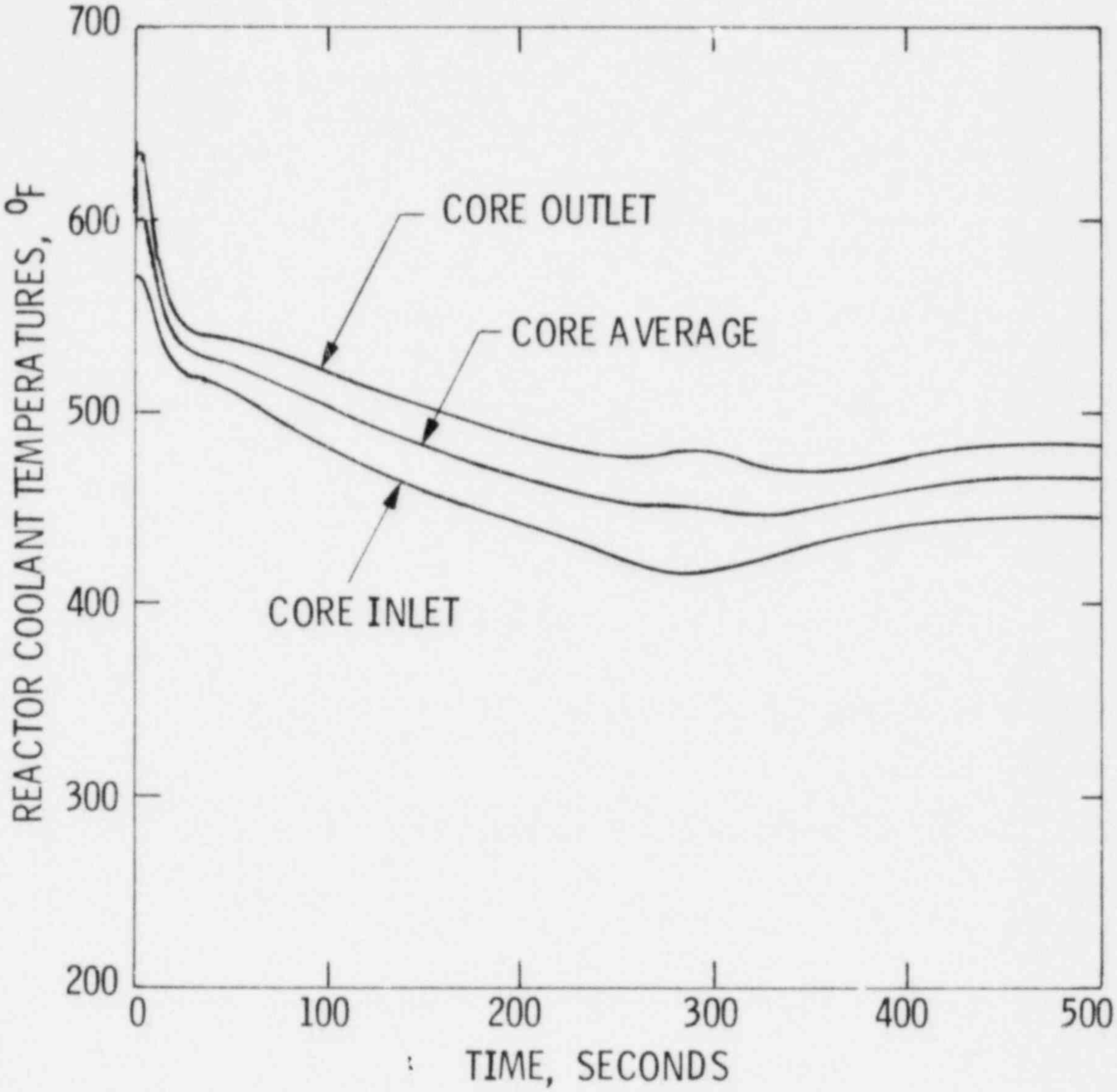
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR COOLANT FLOW RATE vs TIME	Figure 15.1.5-1.4



Amendment No. 7
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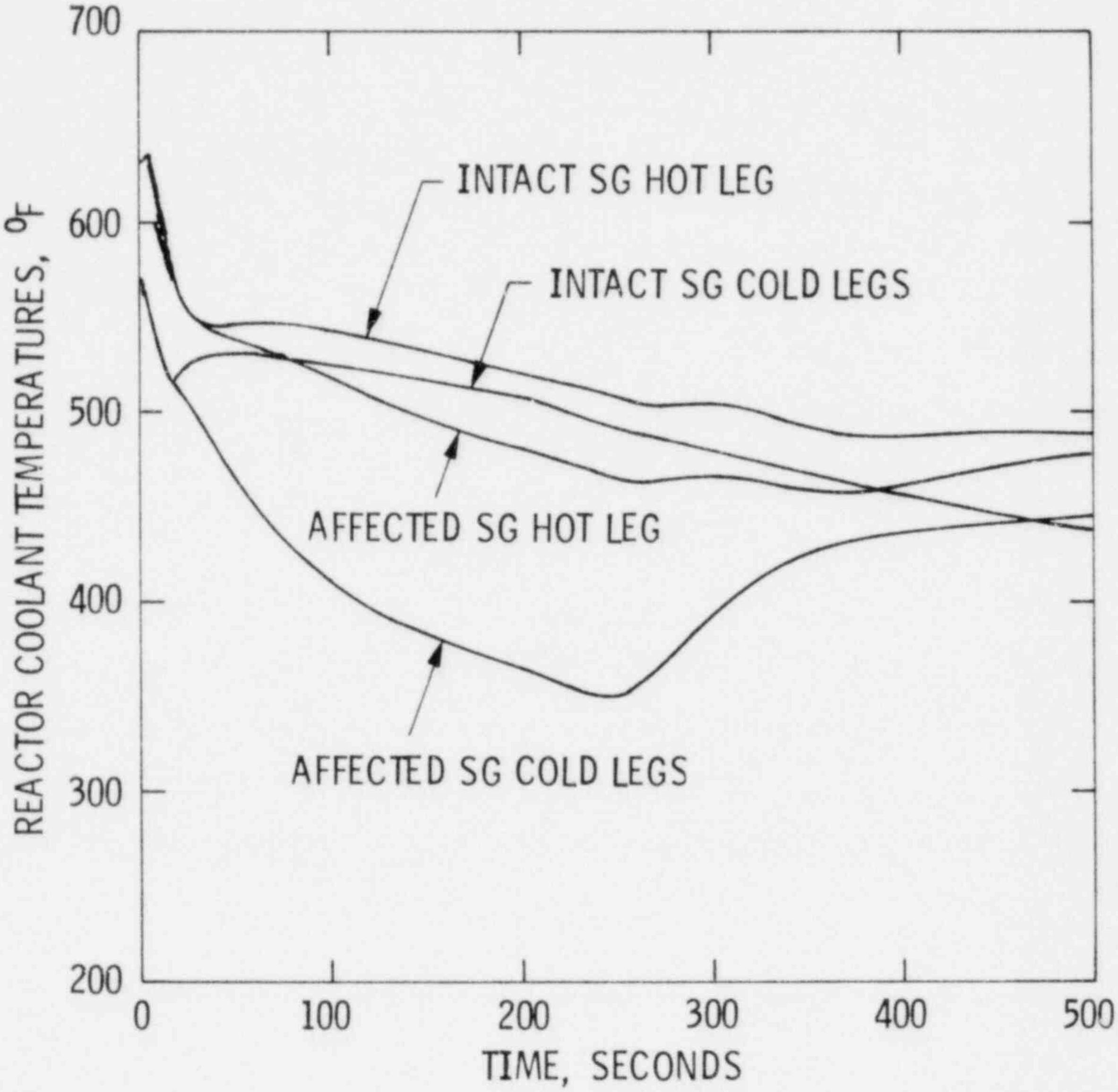
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR COOLANT TEMPERATURES (A) vs TIME	Figure 15.1.5-1.5A



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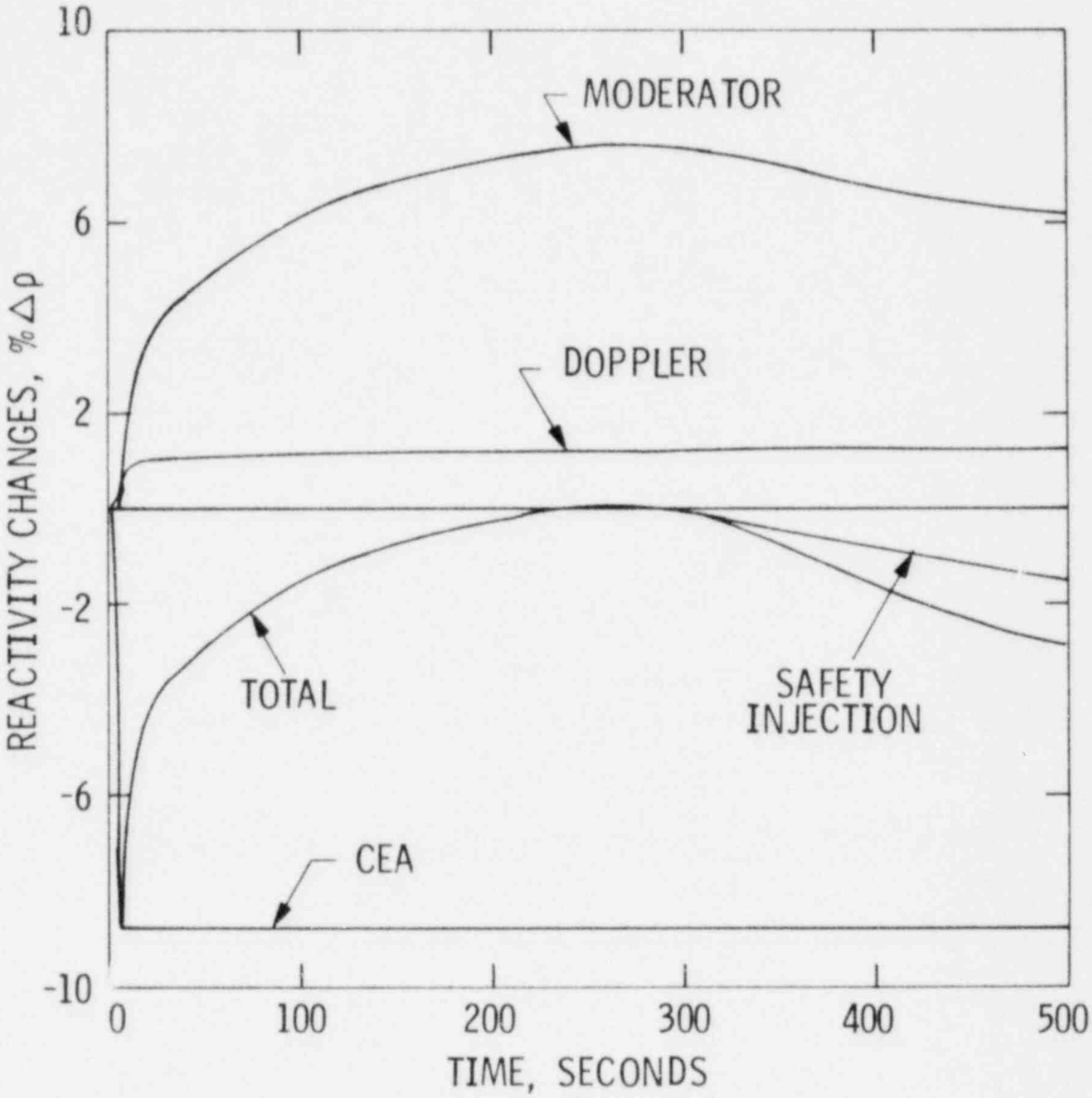
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR COOLANT TEMPERATURES (B) vs TIME	Figure 15.1.5-1.5B



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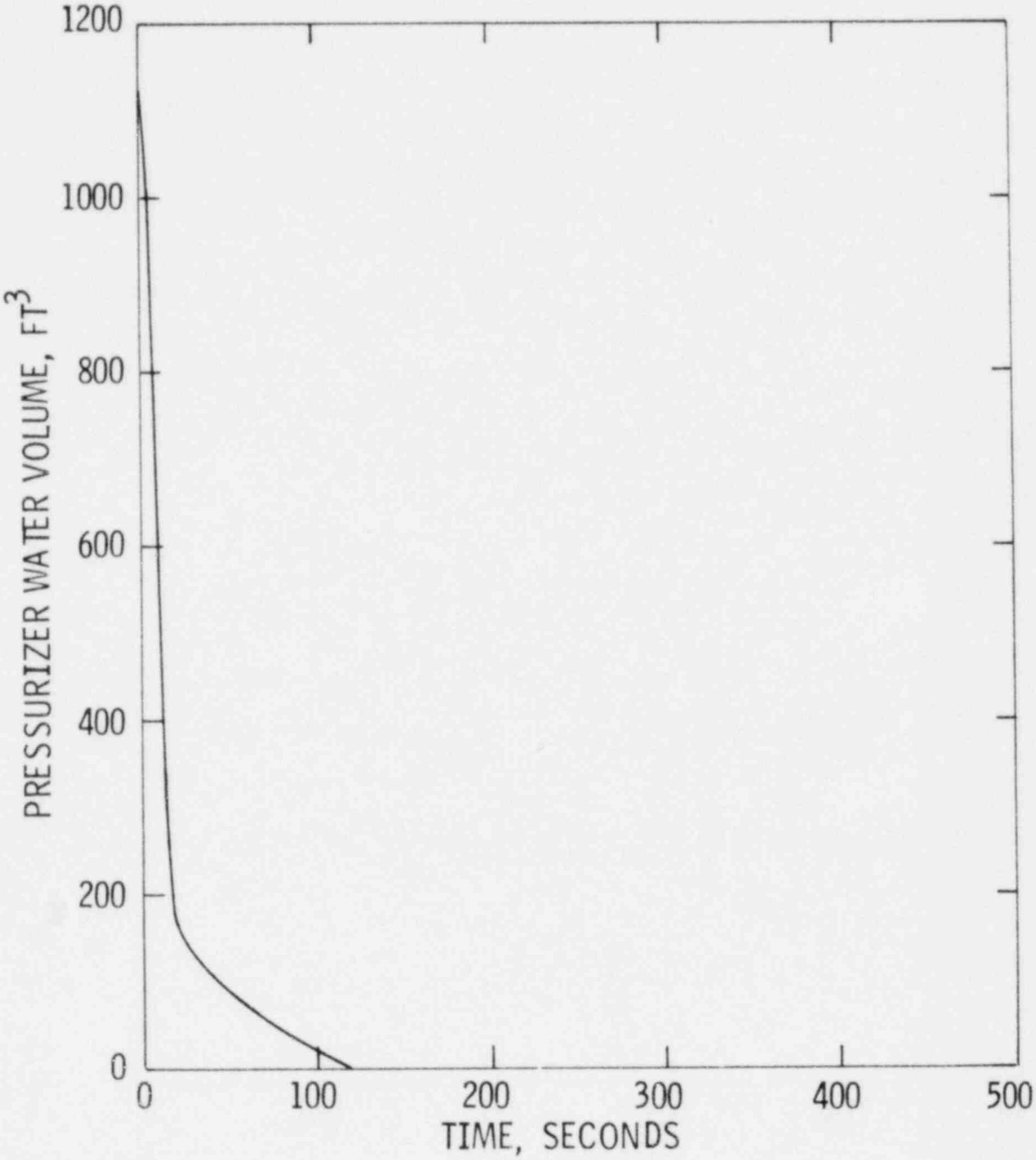
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTIVITY CHANGES vs TIME	Figure 15.1.5-1.6



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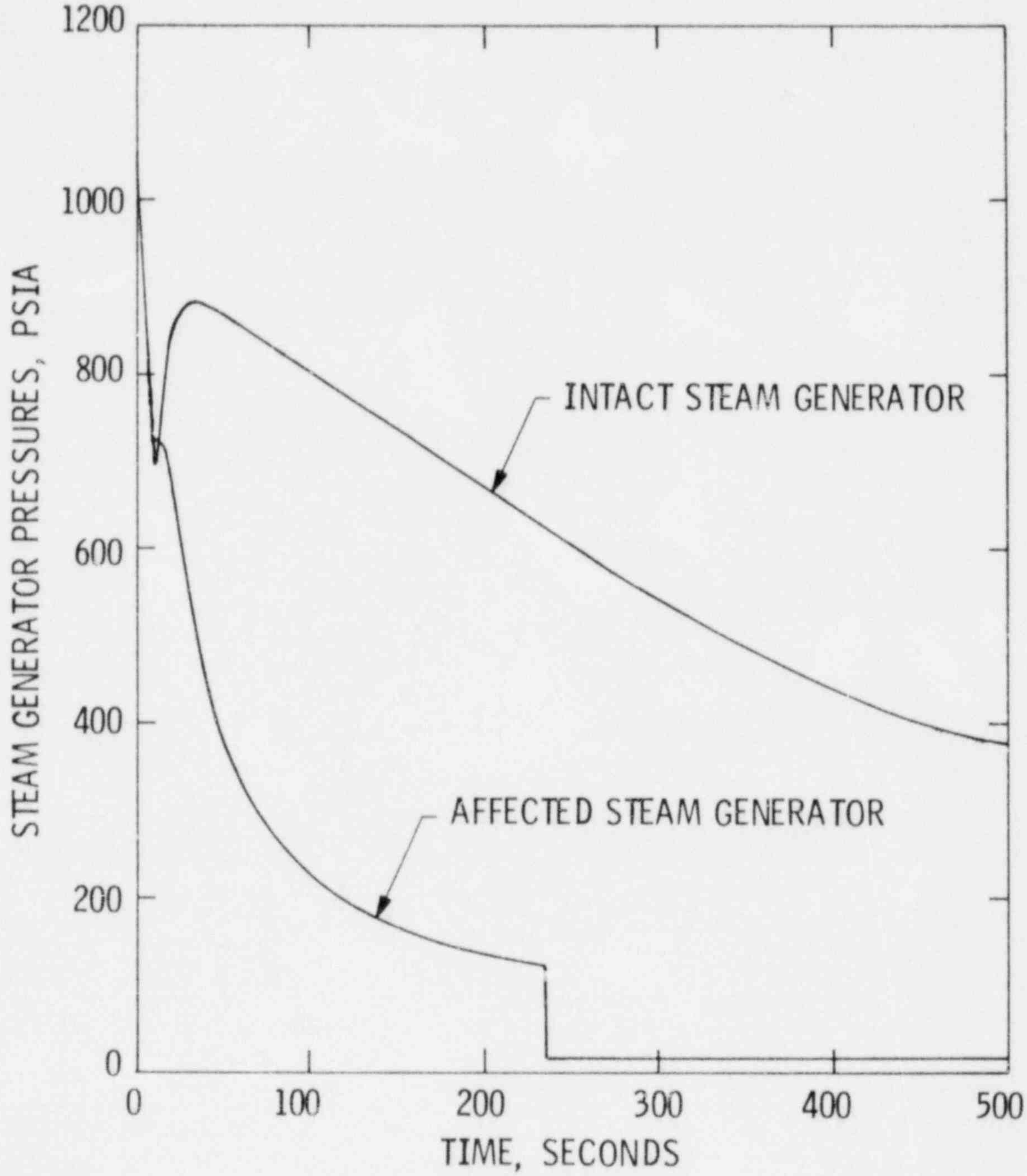
C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER PRESSURIZER WATER VOLUME vs TIME	Figure 15.1.5-1.7



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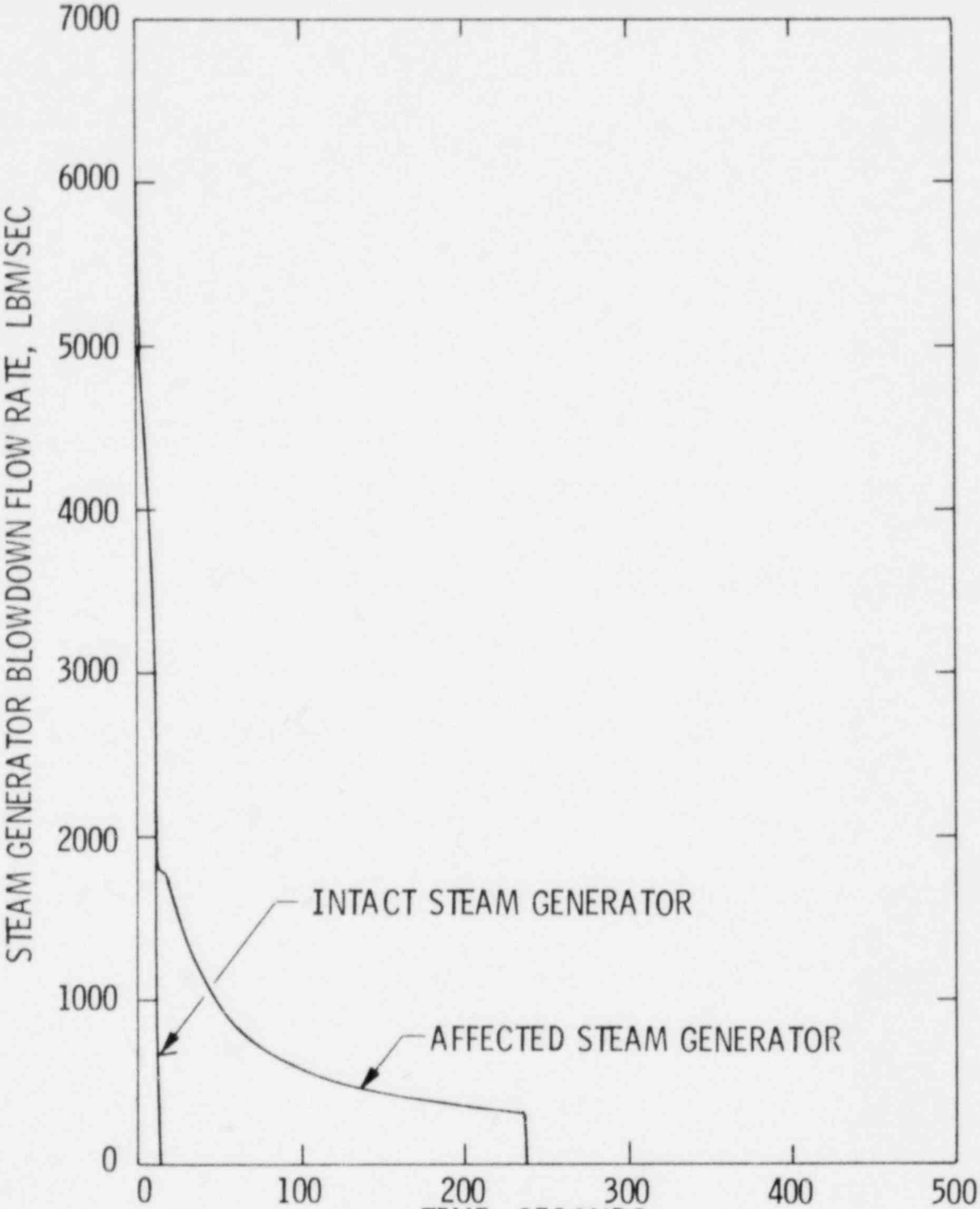
C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER STEAM GENERATOR PRESSURES vs TIME	Figure 15.1.5-1.8



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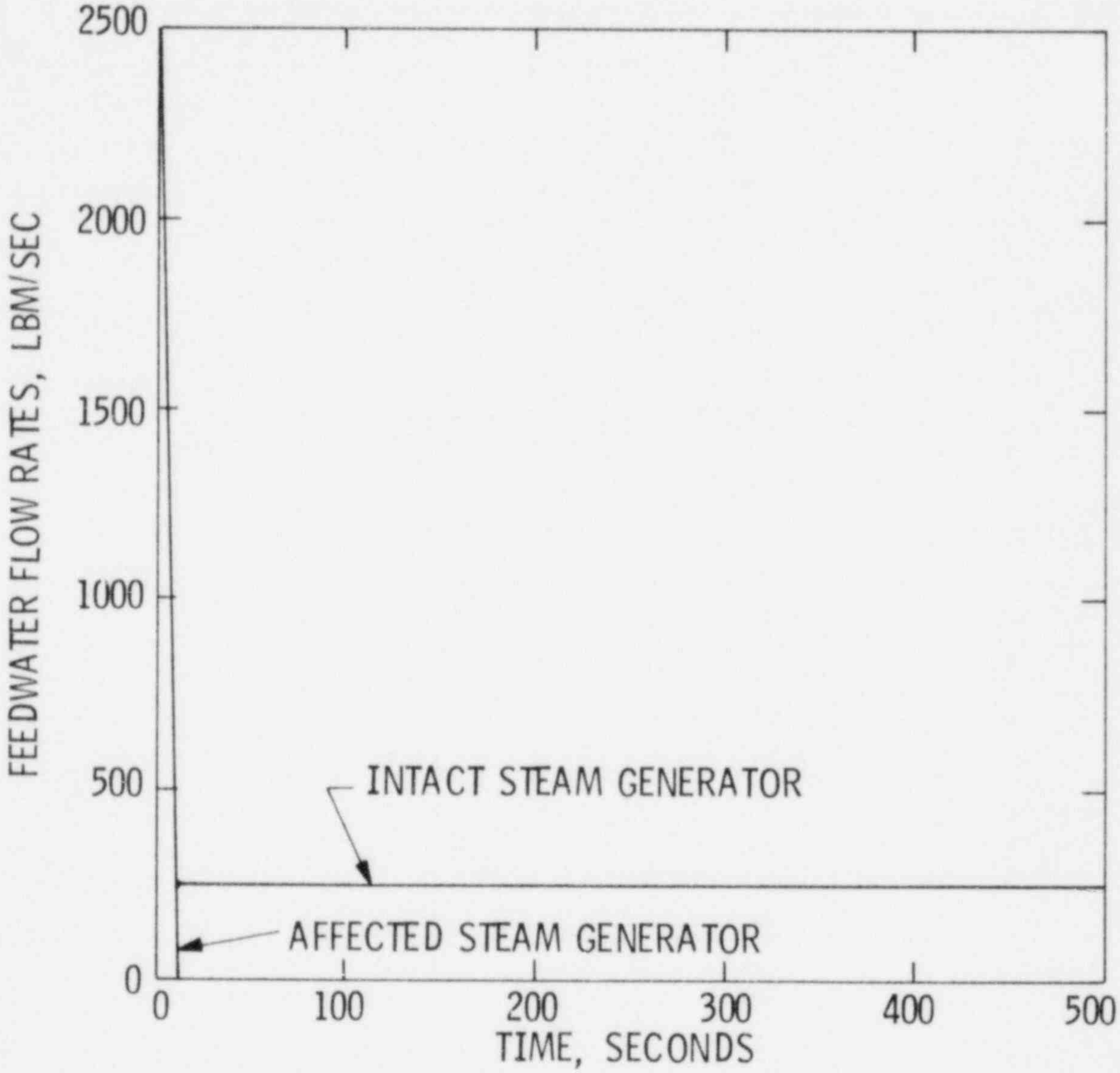
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER STEAM GENERATOR BLOWDOWN RATES vs TIME	Figure 15.1.5-1.9



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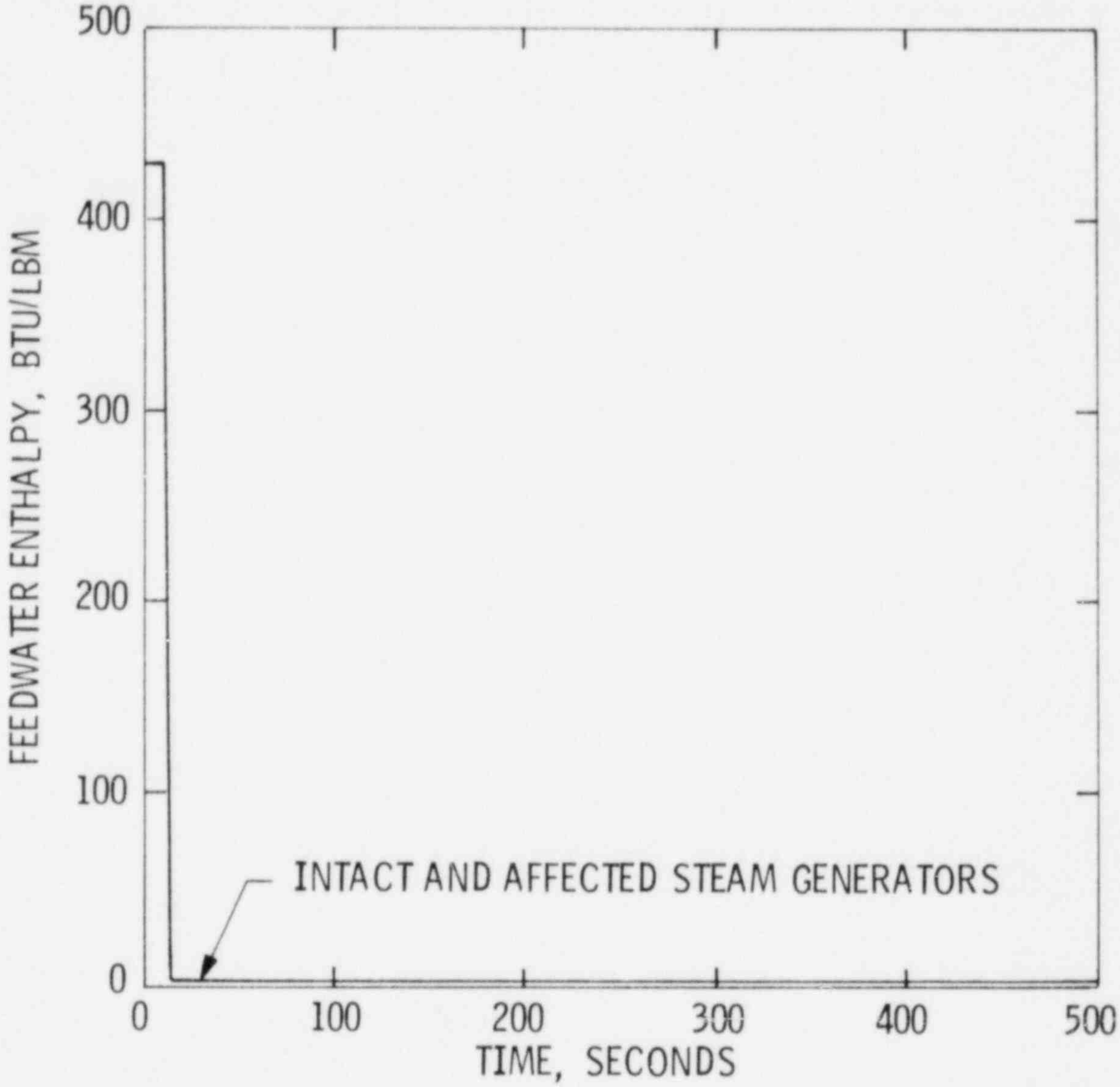
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER FEEDWATER FLOW RATES vs TIME	Figure 15.1.5-1.10



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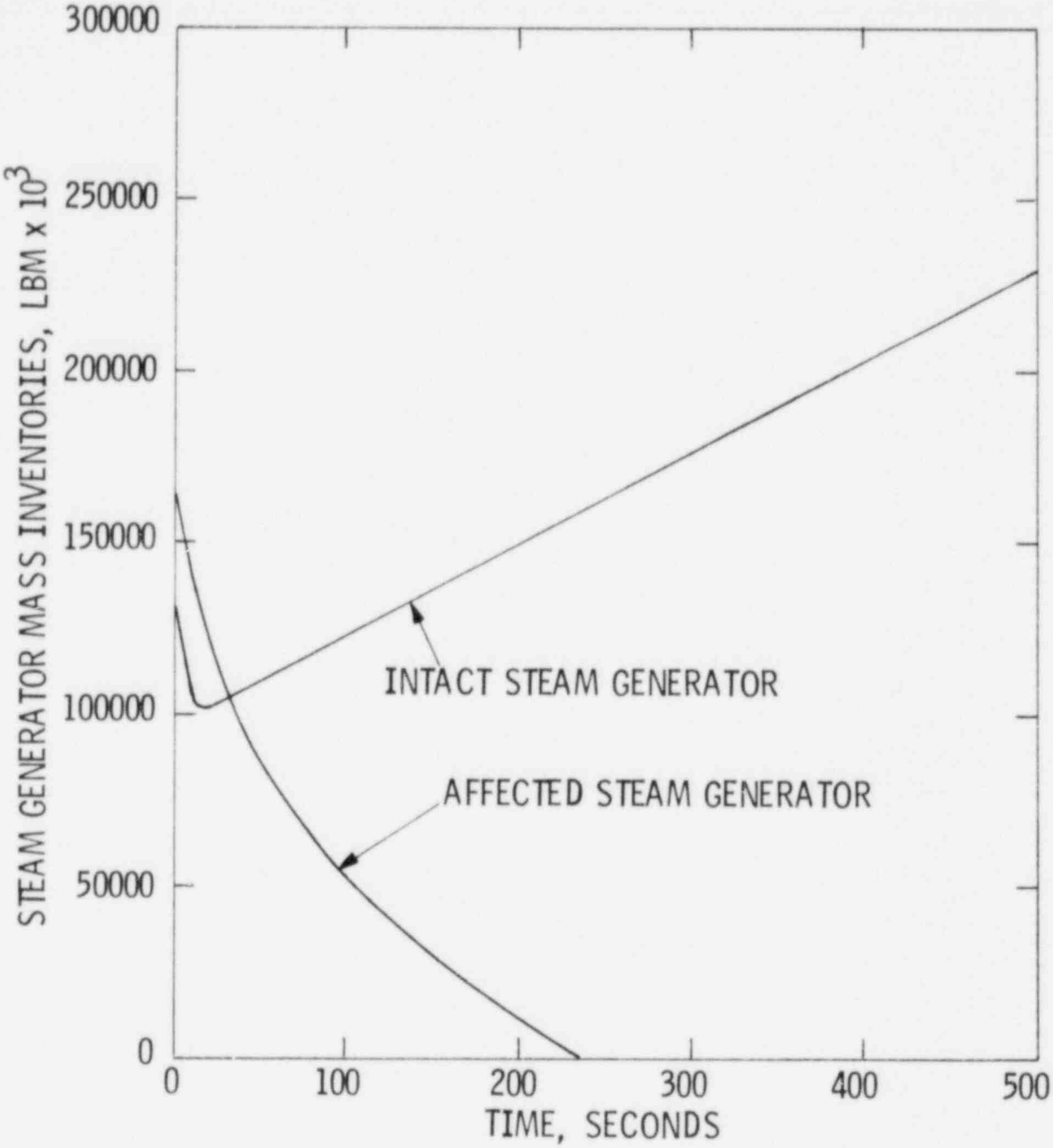
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE BREAK FEEDWATER ENTHALPY vs TIME	Figure 15.1.5-1.11



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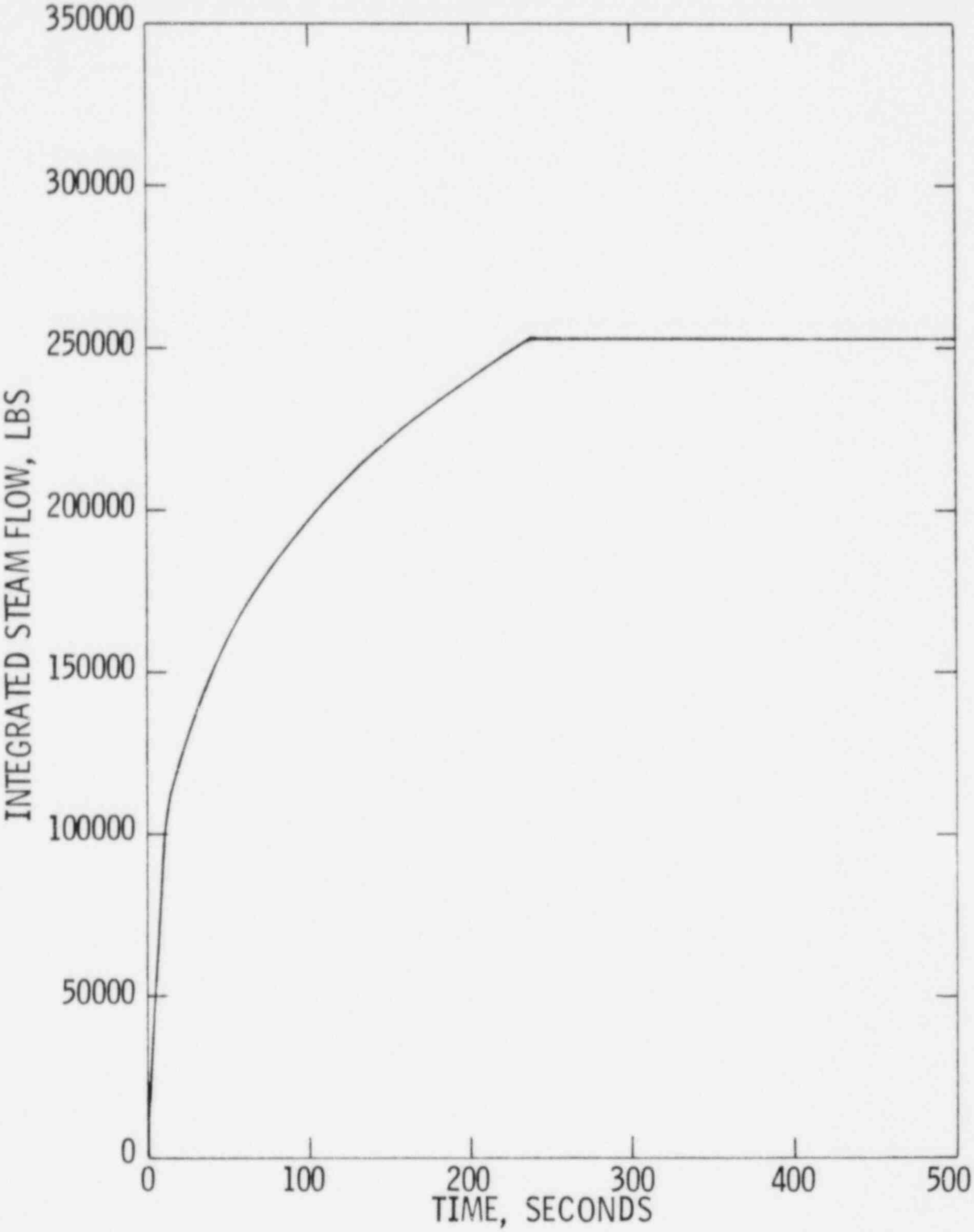
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER STEAM GENERATOR MASS INVENTORIES vs TIME	Figure 15.1.5-1.12



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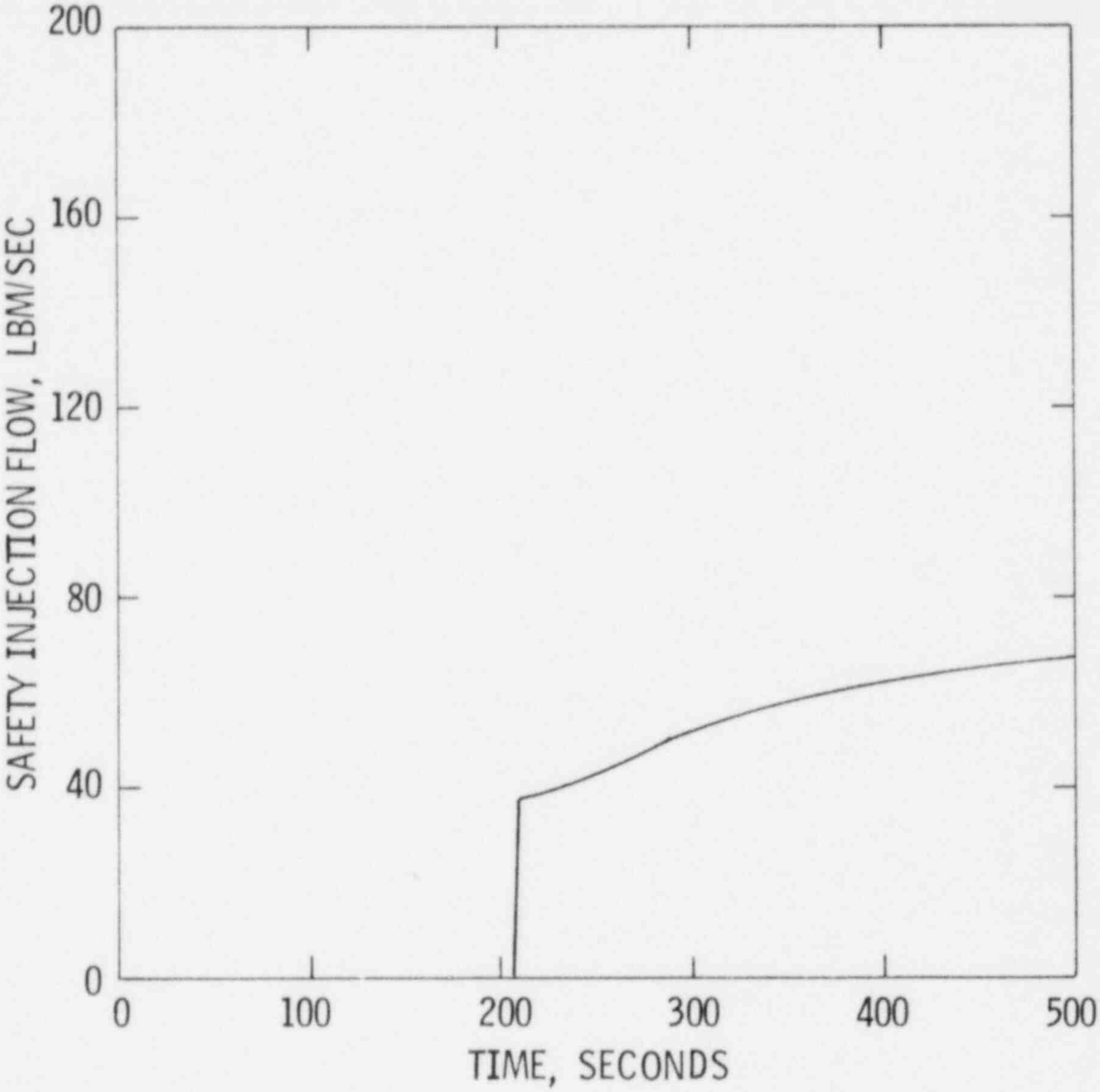
C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER INTEGRATED STM MASS RELEASE THRU BREAK vs TIME	Figure 15.1.5-1.13



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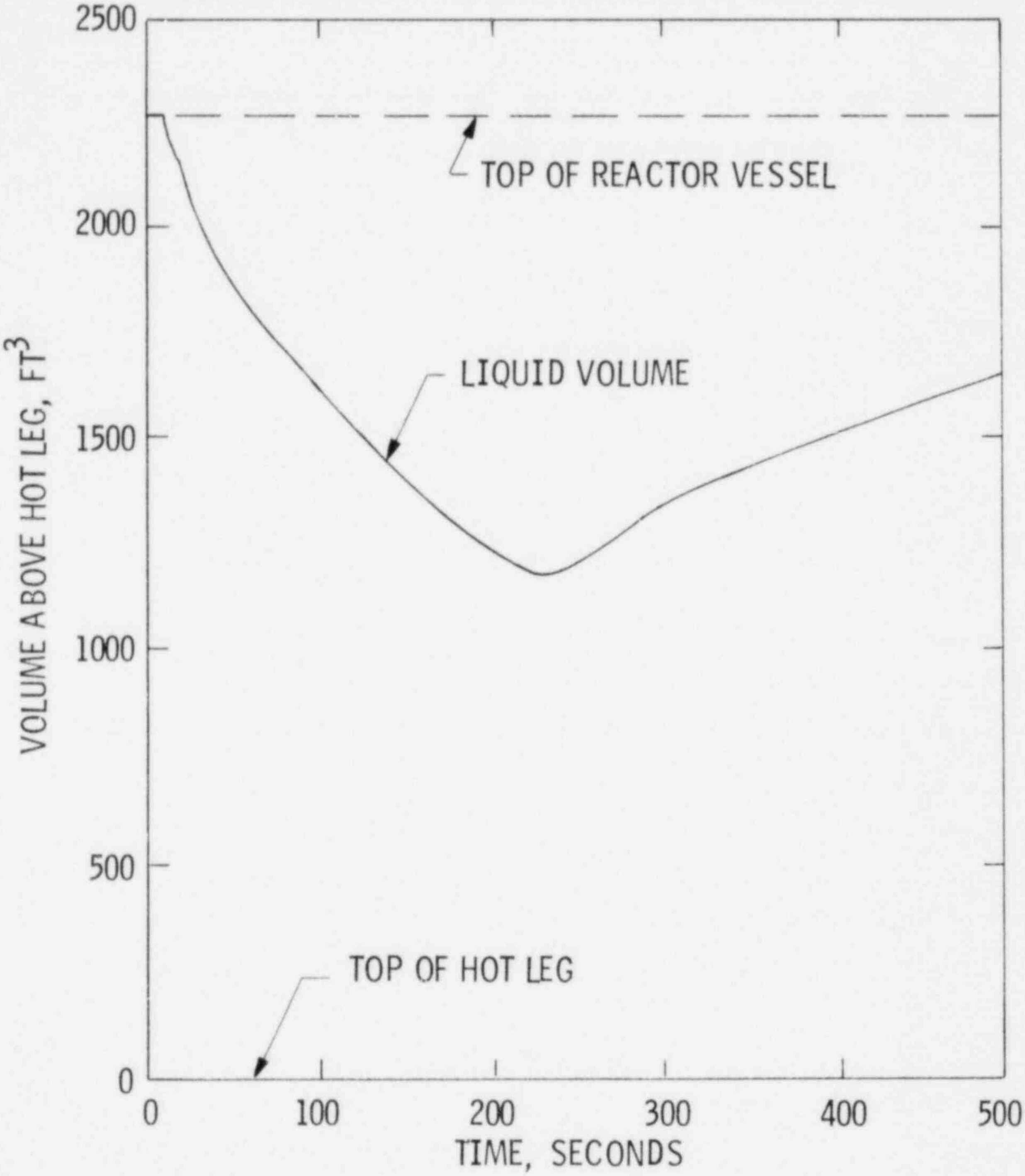
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER SAFETY INJECTION FLOW vs TIME	Figure 15.1.5-1.14



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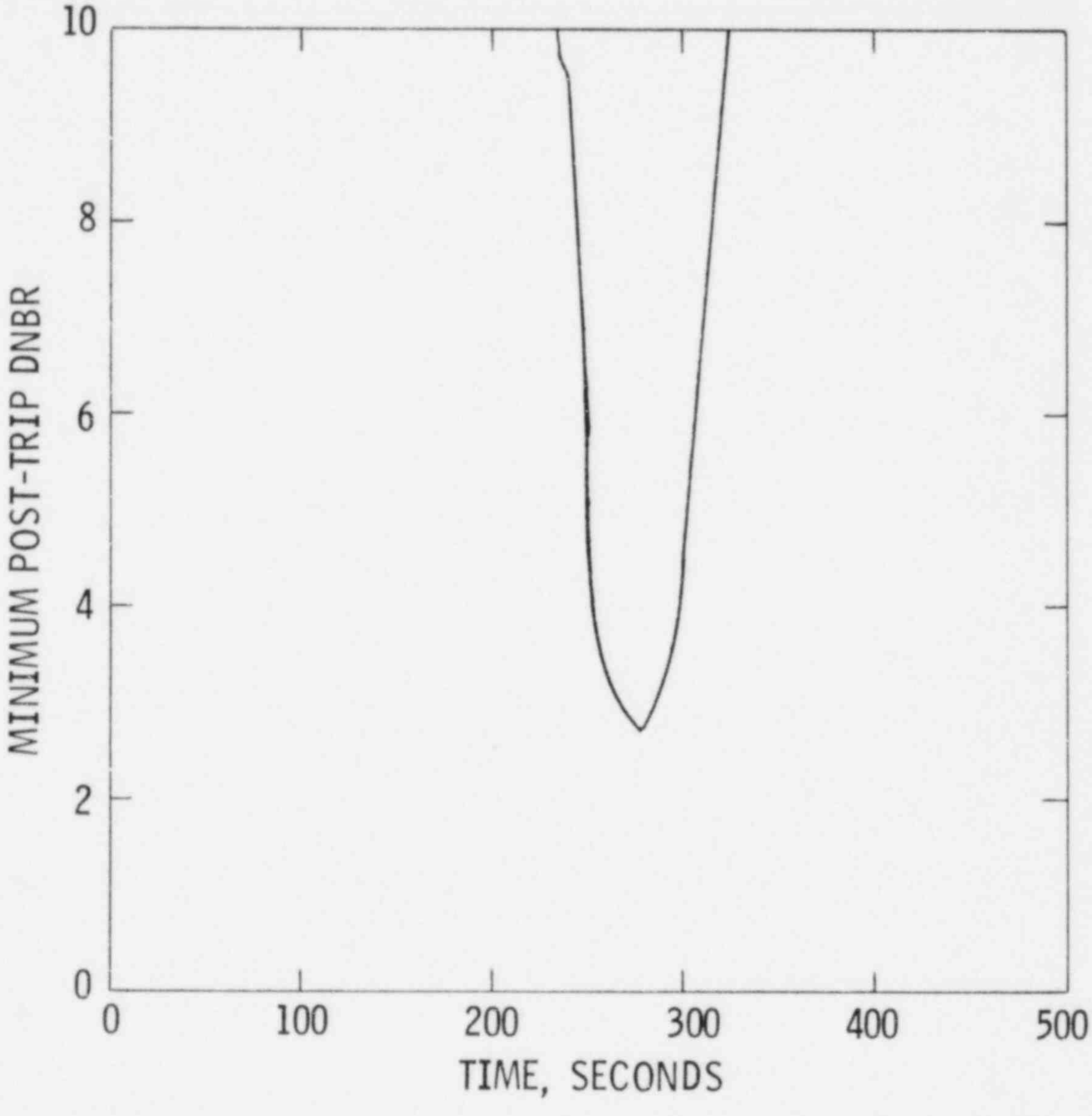
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR VESSEL LIQUID VOLUME vs TIME	Figure 15.1.5-1.15



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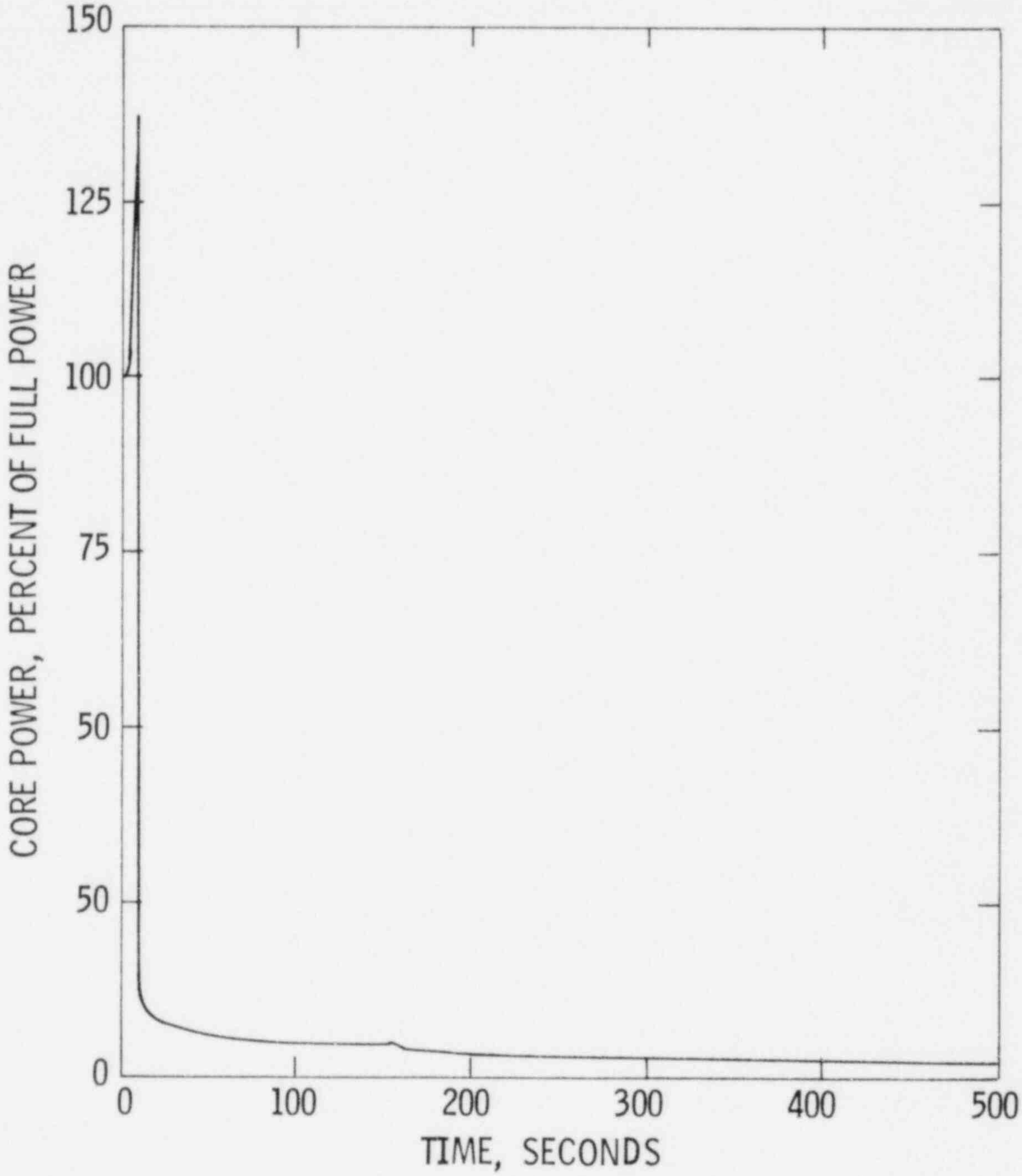
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER MINIMUM POST-TRIP DNBR vs TIME	Figure 15.1.5-1.16



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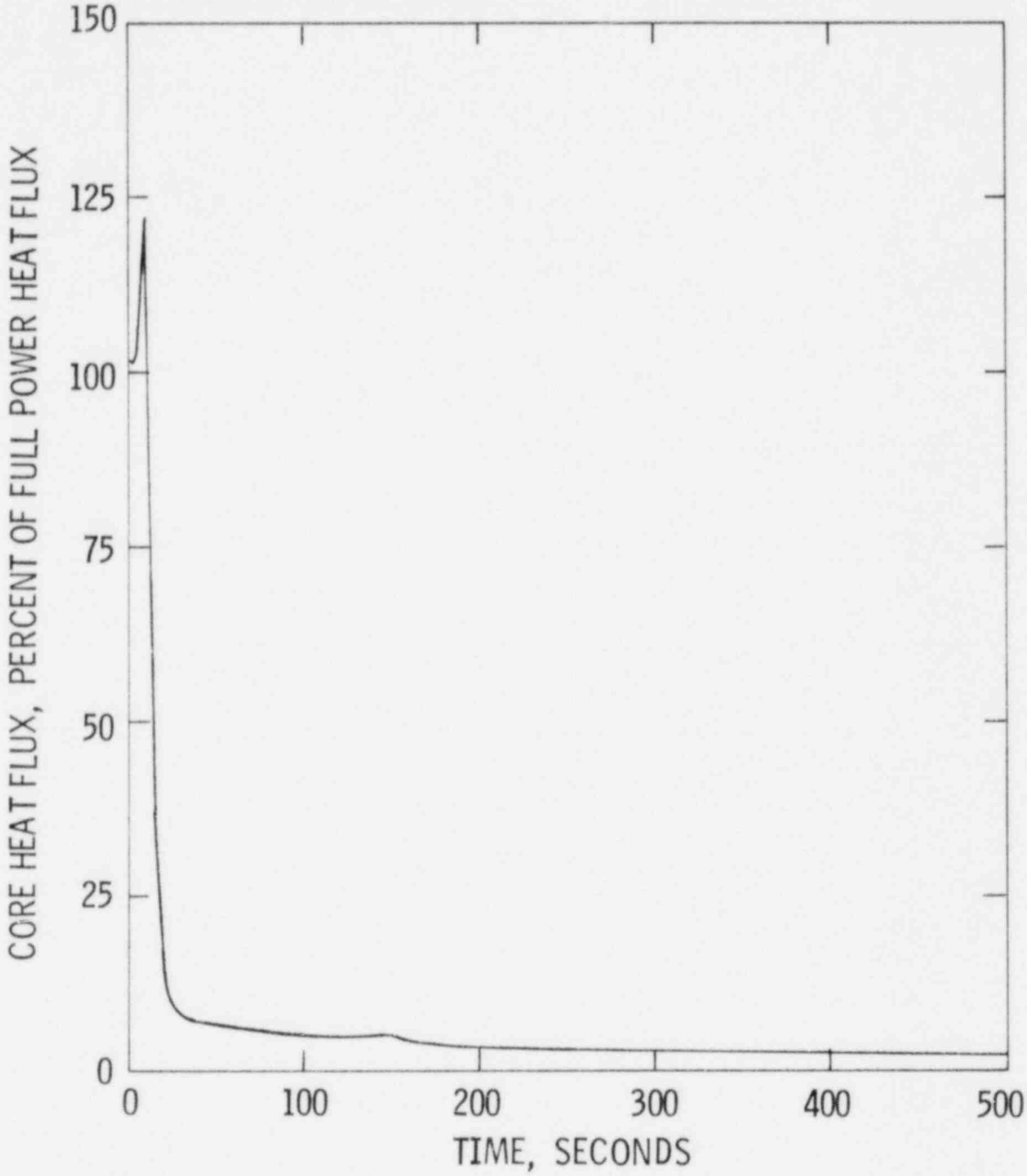
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE CORE POWER vs TIME	Figure 15.1.5-2.1



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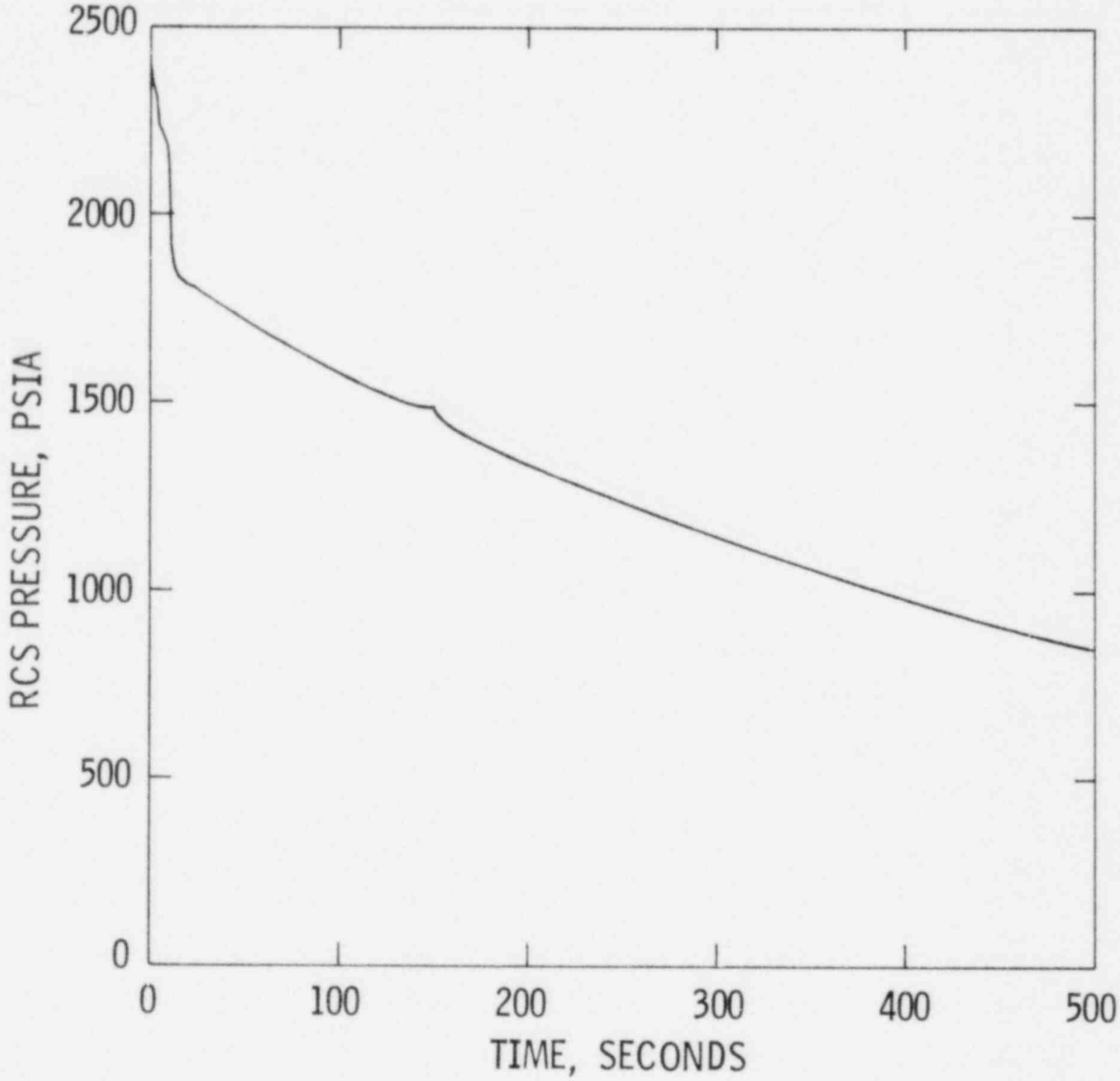
C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE CORE HEAT FLUX vs TIME	Figure 15.1.5-2.2



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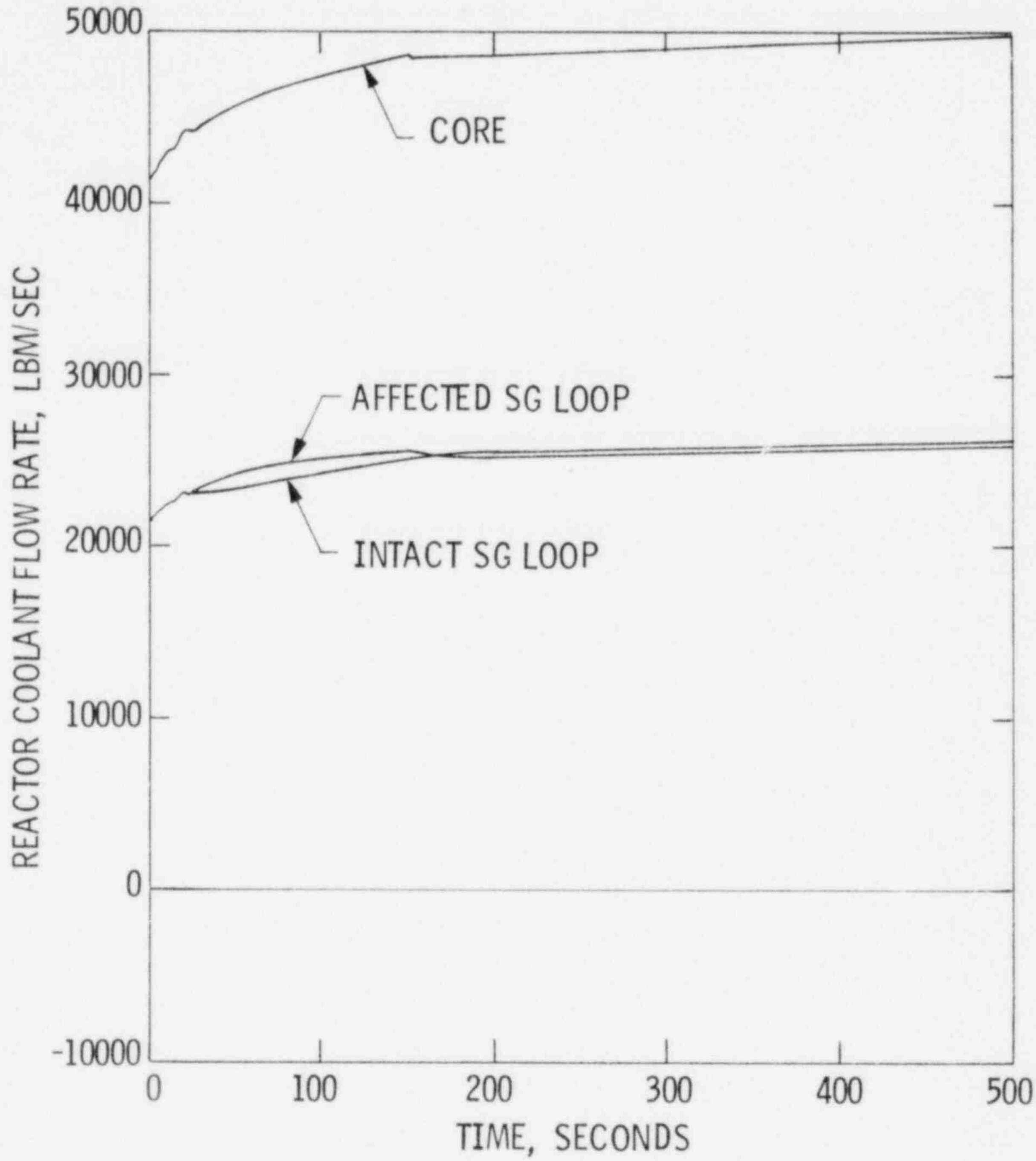
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE RCS PRESSURE vs TIME	Figure 15.1.5-2.3



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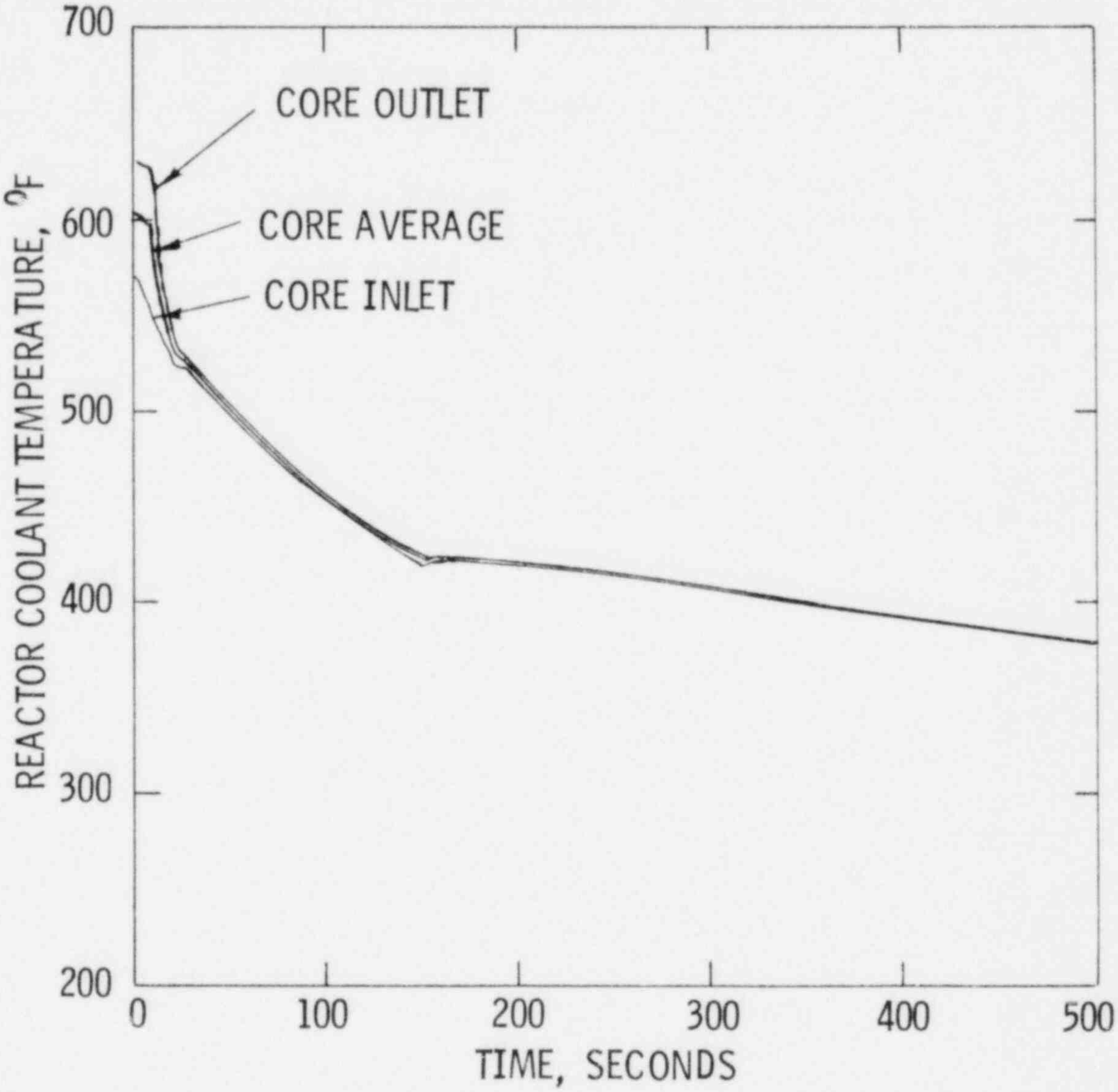
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT FLOW RATE vs TIME	Figure 15.1.5-2.4



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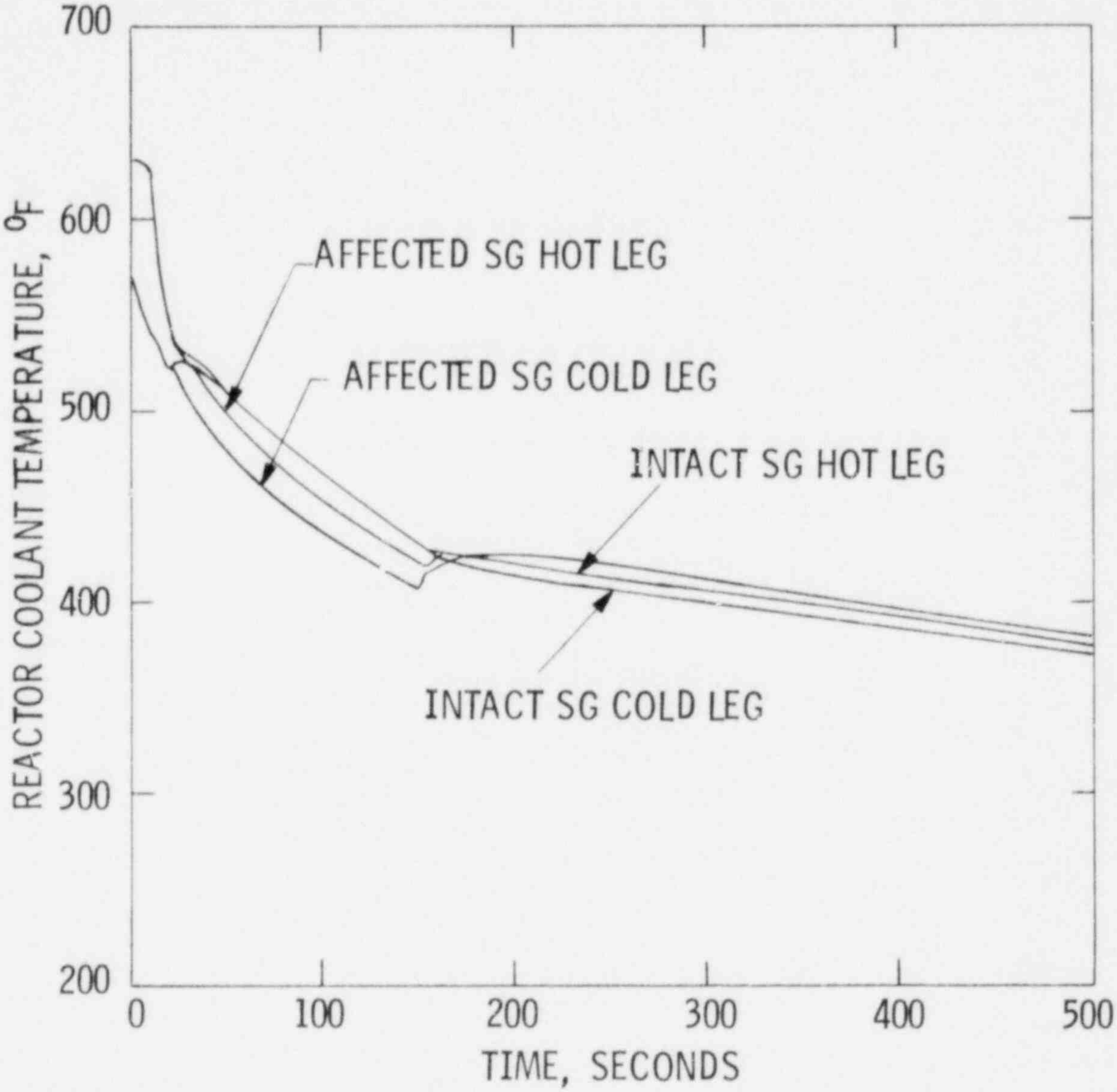
C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT TEMPERATURES (A) vs TIME	Figure 15.1.5-2.5A



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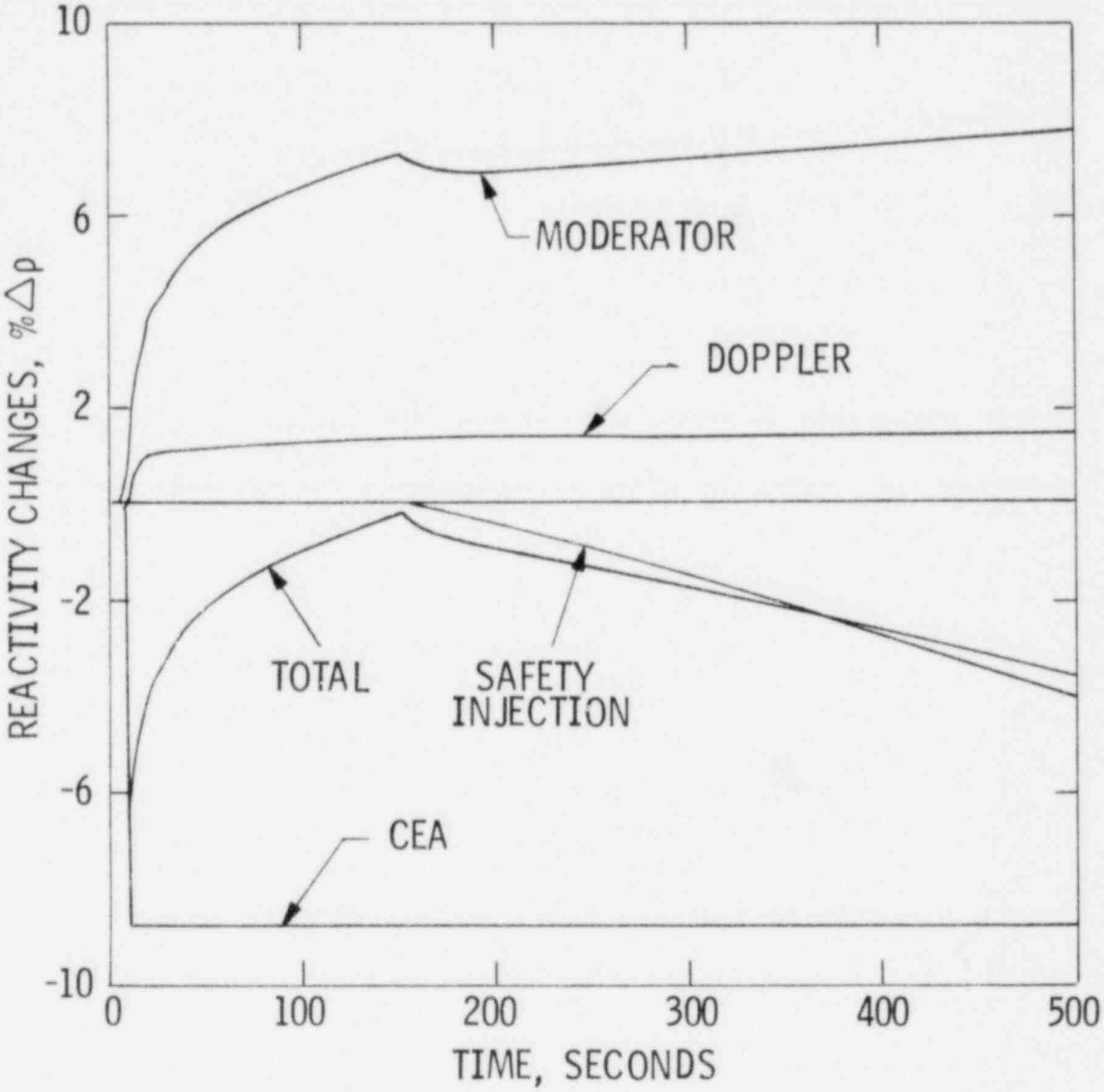
C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT TEMPERATURES (B) vs TIME	Figure 15.1.5-2.5B



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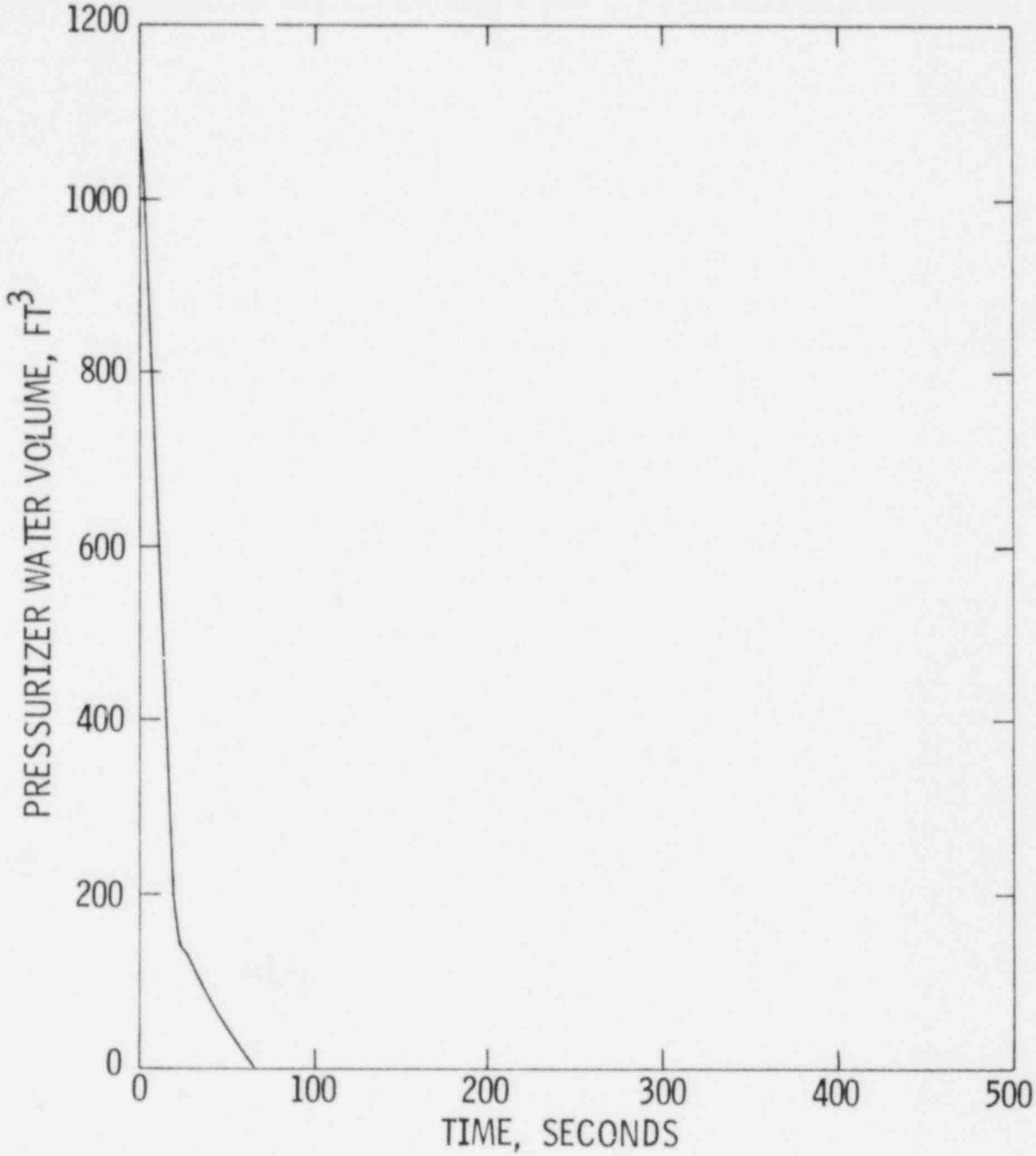
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTIVITY CHANGES vs TIME	Figure 15.1.5-2.6



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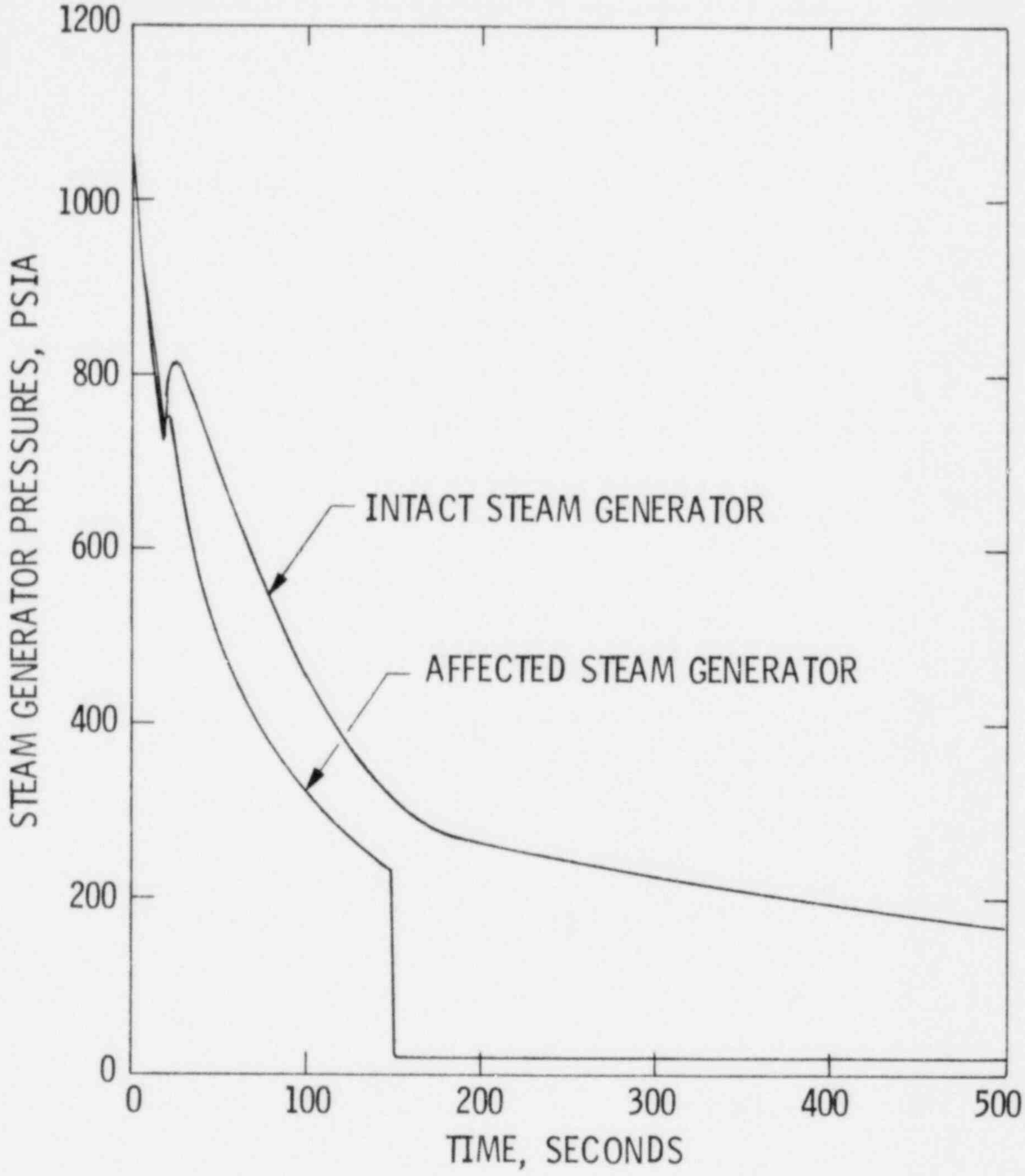
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE PRESSURIZER WATER VOLUME vs TIME	Figure 15.1.5-2.7



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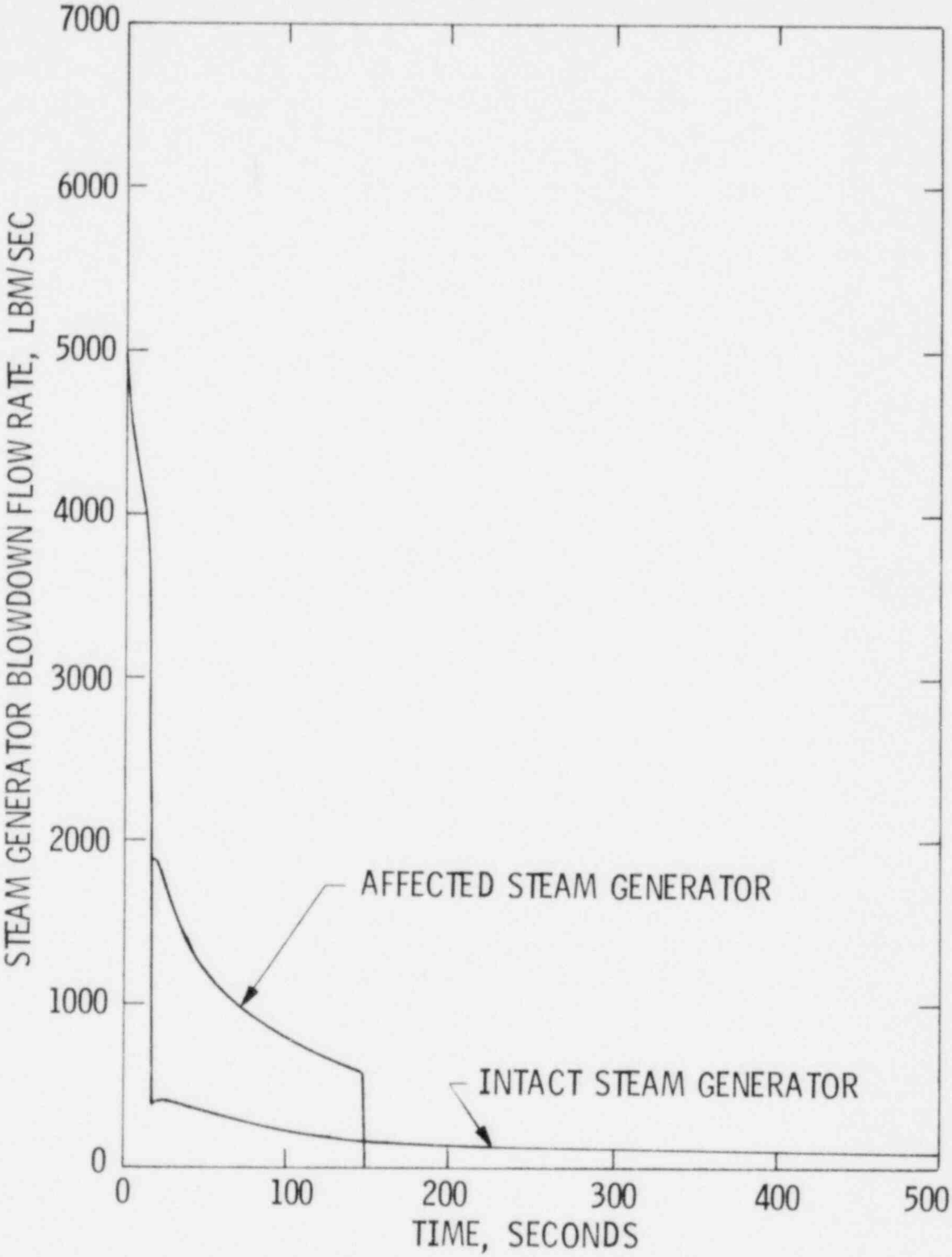
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR PRESSURES vs TIME	Figure 15.1.5-2.8



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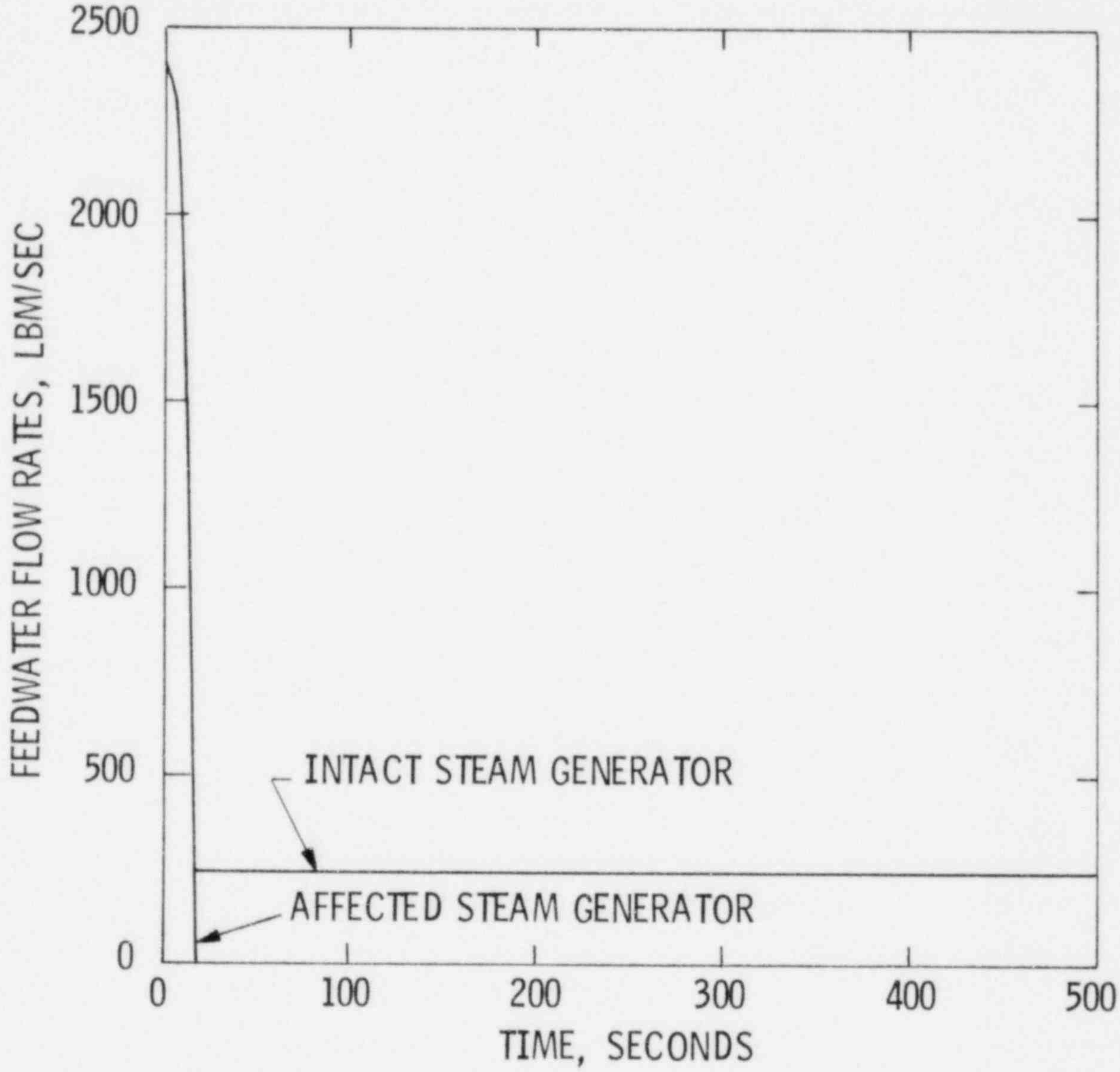
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR BLOWDOWN RATES vs TIME	Figure 15.1.5-2.9



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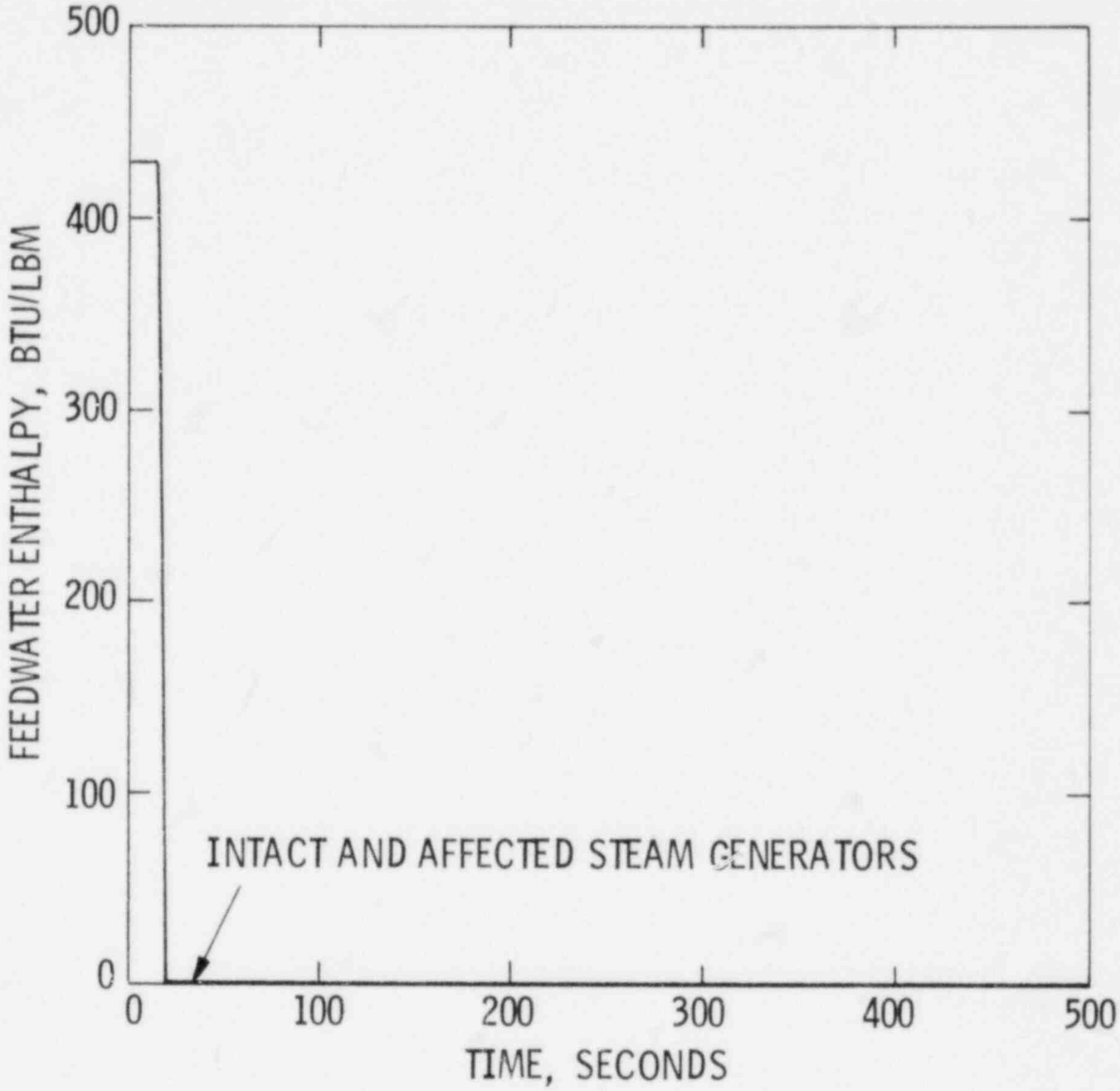
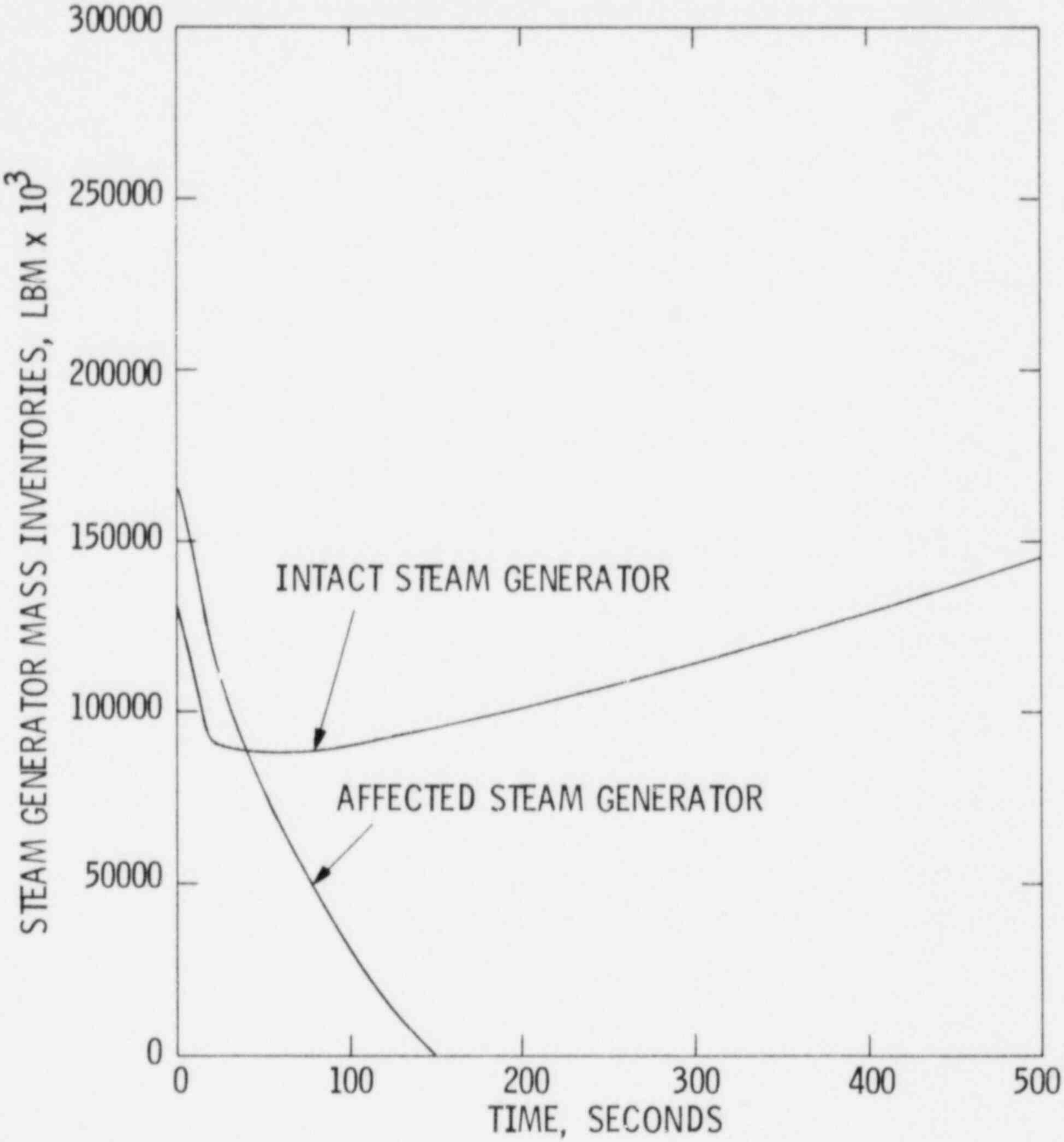
March 31, 1982

C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE FEEDWATER FLOW RATES vs TIME	Figure 15.1.5-2.10



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE FEEDWATER ENTHALPY vs TIME	Figure 15.1.5-2.11



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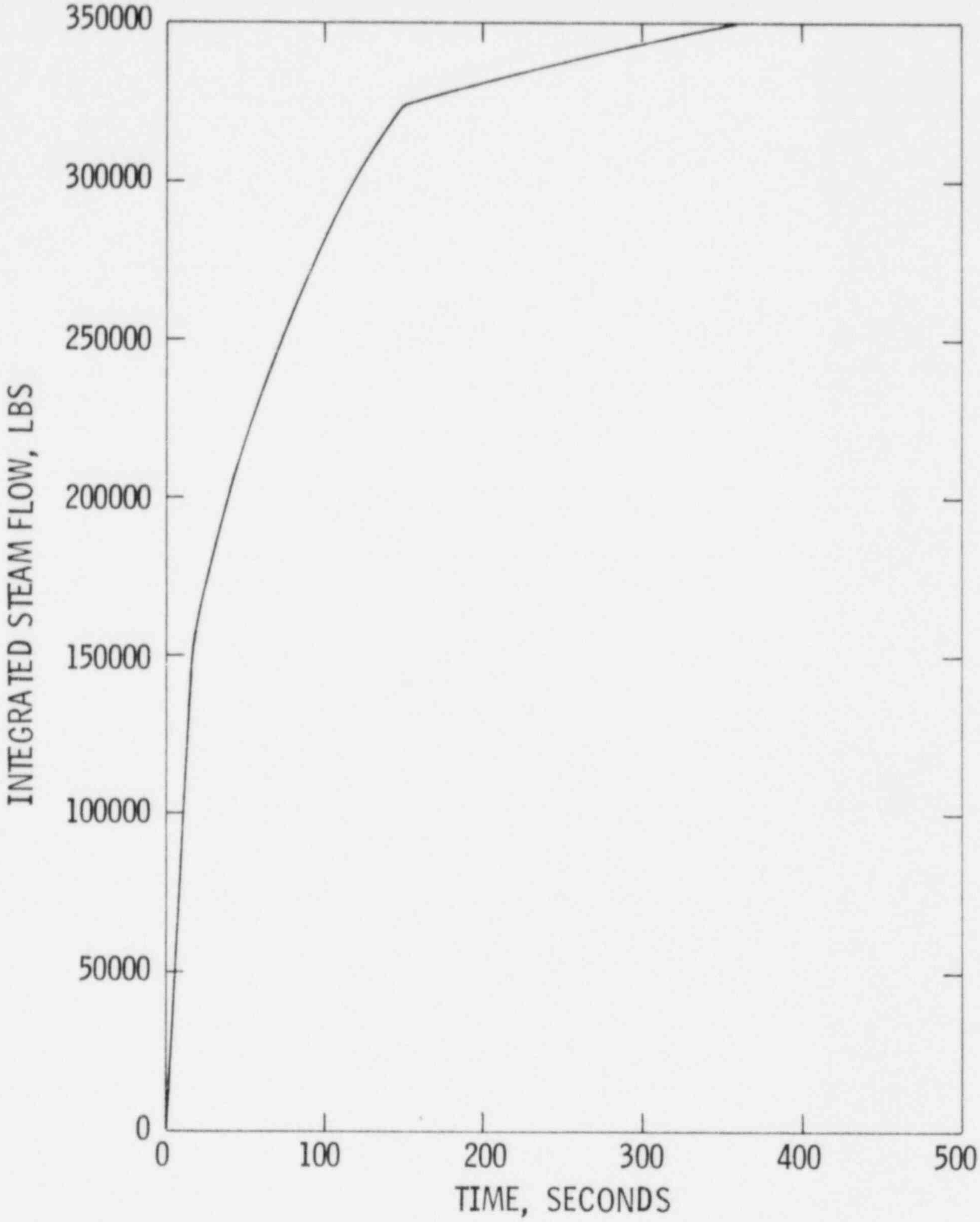
C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR LIQUID MASS vs TIME	Figure 15.1.5-2.12



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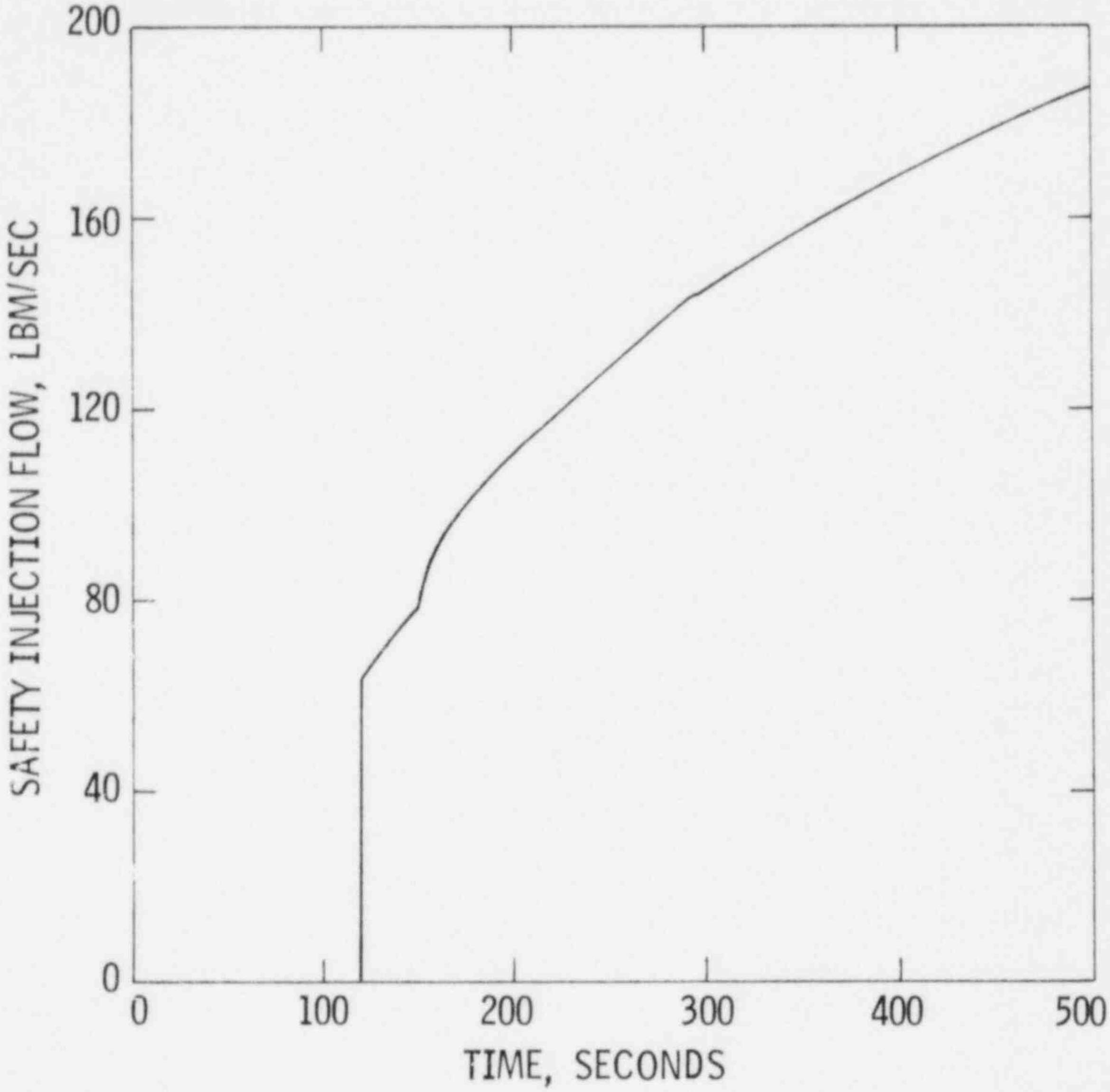
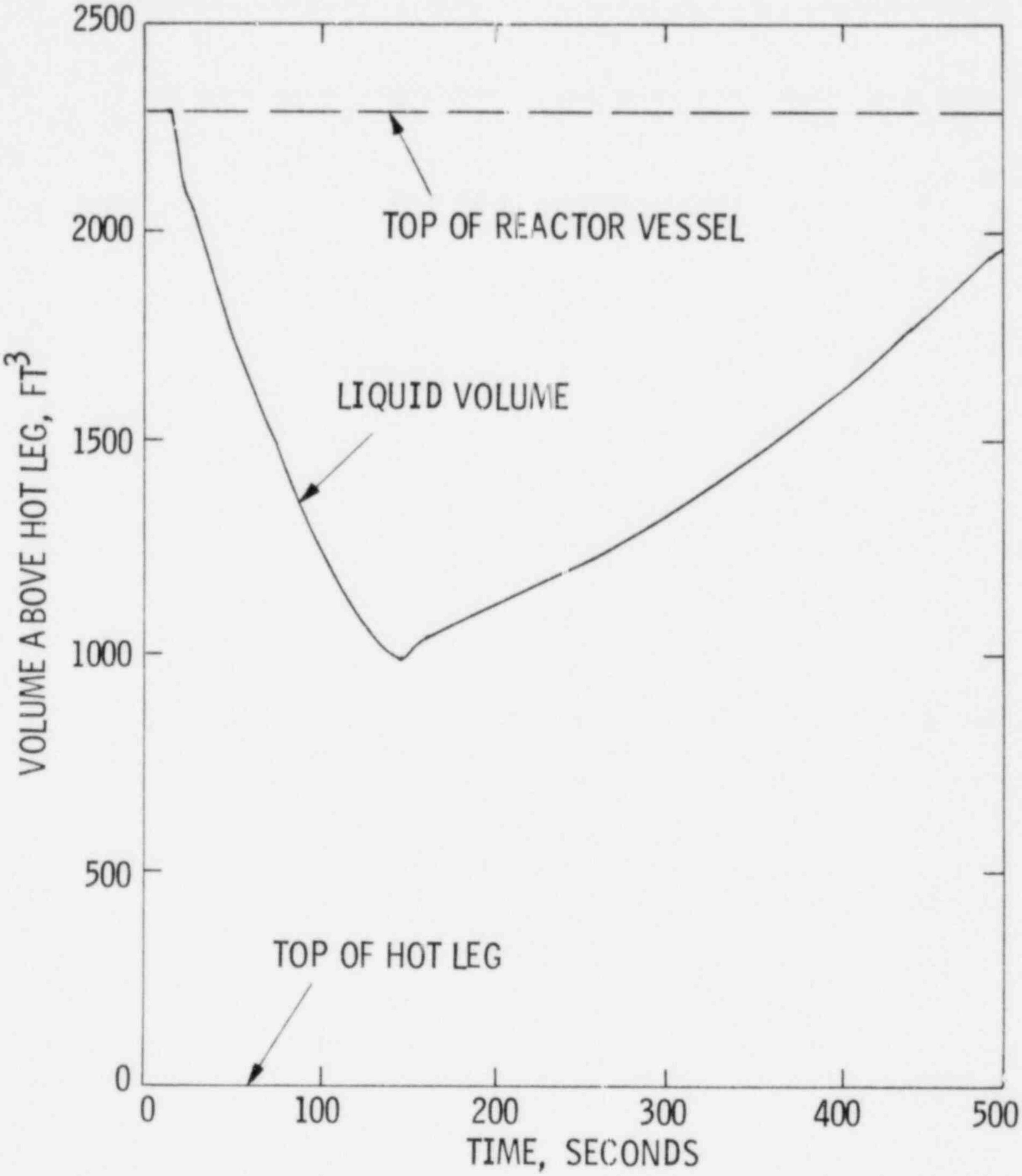
March 31, 1982

C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE INTEGRATED STEAM RELEASE vs TIME	Figure 15.1.5-2.13



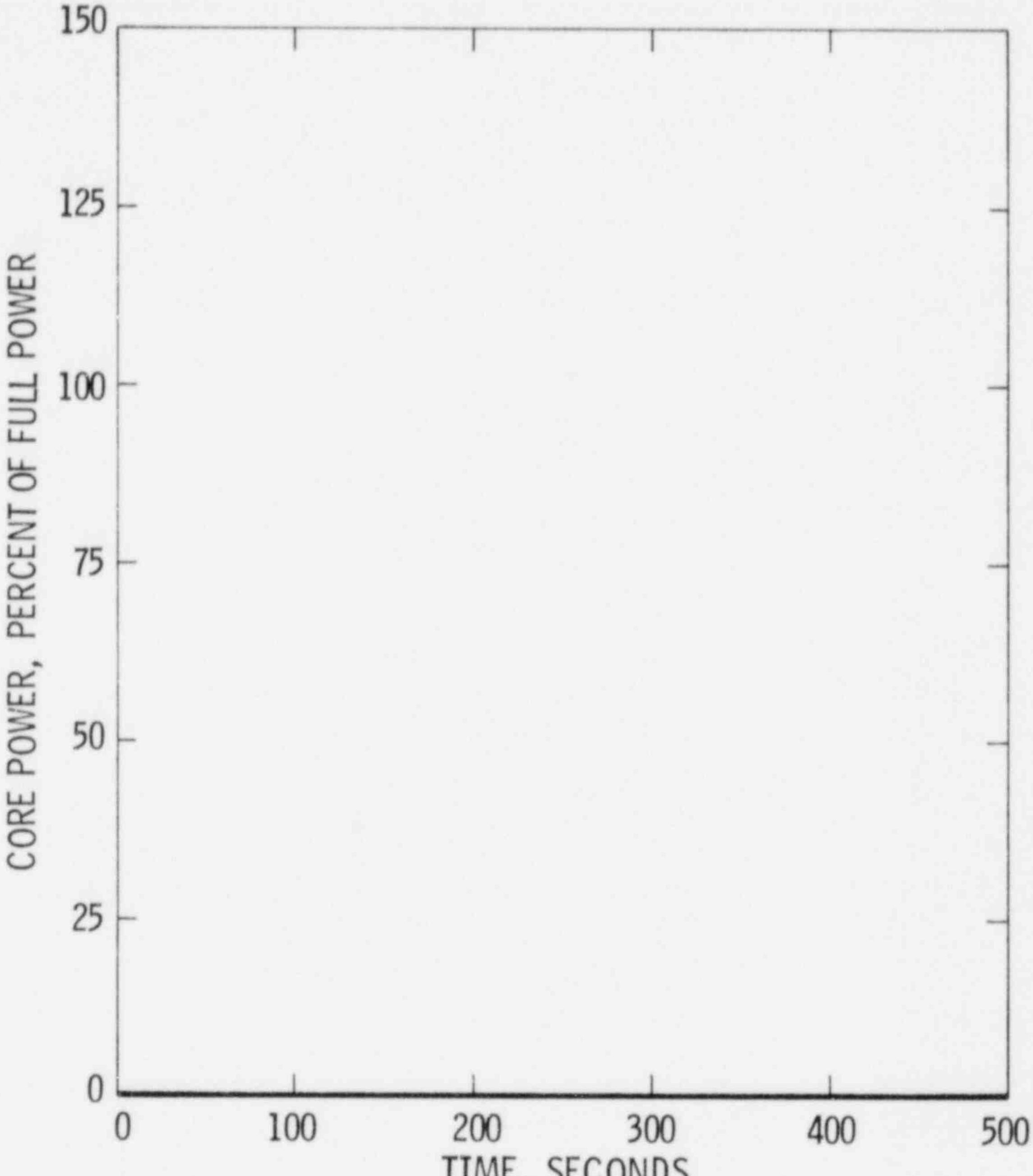
Amendment No. 7
March 31, 1982

C - E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE SAFETY INJECTION FLOW vs TIME	Figure 15.1.5-2.14



Amendment No. 7
March 31, 1982

C-E SYSTEM 80	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR VESSEL LIQUID VOLUME vs TIME	Figure 15.1.5-2.15



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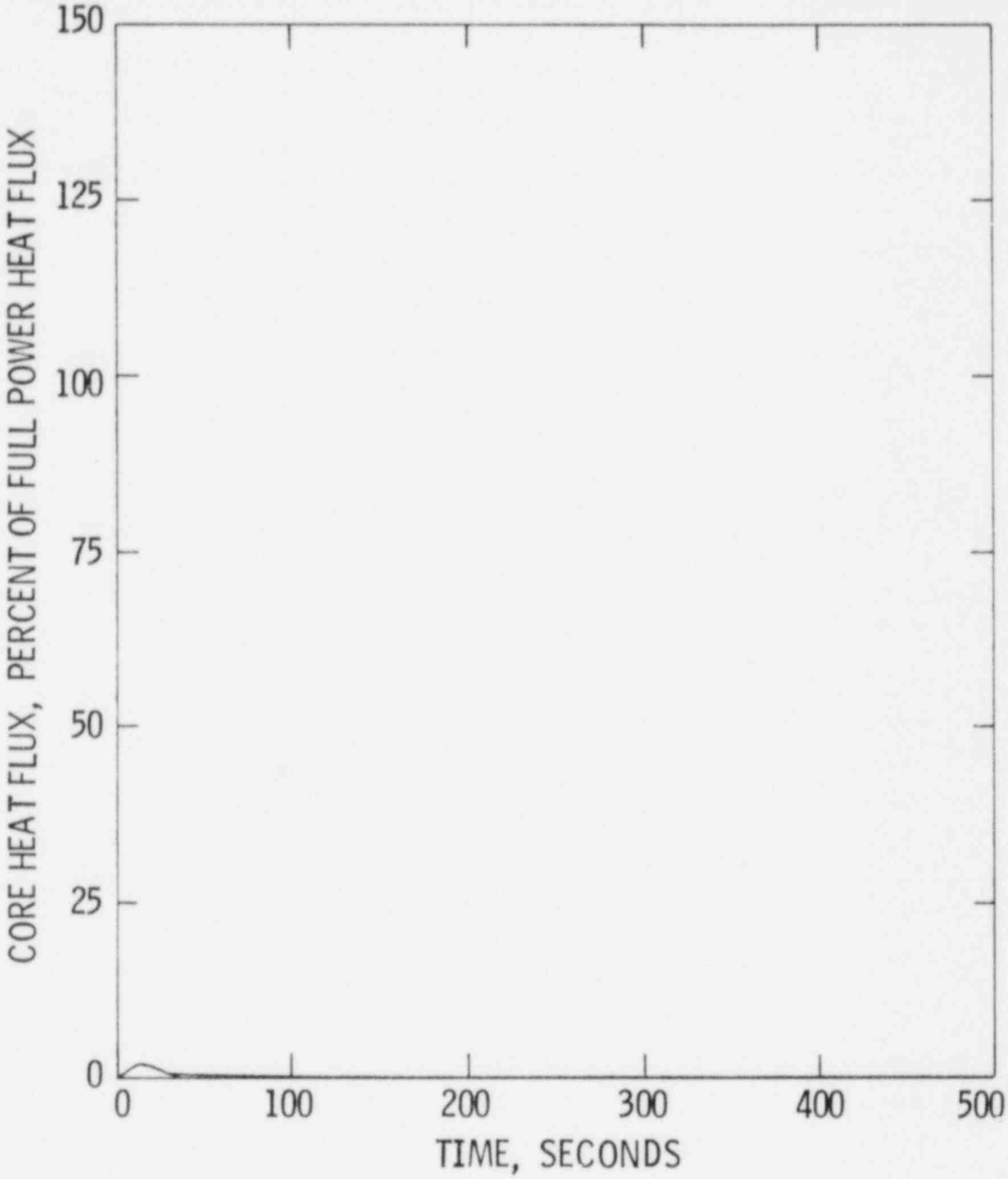
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER CORE POWER vs TIME	Figure 15.1.5-3.1



Amendment No. 7
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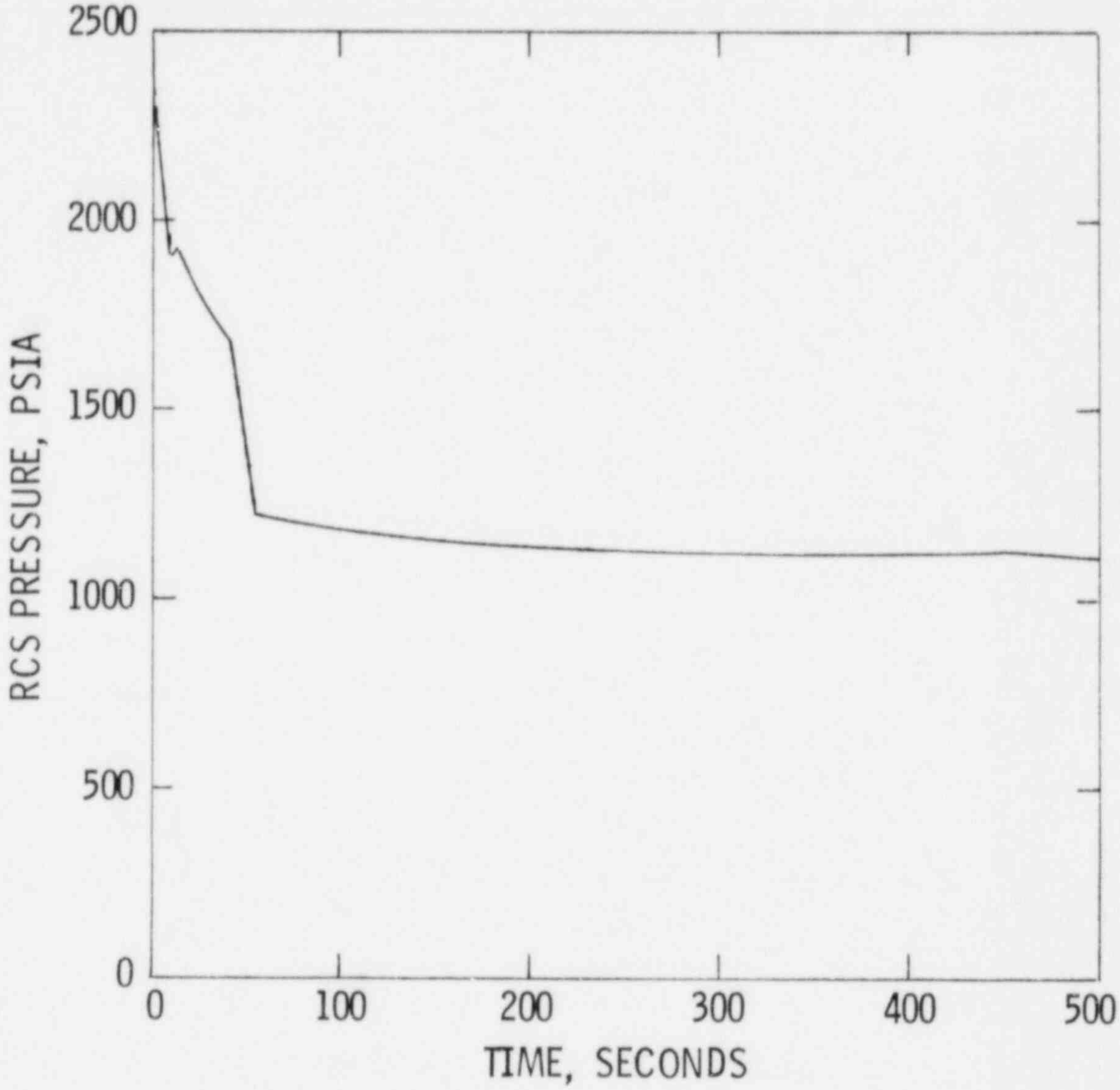
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER CORE HEAT FLUX vs TIME	Figure 15.1.5-3.2



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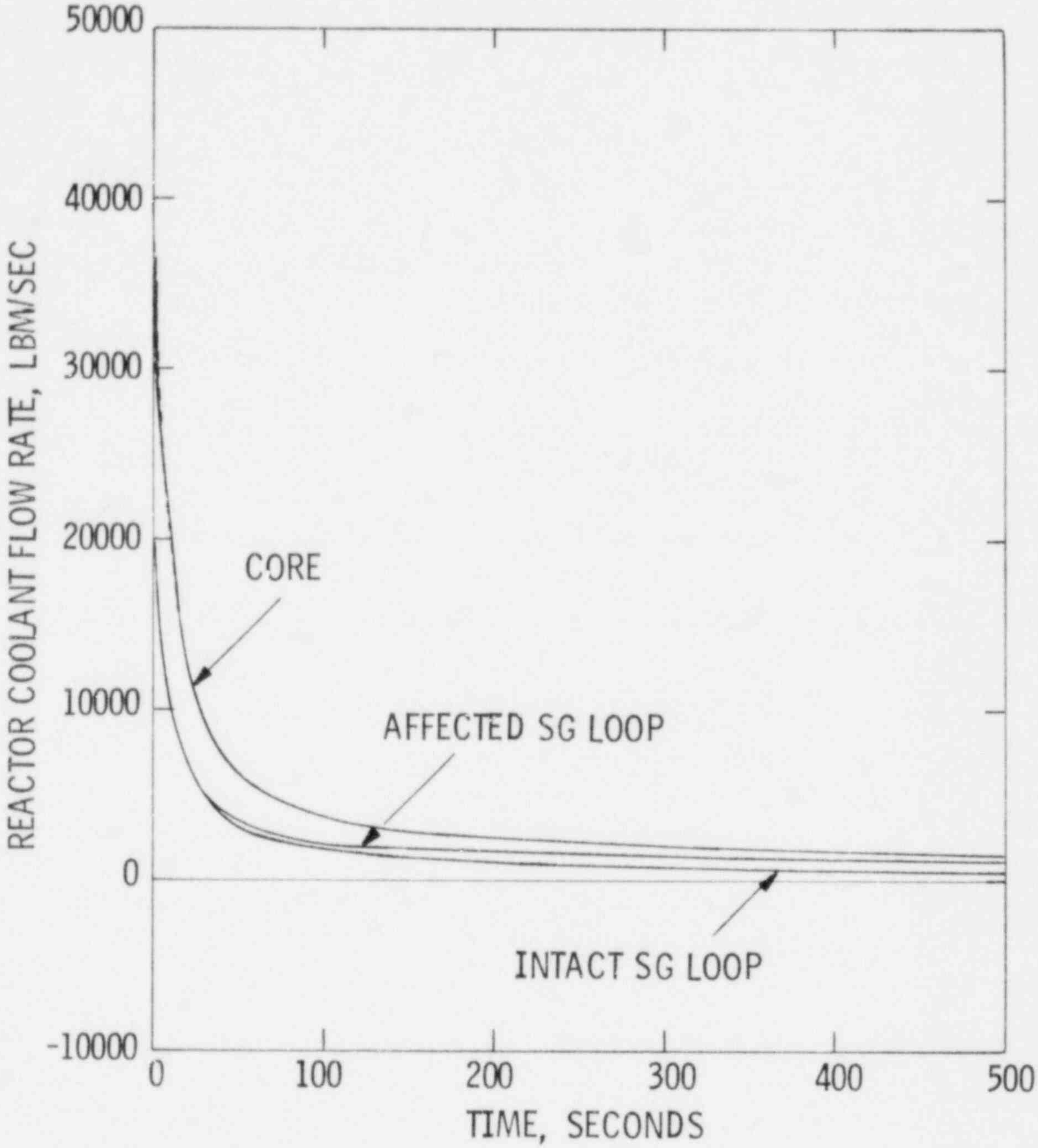
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER RCS PRESSURE vs TIME	Figure 15.1.5-3.3



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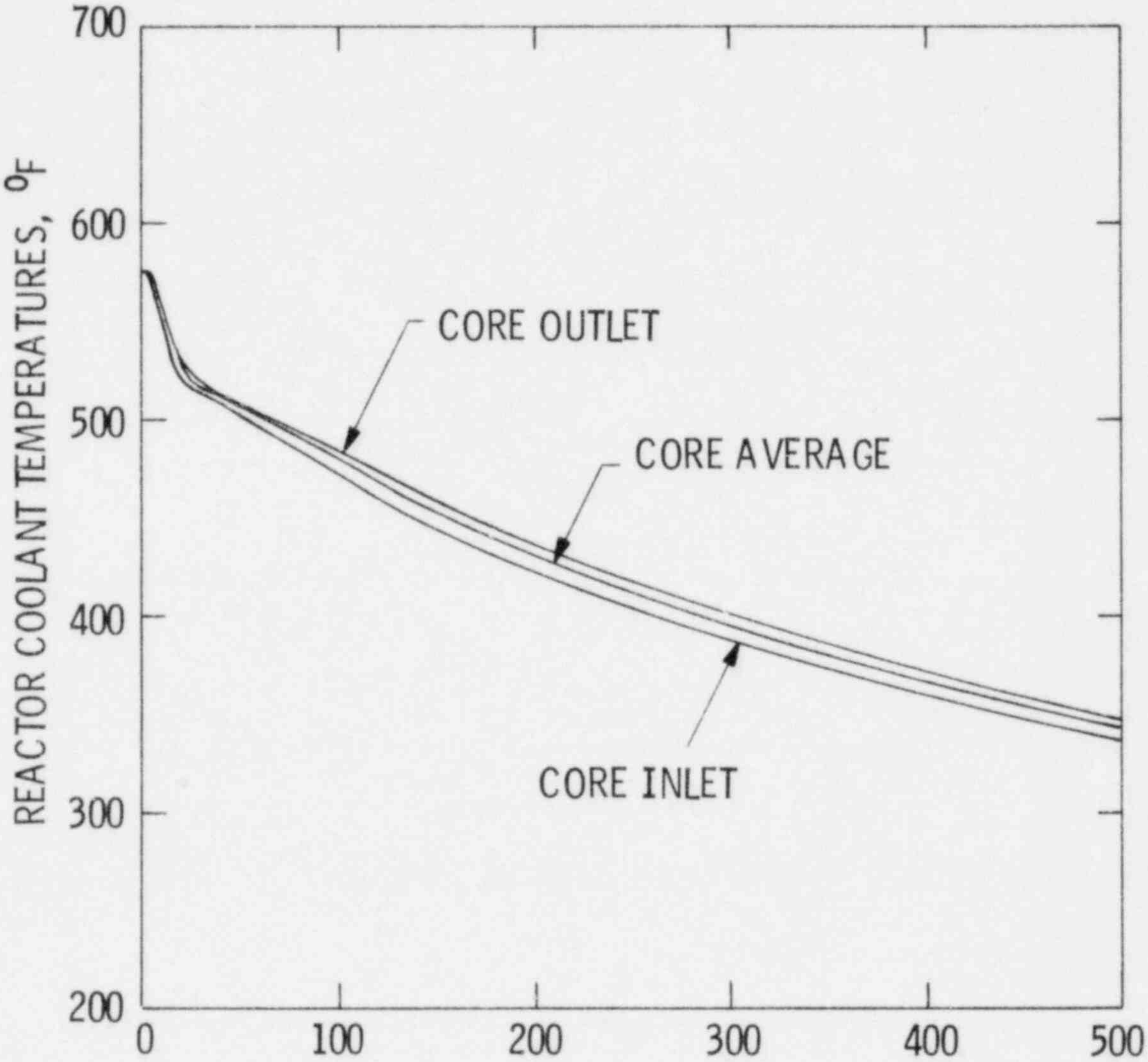
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR COOLANT FLOW RATE vs TIME	Figure 15.1.5-3.4



Amendment No. 7
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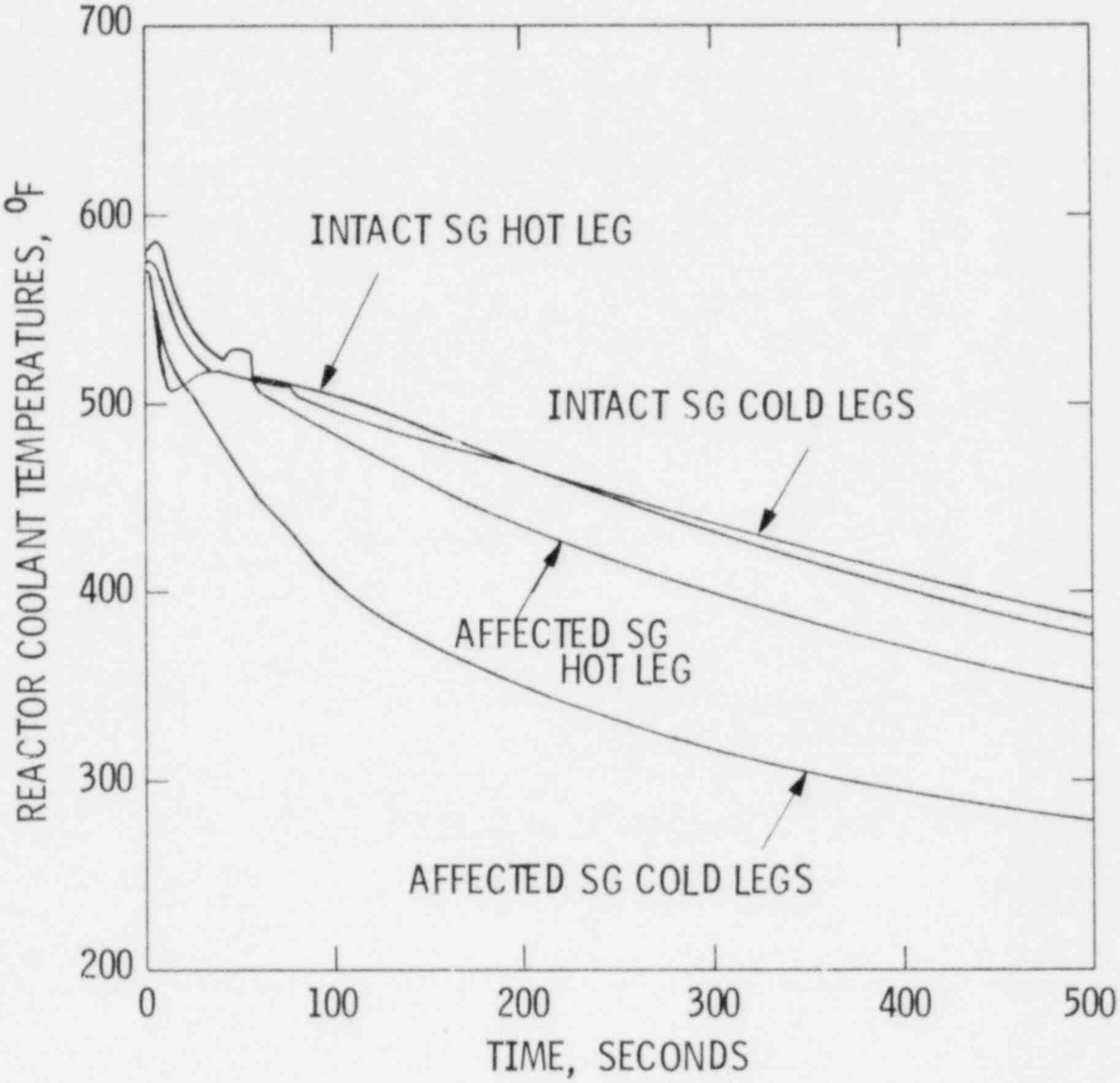
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR COOLANT TEMPERATURES (A) vs TIME	Figure 15.1.5-3.5A



Amendment No. 7
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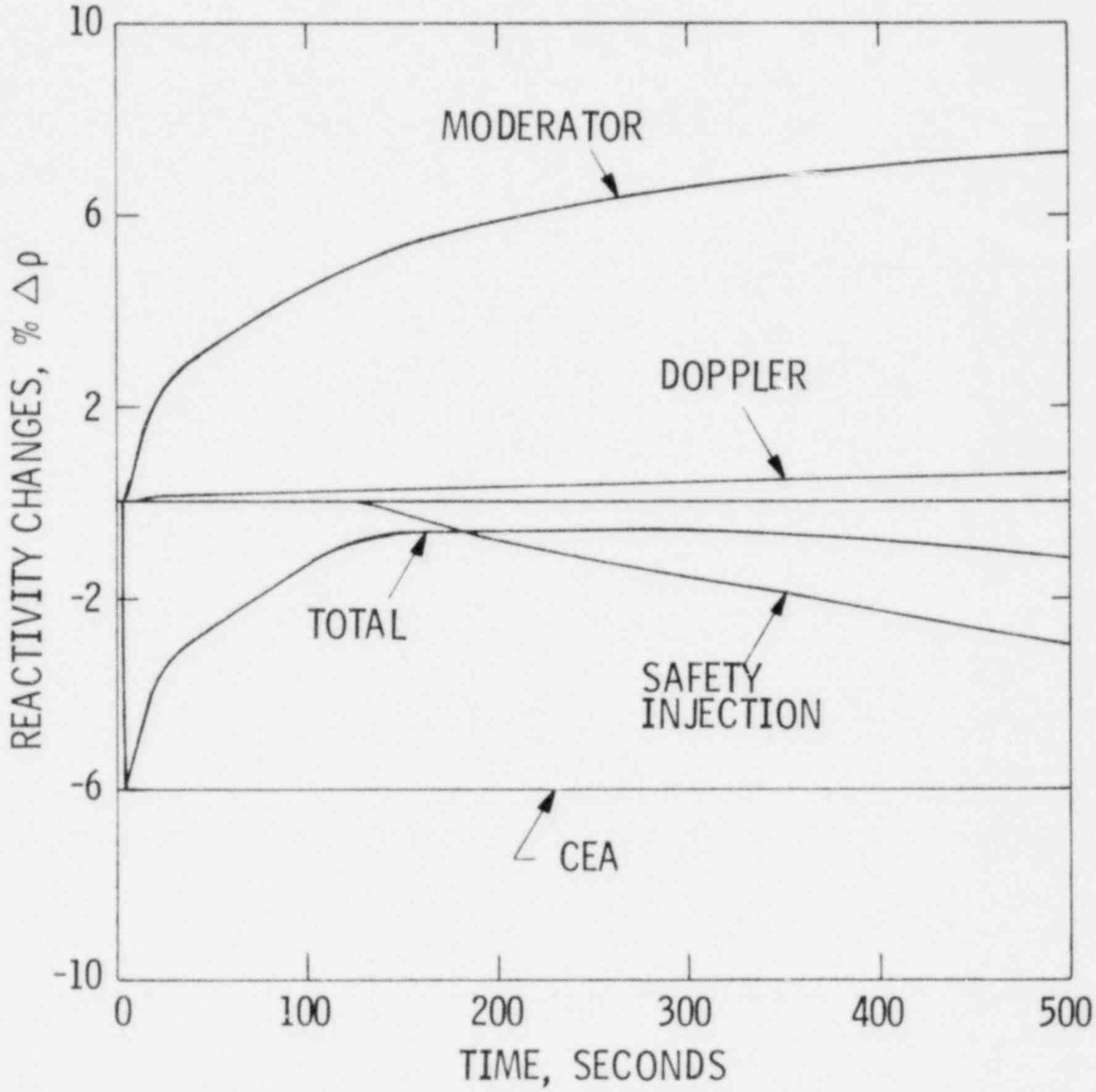
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR COOLANT TEMPERATURES (B) vs TIME	Figure 15.1.5-3.5B



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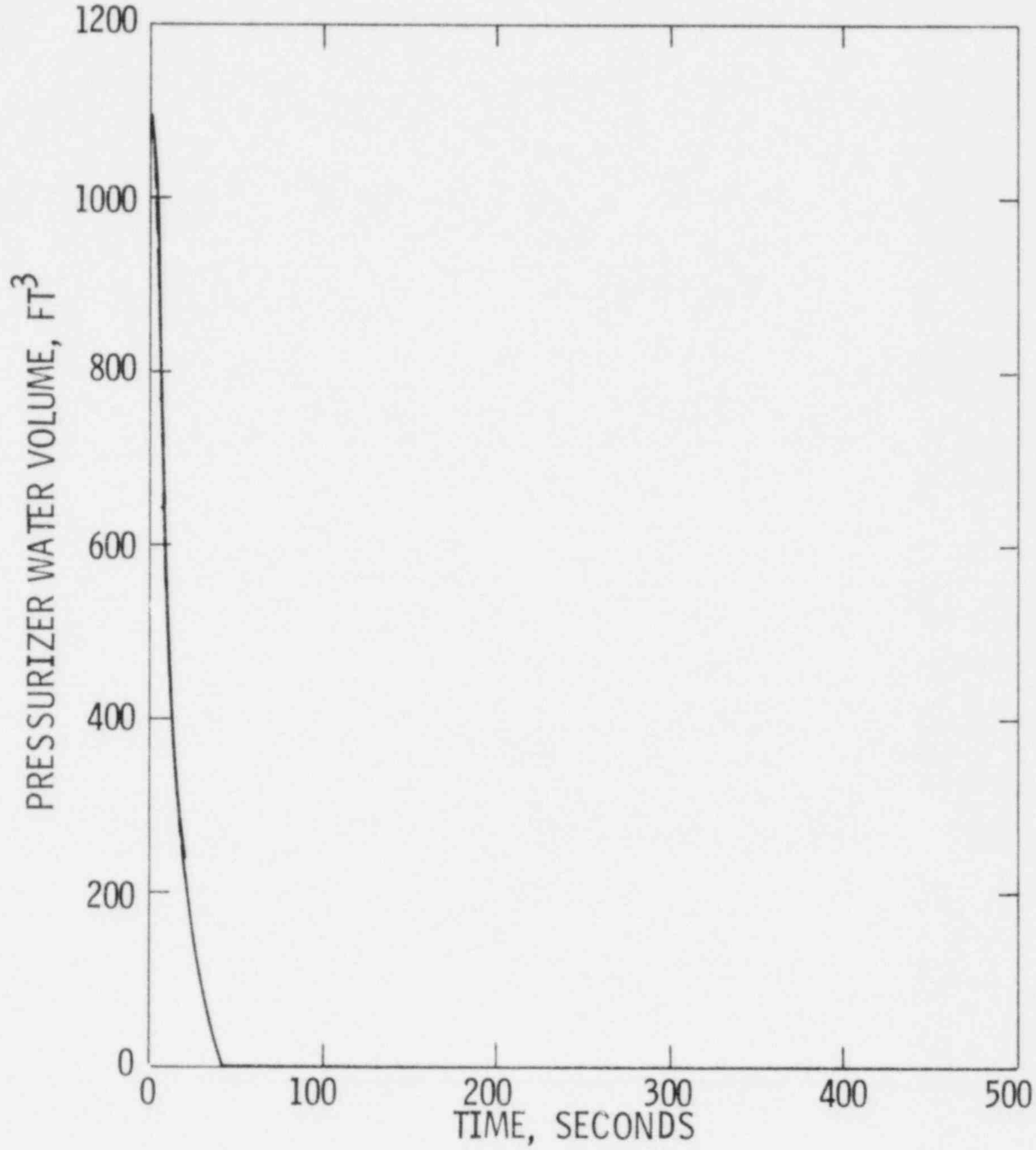
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTIVITY CHANGES vs TIME	Figure 15.1.5-3.6



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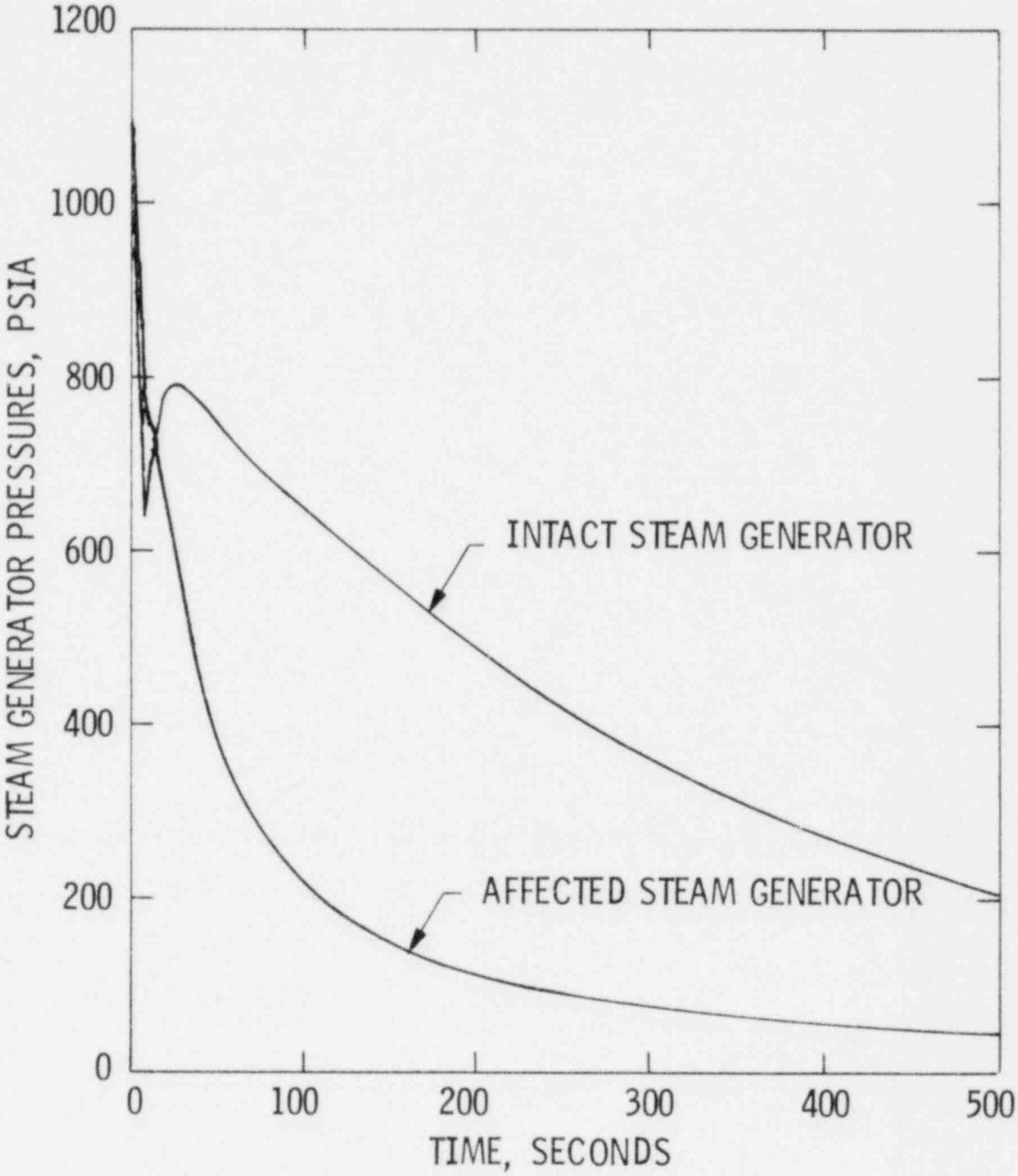
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER PRESSURIZER WATER VOLUME vs TIME	Figure 15.1.5-3.7



Amendment No. 7
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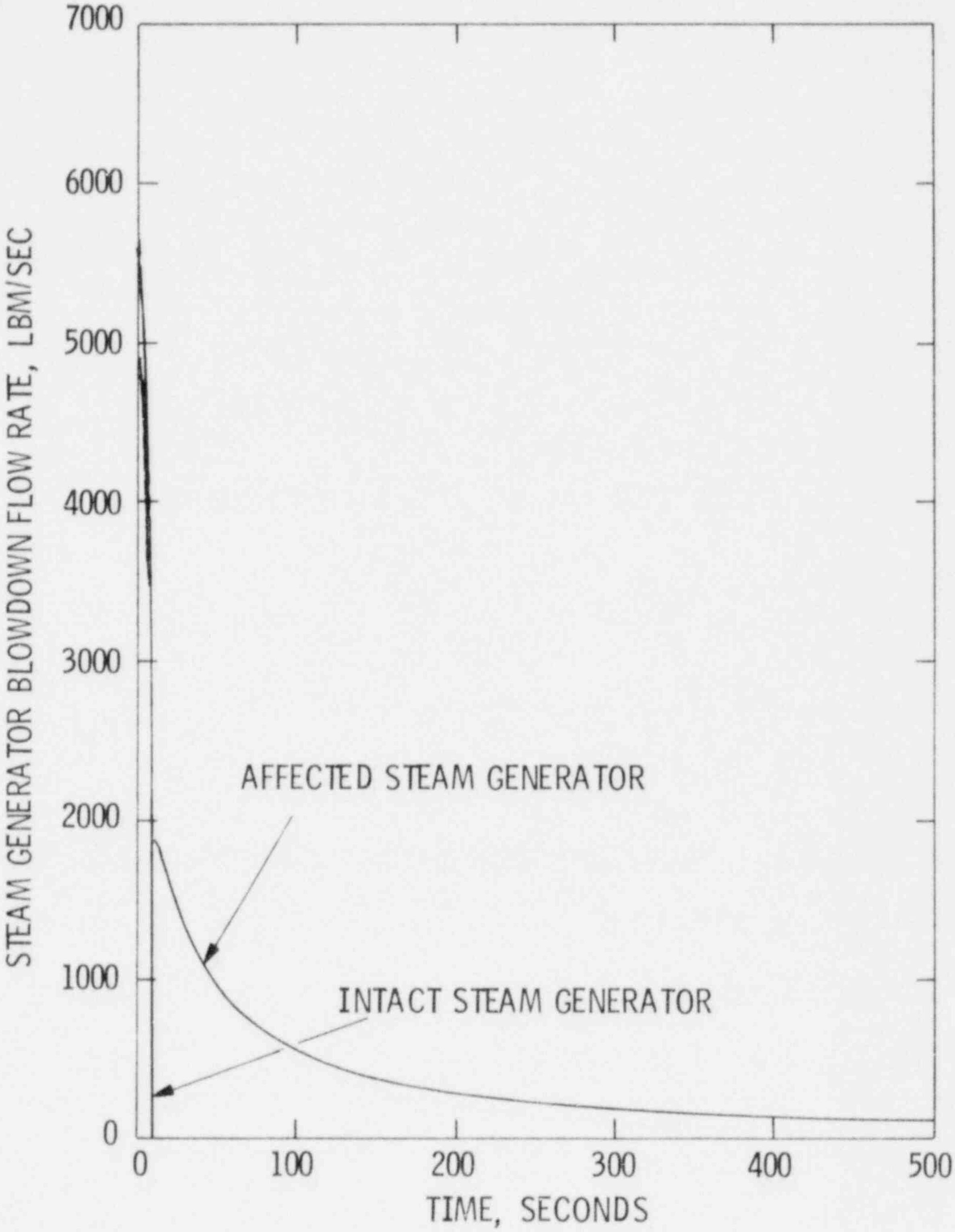
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER STEAM GENERATOR PRESSURES vs TIME	Figure 15.1.5-3.8



Amendment No. 7
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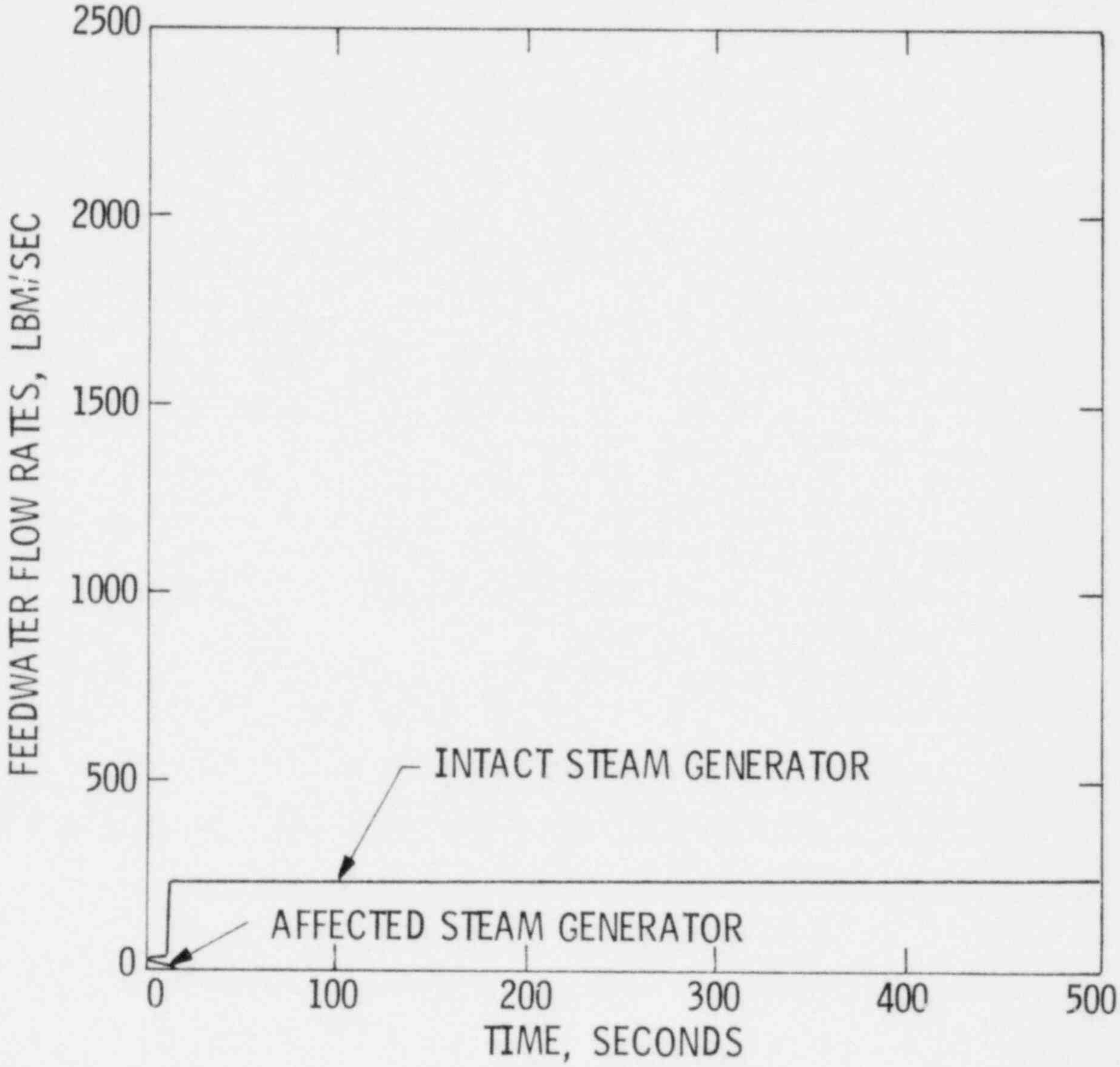
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER STEAM GENERATOR BLOWDOWN RATES vs TIME	Figure 15.1.5-3.9



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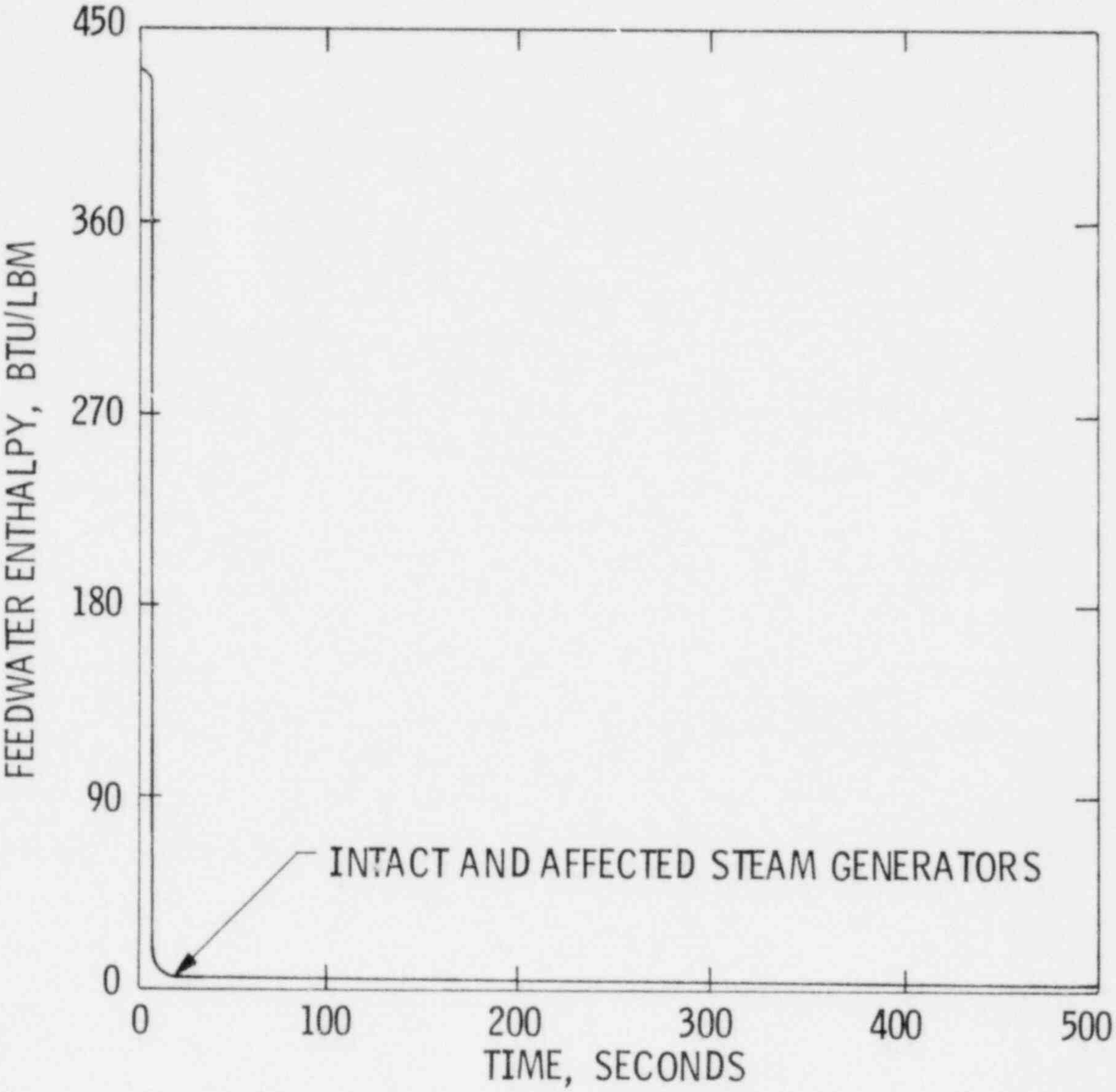
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER FEEDWATER FLOW RATES vs TIME	Figure 15.1.5-3.10



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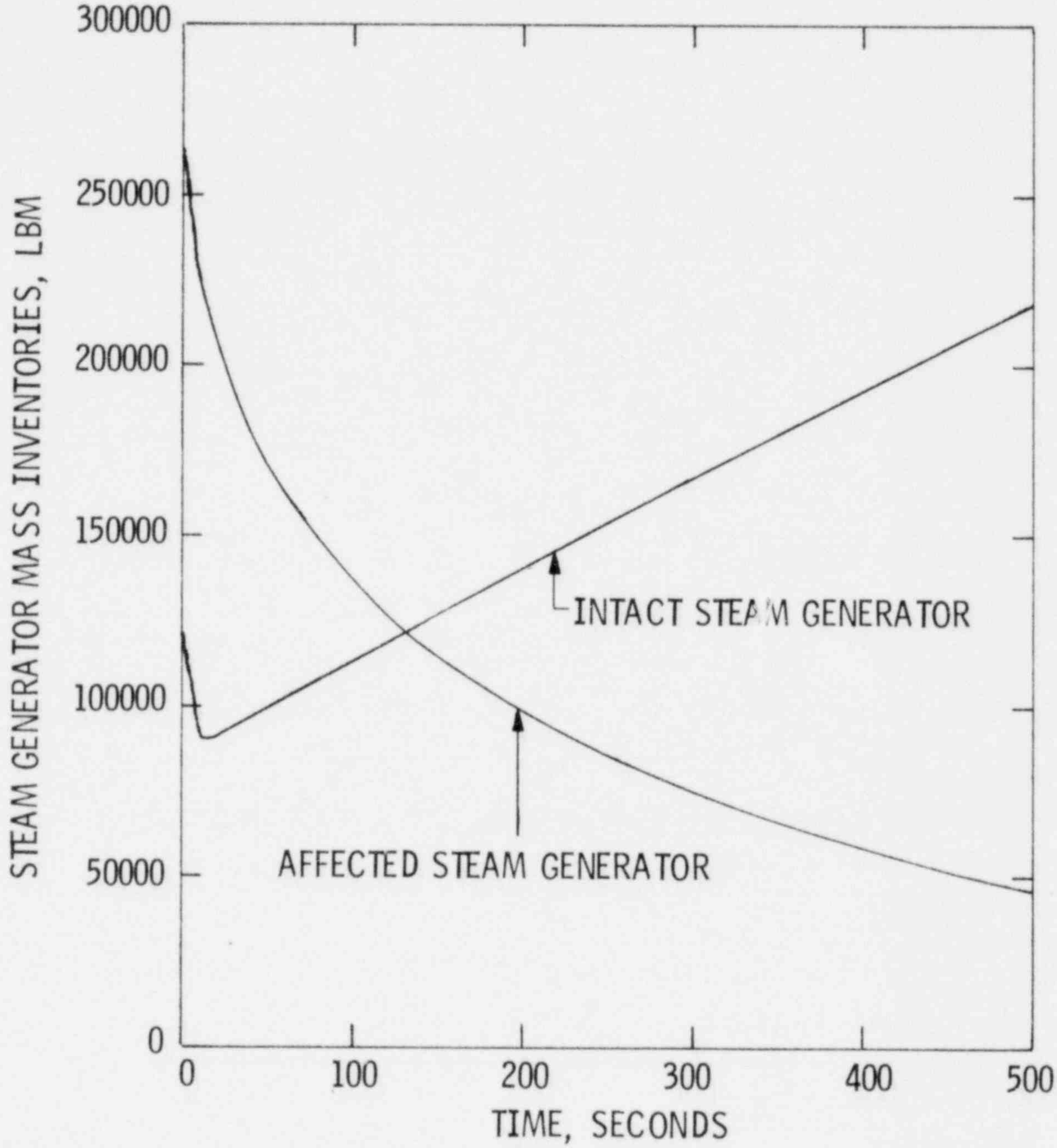
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER FEEDWATER ENTHALPY vs TIME	Figure 15.1.5-3.11



Amendment No. 7
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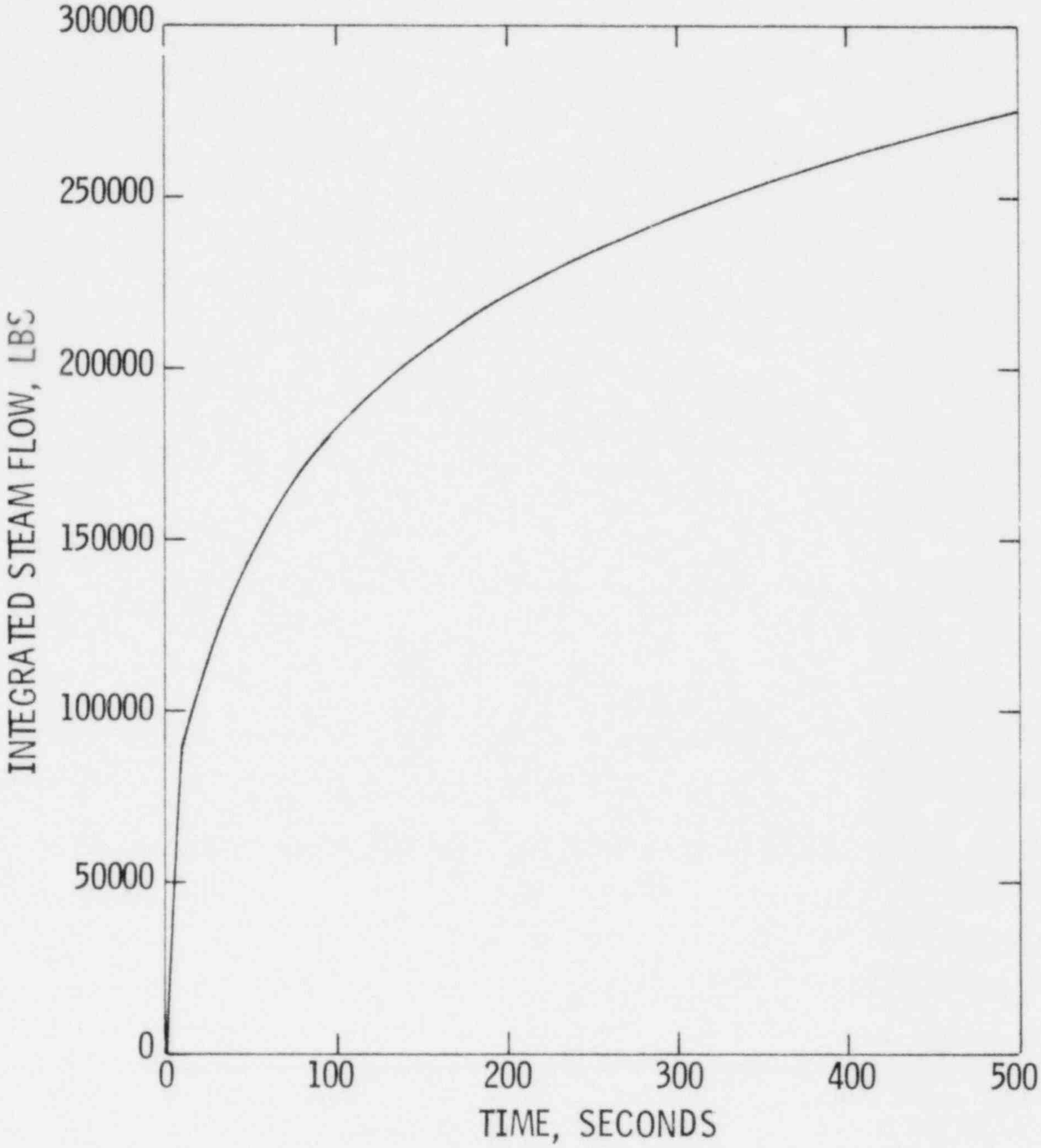
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER STEAM GENERATOR MASS INVENTORIES vs TIME	Figure 15.1.5-3.12



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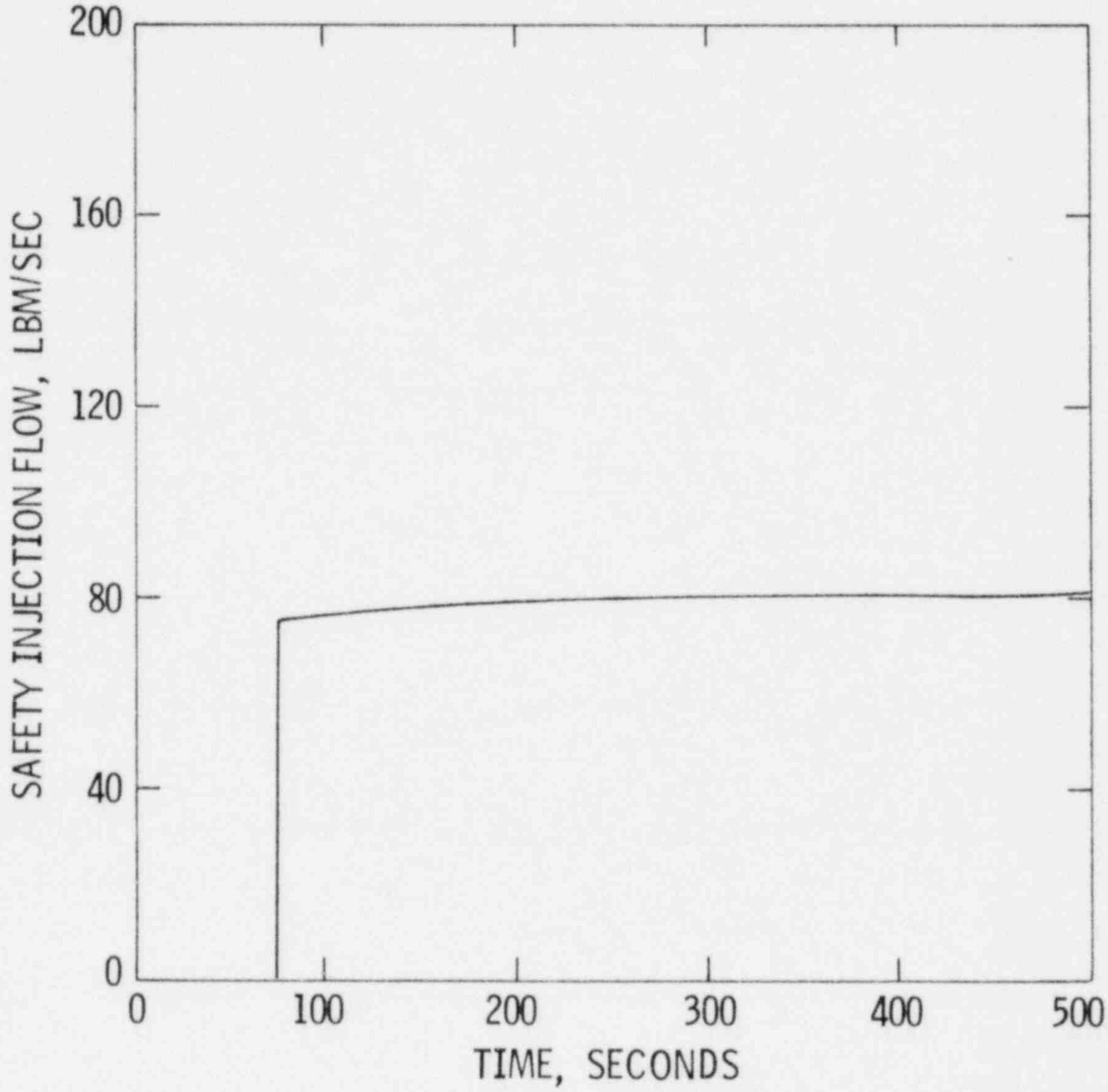
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER INTEGRATED STM MASS RELEASE THRU BREAK vs TIME	Figure 15.1.5-3.13



Amendment No. 7
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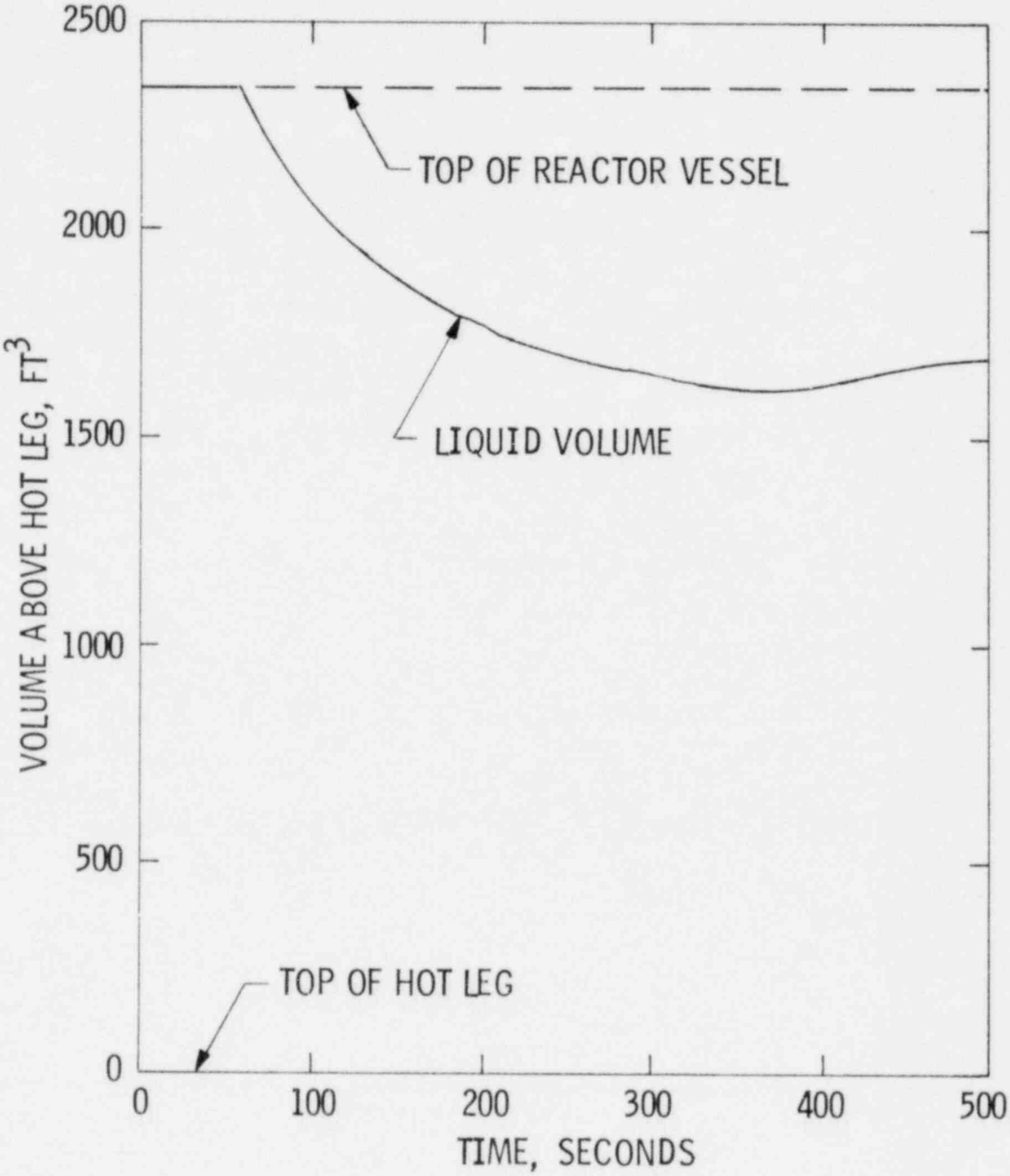
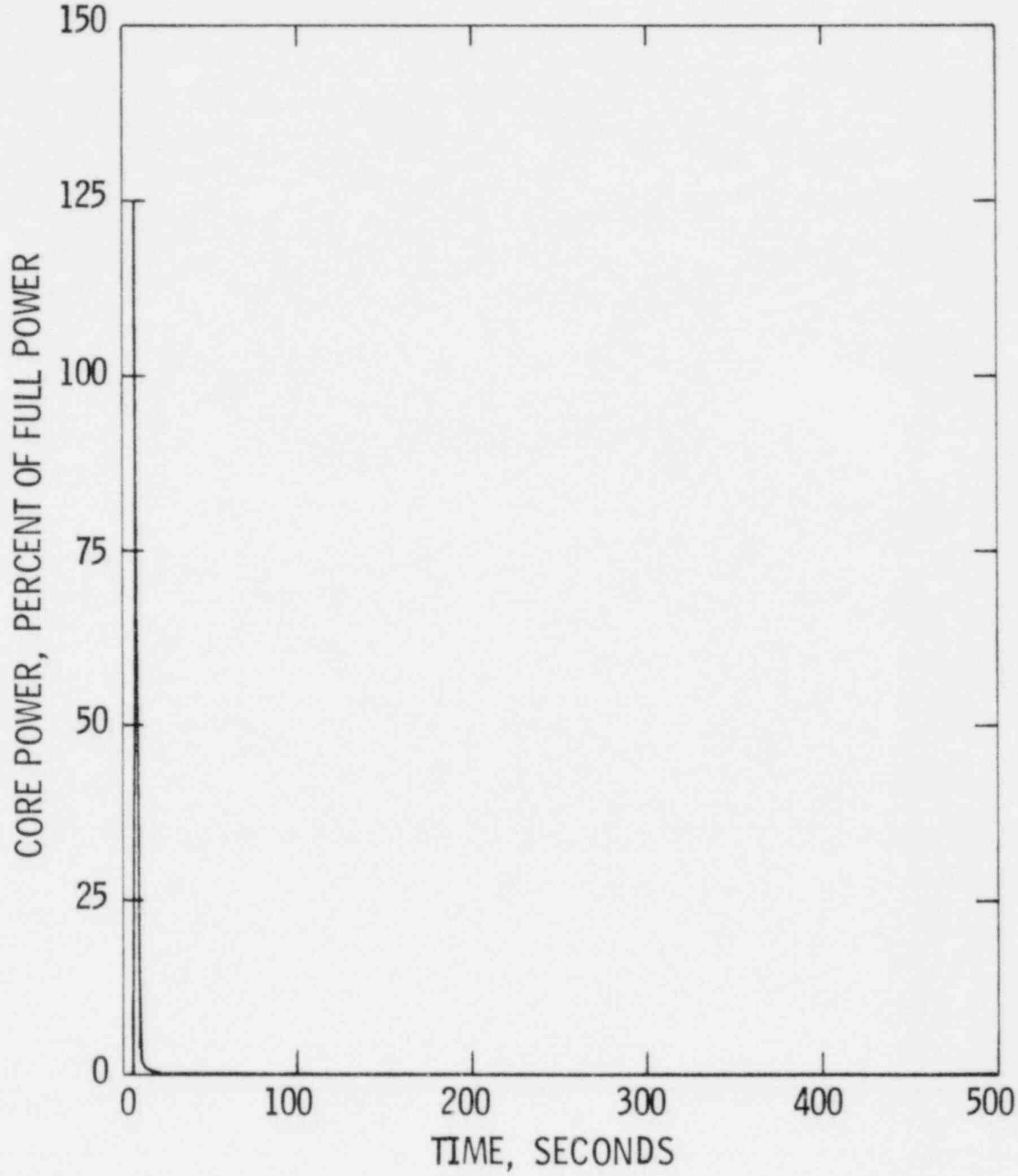
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER SAFETY INJECTION FLOW vs TIME	Figure 15.1.5-3.14



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH CONCURRENT LOSS OF OFFSITE POWER REACTOR VESSEL LIQUID VOLUME vs TIME	Figure 15.1.5-3.15



Amendment No. 7
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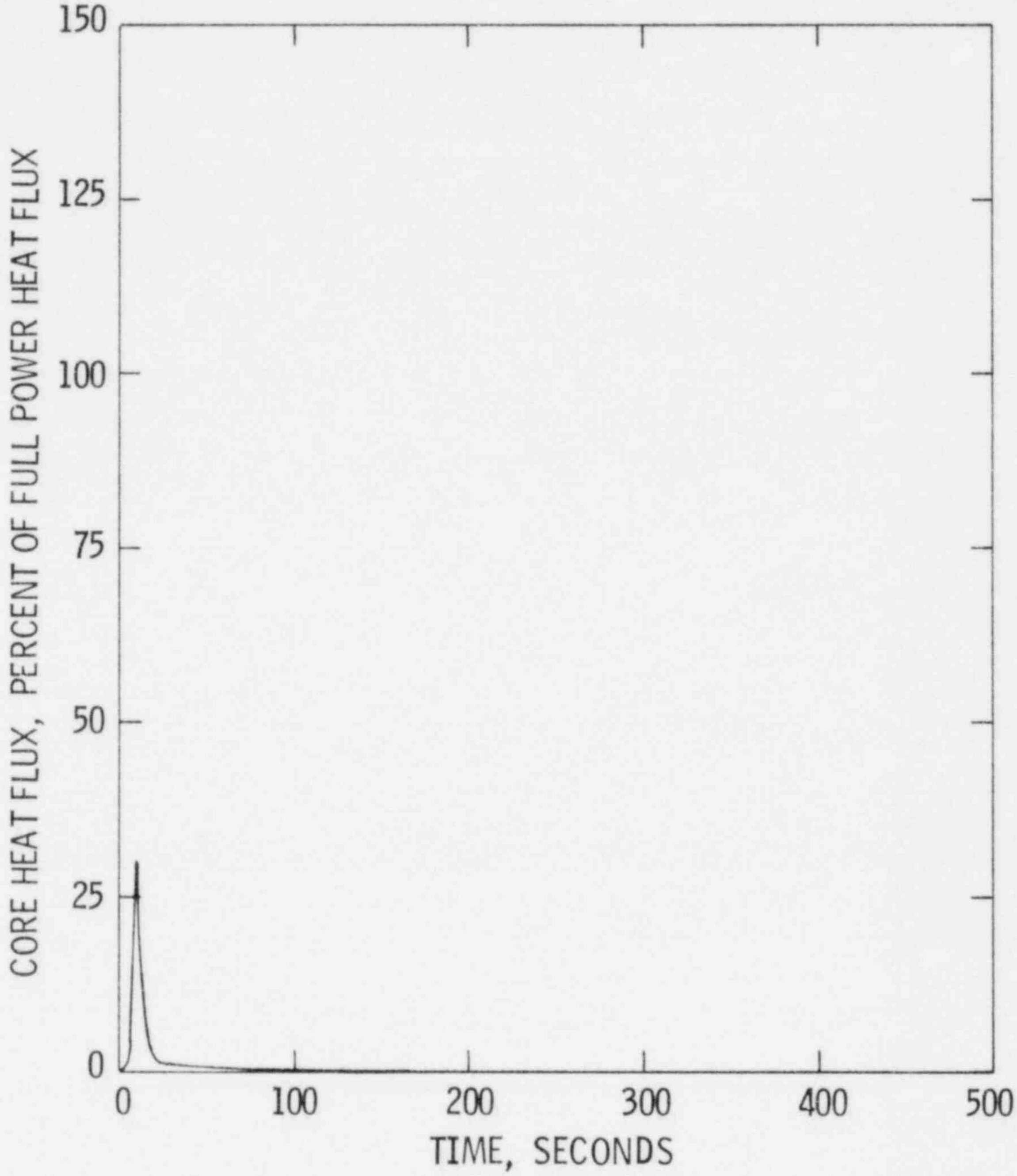
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE CORE POWER vs TIME	Figure 15.1.5-4.1



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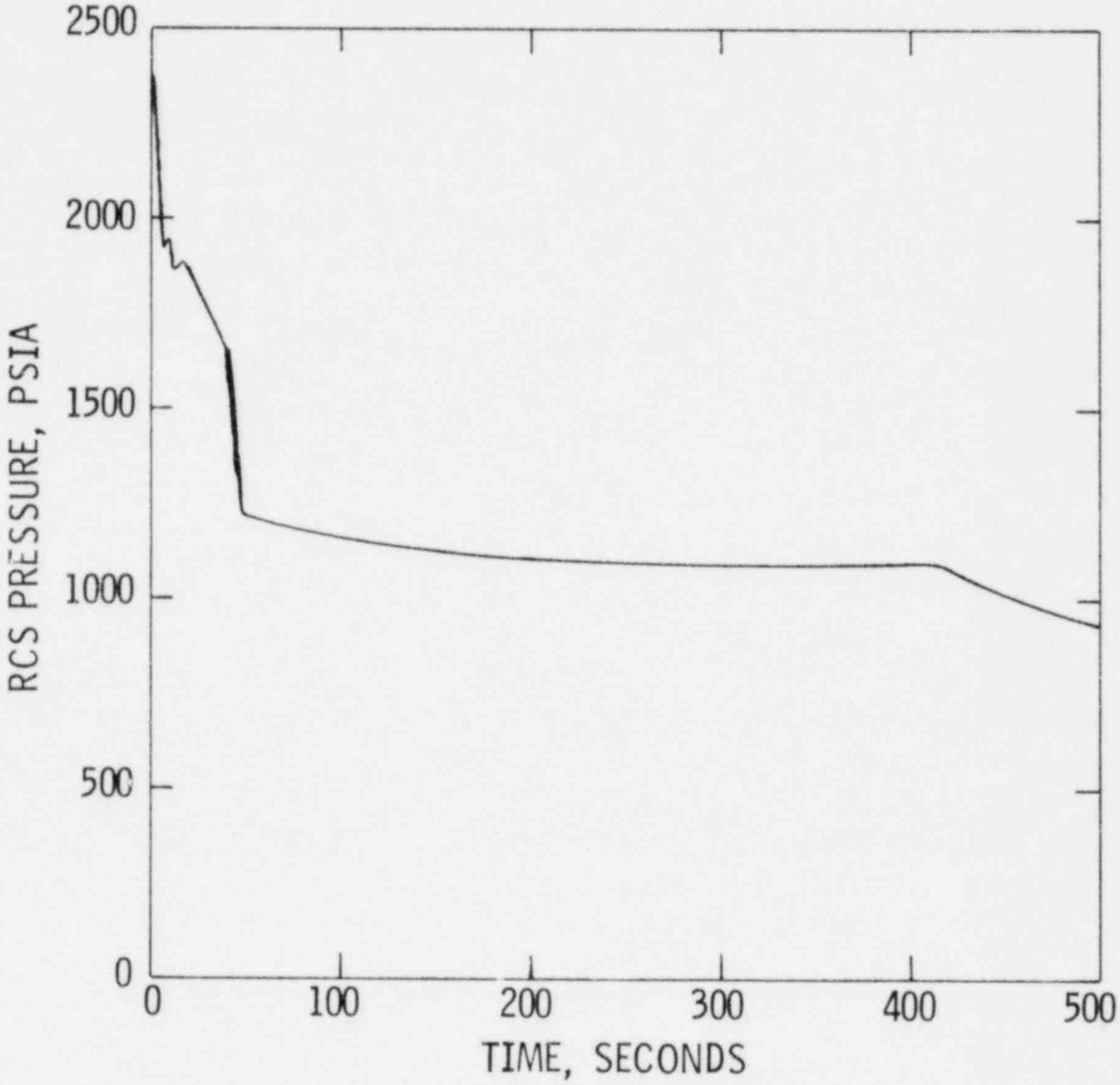
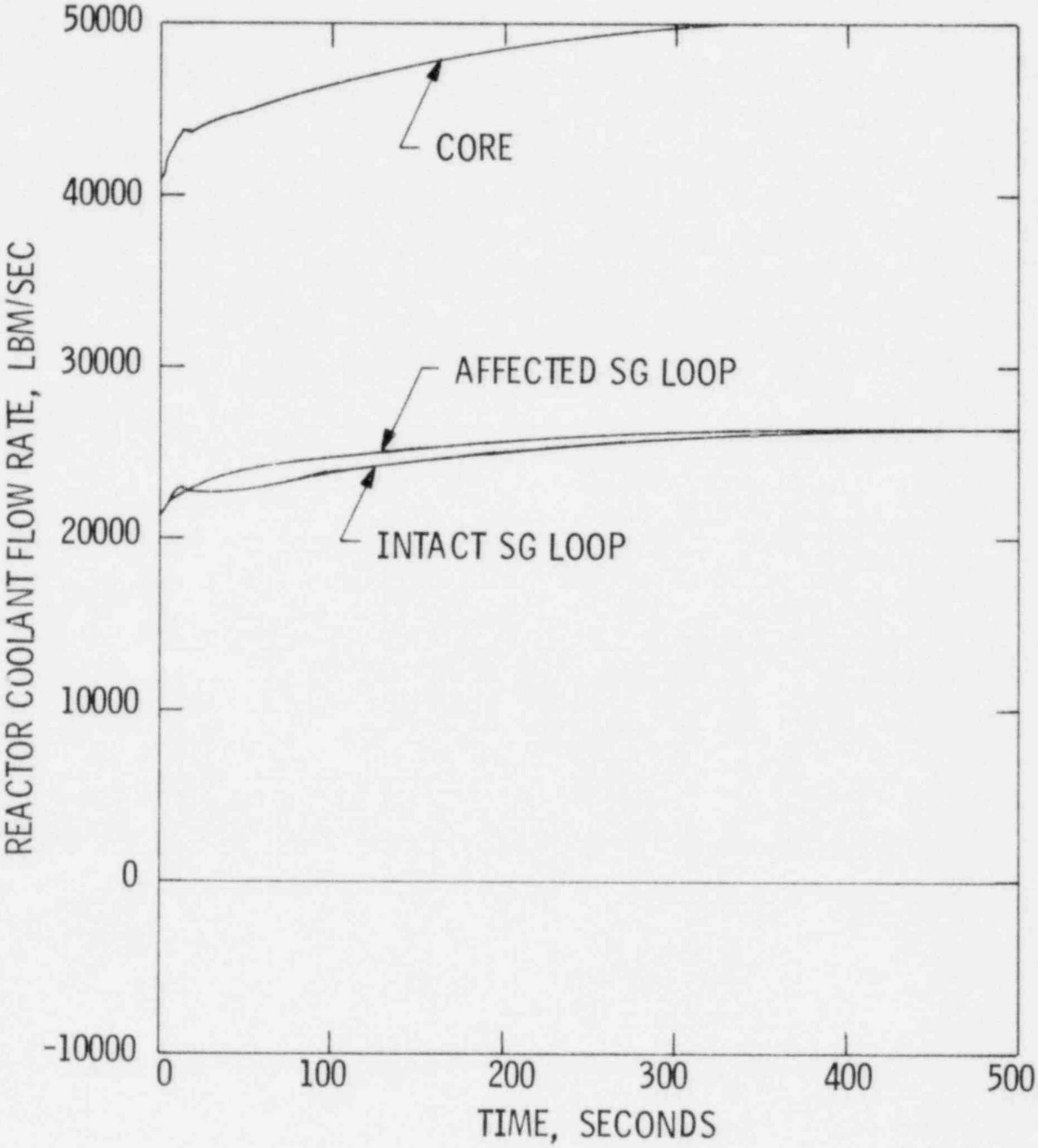
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE CORE HEAT FLUX vs TIME	Figure 15.1.5-4.2



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE RCS PRESSURE vs TIME	Figure 15.1.5-4.3



Amendment No. 7
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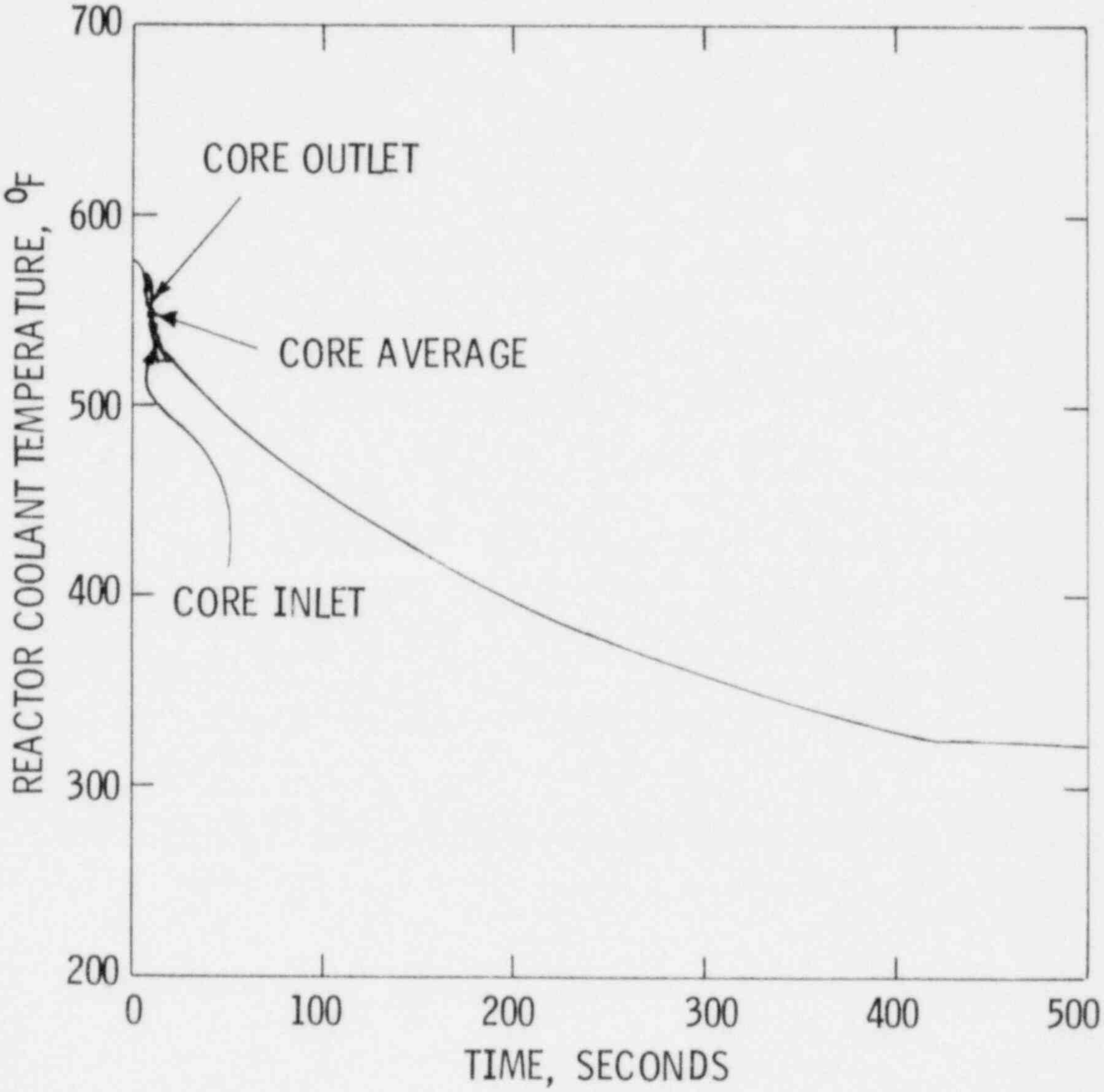
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT FLOW RATE vs TIME	Figure 15.1.5-4.4



Amendment No. 7
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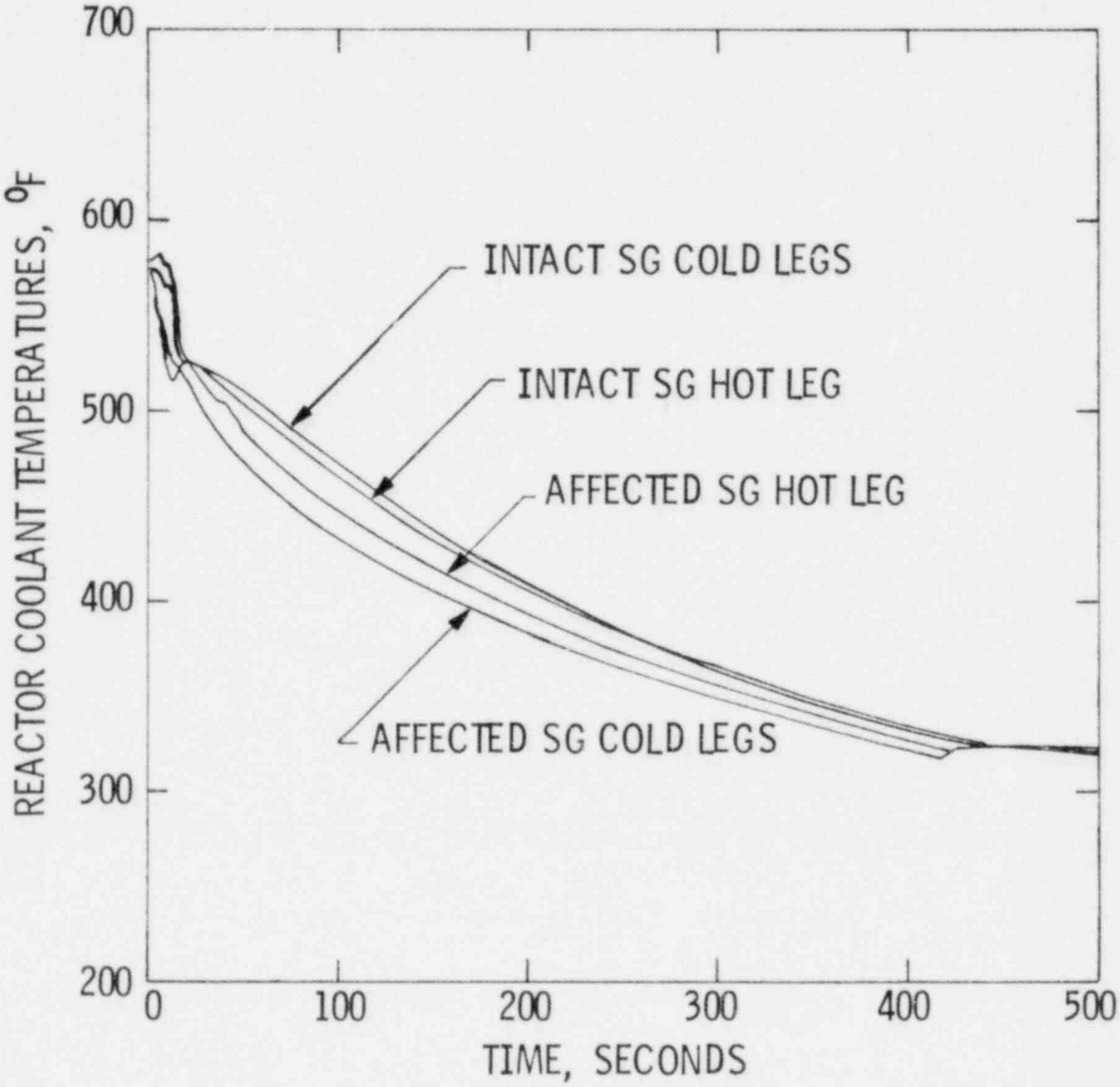
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT TEMPERATURES (A) vs TIME	Figure 15.1.5-4.5A



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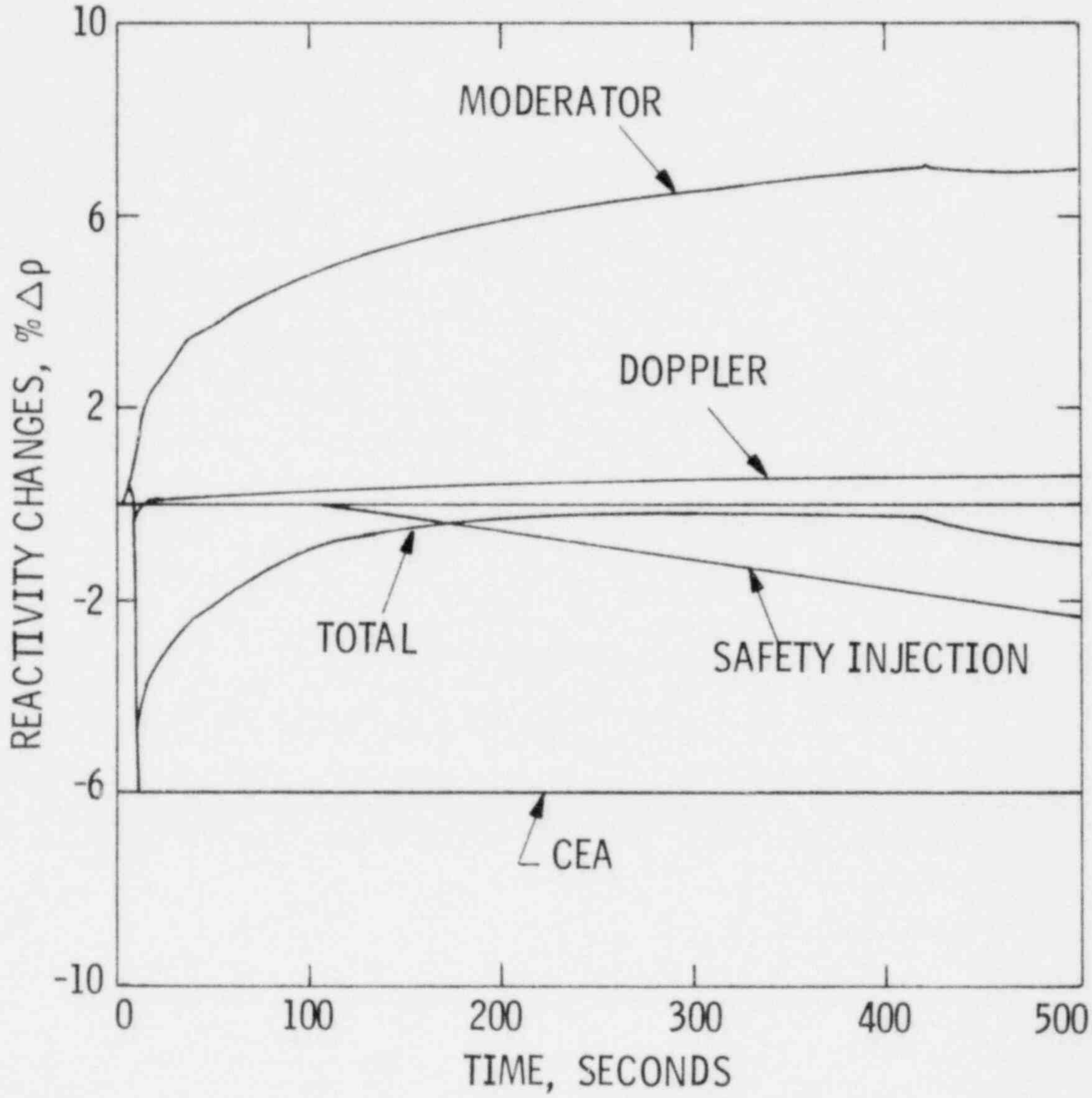
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT TEMPERATURES (B) vs TIME	Figure 15.1.5-4.5B



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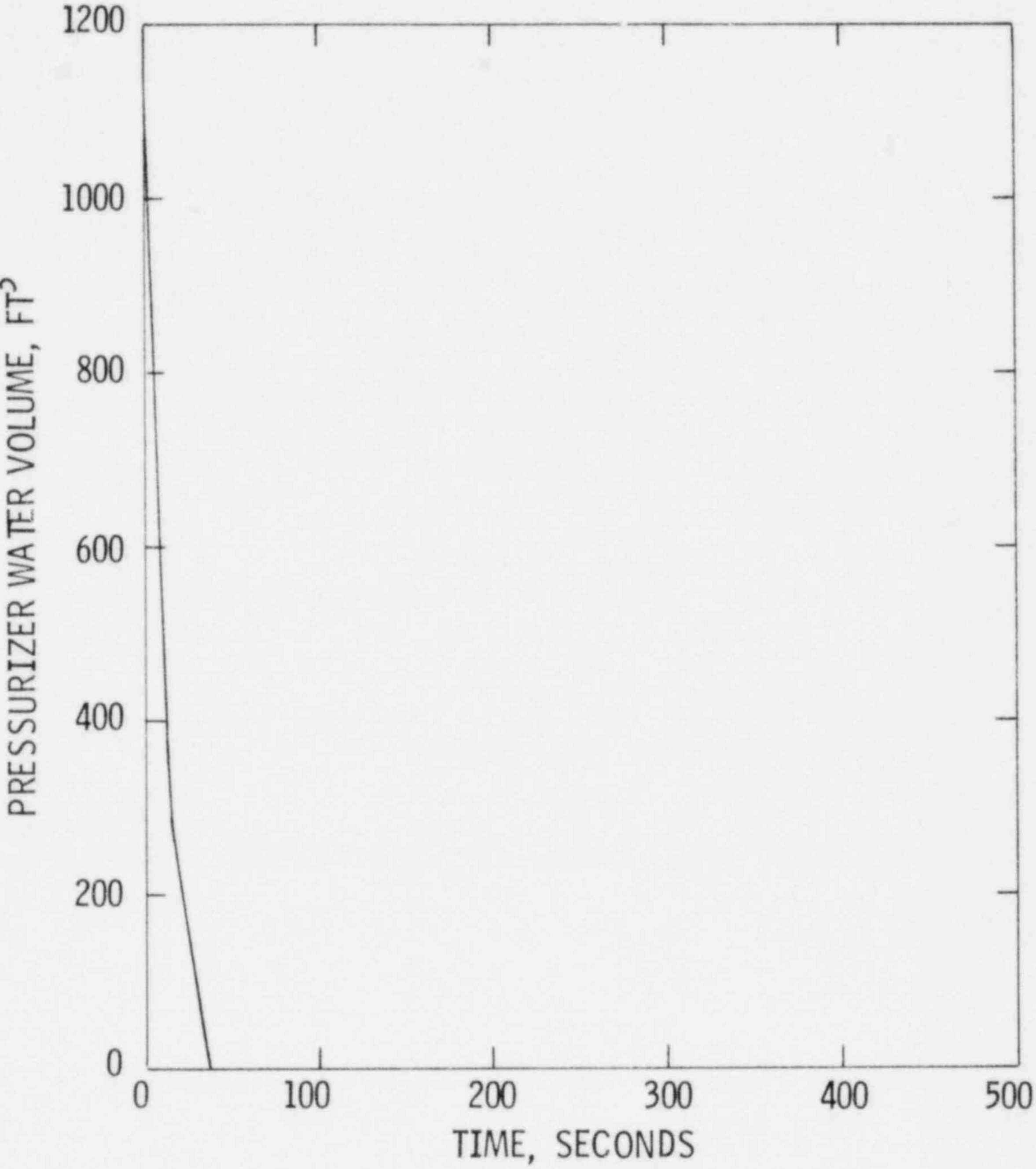
March 31, 1982

C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTIVITY CHANGES vs TIME	Figure 15.1.5-4.6



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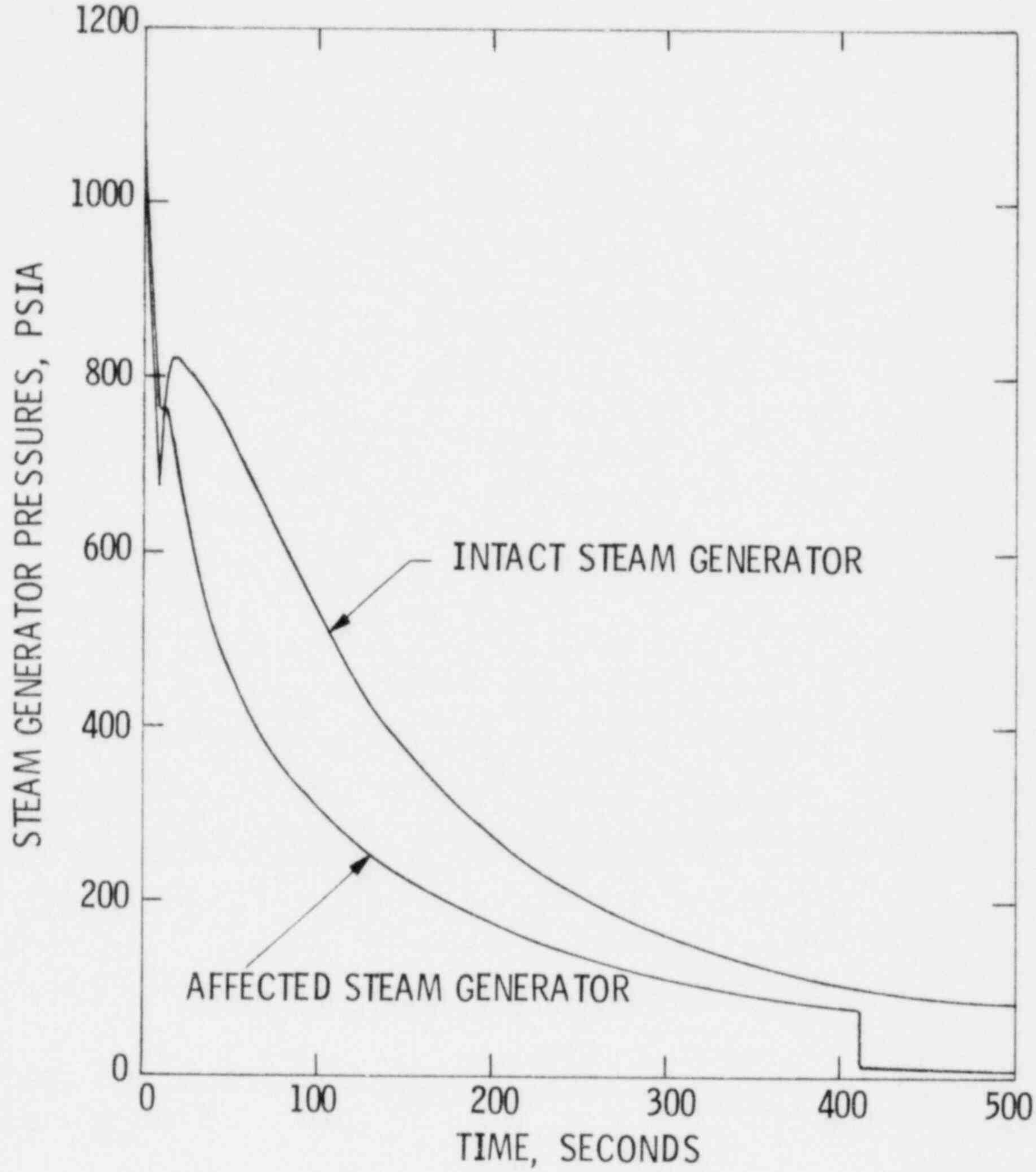
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE PRESSURIZER WATER VOLUME vs TIME	Figure 15.1.5-4.7



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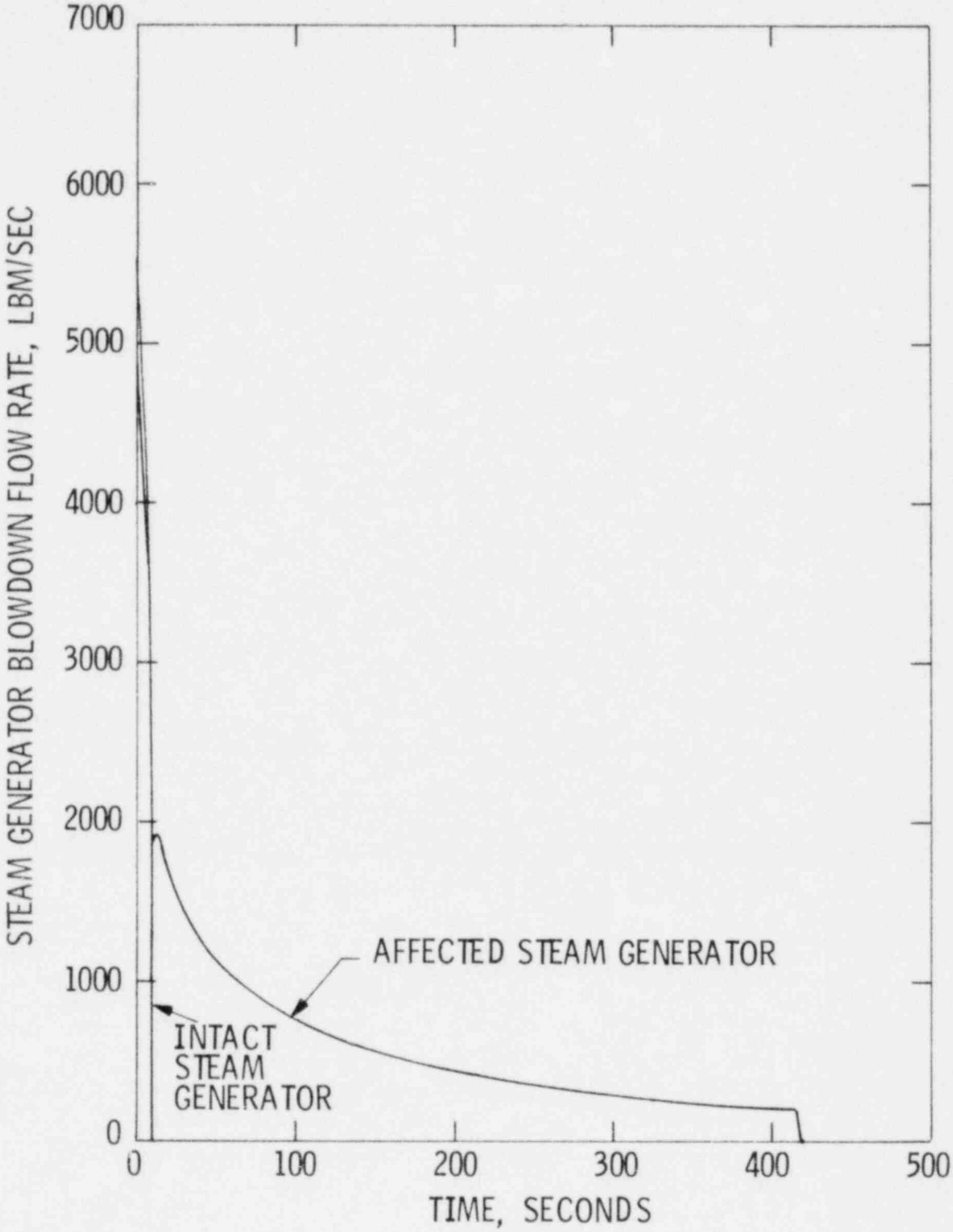
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR PRESSURES vs TIME	Figure 15.1.5-4.8



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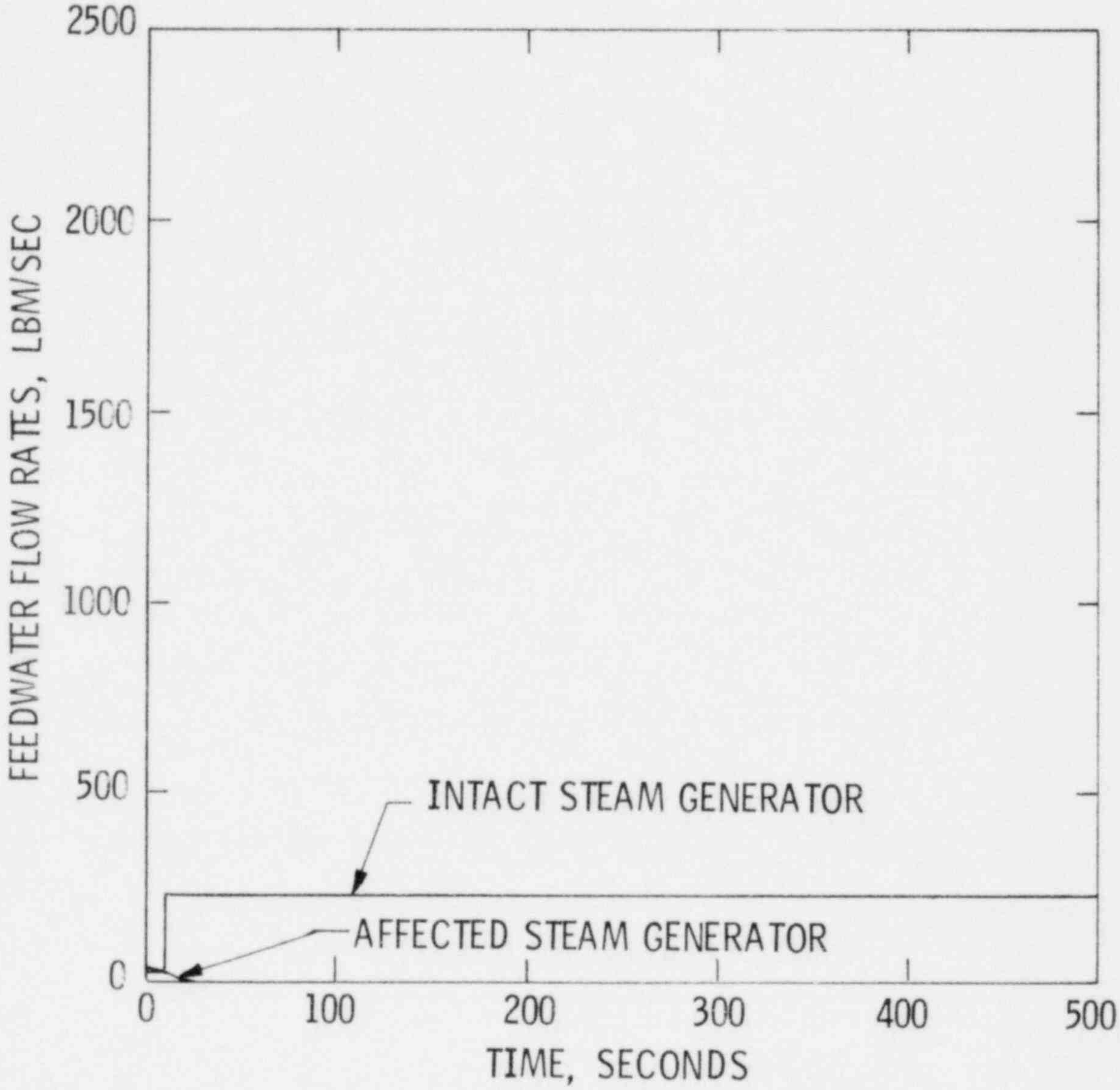
C-E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR BLOWDOWN RATES vs TIME	Figure 15.1.5-4.9



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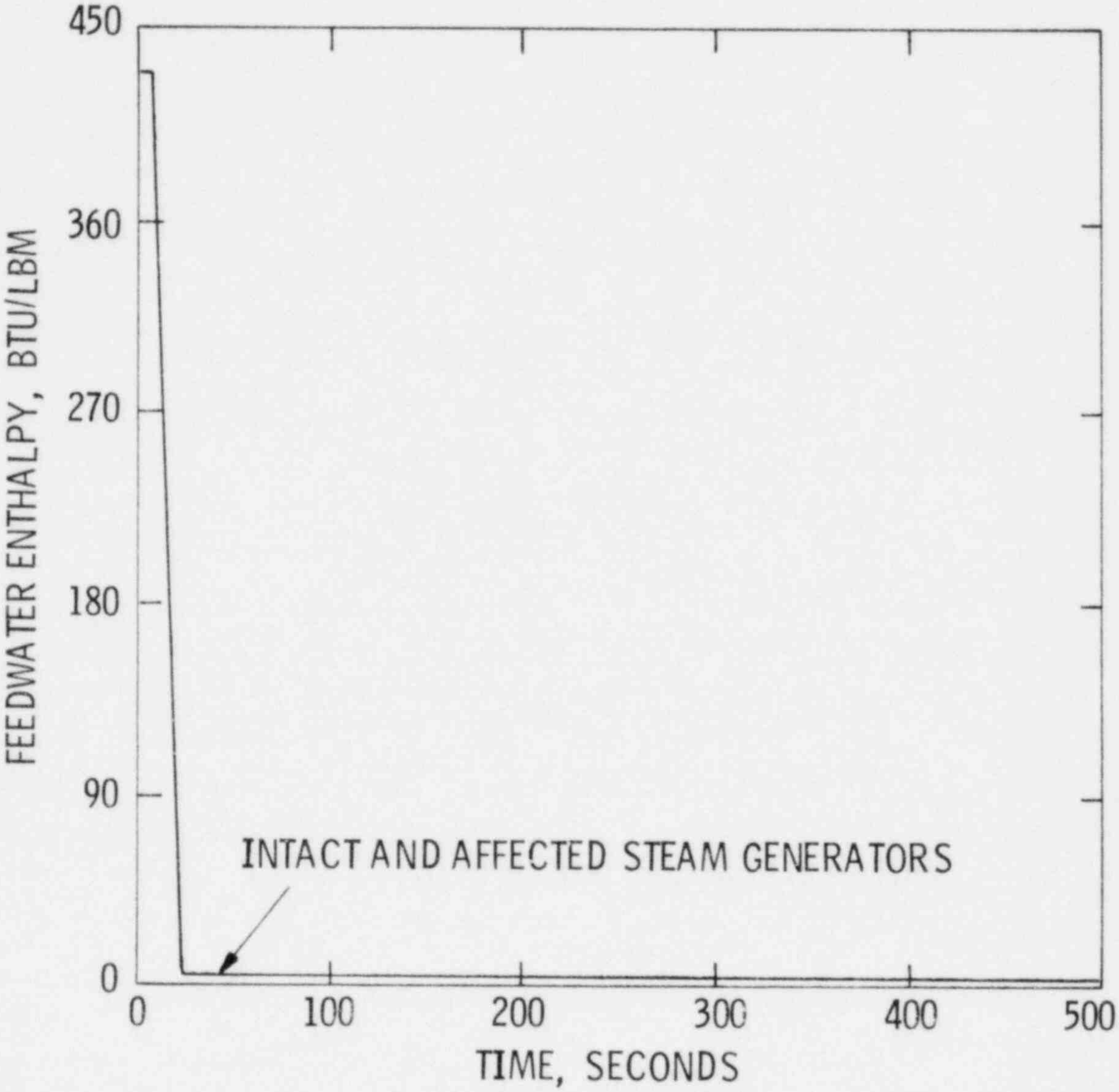
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE FEEDWATER FLOW RATES vs TIME	Figure 15.1.5-4.10



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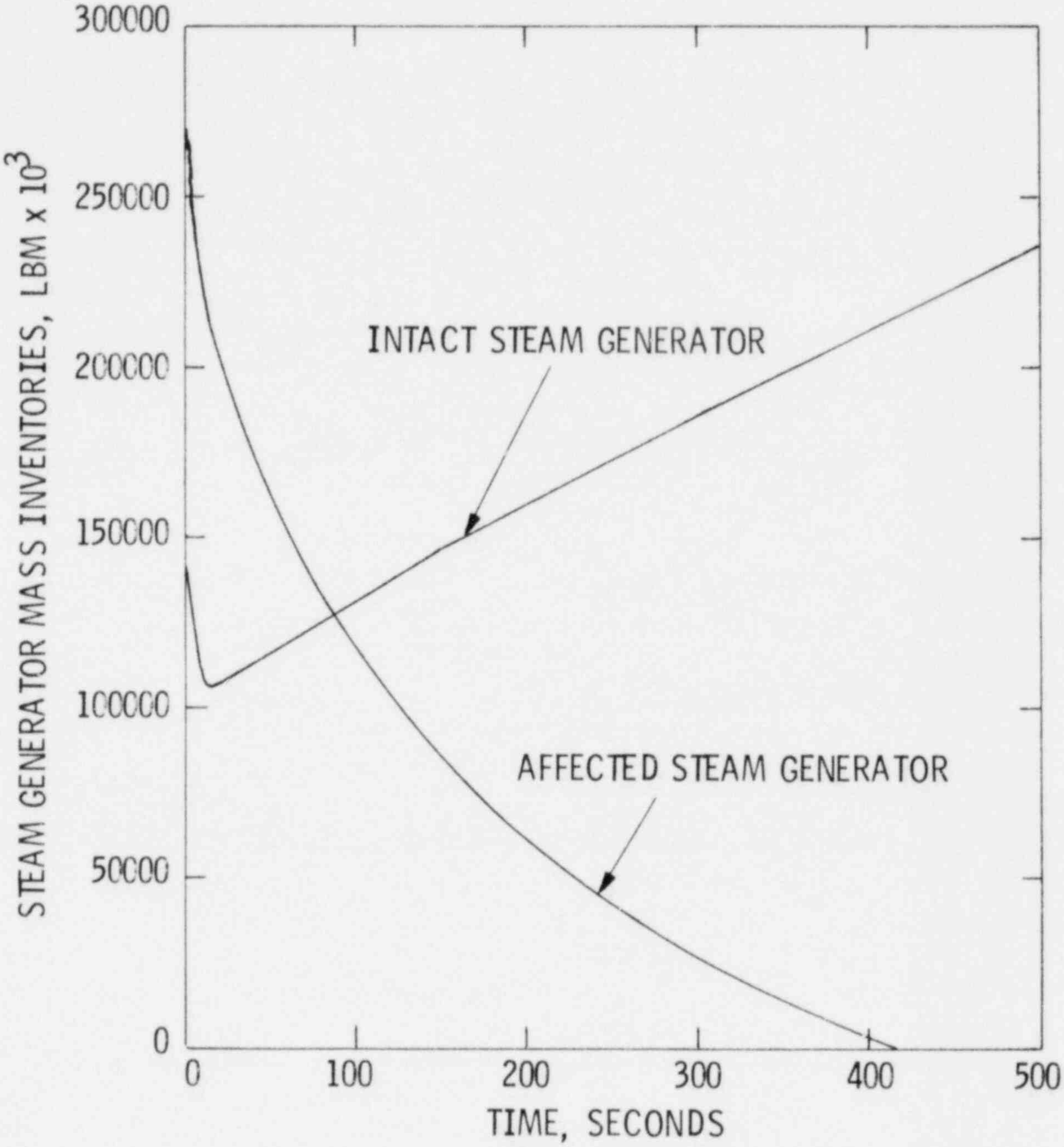
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE FEEDWATER ENTHALPY vs TIME	Figure 15.1.5-4.11



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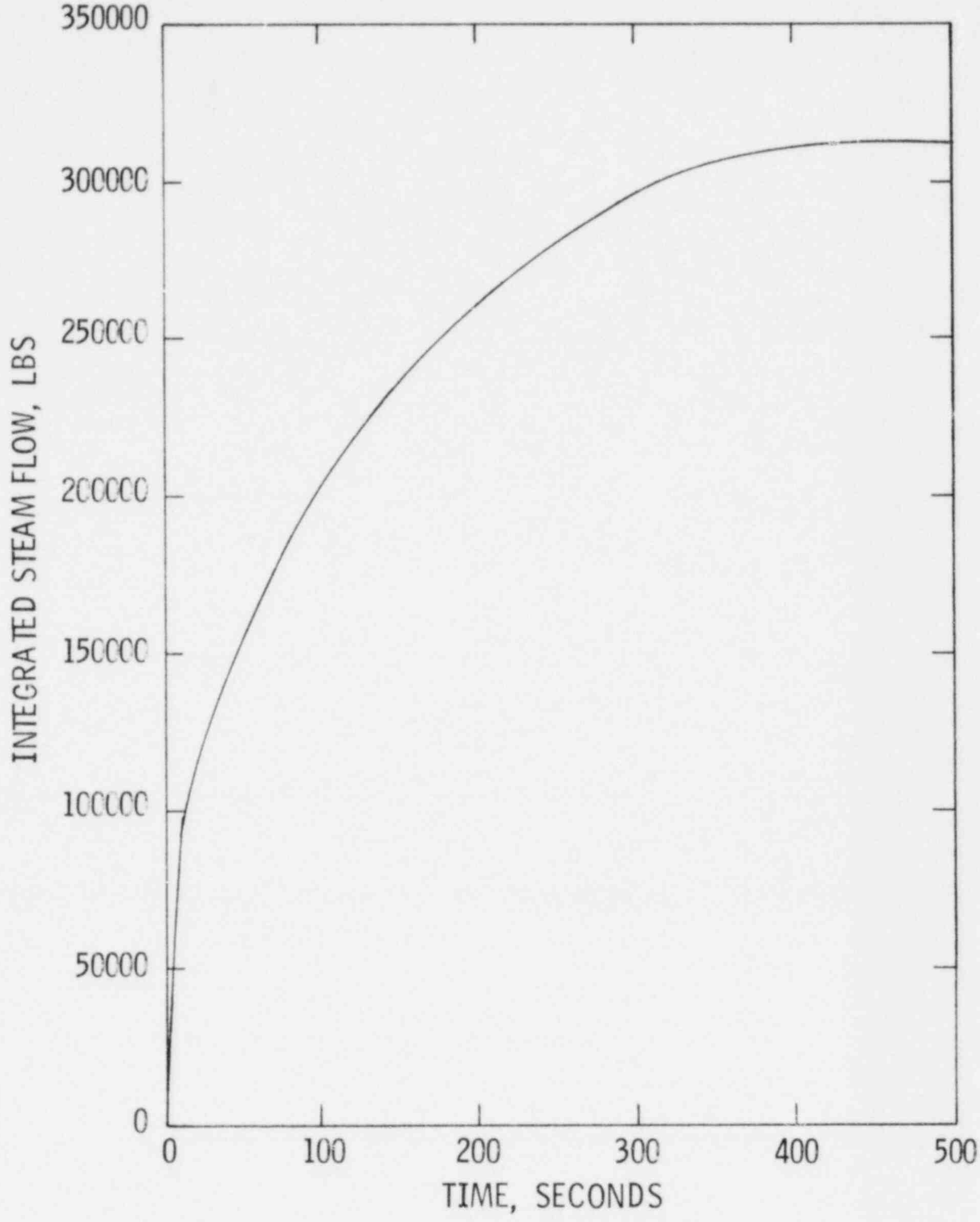
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR LIQUID MASS vs TIME	Figure 15.1.5-4.12



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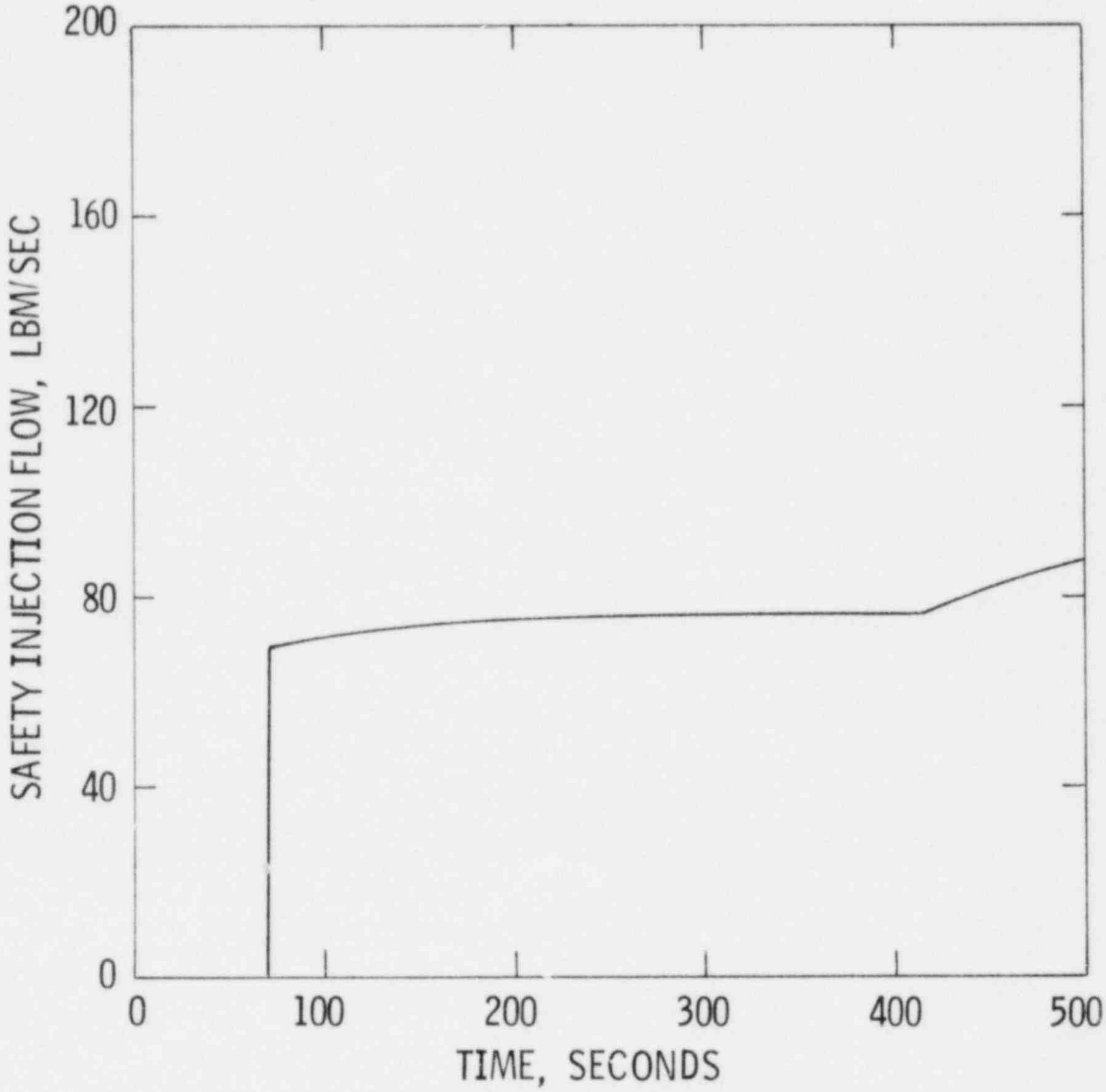
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE INTEGRATED STEAM RELEASE vs TIME	Figure 15.1.5-4.13



Amendment No. 7
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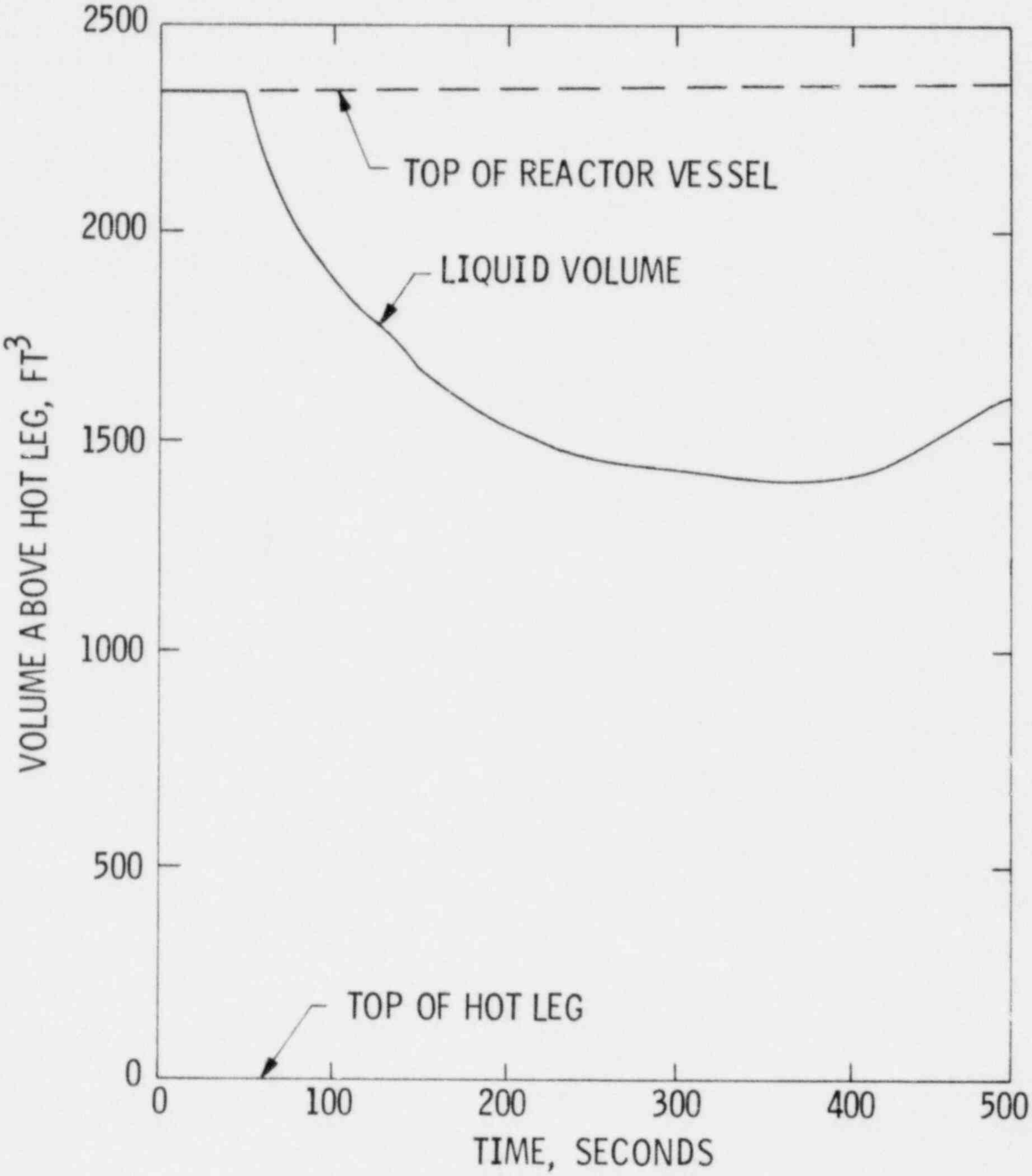
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE SAFETY INJECTION FLOW vs TIME	Figure 15.1.5-4.14



Amendment No. 7
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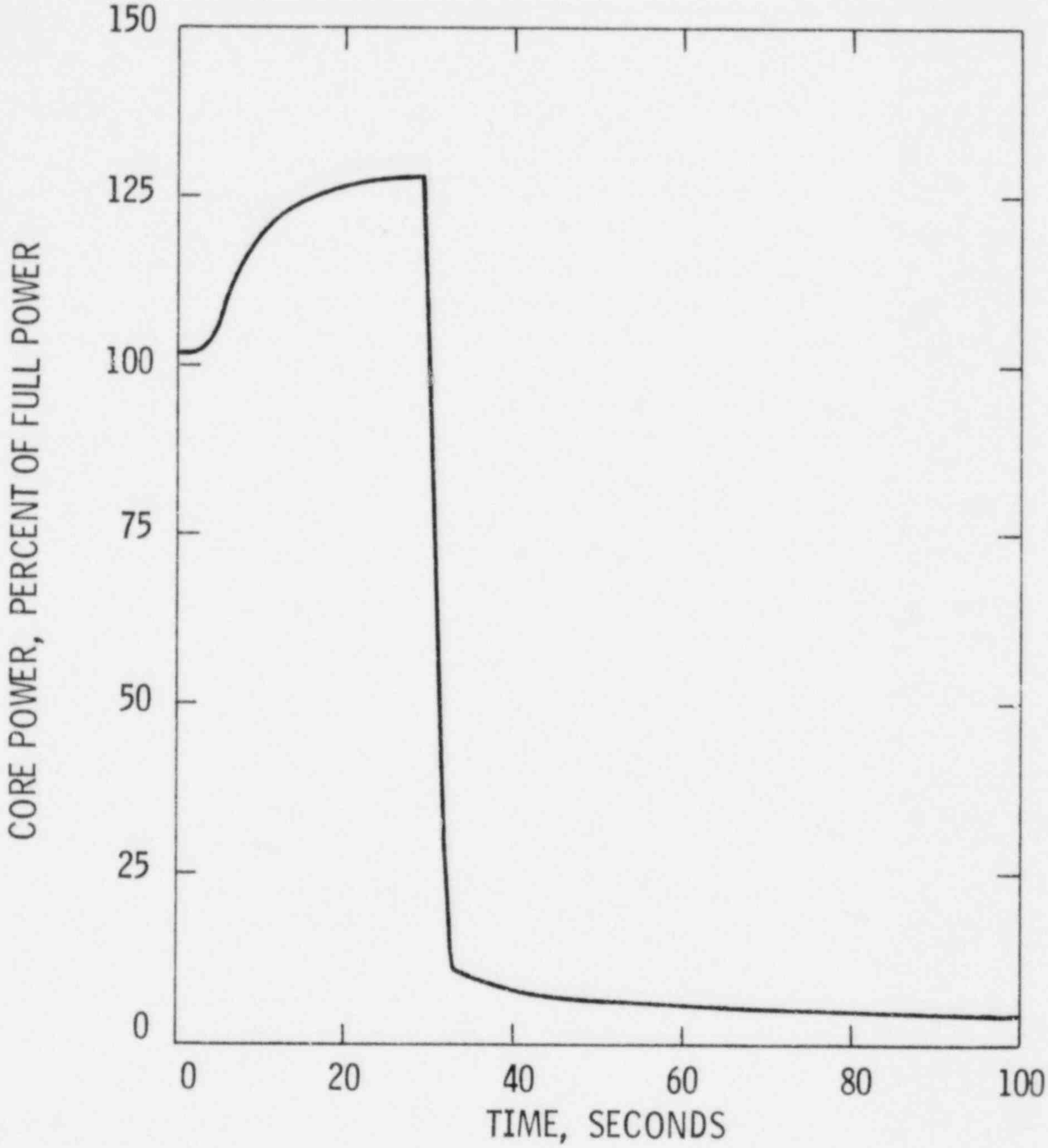
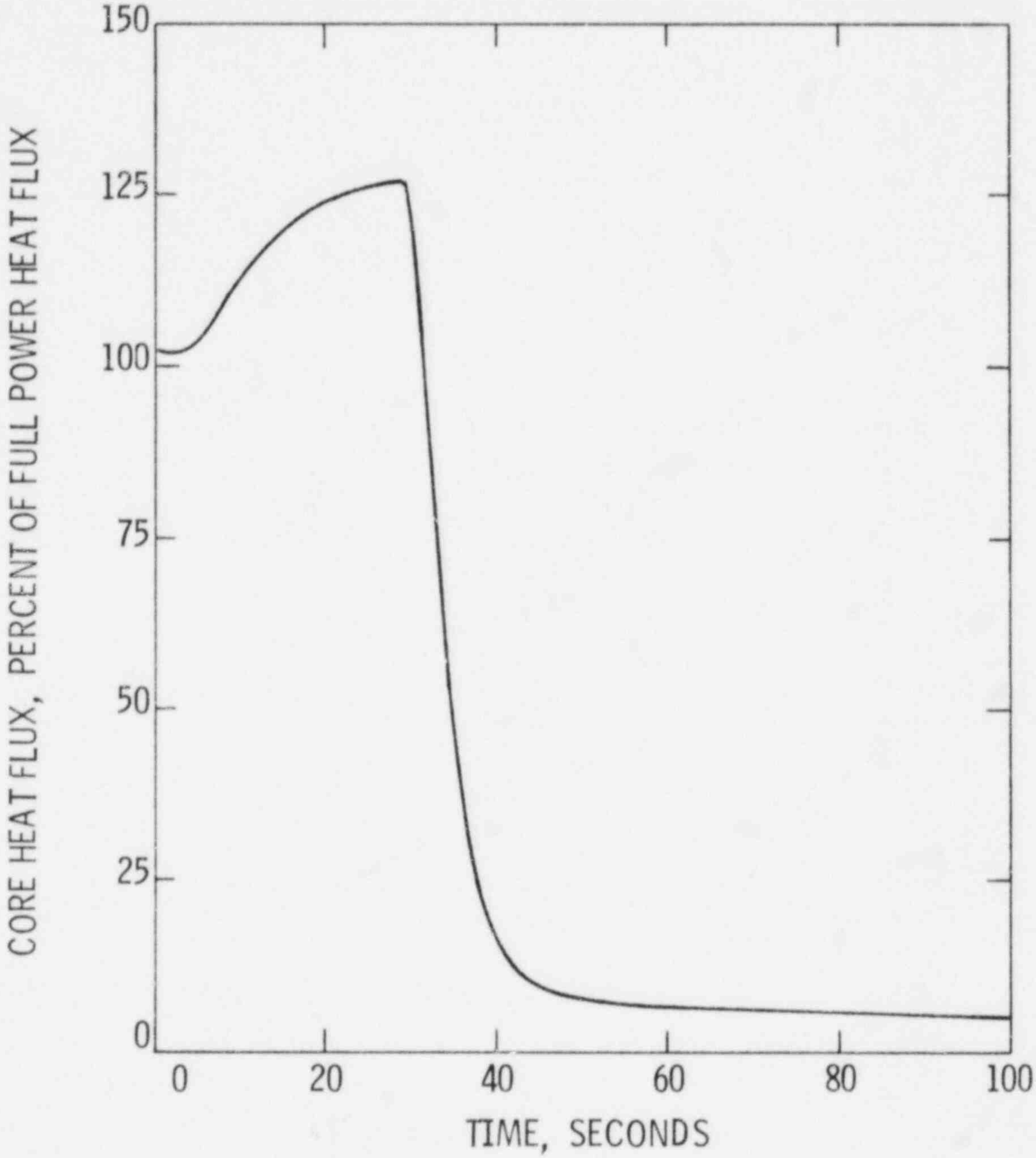
C - E SYSTEM 80	ZERO POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR VESSEL LIQUID VOLUME vs TIME	Figure 15.1.5-4.15



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE CORE POWER vs TIME	Figure 15.1.5-5.1



Amendment No. 7
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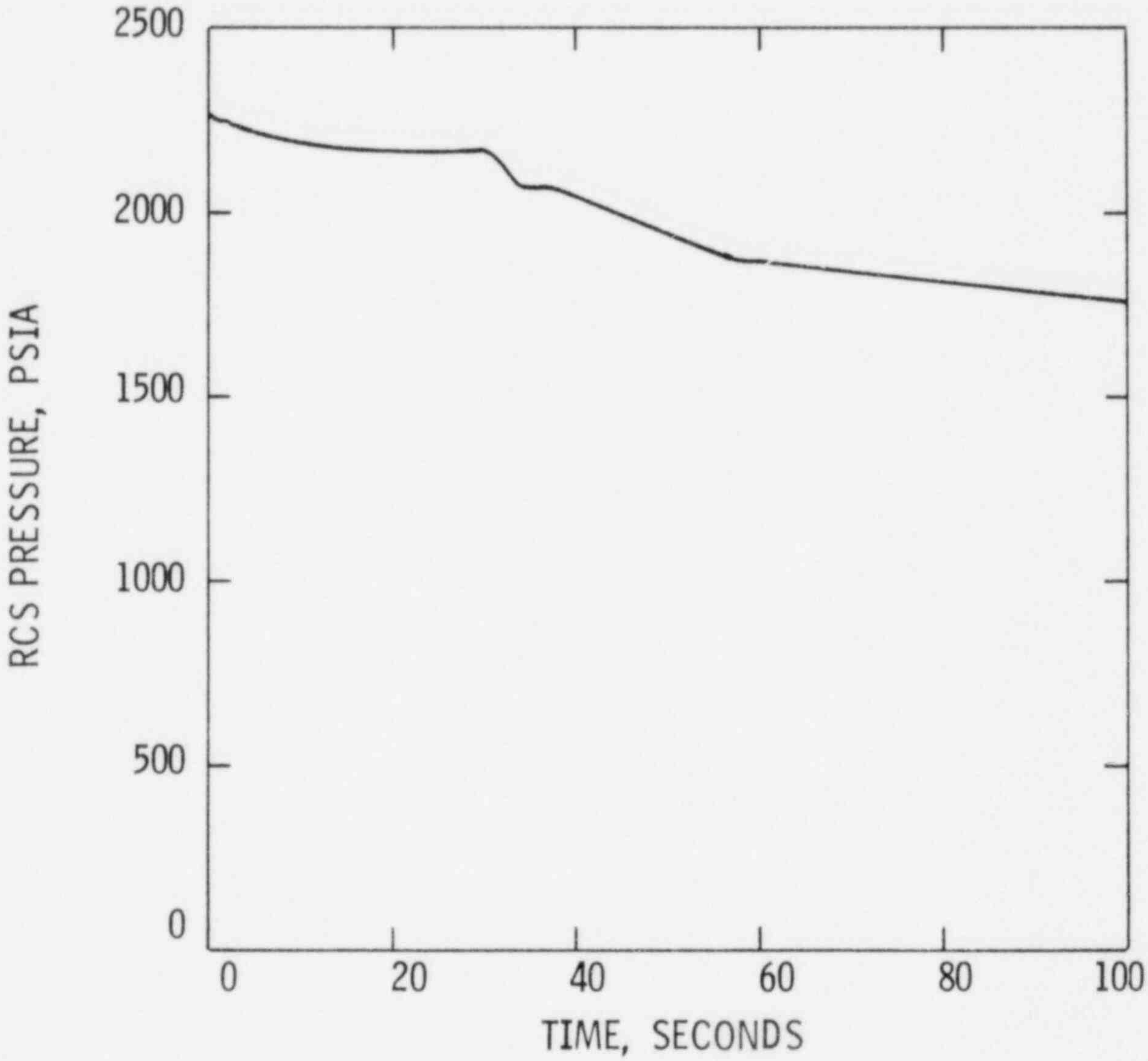
C - E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE CORE HEAT FLUX vs TIME	Figure 15.1.5-5.2



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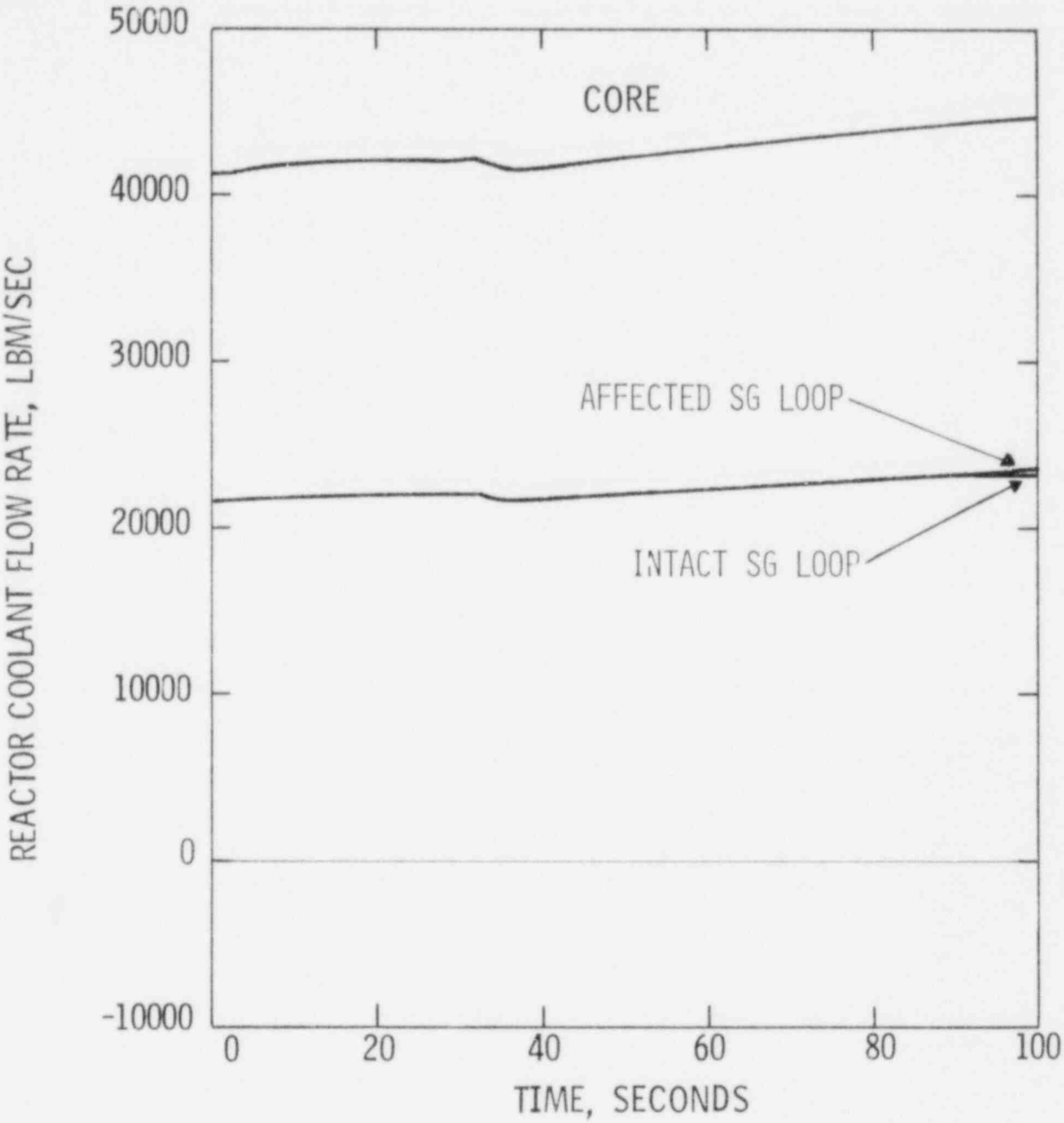
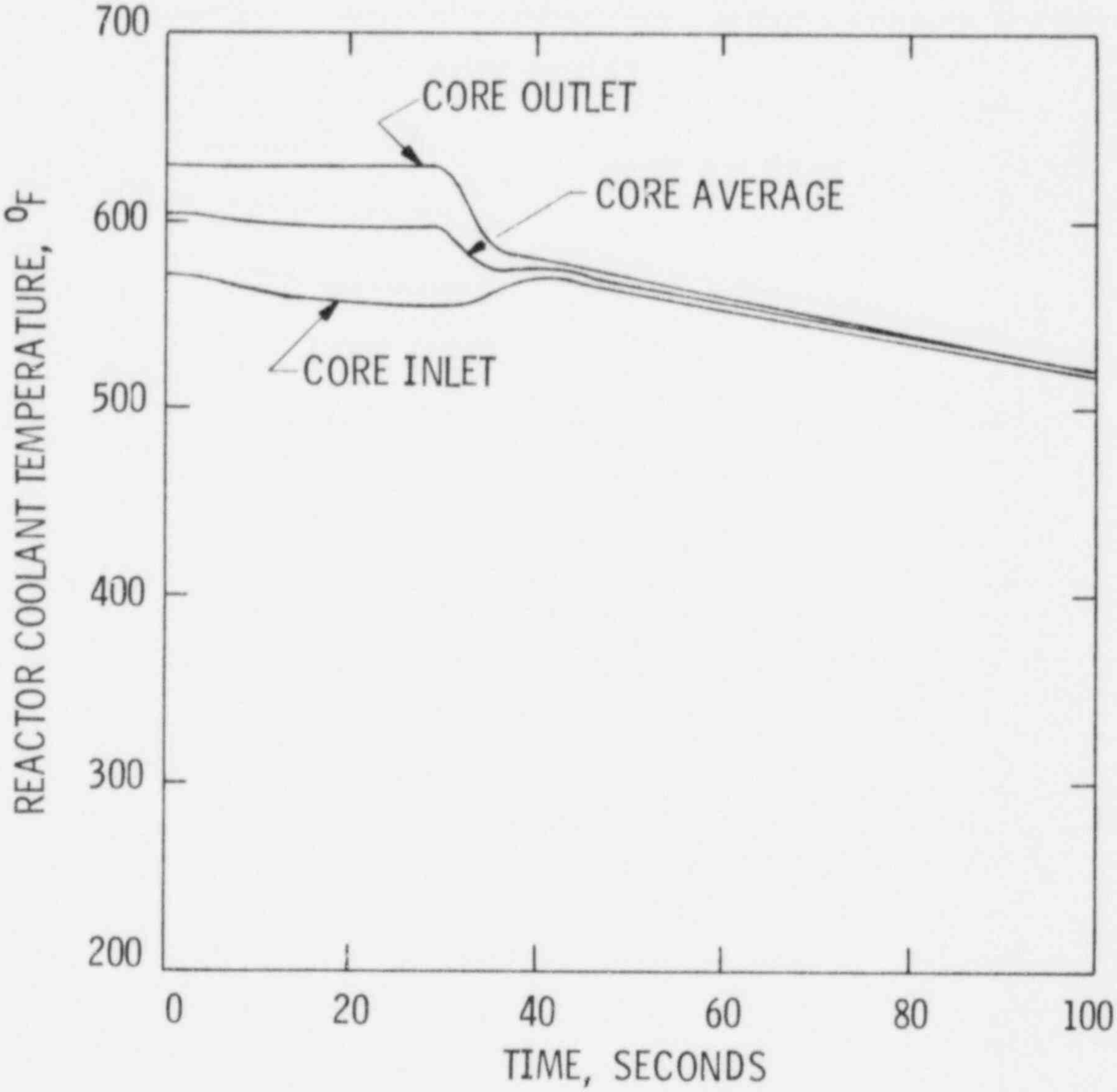
C-E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE RCS PRESSURE vs TIME	Figure 15.1.5-5.3



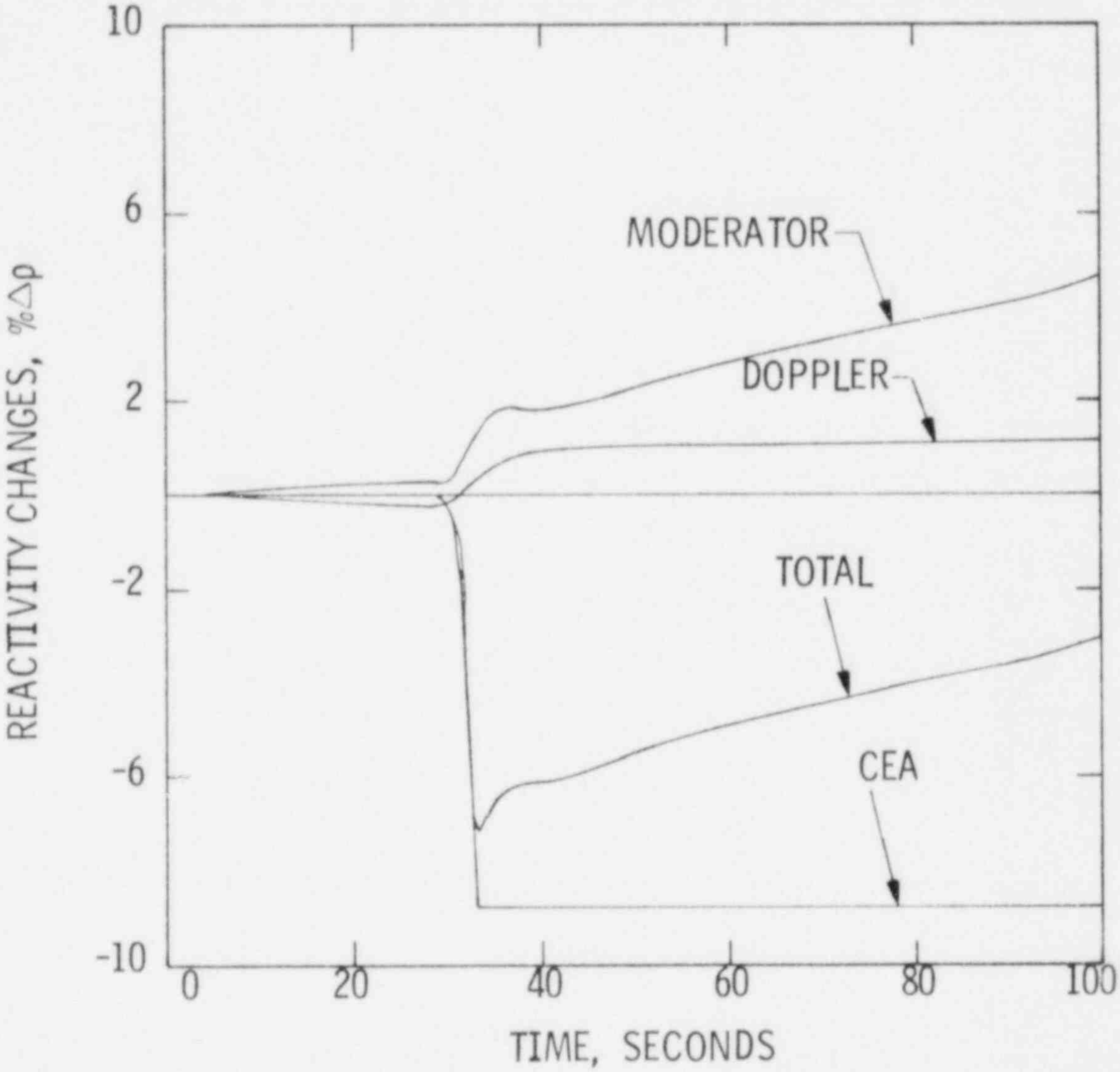
Amendment No. 7
March 31, 1982

C-E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE REACTOR COOLANT FLOW RATE vs TIME	Figure 15.1.5-5.4



Amendment No. 7
March 31, 1982

C-E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE REACTOR COOLANT TEMPERATURES vs TIME	Figure 15.1.5-5.5



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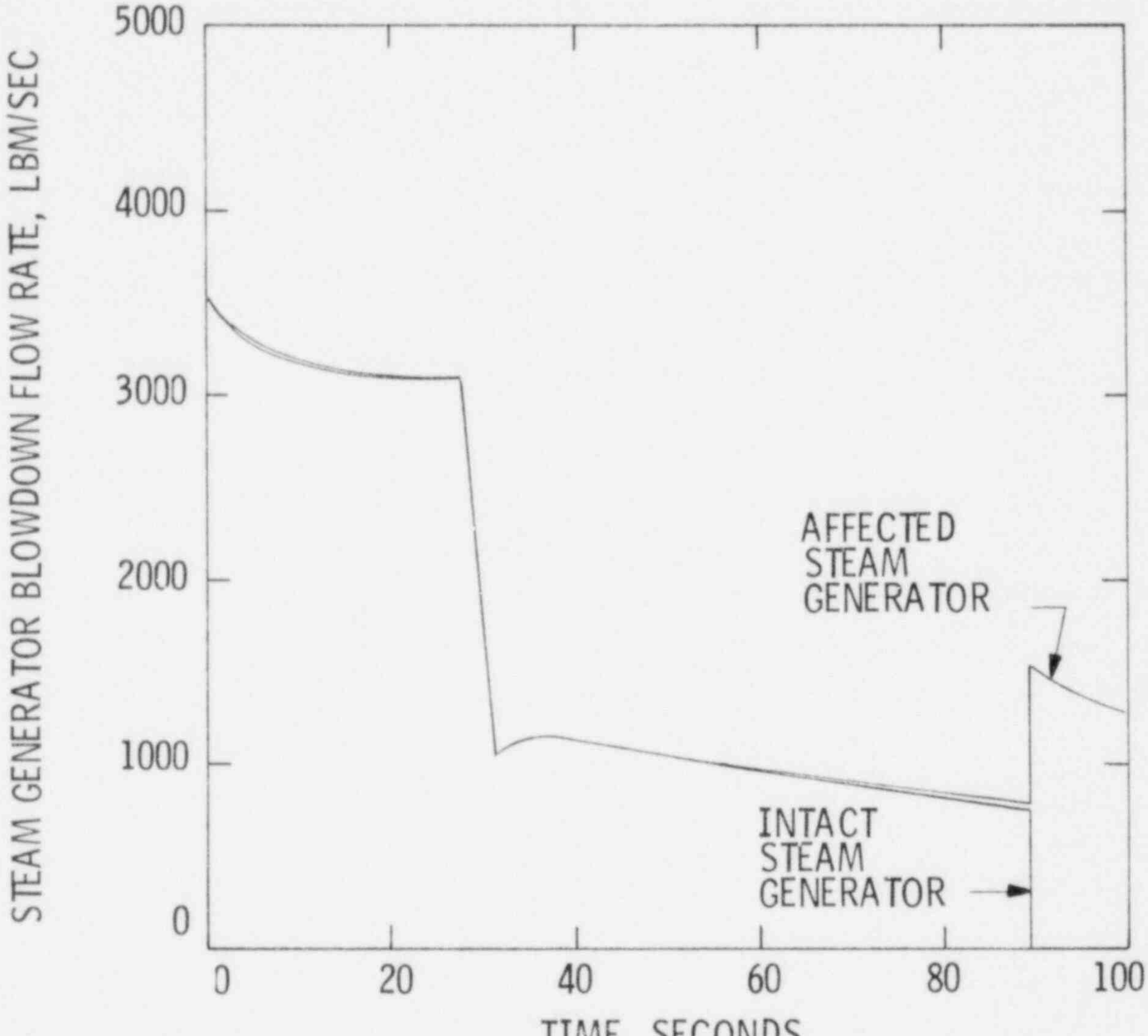
C - E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE REACTIVITY CHANGES vs TIME	Figure 15.1.5-5.6



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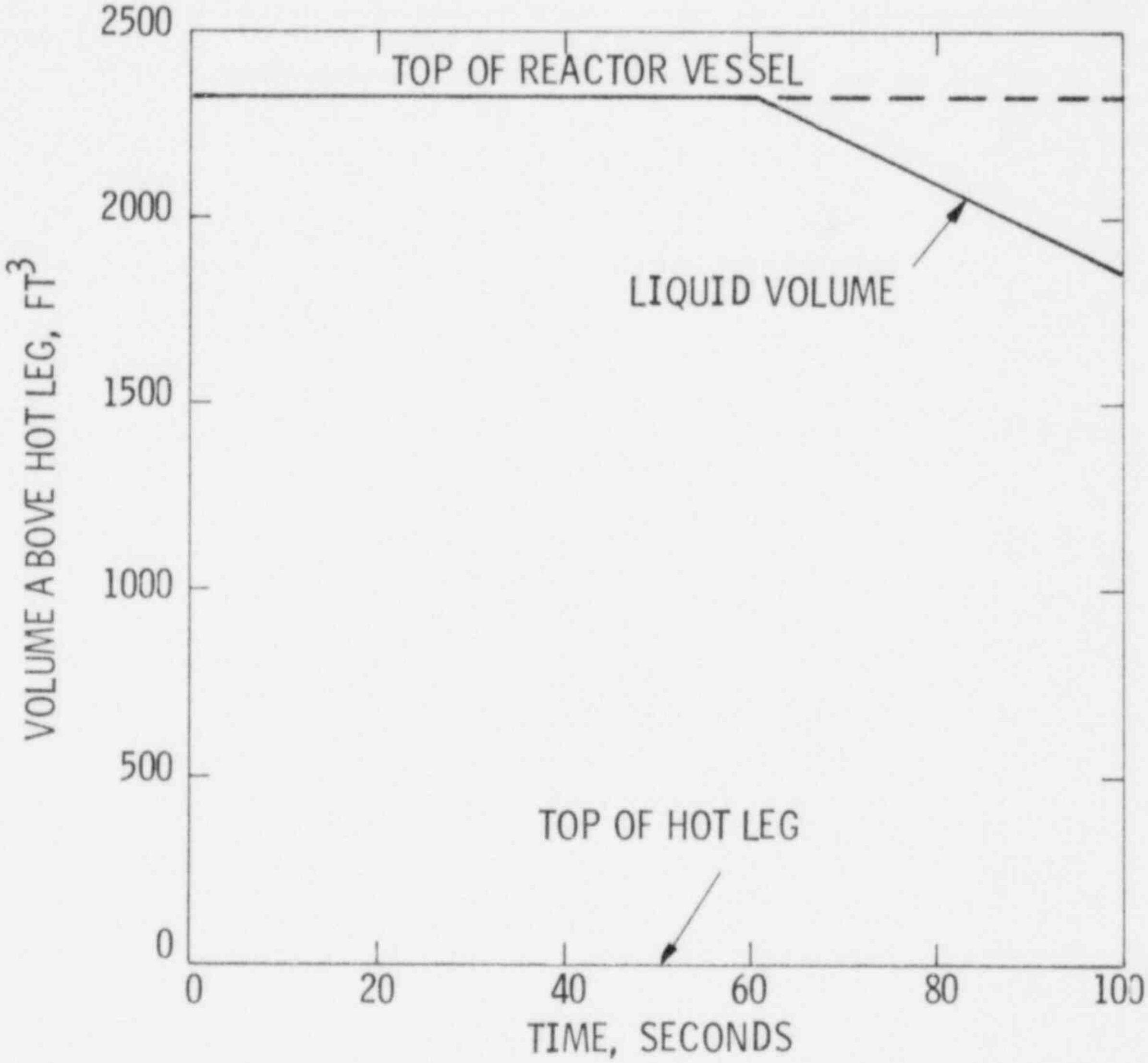
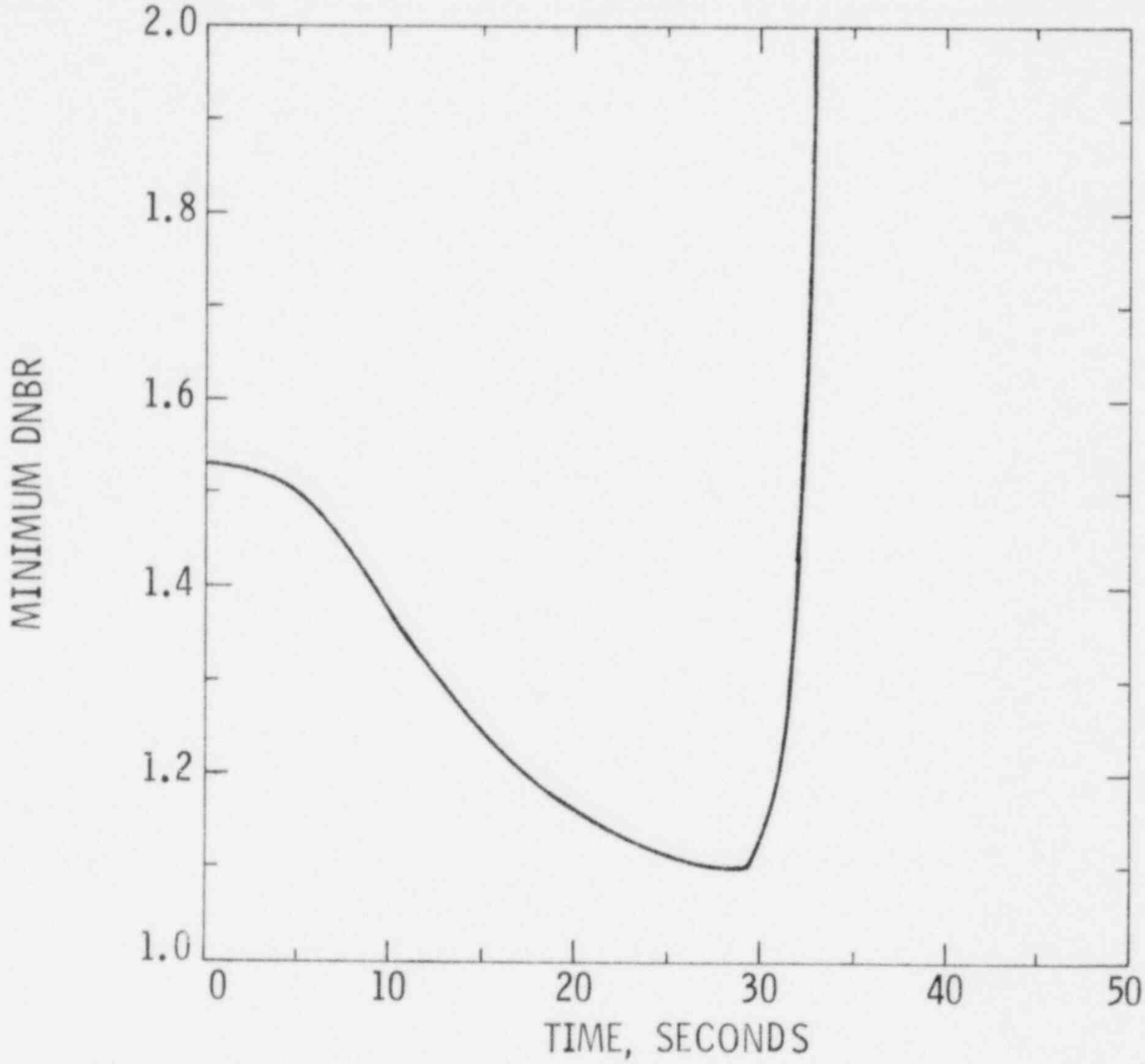
C-E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH CONCURRENT LOSS OF AC POWER STEAM GENERATOR BLOWDOWN RATES vs TIME	Figure 15.1.5-5.7



Amendment No. 7
March 31, 1982

C-E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE REACTOR VESSEL LIQUID VOLUME vs TIME	Figure 15.1.5-5.8



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C-E SYSTEM 80	FULL POWER SMALL STEAM LINE BREAK WITH AC POWER AVAILABLE DNBR vs TIME	Figure 15.1.5-5.9

15.2 DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

15.2.1 LOSS OF EXTERNAL LOAD

15.2.1.1 Identification of Event and Causes

The loss of external load event is caused by the disconnection of the turbine generator from the electrical distribution grid.

15.2.1.2 Sequence of Events and Systems Operation

A loss of external load generates a turbine trip which results in a reduction in steam flow from the steam generators to the turbine due to the closure of the turbine stop valves. The steam bypass control system (SBCS) and reactor power cutback system (RPCS) are both normally in the automatic mode and would be available upon turbine trip to accommodate the load rejection without necessitating reactor trip or the opening of main steam safety valves. Should a turbine trip occur with these systems in manual mode, a complete termination of main steam flow results and reactor trip would occur on high pressurizer pressure. If no credit is taken for immediate operator action, the main steam safety valves will open to limit the secondary pressure increase and provide a heat sink for the NSSS. The operator can initiate a controlled system cooldown using the SBCS any time after reactor trip occurs.

15.2.1.3 Analysis of Effects and Consequences

The results of the loss of load event are no more limiting with respect to RCS pressurization than those of the loss of condenser vacuum (LOCV) event presented in Section 15.2.3. The LOCV also results in a turbine trip, however, feedwater flow is assumed to terminate following LOCV whereas it is assumed to ramp down to 5% following the loss of load. This larger reduction in heat removal capability results in a higher peak RCS pressure for the LOCV.

Like the LOCV, the DNBR increases during the loss of load due to the increasing pressure. Thus, the initial DNBR is also the minimum DNBR. For the loss of load, due to its similarity with the LOCV event, there are no concurrent single failures which when combined with the loss of external load result in consequences more severe than the LOCV event with respect to RCS pressurization. The limiting single failure with respect to fuel performance is the loss of offsite power on turbine trip. This event with a concurrent loss of offsite power results in an event identical to the loss of flow (LOF) event discussed in Section 15.3.1. Results of the LOF event are directly applicable to the loss of external load with loss of offsite power on turbine trip.

15.2.1.4 Conclusions

For the loss of load event and the loss of load with a concurrent single failure, the RCS pressure remains below 2750 psia thus ensuring primary integrity, and the minimum DNBR remains above 1.19 thus ensuring fuel cladding integrity.

15.2.2 TURBINE TRIP

15.2.2.1 Identification of Event and causes

A turbine trip may result from a number of conditions which cause the turbine generator control system (TGCS) to initiate a turbine trip signal. A turbine trip initiates closure of the turbine stop valves.

15.2.2.2 Sequence of Events and Systems Operation

A turbine trip results in a reduction in steam flow from the steam generators to the turbine due to the closure of the turbine stop valves. The steam bypass control system (SBCS) and reactor power cutback system (RPCS) are both normally in the automatic mode and would be available upon turbine trip to accommodate the load rejection without necessitating reactor trip or the opening of main steam safety valves. Should a turbine trip occur with these systems in the manual mode, a complete termination of main steam flow results and reactor trip would occur on high pressurizer pressure. If no credit is taken for immediate operator action, the main steam safety valves will open to limit the secondary pressure increase and provide a heat sink for the NSSS. The operator can initiate a controlled system cooldown using the SBCS any time after reactor trip occurs.

15.2.2.3 Analysis of Effects and Consequences

The results of the turbine trip event are no more limiting with respect to RCS pressurization than those of the loss of condenser vacuum (LOCV) event presented in Section 15.2.3. The LOCV also results in a turbine trip, however, feedwater flow is assumed to terminate following LOCV whereas it is assumed to ramp down to 5% following the turbine trip. This larger reduction in heat removal capability results in a larger peak RCS pressure for the LOCV.

Like the LOCV, the DNBR increases during the turbine trip due to the increasing pressure. Thus, the initial DNBR is also the minimum DNBR for the loss of load. Due to its similarity with the LOCV events, there are no concurrent single failures which when combined with the turbine trip result in consequences more severe than the LOCV event with respect to RCS pressurization. The limiting single failure with respect to fuel performance is the loss of offsite power on turbine trip. This event with a concurrent loss of offsite power results in an event nearly identical to the loss of AC power which initiates the loss of flow (LOF) event discussed in Section 15.3.1. Results of the LOF event are directly applicable to the turbine trip event with loss of offsite power.

15.2.2.4 Conclusions

For the turbine trip event and the turbine trip with a concurrent single failure, the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above 1.19 thus ensuring fuel cladding integrity.

15.2.3 LOSS OF CONDENSER VACUUM

15.2.3.1 Identification of Event and Cause

A loss of condenser vacuum (LOCV) may occur due to the failure of the circulating water system to supply cooling water, failure of the main condenser evacuation system to remove noncondensible gases, or excessive in-leakage of air through a turbine gland. The turbine is assumed to trip immediately coincident with the cause for the loss of condenser vacuum.

When in the automatic mode, the Steam Bypass Control System (SBCS), if it controls atmospheric bypass valves, and the Reactor Power Cutback System (RPCS) will function to reduce the steam generator and RCS pressure increases during a turbine trip. These systems may allow the NSSS to continue operating at a reduced power level. However, in this analysis both the SBCS and RPCS are assumed to be in the manual mode and credit is not taken for their functioning.

Consideration of single failures is addressed in Section 15.2.3.3D.

15.2.3.2 Sequence of Events and Systems Operation

Table 15.2.3-1 presents a chronological sequence of events which occur following the LOCV until operator action is initiated. Figure 15.0-1 contains a glossary of SEA symbols and acronyms which may be used with the Sequence of Events Diagram, Figure 15.2.3-1, to trace the actuation and interaction of the systems utilized to mitigate the consequences of this event.

Table 15.2.3-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient.

The success paths in the Sequence of Events Diagram, Figure 15.2.3-1, are as follows:

Reactivity Control:

An automatic reactor trip occurs on high pressurizer pressure. The CEA's begin to fall and insert negative reactivity. After the reactor trip a SIAS is generated on low pressurizer pressure. Additional negative reactivity is inserted when the borated safety injection water reaches the core. The boron concentration is adjusted to insure that a proper negative reactivity shutdown margin is achieved prior to cooldown. The boron concentration is adjusted by manually controlling the CVCS. If letdown is used for boration, the letdown isolation valves, which were closed on the SIAS/CIAS, must be reopened.

Reactor Heat Removal:

A CIAS occurs on low pressurizer pressure, following which the component cooling water to the RCP's is lost. The operator restores cooling water to the reactor coolant pumps and a normal RCS cooldown is conducted. The SCS is manually actuated when RCS temperature and pressure have been reduced to 350°F and 400 psia. This system provides sufficient cooling to bring the RCS to cold shutdown.

Primary System Integrity:

A large reduction in primary system heat removal occurs when the main feedwater pumps and the turbine all trip. This causes the RCS pressure to increase and open the Primary Safety Valves (PSVs). Steam is initially released from the PSVs to the Reactor Drain Tank (RDT). The total steam release (1634 lbm) exceeds the RDT capacity and will probably cause the rupture disc to fail. A CIAS generated on low pressurizer pressure isolates the RCP controlled bleedoff flow. The bleedoff relief valve opens and passes the bleedoff flow to the ruptured RDT. The containment building receives some of the PSV and bleedoff liquid released in this event. The pressurizer level is restored automatically by the safety injection flow, even though other means are available. During cooldown, the pressurizer pressure and level control systems are manually operated to regulate pressure and level in the primary system. To perform this action, the letdown isolation valves (which were closed on CIAS and SIAS) must be opened. When the RCS pressure has been reduced to approximately 650 psia, the operator will vent or drain the SITs to reduce their pressure and will then isolate them.

Secondary System Integrity:

The turbine and main feedwater pumps automatically trip at time zero on the loss of condenser vacuum. The turbine stop valves close instantly and an SBCS interlock prevents the bypass valves from opening. The secondary system pressure increases and opens the main steam safety valves. Emergency feedwater flow reaches the steam generators and restores the levels. Cancelation and reactuation of emergency feedwater may occur since the main steam safety valves remain open until 346 seconds. Once the plant parameters are stabilized, the operator initiates cooldown by utilizing one feedwater pump designated as "auxiliary" and intended for normal startup and shutdown of the plant in conjunction with the ASDS. If this pump is part of a separate Auxiliary Feedwater System then he will first secure the Emergency Feedwater System. He may also let the ESFAS regulate the feedwater flow by issuing and withdrawing EFAS-1 and/or EFAS-2 signals down to cold shutdown entry conditions. See Applicant's FSAR for details of the Emergency and/or Auxiliary Feedwater Systems.

Control Room Habitability:

CIAS, SIAS or BOP signals may actuate control room habitability systems. See Applicant's FSAR for details.

Fuel Handling Building Habitability:

CIAS, SIAS or BOP signals may actuate fuel handling building habitability systems. See Applicant's FSAR for details.

Radioactive Effluent Control:

CIAS isolates various systems to reduce or terminate radioactive releases. CIAS actuates primary, secondary, and containment isolation equipment. Other actions may be initiated by BOP systems. See Applicant's FSAR for details.

15.2.3.3 <u>Analysis of Effects and Consequences</u>

A. Mathematical Model

The NSSS response to a LOCV was simulated using the CESEC-II computer program described in Section 15.0. The initial DNBR was calculated using the TORC computer code (see Section 15.0.3.1.6) which uses the CE-1 CHF correlation described in Reference 19 of Section 15.0.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a LOCV are discussed in Section 15.0. Table 15.2.3-4 contains the initial conditions and assumptions used for this event. The initial conditions for the principal process variables were varied within the ranges given in Table 15.0-5 to determine the set of initial conditions that would produce the most adverse consequences following a LOCV. Various combinations of initial core inlet temperature, core inlet flow, pressurizer pressure, steam generator level and pressurizer water level were considered in order to evaluate the effects on peak reactor coolant system (RCS) pressure.

Decreasing the initial core inlet temperature reduces the initial steam generator pressure, thereby delaying the heat removal associated with the opening of the main steam safety valves. However, the initial inlet temperature for this event was restricted to a minimum of 560^{O}F. Decreasing the initial inlet temperature (as well as increasing the initial core flow rate) also minimizes the core average coolant temperature which results in the most positive moderator temperature coefficient.

Reduction of the initial pressurizer pressure delays the occurrence of reactor trip on high pressurizer pressure and allows the maximum reduction in steam generator heat removal prior to and following trip. As a result maximum RCS overpressurization occurs, provided that the delay does not allow the main steam safety valves to open prior to reaching the peak pressure condition. Decreasing the initial pressurizer water level produces similar trip delays.

C. Results

The dynamic behavior of important NSSS parameters following the loss of condenser vacuum is presented in Figures 15.2.3-2 to 15.2.3-14.

The sudden reduction of steam flow, caused by the LOCV leads to a reduction of the primary-to-secondary heat transfer. The moderator reactivity increases slightly prior to the reactor trip due to a positive MTC as the average core temperature increases from the initial conditions. This added reactivity causes the core power to reach a maximum at 6.8 seconds. The rapid heatup of the reactor coolant results in a high pressurizer pressure trip condition at 6.4 seconds. The CEAs begin dropping in at the core at 7.3 seconds and limit the maximum core power to 102% of full power.

The pressurizer safety valves open at 6.9 seconds and the maximum RCS pressure of 2742 psia is reached at 8.6 seconds. The main steam safety valves open at 6.9 seconds and the maximum secondary pressure of 1353 psia is reached at 14.0 seconds.

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The RCS pressure decreases rapidly due to the combined effects of reactor trip and primary and main steam safety valves. The pressurizer safety valves close at 12.0 seconds and the main steam safety valves close at 346.0 seconds. Emergency feedwater flow automatically begins at 42.3 seconds and continues to fill the stam generators until a normal level is reached at 1408 seconds. At 963.0 seconds a safety injection actuation signal is generated when the pressurizer pressure decreases below 1580 psia. Borated water enters the RCS at 1150.0 seconds from the high pressure injection pumps. Thirty minutes after initiation of the events, the operator commences a cooldown using the atmospheric dump valves to release steam.

The DNBR during the event, remains above its initial value of 1.4; therefore, DNB does not occur.

D. Single Failures

The LOCV event is assumed to abruptly and completely terminate both main steam and feedwater flow. Considering peak pressure criteria, 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.

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 (FFT) to offsite power or a loss of offsite power (LOP) following turbine trip (i.e., two or four pump coastdown, respectively). The two and four pump coastdowns result in an immediate reactor trip, generated by the Core Protection Calculators (CPC's). Due to the rapid reactor trip, both of these failures reduce the peak pressure relative to the LOCV itself.

With regard to fuel performance, decreased coolant flow is the only parameter which can significantly reduce the minimum DNBR during the LOCV event. FFT and LOP are the only single failures which impact coolant flow. LOCV by itself, however, produces an increasing DNBR (see Figure 15.2.3-2). This results in a greater thermal margin than is required to preclude a DNBR below 1.19 for either single failure. Consequently neither will cause fuel failure. LOP, however, because of the more rapid flow coastdown, causes a greater degradation in DNBR and hence is more limiting. The decrease in DNBR is shown in Figure 15.3.1-9.

15.2.3.4 Conclusions

For both the loss of condenser vacuum event, and LOCV with a single failure, the maximum RCS pressure remains below 2750 psia, thus ensuring primary system integrity. The minimum DNBR remains above 1.19, thus ensuring fuel cladding integrity.

TABLE 15.2.3-1

SEQUENCE OF EVENTS FOR THE LOCV

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	Loss of Condenser Vacuum		
6.4	High Pressurizer Pressure Trip Signal, psia	2450	Reactivity Control
6.7	Main Steam Safety Valves Open psia	1282	Secondary System Integrity
6.7	Low Steam Generator Water Level, percent of wide range	40	Reactivity Control
6.8	Maximum Core Power, % of Design Power	102	Reactivity Control
6.9	Pressurizer Safety Valves, Open, psia	2525	Priamry Integrity System
7.3	CEA's Begin To Drop		Reactivity Control
8.6	Maximum RCS Pressure, psia	2742	
12.0	Pressurizer Safety Valves Close, psia	2462	Primary System Integrity
14.0	Maximum Steam Generator Pressure, psia	1353	
33.0	Emergency Feedwater Actuation Signal, percent of wide range	15	
43.0	Emergency Feedwater Flow Initiated,gpm	875	Secondary System Integrity
346.0	Main Safety Valves Close, psia	1218	Secondary System Integrity
963.0	Safety Injection Actuation Signal, psia	1580	Reactor Heat Removal
1005.0	Safety Injection Flow Initiated		Primary System Integrity

TABLE 15.2.3-1 (Cont'd)

SEQUENCE OF EVENTS FOR THE LOCV

Time (Sec)	Event	Setpoint or Value	Success Path
1150.0	Borated HPSI Flow Enters the Core		Reactivity Control
1408.0	EFAS Withdrawn, percent of wide range	80	Secondary System Integrity
1800.0	Operator Initiates Plant Cooldown		Reactor Heat Removal

TABLE 15.2.3-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR LOCV

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.	INITIATING EVENT	INOPERATIVE FOR LOCV
1. Main Feedwater Control System						✓
2. Main Feedwater Pump Turbine Control System*						✓
3. Turbine-Generator Control System*						✓
4. Steam Bypass Control System						✓
5. Pressurizer Pressure Control System		✓				
6. Pressurizer Level Control System		✓				
7. Control Element Drive Mechanism Control System	✓					
8. Reactor Regulating System		✓				
9. Core Operating Limit Supervisory System	✓					
10. Reactor Coolant Pumps	✓					
11. Chemical and Volume Control System	✓					
12. Secondary Chemistry Control System*	✓					
13. Condenser Evacuation System*					✓	
14. Turbine Gland Sealing System*	✓					
15. Nuclear Cooling Water System*	✓					
16. Turbine Cooling Water System*	✓					
17. Plant Cooling Water System*	✓					
18. Condensate Storage Facilities*	✓					
19. Circulating Water System*	✓					
20. Spent Fuel Pool Cooling and Clean-Up System*	✓					
21. Non-Class 1E (Non-ESF) A.C. Power*	✓					
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems

TABLE 15.2.3-2 (CONTINUED) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR LOCV

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.	INITIATING EVENT	INOPERATIVE FOR LOCV
23. Non-Class 1E D.C. Power*	✓					
24. Class 1E D.C. Power*	✓					

*Balance-of-Plant Systems

TABLE 15.2.3-3

UTILIZATION OF SAFETY SYSTEMS

FOR LOCV

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems	✓				
4. Supplementary Protection System					1
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves	✓				
8. Main Steam Isolation System*			✓		
9. Emergency Feedwater System*	✓				
10. Safety Injection System		✓			
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*	✓				
13. Containment Isolation System*		✓			
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*					
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

Notes:

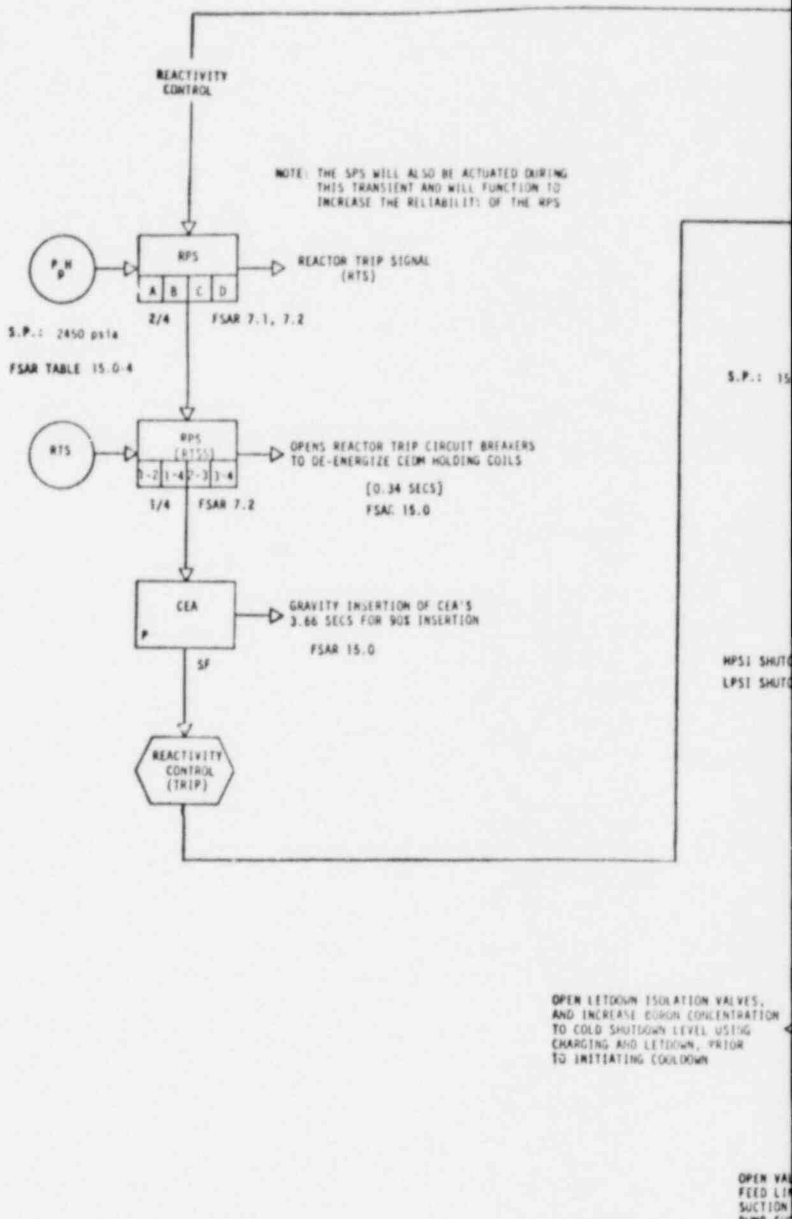
1. Safety grade back-up to a safety grade system.

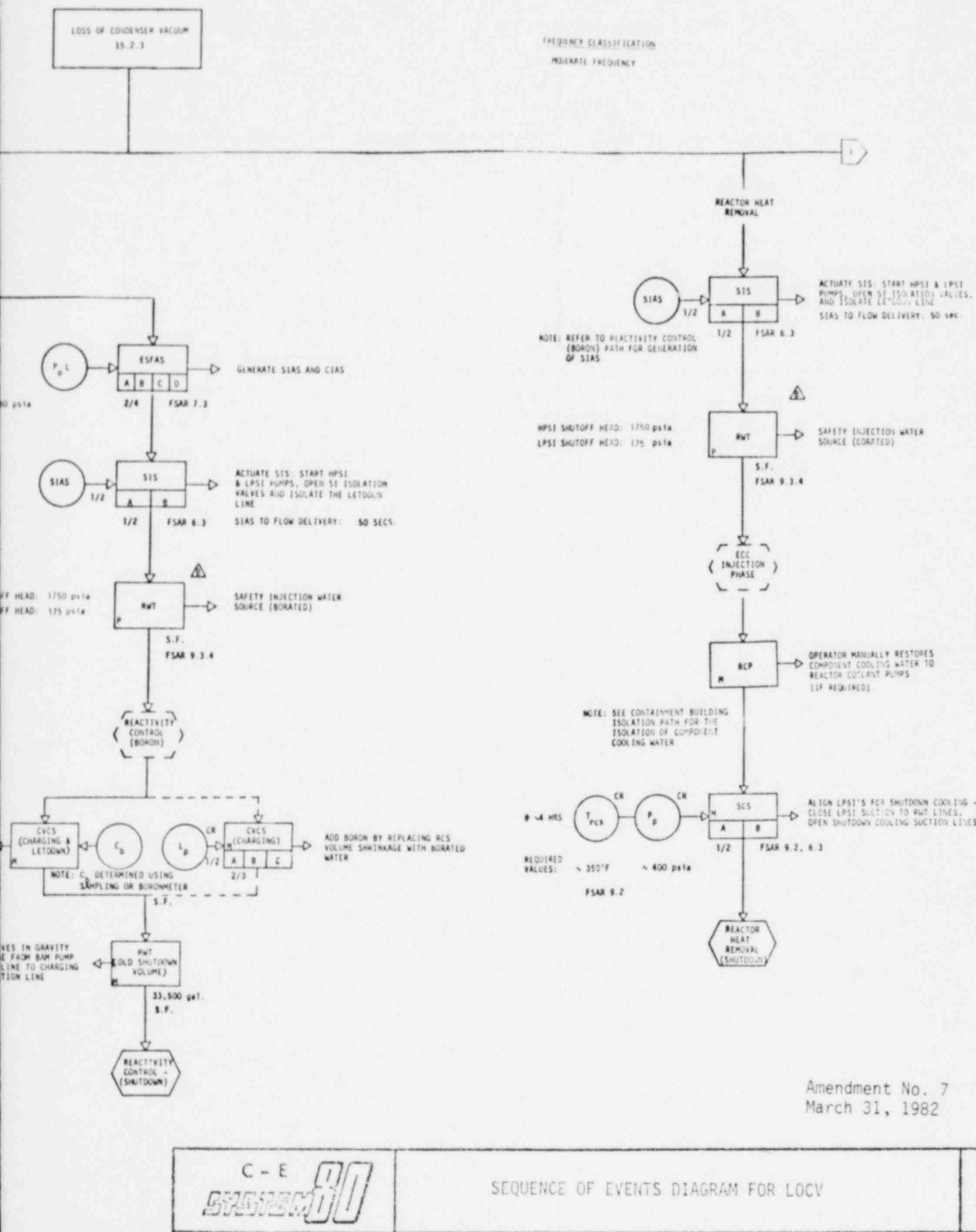
*Balance-of-Plant Systems -

TABLE 15.2.3-4

ASSUMED INITIAL CONDITIONS FOR LOCV

Parameter	Assumed Value
Initial Core Power Level, Mwt	3876
Core Inlet Coolant Temperature, ^{o}F	560
Core Mass Flow, 10^{6} lbm/hr	193.7
Pressurizer Pressure, psia	2200
Initial Pressurizer Water Level, Percent of wide range	26
Initial Core Minimum DNBR	1.4
Radial Peaking Factor	1.62
Steam Generator Water Level, percent of wide range	61
Doppler Coefficient Multiplier	0.85
CEA Worth for Trip, $10^{-2}\Delta\rho$	-10.0


REACTIVITY CONTROL
NOTE: THE SPS WILL ALSO BE ACTUATED DURING THIS TRANSIENT AND WILL FUNCTION TO INCREASE THE RELIABILITY OF THE RPS
RPS
A B C D
REACTOR TRIP SIGNAL (RTS)
2/4
FSAR 7.1, 7.2
S.P.: 2450 psia
FSAR TABLE 15.0-4
RTS
RPS (RTSS)
1-2 1-4 2-3 3-4
OPENS REACTOR TRIP CIRCUIT BREAKERS TO DE-ENERGIZE CEDM HOLDING COILS
[0.34 SECS]
1/4
FSAR 7.2
FSAR 15.0
CEA
P
GRAVITY INSERTION OF CEA'S
3.66 SECS FOR 90% INSERTION
FSAR 15.0
SF
REACTIVITY CONTROL (TRIP)
OPEN LETDOWN ISOLATION VALVES, AND INCREASE BORON CONCENTRATION TO COLD SHUTDOWN LEVEL USING CHARGING AND LETDOWN, PRIOR TO INITIATING COOLDOWN



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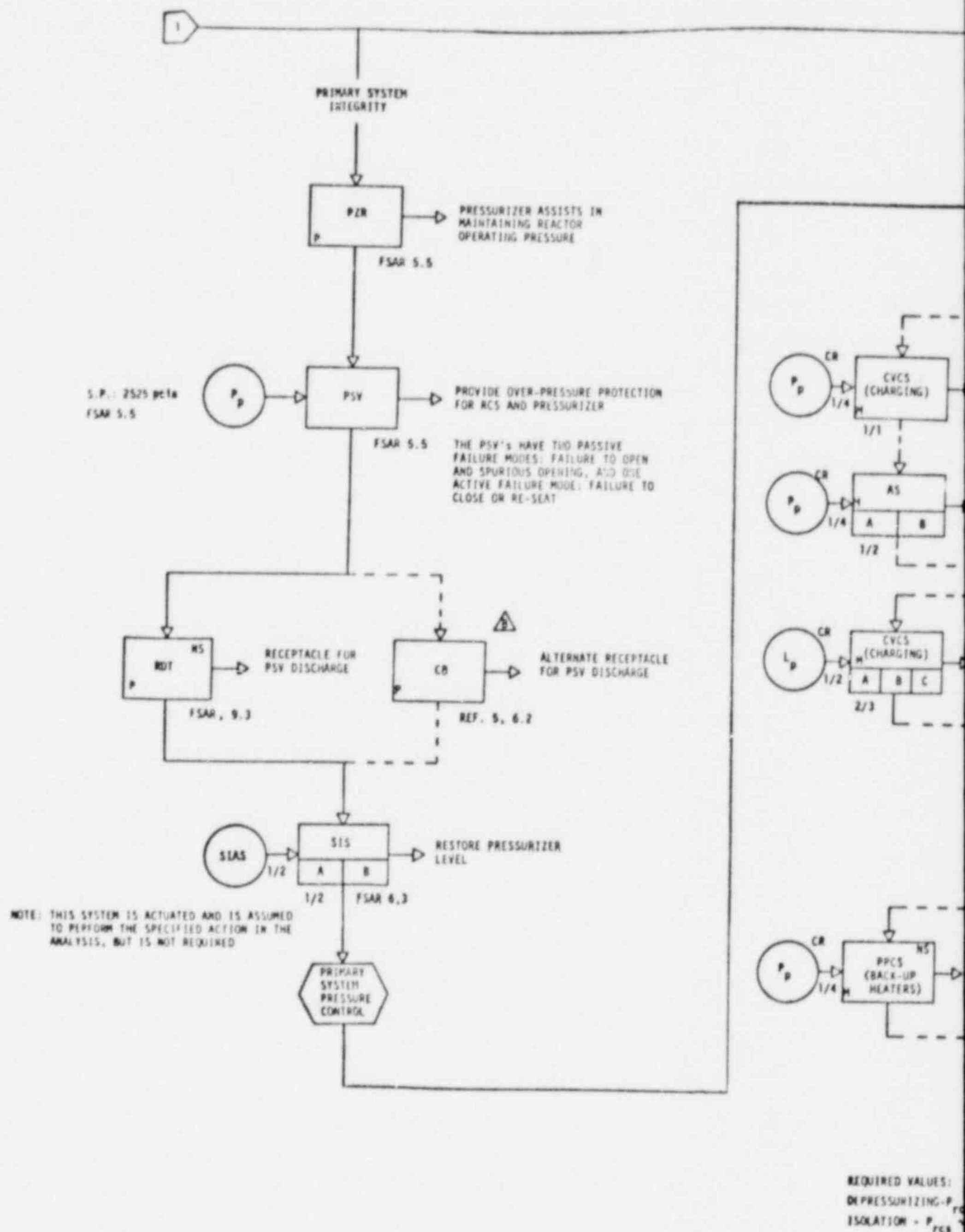
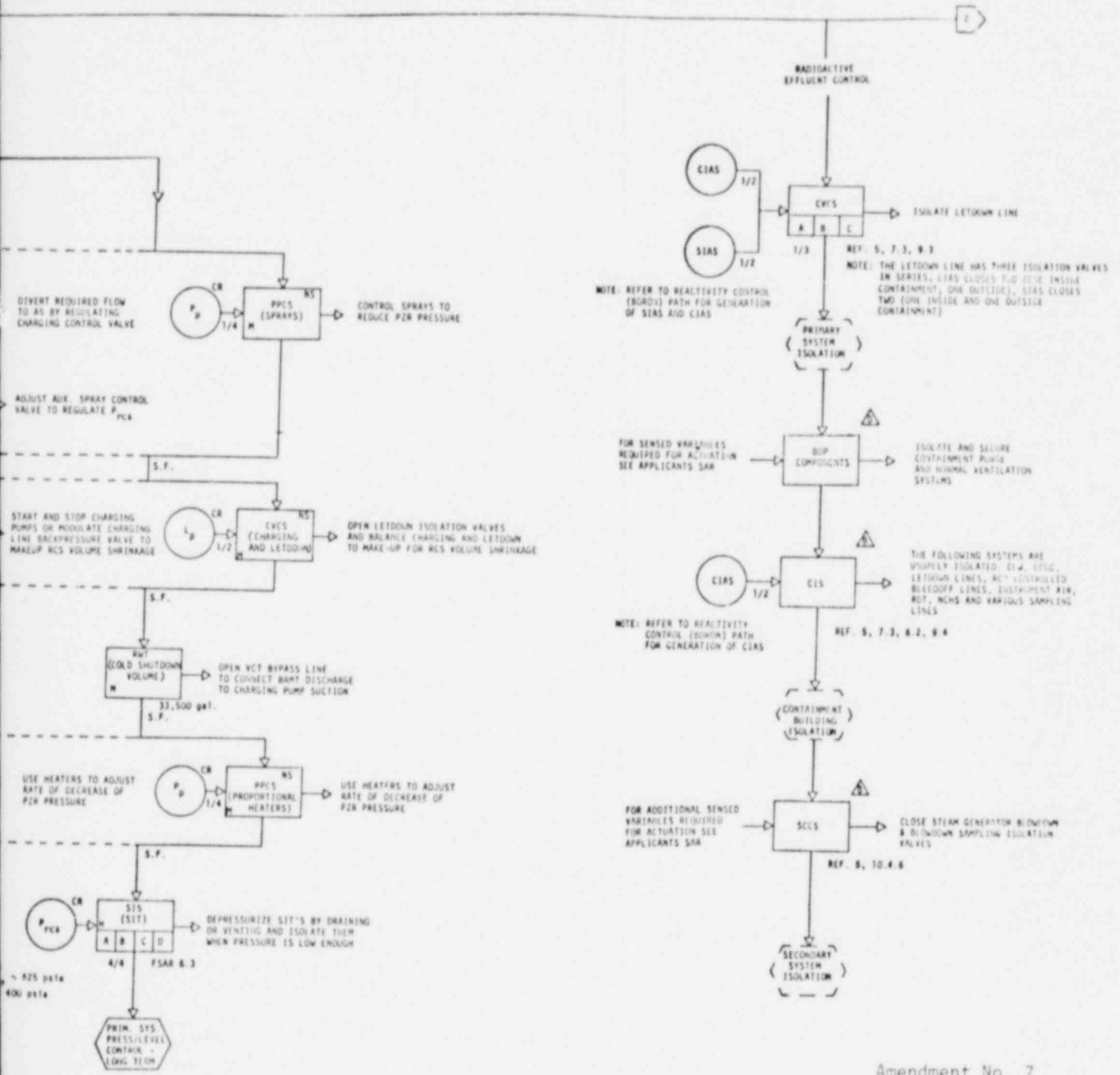
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR LOCV	Figure 15.2.3 #1A


1
PRIMARY SYSTEM INTEGRITY
PZR
P
PRESSURIZER ASSISTS IN MAINTAINING REACTOR OPERATING PRESSURE
FSAR 5.5
S.P.: 2525 psia
FSAR 5.5
P
PSV
PROVIDE OVER-PRESSURE PROTECTION FOR RCS AND PRESSURIZER
FSAR 5.5
THE PSV's HAVE TWO PASSIVE FAILURE MODES: FAILURE TO OPEN AND SPURIOUS OPENING, AND ONE ACTIVE FAILURE MODE: FAILURE TO CLOSE OR RE-SEAT
RDT
NS
P
RECEPTACLE FOR PSV DISCHARGE
FSAR, 9.3
CB
P
ALTERNATE RECEPTACLE FOR PSV DISCHARGE
REF. 5, 6.2
SIAS
1/2
SIS
A
B
RESTORE PRESSURIZER LEVEL
1/2
FSAR 6,3
NOTE: THIS SYSTEM IS ACTUATED AND IS ASSUMED TO PERFORM THE SPECIFIED ACTION IN THE ANALYSIS, BUT IS NOT REQUIRED
PRIMARY SYSTEM PRESSURE CONTROL
P
CR
1/4
CVCS (CHARGING)
M
1/1
P
CR
1/4
AS
M
A
B
1/2
L
CR
1/2
CVCS (CHARGING)
M
A
B
C
2/3
P
CR
1/4
PPCS (BACK-UP HEATERS)
NS
M
REQUIRED VALUES:
DEPRESSURIZING-P
ISOLATION - P



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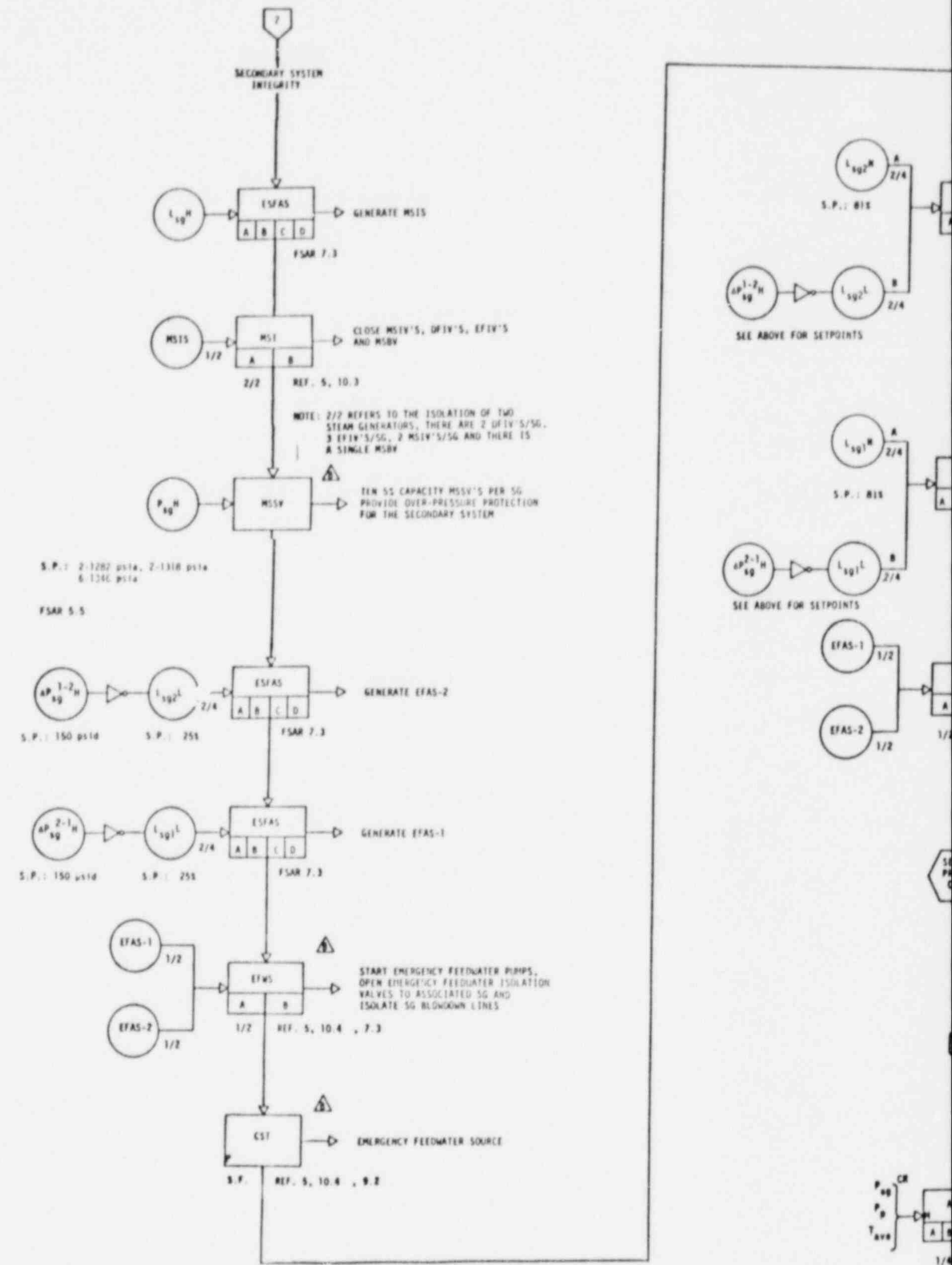
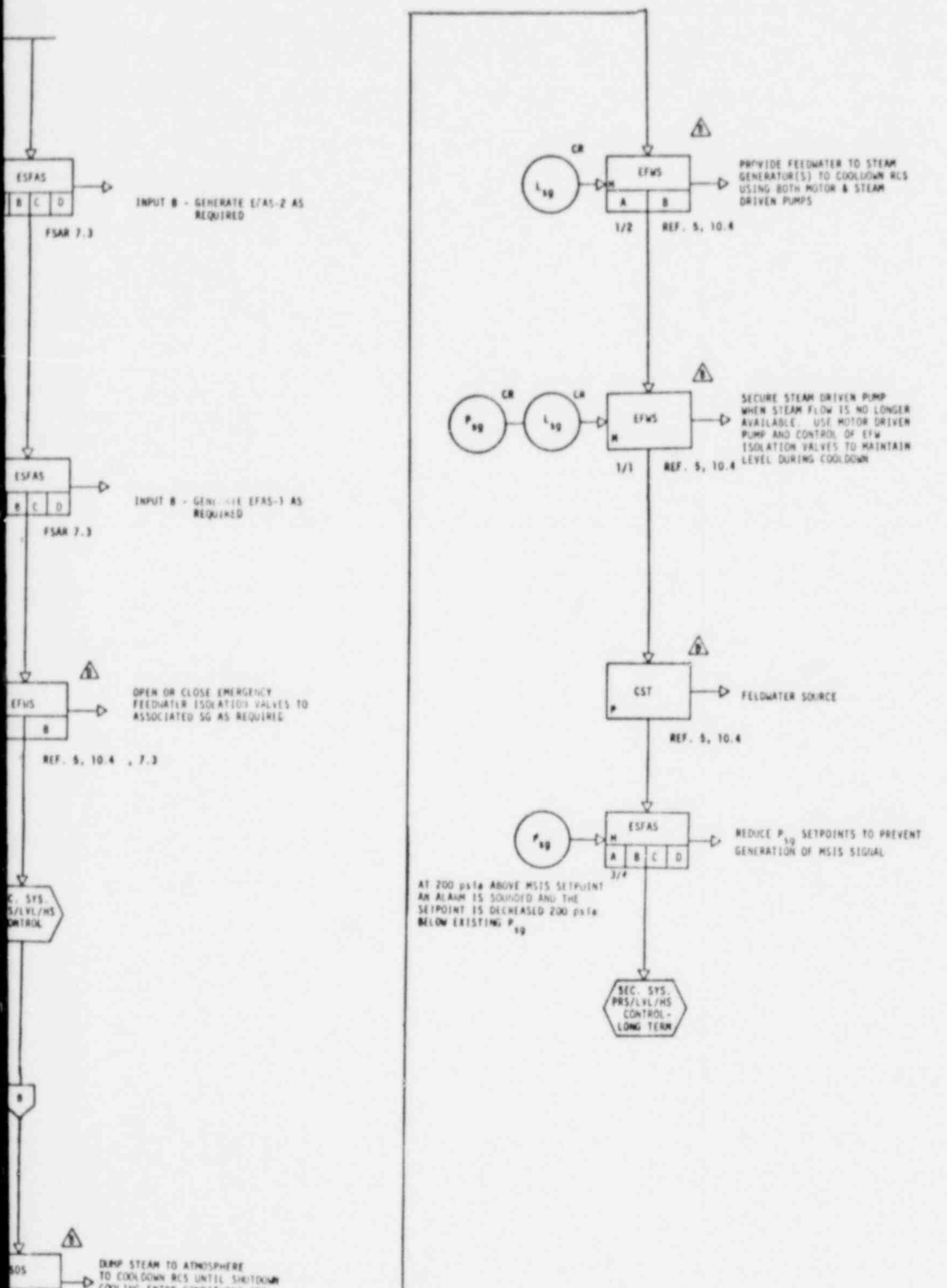
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR LOCV	Figure 15.2.3-1B



7
SECONDARY SYSTEM INTEGRITY
ESFAS
A B C D
GENERATE MSIS
FSAR 7.3
MSIS
1/2
MSI
A B
2/2
REF. 5, 10.3
CLOSE MSIV'S, DFIV'S, EFIV'S AND MSBV
NOTE: 2/2 REFERS TO THE ISOLATION OF TWO STEAM GENERATORS. THERE ARE 2 DFIV'S/SG, 3 EFIV'S/SG, 2 MSIV'S/SG AND THERE IS A SINGLE MSBV
MSSV
TEN 5% CAPACITY MSSV'S PER SG PROVIDE OVER-PRESSURE PROTECTION FOR THE SECONDARY SYSTEM
S.P.: 2-1282 psia, 2-1318 psia 6-1346 psia
FSAR 5.5
S.P.: 150 psid
S.P.: 25%
2/4
ESFAS
A B C D
GENERATE EFAS-2
FSAR 7.3
S.P.: 150 psid
S.P.: 25%
2/4
ESFAS
A B C D
GENERATE EFAS-1
FSAR 7.3
EFAS-1
1/2
EFAS-2
1/2
EFWS
A B
1/2
REF. 5, 10.4 , 7.3
START EMERGENCY FEEDWATER PUMPS, OPEN EMERGENCY FEEDWATER ISOLATION VALVES TO ASSOCIATED SG AND ISOLATE SG BLOWDOWN LINES
CST
EMERGENCY FEEDWATER SOURCE
S.F.
REF. 5, 10.4 , 9.2
S.P.: 81%
SEE ABOVE FOR SETPOINTS
S.P.: 81%
SEE ABOVE FOR SETPOINTS
EFAS-1
1/2
EFAS-2
1/2



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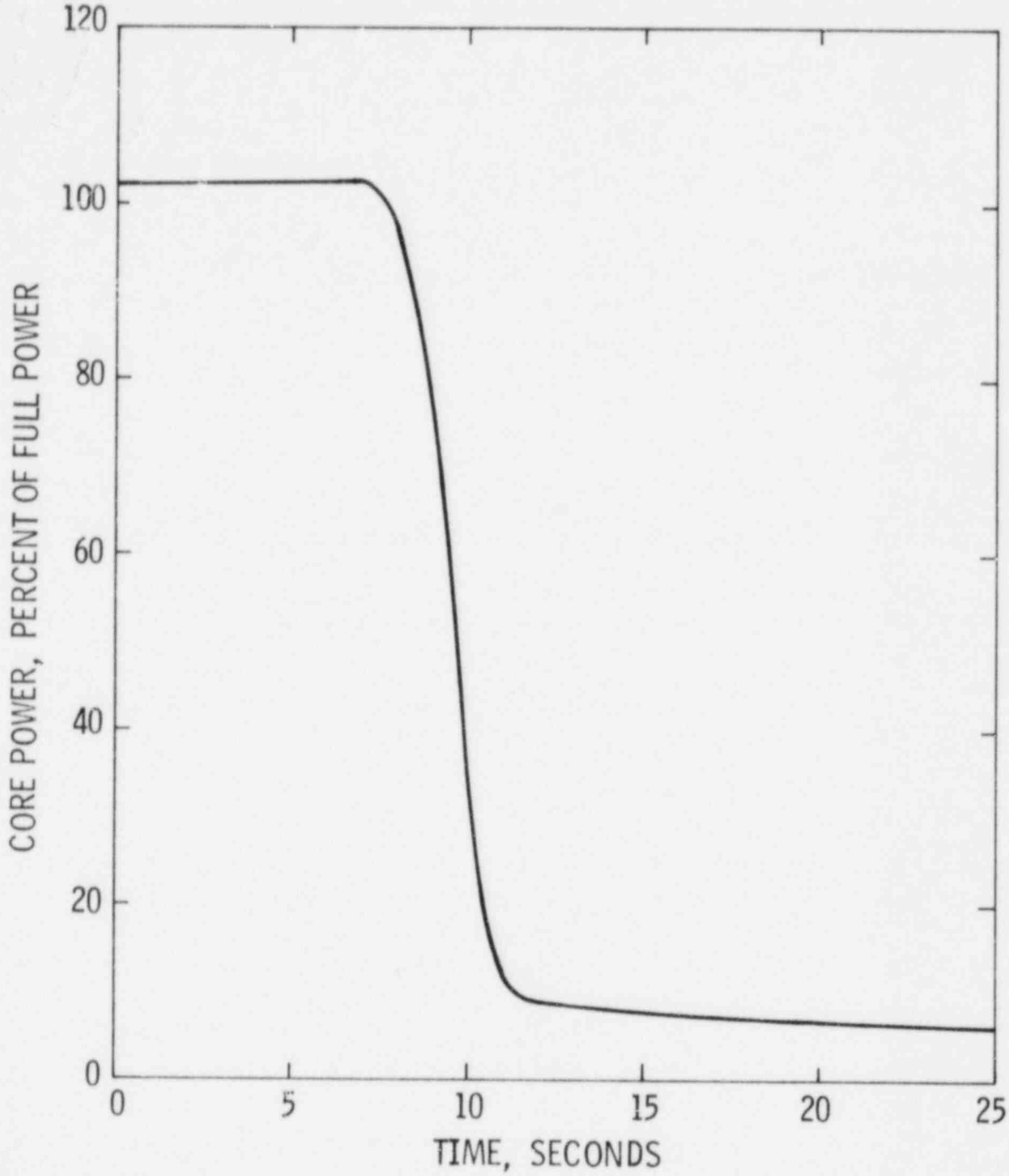
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR LOCV	Figure 15.2.3-1C



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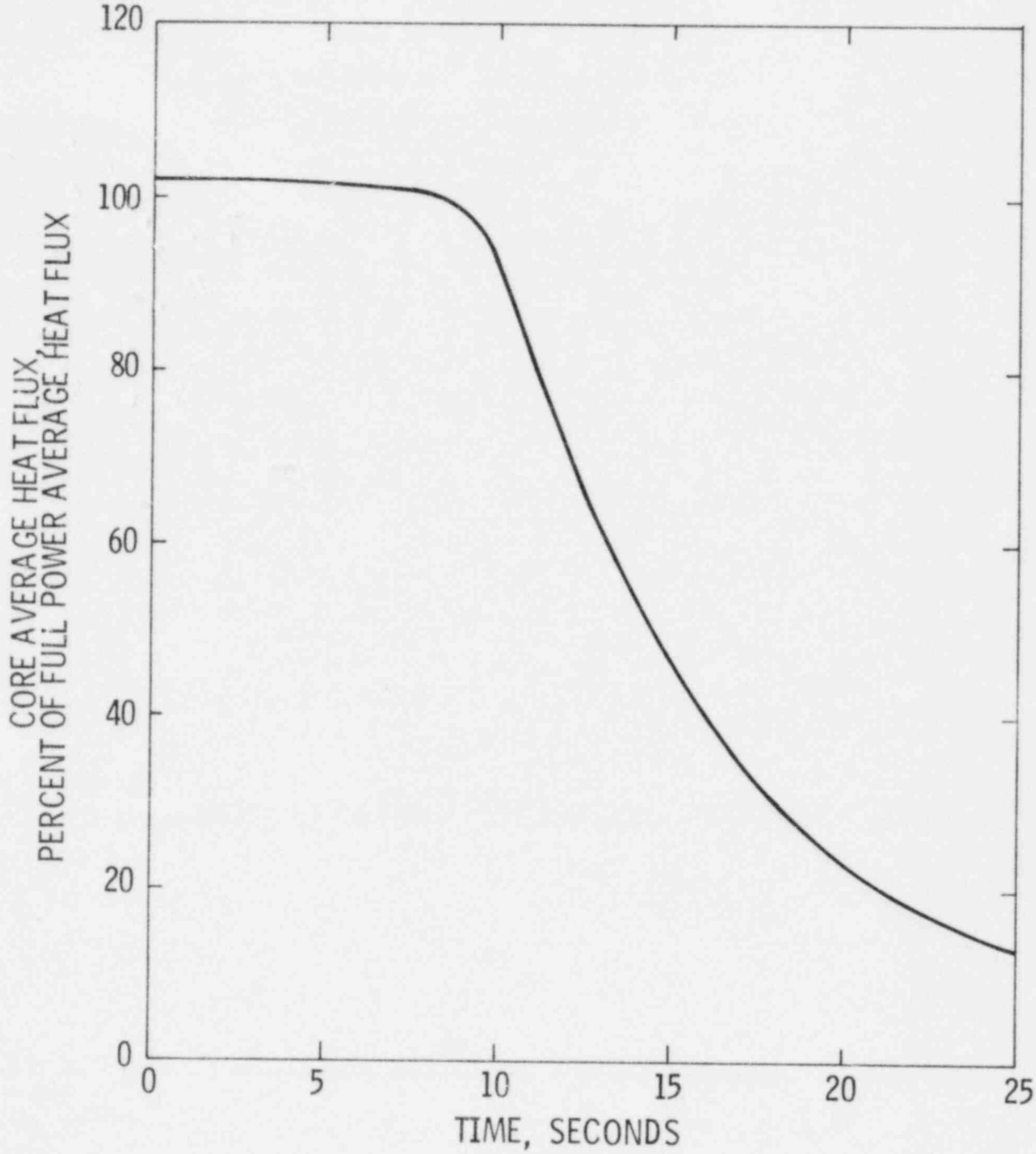
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM CORE POWER vs TIME	Figure 15.2.3-2



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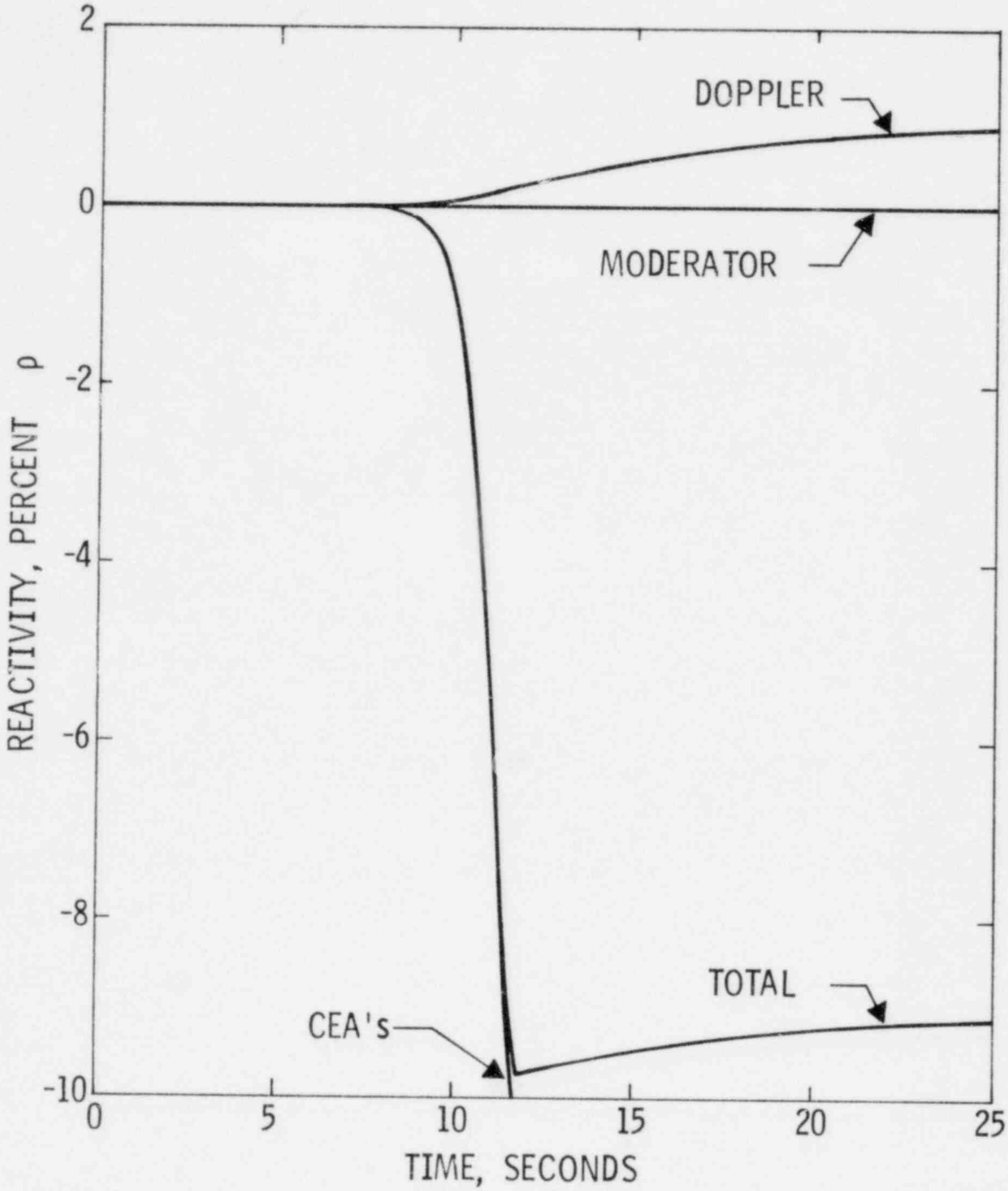
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM CORE AVERAGE HEAT FLUX vs TIME	Figure 15.2.3-3



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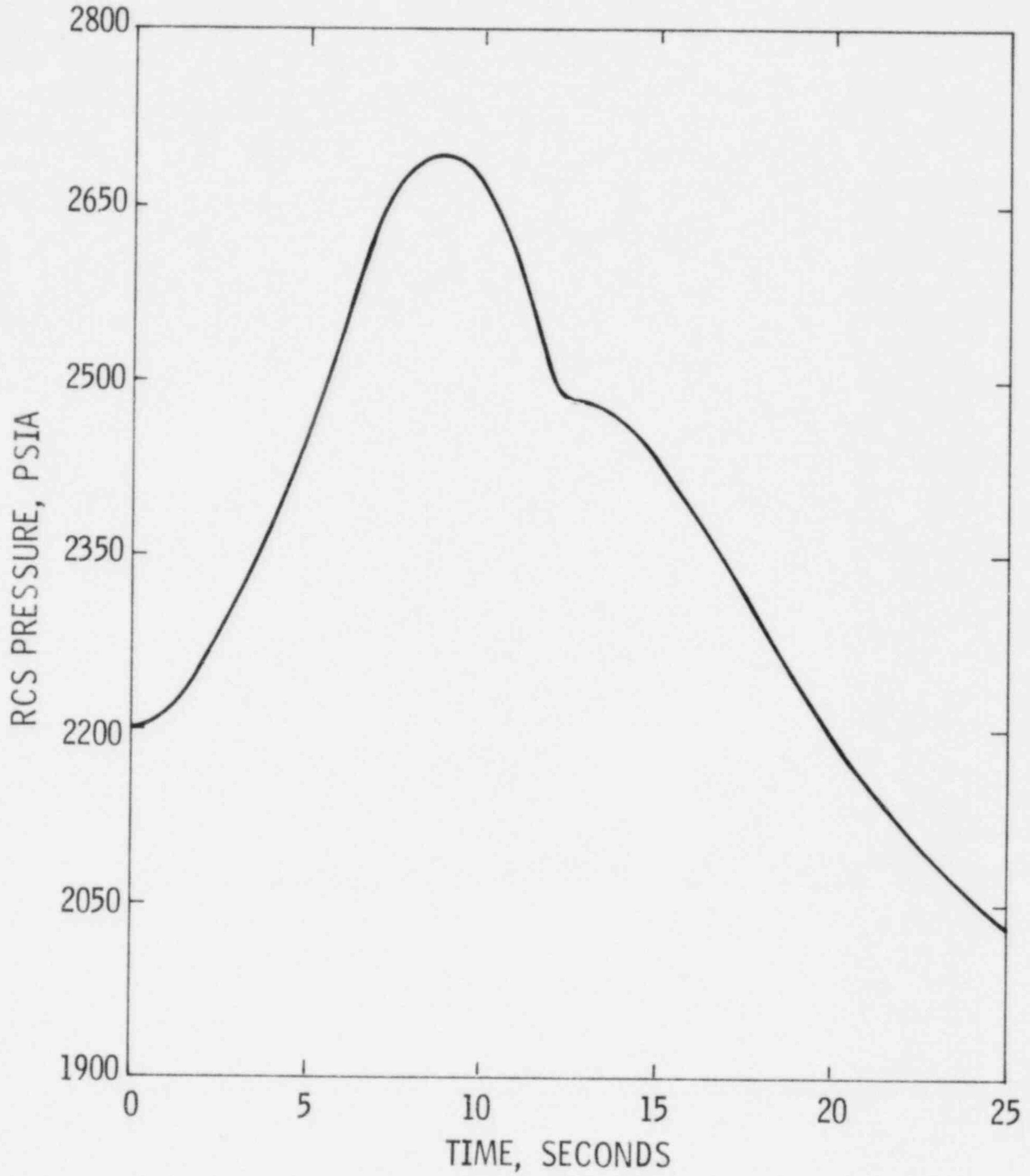
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM REACTIVITY vs TIME	Figure 15.2.3-4



DOES NOT INCLUDE ELEVATION OR REACTOR COOLANT PUMP HEADS

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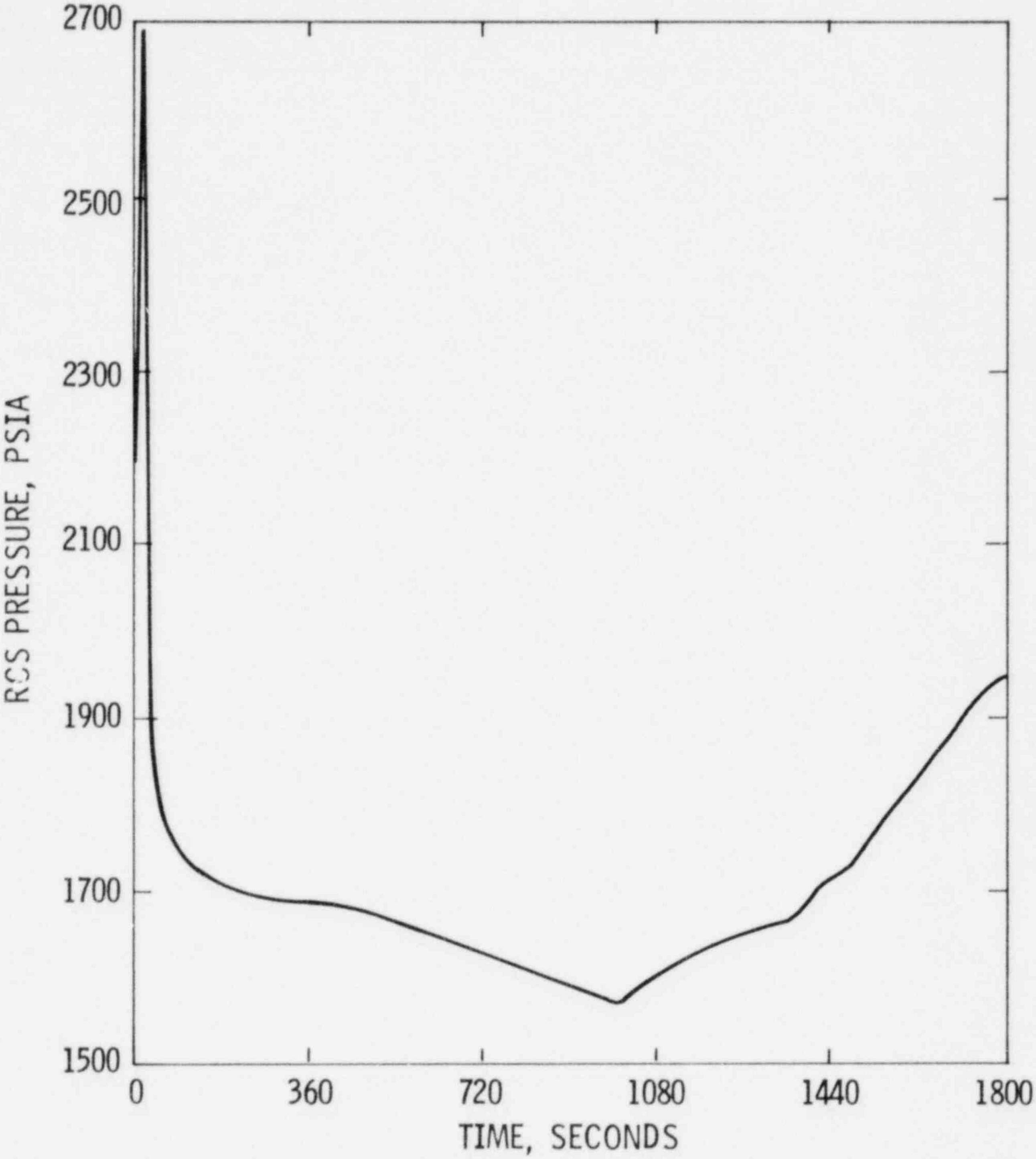
C-E SYSTEM 80	LOSS OF CONDENSER VACUUM RCS PRESSURE vs TIME	Figure 15.2.3-5



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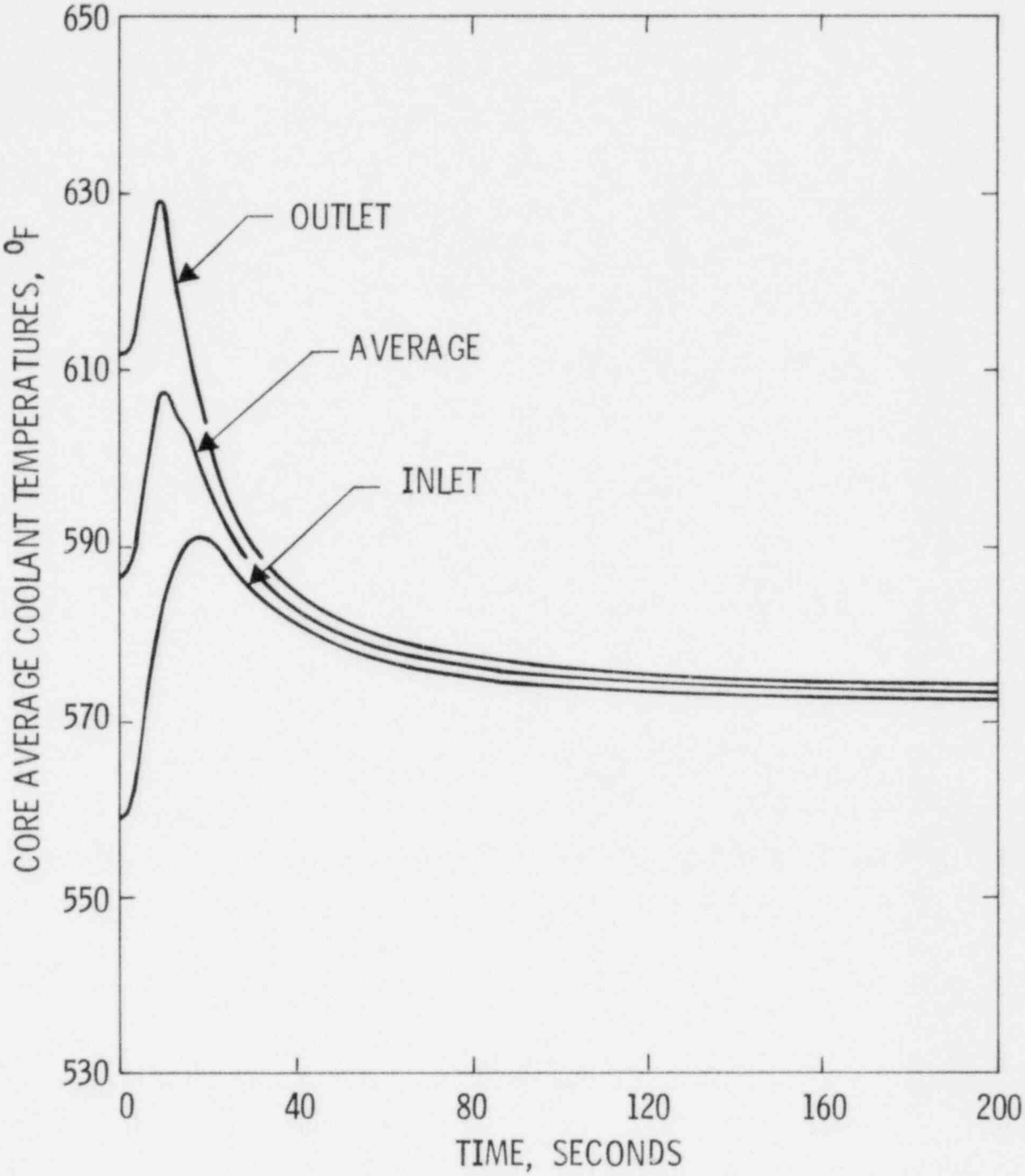
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM RCS PRESSURE vs TIME	Figure 15.2.3-6



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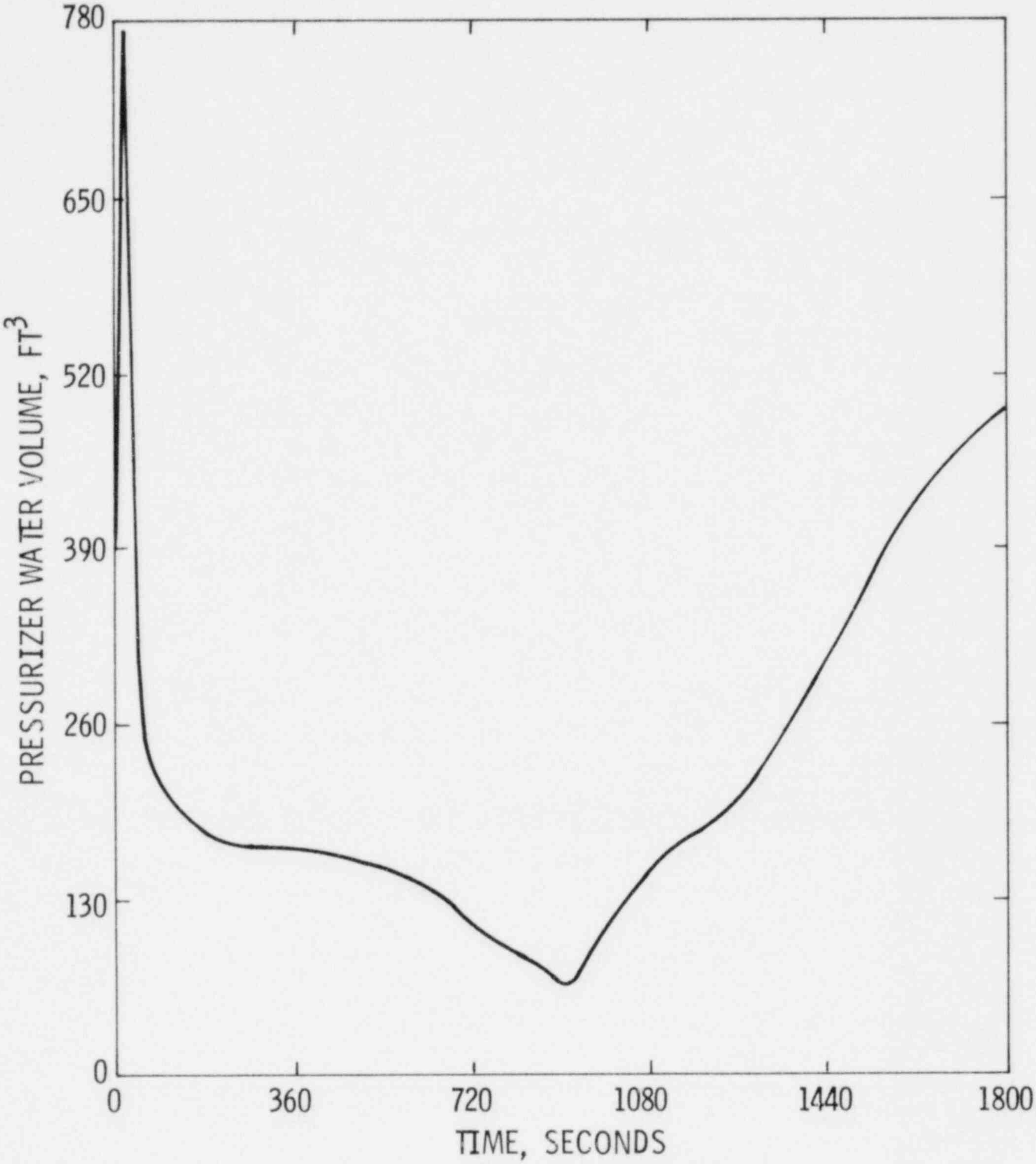
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM CORE AVERAGE COOLANT TEMPERATURES vs TIME	Figure 15.2.3-7



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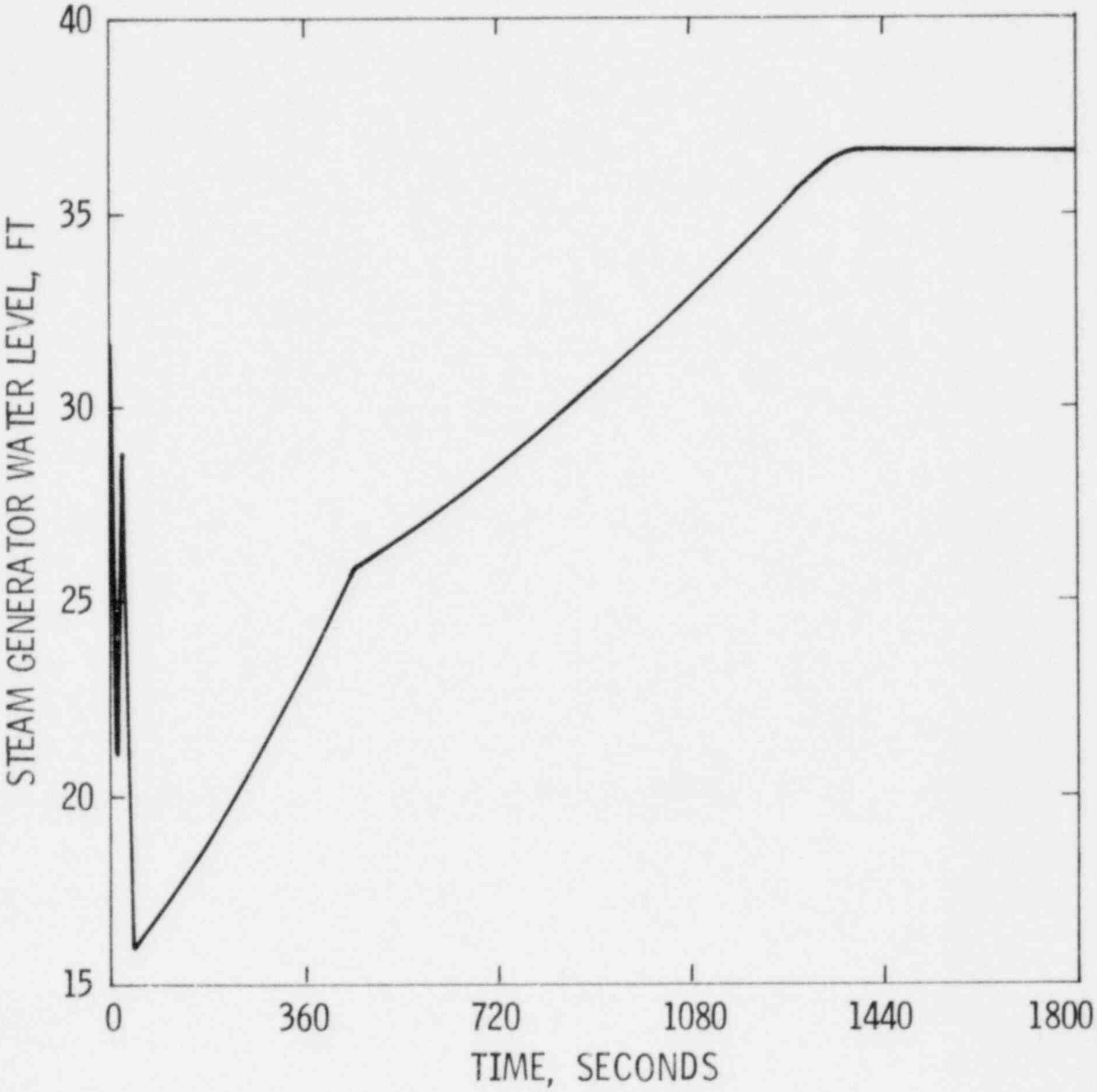
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM PRESSURIZER WATER VOLUME vs TIME	Figure 15.2.3-8



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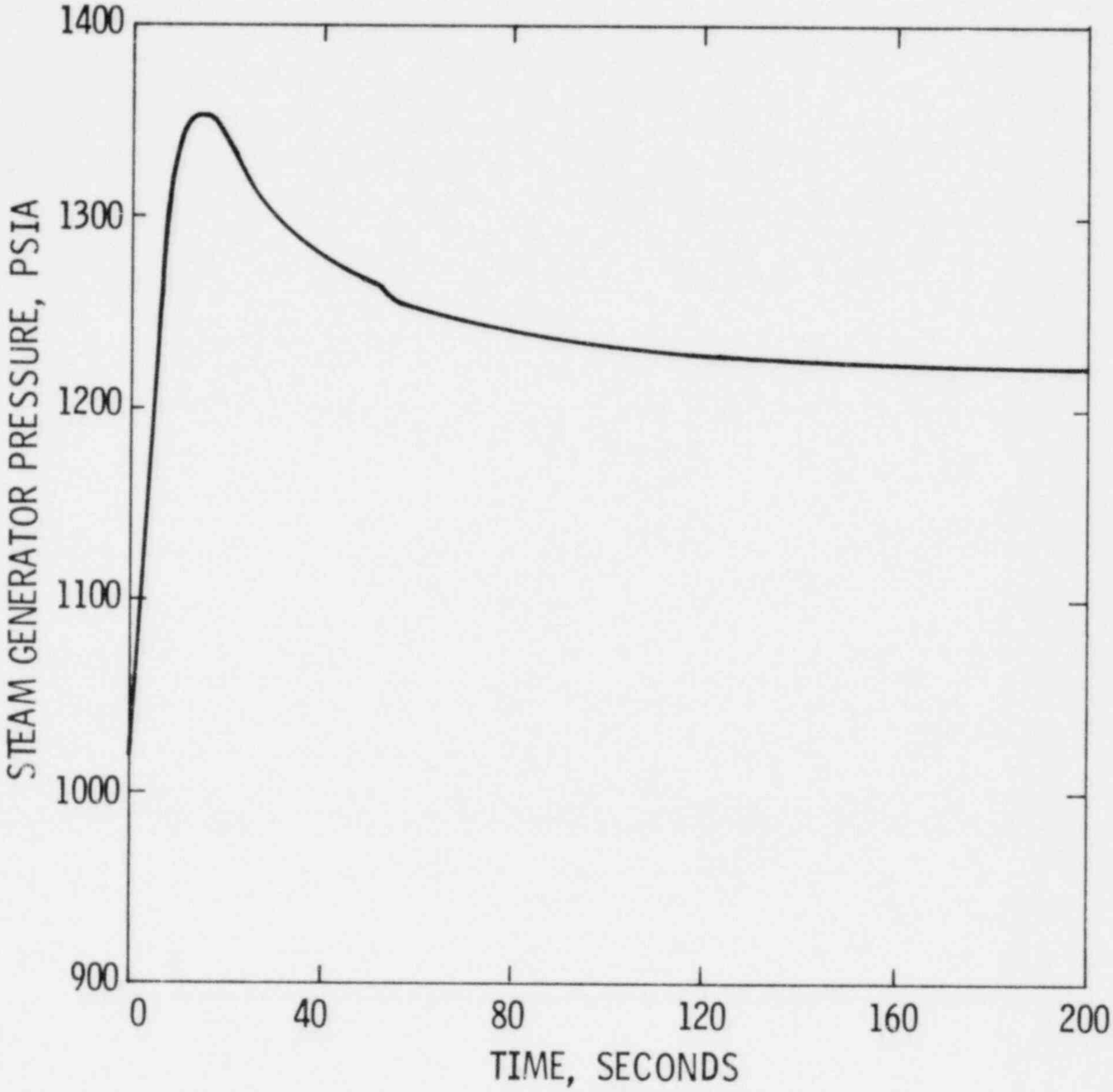
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM STEAM GENERATOR WATER LEVEL vs TIME	Figure 15.2.3-9



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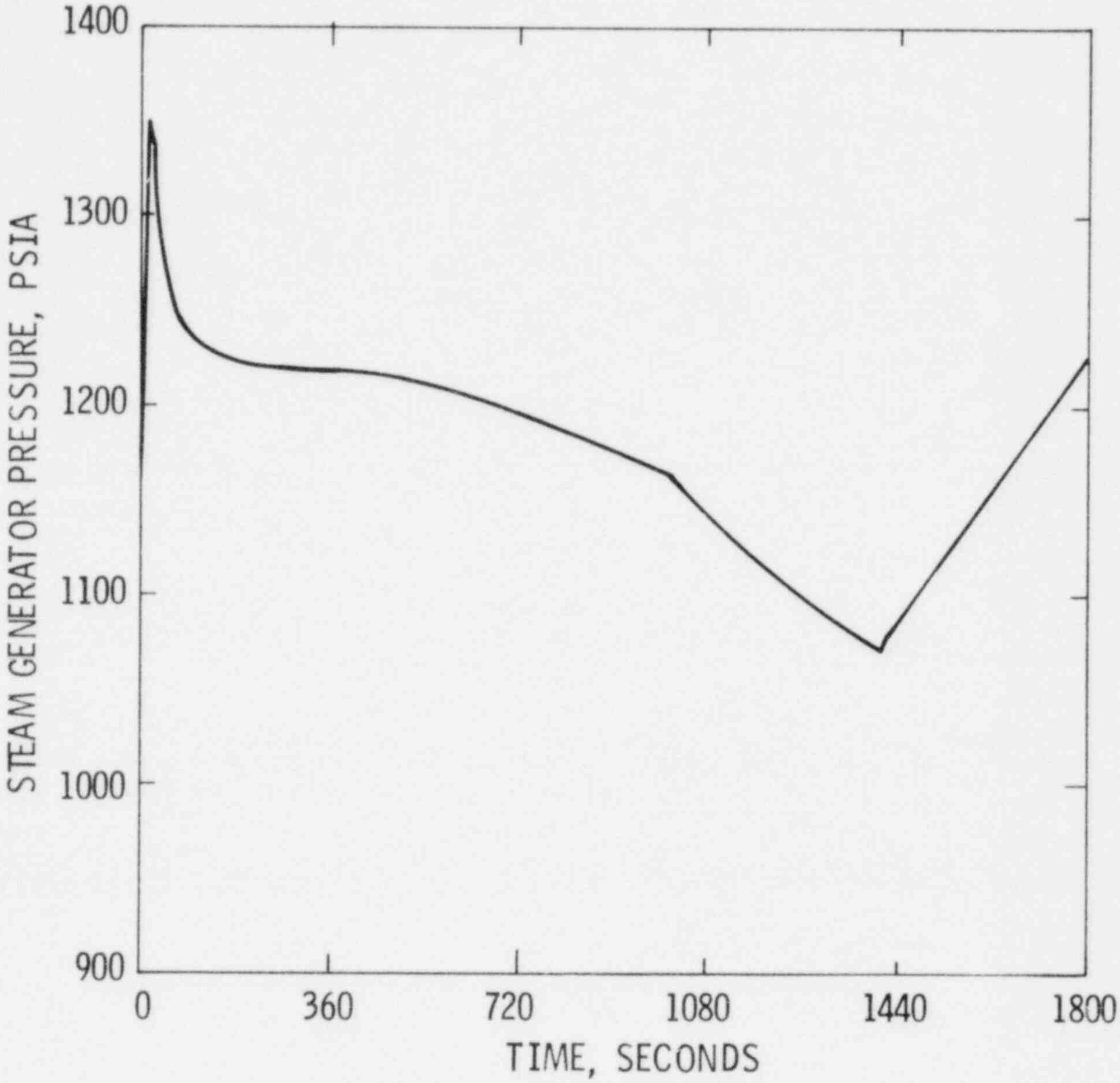
C-E SYSTEM 80	LOSS OF CONDENSER VACUUM STEAM GENERATOR PRESSURE vs TIME	Figure 15.2.3-10



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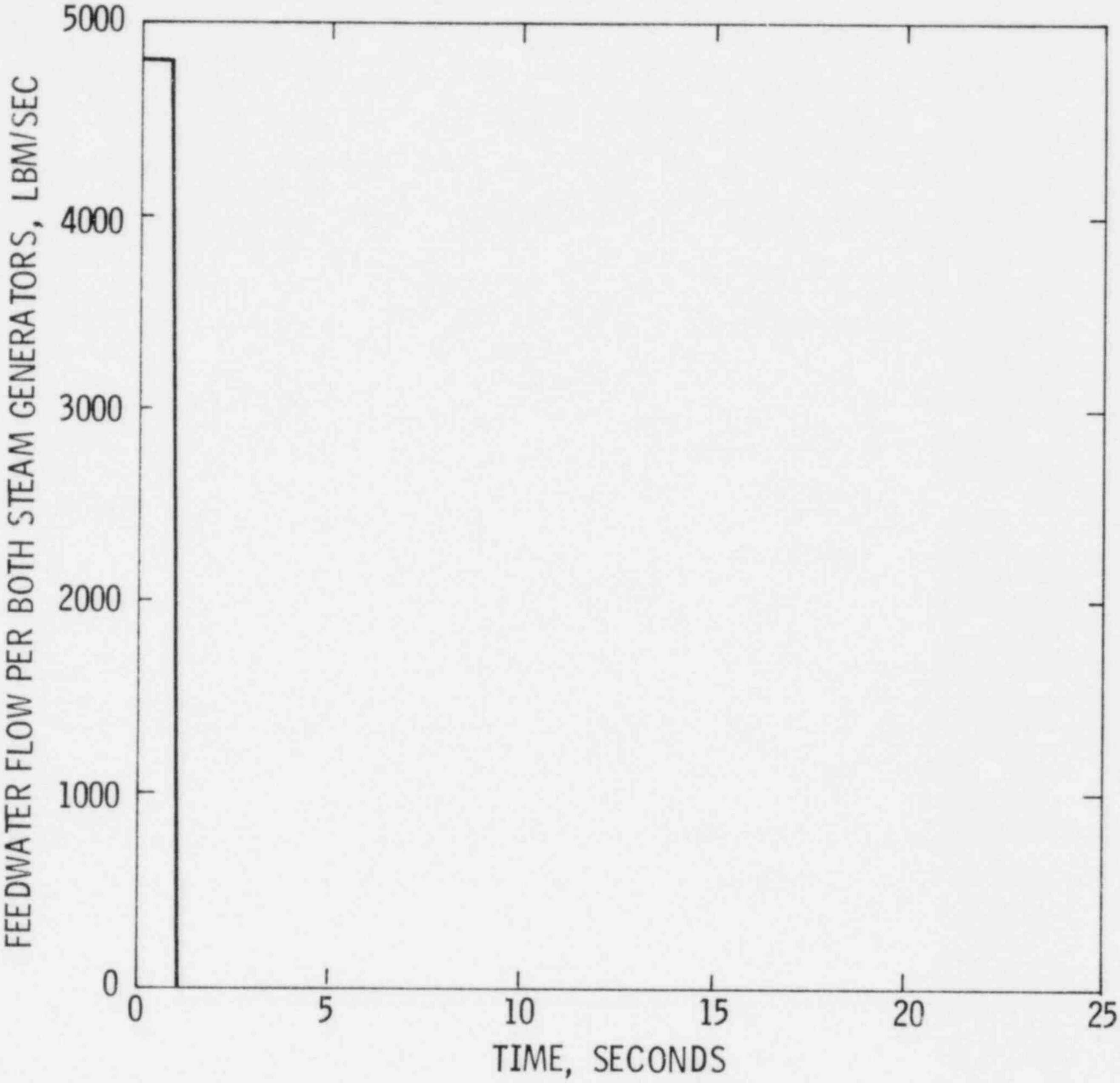
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM STEAM GENERATOR PRESSURE vs TIME	Figure 15.2.3-11



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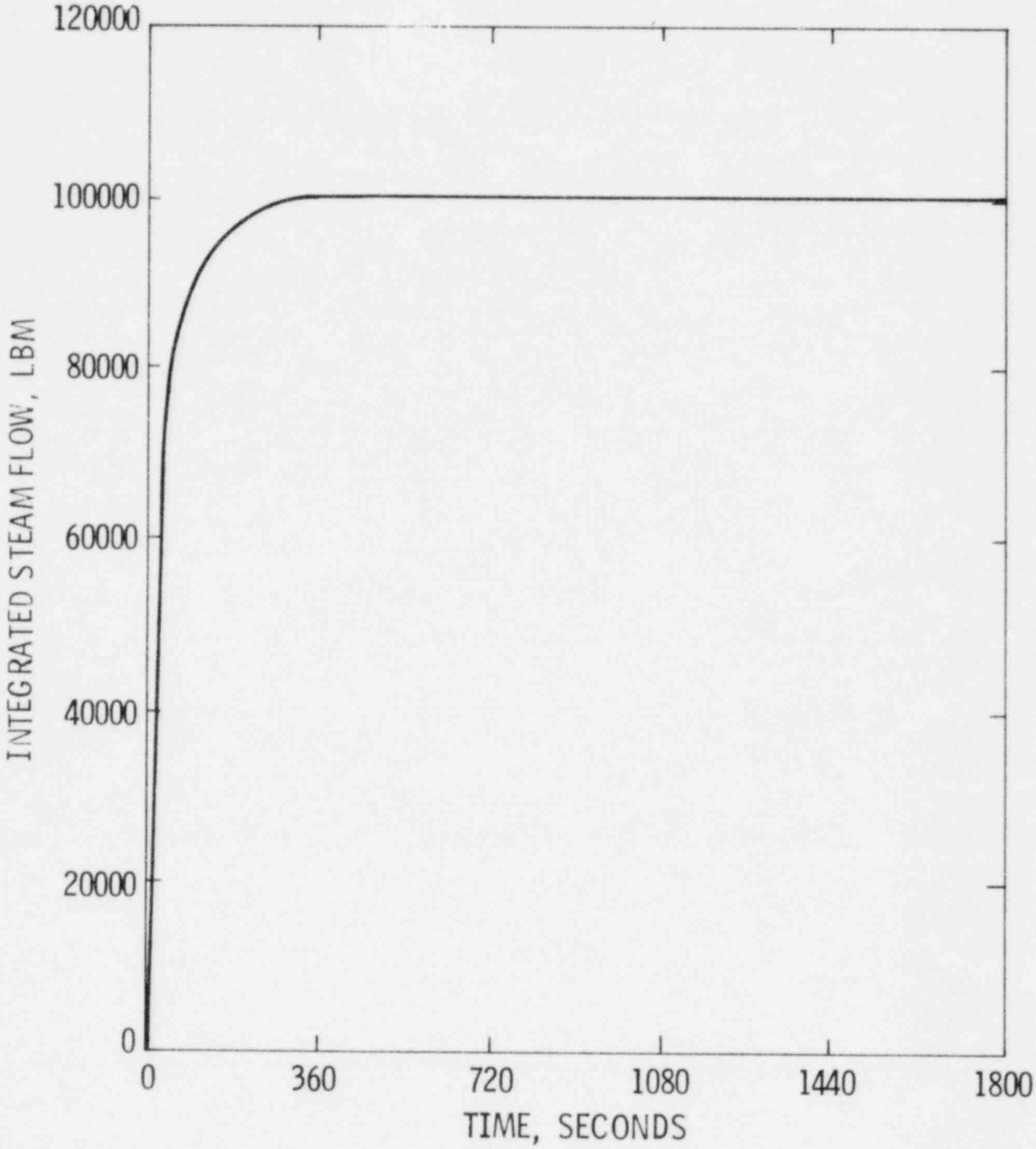
C-E SYSTEM 80

LOSS OF CONDENSER VACUUM
FEEDWATER FLOW vs TIME

Figure
15.2.3-12



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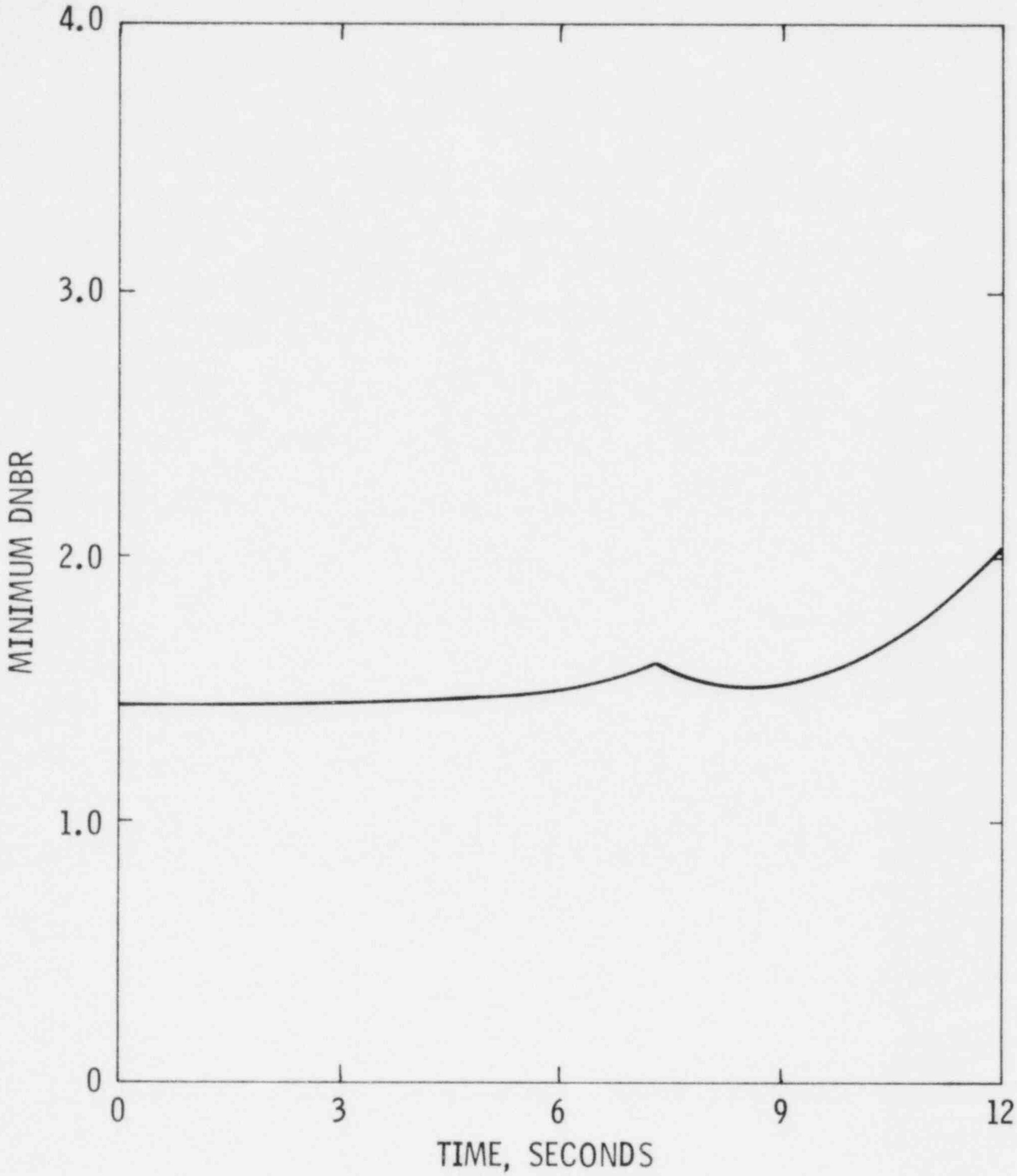
C - E SYSTEM 80	LOSS OF CONDENSER VACUUM INTEGRATED STEAM FLOW vs TIME	Figure 15.2.3-13



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C - E SYSTEM 80	LOSS OF CONDENSER VACUUM MINIMUM DNBR vs TIME	Figure 15.2.3-14

15.2.4 MAIN STEAM ISOLATION VALVE CLOSURE

15.2.4.1 Identification of Event and Causes

The main steam isolation valve (MSIV) closure event is initiated by the closure of all MSIV due to a spurious closure signal.

15.2.4.2 Sequence of Events and Systems Operation

The closure of all MSIV's results in the termination of all main steam flow. The decreased heat removal results in increasing primary and secondary temperatures and pressure. Reactor trip occurs on high pressurizer pressure. The pressure increases in the primary and secondary systems are limited by the pressurizer and steam generator safety valves. The operator can initiate a controlled system cooldown using the steam bypass control system any time after reactor trip occurs.

15.2.4.3 Analysis of Effects and Consequences

The results of the MSIV closure event are no more limiting with respect to RCS pressurization than those of the loss of condenser vacuum (LOCV) event presented in Section 15.2.3. The LOCV also results in the termination of all main steam flow. However, main steam flow is terminated more rapidly during the LOCV since the closure time for the turbine stop valves is much shorter than that for the MSIVs. The faster reduction in heat removal results in a higher peak RCS pressure for the LOCV event.

Like the LOCV, the DNBR increases during the MSIV closure event due to the increasing pressure. Thus, the initial DNBR is also the minimum DNBR for the MSIV closure event.

Due to it similarity with the LOCV event, there are no concurrent single failures which when combined with the MSIV closure event result in consequences more severe than the LOCV event with respect to RCS pressurization. The limiting single failure with respect to fuel performance is the loss of offsite power on turbine trip. This event with a concurrent loss of offsite power results in an event nearly identical to the loss of AC power which initiates the loss of flow (LOF) event discussed in section 15.3.2. Results of the LOF event are directly applicable to the MSIV closure with loss of offsite power on turbine trip.

15.2.4.4 Conclusions

For the MSIV closure event and the MSIV closure with a concurrent single failure, the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above 1.19 thus ensuring fuel cladding integrity.

15.2.5 STEAM PRESSURE REGULATOR FAILURE

This event does not apply to the CESSAR SYSTEM 80 design and therefore is not presented.

15.2.6 LOSS OF NON-EMERGENCY A-C POWER TO THE STATION AUXILIARIES

15.2.6.1 Identification of Event and Causes

The loss of non-emergency AC power to the station auxiliaries (LOAC) may result from either a complete loss of the external grid or a loss of the onsite AC distribution system. The LOAC is presented as the initiating event for the four pump loss of flow event discussed in Section 15.3.1.

15.2.6.2 Sequence of Events and System Operation

When all normal AC power is assumed to be lost to the plant, the turbine stop valves close, and it is assumed that the area of the turbine control valves is instantaneously reduced to zero. Also, the feedwater flow to both steam generators is instanteously assumed to go to zero. The reactor coolant pumps coast down and the reactor coolant flow begins to decrease. A reactor trip will occur as a result of a low DNBR condition as the flow coastdown begins. The pressure increases in the RCS and steam generators are limited by the pressurizer and steam generator safety valves.

The loss of all normal AC power is followed by automatic startup of the standby diesel generators, the power output of which is sufficient to supply electrical power to all necessary engineered safety features system and to provide the capability of maintaining the plant in a safe shutdown condition. Subsequent to the reactor trip, stored and fission product decay energy must be dissipated by the reactor coolant system and main steam system. In the absence of forced reactor coolant flow, convective heat transfer coolant flow. Initially, the residual water inventory in the steam generators is used as a heat sink, and the resultant steam is released to atmosphere by the spring-loaded steam generator safety valves. With the availability of standby diesel power, emergency feedwater is automatically initiated on a low steam generator water level signal. Plant cooldown is operator controlled via the atmospheric dump valves until offsite power is restored at which time the steam bypass control system and the condenser are utilized for the remainder of the cooldown.

15.2.6.3 Analysis of Effects and Consequences

The results of the LOAC event are identical to those of the loss of reactor coolant flow event presented in Section 15.3.1 and are no more limiting with respect to RCS pressurization than the loss of condenser vacuum (LOCV) event discussed in Section 15.2.3. During the LOCV event the plant experiences simultaneous losses of steam and feedwater flow and condenser availability. In addition, the plant experiences a complete loss of forced reactor coolant flow during the LOAC event. The loss of forced reactor coolant flow results in an earlier reactor trip for the LOAC event (on projected low DNBR) compared to the reactor trip for the LOCV event (on high pressurizer pressure). The earlier trip promotes a less severe primary-to-secondary heat imbalance and hence a lower peak RCS pressure for the LOAC event.

The fuel performance for the LOAC is no more limiting than that for the loss of flow (LOF) event discussed in Section 15.3.1. The LOAC is the initiating event for the LOF so the fuel performance results of the LOF event are directly applicable to the LOAC event.

15.2.6.4 Conclusions

For the LOAC event and the LOAC with a concurrent single failure, the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above 1.19 thus ensuring fuel cladding integrity.

15.2.7 LOSS OF NORMAL FEEDWATER FLOW

15.2.7.1 Identification of Event and Causes

The loss of normal feedwater flow (LFW) event may be initiated by losing one or both main feedwater pumps or by a spurious signal being generated by the feedwater control system resulting in a closure of the feedwater control valve(s).

15.2.7.2 Sequence of Events and Systems Operation

LFW results in decreasing water level and increasing pressure and temperature in the steam generators. The RCS pressure and temperature also rise until a reactor trip occurs either due to low steam generator water level or high pressurizer pressure. Assuming the steam bypass control system (SBCS) is in the manual mode of operation, termination of main steam flow due to closure of the turbine stop valves following reactor trip temporarily causes steam generator and RCS pressurization. The decrease in core heat rate after insertion of the CEAs in combination with the main steam safety valves opening restores the RCS to a new steady state condition. Emergency feedwater flow is automatically initiated on a low steam generator water level assuring sufficient steam generator inventory for core decay heat removal and cooldown to shutdown cooling entrance conditions. The cooldown is operator controlled using the SBCS and the condenser.

15.2.7.3 Analysis of Effects and Consequences

The maximum RCS pressure for the LFW event is less than that for the loss of condenser vacuum (LOCV) event discussed in Section 15.2.3. The LOCV event results in the termination of main steam flow prior to reactor trip in addition to the total loss of normal feedwater flow. This additional condition aggravates RCS pressurization by further reducing the rate of primary-to-secondary heat transfer below that of the LFW event.

Like the LOCV, the DNBR increases during the LFW event due to the increasing RCS presure. Thus the initial DNBR is also the minimum DNBR for the LFW event.

There are no concurrent single failures which when combined with LFW result in consequences more severe than the LOCV event with respect to RCS pressurization.

The limiting single failure with respect to fuel performance is the loss of offsite power following turbine trip. For the LFW event, prior to turbine trip the DNBR increases due to the RCS pressure increase. DNBR then briefly decreases after turbine trip due to the reactor coolant flow coast down on loss of offsite power. The DNBR decreases similar to the DNBR transient associated

with the total loss of reactor coolant flow event shown in Section 15.3.1, however, the DNBR decrease for LFW is not as severe due to the earlier reactor trip relative to the initiation of the coolant flow coastdown. Therefore, the minimum DNBR remains above 1.19.

15.2.7.4 Conclusions

For the loss of feedwater flow event and the loss of feedwater flow with a concurrent single failure the RCS pressure remains below 2750 psia thus ensuring primary system integrity, and the minimum DNBR remains above 1.19 thus ensuring fuel cladding integrity.

15.2.8 Feedwater System Pipe Breaks

Appendix 15B describes the methods used to evaluate the feedwater pipe breaks, and the results of the evaluation.

15.3 DECREASE IN REACTOR COOLANT FLOWRATE

15.3.1 TOTAL LOSS OF REACTOR COOLANT FLOW

15.3.1.1 Identification of Events and Causes

A complete loss of forced reactor coolant flow will result from the simultaneous loss of electrical power to all reactor coolant pumps (RCPs). The only credible failure which can result in a simultaneous loss of power is a complete loss of offsite power. In addition, since a loss of offsite power is assumed to result in a turbine trip and renders the steam dump and bypass system unavailable, the plant cooldown is performed utilizing the secondary valves and atmospheric dump valves.

A total loss of forced reactor coolant flow will produce a minimum DNBR more adverse than any partial loss of forced reactor coolant flow event.

The loss of offsite power event plus a single failure will not result in a lower DNBR than that calculated for the loss of offsite power event alone. For decreasing reactor coolant flow events, the major parameter of concern is the minimum hot channel DNBR. This parameter established whether a fuel design limit has been violated and, thus, whether fuel damage might be anticipated. Those factors which cause a decrease in local DNBR are:

a. increasing coolant temperature
b. decreasing coolant pressure
c. increasing local heat flux (including radial and axial power distribution effects)
d. decreasing coolant flow

For the loss of offsite power event, the minimum DNBR occurs during the first few seconds of the transient and the reactor is tripped by the CPCs on the approach to the DNBR limit. Therefore, any single failure which would result in a lower DNBR during the transient would have to affect at least one of the above parameters during the first few seconds of the event. None of the single failures listed in Table 15.0-6 will have any effect on the transient minimum DNBR during this period of time.

Additionally, none of the single failures listed in Table 15.0-6 will have any effect on the peak primary system pressure. The loss of offsite power will make unavailable any systems whose failure could affect the calculated peak pressure. For example, a failure of the steam dump and bypass system to modulate or quick open and a failure of the pressurizer spray control valve to open involve systems (Steam Dump and Bypass System and Pressurizer Pressure Control System (PPCS) which are assumed to be in the manual mode as a result of the loss of offsite power and, hence, unavailable for at least 30 minutes. Another example involving the PPCS would be the failure of the back-up heaters to turn off. Since the event is characterized by increasing RCS pressure, the back-up heaters will not be called upon to operate in such a transient.

For the reasons stated in the above paragraphs the loss of offsite power event with a single failure is no more adverse than the loss of offsite power event in terms of the minimum DNBR and peak primary system pressure.

15.3.1.2 Sequence of Events and Systems Operation

Table 15.3.1-1 presents a chronological list and time of systems actions which occur during the total loss of reactor coolant flow event. Refer to Table 15.3.1-1 while reading this and the following section. The success paths referenced in Table 15.3.1-1 are those given on the sequence of events diagram (SED), Figure 15.3.1-1. This figure, together with Figure 15.0-1, 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 15.3.1-1 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 represents 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 15.3.1-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient.

Table 15.3.1-3 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 15.3.1-1, are as follows:

Reactivity Control:

A loss of electrical power to all reactor coolant pumps produces a reduction of coolant flow through the reactor core. The reduction in coolant flow rate causes an increase in the core average coolant temperature with a concurrent decrease in the margin to DNB. A low DNBR reactor trip is generated by the core protection calculators, as described in Section 7.2. This prevents the minimum DNBR calculated with the CE-1 CHF correlation from decreasing to less than 1.19 at any time during the transient. The CEAs begin to drop into the core 1.09 seconds after the loss of electrical power to the RCPs inserting negative reactivity. The 1.09 second delay conservatively includes the largest possible delay times for sensor delays, CPC calculation period, CEDM dead time, and CEDM coil decay time.

Prior to initiating or during manual cooldown the operator adjusts the boron concentration to insure that a proper negative reactivity shutdown margin is achieved. This is accomplished by using the HPSI pumps which also replace RCS volume shrinkage. The operator must also borate using the charging pumps by manually loading them on the diesel generators and then aligning them to the refueling water tank (RWT), the source of borated water.

Reactor Heat Removal:

Following the total loss of reactor coolant flow, reactor heat removal takes place by means of natural circulation. The steam generators provide primary to secondary heat transfer.

The Shutdown Cooling System (SCS) is manually actuated when RCS temperature and pressure have been reduced to 350°F and 400 psia, respectively. This system provides sufficient cooling flow to cool the RCS to cold shutdown conditions.

Secondary System Integrity:

The turbine is assumed to trip our loss of offsite power. The loss of offsite power produces a loss of load on the turbine which generates a turbine trip signal. The turbine stop valves are closed as a result of the trip. The steam bypass control system becomes unavailable due to the loss of offsite power and subsequent loss of condenser vacuum. Also, as a result of the loss of condensor vacuum, main feedwater flow to the steam generators is lost. This sequence of events results in opening of the Main Steam Safety Valves (MSSVs) which limits secondary system pressure and removes heat stored in the core and the RCS. Once the flow parameters are stablized, the operator initiates cooldown (assumed to be initiated 30 minutes after event initiation) utilizing the Auxiliary Feedwater System (AFWS) and the atmospheric dump valves.

The AFWS may be a separate system or may be one emergency feedwater pump designated as "auxiliary" and intended for normal startup and shutdown of the plant. The operator may let the ESFAS regulate the feedwater flow by issuing and withdrawing EFAS-1 and/or EFAS-2 signals down to cold shutdown entry conditions. See Applicant's FSAR for details of the Emergency and/or Auxiliary Feedwater Systems. As the cooldown proceeds, the operator reduces the main steam isolation actuation setpoint to prevent the inadvertent generation of an MSIS.

Primary System Integrity:

The pressurizer assists in the control of the RCS prssure and volume changes during the transient by compensating for the initial expansion of the RCS fluids. The combination of the loss of primary system heat sink (turbine stop valves close) with the reduction of reactor coolant flow results in an increase in RCS pressure which is limited by the primary safety valves. The reactor drain tank receives the released steam.

During the cooldown, the operator may control RCS pressure and pressurizer level by turning on the HPSI pumps and throttling the HPSI discharge valves to control the rate of change of RCS pressure. The operator may also control RCS pressure and pressurizer level via manual actuation and control of the charging pumps and related auxiliary spray. As the cooldown proceeds, the operator will reduce the safety injection actuation setpoint to prevent the inadvertent generation of an SIAS. When the RCS pressure has been reduced to approximately 650 psia, the operator will vent or drain the safety injection tanks to reduce their pressure and will isolate them.

Restoration 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 (except for load centers). 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.

Spent Fuel Heat Removal:

Spent Fuel Pool (SFP) cooling is terminated on the loss of normal power to the ESF loads. Spent fuel heat removal is continuously accomplished by utilizing the heat capacity of the SFP water. Pool cooling is restored by manually loading the SFP cooling pumps onto the diesel generators and by aligning the SFP heat exchangers to receive essential cooling water.

15.3.1-3 Analysis of Effects and Consequences

A. Mathematical Mode

The NSSS response to a total loss of reactor coolant flow was simulated using the CESEC-II computer program described in Section 15.0.3. The minimum DNBR was calculated using the TORC computer code (see Section 15.0.3.) which uses the CE-1 CHF correlation described in Reference 19 of Section 15.0, and the HERMITE computer code described in Reference 17 of Section 15.0.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a total loss of flow are discussed in Section 15.0. The parameters, which are unique to the analysis, discussed below, are listed in Table 15.3.1-4.

The principal process variables that determine thermal margin to DNB in the core are monitored by COLSS. COLSS computes a power-operating limit which assists the operator in maintaining the thermal margin in the core equal to or greater than that needed to cause the minimum DNBR to remain greater than 1.19, for a four pump loss of flow, assuming immediate reactor trip. COLSS is described in Section 7.7. The set of initial conditions chosen for the analysis presented in this section is one of a very large number of combinations within the reactor operating space given in Table 15.0-5 which would provide the minimum thermal margin required by the COLSS power operating limit. The consequences following a total loss of flow initiated from any one of these combinations of conditions would be no more adverse than those presented herein.

C. Results

The dynomic behavior of important NSSS parameters following a total loss of reactor coolant flow is provided in Figures 15.3.1-2 to 15.3.1-9.

The loss of offsite power causes the plant to experience a simultaneous turbine trip, loss of main feedwater, condenser inoperability, and a four reactor coolant pump coastdown. The loss of steam flow due to closure of the turbine stop valves results in a rapid increase in the steam generator pressure. A

sharp reduction in primary to secondary heat transfer follows which, in conjunction with the loss of forced reactor coolant flow, causes a rapid heat up of the primary coolant. The pressurizer safety valves open at 4.3 seconds, and the MSSVs open at 5.4 seconds. The RCS pressure reaches a maximum of 2576 psia at 5.3 seconds (Figure 15.3.1-4). This is less than 110% of design pressure. At 11.7 seconds the secondary pressure reaches its maximum value of 1338 psia (Figure 15.3.1-8). This pressure is also less than 110% of design pressure.

Subsequently, the RCS pressure decreases rapidly as the combination of reactor trip and primary and main steam safety valves opening reduce the reactor coolant system energy.

The pressurizer safety valves close at 12.2 seconds. A second pressure increase occurs as a result of increasing RCS temperatures caused by the degrading primary to secondary heat transfer resulting from the continuously decreasing reactor coolant system flow rate. The rise in RCS temperatures increases the primary to secondary heat transfer until the heat removed by the secondary system exceeds the primary system heat generation. At this time the RCS temperatures, and subsequently the pressure, begin to decrease. After 30 minutes, the operator commences cooldown using the auxiliary feedwater system and the atmospheric dump valves.

The minimum CE-1 DNBR calculated to occur during the transient is 1.19 (Figure 15.3.1-9); thus, no fuel pins are assumed to experienc DNB for this event.

15.3.1.5 Conclusions

The maximum RCS and secondary system pressures remain within 110% of their design values following the total loss of forced reactor coolant flow event. The minimum DNBR calculated to occur during the transient is 1.19 which ensures that the specified acceptable fuel design limit is not violated.

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TABLE 15.3.1-1

SEQUENCE OF EVENTS FOR TOTAL LOSS OF REACTOR COOLANT FLOW

Time (Sec)	Event	Setpoint Or Value	Success Path
0.0	Loss of Offsite Power - Turbine Trip - Diesel Generator Starting Signal - Reactor Coolant Pumps Coast Down - Main Feedwater is Lost		
0.6	Low DNBR Trip Signal Generated	1.19 Projected	Reactivity Control
1.09	CEA's Begin to Drop		Reactivity Control
2.6	Minimum Transient DNBR	1.19	
4.3	Pressurizer Safety Valves Open, psia	2525	Primary System Integrity
5.3	Maximum RCS Pressure, psia	2576	
5.4	Steam Generator Safety Valves Open, psia	1282	Secondary System Integrity
11.7	Maximum Steam Generator Pressure, psia	1338	
12.2	Pressurizer Safety Valves Closed, psia	2463	Primary System Integrity
1800.0	Operator Initiates Plant Cooldown		

TABLE 15.3.1-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR THE TOTAL LOSS OF REACTOR COOLANT FLOW

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System			✓			
2. Main Feedwater Pump Turbine Control System*			✓			
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System				✓		
5. Pressurizer Pressure Control System				✓		
6. Pressurizer Level Control System				✓		
7. Control Element Drive Mechanism Control System	✓					
8. Reactor Regulating System				✓		
9. Core Operating Limit Supervisory System			✓			
10. Reactor Coolant Pumps				✓		
11. Chemical and Volume Control System				✓		
12. Secondary Chemistry Control System*				✓		
13. Condenser Evacuation System*				✓		
14. Turbine Gland Sealing System*				✓		
15. Nuclear Cooling Water System*				✓		
16. Turbine Cooling Water System*				✓		
17. Plant Cooling Water System*				✓		
18. Condensate Storage Facilities*				✓		
19. Circulating Water System*				✓		
20. Spent Fuel Pool Cooling and Clean-Up System*				✓		
21. Non-Class 1E (Non-ESF) A.C. Power*			✓			1
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems -

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DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR THE TOTAL LOSS OF REACTOR COOLANT FLOW

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.	INITIATING EVENT	INOPERATIVE FOR LOCF
23. Non-Class 1E D.C. Power*		✓				
24. Class 1E D.C. Power*		✓				

Notes:

1. Failure in this system is the initiating event.

*Balance-of-Plant Systems

TABLE 15.3.1-3

UTILIZATION OF SAFETY SYSTEMS
FOR THE TOTAL LOSS OF REACTOR COOLANT FLOW

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator	✓				
3. Engineered Safety Features Actuation Systems			✓		
4. Supplementary Protection System					1
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves	✓				
8. Main Steam Isolation System*	✓		✓		2
9. Emergency Feedwater System*			✓		
10. Safety Injection System					
11. Shutdown Cooling System	✓				2
12. Atmospheric Dump Valve System*	✓				2
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*	✓				
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

Notes:

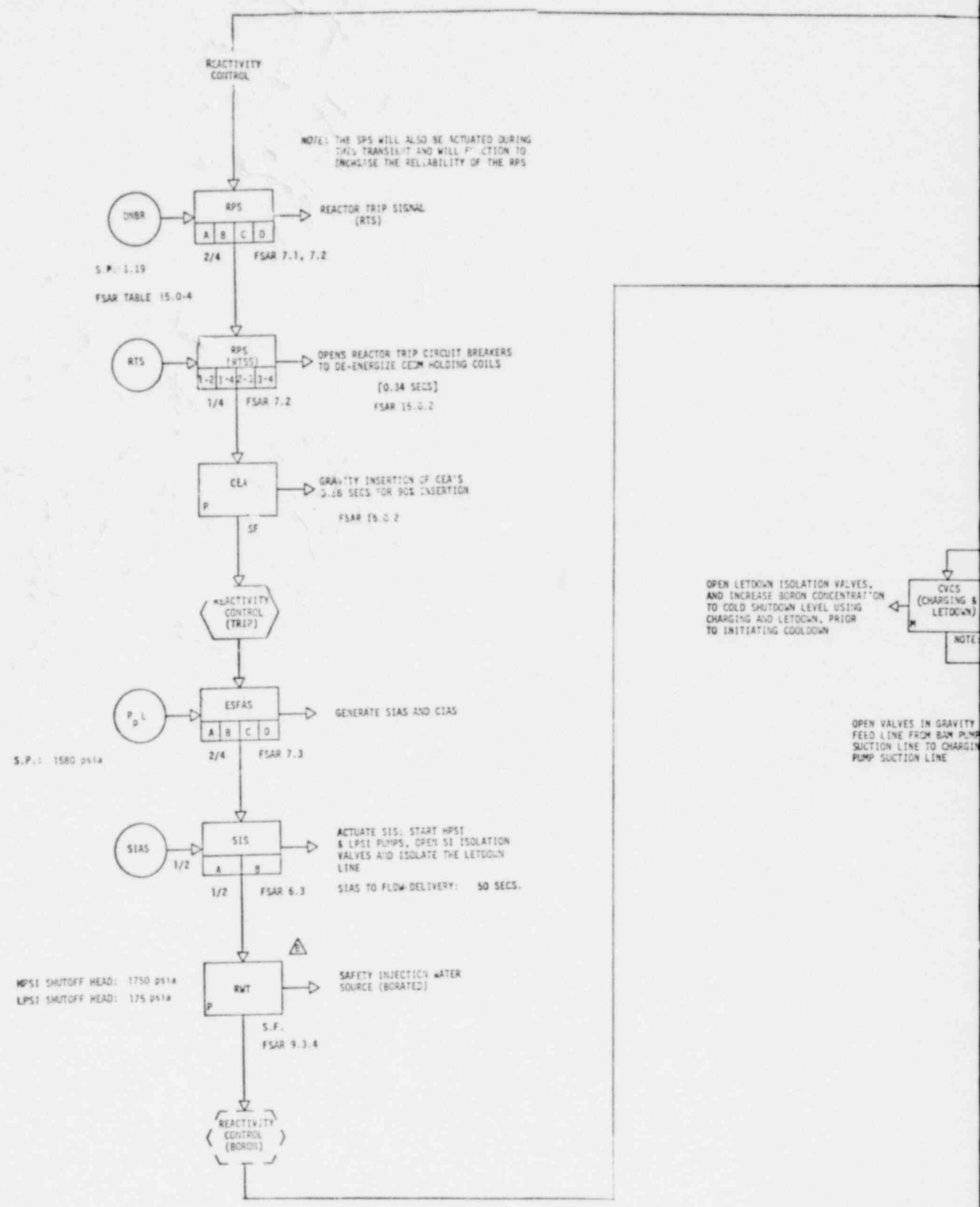
1. Safety grade back-up to a safety grade system.
2. Manually actuated during normal cooldown.

*Balance-of-Plant Systems -

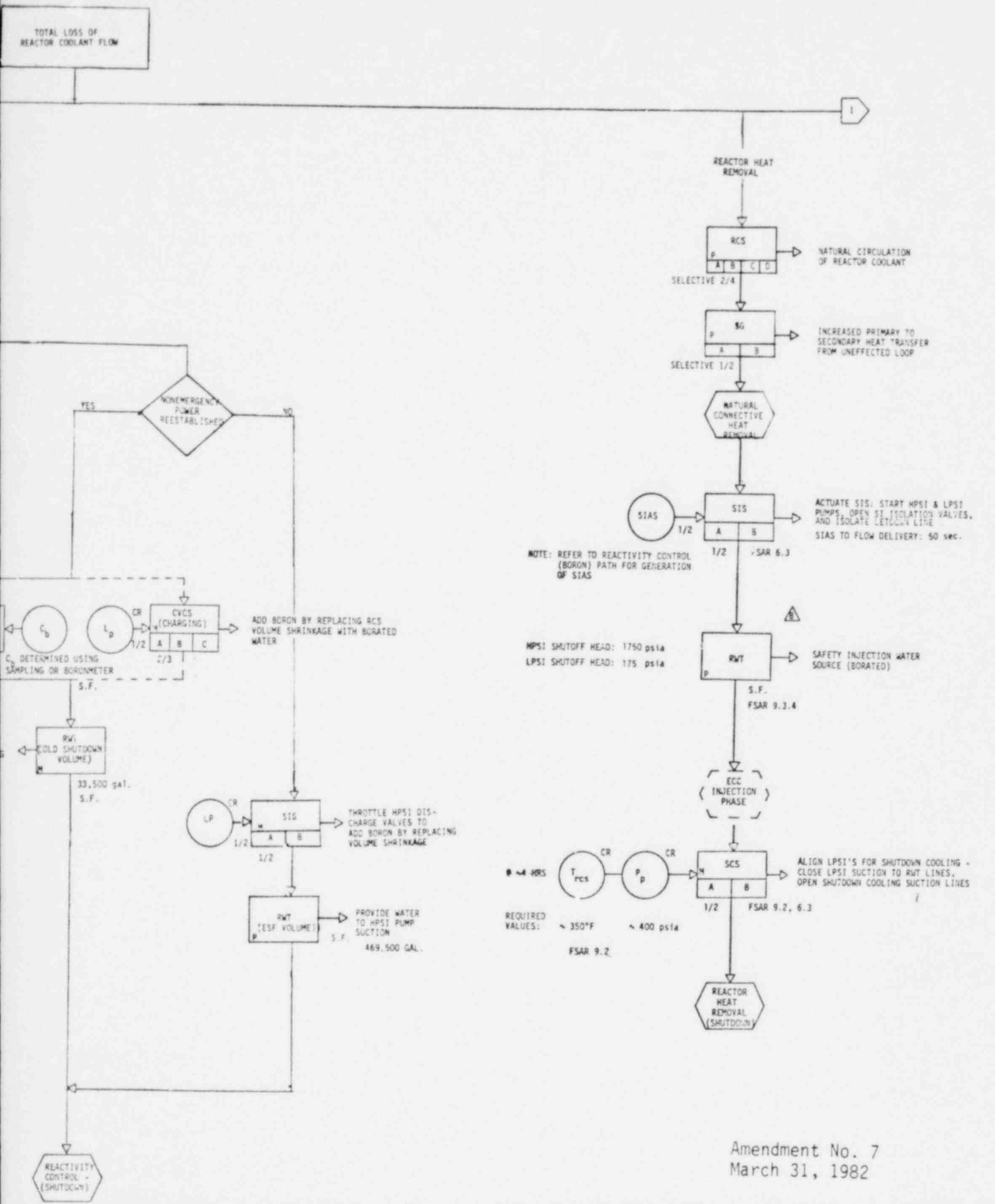
TABLE 15.3.1-4

ASSUMED INITIAL CONDITIONS FOR TOTAL LOSS OF REACTOR COOLANT FLOW

Parameter	Value
Core Power Level, MWt	3876
Core Inlet Coolant Temperature,°F	565
Reactor Coolant System Pressure, psia	2250
Steam Generator Pressure, psia	1070
Core Mass Flow, 10^6 lbm/hr	157.4
Core Minimum DNBR	1.51
Maximum Radial Power Peaking Factor	1.62
Maximum Axial Power Peak	1.47
CEA Worth on Trip, 10^{-2} $\Delta\rho$ (most reactive CEA Stuck)	-10.0



REACTIVITY CONTROL
NOTE: THE SPS WILL ALSO BE ACTUATED DURING THIS TRANSIENT AND WILL FUNCTION TO INCREASE THE RELIABILITY OF THE RPS
DNBR
RPS
A B C D
2/4
FSAR 7.1, 7.2
REACTOR TRIP SIGNAL (RTS)
S.P.: 1.19
FSAR TABLE 15.0-4
RTS
RPS (RTSS)
1-2 1-4 2-3 3-4
1/4
FSAR 7.2
OPENS REACTOR TRIP CIRCUIT BREAKERS TO DE-ENERGIZE CEDM HOLDING COILS
[0.34 SECS]
FSAR 15.0.2
CEA
P
SF
GRAVITY INSERTION OF CEA'S 3.26 SECS FOR 90% INSERTION
FSAR 15.0.2
REACTIVITY CONTROL (TRIP)
P_D L
ESFAS
A B C D
2/4
FSAR 7.3
GENERATE SIAS AND CIAS
S.P.: 1580 psia
SIAS
1/2
SIS
A B
1/2
FSAR 6.3
ACTUATE SIS: START HPSI & LPSI PUMPS, OPEN SI ISOLATION VALVES AND ISOLATE THE LETDOWN LINE
SIAS TO FLOW DELIVERY: 50 SECS.
HPSI SHUTOFF HEAD: 1750 psia
LPSI SHUTOFF HEAD: 175 psia
RWT
P
S.F.
FSAR 9.3.4
SAFETY INJECTION WATER SOURCE (BORATED)
REACTIVITY CONTROL (BORON)
OPEN LETDOWN ISOLATION VALVES, AND INCREASE BORON CONCENTRATION TO COLD SHUTDOWN LEVEL USING CHARGING AND LETDOWN, PRIOR TO INITIATING COOLDOWN
CVCS (CHARGING & LETDOWN)
NOTE:
OPEN VALVES IN GRAVITY FEED LINE FROM BAM PUMP SUCTION LINE TO CHARGING PUMP SUCTION LINE



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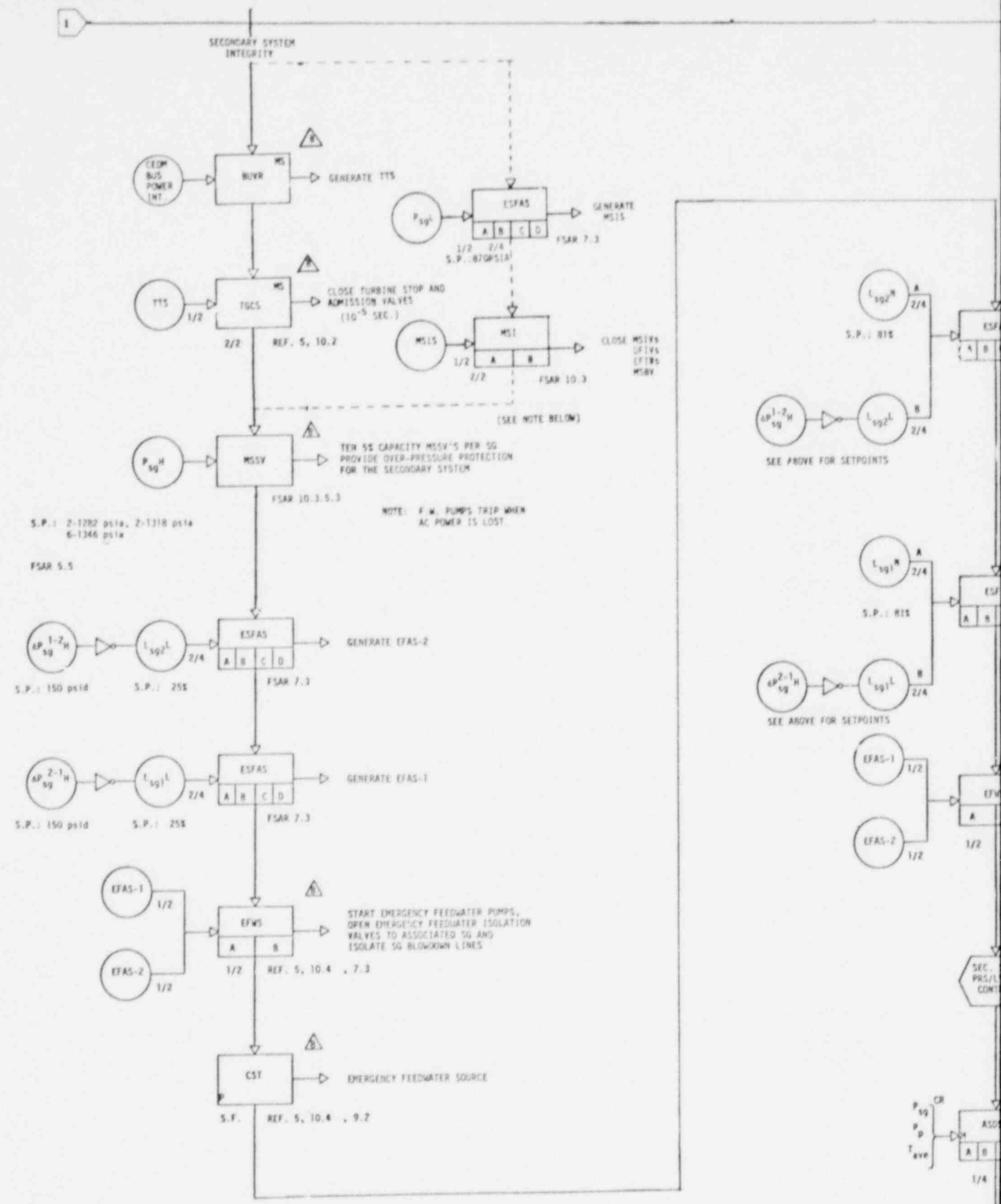
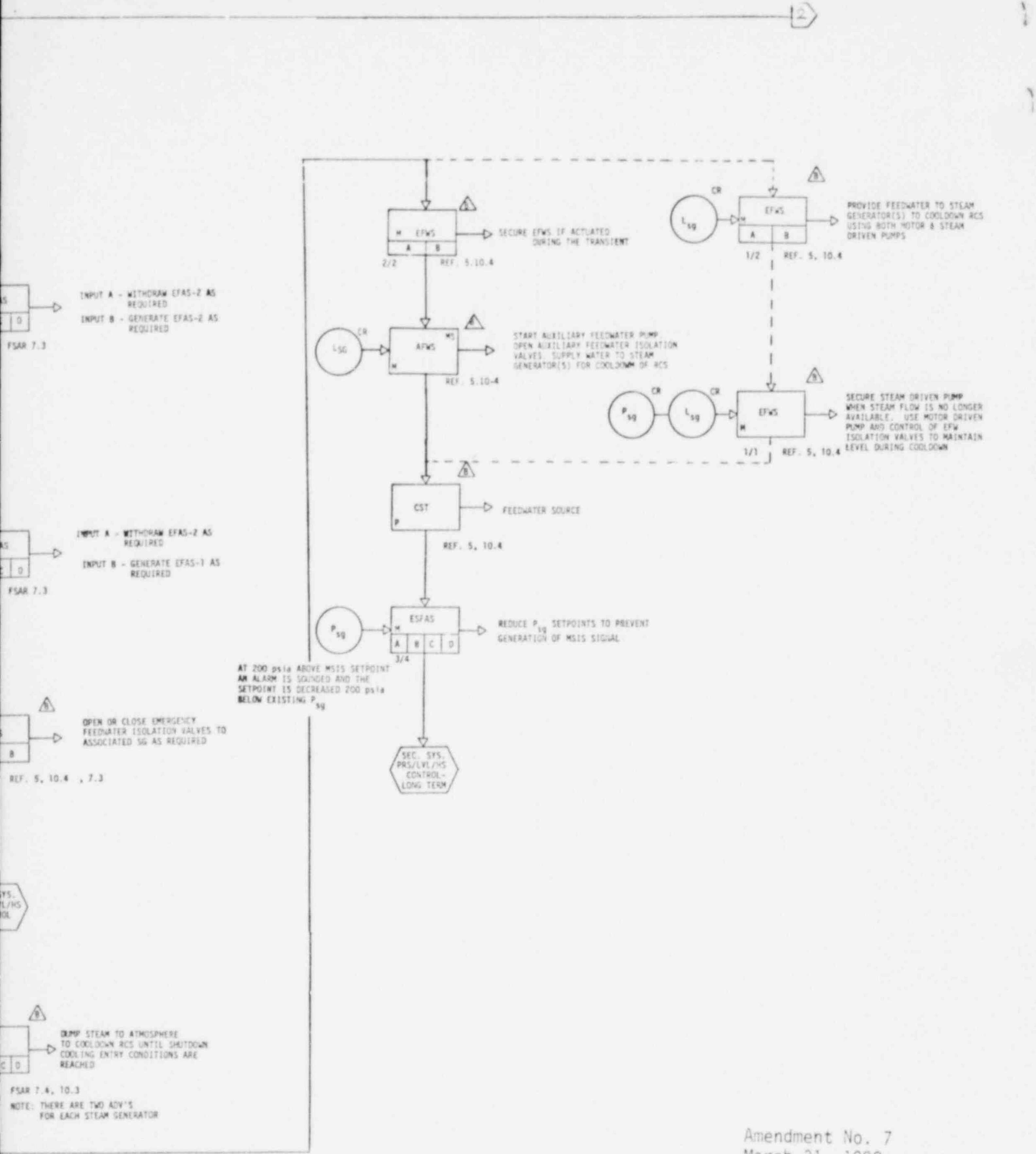
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR TOTAL LOSS OF REACTOR COOLANT FLOW	Figure 15.3.1-1A



1
SECONDARY SYSTEM INTEGRITY
CEDM BUS POWER INT.
BUVR
MS
GENERATE TTS
ESFAS
A B C D
GENERATE MSIS
1/2 2/4
FSAR 7.3
TTS
1/2
TGCS
MS
CLOSE TURBINE STOP AND ADMISSION VALVES
2/2
REF. 5, 10.2
MSIS
1/2
MSI
A B
CLOSE MSIVs
2/2
FSAR 10.3
(SEE NOTE BELOW)
MSSV
TEN 5% CAPACITY MSSV'S PER SG PROVIDE OVER-PRESSURE PROTECTION FOR THE SECONDARY SYSTEM
FSAR 10.3.5.3
NOTE: F.W. PUMPS TRIP WHEN AC POWER IS LOST.
S.P.: 2-1282 psia, 2-1318 psia 6-1346 psia
FSAR 5.5
2/4
GENERATE EFAS-2
S.P.: 150 psid
S.P.: 25%
GENERATE EFAS-1
EFAS-1
1/2
EFAS-2
EFWS
START EMERGENCY FEEDWATER PUMPS, OPEN EMERGENCY FEEDWATER ISOLATION VALVES TO ASSOCIATED SG AND ISOLATE SG BLOWDOWN LINES
REF. 5, 10.4 , 7.3
CST
EMERGENCY FEEDWATER SOURCE
S.F.
REF. 5, 10.4 , 9.2
S.P.: 81%
SEE ABOVE FOR SETPOINTS
1/4



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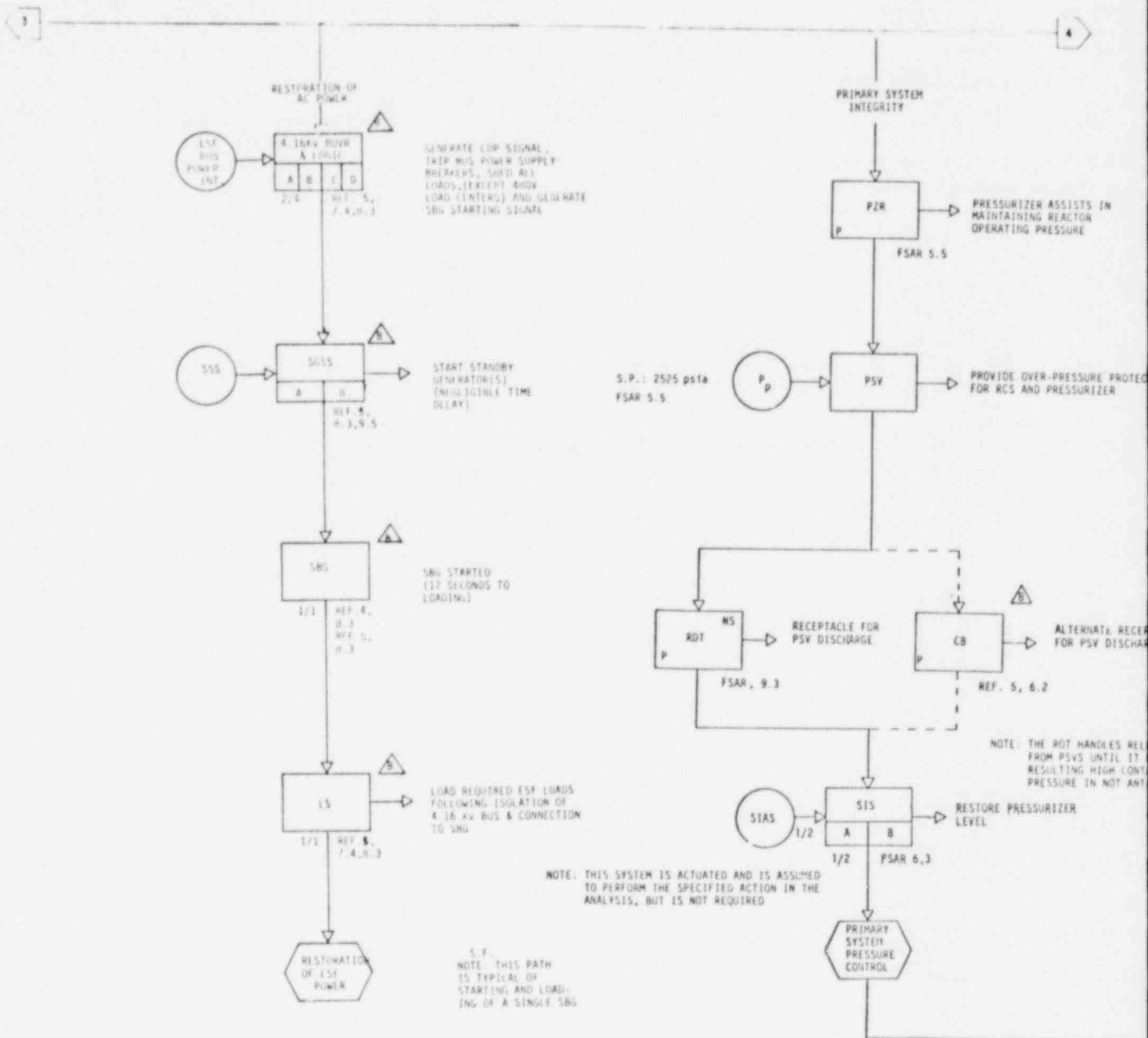
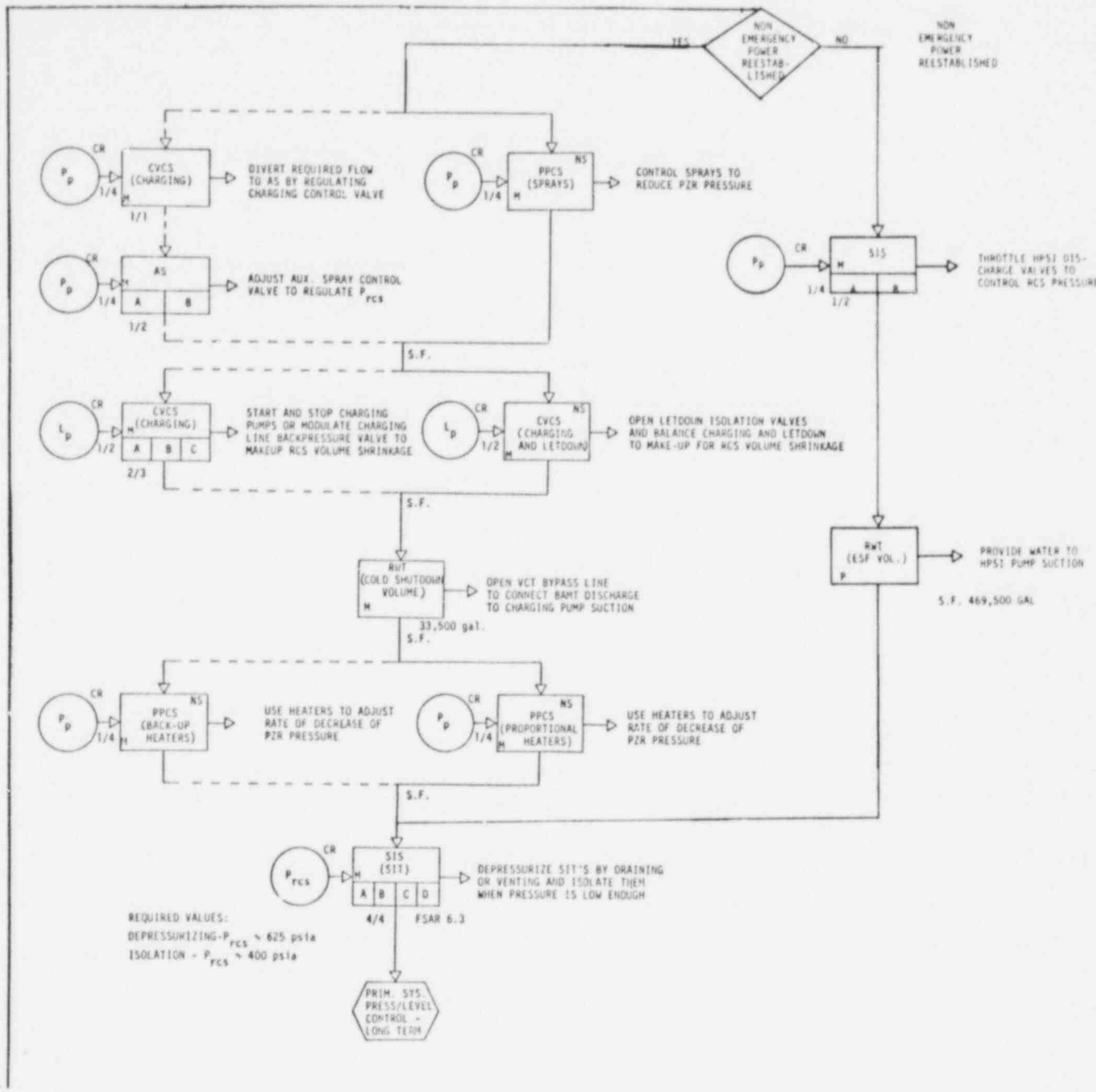
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR TOTAL LOSS OF REACTOR COOLANT FLOW	Figure 15.3.1-1B



RESTORATION OF AC POWER
ESF BUS POWER INT
4.16kv BUVR & LOGIC
A B C D
2/4
REF. 5, 7.4, 8.3
GENERATE LOP SIGNAL, TRIP BUS POWER SUPPLY BREAKERS, SHED ALL LOADS,(EXCEPT 480V LOAD CENTERS) AND GENERATE SBG STARTING SIGNAL
SSS
SGSS
A B
REF. 5, 8.3, 9.5
START STANDBY GENERATOR(S) (NEGLIGIBLE TIME DELAY)
SBG
1/1
REF. 4, 8.3 REF. 5, 8.3
SBG STARTED (12 SECONDS TO LOADING)
LS
1/1
REF 5, 7.4, 8.3
LOAD REQUIRED ESF LOADS FOLLOWING ISOLATION OF 4.16 kv BUS & CONNECTION TO SBG
RESTORATION OF ESF POWER
S.F. NOTE: THIS PATH IS TYPICAL OF STARTING AND LOADING OF A SINGLE SBG
PRIMARY SYSTEM INTEGRITY
PZR
P
FSAR 5.5
PRESSURIZER ASSISTS IN MAINTAINING REACTOR OPERATING PRESSURE
S.P.: 2525 psia
FSAR 5.5
PSV
PROVIDE OVER-PRESSURE PROTEC
FOR RCS AND PRESSURIZER
RDT
NS
P
FSAR, 9.3
RECEPTACLE FOR PSV DISCHARGE
CB
P
REF. 5, 6.2
ALTERNATE RECEP
FOR PSV DISCHAR
NOTE: THE RDT HANDLES REL FROM PSVS UNTIL IT RESULTING HIGH CONT PRESSURE IN NOT ANT
SIAS
1/2
SIS
A B
1/2
FSAR 6,3
RESTORE PRESSURIZER LEVEL
NOTE: THIS SYSTEM IS ACTUATED AND IS ASSUMED TO PERFORM THE SPECIFIED ACTION IN THE ANALYSIS, BUT IS NOT REQUIRED
PRIMARY SYSTEM PRESSURE CONTROL



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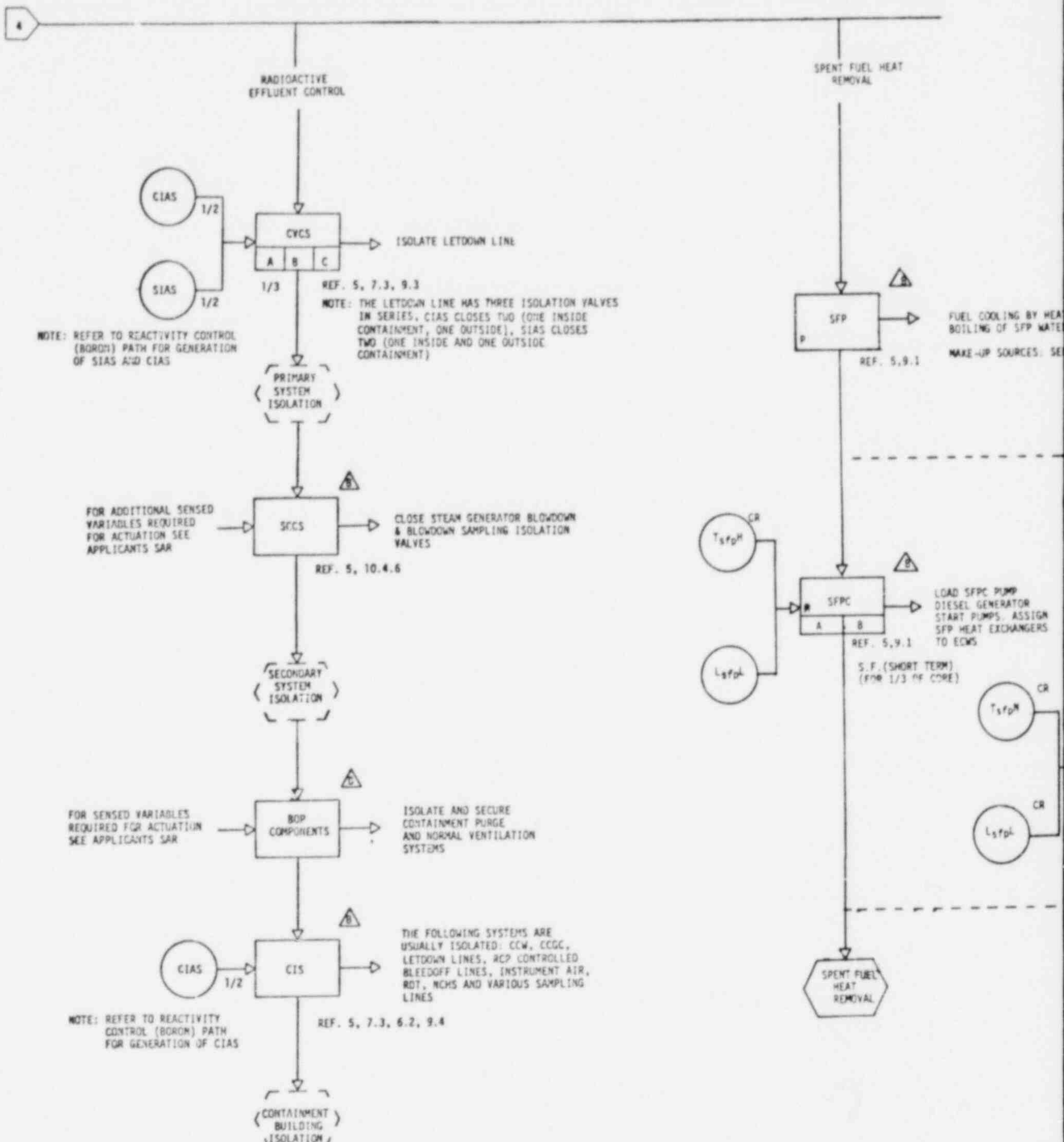
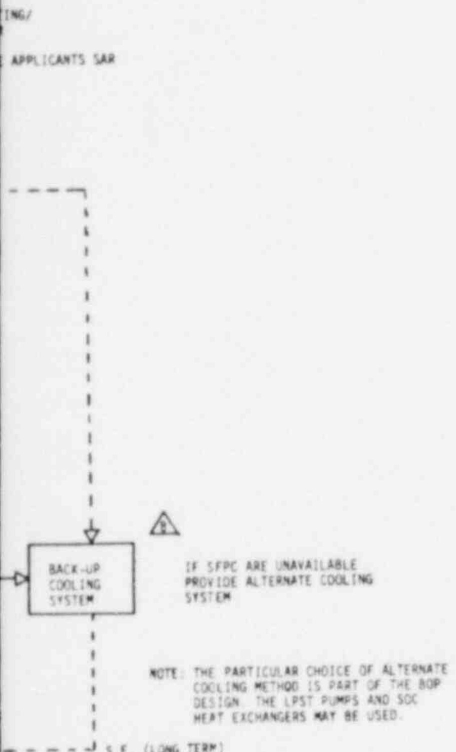
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR TOTAL LOSS OF REACTOR COOLANT FLOW	Figure 15.3.1-1C



4
RADIOACTIVE EFFLUENT CONTROL
CIAS
1/2
SIAS
1/2
CVCS
A B C
1/3
ISOLATE LETDOWN LINE
REF. 5, 7.3, 9.3
NOTE: THE LETDOWN LINE HAS THREE ISOLATION VALVES IN SERIES. CIAS CLOSES TWO (ONE INSIDE CONTAINMENT, ONE OUTSIDE), SIAS CLOSES TWO (ONE INSIDE AND ONE OUTSIDE CONTAINMENT)
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF SIAS AND CIAS
PRIMARY SYSTEM ISOLATION
FOR ADDITIONAL SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
SGCS
CLOSE STEAM GENERATOR BLOWDOWN & BLOWDOWN SAMPLING ISOLATION VALVES
REF. 5, 10.4.6
SECONDARY SYSTEM ISOLATION
FOR SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
BOP COMPONENTS
ISOLATE AND SECURE CONTAINMENT PURGE AND NORMAL VENTILATION SYSTEMS
CIAS
1/2
CIS
THE FOLLOWING SYSTEMS ARE USUALLY ISOLATED: CCW, CCGC, LETDOWN LINES, RCP CONTROLLED BLEEDOFF LINES, INSTRUMENT AIR, RDT, NCHS AND VARIOUS SAMPLING LINES
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF CIAS
REF. 5, 7.3, 6.2, 9.4
CONTAINMENT BUILDING ISOLATION
SPENT FUEL HEAT REMOVAL
SFP
P
FUEL COOLING BY HEA
BOILING OF SFP WATE
MAKE-UP SOURCES: SE
REF. 5,9.1
CR
T_{sfp}^{H}
L_{sfp}^{L}
SFPC
A B
LOAD SFPC PUMP DIESEL GENERATOR START PUMPS. ASSIGN SFP HEAT EXCHANGERS TO ECWS
REF. 5,9.1
S.F.(SHORT TERM) (FOR 1/3 OF CORE)
CR
T_{sfp}^{H}
CR
L_{sfp}^{L}
SPENT FUEL HEAT REMOVAL



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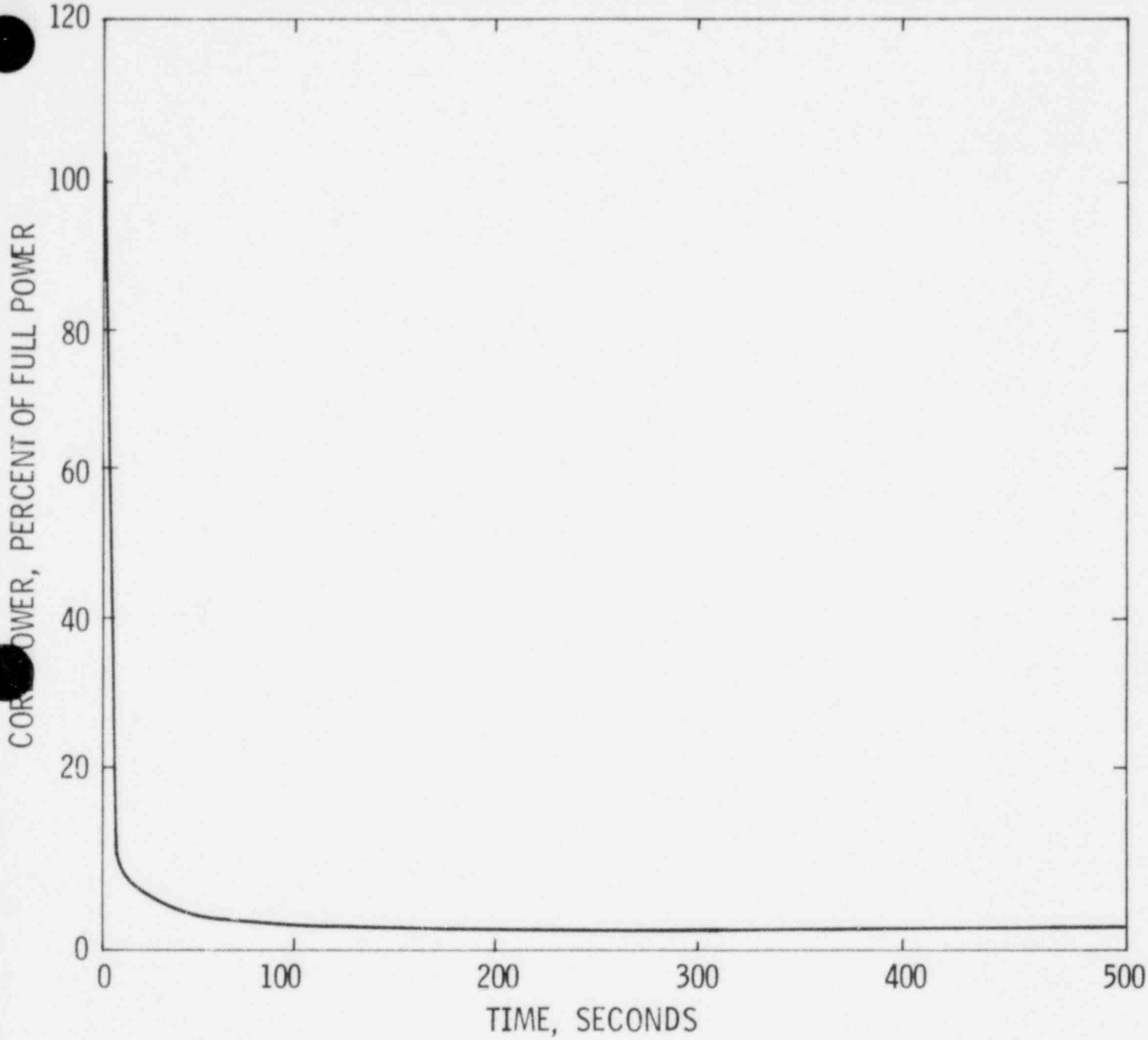
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR TOTAL LOSS OF REACTOR COOLANT FLOW	Figure 15.3.1-1D



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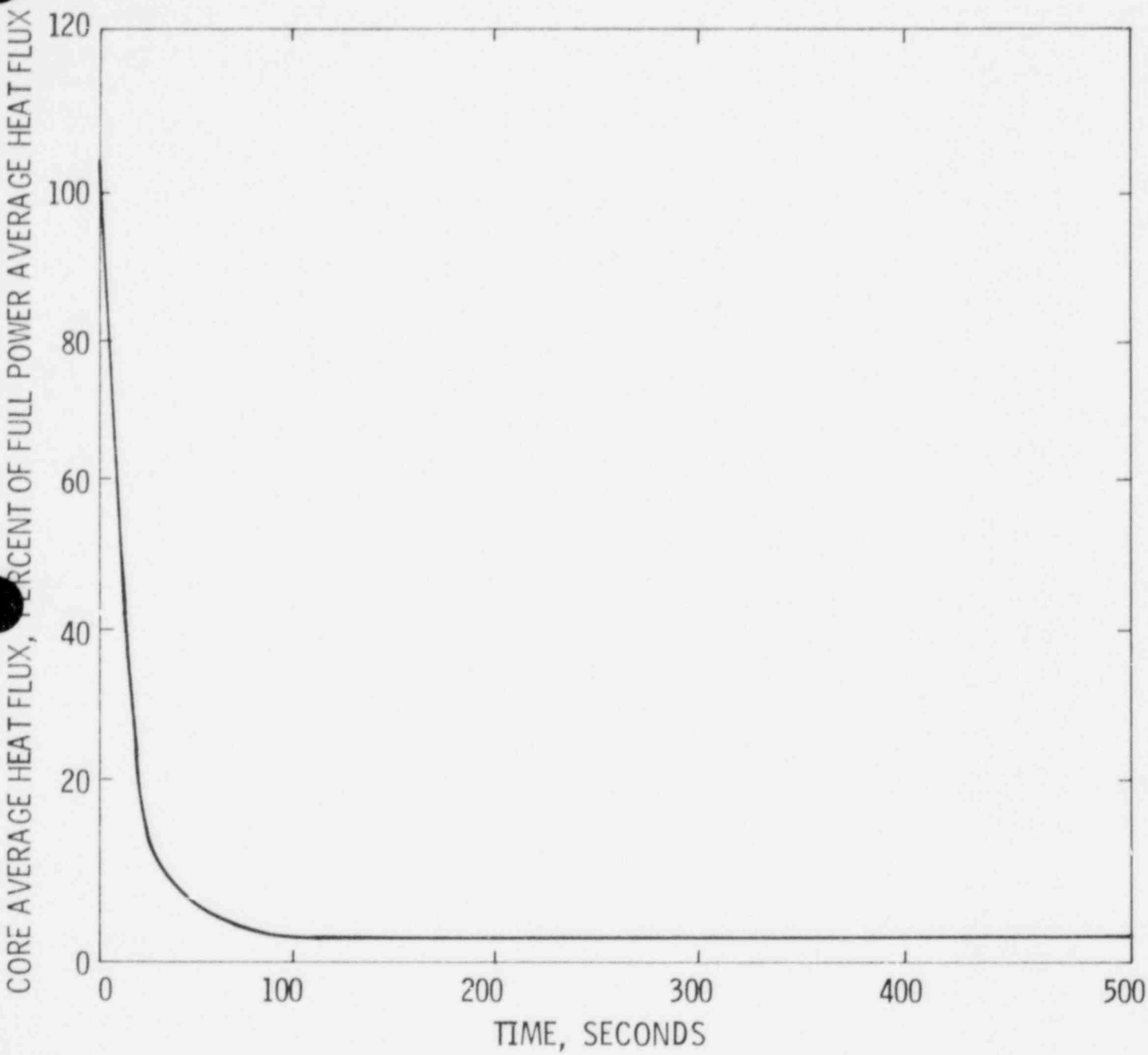
C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW CORE POWER vs TIME	Figure 15.3.1-2



Amendment No. 7
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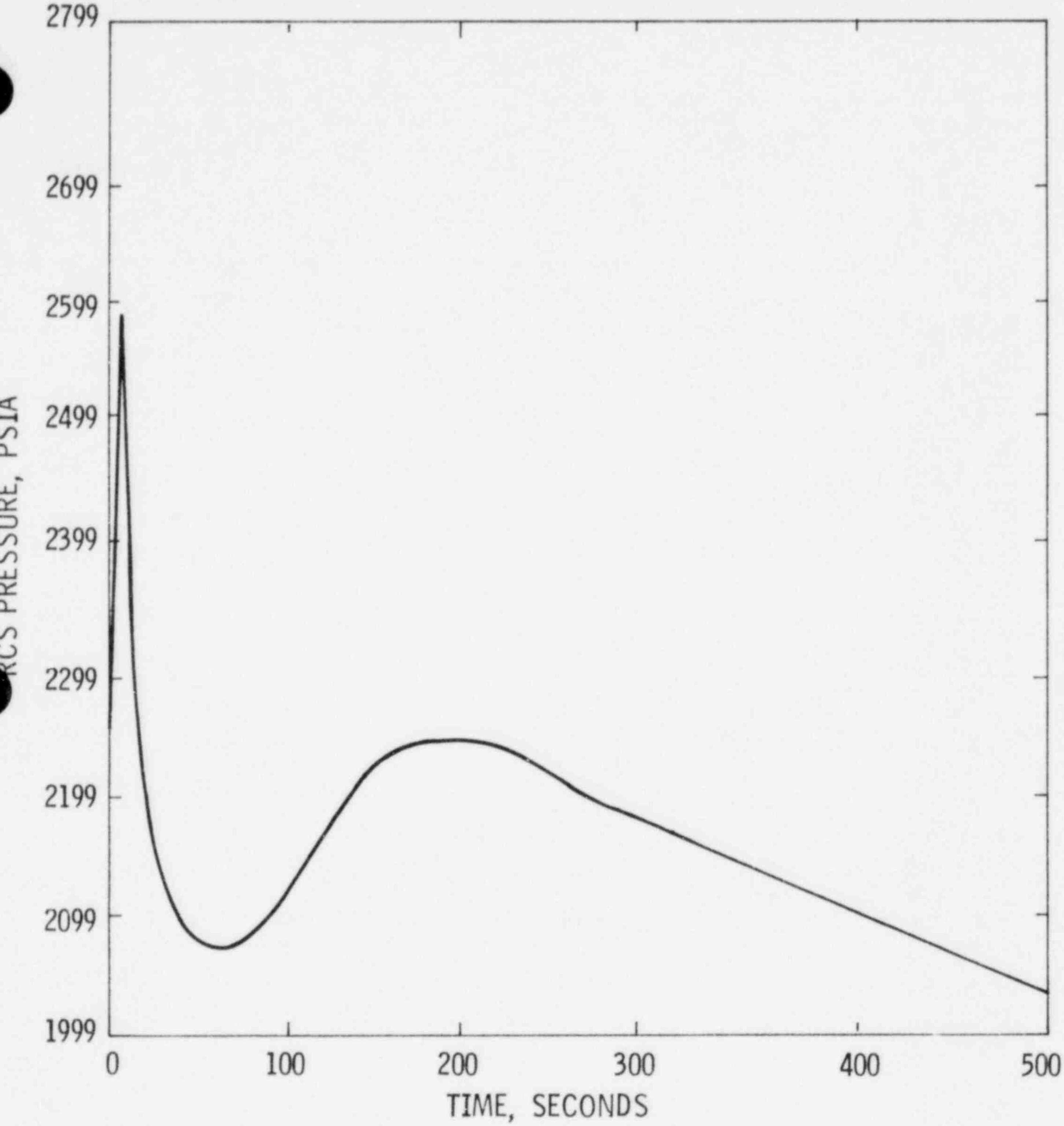
C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW CORE AVERAGE HEAT FLUX vs TIME	Figure 15.3.1-3



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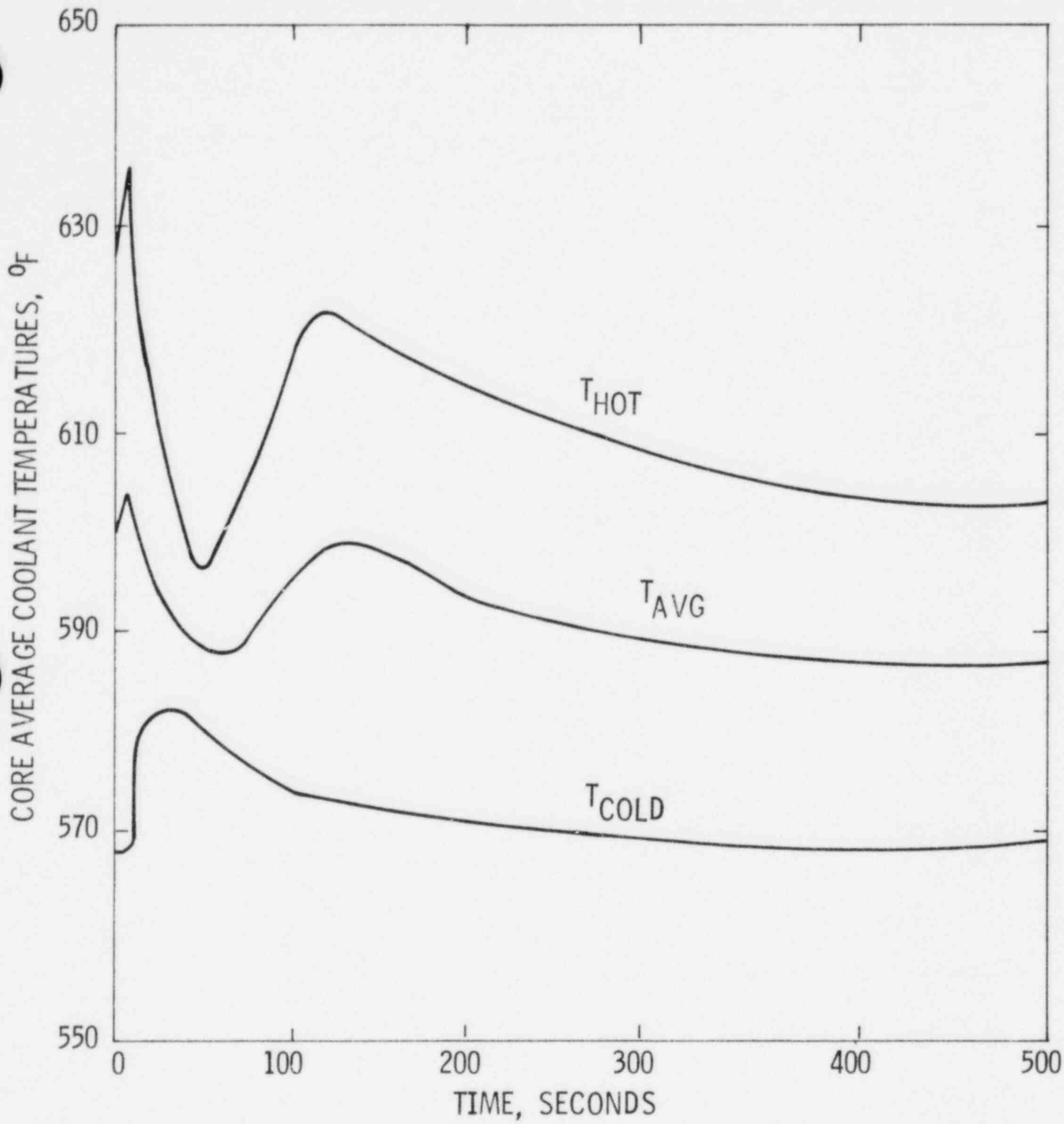
C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW RCS PRESSURE vs TIME	Figure 15.3.1-4



Amendment No. 7
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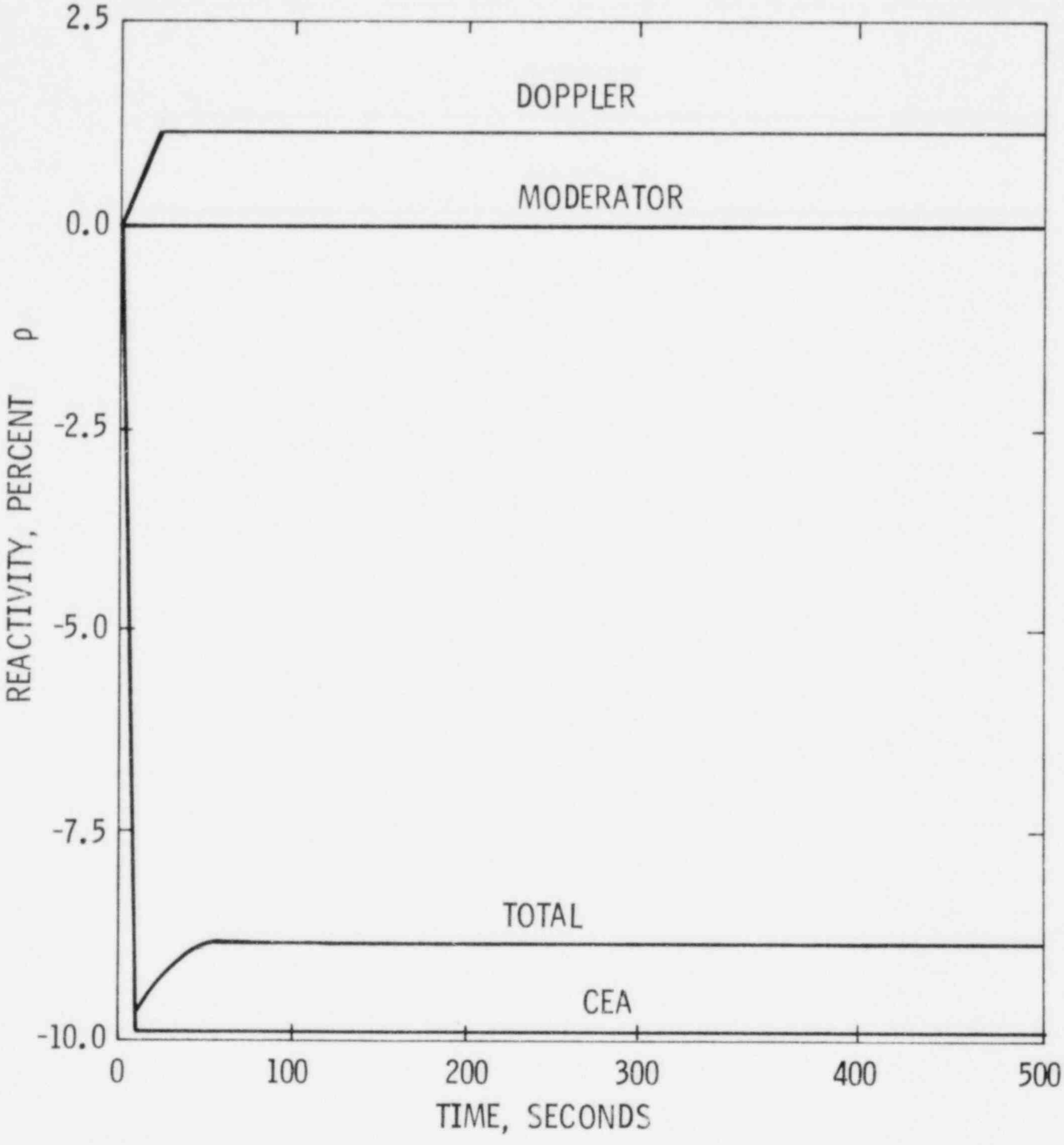
C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW CORE AVERAGE COOLANT TEMPERATURES vs TIME	Figure 15.3.1-5



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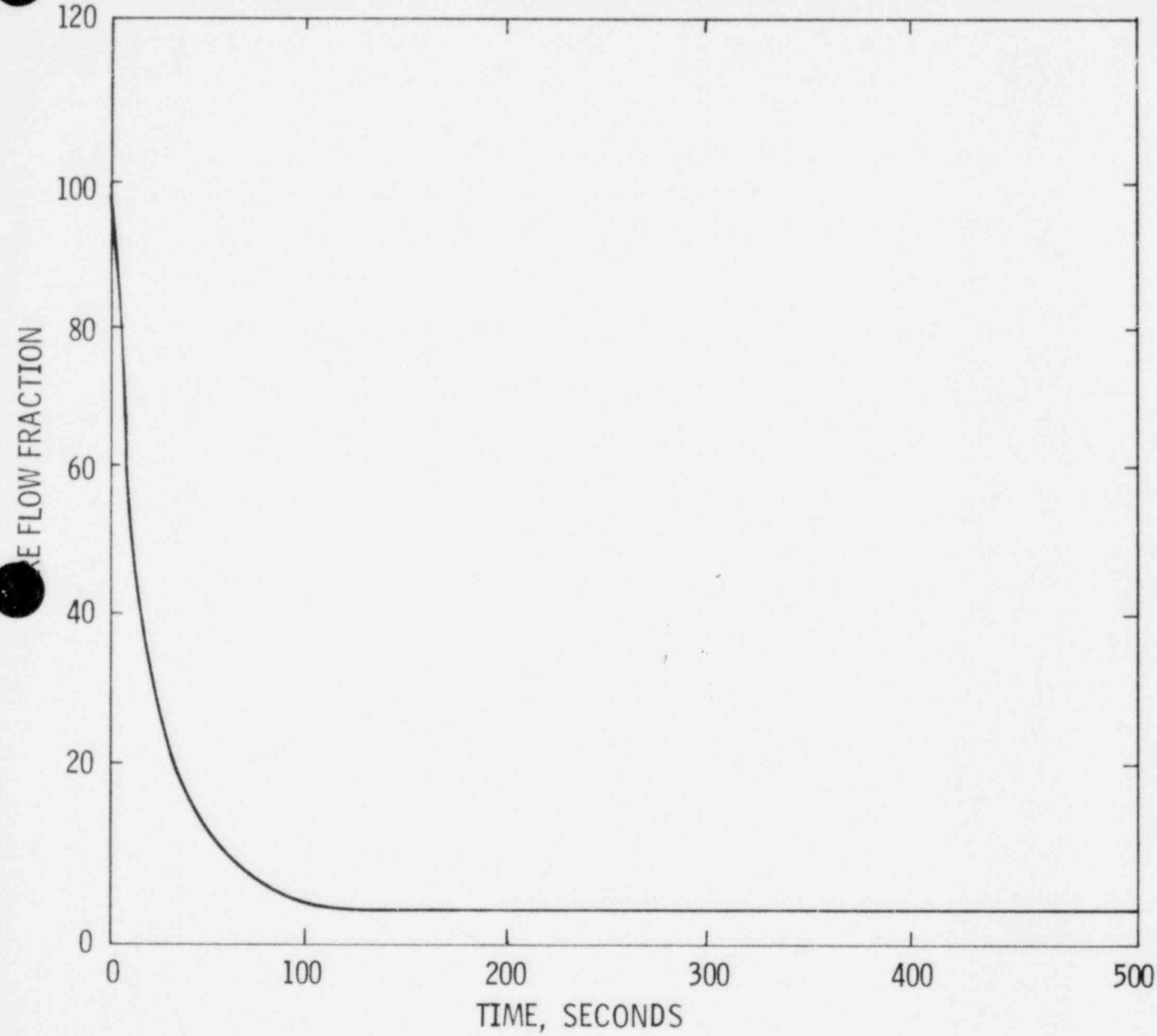
C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW REACTIVITY vs TIME	Figure 15.3.1-6



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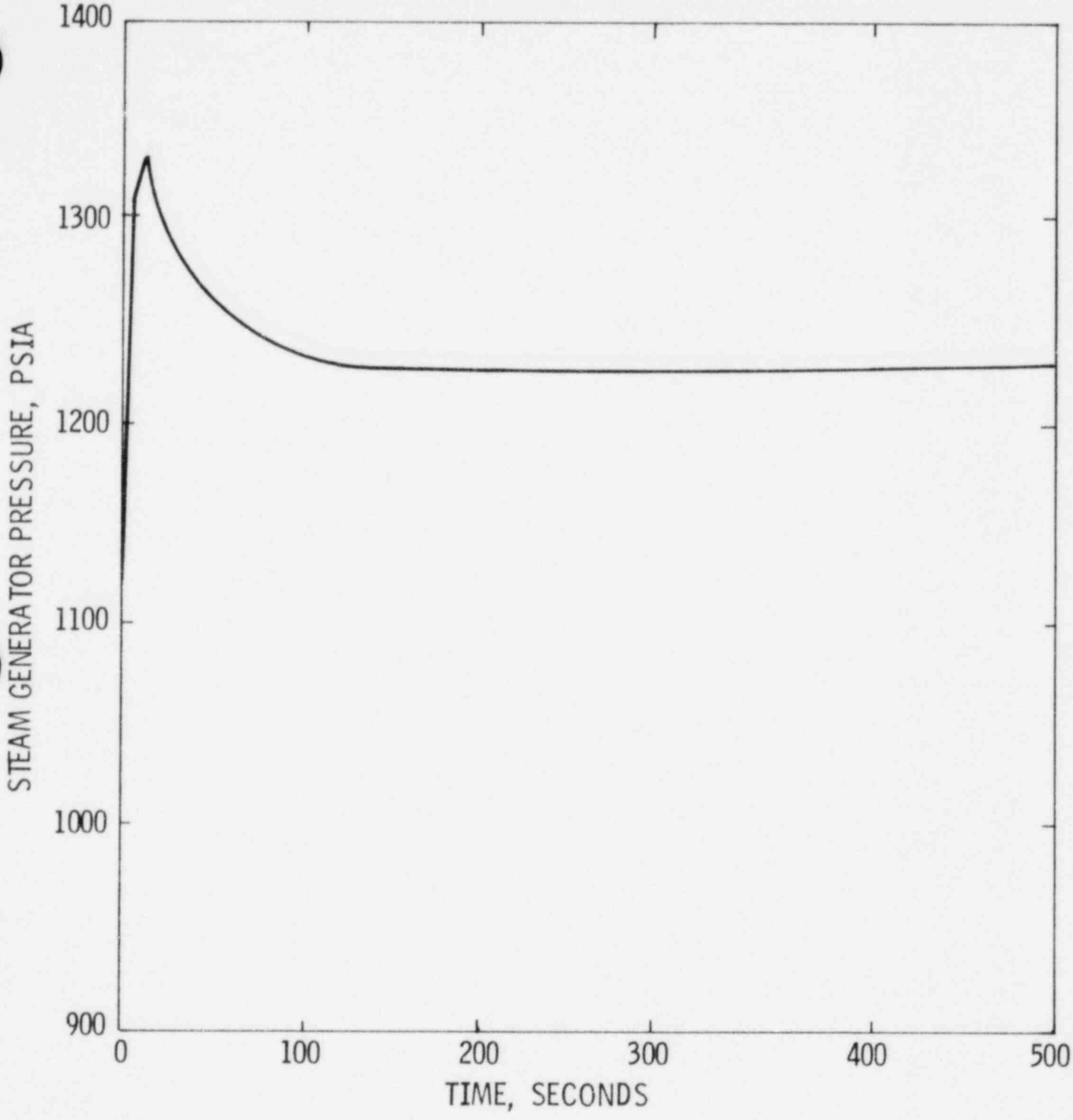
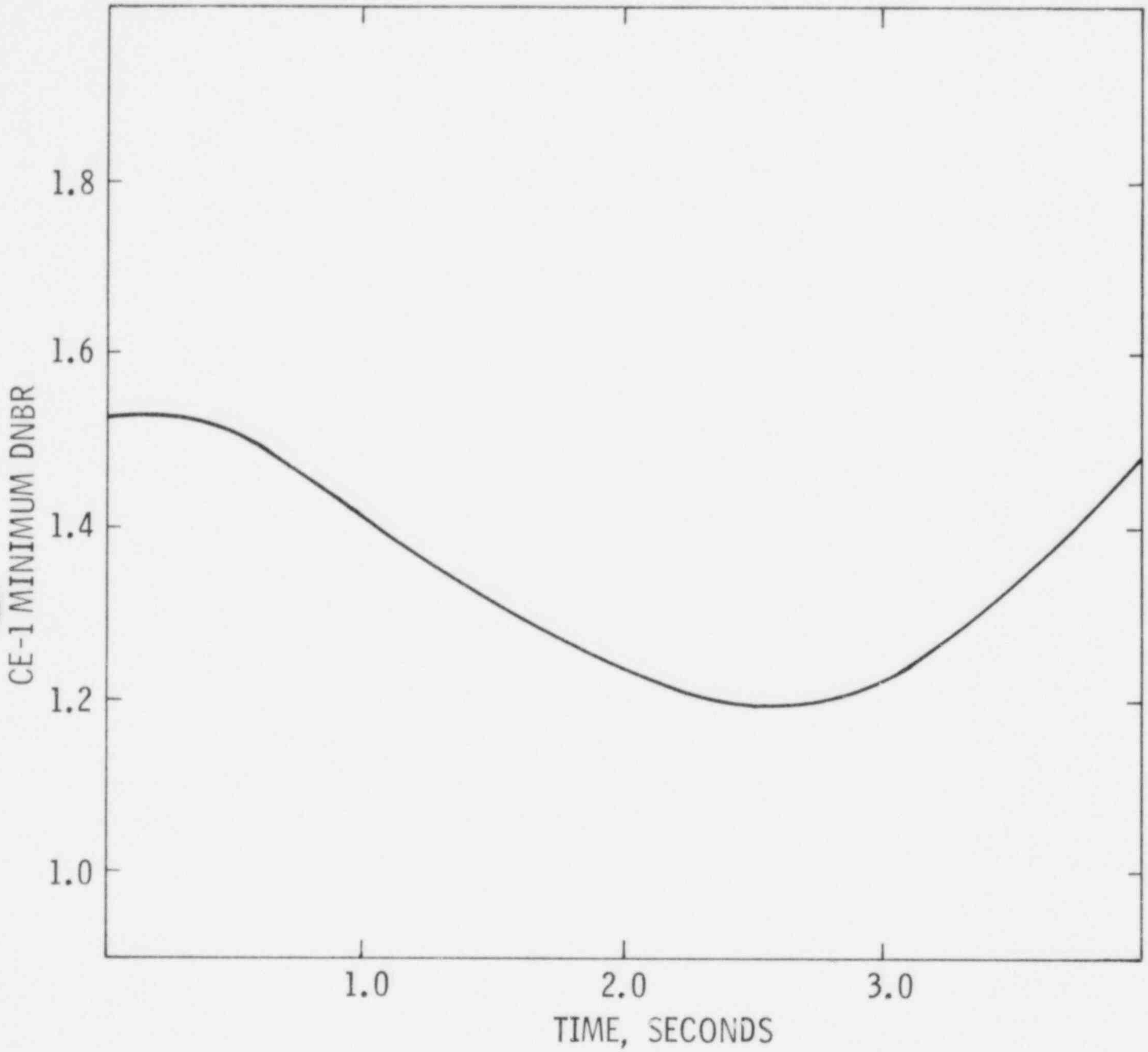
C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW CORE FLOW FRACTION vs TIME	Figure 15.3.1-7



Amendment NO. 7
March 31, 1982

C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW RIGHT HAND & LEFT HAND STEAM GENERATOR PRESSURES vs TIME	Figure 15.3.1-8



Amendment No. 7
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C - E SYSTEM 80	TOTAL LOSS OF REACTOR COOLANT FLOW CE-1 MINIMUM DNBR vs TIME	Figure 15.3.1-9

15.3.2 FLOW CONTROLLER MALFUNCTION CAUSING FLOW COASTDOWN

This event is categorized as a Boiling Water Reactor event in SRP 15.3.2 and, therefore, will not be analyzed.

15.3.3 SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER

15.3.3.1 Identification of Events and Causes

A single reactor coolant pump rotor seizure can be caused by seizure of the upper or lower thrust-journal bearings. Loss of offsite power following turbine/generator trip may be caused by a complete loss of the external electrical grid triggered by the turbine/generator trip. The loss of offsite power causes a loss of power to the start-up transformers which prevents the plant electrical loads from being transfered 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 operability, and a coastdown of all reactor coolant pumps. Approximately 12 seconds after the loss of offsite power occurs the diesel generators start providing power to the two plant 4.16 kV safety buses. No credit is taken for restoration of offsite power prior to initiation of shutdown cooling.

For decreasing reactor coolant flow events, the major parameter of concern is the minimum hot channel DNBR. This parameter establishes whether a fuel design limit has been violated and, thus, whether fuel damage might be anticipated. Those factors which cause a decrease in local DNBR are:

a. increasing coolant temperature
b. decreasing coolant pressure
c. increasing local heat flux (including radial and axial power distribution effects)
d. decreasing coolant flow

For the single reactor coolant pump rotor seizure with a loss of offsite power (as a result of turbine trip) event, the minimum DNBR occurs during the first one to four seconds of the transient, and the reactor is tripped by the CPCs on the approach to the DNBR limit. Therefore, any single failure which would result in a lower DNBR during the transient would have to affect at least one of the above parameters during the first one to four seconds of the event.

The single failures that have been postulated are listed in Table 15.0-6. Most of these failures affect the secondary system, and during the first one to four seconds they do not affect the primary system parameters which determine the DNBR. The only failures which could affect the RCS behavior during this interval are (1) a loss of normal AC, (2) a failure of the pressurizer level control system, (3) a failure of the pressurizer pressure control system, and (4) a failure of the reactor regulating system. The loss of normal AC power, which is assumed, results in loss of power to the reactor coolant pumps, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control systems, the reactor regulating system, and the feedwater control system.

Loss of function of the condensate and circulating water pumps and the feedwater control system initially affect only the secondary system and, thus,

do not affect DNBR in the first one to four seconds of the transient. Loss of power to the reactor regulating system and pressurizer level and pressure control systems renders those systems inoperable. This inoperability will have no significant impact on DNBR during the first one to four seconds. Loss of power to the reactor coolant pumps is the only significant failure with regard to DNBR which results from a loss of AC.

Failure of the pressurizer level control, pressure control, or reactor regulating systems cannot appreciably affect any of the four factors which determine DNBR during the first one to four seconds of the event. Thus, none of the single failures listed in Table 15.0-6 with the exception of loss of A , will result in a more adverse transient minimum DNBR than that predicted for the single reactor coolant pump rotor seizure with loss of offsite power as a result of turbine trip.

15.3.3.2 Sequence of Events and System Operation

Table 15.3.3-1 presents a chronological list and time of system actions which occur following the rotor seizure of a reactor coolant pump. Refer to Table 15.3.3-1 while reading this and the following section. Loss of offsite power is assumed to occur concurrent with the generator trip at 1.09 seconds after the event initiation. The success paths referenced are those given on the sequence of events diagram (SED), Figure 15.3.3-1. This figure, together with Figure 15.0-1, 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 15.3.3-1 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 represents 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 15.3.3-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient.

Table 15.3.3-3 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 15.3.3-1, are as follows:

Reactivity Control:

Following seizure of a reactor coolant pump shaft, the core flow rapidly decreases to the value that would occur with only three reactor coolant pumps operating. The rapid reduction in primary coolant flow rate causes an increase in the average coolant temperature in the core, a corresponding reduction in the margin to DNB, and an increase in the primary system pressure. A low DNBR

reactor trip is generated by the core protection calculators. The trip conservatively assumes the largest possible delay time for the sensor delay, calculation period, CEDM dead time and the CEDM coil delay time (see Chapter 7). The CEAs begin to drop into the core at 1.09 seconds inserting negative reactivity.

Prior to initiating or during manual cooldown the operator adjusts the boron concentration to insure that a proper negative reactivity shutdown margin is achieved. This is accomplished by using the HPSI pumps which also replace RCS volume shrinkage. The operator may also borate using the charging pumps by manually loading them on the diesel generators and then aligning them to the refueling water tank (RWT), the source of borated water.

Reactor Heat Removal:

The reactor heat removal takes place by means of natural circulation in the reactor coolant system following the coastdown of the undamaged reactor coolant pumps. The steam generator provides primary to secondary heat transfer.

The Shutdown Cooling System (SCS) is manually actuated when the RCS temperature and pressure have been reduced to the shutdown cooling entry conditions of $350^{\circ}F$ and 400 psia, respectively. This system provides sufficient cooling to bring the RCS to cold shutdown.

Secondary System Integrity:

The CEDM bus undervoltage relays sensing the interruption of power on the CEDM power supply buses generates a turbine trip signal. This results in closure of the turbine stop valves. The external grid which the plant is feeding is assumed to collapse as a result of turbine trip. The loss of offsite power causes a loss of power to the start-up transformer 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 experiences a simultaneous loss of feedwater flow, condenser inoperability, and a coastdown of all reactor coolant pumps. The pressure in both steam generators increases resulting in the opening of the main steam safety valves (MSSVs), which prevents secondary pressure from exceeding safety limits. The MSSVs close when the secondary pressure drops. Water level in each of the steam generators begins decreasing immediately after the loss of main feedwater flow and an emergency feedwater actuation signal is generated on low steam generator water level. The Emergency Feedwater Actuation System (EFAS) setpoint is first reached in the steam generator in the unaffected loop. This leads to the start-up of the emergency feedwater pumps. The primary source of the emergency feedwater is the condensate storage tank. The capacity of the storage tank is 300,000 gallons which is sufficient feedwater to maintain the plant at hot standby for 8 hours. The condensate storage tank is provided with an atmospheric vent to maintain atmospheric pressure inside the tank. The maximum condensate radioactivity concentration is 0.1 μCi/lbm (2.2×10^{-4} μCi/gm) dose equivalent I-131.

After 30 minutes the operator initiates cooldown of the RCS by using the atmospheric dump valves and the Auxiliary Feedwater System (AFWS) until shutdown cooling entry conditions are reached. The AFWS may be a separate system or may be one emergency feedwater pump designated as "auxiliary" and intended for normal startup and shutdown of the plant. The operator may let the ESFAS regulate the feedwater flow by issuing and withdrawing EFAS-1 and/or

EFAS-2 signals down to cold shutdown entry conditions. See applicant's FSAR for details of the Emergency and/or Auxiliary Feedwater Systems. As the cooldown proceeds, the operator reduces the main steam isolation actuation setpoint to prevent the inadvertent generation of an MSIS.

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. The combination of the loss of primary system heat sink (turbine stop valves close) with the reduction of reactor coolant flow results in an increase in RCS pressure.

During cooldown, the operator may control RCS pressure and pressurizer level by turning on the HPSI pumps and throttling the HPSI discharge valves to control the rate of change of RCS pressure. The operator may also control RCS pressure and pressurizer level via manual actuation and control of the charging pumps and related auxiliary spray. As the cooldown proceeds, the operator will reduce the safety injection actuation setpoint to prevent the inadvertent generation of an SIAS. When the RCS pressure has been reduced to approximately 650 psia, the operator will vent or drain the safety injection tanks to reduce their pressure and will isolate them.

Restoration 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 (except 480 V load centers). 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.

Radioactive Effluent Control:

Containment Isolation Actuation Signal (CIAS) isolates various systems to reduce or terminate radioactive releases. CIAS actuates primary, secondary, and containment isolation equipment. Other actions may be initiated by BOP systems. See Applicant's FSAR for details.

Spent Fuel Heat Removal:

Spent Fuel Pool (SFP) cooling is terminated on the loss of normal power to the ESF loads. Spent fuel heat removal is continuously accomplished by utilizing the heat capacity of the SFP water. Pool cooling is restored by manually loading the SFP cooling pumps onto the diesel generators and by aligning the SFP heat exchangers to receive essential cooling water.

15.3.3.3 Analysis of Effects and Consequences

15.3.3.3.1 Core and System Performance

A. Mathematical Model

The NSSS response to a single reactor coolant pump rotor seizure with loss of offsite power resulting from turbine trip was simulated using the CESEC-III

computer program described in Reference 27 of Section 15.0. The initial DNBR was calculated using the TORC computer code (see Section 15.0.3) which uses the CE-1 CHF correlation described in Reference 19 of Section 15.0.

B. Input and Parameters and Initial Conditions

The ranges of initial conditions considered are given in Section 15.0. Table 15.3.3-4 gives the initial conditions used in this analysis. The rationale 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. A high core inlet temperature was chosen to minimize the degree of subcooling in the core. This also results in higher steam generator pressures and, thus, quicker opening of the secondary safety valves, which is more adverse from a radiological standpoint. The reactor coolant flow was chosen to be its minimum value of 146.1 x 10^6 lbm/hr. This low flow was chosen in combination with the other conditions mentioned above since this will allow operation with a low radial peaking factor. The use of a low radial peaking factor maximizes the amount of fuel pins which may experience DNB. The primary system pressure was chosen to be compatible with the other initial conditions. The most positive moderator temperature coefficient and the minimum available scram CEA worth tend to maximize the heat flux after a reactor trip occurs, increasing the RCS heat-up. The operator initiation of 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 the assumed one gallon per minute steam generator tube leak. The initial secondary activity is assumed to be at 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 4.6 μCi/gm (see Table 15.3.3-5)

C. Results

The dynamic behavior of important NSSS parameters following a single reactor coolant pump rotor seizure with a loss of offsite power is presented on Figures 15.3.3-2 to 15.3.3-10. Table 15.3.3-1 summarizes the significant results of the event. Refer to Table 15.3.3-1 while reading this section.

The single reactor coolant pump rotor seizure event results in a flow coastdown in the affected loop, a consequent reduction in flow through the core, an increase in the average coolant temperature in the core, a corresponding reduction in the margin to DNB, and an increase in the primary system pressure. A low DNBR reactor trip is generated by the core protection calculators. The reactor trip causes a turbine trip signal to occur. The CEAs begin to drop into the core at 1.09 seconds. At this time the generator trips and the loss of offsite power occurs. The flow in the unaffected cold legs increases until the loss of offsite power 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 15.3.3-8. The opening of the MSSVs limits this pressure increase. The maximum secondary system pressure is 1347 psia which is less than 110% of design pressure.

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 15.3.3-7) result in 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 15.3.3-5. The core coolant temperatures peak shortly after the time of reactor trip.

The increase in RCS temperature leads to an increase in RCS pressure, as shown in Figure 15.3.3-4, caused by the thermal expansion of the RCS fluid. The RCS pressure reaches a maximum value of 2387 psia at 4.2 seconds which is less than 110% of design pressure. After this time, the RCS pressure decreases rapidly due to the declining core heat flux (see Figure 15.3.3-3), in combination with the opening of the MSSVs. Opening of the MSSVs limits the peak temperature and pressure of the secondary system. The MSSVs cycle until the emergency feedwater begins entering the steam generators. Emergency feedwater begins entering the steam generator in the unaffected loop at 263 seconds, thus, enhancing the RCS cooldown and the subsequent reduction in pressure.

During the first few seconds of the transient, the combination of decreasing flow rate, and increasing RCS temperatures results in a decrease in the fuel pins' DNBR. The transient minimum DNBR of 0.894 occurs at 1.7 seconds as indicated in Table 15.3.3-1. Figure 15.3.3-9 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 5.0 percent of the fuel pins are calculated to experience DNB. All fuel pins which experience DNB are conservatively assumed to fail.

The offsite doses for this event result from steam released through the main steam safety valves (MSSVs) and atmospheric dump valves (ADVs).

At 30 minutes, the operator is assumed to use the ADVs to begin cooldown. Table 15.3.3-1 shows the integrated steam release from the MSSVs and the ADVs. The radiological release produced by the transient results in a 29.5 rem two hour thyroid inhalation dose at the exclusion area boundary. The two hour thyroid inhalation dose at the exclusion area boundary is shown in Table 15.3.3-7.

15.3.3.3.2 Radiological Consequences

A. Physical Model

To evaluate the consequences of the single reactor coolant pump rotor seizure with a loss of offsite power event it is assumed that the condenser is not available for the entirety of the transient. For the first thirty minutes of the event the cooldown is performed via the main steam safety valves. Afterwards, the cooldown is performed manually by the operator via the atmospheric dump valves.

B. Assumptions, Parameters, and Calculational Methods

The major assumptions, parameters, and calculational methods used to evaluate the radiological consequences of the single reactor coolant pump rotor seizure

are presented in Tables 15.3.3-5 and 15.3.3-6. Additional clarification is provided as follows:

1. The Reactor Coolant System (RCS) equilibrium activity is based on long-term operation at 108% of the ultimate core power level of 3800 MWt (3800 MWt x 1.08 = 4100 MWt) with 1% failed fuel. Refer to Table 11.1.1-2 for the isotopic distribution of RCS activity.

   The RCS activity was calculated to determine the total amount of activity transmitted into the secondary system during the duration of the accident due to a 1 gal/min primary to secondary leak. The primary-to-secondary leakage of 1 gal/min (technical specification limit) is assumed to continue to the steam generators for the entire event. The activity in the fuel clad gap is 10% of the iodines and 10% of the noble gases accumulated in the fuel at the end of core life, assuming continuous full power operation. All of the activity in the fuel gap for fuel rods that are calculated to experience DNB is assumed to be uniformly mixed with the reactor coolant. This assumption is consistent with Regulatory Guide 1.77.

2. The steam generator equilibrium activity for the affected steam generator is assumed to be 0.1 μCi/gm dose equivalent Iodine-131 (I-131) prior to the accident. This is the technical specificaion limit for steam generator activity.

3. Offsite power is not available. At 1800 seconds the operator takes control of the plant and conducts on orderly cooldown using the atmospheric dump valves.

4. Credit is assumed for emergency feedwater flow. For the fluid leaked from primary to secondary and not flashing to steam, iodine is assumed to be released to the atmosphere with a partition coefficient of 100. For the fluid leaked from primary to secondary and flashing to steam (maximum fraction < 4%), iodine is assumed to be released to the atmosphere with a partition coefficient of 1.0.

5. No credit for radioactive decay in transient to dose point is assumed.

6. The atmospheric dispersion factors used in his analysis, which are based on meteorological conditions assumed present during the course of the accident, are calculated according to the model described in subsection 2.3.4. The 5% level X/Q presented in Table 2.3-1 was used.

7. The mathematical model used to analyze the activity released during the course of the accident is described in Section 15.0.

8. The duration of mass release was 10,441 seconds until the RCS temperature reached $350^{\circ}F$ and the shutdown cooling system was placed in operation. Table 15.3.3-6 presents the integrated mass releases from the secondary safety valves and atmospheric dump valves and the total primary to secondary leakage.

9. Calculated secondary mass releases are presented in Table 15.3.3-6.

C. Identification of Uncertainties and Conservatisms in the Evaluation of the Results

The uncertainties and conservatisms in the assumptions used to evaluate the radiological consequences of the single reactor coolant pump rotor seizure with a loss of offsite power are as follows:

1. The RCS equilibrium activity is based on 1% failed fuel, which is greater by a factor of two to eight than that normally observed in past PWR operation.

2. The steam generator equilibrium activity for the affected steam generator is assumed to be equal to the technical specification limit (0.1 Ci/gm dose equivalent I-131). This specific activity is greater by a factor of approximately 1300 than the normal expected steam generator activity (refer to Table 11.1.8-1)

3. The primary to secondary leakage of 1 gal/min (technical specification limit) is conservative because operation with a 1 gal/min primary-to-secondary leak is not expected (the expected leakage rate is equal to 20 gal/day).

4. The meteorological conditions assumed to be present at the site during the course of the accident are based on 5% level X/Qs. Meteorological conditions will be less severe 95% of the time. This results in the poorest values of atmospheric dispersion calculated for the EAB or LPZ outer boundary. Furthermore, no credit has been taken for the transit time required for activity to travel from the point of release to the EAB or LPZ outer boundary.

5. The assumption of no operator action for 1800 seconds (30 minutes) is a conservative assumption.

15.3.3.4 Conclusions

The maximum RCS and steam generator pressures due to a single reactor coolant pump rotor seizure in combination with loss of offsite power following generator trip event remain less than 110% of their design values. Only a small fraction of the fuel pins experience DNB and are conservatively assumed to fail. The two hour thyroid dose is a small fraction of 10CFR100 guidelines.

Table 15.3.3-1

(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP.

Time (Sec).	Event	Setpoint or Value	Total Integrated Safety Valves Flow (lbm)	Success Path
0.0	Seizure of a Single Reactor Coolant Pump	____	____	____
0.6	Low DNBR Trip Signal Generated, projected	1.19	____	Reactivity Control
1.09	CEAs Begin to Drop Into the Core	____	____	Reactivity Control
1.09	Turbine Trip/Generator Trip/Loss of Offsite Power Occurs	____	____	____
1.7	Minimum Transient DNBR	0.894	____	____
4.1	Main Steam Safety Valves Open, Unaffected loop, psia	1280	____	Secondary Sysem Integrity
4.2	Maximum RCS Pressure, psia	2387	____	____
4.5	Main Steam Safety Valves Open, Affected Loop, psia	1280	____	Secondary System Integrity
6.8	Maximum Steam Generator Pressure, Unaffected Loop, psia	1347	3,492	____
7.4	Maximum Steam Generator Pressure, Affected Loop, Psia	1340	5,451	____
218.	Low Water Level EFAS Setpoint Reached in the Steam Generator, Unaffected Loop, Percent of Wide Range	20	85,679	Secondary System Integrity

Table 15.3.3-1 (Continued).

(Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP.

(Sec).	Event	Setpoint or Value	Total Integrated Safety Valves Flow (lbm)	Success Path
263.	Emergency Feedwater Begins Entering Steam Generator, Unaffected Loop, lbm/sec	119	91,407	Secondary System Integrity
697	Low Water Level EFAS Setpoint Reached in the Steam Generator, Affected Loop, Percent of Wide Range	20	115,189	Secondary System Integrity
	Emergency Feedwater Begins Entering the Steam Generator, Affected Loop, lbm/sec.	119		
821	Steam Generator Safety Valves Close, Affected and Unaffected Loop, psia	1218	120,398	Secondary System Integrity
1800.	Atmospheric Dump Valves Opened to Initiate Plant Cooldown, ^{o}F/hour	-100.0	120,398	Secondary System Integrity
7200.	Total Steam Release to Atmosphere, lbm	______	872,000	______
10441	Shutdown Cooling Entry Conditions Reached, RCS Pressure, psia/ Temperature, ^{o}F	400/350	______	Reactor Heat Removal

TABLE 15.3.3-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE
WITH LOSS OF OFFSITE POWER RESULTING FROM 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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System			✓			
2. Main Feedwater Pump Turbine Control System*			✓			
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System				✓		
5. Pressurizer Pressure Control System				✓		
6. Pressurizer Level Control System				✓		
7. Control Element Drive Mechanism Control System	✓					
8. Reactor Regulating System				✓		
9. Core Operating Limit Supervisory System			✓			
10. Reactor Coolant Pumps				✓		1
11. Chemical and Volume Control System				✓		
12. Secondary Chemistry Control System*				✓		
13. Condenser Evacuation System*				✓		
14. Turbine Gland Sealing System*				✓		
15. Nuclear Cooling Water System*				✓		
16. Turbine Cooling Water System*				✓		
17. Plant Cooling Water System*				✓		
18. Condensate Storage Facilities*				✓		
19. Circulating Water System*				✓		
20. Spent Fuel Pool Cooling and Clean-Up System*				✓		
21. Non-Class 1E (Non-ESF) A.C. Power*			✓			
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems -

TABLE 15.3.3-2 (Cont'd) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE
WITH LOSS OF OFFSITE POWER RESULTING FROM 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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*		✓				
24. Class 1E D.C. Power*		✓				

*Balance-of-Plant Systems

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TABLE 15.3.3-3

UTILIZATION OF SAFETY SYSTEMS
FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE
WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator	✓				
3. Engineered Safety Features Actuation Systems			✓		
4. Supplementary Protection System					1
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves					
8. Main Steam Isolation System*	✓		✓		2
9. Emergency Feedwater System*	✓		✓		
10. Safety Injection System					
11. Shutdown Cooling System	✓				2
12. Atmospheric Dump Valve System*	✓				2
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*	✓				
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

Notes:

1. Safety grade back-up to a safety grade system.
2. Manually actuated during normal cooldown

*Balance-of-Plant Systems -

Table 15.3.3-4

ASSUMED INITIAL CONDITIONS FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Parameter	Value
Core Power Level, MWt	3876
Core Inlet Coolant Temperature, °F	580
Reactor Coolant Sysem Pressure, psia	2243
Steam Generator Pressure, psia	1221
Core Mass Flow, 10^6 lbm/hr	146.1
Maximum Radial Power Peaking Factor	1.40
Maximum Axial Power Peak	1.47
Core Minimum DNBR	1.40
Doppler Coefficient Multiplier	0.85
CEA Worth on Trip, $10^{-2}\,\Delta\rho$ (Most Reactive CEA stuck)	-10.0
Moderator Temperature Coefficient	0.0

TABLE 15.3.3-5
(Sheet 1 of 3)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Parameters		Value
A.	Data and Assumptions Used to Evaluate the Radioactive Source Term	
a.	Power Level, Mwt	4200
b.	Burnup	2 year
c.	Percent of Fuel Calculated to Experience DNB, %	5.0
d.	Reactor Coolant Activity Before Event (based on 4100 MWt)	4.6 μCi/gm Table 11.1.1-2
e.	Secondary System Activity Before Event	Section 15.0.4
f.	Primary Sysem Liquid Inventory, lbm	525,600
g.	Steam Generator Inventory	
	- Liquid, lbm per steam generator	167,075
	- Steam, lbm per steam generator	14,863
B.	Data and Assumptions Used to Estimate Activity Released from the Secondary System	
a.	Primary to Secondary Leak Rate, gallon/min	1.0 (total)
b.	Total Mass Release Through the Main Steam Safety Valves and Atmospheric Dump Valves (2 hours)	872,000

TABLE 15.3.3-5 (Cont'd.) (Sheet 2 of 3)

PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A SINGLE REACTOR COOLANT PUMP ROTOR
SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Parameters	Value
C. Reactor Coolant System Activity After Event, Ci	
Isotope	
I-131	9.48 (+5)
I-132	1.39 (+6)
I-133	1.91 (+6)
I-134	2.07 (+6)
I-135	1.78 (+6)
Kr-85M	2.39 (+7)
Kr-85	7.59 (+5)
Kr-87	4.38 (+7)
Kr-88	6.25 (+7)
Xe-131M	6.68 (+5)
Xe-133	1.92 (+8)
Xe-135	3.44 (+7)
Xe-138	1.53 (+8)
d. Percent of Core Fission Products Assumed Release to Reactor Coolant	Refer to Section 15.3.3.3.2B
e. Iodine Partition Coefficient in the Steam Generators (Primary Liquid)	100.0
f. Iodine Partition Coefficient in the Steam Generators (Primary Steam)	1.0
g. Credit for Radioactive Decay in Transit to Dose Point	No
h. Loss of Offsite Power	Yes
C. Dispersion Data	
1. Distance to Exclusion Area Boundary, m	500

TABLE 15.3.3-5 (Cont'd.) (Sheet 3 of 3)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TRIP

Parameters	Value
2. Distance to Low Population Zone Outer Boundary, m	3000.0
3. Atmospheric Dispersion Factor, sec/m^3	2.00×10^{-3}
D. Dose Data	
1. Method of Dose Calculation	Section 15.0-4
2. Dose Conversion Assumptions	Section 15.0-4
3. Control Room Design Parameters	See Applicant's FSAR

TABLE 15.3.3-6

SECONDARY SYSTEM MASS RELEASE
TO THE ATMOSPHERE FOR THE SINGLE REACTOR COOLANT PUMP ROTOR
SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP EVENT

Time (Sec)	Integrated Safety Valve Flow (lbm)	Integrated Primary to Secondary Leakage (gallons)
0.0	0.0	0.00
2.0	0.0	0.03
3.0	0.0	0.05
5.0	480	0.08
10.0	13,884	0.17
20.0	36,677	0.33
40.0	53,354	0.67
60.0	54,812	1.00
80.0	62,536	1.33
100.0	66,282	1.67
150.0	73,248	2.50
200.0	83,047	3.33
300.0	95,560	5.00
500.0	108,710	8.33
821.0*	120,398	13.68
1800.0**	120,398	30.00

* Main Steam Safety Valves close

** Operator takes control of plant and begins cooldown utilizing the Atmospheric Dump Valves

TABLE 15.3.3-7

RADIOLOGICAL CONSEQUENCES OF A POSTULATED SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Result	From Secondary System Steam Releases
Exclusion Area Boundary Dose (0-2 hours), rem:	
Thyroid	29.5

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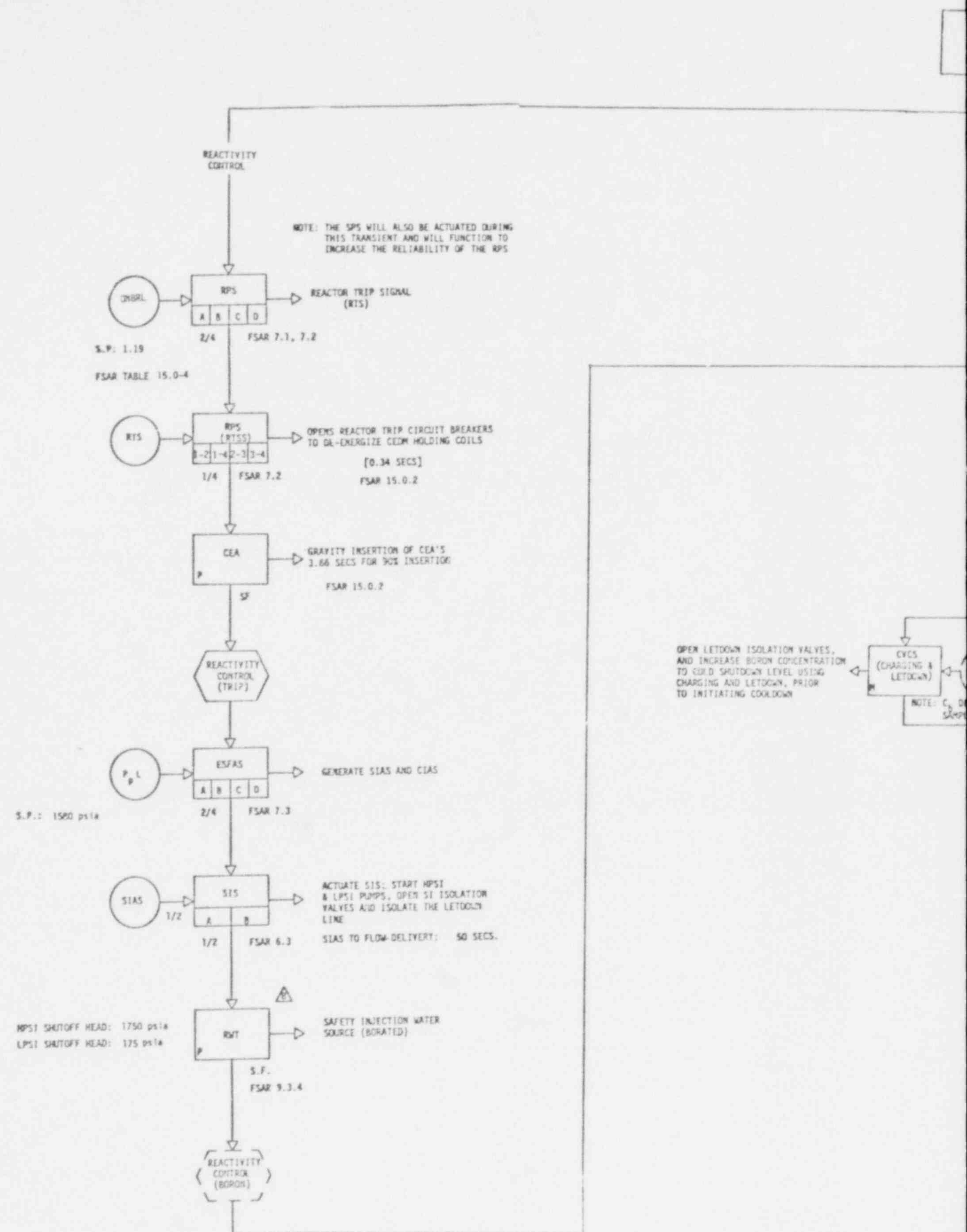
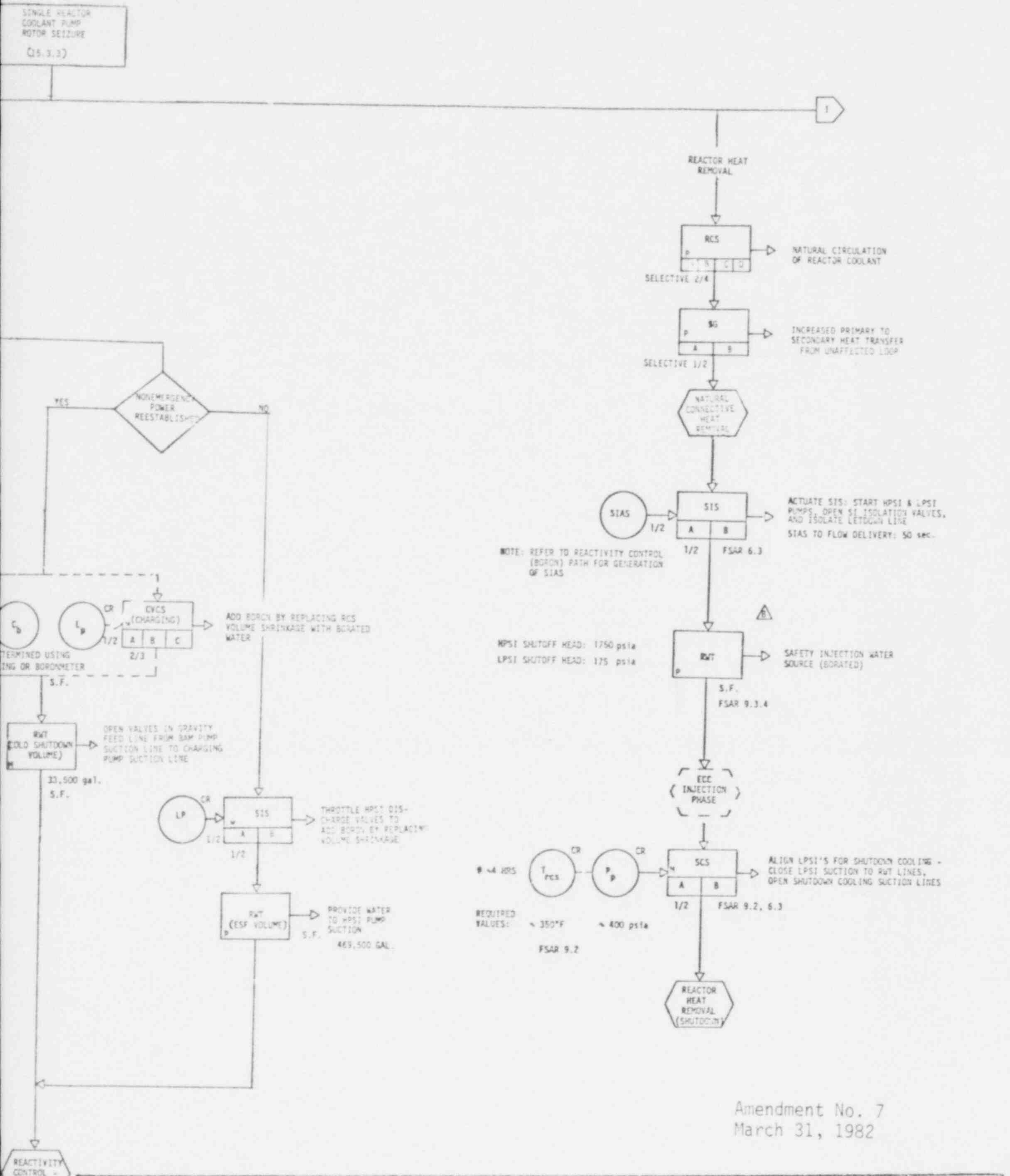

REACTIVITY CONTROL
NOTE: THE SPS WILL ALSO BE ACTUATED DURING THIS TRANSIENT AND WILL FUNCTION TO INCREASE THE RELIABILITY OF THE RPS
DNBRL
RPS
A B C D
REACTOR TRIP SIGNAL (RTS)
2/4
FSAR 7.1, 7.2
S.P: 1.19
FSAR TABLE 15.0-4
RTS
RPS (RTSS)
1-2 1-4 2-3 3-4
OPENS REACTOR TRIP CIRCUIT BREAKERS TO DE-ENERGIZE CEDM HOLDING COILS
[0.34 SECS]
FSAR 15.0.2
1/4
FSAR 7.2
CEA
P
GRAVITY INSERTION OF CEA'S 3.66 SECS FOR 90% INSERTION
FSAR 15.0.2
SF
REACTIVITY CONTROL (TRIP)
$P_P L$
ESFAS
A B C D
GENERATE SIAS AND CIAS
S.P.: 1580 psia
2/4
FSAR 7.3
SIAS
1/2
SIS
A B
ACTUATE SIS: START HPSI & LPSI PUMPS, OPEN SI ISOLATION VALVES AND ISOLATE THE LETDOWN LINE
SIAS TO FLOW DELIVERY: 50 SECS.
1/2
FSAR 6.3
HPSI SHUTOFF HEAD: 1750 psia
LPSI SHUTOFF HEAD: 175 psia
RWT
P
SAFETY INJECTION WATER SOURCE (BORATED)
S.F.
FSAR 9.3.4
REACTIVITY CONTROL (BORON)
OPEN LETDOWN ISOLATION VALVES, AND INCREASE BORON CONCENTRATION TO COLD SHUTDOWN LEVEL USING CHARGING AND LETDOWN, PRIOR TO INITIATING COOLDOWN
CVCS (CHARGING & LETDOWN)
NOTE: C_B D
SAMP



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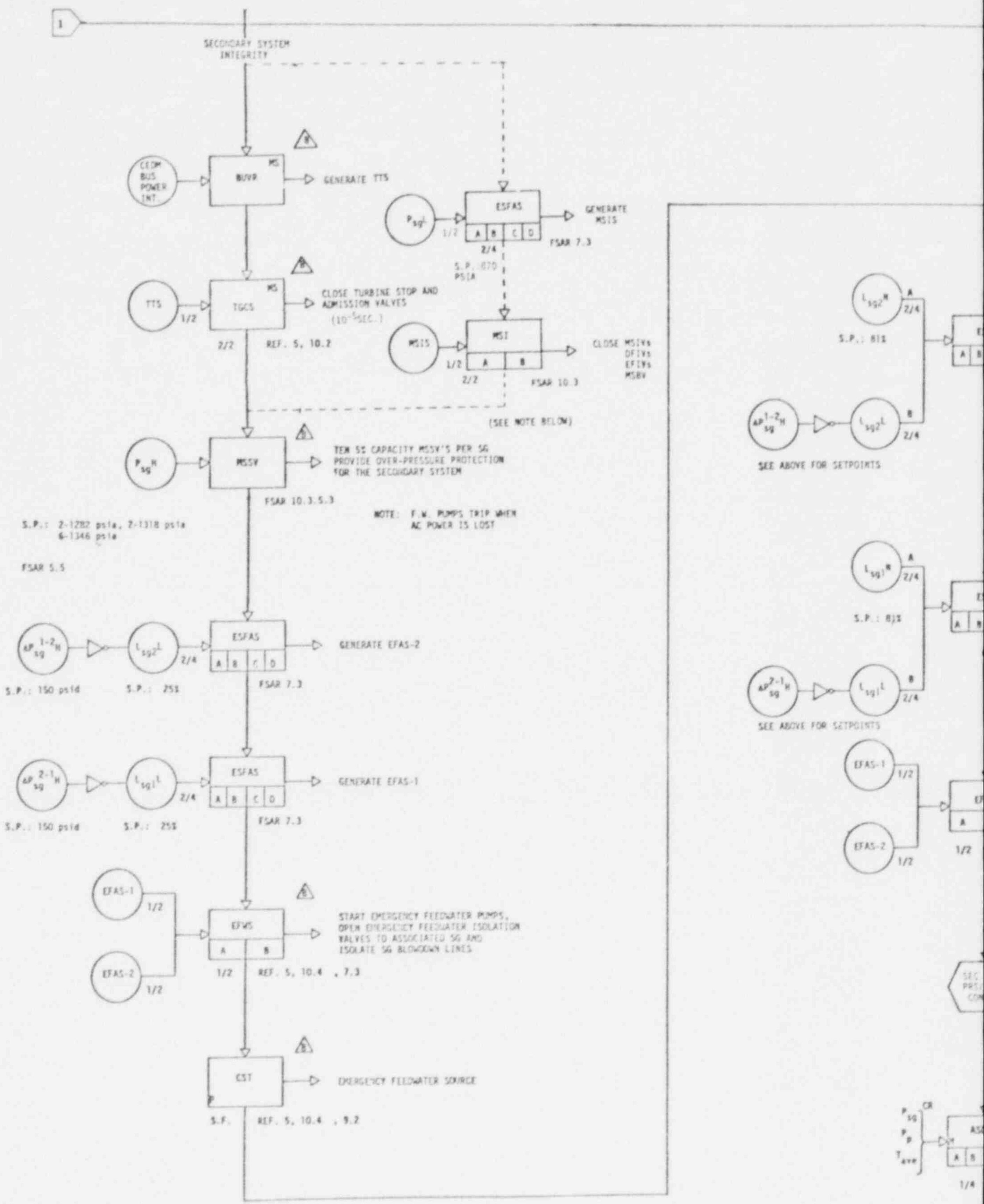
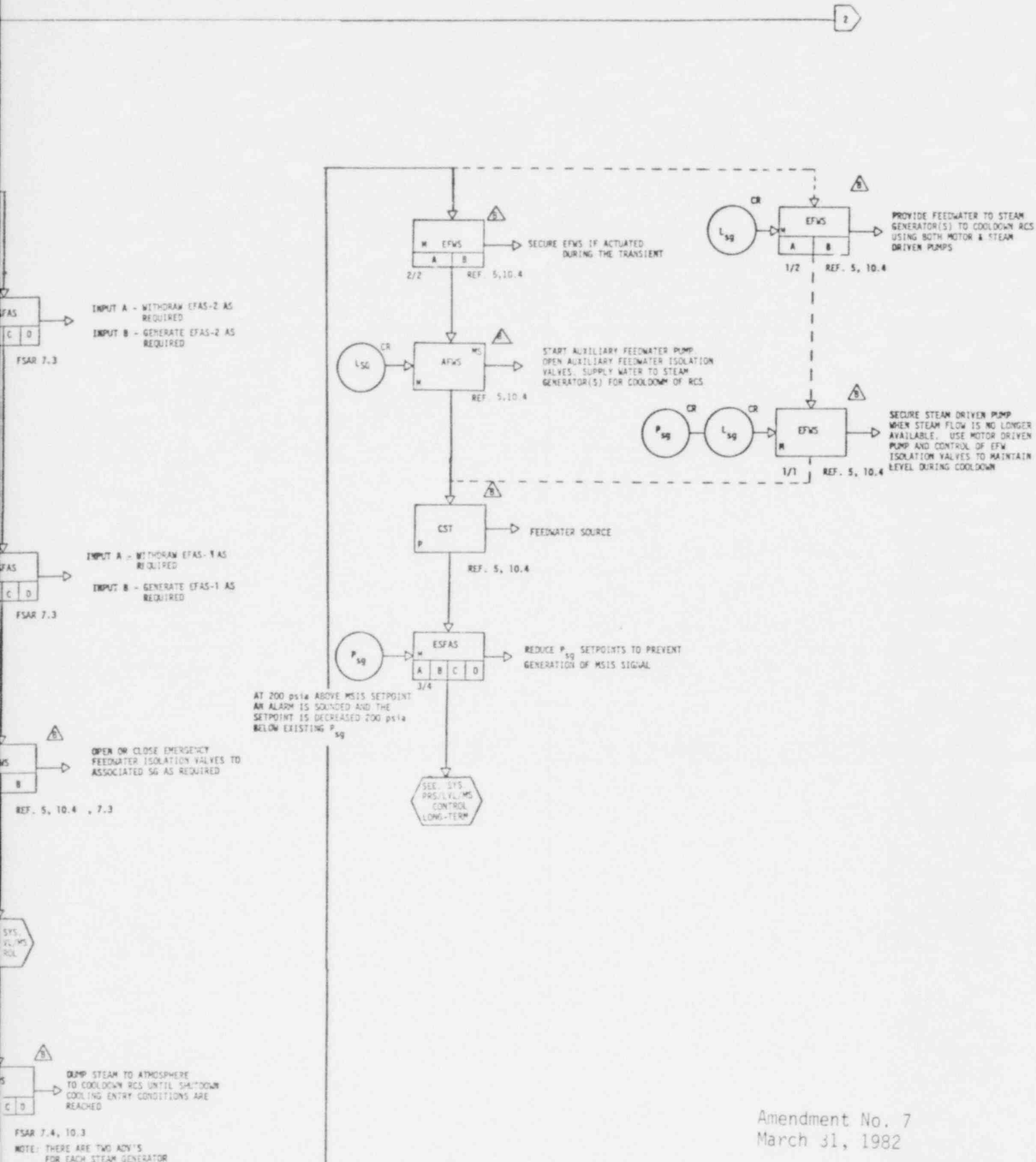
C - E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM FOR SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Figure 15.3.3-1A


1
SECONDARY SYSTEM INTEGRITY
CEDM BUS POWER INT.
BUVR
MS
GENERATE TTS
P_{sg}^{L}
1/2
ESFAS
A B C D
2/4
GENERATE MSIS
FSAR 7.3
S.P. 870 PSIA
TTS
1/2
TGCS
MS
CLOSE TURBINE STOP AND ADMISSION VALVES
2/2
REF. 5, 10.2
MSIS
1/2
MSI
A B
2/2
CLOSE MSIVs DFIVs EFIVs MSBV
FSAR 10.3
(SEE NOTE BELOW)
P_{sg}^{H}
MSSV
TEN 5% CAPACITY MSSV'S PER SG PROVIDE OVER-PRESSURE PROTECTION FOR THE SECONDARY SYSTEM
FSAR 10.3.5.3
NOTE: F.W. PUMPS TRIP WHEN AC POWER IS LOST
S.P.: 2-1282 psia, 2-1318 psia
6-1346 psia
FSAR 5.5
$\Delta P_{sg}^{1-2}H$
L_{sg2}^{L}
2/4
ESFAS
A B C D
GENERATE EFAS-2
S.P.: 150 psid
S.P.: 25%
FSAR 7.3
$\Delta P_{sg}^{2-1}H$
L_{sg1}^{L}
2/4
ESFAS
A B C D
GENERATE EFAS-1
S.P.: 150 psid
S.P.: 25%
FSAR 7.3
EFAS-1
1/2
EFAS-2
1/2
EFWS
A B
1/2
REF. 5, 10.4 , 7.3
START EMERGENCY FEEDWATER PUMPS, OPEN EMERGENCY FEEDWATER ISOLATION VALVES TO ASSOCIATED SG AND ISOLATE SG BLOWDOWN LINES
CST
P
EMERGENCY FEEDWATER SOURCE
S.F.
REF. 5, 10.4 , 9.2
L_{sg2}^{H}
A
2/4
S.P.: 81%
$\Delta P_{sg}^{1-2}H$
L_{sg2}^{L}
B
2/4
SEE ABOVE FOR SETPOINTS
L_{sg1}^{H}
A
2/4
S.P.: 81%
$\Delta P_{sg}^{2-1}H$
L_{sg1}^{L}
B
2/4
SEE ABOVE FOR SETPOINTS
EFAS-1
1/2
EFAS-2
1/2
1/2
P_{sg}^{CR}
P_{p}
T_{ave}
1/4



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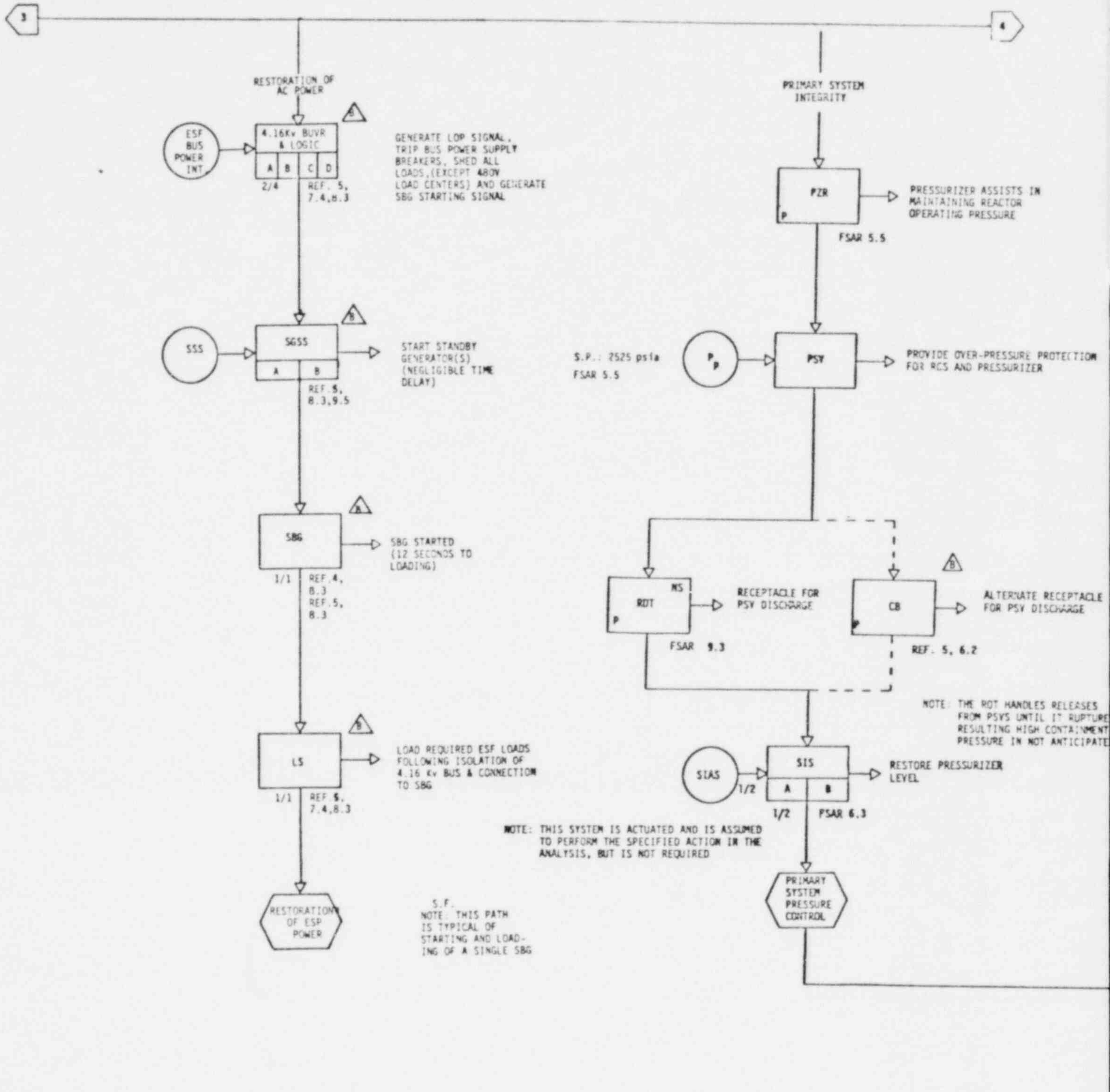
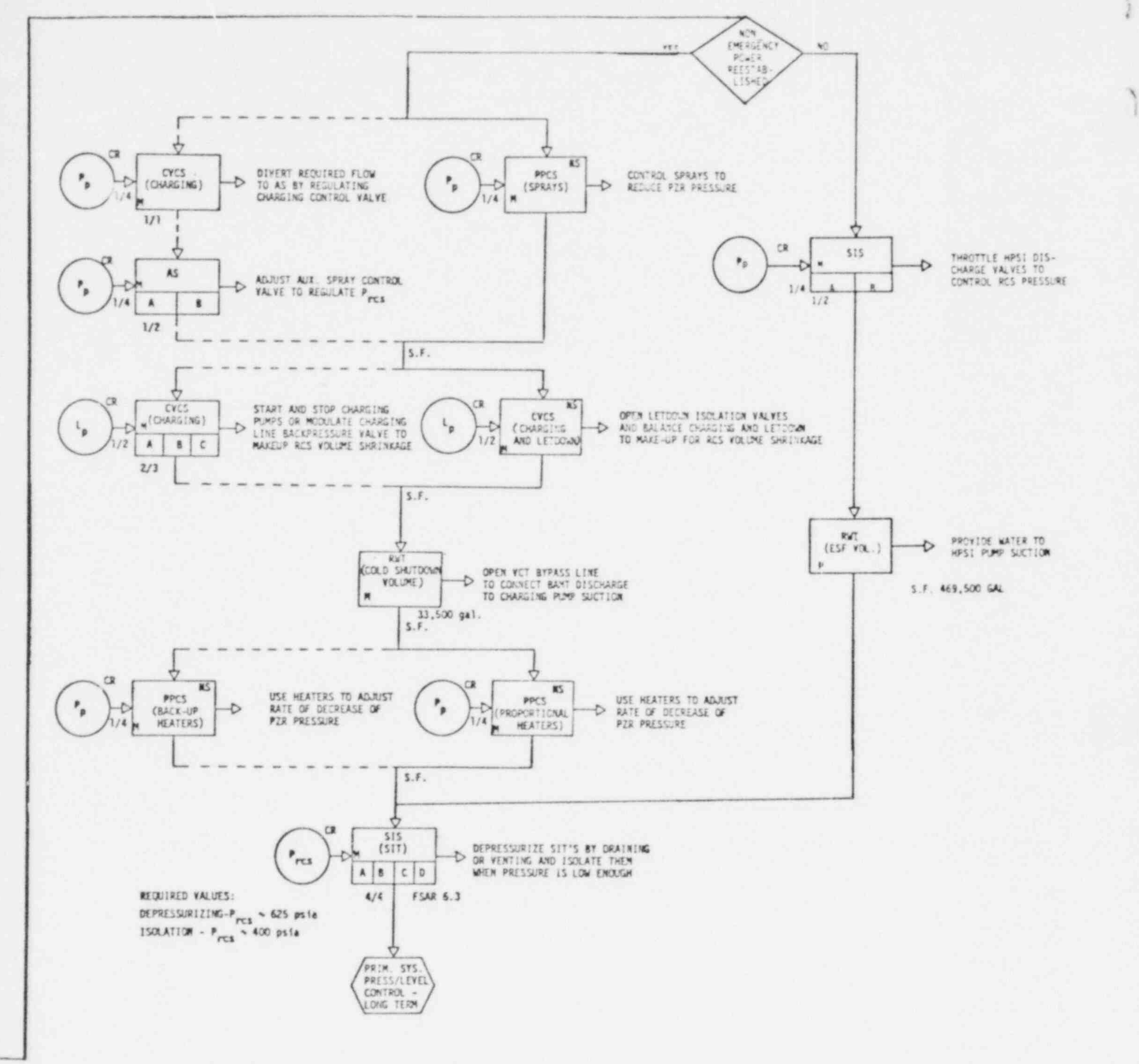
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP	Figure 15.3.3 -1B



3
4
RESTORATION OF AC POWER
ESF BUS POWER INT
4.16Kv BUVR & LOGIC
A B C D
2/4
REF. 5, 7.4,8.3
GENERATE LOP SIGNAL, TRIP BUS POWER SUPPLY BREAKERS, SHED ALL LOADS,(EXCEPT 480V LOAD CENTERS) AND GENERATE SBG STARTING SIGNAL
SSS
SGSS
A B
REF. 5, 8.3,9.5
START STANDBY GENERATOR(S) (NEGLIGIBLE TIME DELAY)
SBG
1/1
REF.4, 8.3 REF.5, 8.3
SBG STARTED (12 SECONDS TO LOADING)
LS
1/1
REF 5, 7.4,8.3
LOAD REQUIRED ESF LOADS FOLLOWING ISOLATION OF 4.16 Kv BUS & CONNECTION TO SBG
RESTORATION OF ESP POWER
S.F. NOTE: THIS PATH IS TYPICAL OF STARTING AND LOADING OF A SINGLE SBG
PRIMARY SYSTEM INTEGRITY
PZR
P
FSAR 5.5
PRESSURIZER ASSISTS IN MAINTAINING REACTOR OPERATING PRESSURE
S.P.: 2525 psia
FSAR 5.5
P_p
PSV
PROVIDE OVER-PRESSURE PROTECTION FOR RCS AND PRESSURIZER
RDT
NS
P
FSAR 9.3
RECEPTACLE FOR PSV DISCHARGE
CB
P
REF. 5, 6.2
ALTERNATE RECEPTACLE FOR PSV DISCHARGE
NOTE: THE RDT HANDLES RELEASES FROM PSVS UNTIL IT RUPTURE RESULTING HIGH CONTAINMENT PRESSURE IN NOT ANTICIPATE
SIAS
1/2
SIS
A B
1/2
FSAR 6.3
RESTORE PRESSURIZER LEVEL
NOTE: THIS SYSTEM IS ACTUATED AND IS ASSUMED TO PERFORM THE SPECIFIED ACTION IN THE ANALYSIS, BUT IS NOT REQUIRED
PRIMARY SYSTEM PRESSURE CONTROL



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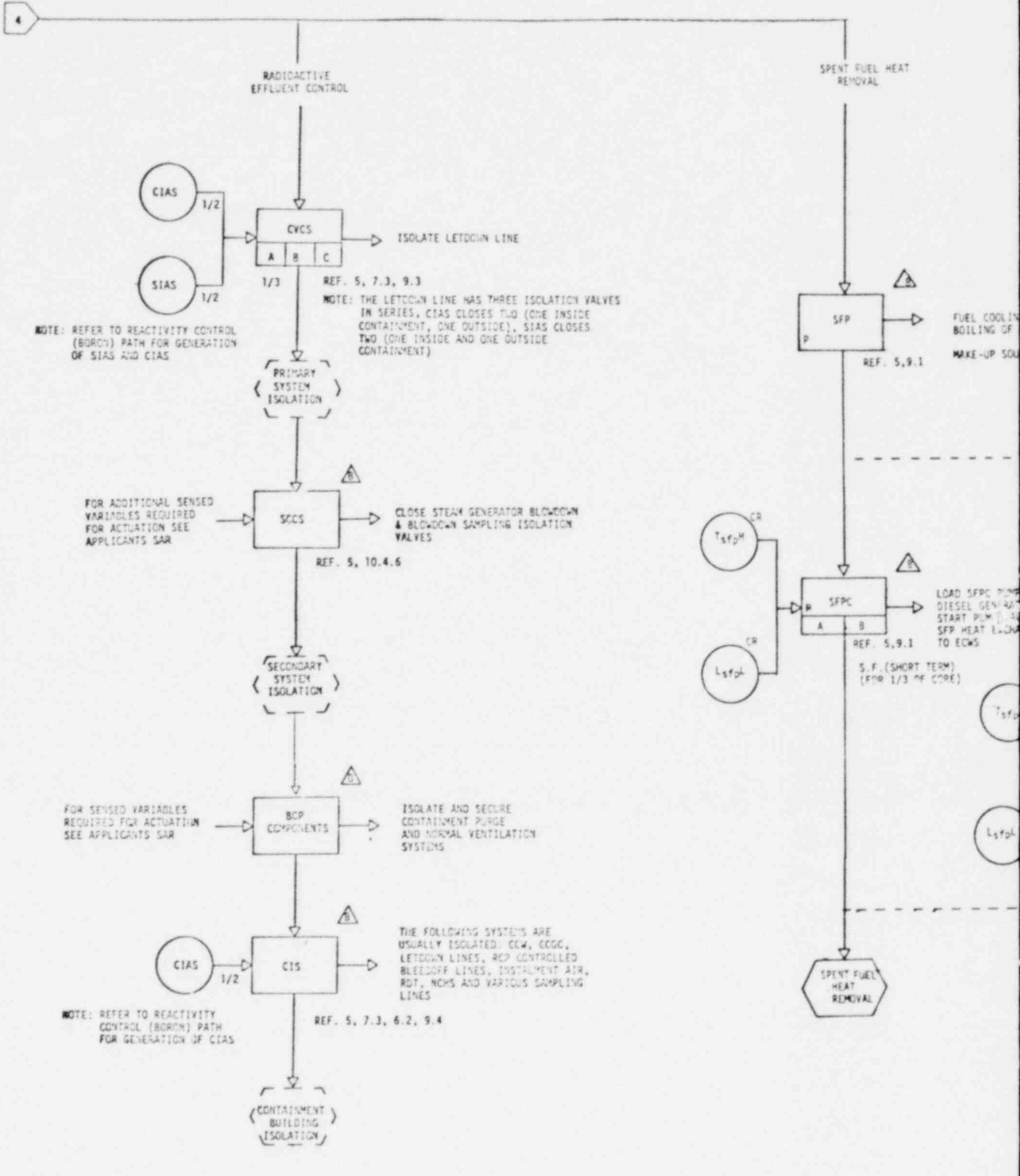
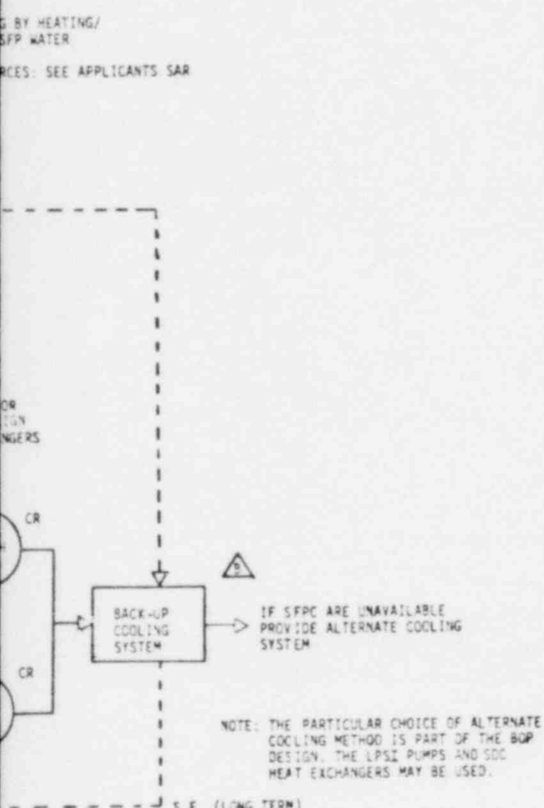
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP	Figure 15.3.3-1C


4
RADIOACTIVE EFFLUENT CONTROL
SPENT FUEL HEAT REMOVAL
CIAS
1/2
SIAS
1/2
CVCS
A B C
1/3
ISOLATE LETDOWN LINE
REF. 5, 7.3, 9.3
NOTE: THE LETDOWN LINE HAS THREE ISOLATION VALVES IN SERIES, CIAS CLOSES TWO (ONE INSIDE CONTAINMENT, ONE OUTSIDE), SIAS CLOSES TWO (ONE INSIDE AND ONE OUTSIDE CONTAINMENT)
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF SIAS AND CIAS
PRIMARY SYSTEM ISOLATION
SFP
P
REF. 5,9.1
FOR ADDITIONAL SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
SGCS
CLOSE STEAM GENERATOR BLOWDOWN & BLOWDOWN SAMPLING ISOLATION VALVES
REF. 5, 10.4.6
SFPC
A B
CR
CR
REF. 5,9.1
TO ECWS
S.F. (SHORT TERM) (FOR 1/3 OF CORE)
SECONDARY SYSTEM ISOLATION
FOR SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
BCP COMPONENTS
ISOLATE AND SECURE CONTAINMENT PURGE AND NORMAL VENTILATION SYSTEMS
CIAS
1/2
CIS
THE FOLLOWING SYSTEMS ARE USUALLY ISOLATED: CCW, CCGC, LETDOWN LINES, RCP CONTROLLED BLEEDOFF LINES, INSTRUMENT AIR, RDT, NCHS AND VARIOUS SAMPLING LINES
REF. 5, 7.3, 6.2, 9.4
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF CIAS
SPENT FUEL HEAT REMOVAL
CONTAINMENT BUILDING ISOLATION



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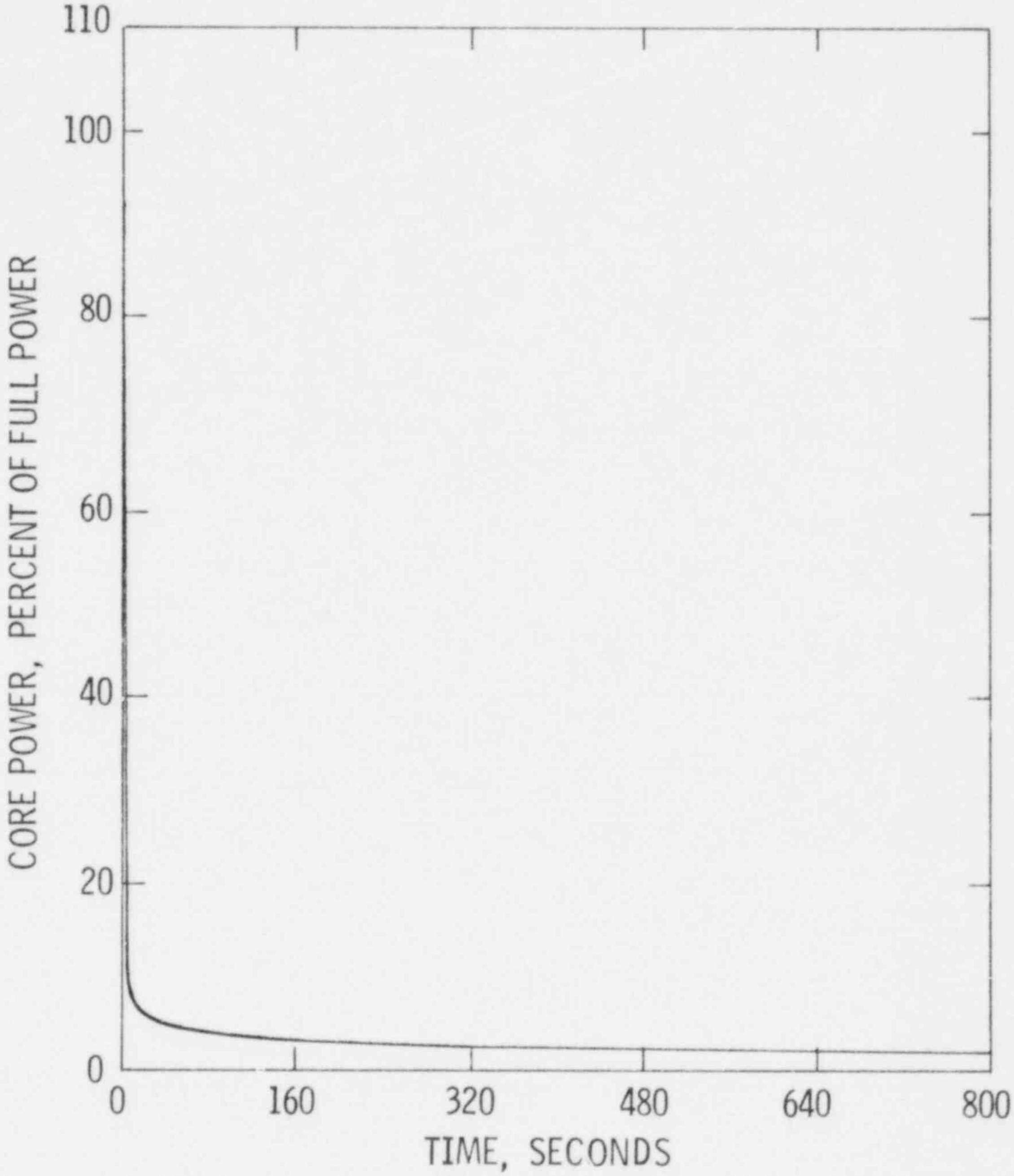
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP	Figure 15.3.3-1D



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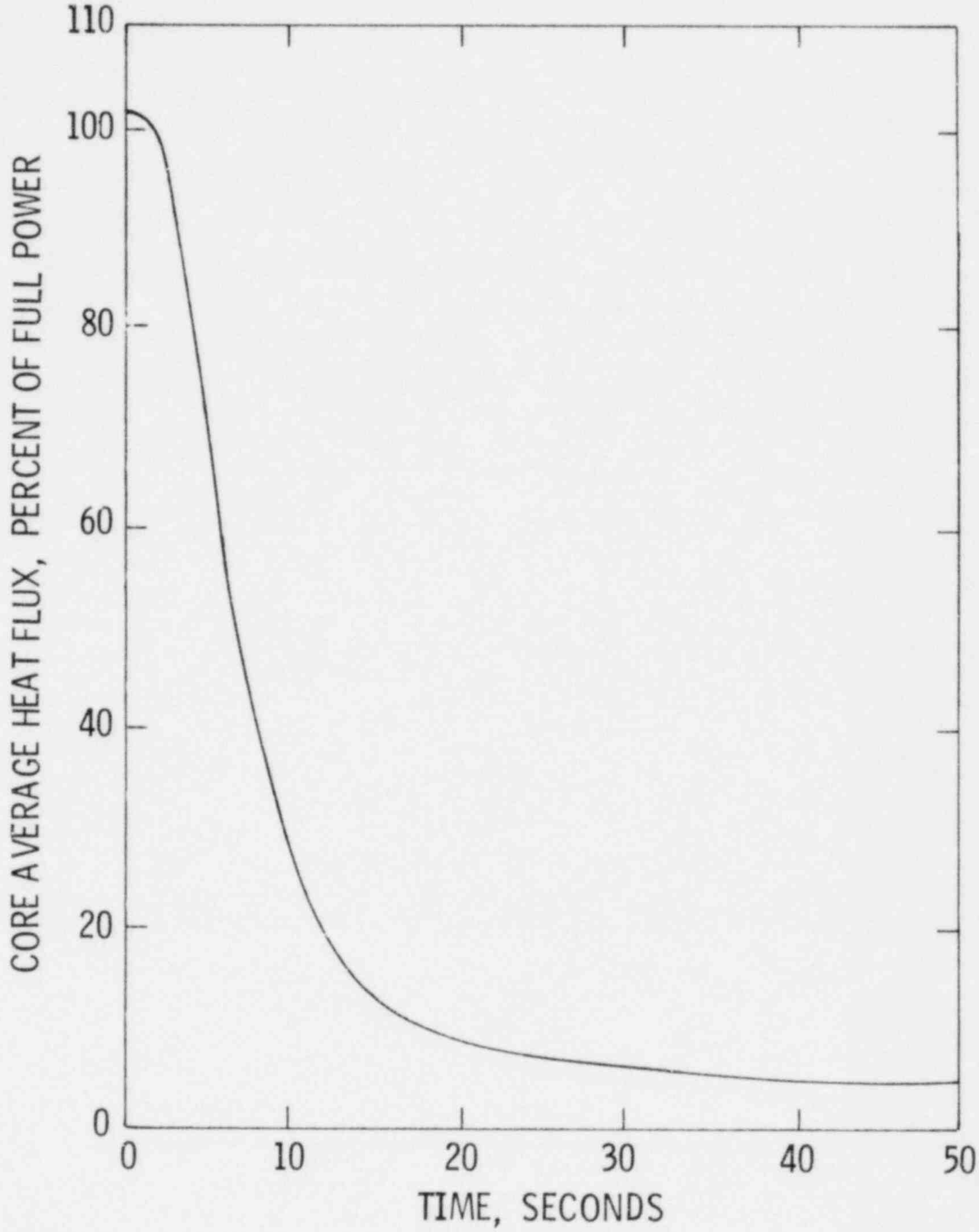
C - E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP CORE POWER vs TIME	Figure 15.3.3-2



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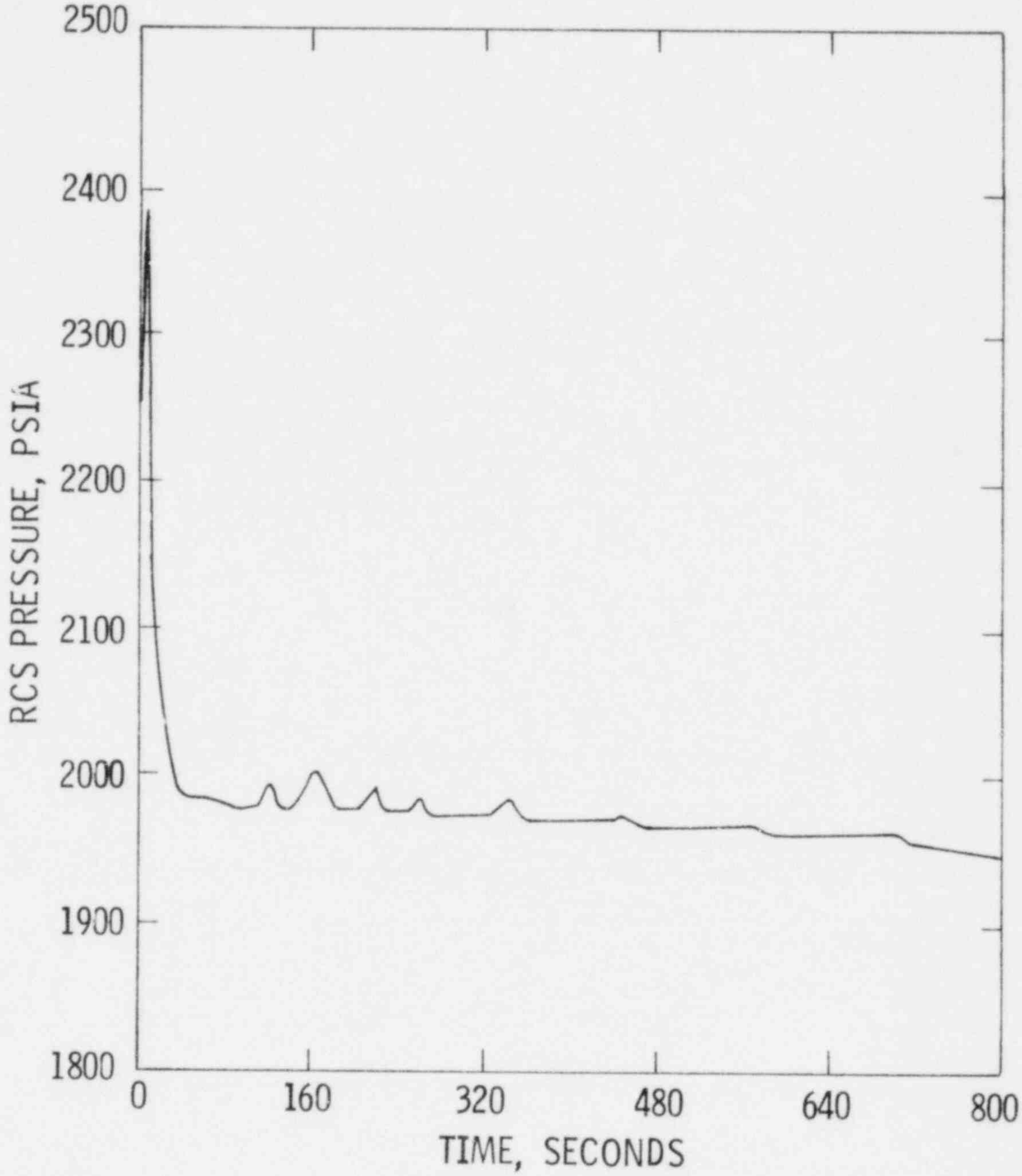
C - E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP CORE AVERAGE HEAT FLUX vs TIME	Figure 15.3.3-3



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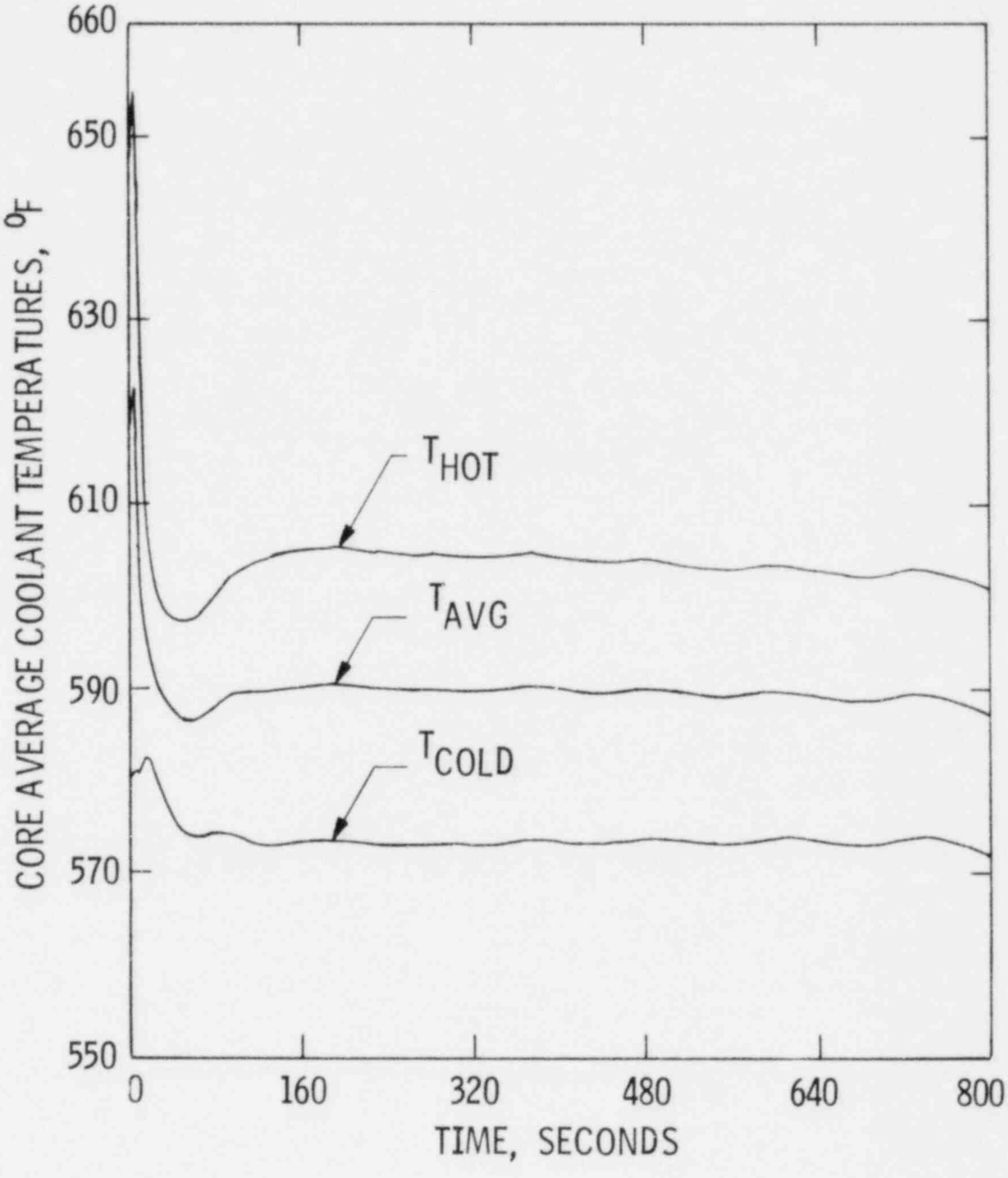
C-E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP RCS PRESSURE vs TIME	Figure 15.3.3-4



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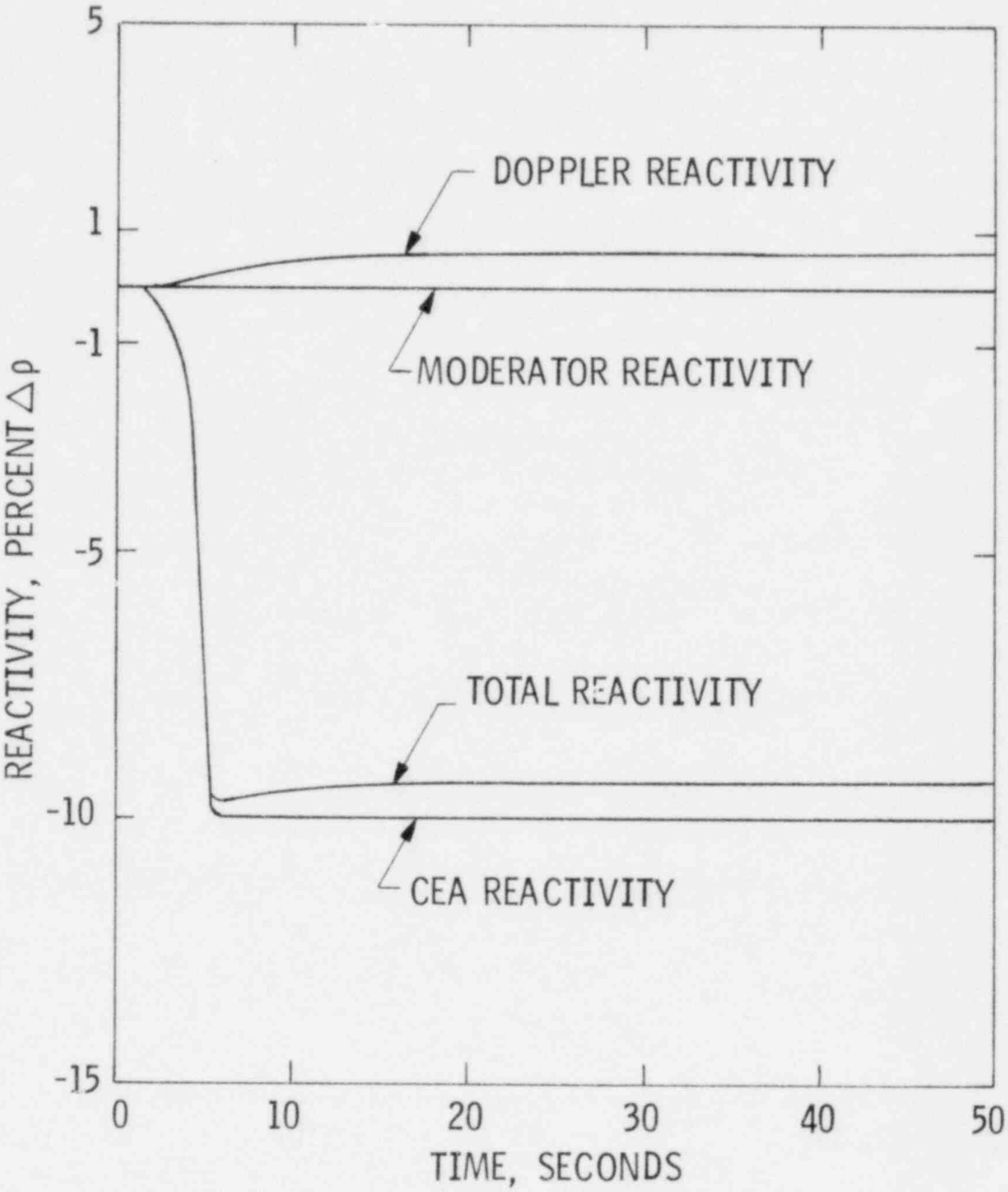
C - E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP CORE AVERAGE COOLANT TEMPERATURES vs TIME	Figure 15.3.3-5



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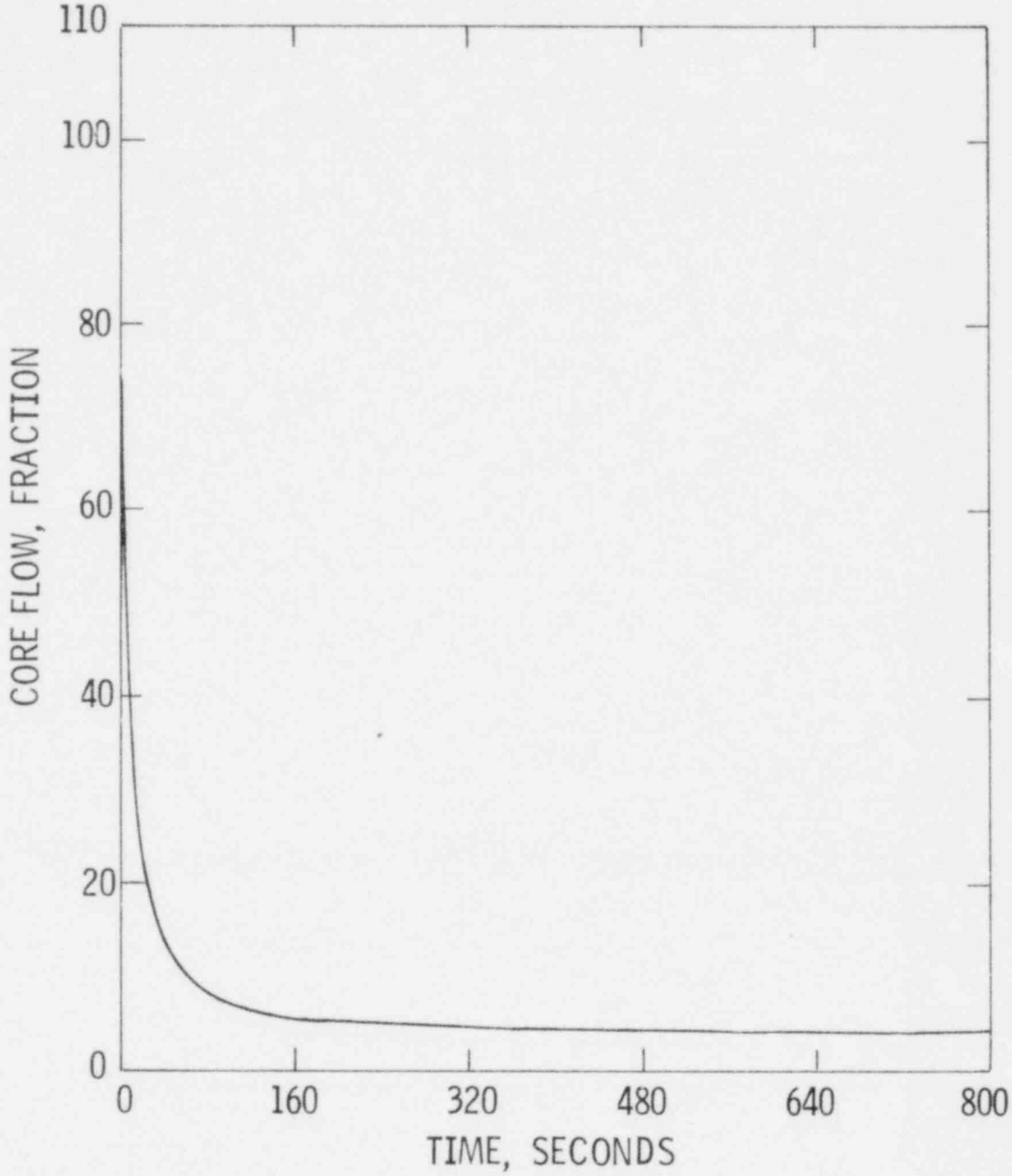
C-E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP REACTIVITY vs TIME	Figure 15.3.3-6



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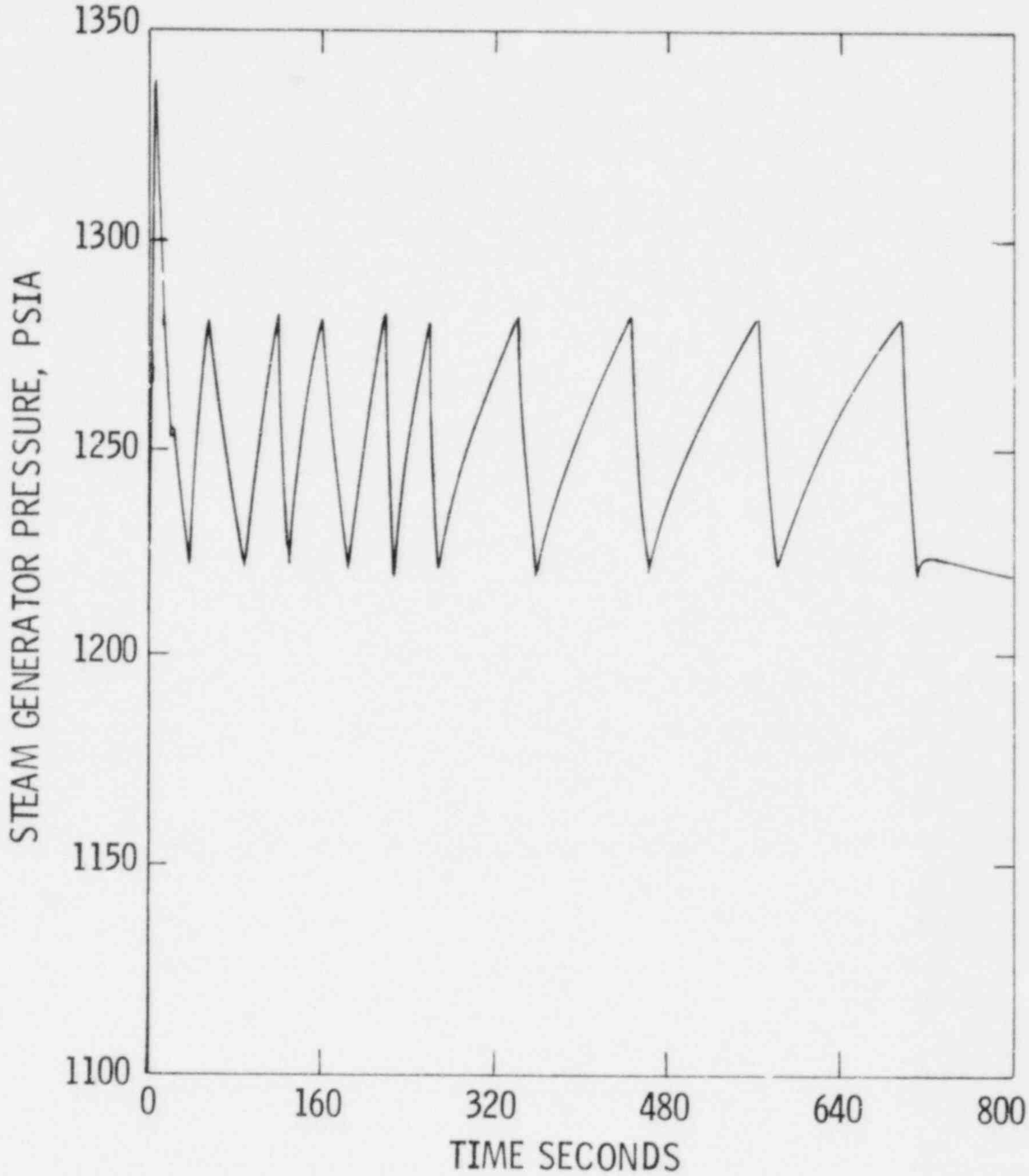
C - E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP CORE FLOW FRACTION vs TIME	Figure 15.3.3-7



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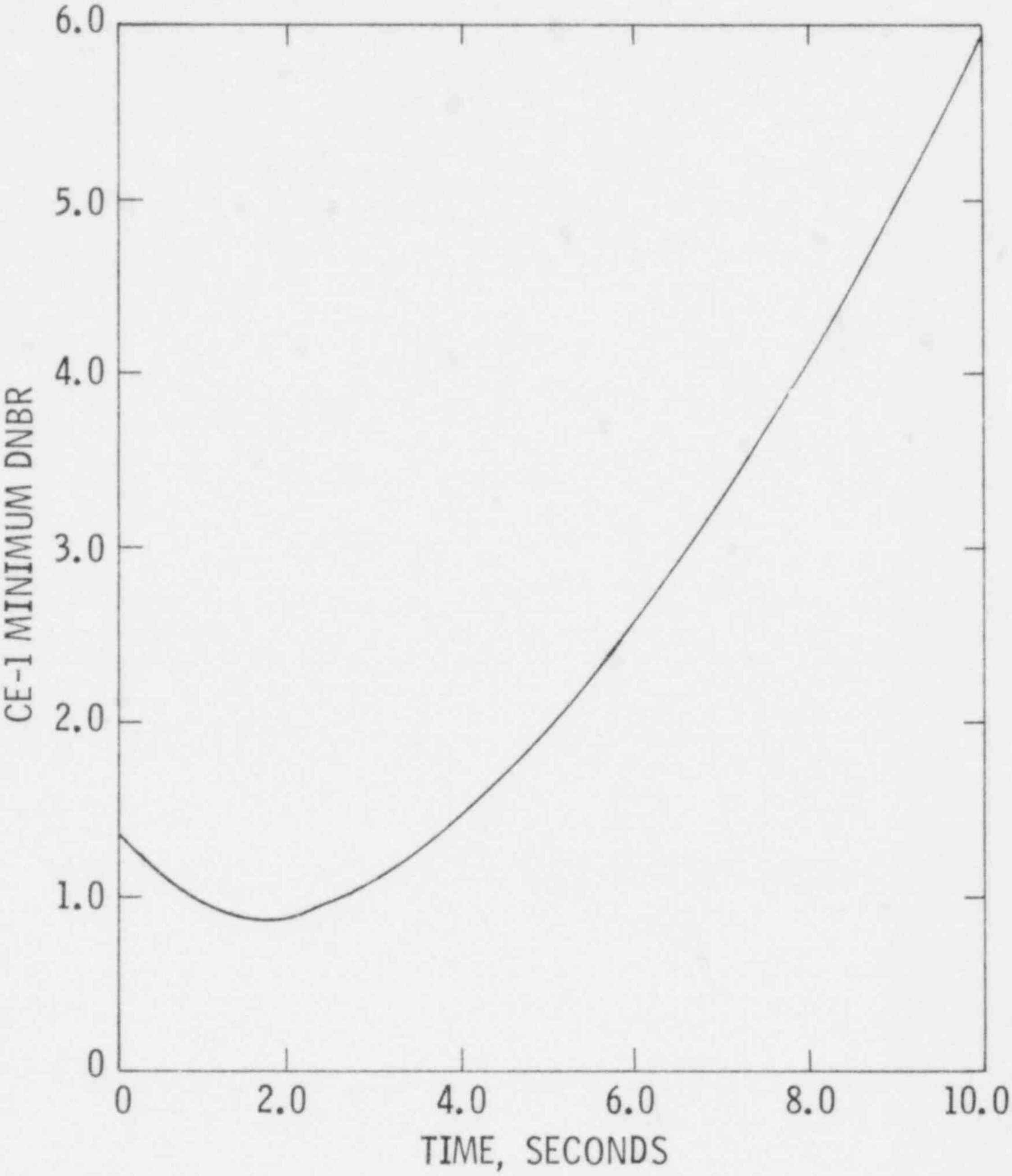
C-E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP STEAM GENERATOR PRESSURE vs TIME	Figure 15.3.3-8



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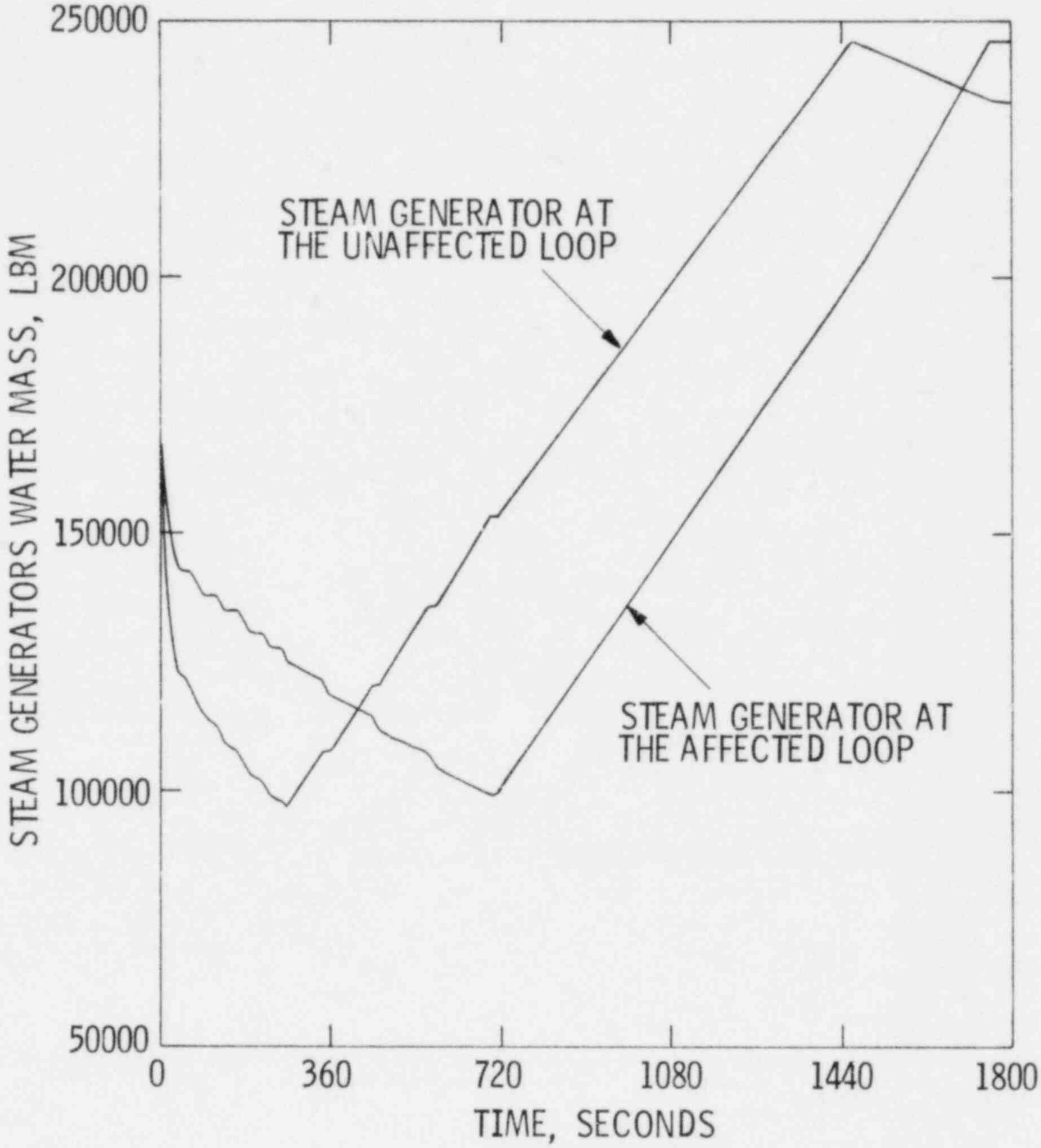
C - E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP CE-1 MINIMUM DNBR vs TIME	Figure 15.3.3-9



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C - E SYSTEM 80	SINGLE RCP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP STEAM GENERATORS WATER MASS vs TIME	Figure 15.3.3-10

15.3.4 REACTOR COOLANT PUMP SHAFT BREAK WITH LOSS OF OFFSITE POWER

15.3.4.1 Identification of Event and Causes

A single reactor coolant pump sheared shaft could be caused by mechanical failure of the pump shaft. This is assumed to result from a manufacturing defect in the shaft. Loss of offsite power following turbine/generator trip may be caused by a complete loss of the external electrical grid triggered by the turbine/generator trip.

15.3.4.2 Sequence of Events and Systems Operation

The sequence of events and systems operations is similar to that for the reactor coolant pump rotor seizure event, Section 15.3.3. The difference is that for the shaft break event, the reactor is tripped on differential pressure across either steam generator, whereas for the pump rotor seizure event the reactor is tripped by the CPC on a low projected DNBR condition.

The flow coastdown for a rotor seizure (RS) event is faster than the coastdown for a shaft break (SB) event. For a shaft break, the rotor is still capable of rotating, thereby offering less resistance to flow during the rapid flow decrease. This results in the less severe coastdown for the shaft break event than for the rotor seizure event. The SB trip time is 1.2 seconds; the RS trip time is 0.75 seconds. Both RS and SB have relatively fast coastdowns such that their minimum DNBR's occur after the coastdowns have reached equilibrium flow. For any trip time between the times of interest (i.e., 0.75 and 1.2 seconds), the actual trip time does not impact the number of fuel pins in DNB as the calculation is based on a steady state solution with equilibrium minimum flow and full power. Therefore, RS and SB have the same minimum DNBR, number of fuel pins in DNB, and number of fuel pins assumed to fail.

Both RS and SB include relatively fast 1-pump coastdowns which reach asymptotic flow before the time of minimum DNBR. The additional effect of a 3 pump flow coastdown on loss of offsite power is the same for both events. The remaining three pump coastdown does not start until after the turbine trip on reactor trip. Therefore, the relative timing between the flow coastdown and the heat flux decrease is the same for both events and as a result, although SB has a later time of minimum DNBR than RS, both events have the same minimum DNBR.

15.3.4.3 Analysis of Effects and Consequences

15.3.4.3.1 Core and System Performance

The analysis of effects and consequences for this event is similar to that for the reactor coolant pump rotor seizure event, Section 15.3.3. The SB coastdown is slightly slower and trip is later than those of the rotor seizure event. However, due to the analytical assumptions, both events produce the same minimum DNBR and subsequent radiological release. Although SB with a concurrent loss of offsite power (LOP) has a later time of minimum DNBR than RS with a LOP, both events have the same minimum DNBR, calculated fuel damage, and radiological releases.

15.3.4.3.2 Radiological Consequences

The radiological consequences due to steam release from the secondary system would be identical to the consequences of the RS event as described in Section

15.3.3. Thus, the two hour thyroid inhalation dose for the SB with loss of offsite power event is 29.5 rem.

15.3.4.4 Conclusion

The conclusion from the SB event is that this event would be no more adverse than the RS event. For both events the total number of fuel pins calculated in DNB, and which are conservatively assumed to fail, is 5.0%. The resultant radiological consequences which are given in Table 15.3.3-7 are within the guidelines of 10CFR100.

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15.4.1 UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL FROM A SUBCRITICAL OR LOW POWER CONDITION

15.4.1.1 Identification of Event and Causes

An uncontrolled sequential withdrawal of CEA's is assumed to occur as a result of a single failure in the Control Element Drive Mechanism (CEDM), Control Element Drive Mechanism Control System (CEDMCS), reactor regulating system, or as a result of operator error.

15.4.1.2 Sequence of Events and Systems Operation

The withdrawal of CEA's from subcritical or low power conditions adds reactivity to the reactor core, causing both the core power level and the core heat flux to increase together with corresponding increases in reactor coolant temperatures and Reactor Coolant System (RCS) pressure. The withdrawal motion of CEA's also produces a time dependent redistribution of core power. These transient variations in core thermal parameters result in the system's approach to the specified fuel design limits, thereby requiring the protective action of the Reactor Protection System (RPS).

Reactivity Control:

The reactivity insertion rate accompanying the uncontrolled CEA withdrawal is dependent primarily upon the CEA withdrawal rate and the CEA worth, since, at subcritical and lower power conditions, the normal reactor feedback mechanisms do not occur until power generation in the core is large enough to cause changes in the fuel and moderator temperatures. The reactivity insertion rate determines the rate of approach to the fuel design limits. Depending on the system initial conditions and reactivity insertion rate, the uncontrolled CEA withdrawal transient is terminated by either a variable overpower trip, high pressurizer pressure trip, a low Departure from Nucleate Boiling Ratio (DNBR) trip or a high local power density trip.

Reactor Heat Removal:

Following the cooldown phase in which the steam bypass control system is used, the Shutdown Cooling System (SCS) is manually actuated when the RCS temperature and pressure have been reduced to $350^{\circ}F$ and 400 psia, respectively. This system provides sufficient cooling flow to cool the RCS to cold shutdown.

Primary System Integrity:

The RCS pressure remains below the pressurizer pressure safety valve setpoint and remains less than 110% of design pressure. The pressurizer pressure control system and the pressurizer level control system are manually operated to regulate RCS pressure and coolant inventory during the cooldown phase.

Secondary System Integrity:

The secondary system pressure increases following reactor trip and is limited by the steam generator safety valves. The atmospheric dump valves are used to

cool the plant down to shutdown cooling entry conditions. The feedwater flow rate is in manual mode and is very low because it matches steam flow rate.

Table 15.4.1-1 gives the sequence of events for the limiting CEA withdrawal transient at low power (1 MWt) identified in paragraph 15.4.1.3.

15.4.1.3 Analysis of Effects and Consequences

A. Mathematical Model

The Nuclear Steam Suppy System (NSSS) response to a CEA sequential withdrawal from subcritical or low power conditions was simulated using the CESEC computer program described in Section 15.0. The thermal margin on DNBR in the reactor core was simulated using the TORC computer program described in Section 15.0 with the CE-1 CHF correlation described in Chapter 4.

B. Input parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a CEA sequential withdrawal from subcritical or low power conditions are discussed in Section 15.0. In particular, those parameters which were unique to the analysis discussed below are listed in Table 15.4.1-4.

The initial conditions and NSSS characteristics assumed in this analysis have been determined to be the limiting set of conditions allowed by the limiting conditions for operation (LCO's) in terms of providing the closest approach to the fuel design limits for a CEA withdrawal from low power level. The initial conditions which provide the closest approach to the fuel design limits correspond to zero power, core inlet temperature of 564°F, core inlet flow of 95% of design flow and minimum RCS pressure of 1785 psia. The initial RCS pressure is chosen to be the lowest allowed pressure within the LCO's since this allows the transient response to the CEA withdrawal to proceed for a longer time by delaying actuation of the high pressurizer pressure trip. The initial core average axial power distribution assumed in the analysis corresponds to an axial shape index (ASI) of -0.64. Studies have shown that this initial shape undergoes a significant and rapid shift to the top of the core during the transient. A one pin radial peaking factor of 2.53 including uncertainties, is also conservatively assumed for this analysis. The radial peaking factor is the highest radial peak expected for any CEA configuration and time in core lifetime.

Parametric analyses have indicated that an initial power level of 1 MWt, critical core condition, results in the closest approach to the fuel design limits during the CEA withdrawal transient. Initially subcritical, zero power CEA withdrawal transients are terminated by a variable overpower trip, high pressurizer pressure trip, low DNBR trip, or high local power density trip. At power levels above 1 MWt, reactivity feedback mechanisms prevail and provide a dampening effect on the severity of the transient. Based on parametric studies, a moderator temperature coefficient of $+0.5 \times 10^{-4}\ \Delta\rho/^{\circ}F$ is assumed for this analysis.

The regulating CEA positions are initially in the fully inserted position when the CEA withdrawal is initiated. Based on calculated CEA worths and the maximum CEA withdrawal rate of the CEA drive system, the assumed rate is conservative. For this analysis, the reactivity insertion is the maximum expected rate of $2.5 \times 10^{-4}\ \Delta\rho/s$, i.e., 0.05%$\Delta\rho$ per inch of rod. This rate

corresponds to the largest insertion rate expected from the sequential withdrawal of the CEA groups with 40% overlap at the maximum speed of 30 in./minute.

C. Results

The dynamic behavior of important NSSS parameters following a CEA withdrawal from low power conditions is presented in Figures 15.4.1-1 through 15.4.1-8.

The withdrawal of CEA's from low power conditions (1 MWt power) adds reactivity to the reactor core, causing both the core power level and the core heat flux to increase. The power transient causes increasing temperature and pressure transients, which together with a top peaked axial power distribution, produce the closest approach to the specified acceptable fuel design limit on DNBR. Since the transient is initiated at low power levels, one of the normal reactor feedback mechanisms, moderator feedback, does not contribute to any appreciable extent to the power excursion transient. At 23.4 seconds into the transient, a variable overpower trip is actuated. The CEA's begin dropping into the core at 24.2 seconds which terminates the transient with a hot channel minimum DNBR of 5.4. If the maximum rod radial peaking factor occurs in the region of the axial power peak, the peak linear heat generation rate during the transient reaches 13.1 KW/ft.

15.4.1.4 Conclusions

The uncontrolled CEA withdrawal from a subcritical or low power condition event meets general design criteria 25 and 20. These criteria require that the specified acceptable fuel design limits are not exceeded and the protection system action is initiated automatically. The withdrawal of CEA's from low power conditions meets the following fuel design limits which serve as the acceptance criteria for this event: the transient terminates with a hot channel minimum DNBR greater than or equal to 1.19 and the peak linear heat generation rate during the transient is less than 21 KW/ft.

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TABLE 15.4.1-1

SEQUENCE OF EVENTS FOR THE SEQUENTIAL CEA WITHDRAWAL EVENT

Time(sec)	Event	Setpoint or Value	Success Path
0.0	Withdrawal of CEA's - Initiating Event	--	Reactivity Control
23.4	Variable Overpower Trip, % of Design Power	17.0	Reactivity Control
23.9	CEDM Power Supply Breakers Open	--	Reactivity Control
24.2	CEA's Begin to Drop	--	Reactivity Control
25.2	Maximum Core Power, % of Design Power	43.5	
26.7	Maximum Core Average Heat Flux, % of Full Power Heat Flux	16.9	
27.0	Minimum DNBR	5.40	
35.2	Maximum Pressurizer Pressure, psia	1894	

TABLE 15.4.1-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR THE SEQUENTIAL CEA WITHDRAWAL AT LOW POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System	✓					
2. Main Feedwater Pump Turbine Control System*	✓					
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System		✓				
5. Pressurizer Pressure Control System	✓					
6. Pressurizer Level Control System	✓					
7. Control Element Drive Mechanism Control System	✓					1
8. Reactor Regulating System	✓					1
9. Core Operating Limit Supervisory System	✓					
10. Reactor Coolant Pumps	✓					
11. Chemical and Volume Control System	✓					
12. Secondary Chemistry Control System*	✓					
13. Condenser Evacuation System*	✓					
14. Turbine Gland Sealing System*	✓					
15. Nuclear Cooling Water System*	✓					
16. Turbine Cooling Water System*	✓					
17. Plant Cooling Water System*	✓					
18. Condensate Storage Facilities*	✓					
19. Circulating Water System*	✓					
20. Spent Fuel Pool Cooling and Clean-Up System*	✓					
21. Non-Class 1E (Non-ESF) A.C. Power*	✓					
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems

TABLE 15.4.1-2 (CONTINUED) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR THE SEQUENTIAL CEA WITHDRAWAL
AT LOW POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*	✓					
24. Class 1E D.C. Power*	✓					

NOTES:

1. This system may be the cause of the initiating event.

*Balance-of-Plant Systems

TABLE 15.4.1-3

UTILIZATION OF SAFETY SYSTEMS

FOR THE SEQUENTIAL CEA WITHDRAWAL

AT LOW POWER

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System			✓		
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems			✓		
4. Supplementary Protection System					
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves					
8. Main Steam Isolation System*			✓		
9. Emergency Feedwater System*			✓		
10. Safety Injection System			✓		
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*			✓		
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*					
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

*Balance-of-Plant Systems

TABLE 15.4.1-4

ASSUMPTIONS AND INITIAL CONDITION FOR THE LOW POWER CEA WITHDRAWAL ANALYSIS

Parameter	Value
Initial core power level, MWt	1
Core inlet coolant temperature, ^{o}F	564.5
Core mass flowrate, 10^6 lb_m/h	142.1
Reactor coolant system pressure, psia	1785
One pin radial peaking factor, with uncertainty	2.53
Steam generator pressure, psia	1178.
Moderator temperature coefficient, 10^{-4} $\Delta\rho$ $/^{o}F$	+0.5
Doppler coefficient multiplier	.85
CEA reactivity addition rate, 10^{-4} $\Delta\rho/^{o}sec$	2.5
CEA Worth on trip, 10^{-2} $\Delta\rho$	-3.6[a]
Steam bypass control system	Manual

a. The scram worth used in this analysis does not take credit for the additional worth available from the withdrawn CEA's and is therefore considered conservative. Furthermore, the worth assumed is less negative than that calculated or expected.

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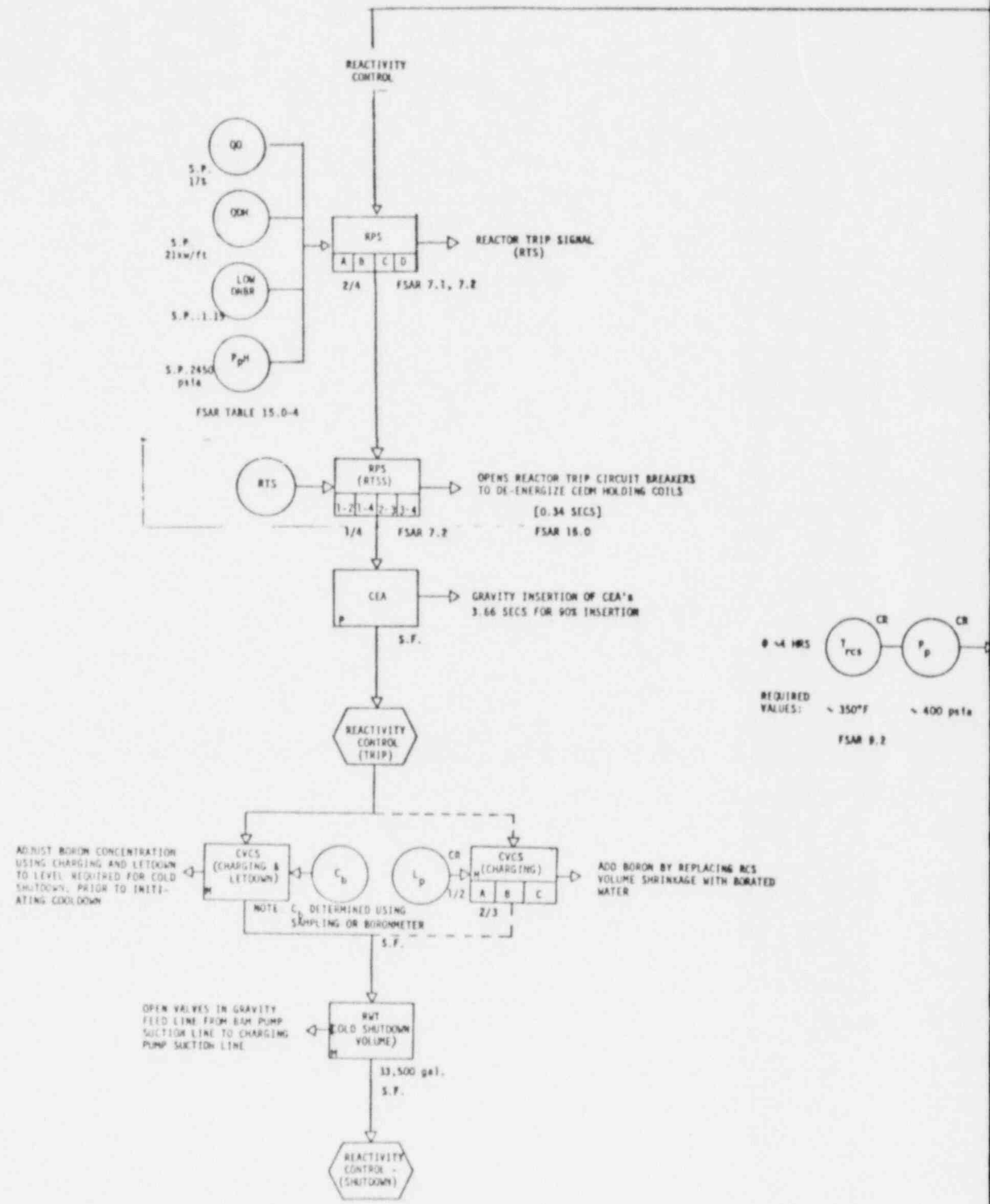
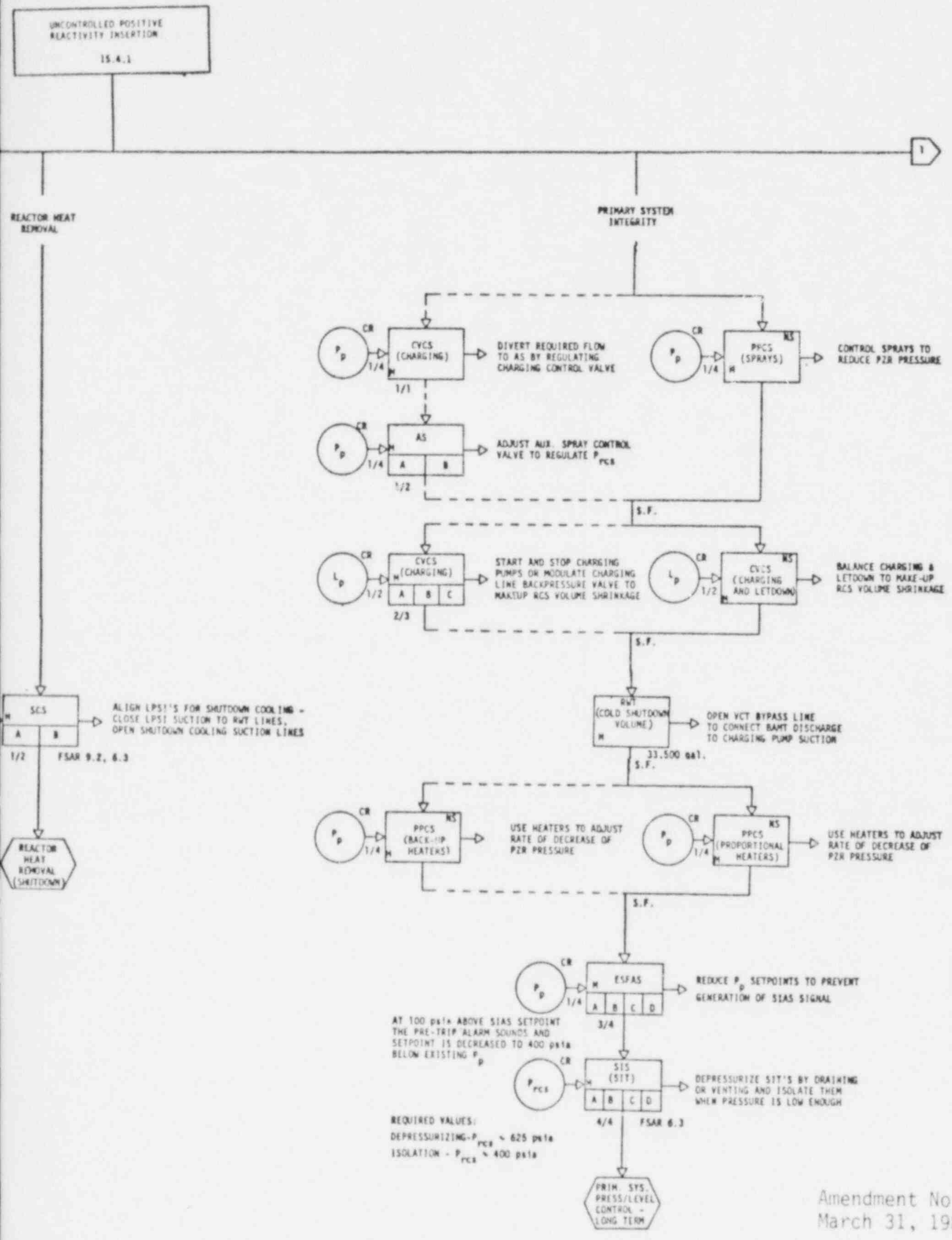
SPECIFIC EVENT

SEQUENTIAL CEA WITHDRAWAL
AT SUBCRITICAL OR LOW POWER





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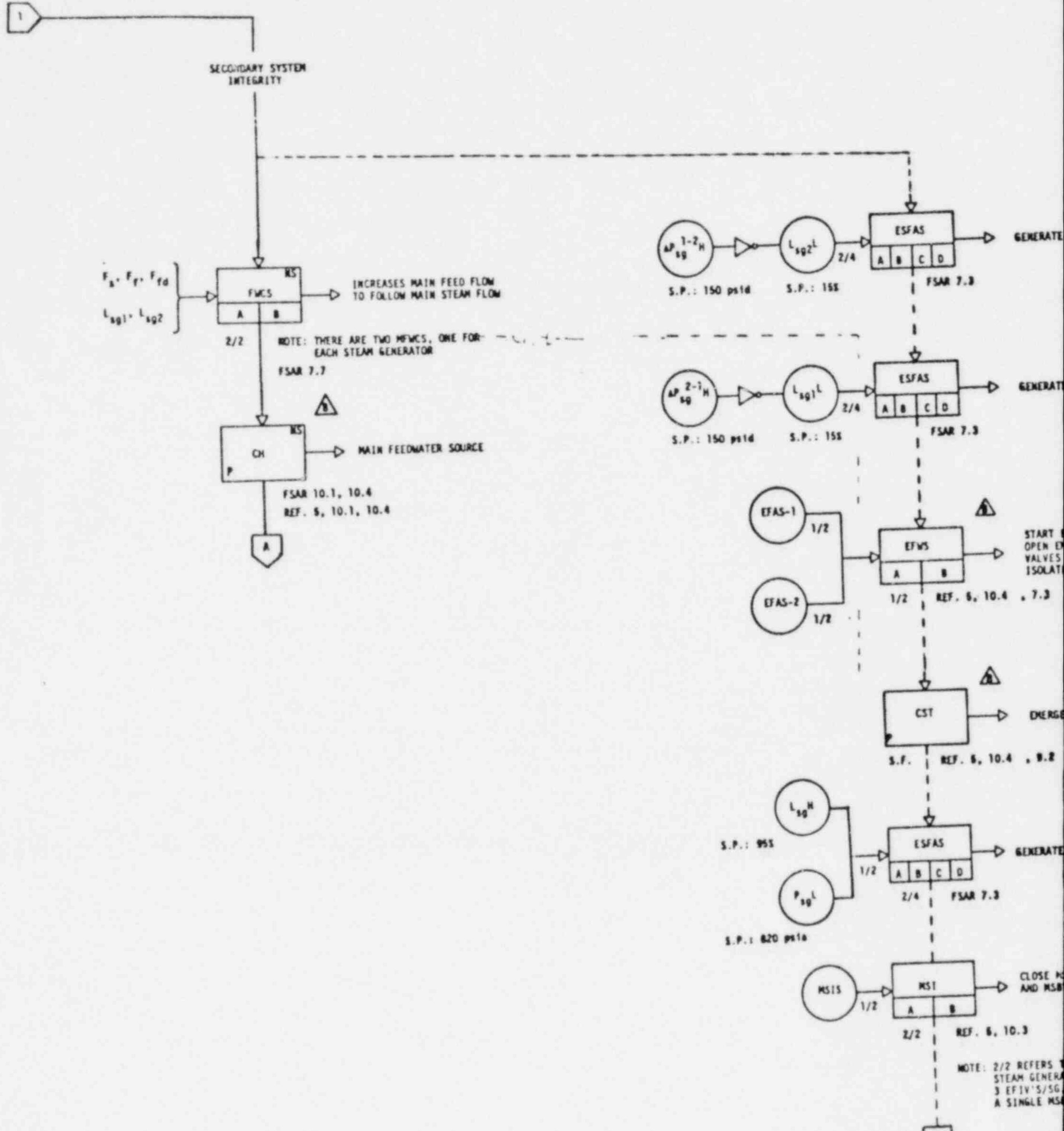
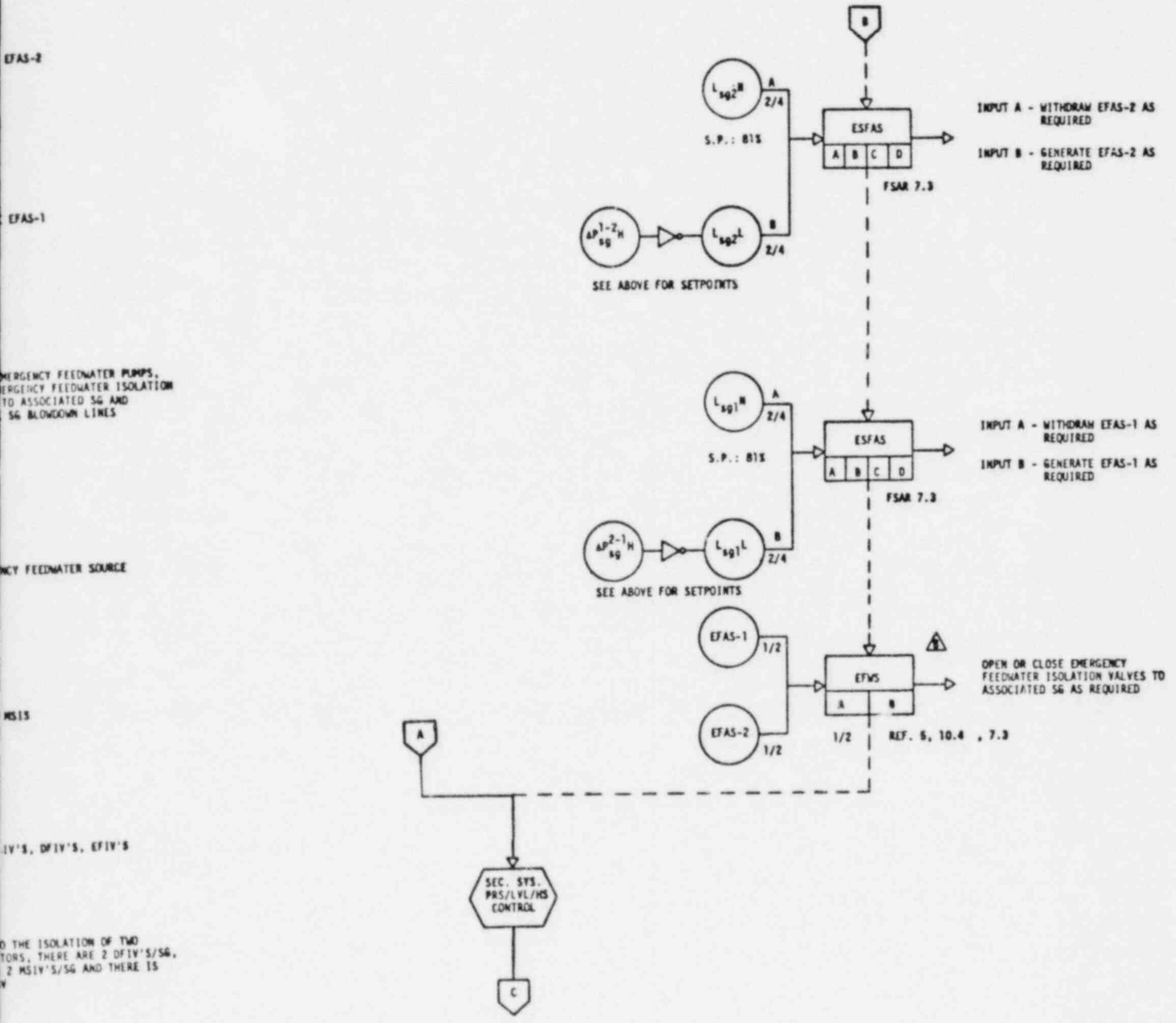
C - E SYSTEM 80	SEQUENCE OF EVENTS FOR UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL FROM A SUBCRITICAL OR LOW POWER CONDITION	Figure 15.4.1-1A



1
SECONDARY SYSTEM INTEGRITY
FWCS
RS
A B
INCREASES MAIN FEED FLOW TO FOLLOW MAIN STEAM FLOW
2/2
NOTE: THERE ARE TWO MFWCS, ONE FOR EACH STEAM GENERATOR
FSAR 7.7
CH
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
A
ESFAS
GENERATE
S.P.: 150 psid
S.P.: 15%
2/4
FSAR 7.3
EFAS-1
EFAS-2
1/2
EFWS
START
OPEN
VALVES
ISOLAT
REF. 5, 10.4 , 7.3
CST
S.F.
REF. 5, 10.4 , 9.2
S.P.: 95%
S.P.: 820 psia
MSIS
MSI
CLOSE
AND MSB
REF. 5, 10.3
NOTE: 2/2 REFERS
STEAM GENERA
3 EFIV'S/SG
A SINGLE MS
B



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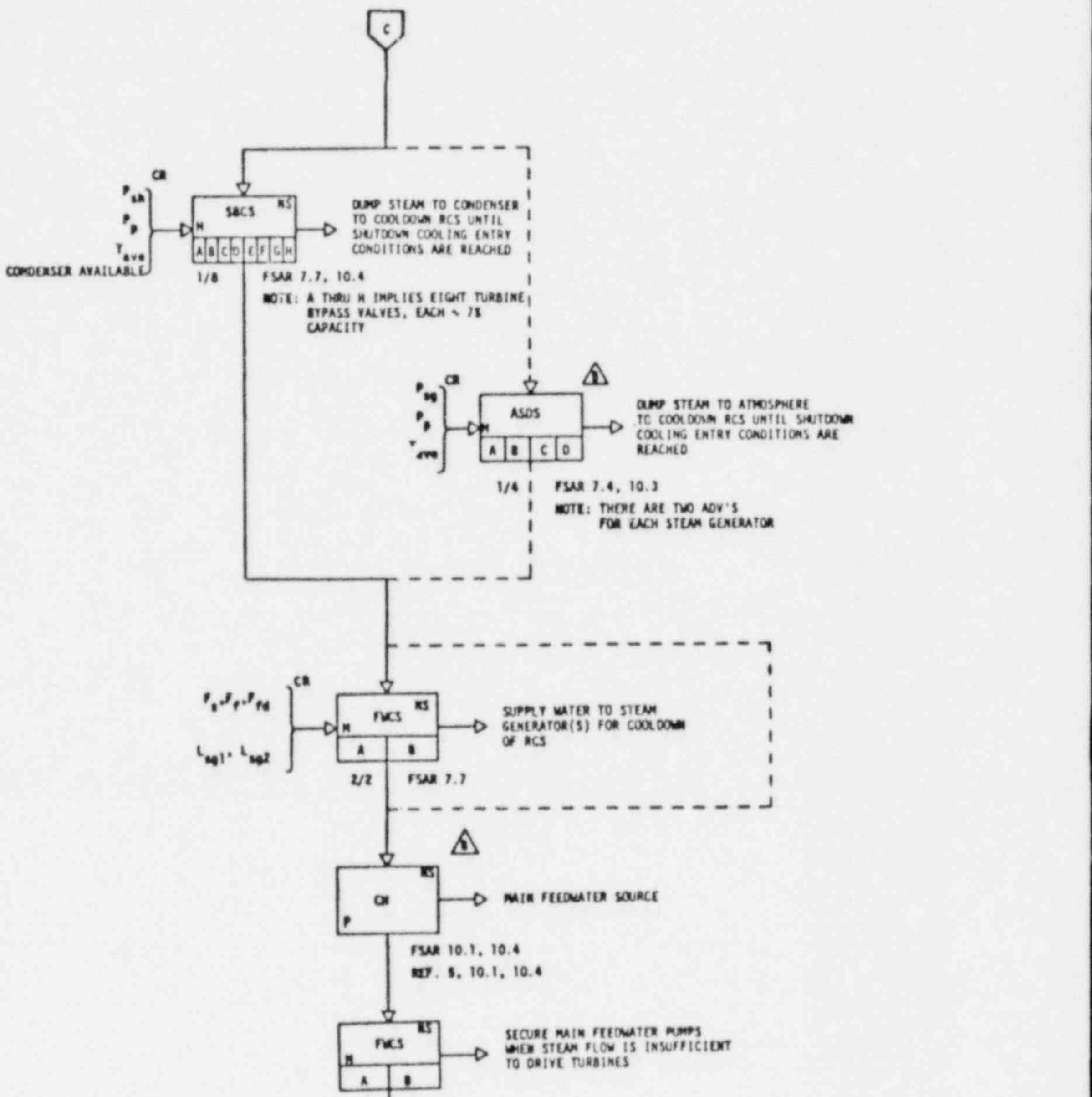
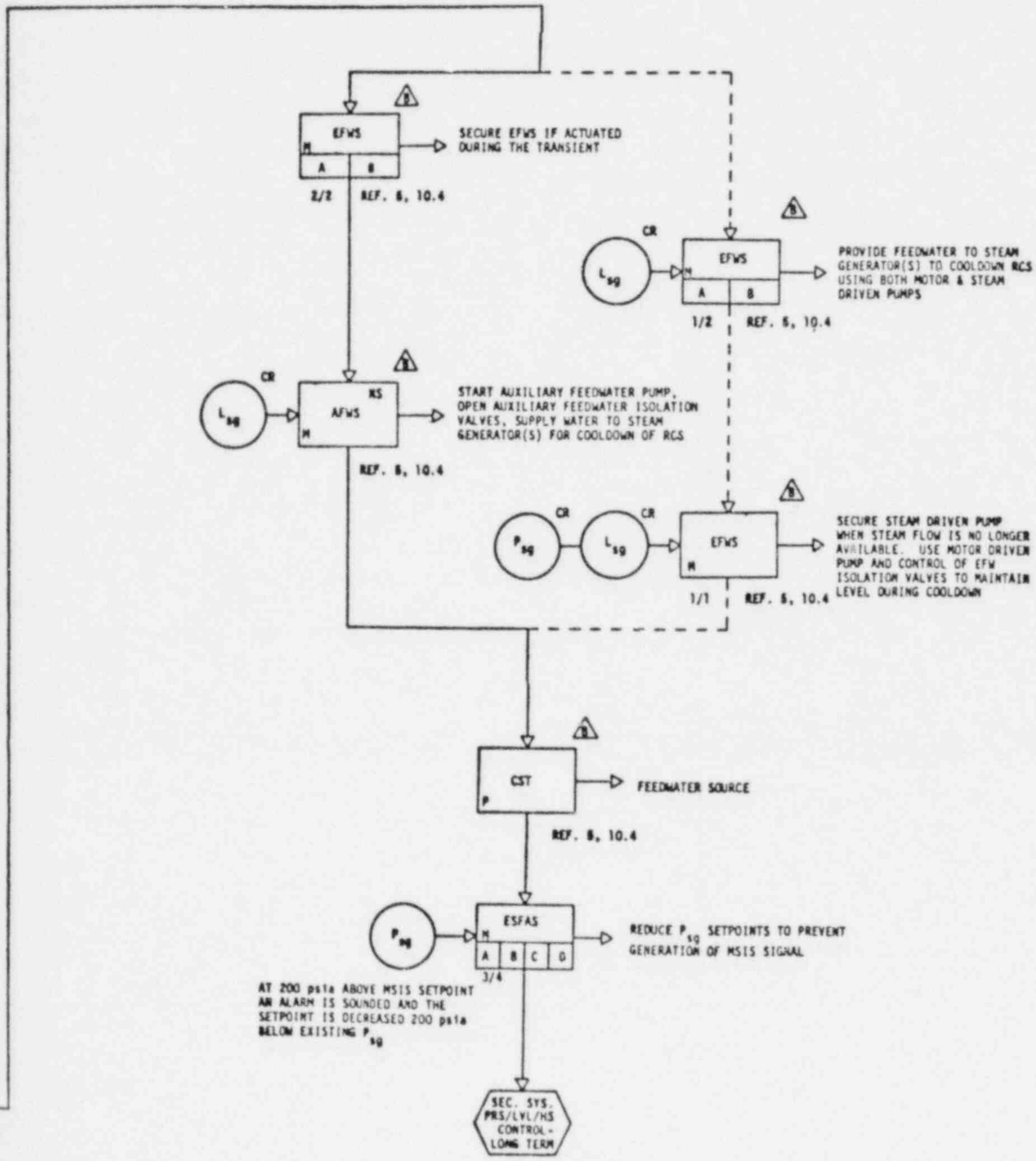
C – E SYSTEM 80	SEQUENCE OF EVENTS FOR UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITH-DRAWAL FROM A SUBCRITICAL OR LOW POWER CONDITION	Figure 15.4.1-1B


C
CR
P_{sh}
P_p
T_{ave}
CONDENSER AVAILABLE
SBCS
NS
M
A B C D E F G H
DUMP STEAM TO CONDENSER TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
1/8
FSAR 7.7, 10.4
NOTE: A THRU H IMPLIES EIGHT TURBINE BYPASS VALVES, EACH ~ 7% CAPACITY
CR
P_{sg}
P_p
T_{ave}
ASDS
A B C D
DUMP STEAM TO ATMOSPHERE TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
1/4
FSAR 7.4, 10.3
NOTE: THERE ARE TWO ADV'S FOR EACH STEAM GENERATOR
CR
F_s, F_f, F_{fd}
L_{sg1}, L_{sg2}
FWCS
NS
M
A B
SUPPLY WATER TO STEAM GENERATOR(S) FOR COOLDOWN OF RCS
2/2
FSAR 7.7
CN
NS
P
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
FWCS
NS
M
A B
SECURE MAIN FEEDWATER PUMPS WHEN STEAM FLOW IS INSUFFICIENT TO DRIVE TURBINES
2/2
FSAR 7.7



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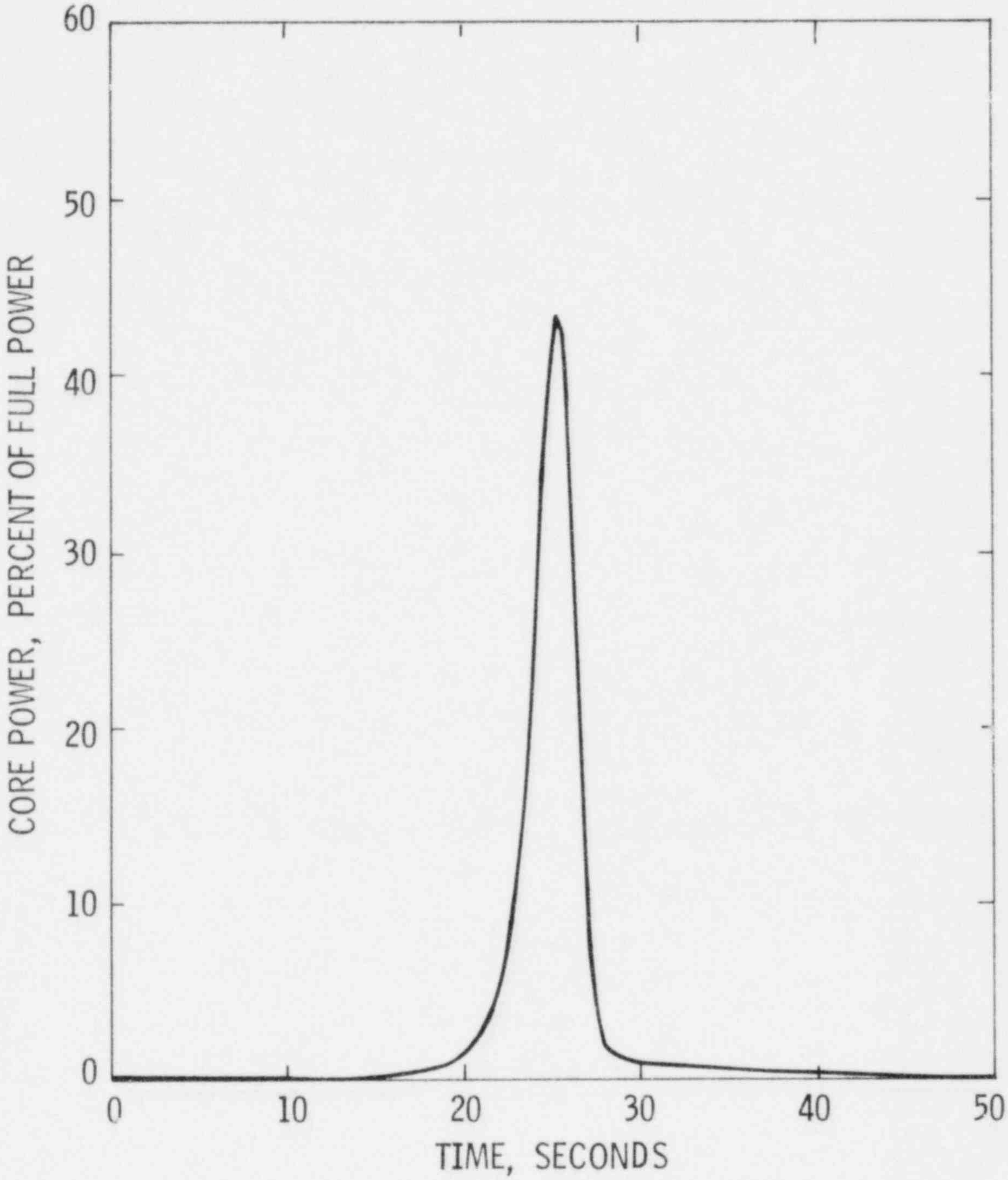
C – E SYSTEM 80	SEQUENCE OF EVENTS FOR UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITH-DRAWAL FROM A SUBCRITICAL OR LOW POWER CONDITION	Figure 15.4.1 -1C



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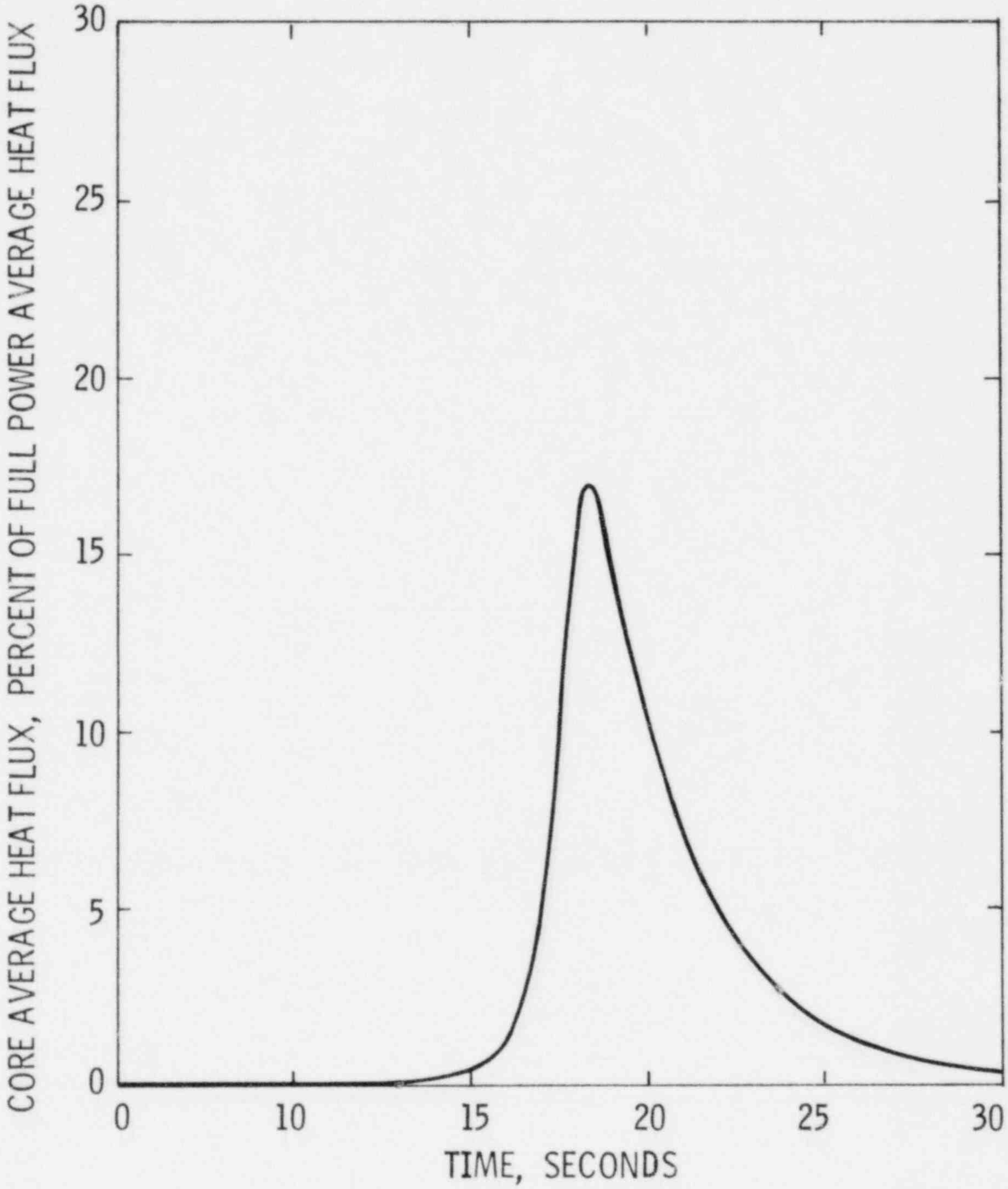
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER CORE POWER vs TIME	Figure 15.4.1-2



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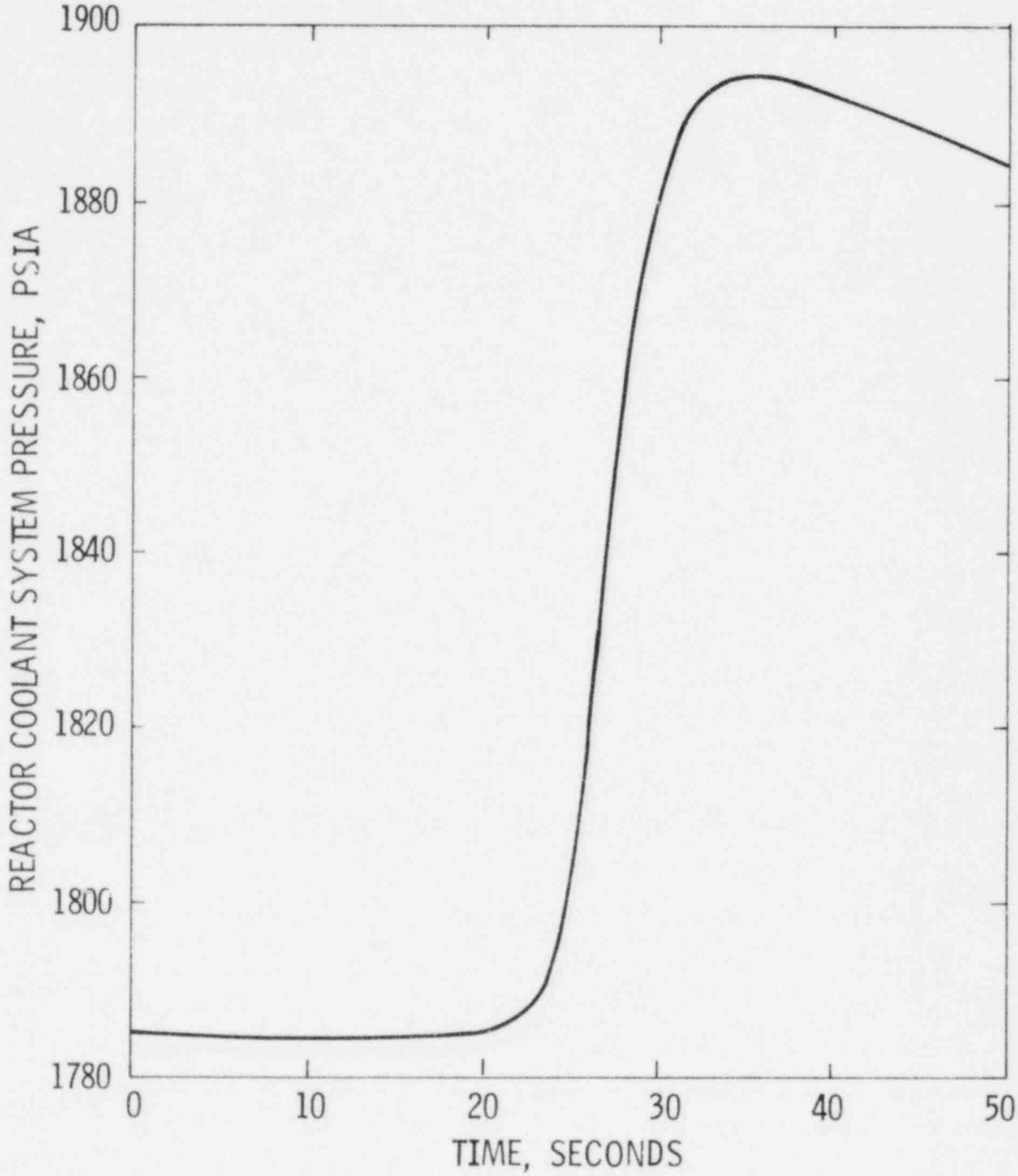
C-E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER CORE AVERAGE HEAT FLUX vs TIME	Figure 15.4.1-3



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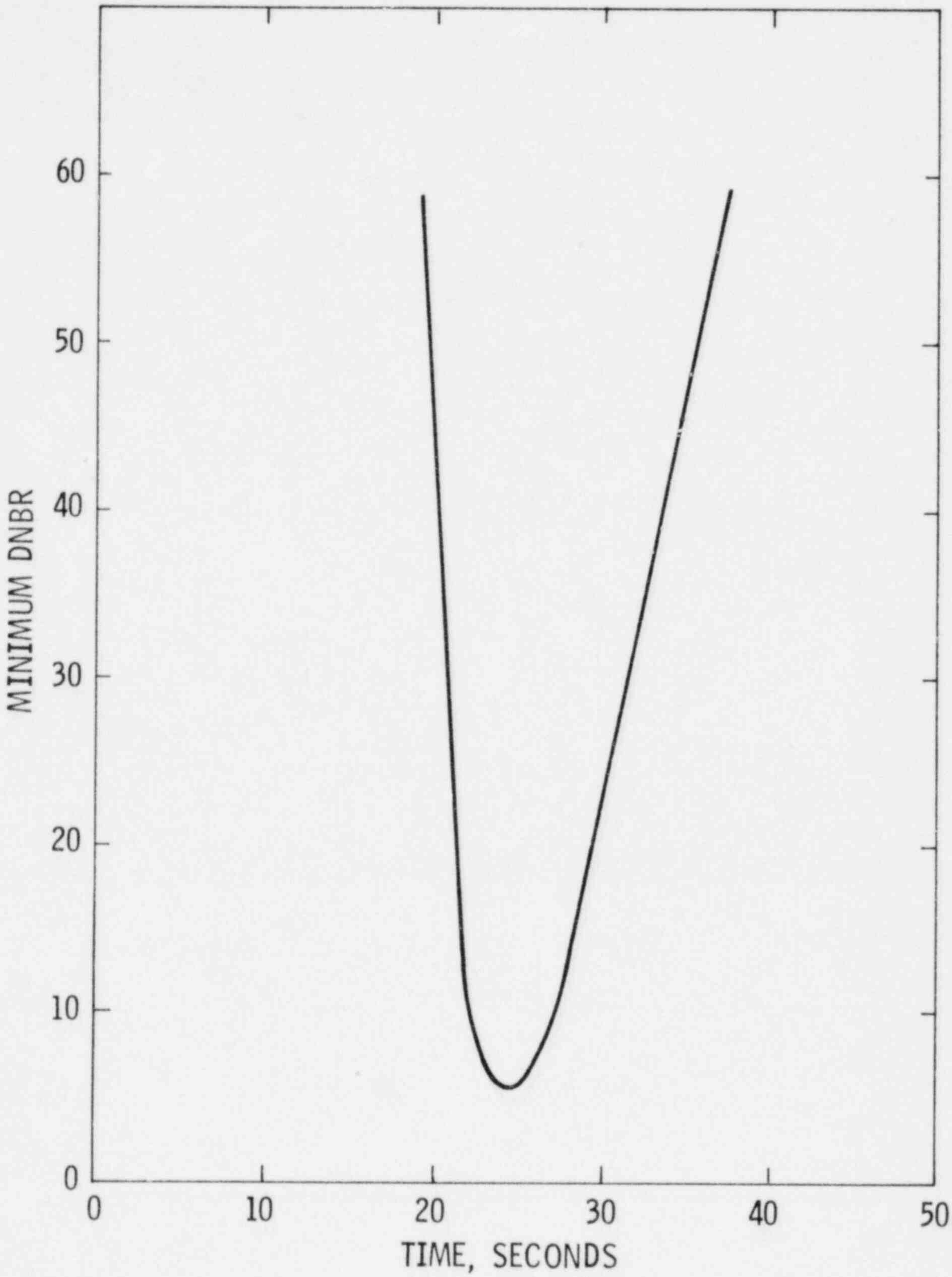
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER REACTOR COOLANT SYSTEM PRESSURE vs TIME	Figure 15.4.1-4



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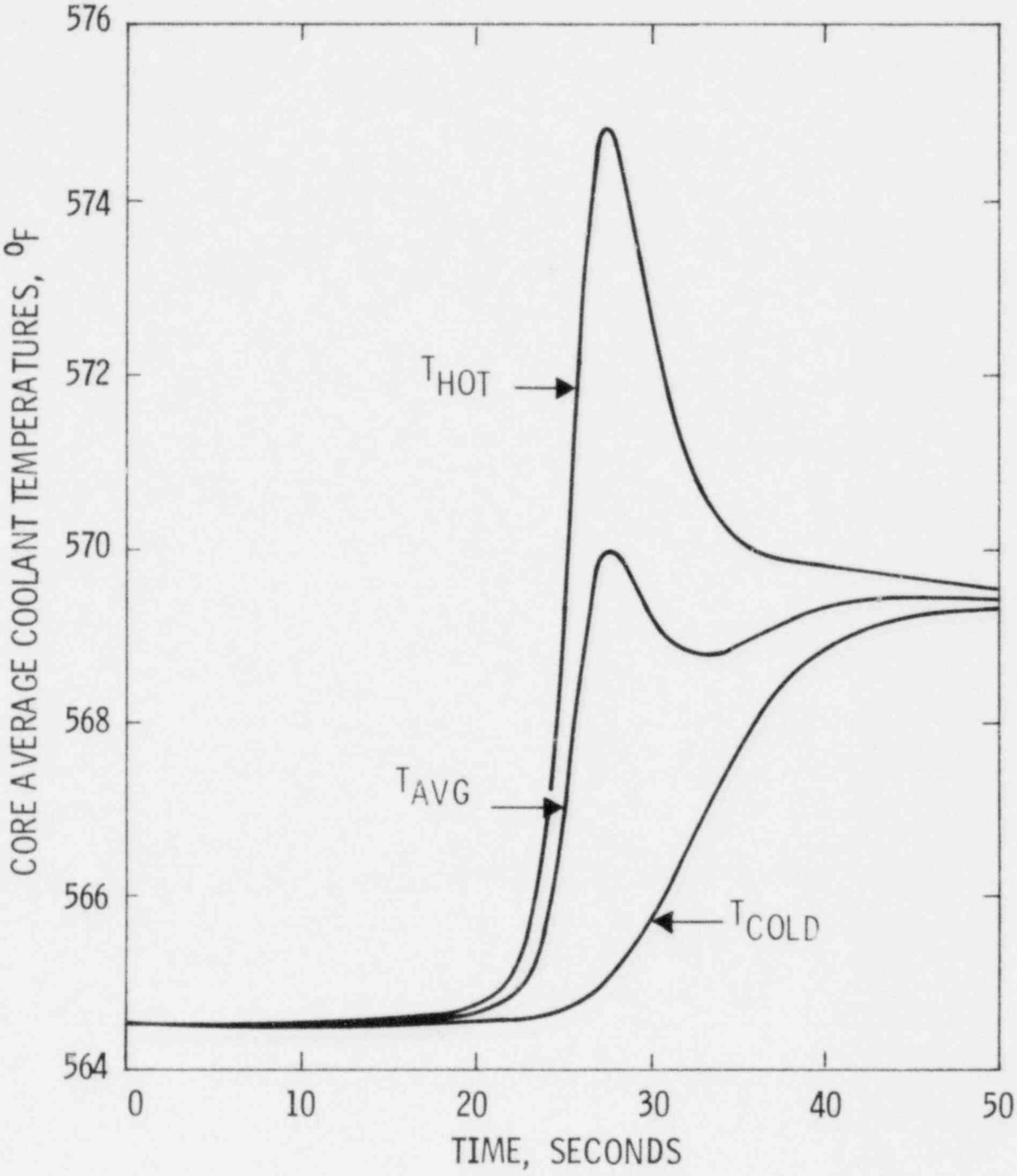
C-E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER MINIMUM DNBR vs TIME	Figure 15.4.1-5



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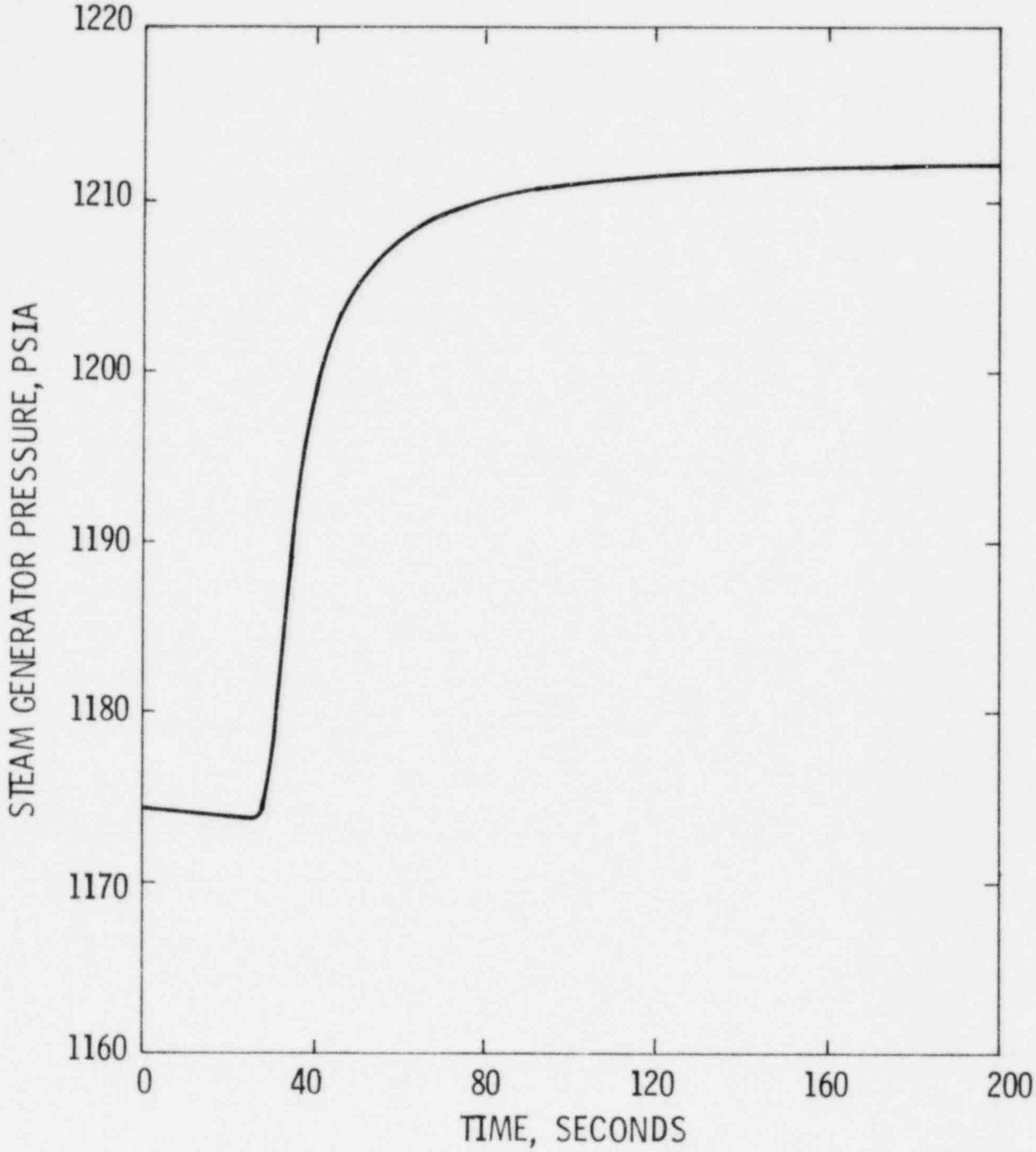
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER CORE AVERAGE COOLANT TEMPERATURES vs TIME	Figure 15.4.1-6



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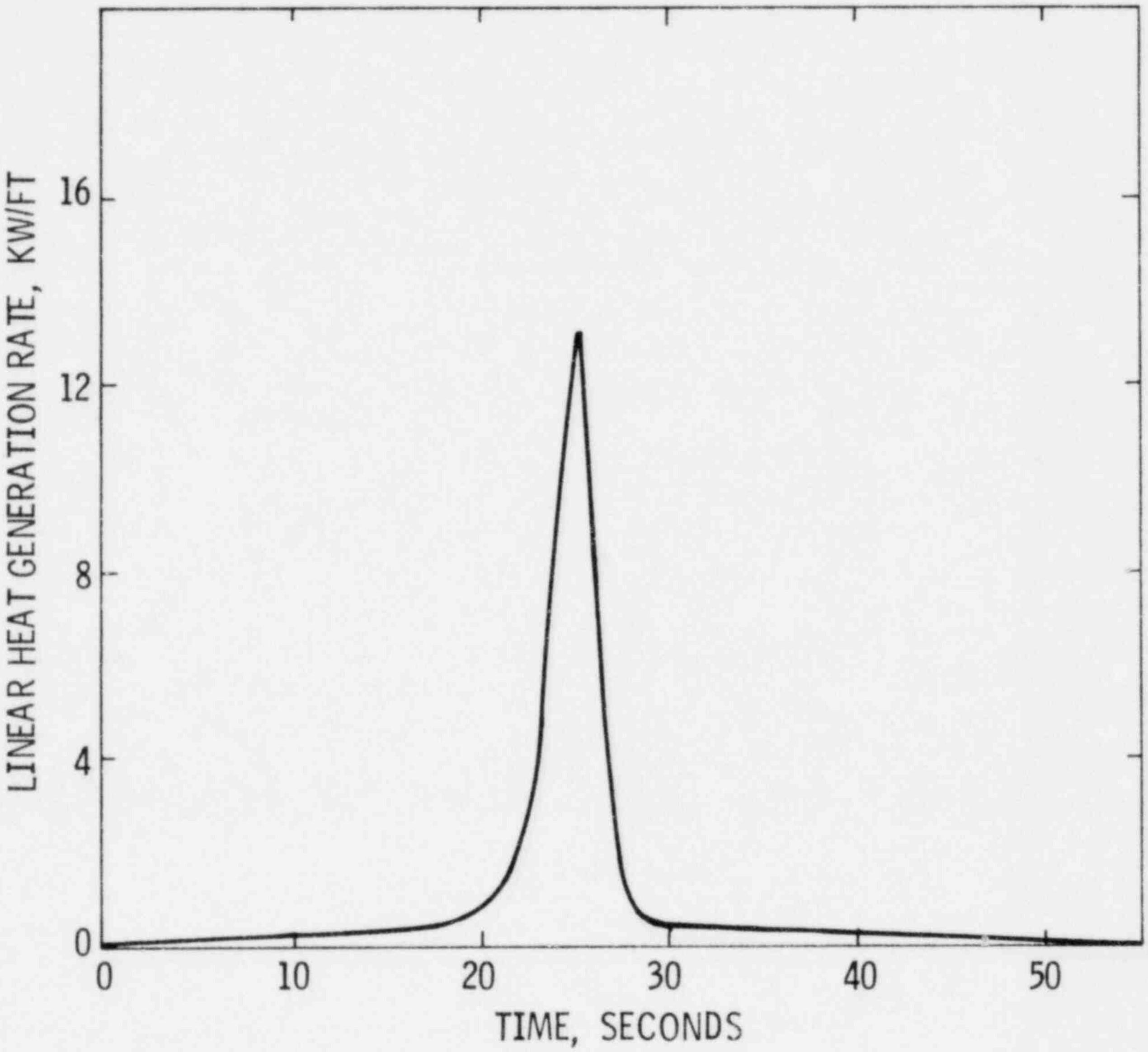
C-E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER STEAM GENERATOR PRESSURE vs TIME	Figure 15.4.1-7



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C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT LOW POWER LINEAR HEAT GENERATION RATE vs TIME	Figure 15.4.1-8

15.4.2 UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL AT POWER

15.4.2.1 Identification of Event and Causes

An uncontrolled sequential withdrawal of CEA's is assumed to occur as a result of a single failure in either the Control Element Drive Mechanism Control System (CEDMCS) or the Reactor Regulating System (RRS).

15.4.2.2 Sequence of Events and Systems Operation

Table 15.4.2-1 presents a chronological sequence of events which occur during a sequential CEA group withdrawal transient from the time the CEA's start to withdraw until the operator initiates cooldown. The corresponding success paths are given in the Sequence of Events diagram, Figure 15.4.2 Figure 15.0-1, which contains a glossary of SEA symbols and acronyms, may be used with Figure 15.4.2-1 to trace the actuation and interaction of the systems utilized to mitigate the consequences of this event. Table 15.4.2-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient.

The success paths in the Sequence of Events diagram in Figure 15.4.2-1 are as follows:

Reactivity Control:

As the CEA's are withdrawn, the core power level and thus, the RCS pressure increase. A low DNBR trip is generated, and the CEA's drop into the core. Once the plant parameters have been stabilized, the operator adjusts the boron concentration to insure that a proper negative reactivity shutdown margin is achieved prior to cooldown. This is accomplished using the Chemical Volume Control System (CVCS).

Reactor Heat Removal:

Following the cooldown phase, the shutdown cooling system (SCS) is manually actuated when the RCS temperature and pressure have been reduced to 350^{o}F and 400 psia, respectively. This system provides sufficient cooling flow to cool the RCS to cold shutdown.

Primary System Integrity:

During the pressure transient in the primary system, the pressurizer bubble acts to dampen the RCS pressure increase. The RCS pressure remains below the pressurizer pressure safety valve setpoint and remains less than 110% of design pressure. During the cooldown phase, the pressurizer pressure and level control systems may be used to regulate pressure and level in the primary system. When the RCS pressure has been reduced to approximately 650 psia, the operator will vent or drain the SIT's to reduce their pressure and will then isolate them. As the cooldown proceeds, the operator will reduce the safety injection actuation setpoint to prevent the inadvertent generation of an SIAS.

Secondary System Integrity:

Following the generation of a turbine trip on reactor trip, the Main Feedwater Control System (FWCS) enters the reactor trip override mode and reduces feedwater flow to 5% of nominal, full power flow. Since the Steam Bypass

Control System (SBCS) is assumed to be in manual mode with all bypass valves closed, the Main Steam Safety Valves (MSSV's) open to limit secondary system pressure and remove heat stored in the core and the RCS. Following the closure of the MSSV's, the FWCS is prevented from over-feeding the steam generators by the High-Level Override (HLO), which terminates feedwater flow until the steam generator level decreases to its nominal range. Once the plant parameters are stabilized, the operator initiates cooldown utilizing main feedwater and the SBCS. As the cooldown proceeds, the operator reduces the main steam isolation actuation setpoint to prevent the inadvertent generation of an MSIS. When steam pressure decreases to a point where the main feedwater pumps can no longer be used, the operator secures the main pumps. Cooldown is continued by utilizing one feedwater pump designated as "auxiliary" and intended for normal startup and shutdown of the plant in conjunction with SBCS. He may also let the ESFAS regulate the feedwater flow by issuing and withdrawing EFAS-1 and/or EFAS-2 signals down to cold shutdown entry conditions. See Applicant's FSAR for details of the Emergency and/or Auxiliary Feedwater Systems.

Table 15.4.2-3 contains a matrix which summarizes the utilization of the safety systems as they appear in this transient analysis.

15.4.2.3 Analysis of Effects and Consequences

A. Mathematical Mode

The Nuclear Steam Supply System (NSSS) response to a CEA group withdrawal at power was simulated using the CESEC-II computer program described in Section 15.0.3.

B. Input Parameters and Initial Conditions

Table 15.4.2-4 lists the assumptions and initial conditions used for this analysis in addition to those discussed in Section 15.0. These initial conditions (i.e., radial power peak, core flow, and inlet temperature) were chosen such that a reactor trip on low DNBR is actuated prior to or at the same time as trips on high pressurizer pressure or variable overpower would be initiated. The selection of these parameters in this manner minimizes the hot channel minimum DNBR.

The initial conditions and NSSS characteristics used in this analysis yield the minimum DNBR for any CEA group withdrawal incident. Parametric studies were performed on core inlet temperature, pressurizer pressure, and core flow. The studies indicated that minimum DNBR during the CEA withdrawal is most sensitive to initial core inlet temperture. Thus, the maximum allowable core inlet temperature was assumed. The RCS pressure was chosen so that the reactor was operating at a Power Operating Limit (POL) and was low enough to avoid a high pressurizer pressure trip. Thus, the conditions chosen yield the minimum DNBR for a CEA withdrawal at power.

The power level from which the withdrawal is initiated was assumed to be 102% of rated power. Minimum DNBR during the CEA withdrawal is more sensitive to high initial power levels. The initial core average axial power distribution for this analysis is a shape characterized by an axial shape index equal to -0.13. This distribution is assumed because it maximizes the shift of power to the top of the core during the transient, and, thus, minimizes the DNBR.

Other input parameters which are important to this analysis are the Moderator Temperature Coefficient (MTC) and Fuel Temperature Coefficient (FTC) of reactivity. A moderator temperature coefficient was assumed in this analysis which corresponds to beginning-of-life core conditions. This MTC has the smallest impact on retarding the rate of change of power, coolant temperature, and DNBR. A fuel temperature coefficient corresponding to beginning-of-life conditions was used in the analysis, since this FTC causes the least amount of negative reactivity change for mitigating the transient increases in core power, heat flux, and the reactor coolant temperatures. The uncertainty on the fuel temperature coefficients used in the analyses is listed in Table 15.4.2-4.

The regulating CEA position from which the CEA withdrawal is initiated corresponds to 25% insertion of the first regulating bank. This particular insertion was selected based on the calculated CEA worth and associated uncertainties to produce the worst transient. A corresponding maximum differential worth of 0.01% $\Delta\rho$ per inch of rod motion was conservatively assumed in the present analysis. This corresponds to a maximum reactivity withdrawal rate of 0.5×10^{-4} $\Delta\rho$ per second based on the maximum CEA withdrawal speed of 30 inches per minute, including all uncertainties.

All the control systems listed in Table 15.4.2-2, except the steam bypass control system, were assumed to be in the automatic mode since these systems have no impact on the minimum DNBR obtained during the transient. The steam bypass control system is assumed to be in manual mode because this minimizes DNBR during the transient.

C. Results

The dynamic behavior of important NSSS parameters following an uncontrolled CEA group withdrawal are presented in Figures 15.4.2-1 to 15.4.2-11.

The withdrawal of CEA's causes a positive reactivity change, resulting in an increase in the core power and heat flux. As a consequence, the reactor coolant temperature and pressurizer pressure increase. At 9.5 seconds after initiation of the transient, a reactor trip on low DNBR is actuated. At 9.7 seconds the trip breakers are opened. The CEA's begin dropping into the core 10.0 seconds which terminates the transient. The minimum DNBR reached during the transient is 1.19 at 11.0 seconds. If the maximum rod radial peaking factor occurs in the region of the axial power peak, the peak linear generation rate during the transient reaches 16.7 KW/ft. Table 15.4.2-1 lists the sequence of events for the limiting DNBR case.

15.4.2.4 Conclusions

The uncontrolled CEA withdrawal event meets general design criteria 25 and 20. These criteria require that the specified acceptable fuel design limits are not exceeded and the protection system action is initiated automatically. The withdrawal of CEA's from full power conditions meets meets the following fuel design limits which serve as the acceptance criteria for this event: the transient terminates with a hot channel minimum DNBR greater than or equal to 1.19 and the peak linear heat generation rate during the transient is less than 21 KW/ft.

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TABLE 15.4.2-1

SEQUENCE OF EVENTS FOR THE SEQUENTIAL CEA WITHDRAWAL EVENT

TIME(sec)	Event	SETPOINT OR VALUE	SUCCESS PATH
0.0	Withdrawal of CEA's - Initiating Event	--	Reactivity Control
9.5	Low DNBR Trip Signal	1.19	Reactivity Control
9.7	CEDM Power Supply Breakers Open	--	Reactivity Control
10.0	CEA's Begin to Drop	--	Reactivity Control
10.1	Maximum Core Power, % of Design Power	108.2	
11.0	Minimum DNBR	1.19	
11.4	Maximum Core Average Heat Flux, % of Full Power Heat Flux	105.6	
12.3	Maximum Pressurizer Pressure, psia	2363	

TABLE 15.4.2-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR THE SEQUENTIAL CEA WITHDRAWAL

AT FULL POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System	✓					
2. Main Feedwater Pump Turbine Control System*	✓					
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System		✓				
5. Pressurizer Pressure Control System	✓					
6. Pressurizer Level Control System	✓					
7. Control Element Drive Mechanism Control System	✓					1
8. Reactor Regulating System	✓					1
9. Core Operating Limit Supervisory System	✓					
10. Reactor Coolant Pumps	✓					
11. Chemical and Volume Control System	✓					
12. Secondary Chemistry Control System*	✓					
13. Condenser Evacuation System*	✓					
14. Turbine Gland Sealing System*	✓					
15. Nuclear Cooling Water System*	✓					
16. Turbine Cooling Water System*	✓					
17. Plant Cooling Water System*	✓					
18. Condensate Storage Facilities*	✓					
19. Circulating Water System*	✓					
20. Spent Fuel Pool Cooling and Clean-Up System*	✓					
21. Non-Class 1E (Non-ESF) A.C. Power*	✓					
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems

TABLE 15.4.2-2 (CONTINUED) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR THE SEQUENTIAL CEA WITHDRAWAL

AT FULL POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*	✓					
24. Class 1E D.C. Power*	✓					

Notes:

1. This system may be cause of initiating event.

*Balance-of-Plant Systems

TABLE 15.4.2-3

UTILIZATION OF SAFETY SYSTEMS

FOR THE SEQUENTIAL CEA WITHDRAWAL

AT FULL POWER

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems			✓		
4. Supplementary Protection System					1
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves	✓				
8. Main Steam Isolation System*			✓		
9. Emergency Feedwater System*			✓		
10. Safety Injection System					
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*			✓		
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*					
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

Notes:

1. Safety backup for safety system.

*Balance-of-Plant Systems

TABLE 15.4.2-4

ASSUMPTIONS AND INITIAL CONDITIONS
FOR THE SEQUENTIAL CEA WITHDRAWAL ANALYSIS

PARAMETER	Value
Core Power Level, MWt	3876
Core Inlet Temperature, ^{o}F	580
Core Mass Flow Rate, 10^6 lbm/hr	182.6
Reactor Coolant System Pressurizer, psia	2350
One Pin Radial Peaking Factor, with Uncertainty	1.77
Initial Core Minimum DNBR	1.52
Steam Generator Pressure, psia	1178
Doppler Coefficient Multiplier	0.85
CEA Worth at Trip, $10^{-2}\ \Delta\rho$	-10.0
Reactivity Insertion Rate, $10^{-4}\Delta\rho$/sec	0.5
CEA Withdrawal Spped, inches/min	30.0

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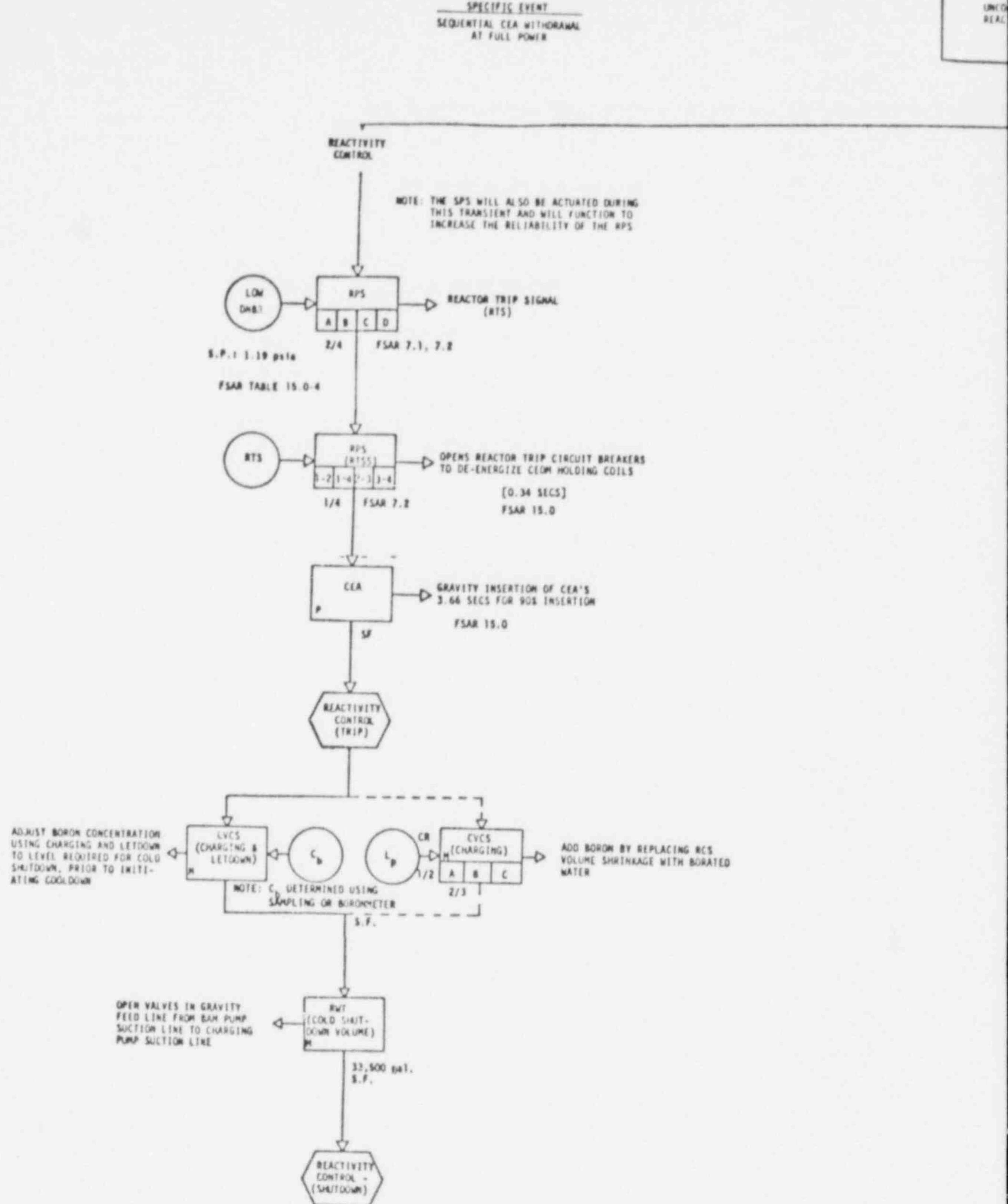
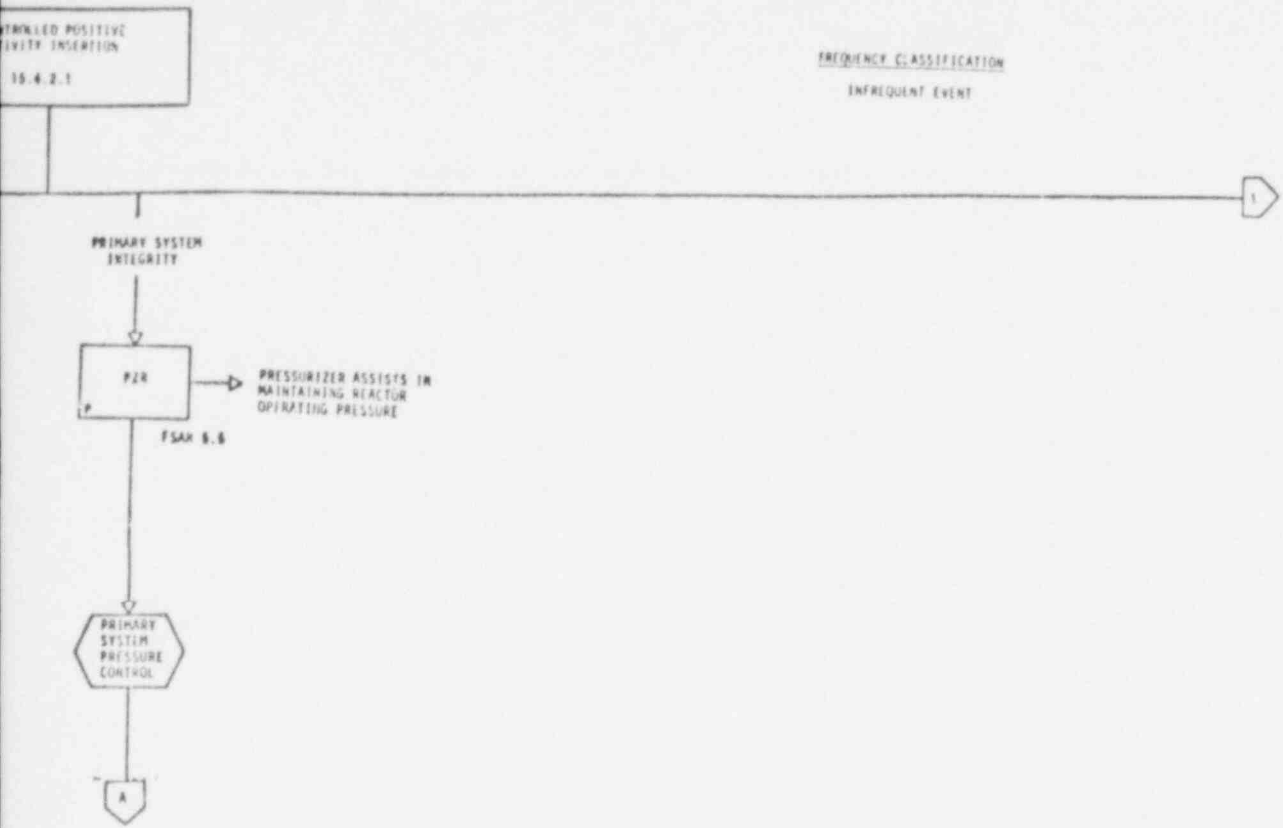
SPECIFIC EVENT

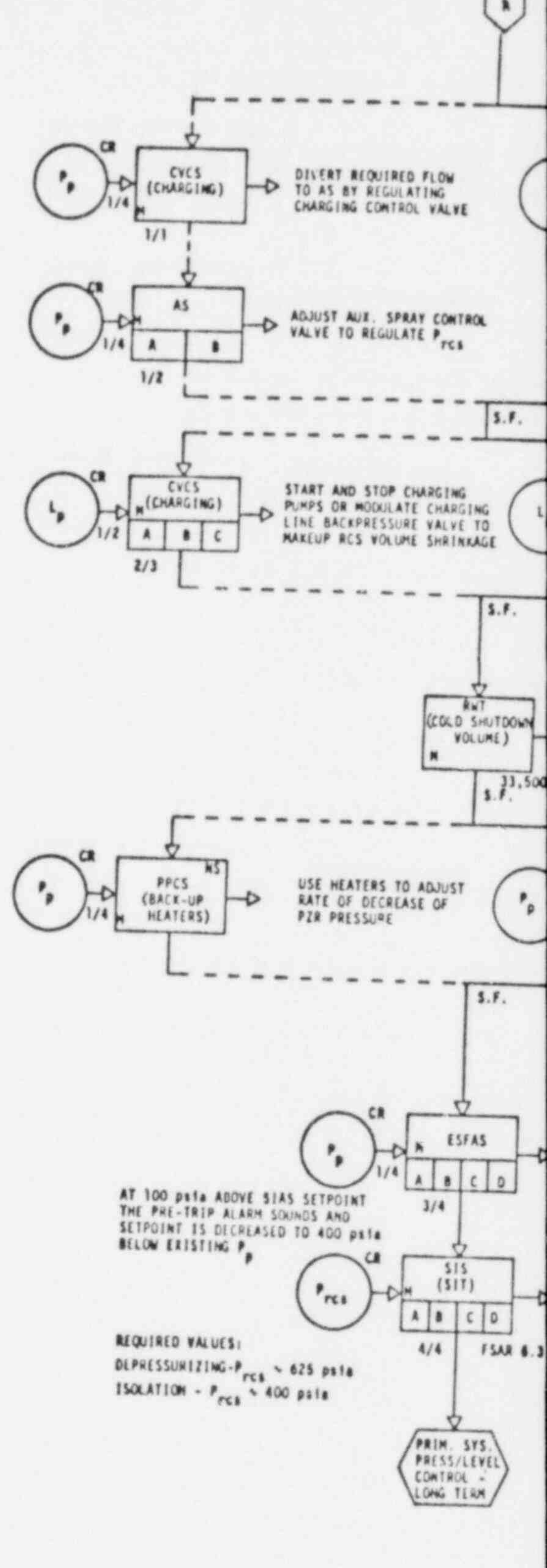
SEQUENTIAL CEA WITHDRAWAL
AT FULL POWER



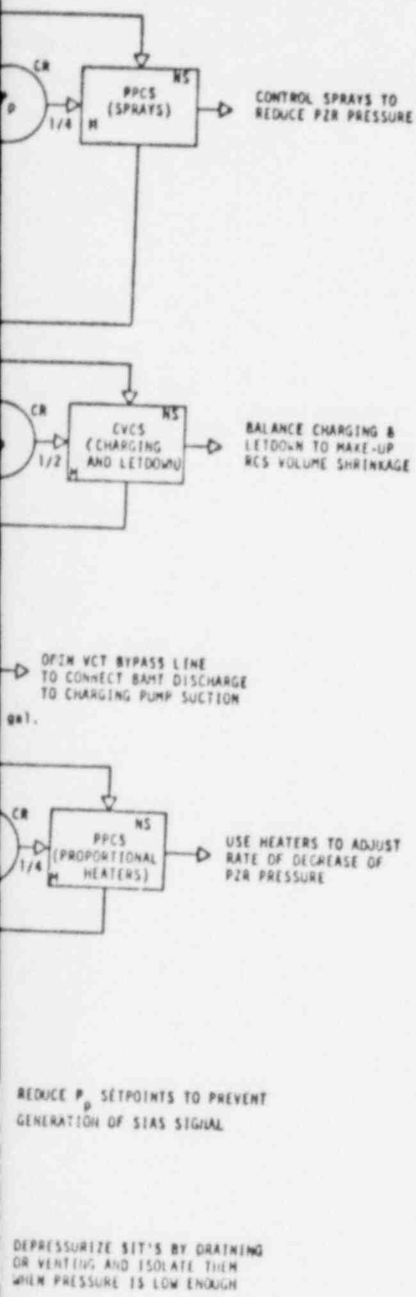


Amendment No. 7
March 31, 1982

C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL AT POWER	Figure 15.4.2 -1A

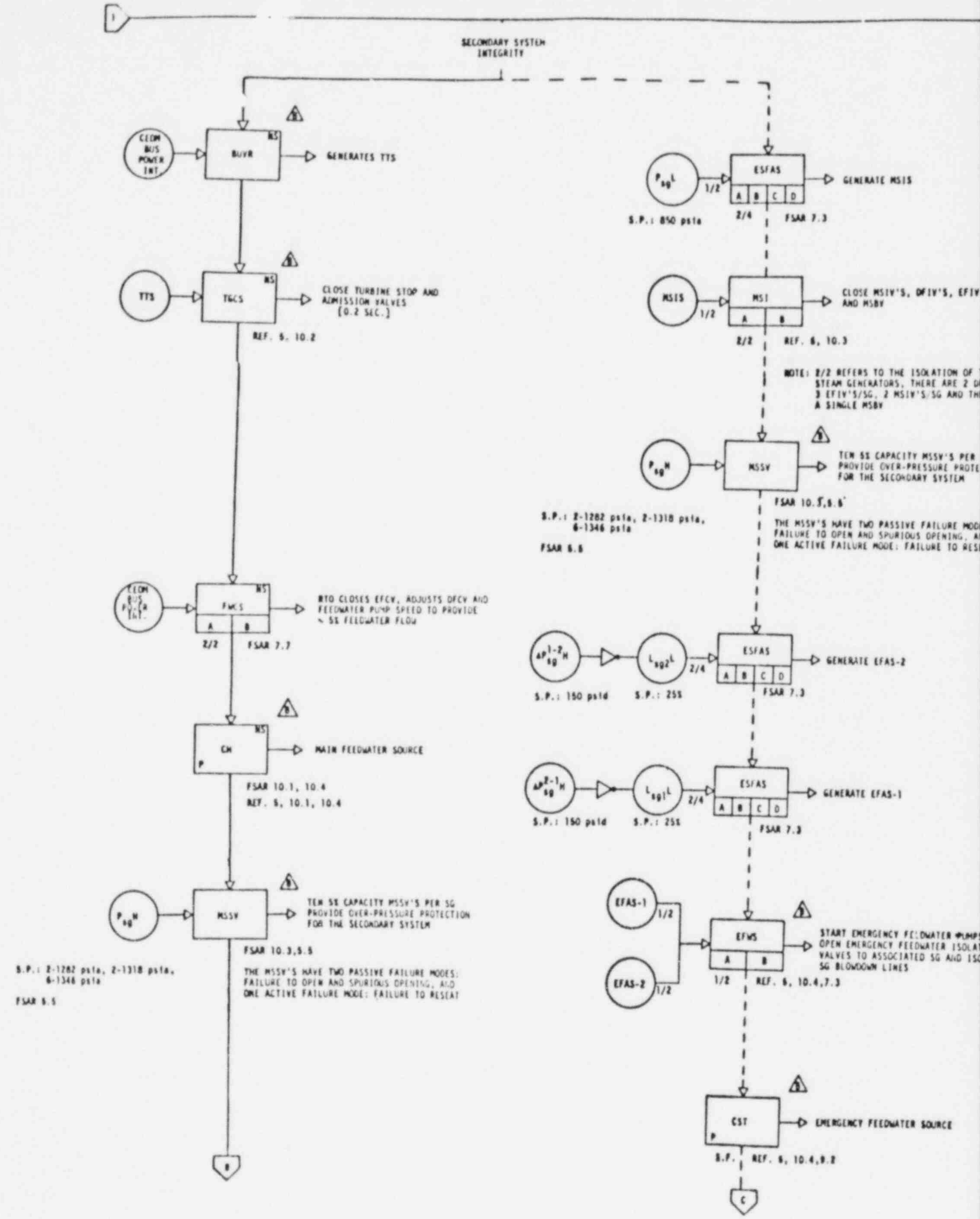


A
CR
P_p
1/4
CVCS (CHARGING)
M
1/1
DIVERT REQUIRED FLOW TO AS BY REGULATING CHARGING CONTROL VALVE
AS
A
B
1/2
ADJUST AUX. SPRAY CONTROL VALVE TO REGULATE P_{rcs}
S.F.
L_p
1/2
CVCS (CHARGING)
A
B
C
2/3
START AND STOP CHARGING PUMPS OR MODULATE CHARGING LINE BACKPRESSURE VALVE TO MAKEUP RCS VOLUME SHRINKAGE
RWT (COLD SHUTDOWN VOLUME)
33,500
PPCS (BACK-UP HEATERS)
NS
USE HEATERS TO ADJUST RATE OF DECREASE OF PZR PRESSURE
ESFAS
A
B
C
D
3/4
AT 100 psia ABOVE SIAS SETPOINT THE PRE-TRIP ALARM SOUNDS AND SETPOINT IS DECREASED TO 400 psia BELOW EXISTING P_p
P_{rcs}
SIS (SIT)
4/4
FSAR 6.3
REQUIRED VALUES:
DEPRESSURIZING-P_{rcs} ~ 625 psia
ISOLATION - P_{rcs} ~ 400 psia
PRIM. SYS. PRESS/LEVEL CONTROL - LONG TERM

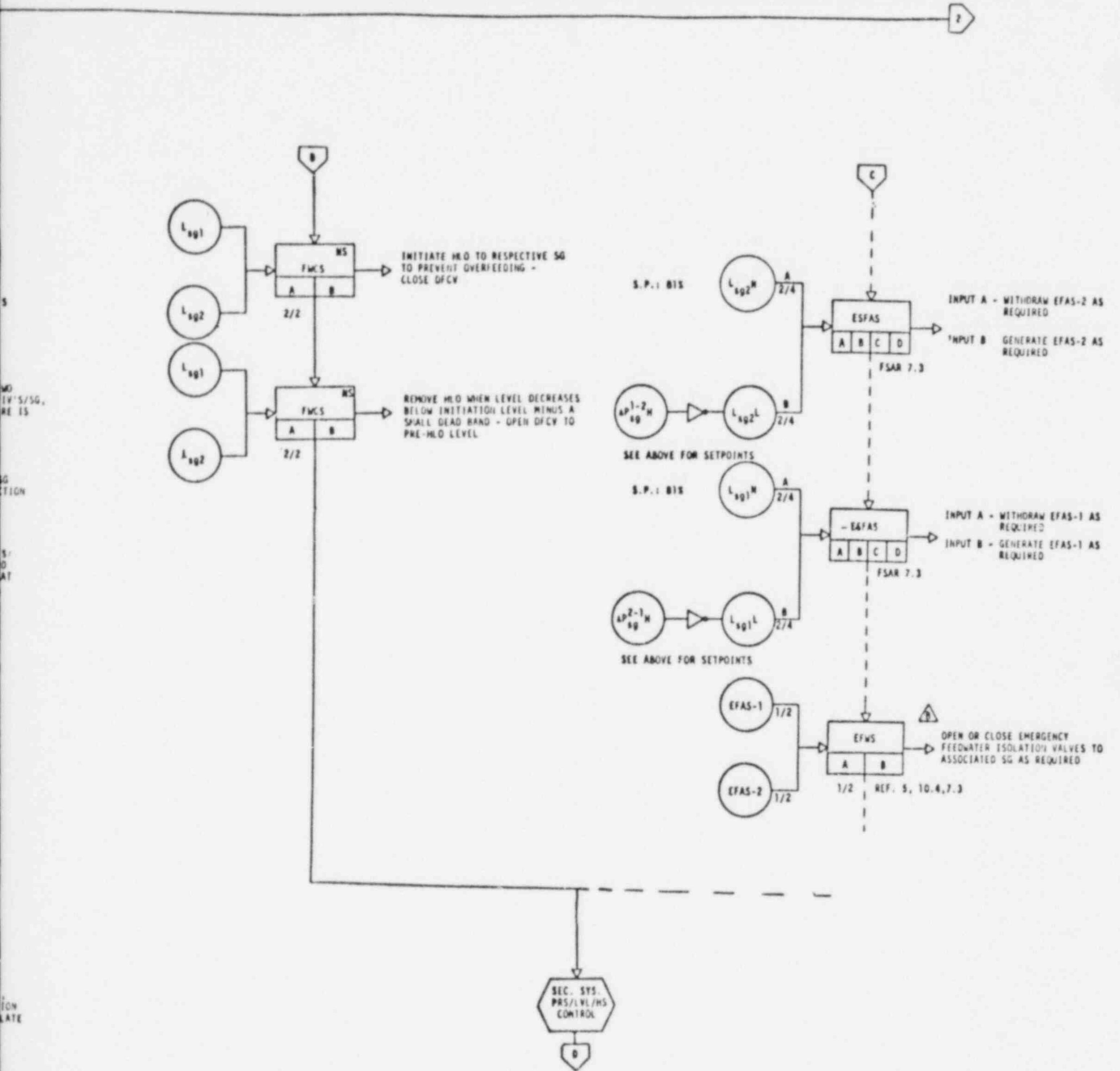


Amendment No. 7
March 31, 1982

C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL AT POWER	Figure 15.4.2 -1B



SECONDARY SYSTEM INTEGRITY
CEDM BUS POWER INT.
BUVR
NS
GENERATES TTS
TTS
TGCS
CLOSE TURBINE STOP AND ADMISSION VALVES (0.2 SEC.)
REF. 5, 10.2
CEDM BUS PWR INT.
FWCS
A
B
RTO CLOSES EFCV, ADJUSTS DFCV AND FEEDWATER PUMP SPEED TO PROVIDE ~ 5% FEEDWATER FLOW
2/2
FSAR 7.7
CH
P
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
MSSV
TEN 5% CAPACITY MSSV'S PER SG PROVIDE OVER-PRESSURE PROTECTION FOR THE SECONDARY SYSTEM
FSAR 10.3,5.5
THE MSSV'S HAVE TWO PASSIVE FAILURE MODES: FAILURE TO OPEN AND SPURIOUS OPENING, AND ONE ACTIVE FAILURE MODE: FAILURE TO RESEAT
S.P.: 2-1282 psia, 2-1318 psia, 6-1346 psia
FSAR 5.5
B
ESFAS
1/2
A
B
C
D
GENERATE MSIS
2/4
FSAR 7.3
S.P.: 850 psia
MSIS
MSI
CLOSE MSIV'S, DFIV'S, EFIV
AND MSBV
2/2
REF. 6, 10.3
NOTE: 2/2 REFERS TO THE ISOLATION OF T
STEAM GENERATORS, THERE ARE 2 D
3 EFIV'S/SG, 2 MSIV'S/SG AND TH
A SINGLE MSBV
MSSV
TEN 5% CAPACITY MSSV'S PER
PROVIDE OVER-PRESSURE PROTE
FOR THE SECONDARY SYSTEM
FSAR 10.3,5.5
THE MSSV'S HAVE TWO PASSIVE FAILURE MOD
FAILURE TO OPEN AND SPURIOUS OPENING, A
ONE ACTIVE FAILURE MODE: FAILURE TO RES
S.P.: 2-1282 psia, 2-1318 psia, 6-1346 psia
FSAR 5.5
ESFAS
GENERATE EFAS-2
S.P.: 150 psid
S.P.: 25%
FSAR 7.3
ESFAS
GENERATE EFAS-1
S.P.: 150 psid
S.P.: 25%
FSAR 7.3
EFAS-1
EFAS-2
EFWS
START EMERGENCY FEEDWATER PUMPS
OPEN EMERGENCY FEEDWATER ISOLAT
VALVES TO ASSOCIATED SG AND ISO
SG BLOWDOWN LINES
1/2
REF. 6, 10.4,7.3
CST
P
EMERGENCY FEEDWATER SOURCE
S.F.
REF. 6, 10.4,9.2
C



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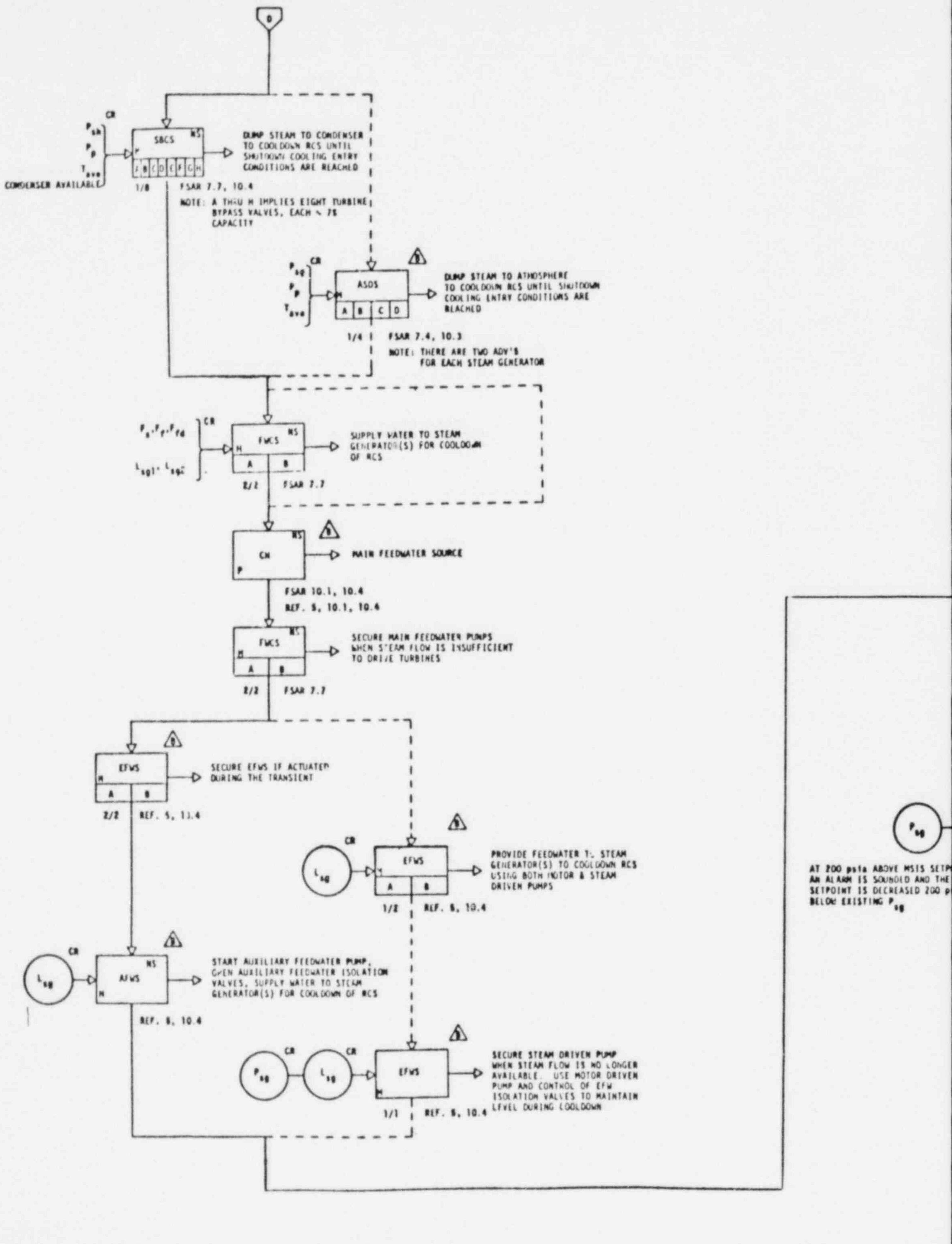
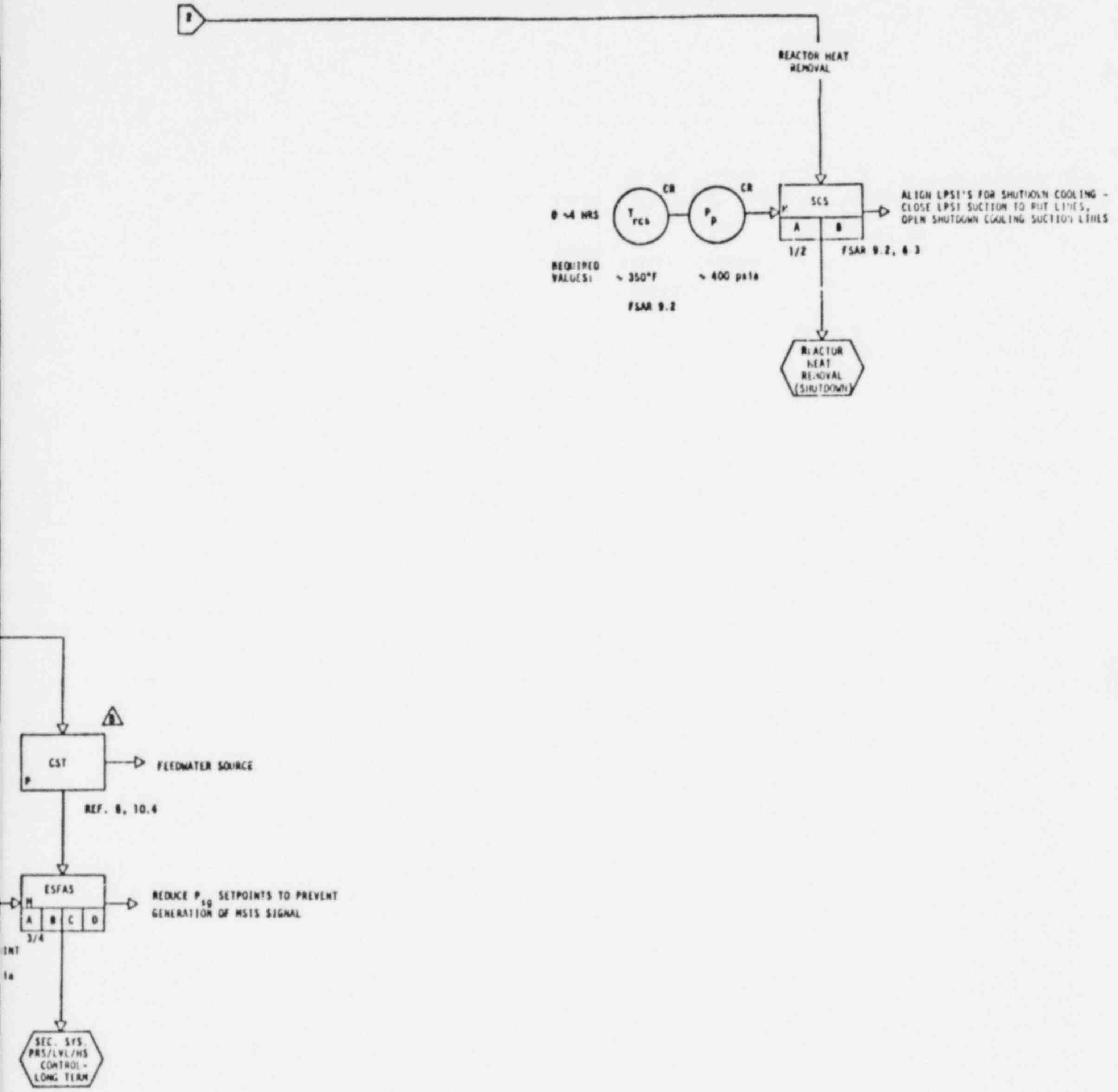
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL AT POWER	Figure 15.4.2 -1C


D
SBCS
NS
CR
P_{sh}
P_p
T_{ave}
CONDENSER AVAILABLE
DUMP STEAM TO CONDENSER TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
1/8
FSAR 7.7, 10.4
NOTE: A THRU H IMPLIES EIGHT TURBINE BYPASS VALVES, EACH ~ 7% CAPACITY
ASDS
P_{sg}
P_p
T_{ave}
DUMP STEAM TO ATMOSPHERE TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
1/4
FSAR 7.4, 10.3
NOTE: THERE ARE TWO ADV'S FOR EACH STEAM GENERATOR
FWCS
F_s, F_f, F_{fd}
L_{sg1}, L_{sg2}
SUPPLY WATER TO STEAM GENERATOR(S) FOR COOLDOWN OF RCS
2/2
FSAR 7.7
CW
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
FWCS
SECURE MAIN FEEDWATER PUMPS WHEN STEAM FLOW IS INSUFFICIENT TO DRIVE TURBINES
2/2
FSAR 7.7
EFWS
SECURE EFWS IF ACTUATED DURING THE TRANSIENT
2/2
REF. 5, 11.4
EFWS
L_{sg}
PROVIDE FEEDWATER TO STEAM GENERATOR(S) TO COOLDOWN RCS USING BOTH MOTOR & STEAM DRIVEN PUMPS
1/2
REF. 5, 10.4
AFWS
L_{sg}
START AUXILIARY FEEDWATER PUMP, OPEN AUXILIARY FEEDWATER ISOLATION VALVES, SUPPLY WATER TO STEAM GENERATOR(S) FOR COOLDOWN OF RCS
REF. 5, 10.4
EFWS
P_{sg}
L_{sg}
SECURE STEAM DRIVEN PUMP WHEN STEAM FLOW IS NO LONGER AVAILABLE. USE MOTOR DRIVEN PUMP AND CONTROL OF EFW ISOLATION VALVES TO MAINTAIN LEVEL DURING COOLDOWN
1/1
REF. 5, 10.4
P_{sg}
AT 200 psia ABOVE MSIS SETP
AN ALARM IS SOUNDED AND THE
SETPOINT IS DECREASED 200 p
BELOW EXISTING P_{sg}



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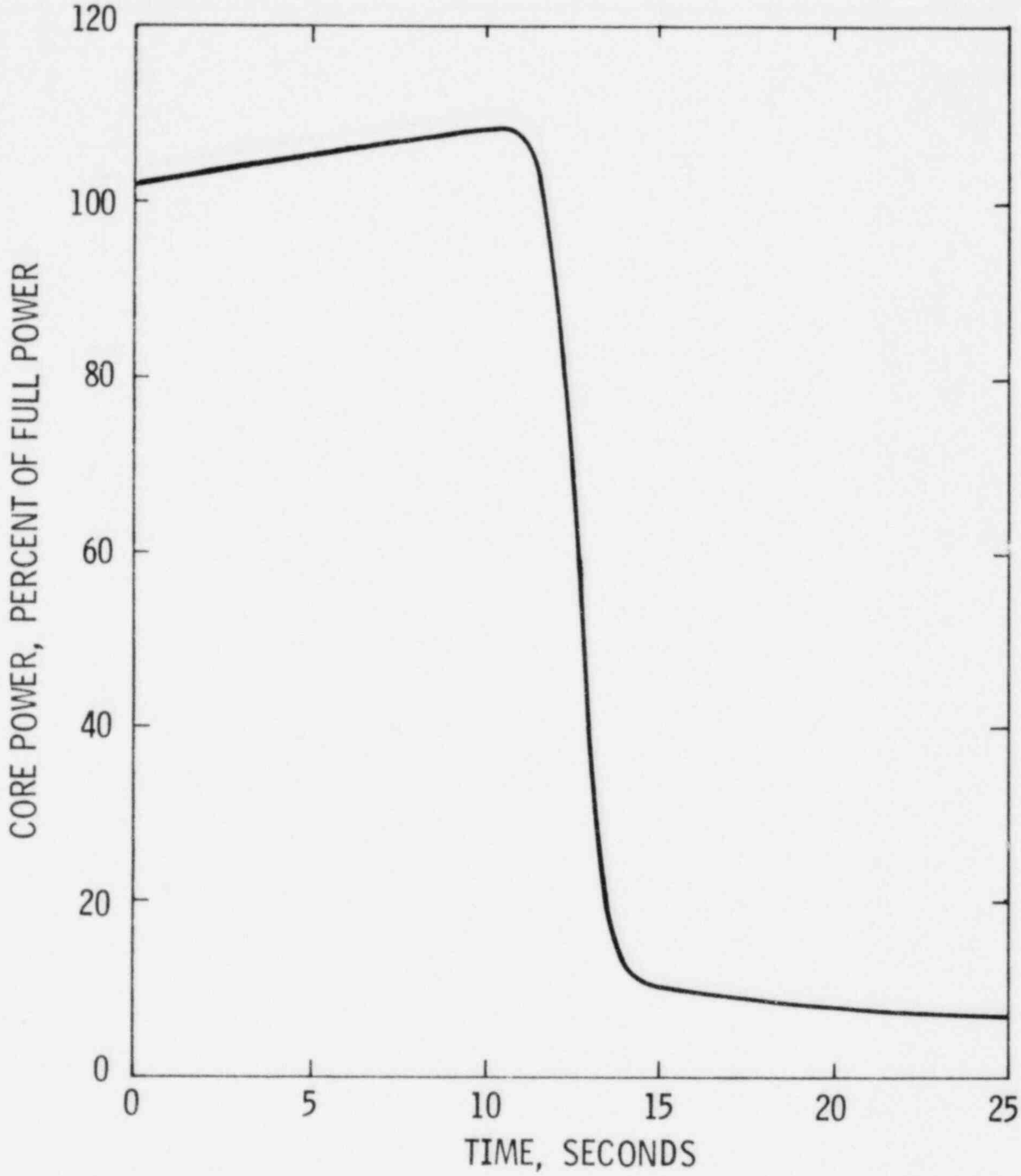
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR UNCONTROLLED CONTROL ELEMENT ASSEMBLY WITHDRAWAL AT POWER	Figure 15.4.2-1D



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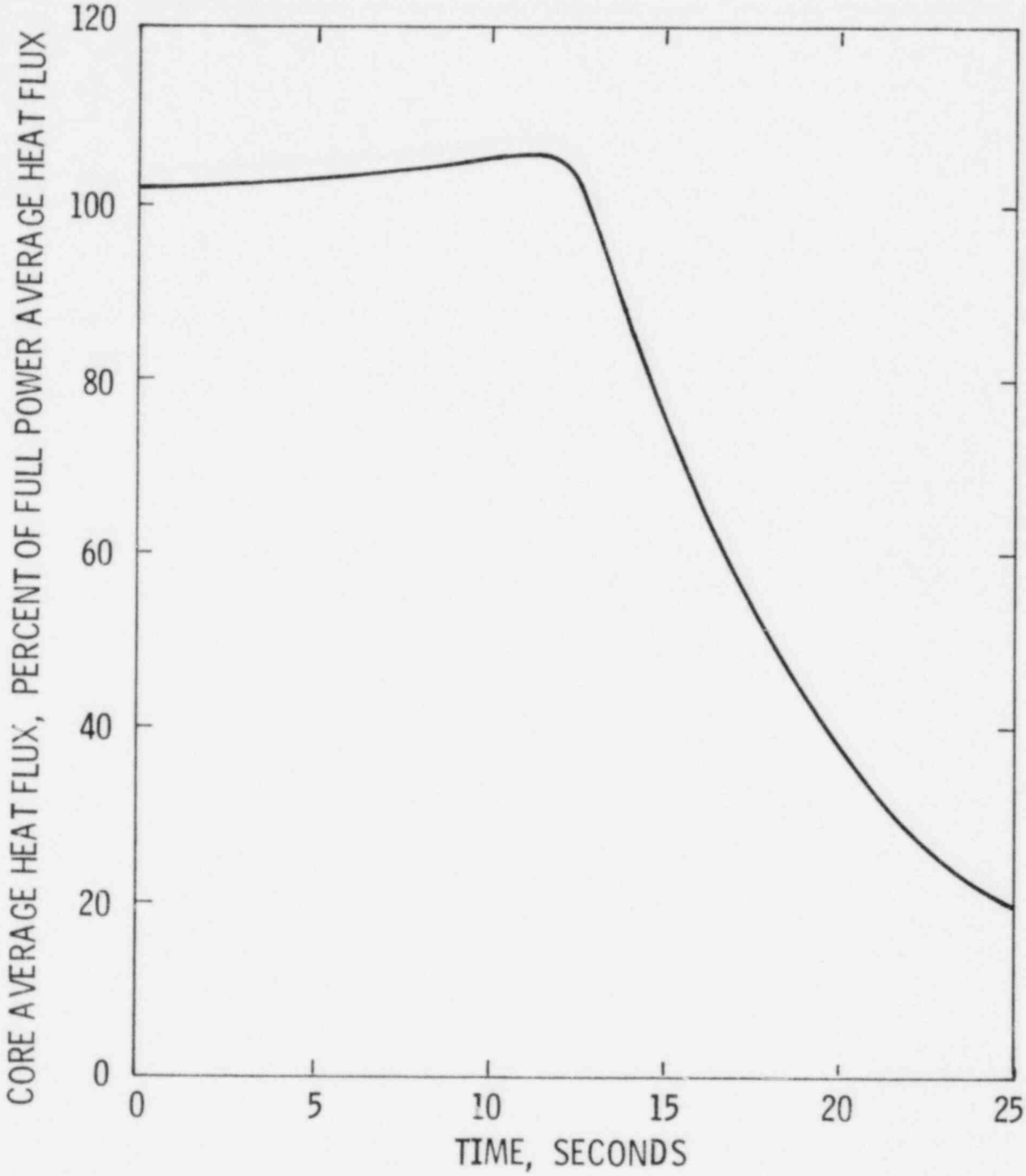
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER CORE POWER vs TIME	Figure 15.4.2-2



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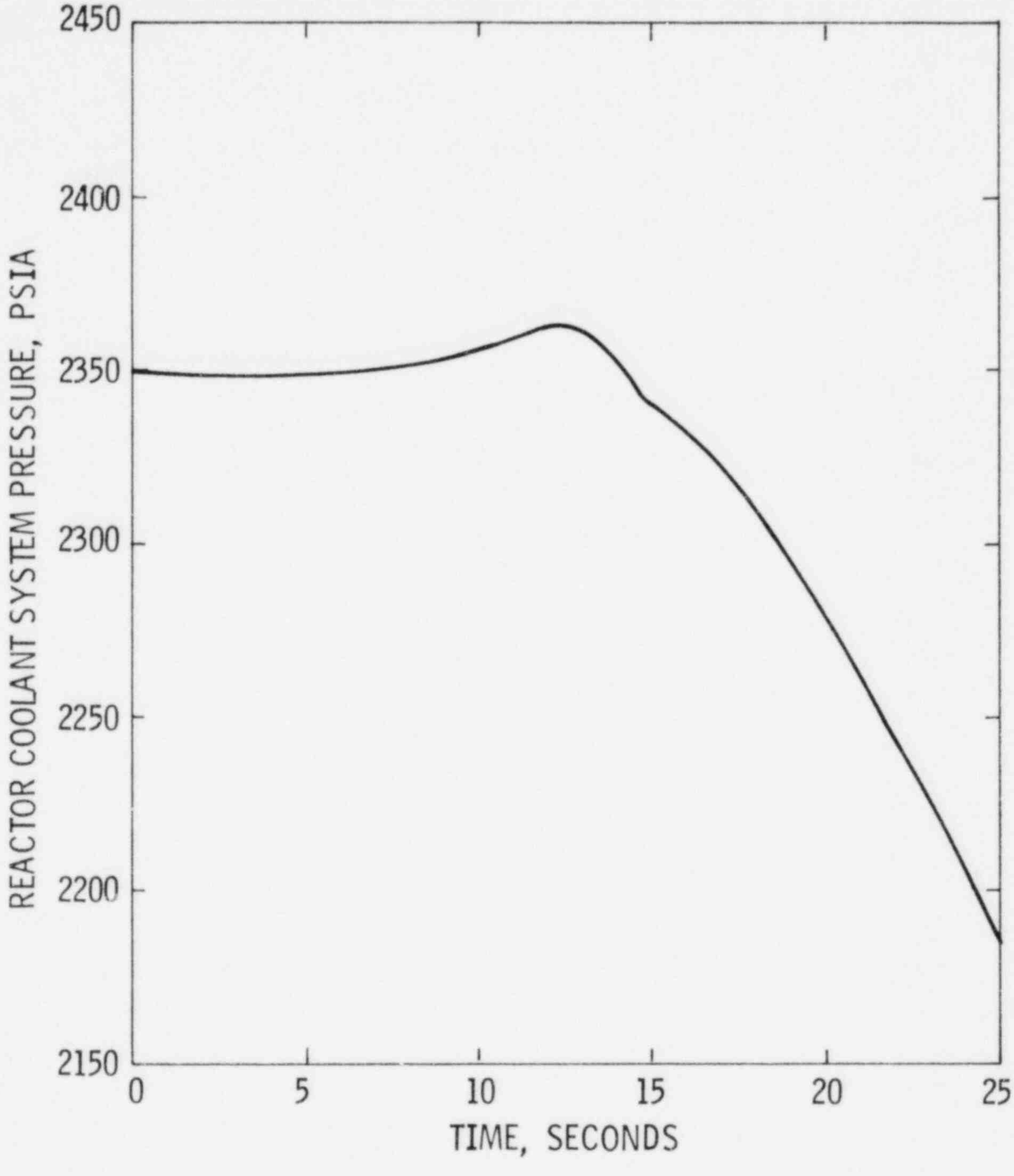
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER CORE AVERAGE HEAT FLUX vs TIME	Figure 15.4.2-3



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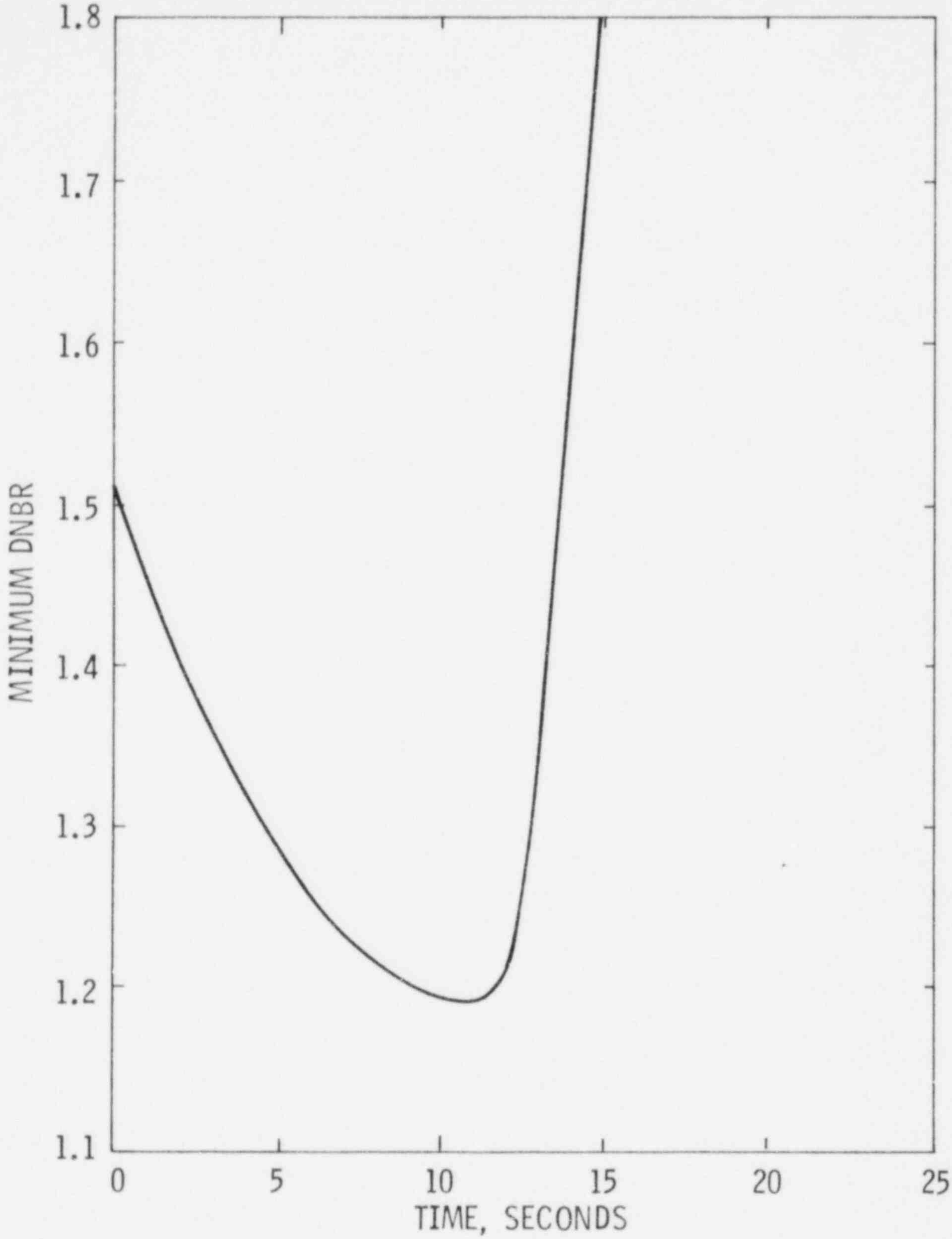
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER REACTOR COOLANT SYSTEM PRESSURE vs TIME	Figure 15.4.2-4



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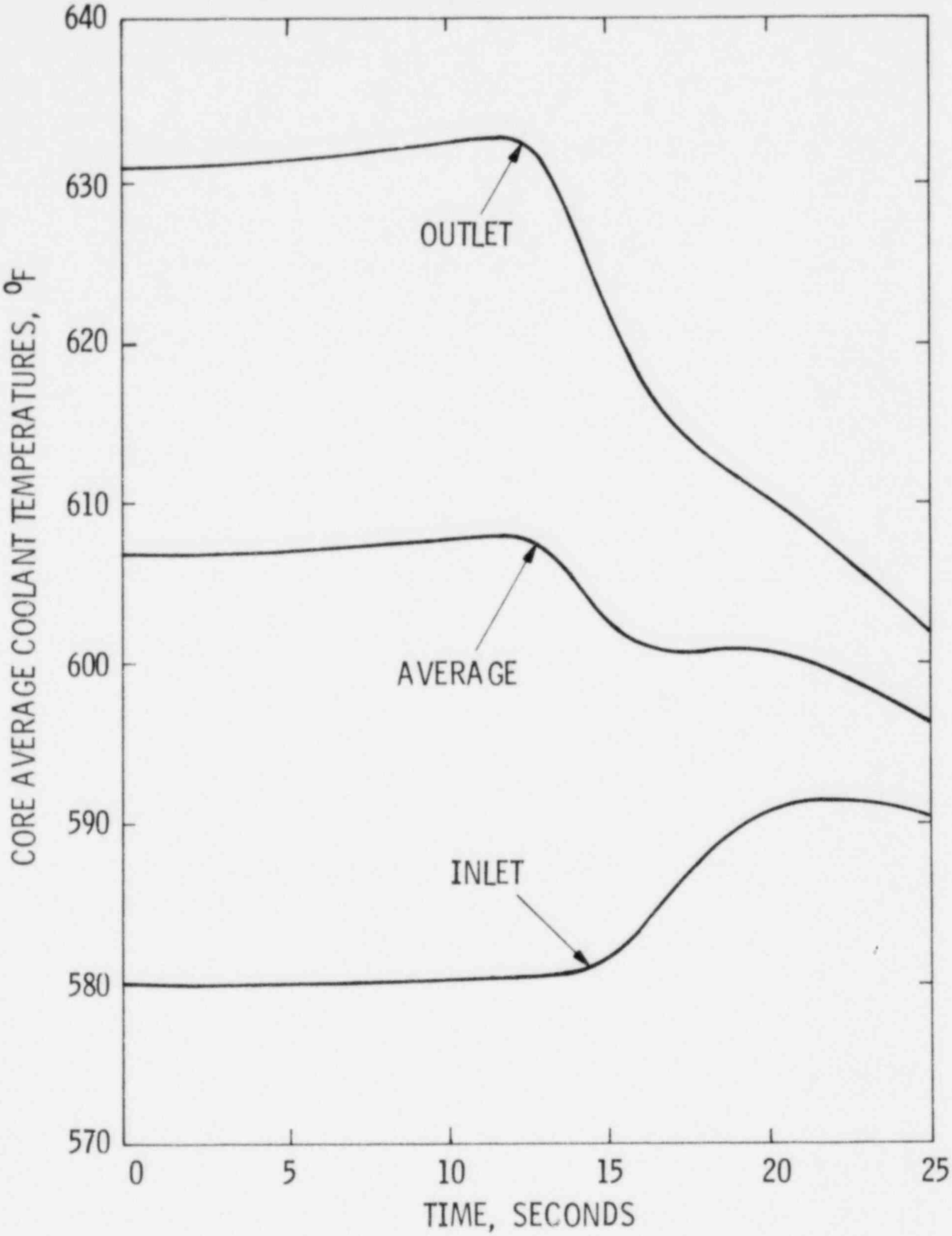
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER MINIMUM DNBR vs TIME	Figure 15.4.2-5



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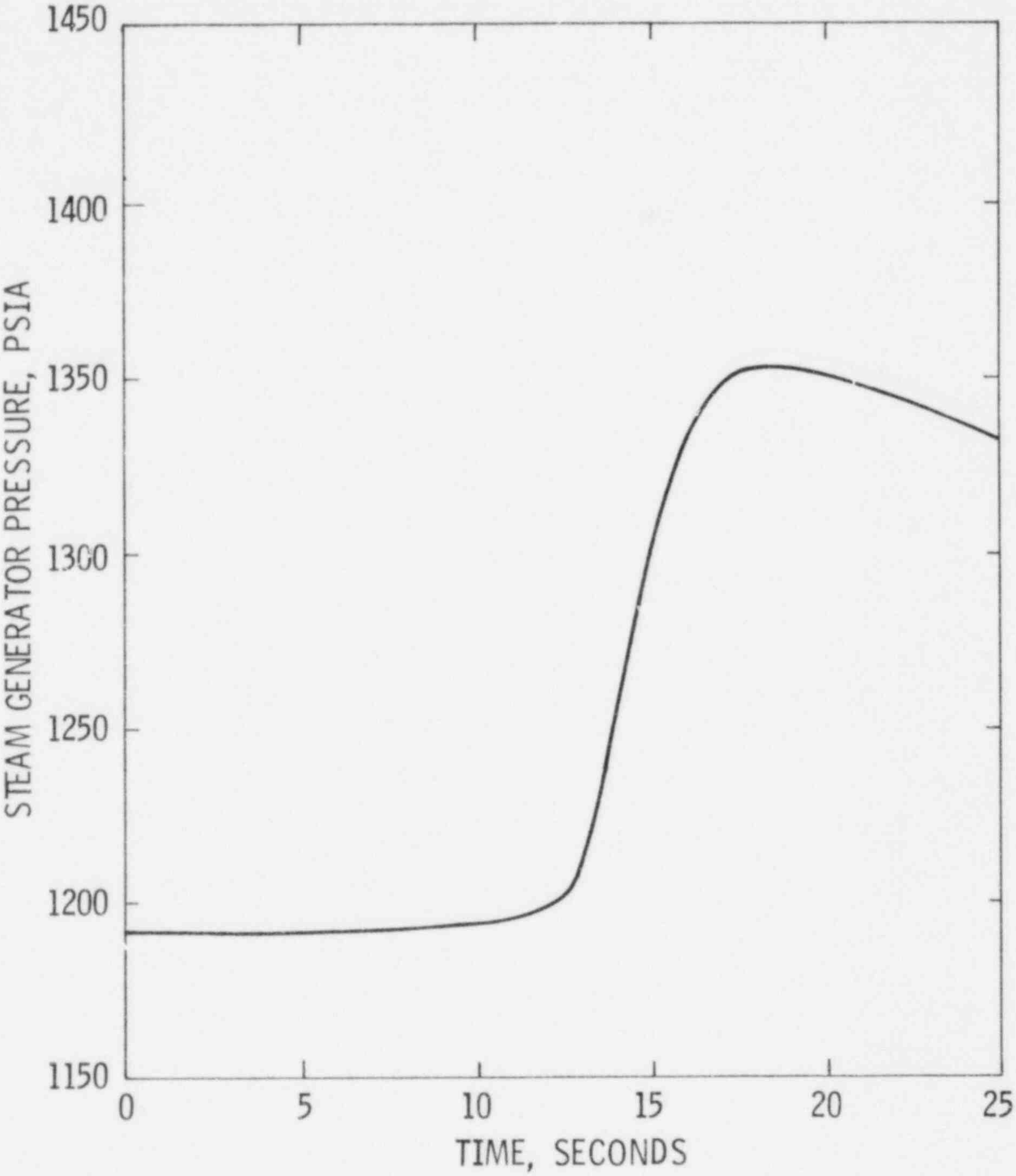
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER CORE AVERAGE COOLANT TEMPERATURES vs TIME	Figure 15.4.2-6



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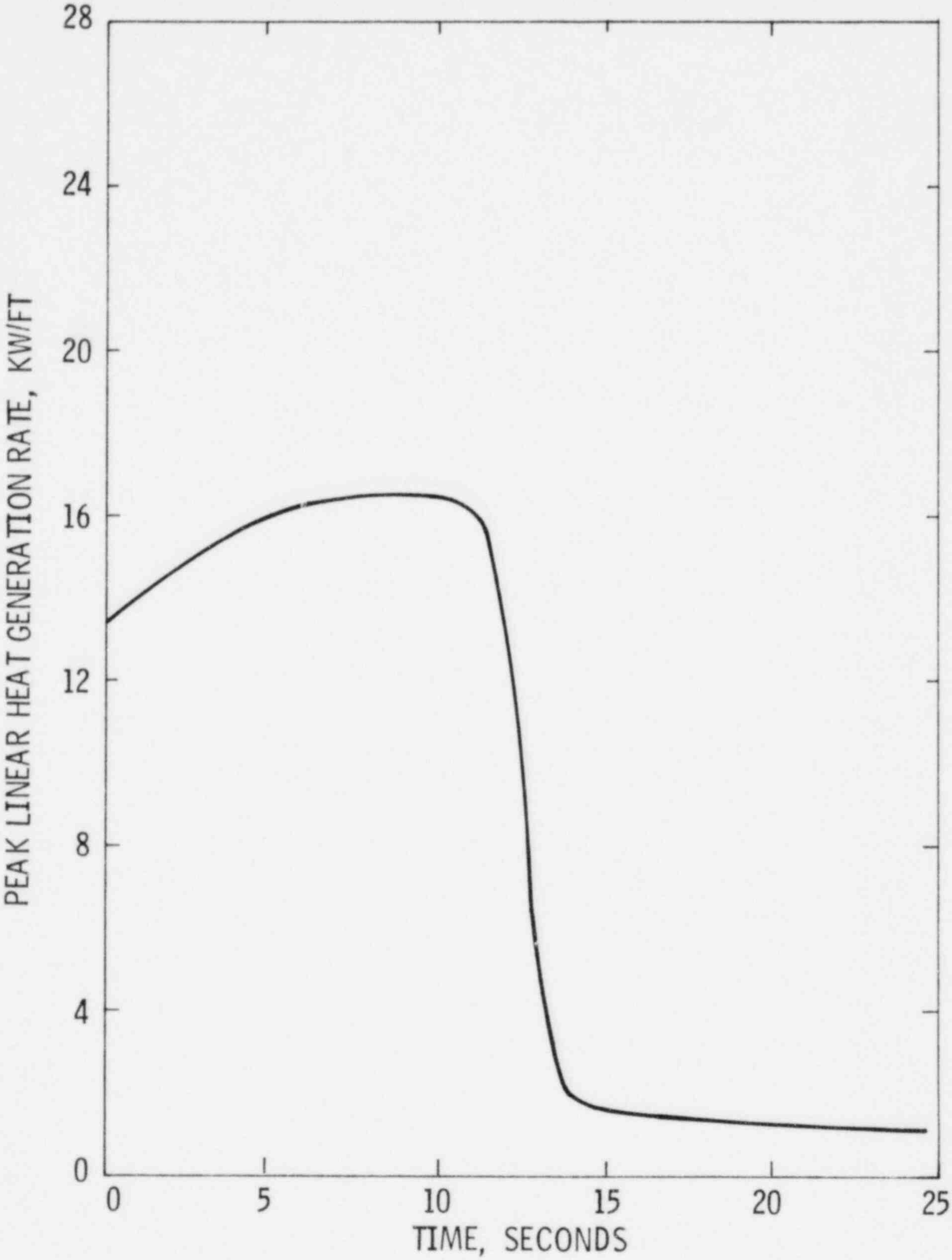
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER STEAM GENERATOR PRESSURE vs TIME	Figure 15.4.2-7



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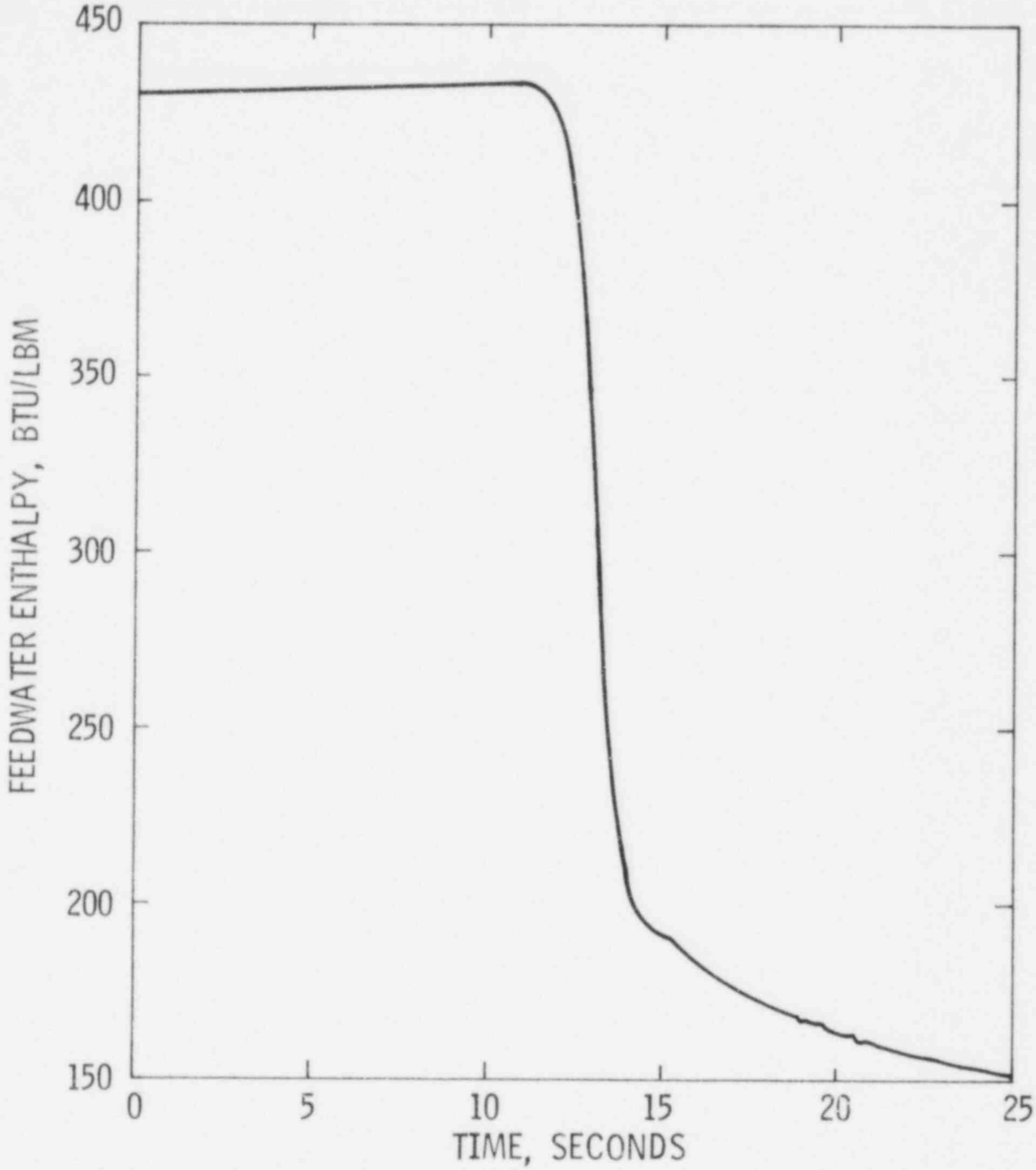
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER PEAK LINEAR HEAT GENERATION RATE	Figure 15.4.2-8



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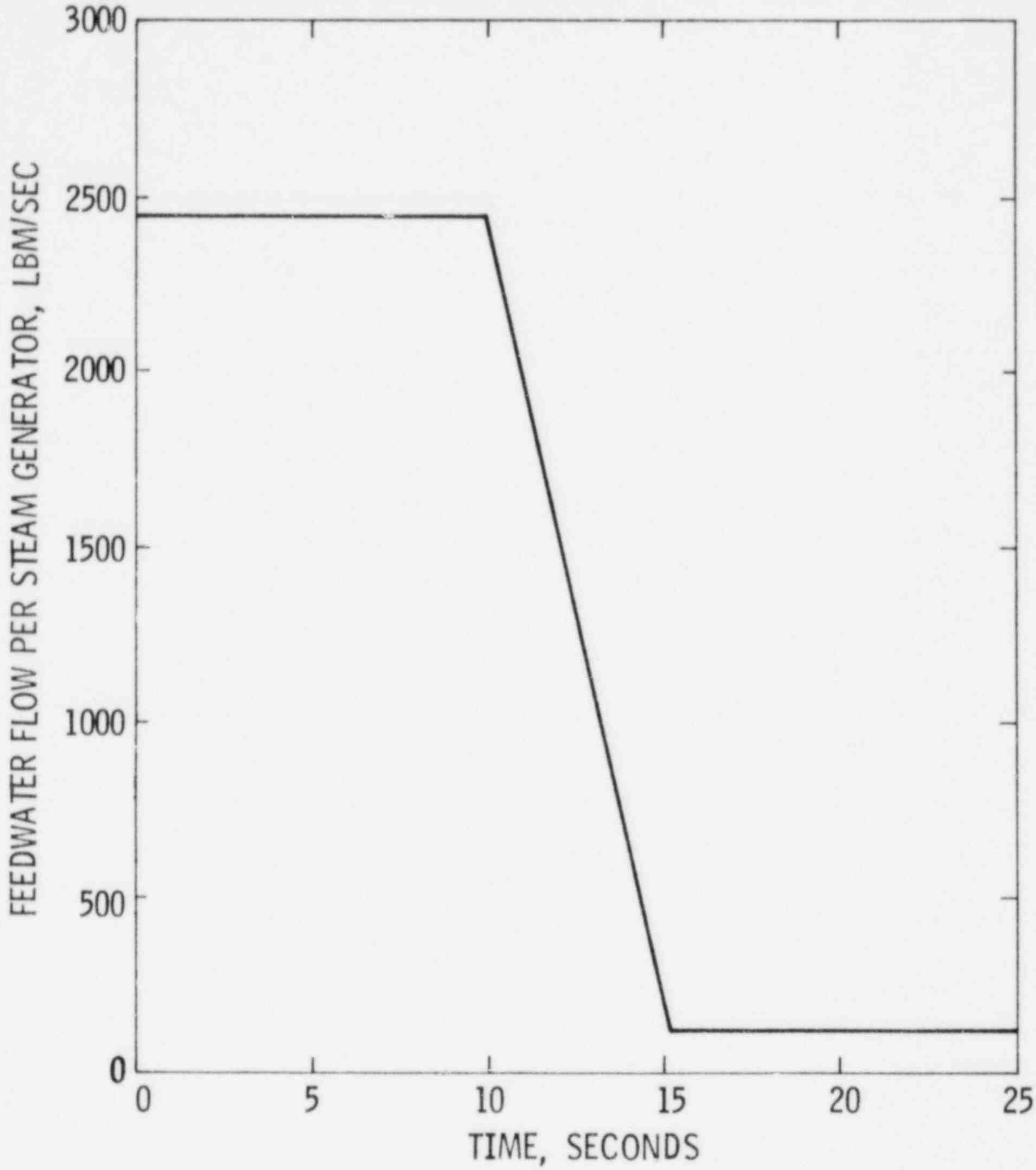
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER FEEDWATER ENTHALPY vs TIME	Figure 15.4.2-9



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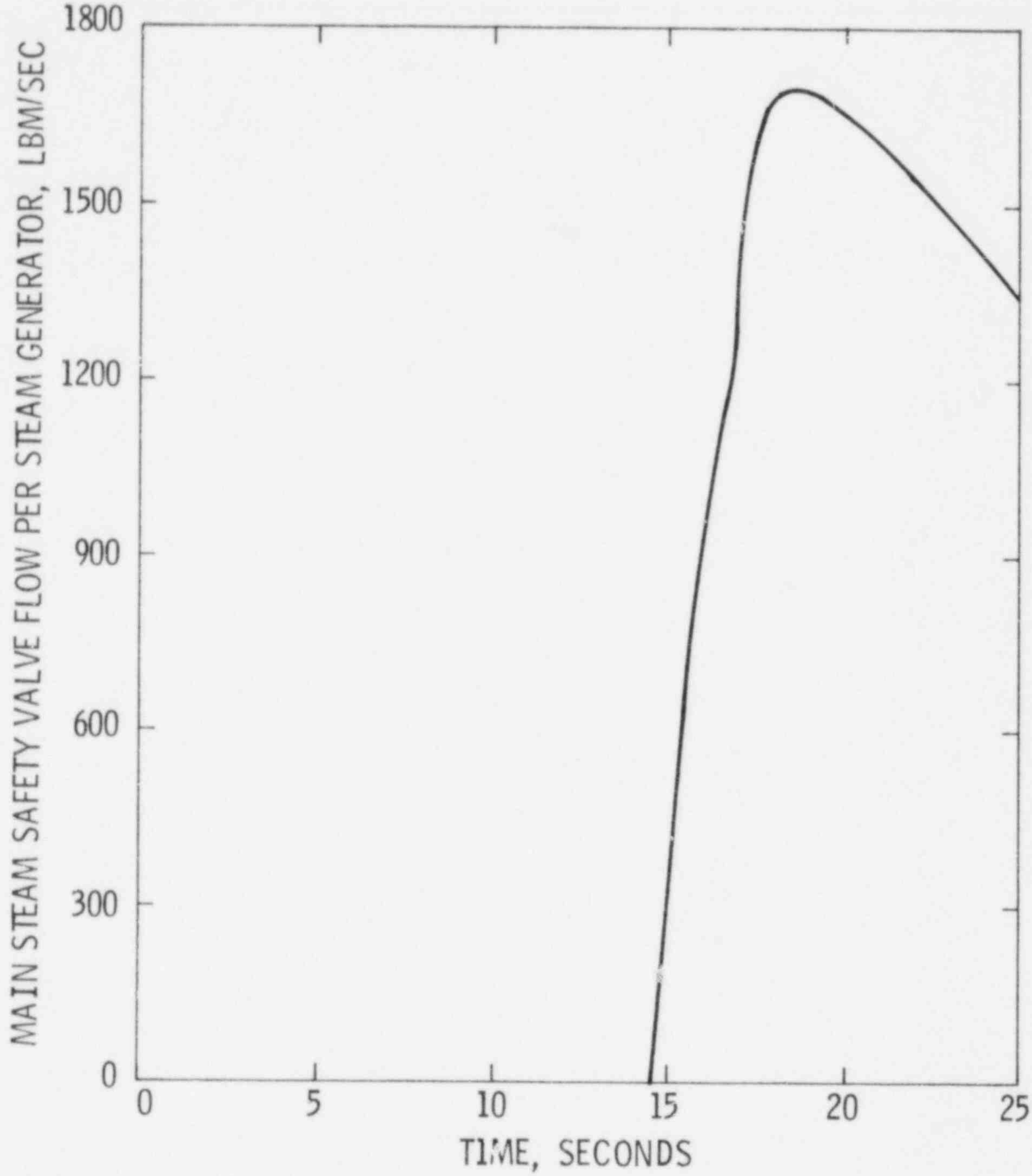
C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER FEEDWATER FLOW vs TIME	Figure 15.4.2-10



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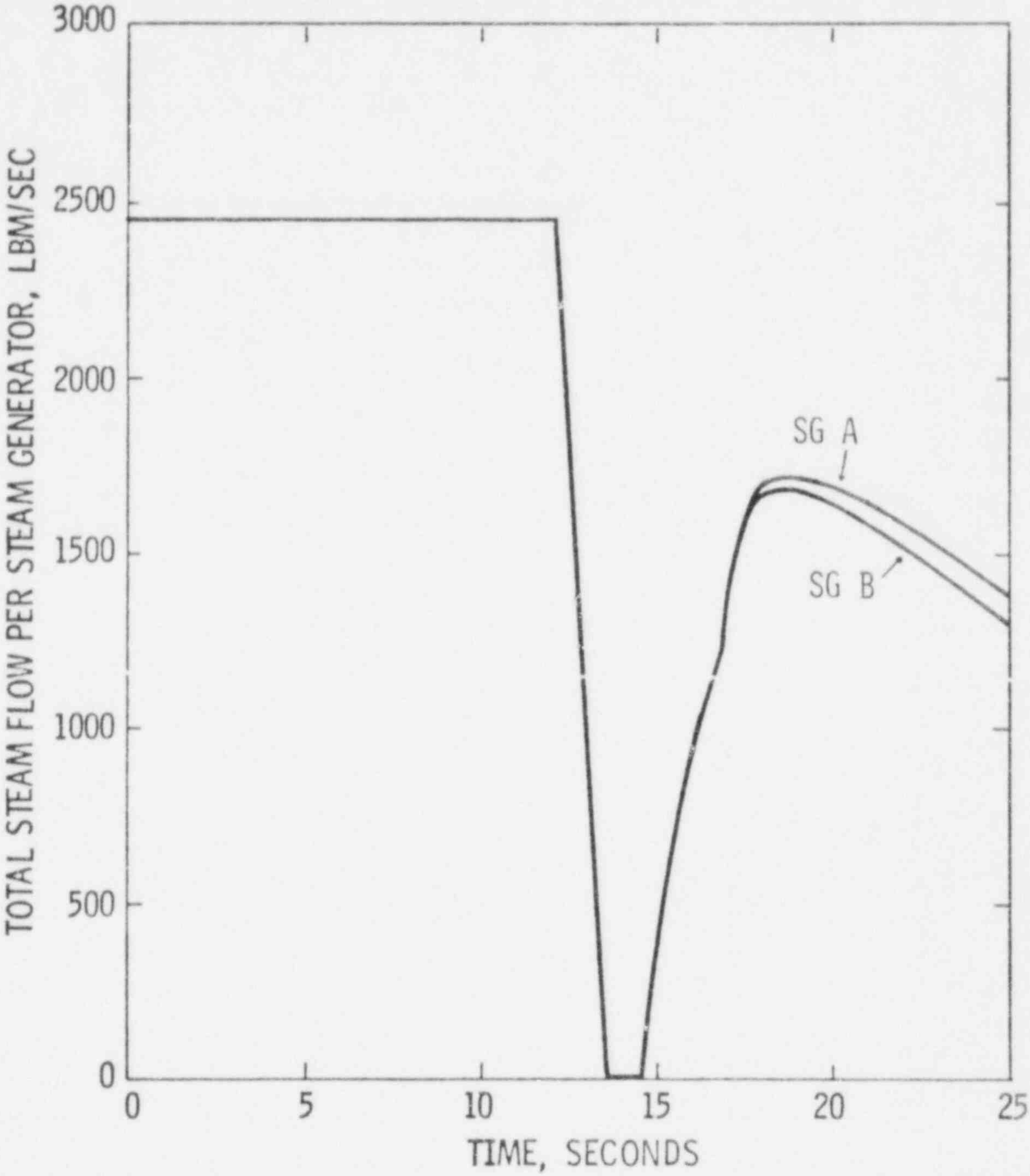
C-E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER MAIN STEAM SAFETY VALVE FLOW vs TIME	Figure 15.4.2-11



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C - E SYSTEM 80	SEQUENTIAL CEA WITHDRAWAL AT POWER TOTAL STEAM FLOW vs TIME	Figure 15.4.2-12

15.4.3 SINGLE FULL LENGTH CONTROL ELEMENT ASSEMBLY DROP

15.4.3.1 Identification of Event and Causes

A single full length CEA drop results from an interruption in the electrical power to the Control Element Drive Mechanism (CEDM) holding coil of a single full length CEA. This interruption can be caused by a holding coil failure or loss of power to the holding coil. The limiting case is the CEA drop which does not cause a trip to occur but results in an approach to the DNBR criterion of 1.19.

15.4.3.2 Sequence of Events and Systems Operation

The transient is initiated by the release and subsequent drop of a full length control element assembly. The resultant increase in the hot pin radial peaking factor coupled with a return to 102% of full power (following a temporary power depression) results in a minimum DNBR of 1.19 at approximately 36 seconds.

Table 15.4.3-1 presents a chronological list of events that occur during the single full length CEA drop transient, from initiation to the attainment of steady state conditions.

Table 15.4.3-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient analysis. No systems other than the normally operating systems are utilized to mitigate the consequences of this event.

15.4.3.3 Analysis of Effects and Consequences

A. Mathematical Model

The Nuclear Steam Supply (NSSS) response to the single full length CEA drop was simulated using the CESEC-II computer program described in Section 15.0.3. The time-dependent thermal margin on DNBR in the reactor core was calculated using the TORC computer program which uses the CE-1 critical heat flux correlation described in Chapter 4.

B. Input Parameters and Initial Conditions

Table 15.4.3-3 lists the assumptions and initial conditions used for this analysis in addition to those discussed in Section 15.0.

The sets of initial conditions (power, pressure, temperature, coolant flow rate, radial peaking factors, and axial power distribution) were chosen such that a minimum initial thermal margin was obtained. This initial thermal margin corresponds to a DNBR of 1.37. This was done so that the transient minimum DNBR could be determined as a function of the dropped rod radial peaking factor increase. This information was then used to select the maximum change in radial peaking factor which, in conjunction with the extreme initial conditions on other parameters, causes the DNBR to reach 1.19 without a reactor trip. For the initial conditions selected, if the radial peak increases are large enough to cause the Core Protection Calcualtors (CPC) to initiate a reactor trip, there is no appreciable decrease in thermal margin. Under the latter circumstances, both the local and core average power decrease;

therefore, none of the criteria are approached. For transients initiated at other sets of initial conditions, a trip may or may not be required depending on whether the initial thermal margin is as low for the combination of conditions used in this analysis.

The negative reactivity inserted by a dropped CEA causes the power to initially decrease everywhere in the core. With no reactor trip, the coolant inlet temperature and pressure will gradually decrease. Concurrently, the radial peaking factor will increase to an asymptotic post drop value. The decreasing coolant temperature combined with the negative doppler and moderator temperature coefficients causes a positive reactivity insertion which brings the core back to 102% power at the time of minimum DNBR.

To compute the minimum DNBR, the heat flux is based on the 102% power conditions and the asymptotic radial peaking factor existing at that time. However, for conservatism, it is assumed that the coolant inlet temperature and pressure are at their initial pre-transient values. This is conservative because the net effect of decreasing coolant temperature and pressure is to offset the degradation in DNBR caused by the higher post drop peaking factors. Figures 15.4.3-3 and 15.4.3-5 reflect the conservatism in that the changes in hot channel heat flux and DNBR shown are based only on the change in radial peak.

The Reactor Regulating System is assumed to be in the automatic mode. For this analysis, the choice of mode is inconsequential because there would be no regulating bank motion if the system were in manual mode; and in the automatic mode the CEA Withdrawal Prohibit (CWP), actuated on the DNBR pretrip signal, prevents the motion of any regulating bank following the drop of a single full length CEA which causes the CPC calculated DNBR to approach 1.19.

C. Results

The dynamic behavior of important NSSS parameters following the drop of a single full length CEA is presented in Figures 15.4.3-1 to 15.4.3-12. The full length CEA drop is characterized by a prompt decrease in core average and local power followed by an increasing distortion in radial power distribution. As the dropped CEA is detected by the CEA calculators, a conservative power distribution penalty factor is supplied as input to the CPC along with other measured process parameters. The sequence of events during the transient is enough to cause a reactor trip, then the reactivity feedbacks (due to the decreasing core inlet and average temperatures) cause the power (which was initially depressed immediately following the drop) to rise. The higher radial peaking factor, coupled with the core average power returning to its initial value, causes a decrease in DNBR.

The results of parametric analyses of the change in radial peak (distortion) indicate that an increase in the integrated radial peak of 6%, in conjuction with the assumed values of other initial parameters, can be tolerated without a reactor trip. Therefore, if the plant is operating at the assumed extreme initial conditions, the drop of a rod which causes an increase in the asymptotic radial peaking factor of greater than 6% would cause a reactor trip to occur. For transients initiated at other sets of initial conditions a trip may or may not be required depending on whether the initial thermal margin is as low as for the combination of conditions used in this analysis.

For the case in which a trip does not occur a minimum DNBR of 1.19 is reached at 36 seconds. The pressure drop beyond this point is arrested by the return to full power and a new steady state is reached at about 50 seconds. The peak centerline temperature obtained during the transient is less than 4000^{o}F. If the maximum rod radial peaking factor occurs in the region of the axial power peak, the peak linear heat generation rate during the transient reaches 12.5 KW/ft.

15.4.3.4 Conclusions

The single full length CEA drop event meets general design criteria 25 and 20. These criteria require that the specified acceptable fuel design limits are not exceeded and the protection system action is initiated automatically. The drop of a CEA meets the following fuel design limits which serve as the acceptance criteria for this event: the transient terminates with a hot channel minimum DNBR greater than or equal to 1.19 and the peak linear heat generation rate during the transient is less than 21 KW/ft.

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TABLE 15.4.3-1

SEQUENCE OF EVENTS FOR THE SINGLE FULL LENGTH CEA DROP EVENT

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	A Single Full Length CEA Begins to Drop	--	--
22.0	Minimum Pressurizer Pressure, psia	2048	--
36.0	Minimum DNBR	1.19	--
380.0	Maximum Pressurizer	2077	--

TABLE 15.4.3-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR THE SINGLE FULL LENGTH

CEA DROP

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System	✓					
2. Main Feedwater Pump Turbine Control System*	✓					
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System	✓					
5. Pressurizer Pressure Control System	✓					
6. Pressurizer Level Control System	✓					
7. Control Element Drive Mechanism Control System	✓					1
8. Reactor Regulating System	✓					
9. Core Operating Limit Supervisory System	✓					
10. Reactor Coolant Pumps	✓					
11. Chemical and Volume Control System	✓					
12. Secondary Chemistry Control System*	✓					
13. Condenser Evacuation System*	✓					
14. Turbine Gland Sealing System*	✓					
15. Nuclear Cooling Water System*	✓					
16. Turbine Cooling Water System*	✓					
17. Plant Cooling Water System*	✓					
18. Condensate Storage Facilities*	✓					
19. Circulating Water System*	✓					
20. Spent Fuel Pool Cooling and Clean-Up System*	✓					
21. Non-Class 1E (Non-ESF) A.C. Power*	✓					
22. Class 1E (ESF) A.C. Power*	✓					
*Balance-of-Plant Systems -						

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR THE SINGLE FULL LENGTH

CEA DROP

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*	✓					
24. Class 1E D.C. Power*	✓					

NOTES:

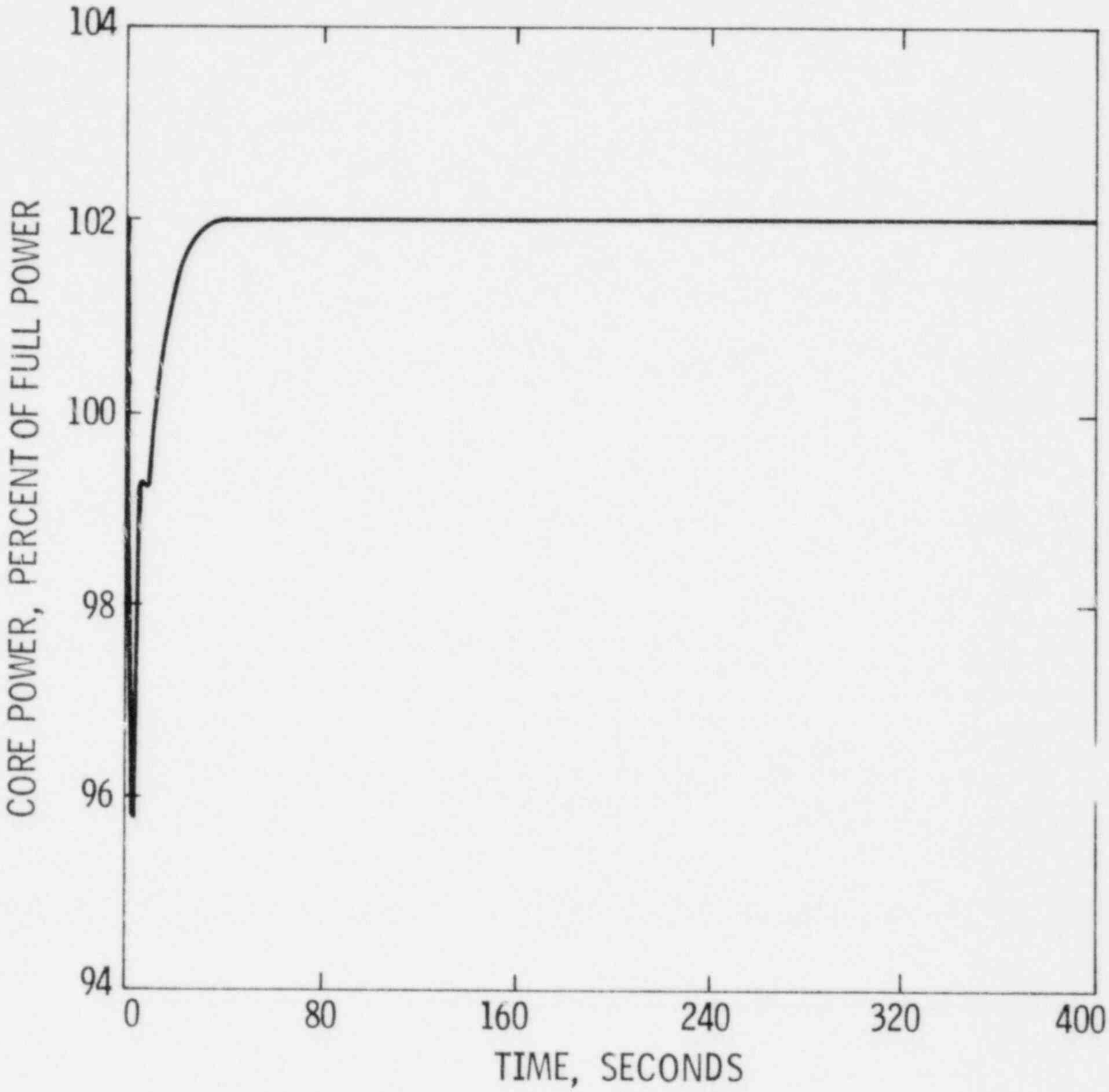
1. A single-failure within this system may be responsible for the initiation of this event.

*Balance-of-Plant Systems

TABLE 15.4.3-3

ASSUMPTIONS AND INITIAL CONDITIONS FOR THE SINGLE FULL LENGTH CONTROL ELEMENT ASSEMBLY DROP

Parameter	Value
Core Power Level, Mwt	3876
Core Inlet Coolant Temperature, $^{\circ}F$	580
Core Mass Flowrate, 10^6 lbm/hr	145.2
Pressurizer Pressure, psia	2067
Steam Generator Pressure, psia	1199
Axial Shape Index	-0.3
Core Minimum DNBR	1.37
Integrated Radial Heat Flux Peak	1.34
Integrated Radial Peaking Factor at Time of Minimum DNBR	1.43
Dropped CEA Reactivity Worth, 10^{-2}	-0.06
Time for Dropped CEA to be Fully Inserted, sec	2.0
Doppler Coefficient Multiplier	1.15



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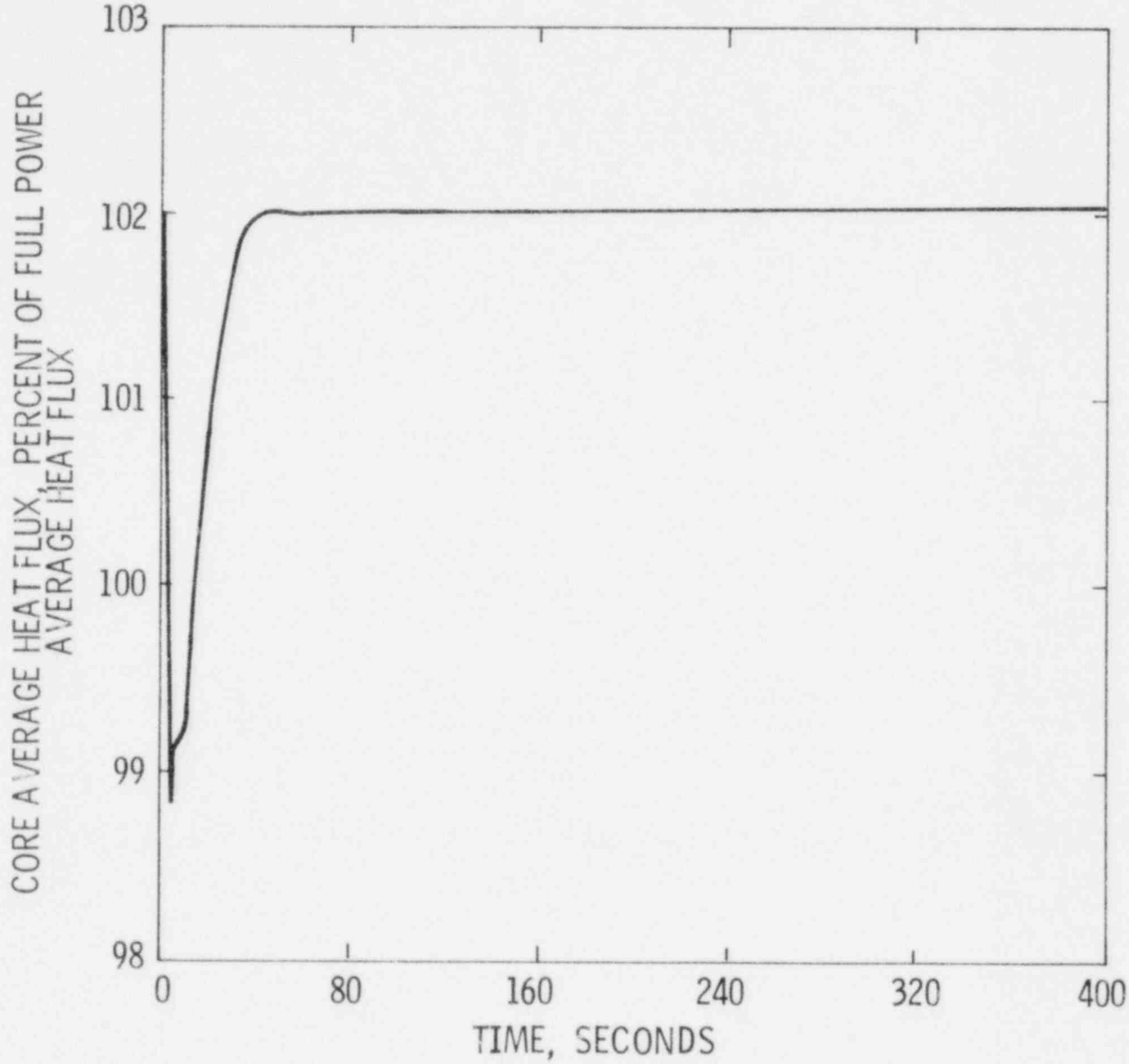
C - E SYSTEM 80	SINGLE FULL LENGTH CEA DROP CORE POWER vs TIME	Figure 15.4.3-2



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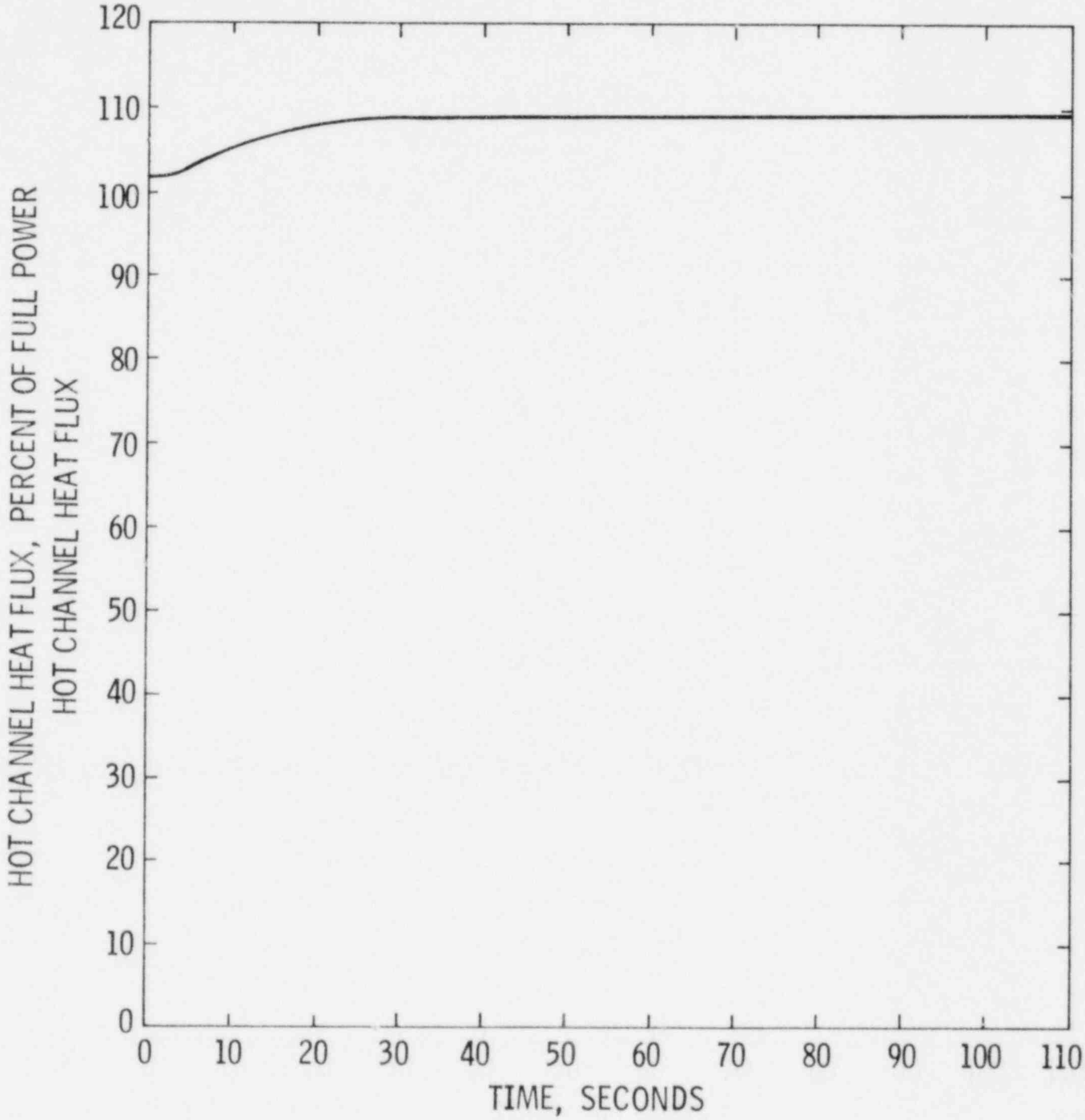
C-E SYSTEM 80	SINGLE FULL LENGTH CEA DROP CORE AVERAGE HEAT FLUX vs TIME	Figure 15.4.3-3



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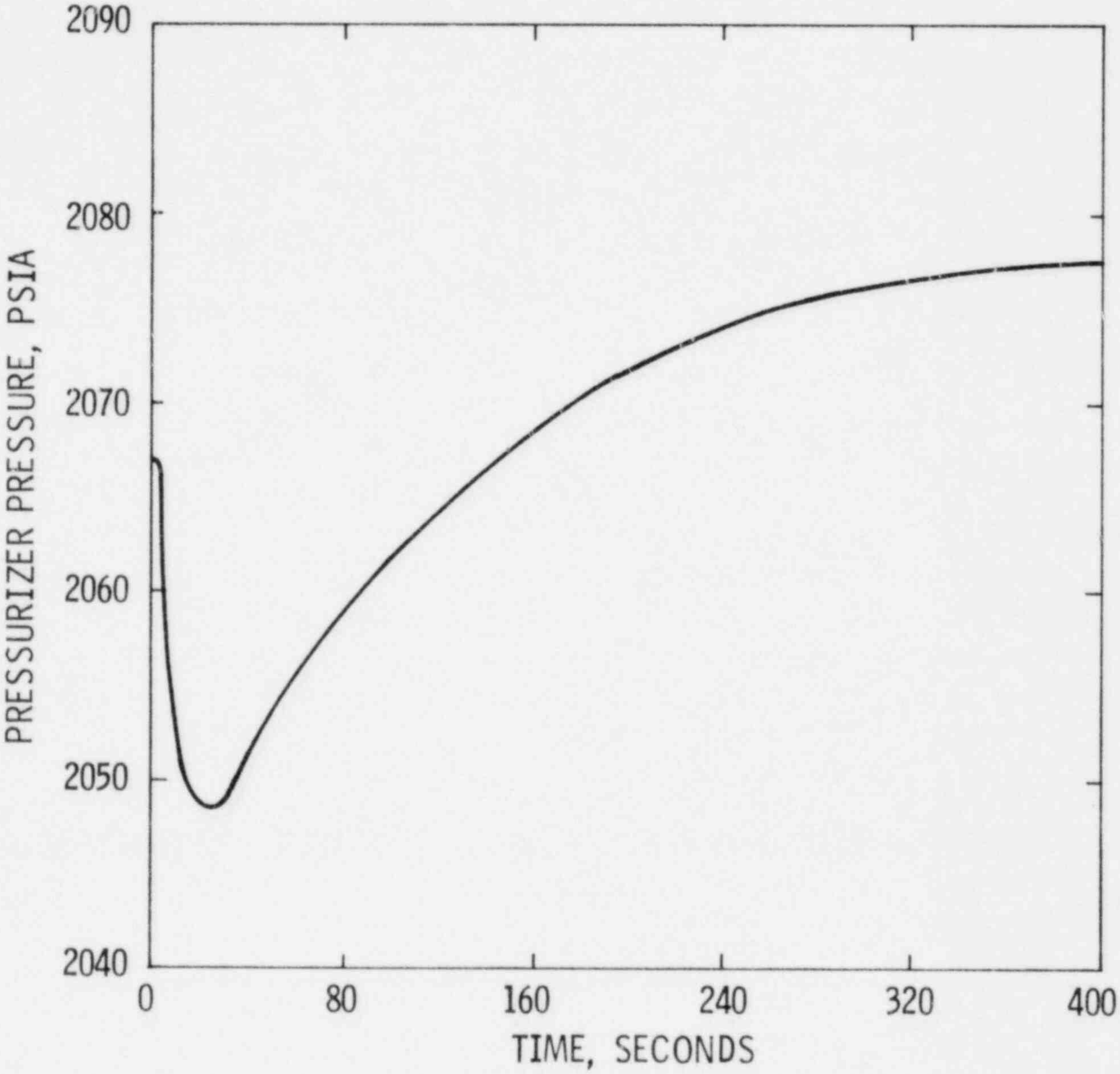
C-E SYSTEM 80	SINGLE FULL LENGTH CEA DROP HOT CHANNEL HEAT FLUX vs TIME	Figure 15.4.3-4



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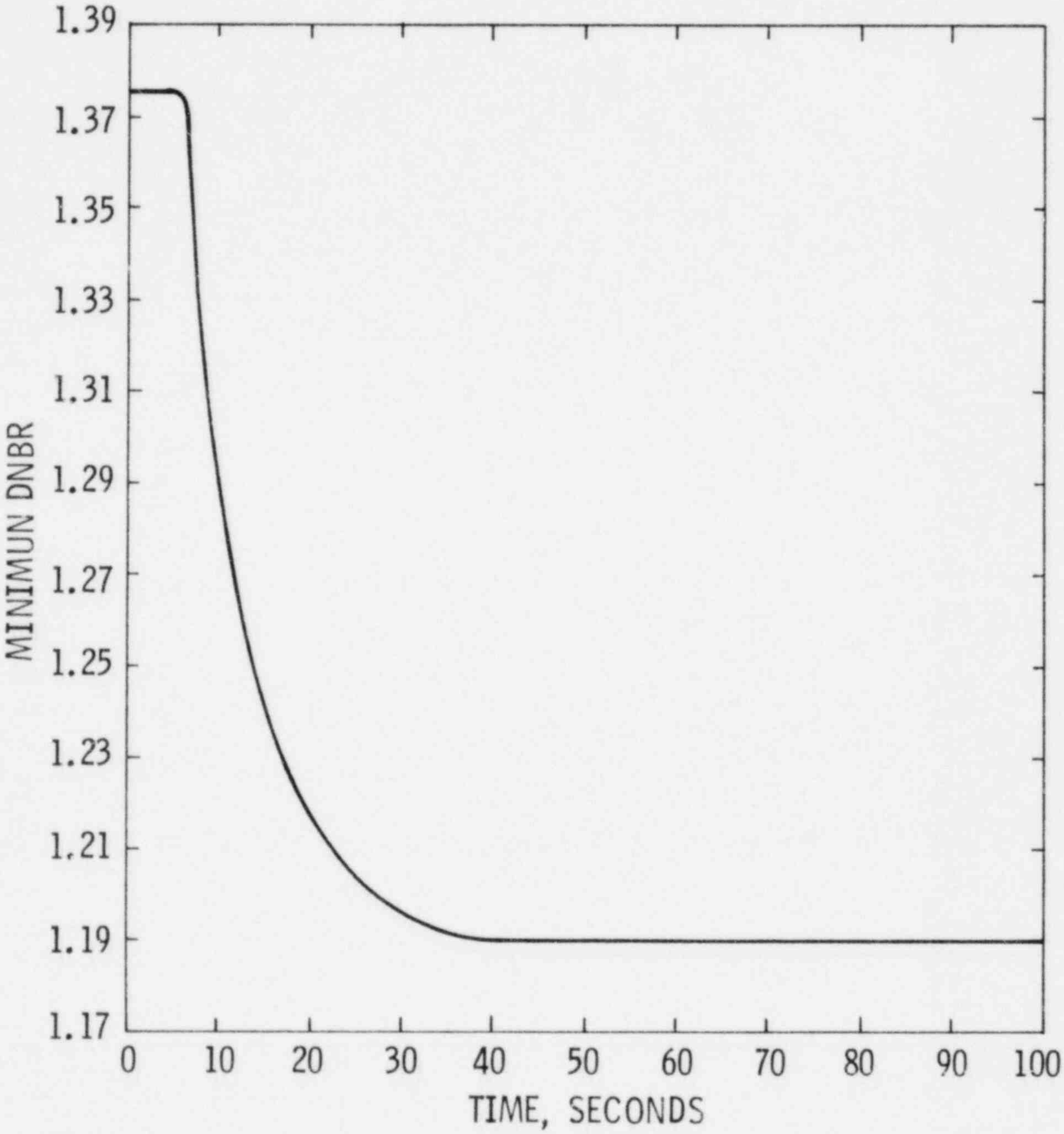
C - E SYSTEM 80	SINGLE FULL LENGTH CEA DROP PRESSURIZER PRESSURE vs TIME	Figure 15.4.3-5



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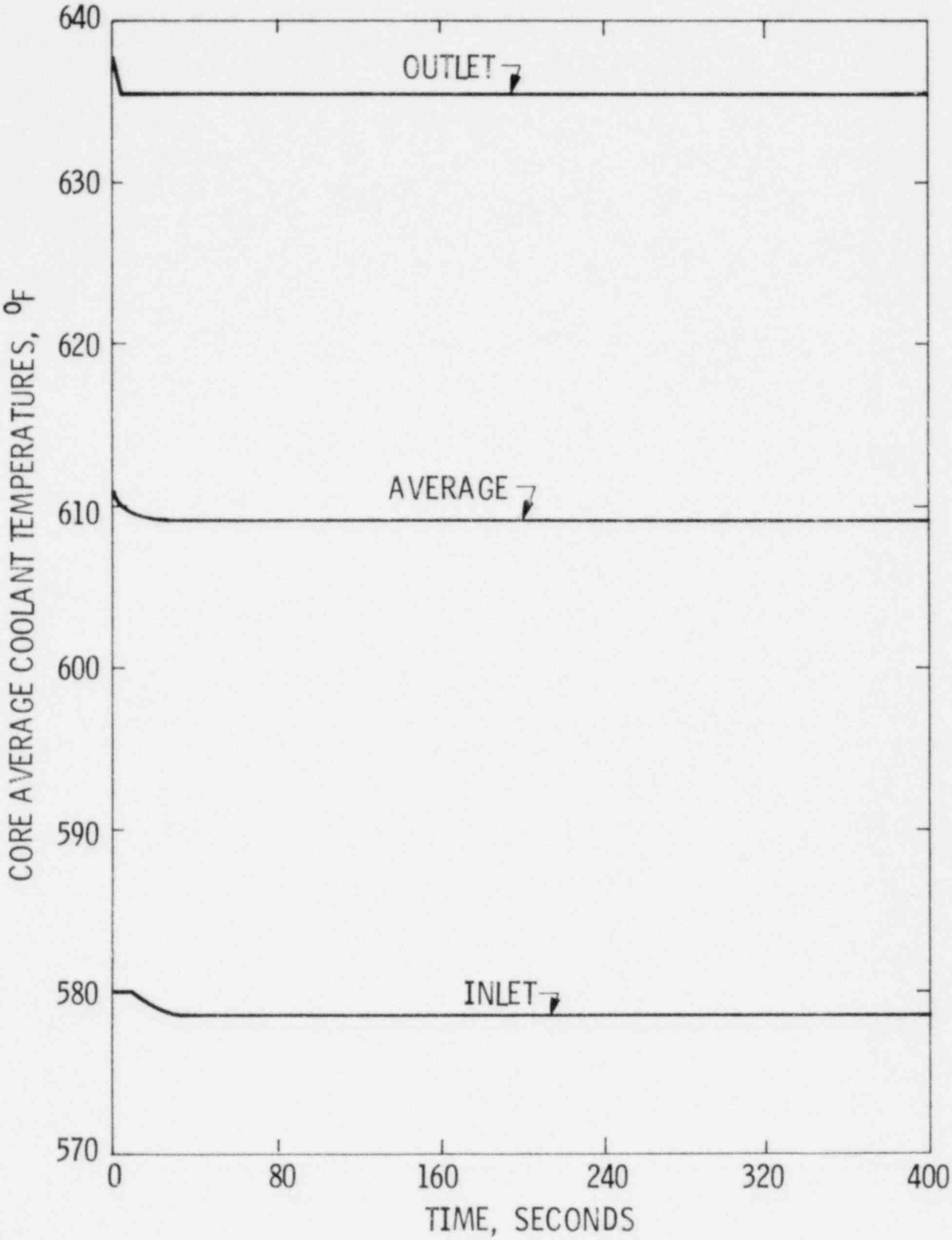
C - E SYSTEM 80	SINGLE FULL LENGTH CEA DROP MINIMUM DNBR vs TIME	Figure 15.4.3-6



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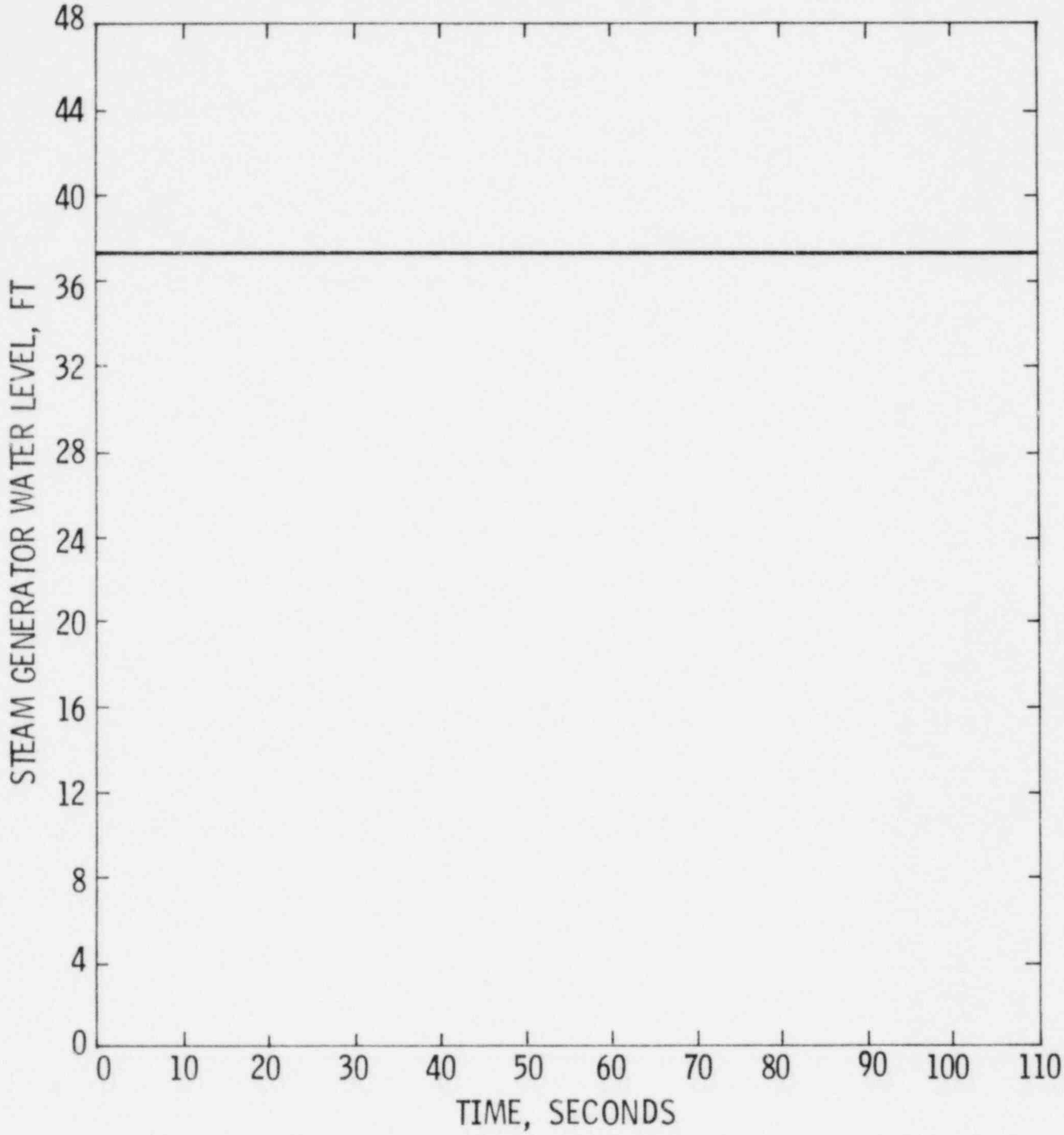
C - E SYSTEM 80	SINGLE FULL LENGTH CEA DROP CORE AVERAGE COOLANT TEMPERATURES vs TIME	Figure 15.4.3-7



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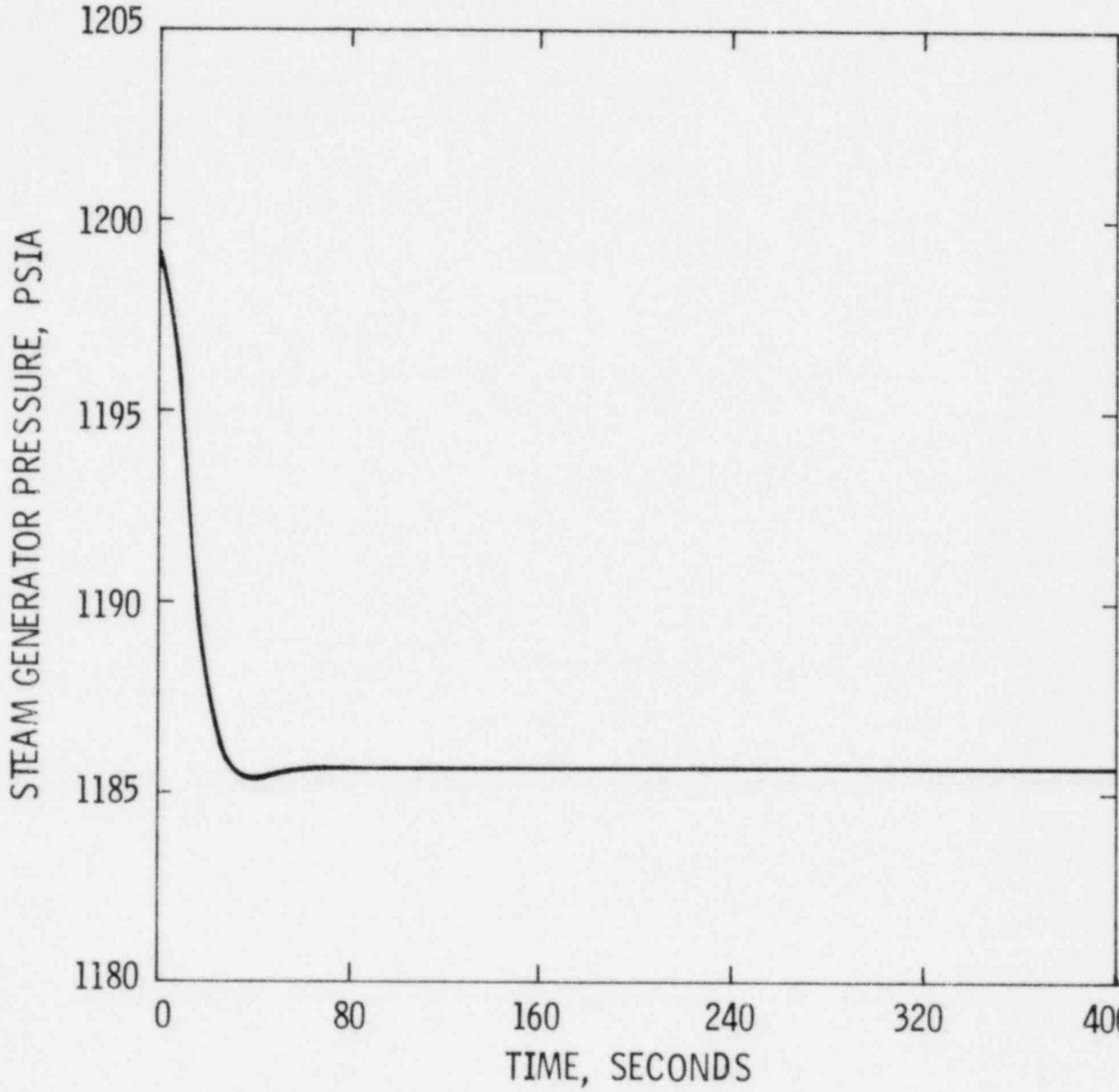
C-E SYSTEM 80	SINGLE FULL LENGTH CEA DROP STEAM GENERATOR WATER LEVEL vs TIME	Figure 15.4.3-8



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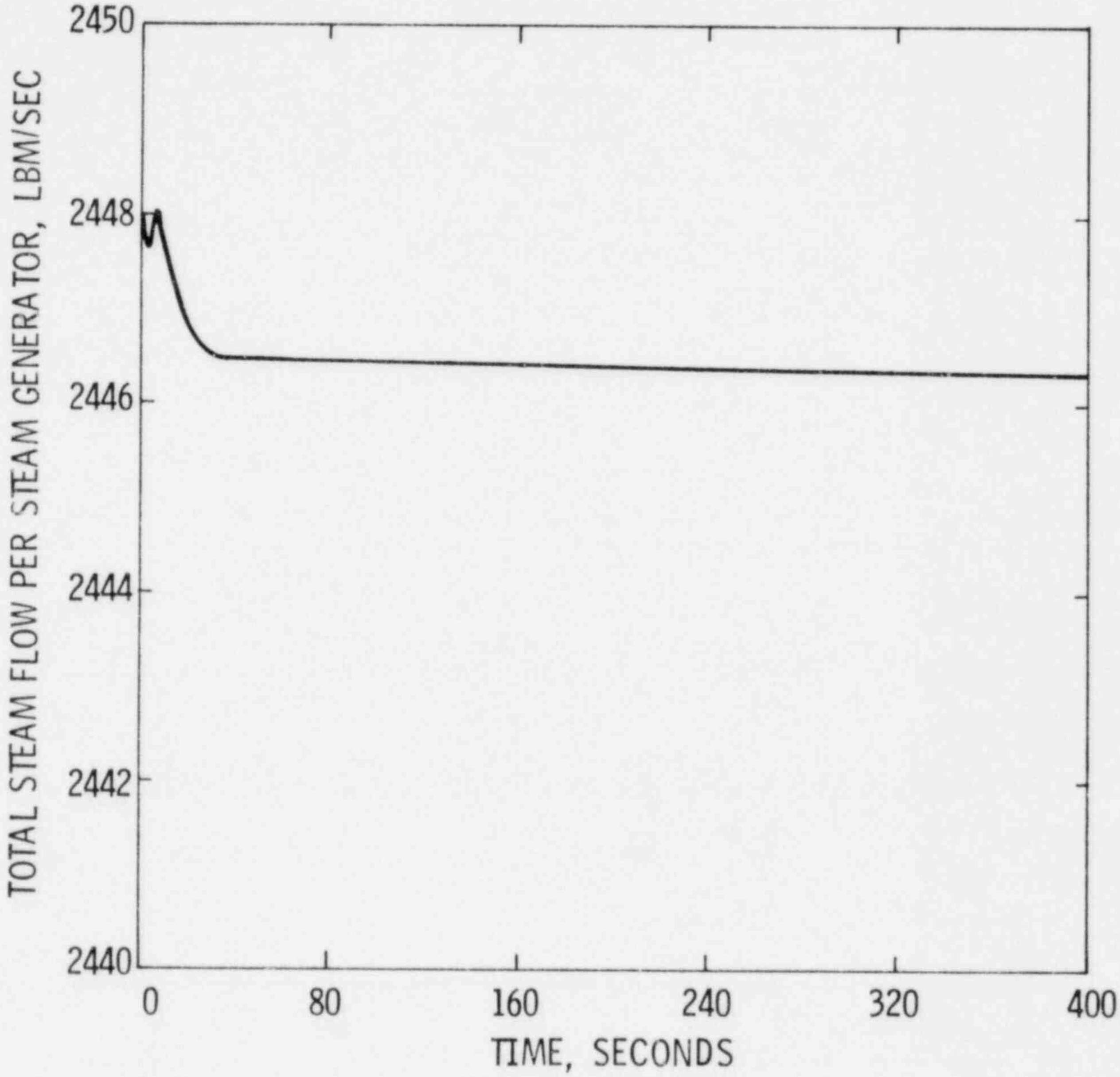
C - E SYSTEM 80	SINGLE FULL LENGTH CEA DROP STEAM GENERATOR PRESSURE vs TIME	Figure 15.4.3-9



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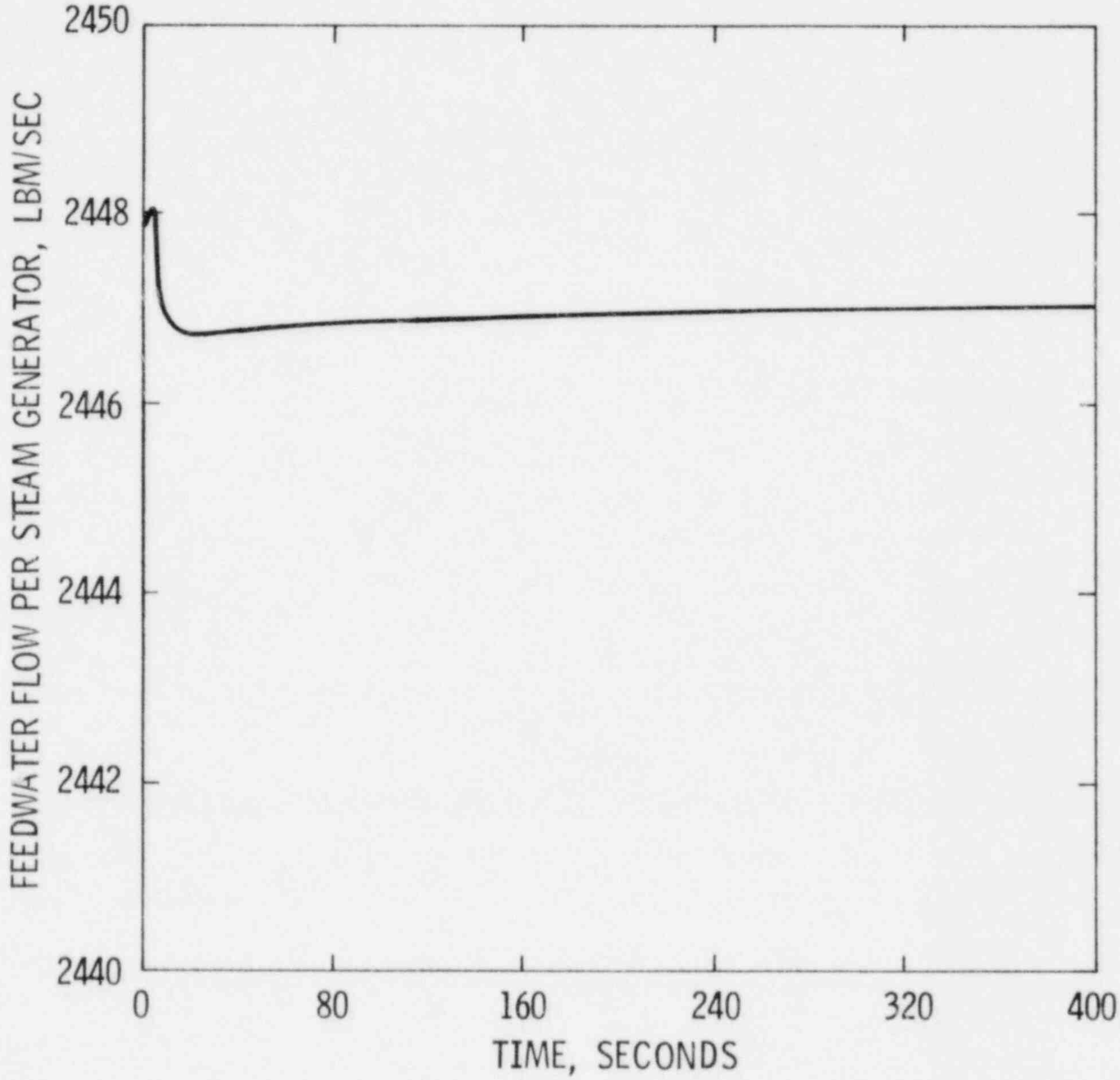
C-E SYSTEM 80	SINGLE FULL LENGTH CEA DROP TOTAL STEAM FLOW vs TIME	Figure 15.4.3-10



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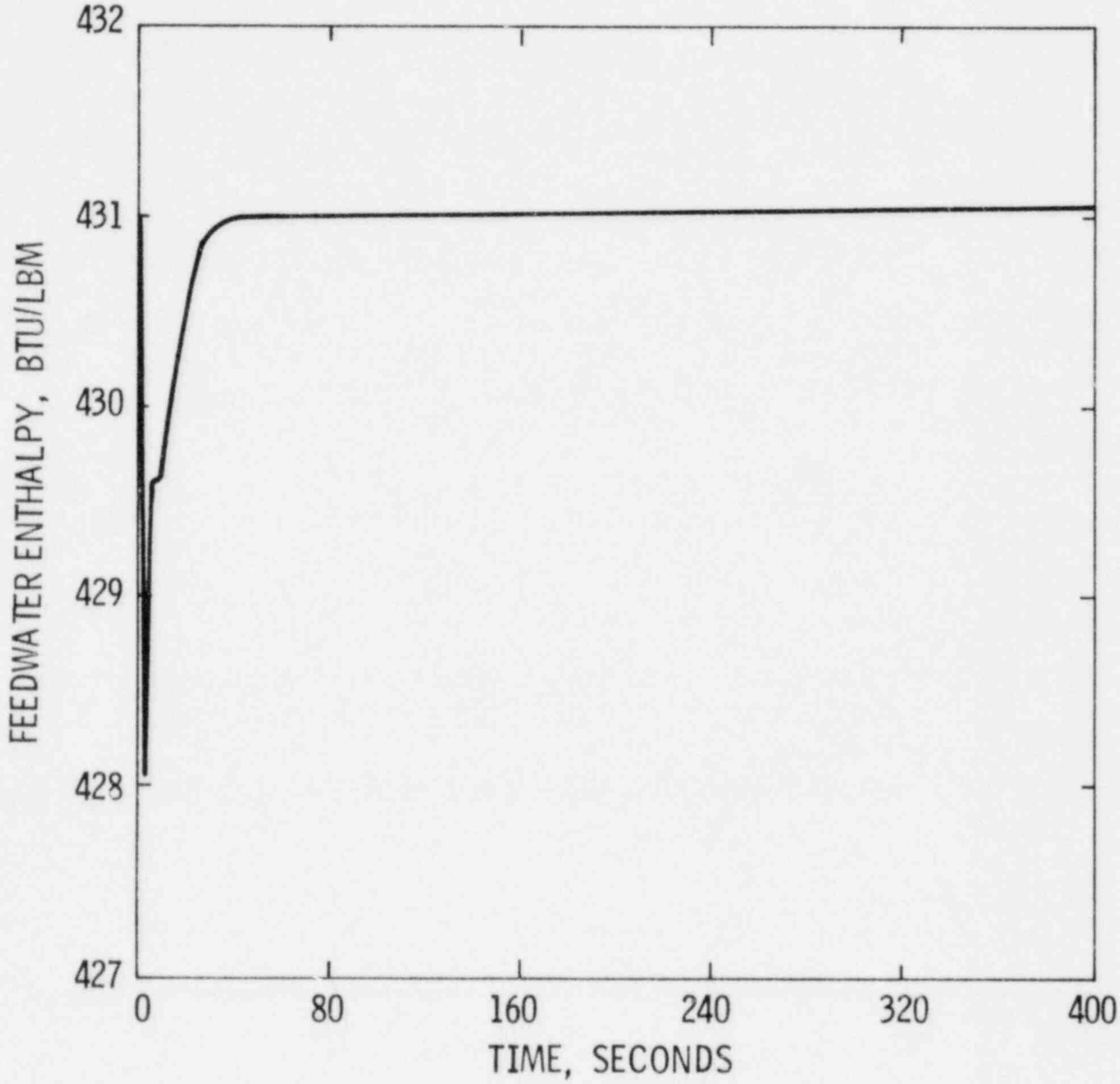
C - E SYSTEM 80	SINGLE FULL LENGTH CEA DROP FEEDWATER FLOW vs TIME	Figure 15.4.3-11



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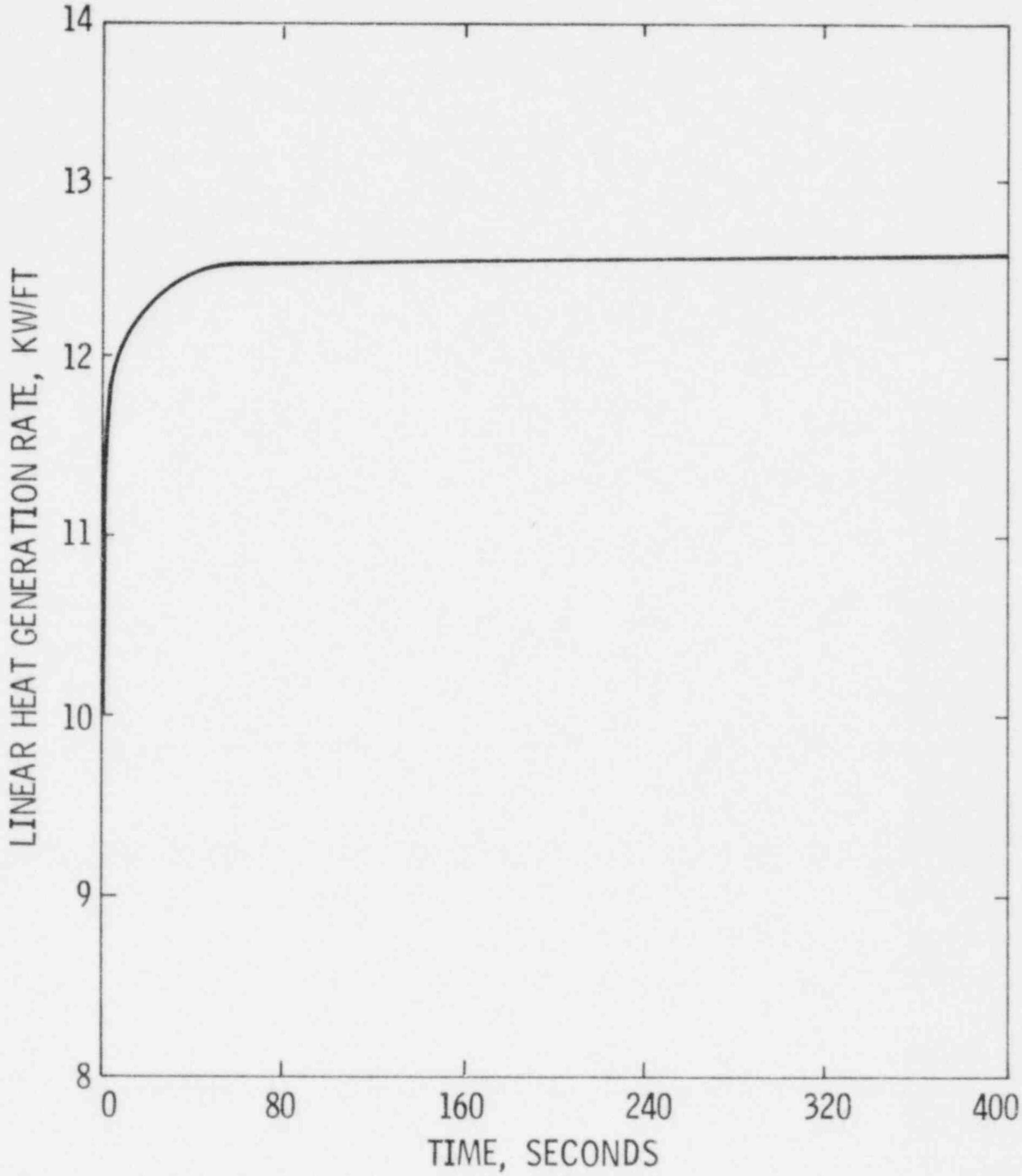
C - E SYSTEM 80	SINGLE FULL LENGTH CEA DROP FEEDWATER ENTHALPY vs TIME	Figure 15.4.3-12



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C-E SYSTEM 80	SINGLE FULL LENGTH CEA DROP LINEAR HEAT GENERATION RATE vs TIME	Figure 15.4.3-13

15.4.4 STARTUP OF AN INACTIVE REACTOR COOLANT PUMP

15.4.4.1 Identification of Event and Causes

The startup of an inactive reactor coolant pump (SIRCP) is presented here with respect to RCS pressure and fuel performance criteria. The event was evaluated during modes 3 through 6 since plant operation with less than all four reactor coolant pumps is permitted only during those modes. The cases considered were no more than one reactor coolant pump operation or two reactor coolant pumps operating in one loop (the other loop idle) to maximize the pressure increase.

15.4.4.2 Sequence of Events and Systems Operation

SIRCP causes a sudden surge of relatively cold water to enter the core which may cause a core power and RCS pressure increase. For modes 3 and 4 the primary safety valves valves, main steam safety valves, and the Reactor Protection System are designed to maintain the RCS below 110% of design pressure. During modes 5 and 6 when the shutdown cooling system is aligned overpressure protection is provided by the shutdown cooling system relief valves. The valves set pressure and is listed in Section 5.2.2 and 5.4.7.

15.4.4.3 Analysis of Effects and Consequences

With no more than one reactor coolant pump operating or two reactor coolant pumps operating in one loop (the other loop idle), the SIRCP may lead to an increase in RCS pressure. However, as stated in Section 5.2.2 and Appendix 5A, the overpressure protection for C-E's System 80 pressurized water reactor, steam generators, and reactor coolant system is in accordance with the requirements set fourth in ASME Boiler and Pressure Vessel Code, Section III. For modes 3 and 4 the primary safety valves, main steam safety valves, and Reactor Protection System are designed to maintain the RCS below 110% of design pressure during the worst case pressure transients. During modes 5 and 6 when the shutdown cooling system is aligned, overpressure protection is provided by the shutdown cooling system relief valves.

15.4.4.4 Conclusion

Based on the design of the valves described in Subsection 15.4.4.3 the maximum pressure within the RCS occurring during a SIRCP will not exceed 110% design value. For modes 3 and 4, the heat imbalance due to the SIRCP is less limiting than that caused by the CEA withdrawal event. In modes 5 and 6, the capacity of the shutdown cooling relief valves prevents the RCS pressure following a SIRCP from exceeding the pressure/temperature limits for these modes. Regarding the approach to fuel design limits for the SIRCP, the minimum DNBR in the hot channel will increase as the transient progresses; therefore no fuel damage is expected.

15.4.5 FLOW CONTROLLER MALFUNCTION CAUSING AN INCREASE IN BWR CORE FLOW RATE

This event is not applicable to Pressurized Water Reactors and therefore is not incuded in this FSAR.

15.4.6 INADVERTENT DEBORATION

15.4.6.1 Identification of Event and Causes

The Inadvertent Deboration (ID) event is presented here with respect to time available for operator corrective action prior to the loss of minimum required shutdown margin. Fuel integrity is not challenged by this event.

The ID event may be caused by improper operator action or by a failure in the boric acid makeup flow path which reduces the flow of borated water to the charging pump suction. Either cause can produce a boron concentration of the charging flow which is below the concentration of the reactor coolant.

Analysis of the ID event initiated during each of the six operational modes defined in the Technical Specifications was performed. These analyses show that Mode 5 (cold shutdown) results in the least time available for detection and termination of the event. This is because the shutdown margin requirement which will be specified by the Technical Specifications is smallest in mode 5.

Since boron dilution is conducted under strict procedural controls which specify limits on the rate the magnitude of any required change in boron concentration, the probability of a sustained and erroneous dilution due to operator error is very low.

The indications and/or alarms available to alert the operators that a boron dilution event is occurring in each of the operational modes are outlined below.

1. The following control room indications and corresponding pre-trip alarms are available for MODES 1 and 2: a high power or, for some set of conditions, a high pressurizer pressure trip in MODE 1 or a high logarithmic power level trip in MODE 2. Furthermore, a high T_{AVG} alarm may also occur prior to trip.

2. In MODES 3 and 4 with CEAs withdrawn, the high logarithmic power level trip and pre-trip alarm and high neutron flux alarm will provide an indication to alert the operator of an inadvertent boron dilution.

3. In MODES 3, 4, and 5 with CEAs fully inserted and in MODE 6, a high neutron flux alarm on the startup flux channels will provide indication of any boron dilution event.

4. In MODE 5 with the RCS partially drained for system maintenance, the startup flux channel alarm will provide indication of any boron dilution event. In this plant condition, administrative controls would allow operation of only one charging pump at a maximum rate of 44 gpm. Plant operating procedure will require that the power to the other two charging pumps be removed and their breakers locked out. This drained down case is less limiting than the MODE 5 event presented below.

The operational procedure guidelines, in addition to these indications and/or alarms, will assure detection and termination of the boron dilution event before the shutdown margin is loss.

15.4.6.2 Sequence of Events and Systems Operation

Refer to Figure 15.4.6.1 for the Sequence of Events Diagram.

The core is initially subcritical with shutdown margin at the minimum value consistent with the technical specification limit for cold shutdown. An inadvertent deboration occurs which causes unborated water to be pumped into the RCS. The resulting decreases in RCS boron concentration adds positive reactivity to the core. Assuming dilution continues at the maximum possible rate, 95 minutes would elapse before the core becomes critical.

The success path in the sequence of events diagram, Figures 15.4.6-1 is as follows:

Reactivity Control:

The operator is alerted to a decrease in the reactor coolant system (RCS) boron concentration either through a high neutron flux alarm on the startup flux channel, sampling, boronmeter indications, or boric acid flow rate. He turns off the charging pump(s) and closes the letdown control valves in order to halt further dilution. Next, he increases the RCS boron concentration by implementing the emergency boration procedure for achieving cold shutdown boron concentration.

15.4.6.3 Analysis of Effects and Consequences

A. Mathematical Model

Assuming complete mixing of boron in the RCS, the rate of change of boron concentration during dilution is described by the following equation.

$$M \frac{dC}{dt} = -WC$$

Where:

M = RCS mass

C = RCS boron concentration

W = Charging mass flow rate of unborated water

dC/dt is maximized by maximizing W and minimizing M.

Assuming:

W = Constant, equal to the maximum possible value,

and choosing:

M = Constant, equal to the minimum value occurring during the boron dilution incident.

the solution of Equation (1) can be written

$$C(t) = C(o)e^{-t/\tau} \quad (2)$$

Where:

τ = M/W = Boron dilution time constant

c(o) = Initial boron concentration

The time T required to dilute to critically is given by

$$T = \tau \ln \frac{C(o)}{\overline{C}_{crit}} \quad (3)$$

Where:

C_{crit} = Critical boron concentration

B. Input Parameters and Initial Conditions

It is assumed that the inadvertent deboration proceeds at the maximum possible rate. For this to occur, all charging pumps must be on, the reactor makeup water tank must be aligned with the charging pump suction, a reactor makeup water pump must be on, letdown flow must be diverted from the volume control tank, and a failure in the boric acid makeup water flow path (e.g., flow control valve, CH-210Y failing in the closed position) must terminate borated water flow to the charging pump suction.

Analysis of ID events initiated during each of the six plant operational modes (defined in the technical specifications) were performed. These analyses show that mode 5 (cold shutdown) results in the shortest available time for detection and termination of the event. Therefore, the initial conditions and analysis parameters are chosen for the cold shutdown operational mode to minimize the interval from initiation of dilution to the time at which criticality is reached. Since a minimum flow of 4000 gpm is circulated through the RCS by the Shutdown Cooling System, complete mixing of boron within the RCS is assumed.

1. The technical specification lower limit on shutdown margin for cold shutdown is assumed, 2.0% $\Delta\rho$.

2. The most adverse initial core condition would be for an initial K_{eff} corresponding to 2.0% $\Delta\rho$ subcritical and assuming subcriticality is supplied by boron concentration only.

3. The cold reactor coolant volume, excluding pressurizer and surge line, is 11,950 ft^3. A conservatively low reactor coolant mass was assumed by using the cold RCS internal volume. Assuming the coolant temperature of 210^{0}F, the technical specification upper limit for cold shutdown, the resulting mass is 718,200 lbm.

4. All three charging pumps are assumed to be on at their maximum rate; 44 gpm per pump, for a total of 132 gpm. The corresponding mass flow rate, assuming cold liquid flow, is 18.36 lbm/sec.

5. The initial boron concentration with all rods in and the inverse boron worth are 713 ppm and 56 ppm/%$\Delta\rho$ respectively including uncertainties for the cold shutdown conditions: The initial subcritical boron concentration for the cold shutdown mode is found by adding the product of the inverse boron worth and the minimum shutdown margin (i.e. two percent) to the critical boron concentration. The resulting minimum initial boron concentration is Mode 5 is 825 ppm. Thus, the change of boron concentration from 2%$\Delta\rho$ subcritical to critical is 112 ppm.

The parameters discussed above are summarized in Table 15.4.6-1.

C. Results

Using the above conservative parameters in Equation (3), the minimum possible time interval to dilute from 2.0%$\Delta\rho$ subcritical to criticality is 95 minutes. Given the numerous indications of improper operation and the high neutron flux alarm on the startup flux channel, as provided in Figure 15.4.6-1, sufficient time is available to assure detection of a boron dilution event at least 15 minutes prior to criticality. Boron dilution will then be terminated before loss of shutdown margin by the operator actions discussed in subsection 15.4.6.2.

15.4.6.4 Conclusions

The inadvertent deboration event will result in acceptable consequences. Sufficient time is available for the operator to detect and to terminate an inadvertent deboration event if it occurs. Fuel integrity is not challenged during this event.

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TABLE 15.4.6-1

ASSUMPTIONS FOR THE INADVERTENT DEBORATION ANALYSIS

Parameter	Assumptions
Cold RCS Volume (excluding pressurizer surge line), ft^3	11,950
RCS Mass (excluding pressurizer and surge line), lbm	718,200
Volumetric Charging Rate, gpm	132
Mass Charging Rate, lbm/sec	18.36
Dilution Time Constant, τ , sec	3[illegible]
Initial Boron Concentration-C(o), ppm	825
Critical Boron Concentration-C_{crit}, ppm	713

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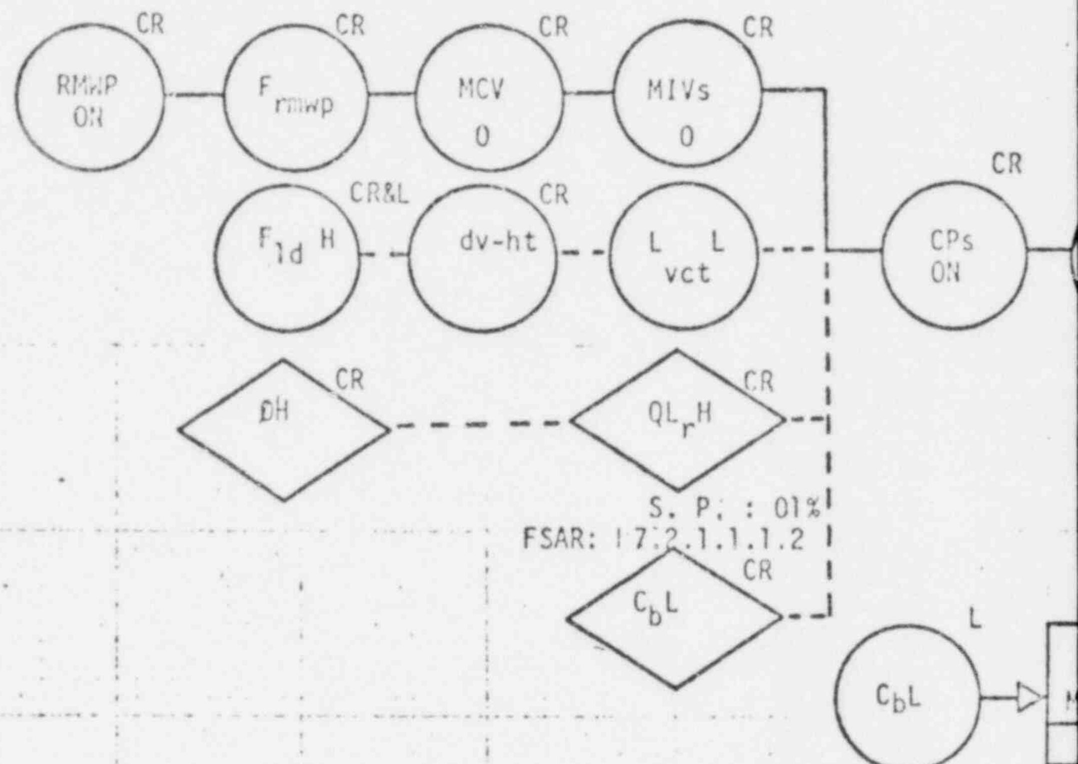


LEGEND:

RMWP - REACTOR MAKEUP WATER PUMP

MCV - MAKEUP CONTROL VALVE (CH-210X)

MIV - MAKEUP ISOLATION VALVE (CH512 or CH527)

ld - LETDOWN

dv-ht - DIVERTER VALVE OPEN TO HOLDUP TANK

C_b - CONCENTRATION OF BORON

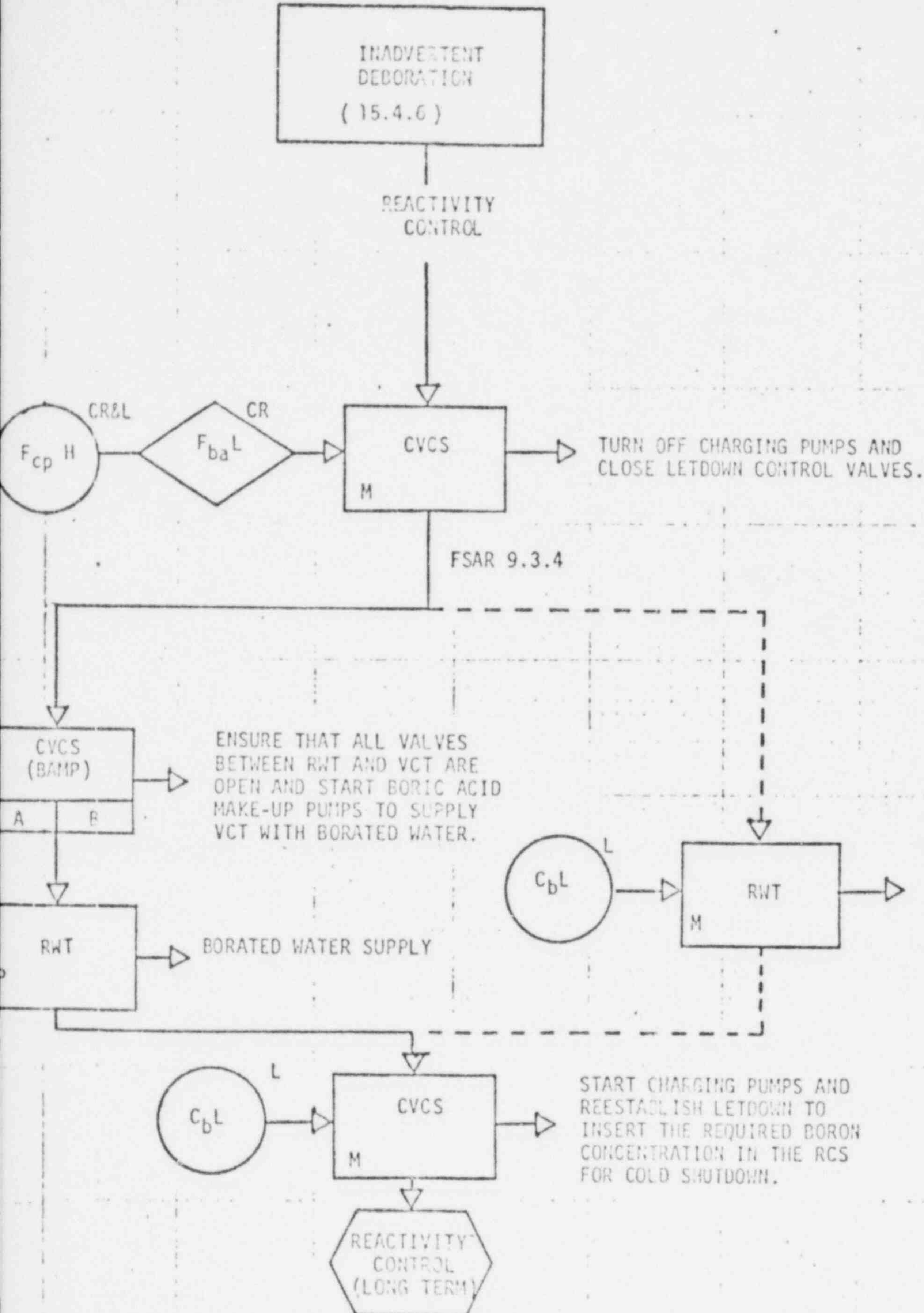
CP - CHARGING PUMP

ba - BORIC ACID

Ø - NEUTRON FLUX ON THE STARTUP FLUX CHANNEL

vct - VOLUME CONTROL TANK

QL_r - LOGARITHMIC POWER LEVEL



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C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR INADVERTENT DEBORATION	Figure 15.4.6-1

15.4.7 INADVERTENT LOADING OF A FUEL ASSEMBLY INTO THE IMPROPER POSITION

15.4.7.1 Identification Of Events and Causes

The Inadvertent Loading of a Fuel Assembly into the Improper Position event is initiated by interchanging two fuel assemblies. The likelihood of an error in core loading is considered to be extremely remote becuase of the strict procedural control used during core loading.

15.4.7.2 Sequence of Events and System Operation

The fuel enrichment within a fuel assembly is identified by a coded serial number marked on the exposed surface of the top end plate of the fuel assembly. This serial number is used as a means of positive identification for each assembly in the plant. A tag board is provided in the main control room showing a schematic representation of the reactor core, spent fuel storage area. During the period of core loading, the location of each CEA, fuel assembly, and source will be shown on this tag board by a tag carrying its identification number.

The tag board in the main control room will be constantly updated by a designated member of the reactor operations staff whenever a fuel assembly is being moved. He will be in constant communication with each area where this is occurring. Also, a licensed operator will be present in the area where fuel assemblies are being handled to ensure that the assemblies are moved to the correct locations. Fuel assemblies will not be moved unless these lines of communication are available. In addition to these precautions, periodic independent inventories of components in the reactor core, spent fuel, and new fuel storage areas will be made to ensure that the tag board is correct. Also, at the completion of core loading, the exposed surfaces of the top end plates are inspected to verify that all assemblies are correctly located. These precautions are included in the core loading procedures which are to be reviewed by appropriate plant personnel.

If, in spite of the extreme precautions described above, a fuel misloading does occur the consequences depend on the types and locations of the fuel assemblies that have been interchanged. The misloading of a fuel assembly may affect the core power distribution only slightly, for example, if assemblies of similar enrichments and reactivities are misloaded. Alternatively, if assemblies having very different enrichments or reactivities are misloaded the core power distribution may be affected enough so that core performance would be degraded.

In the unlikely event that two assemblies of different enrichments would be interchanged, some misloadings would be detected using ex-core startup detectors and the reactivity computer during the low power physics testing. In these tests a symmetry check is performed in which the reactivity worths of symmetrically located CEAs are compared against one another. The interchange of two or more fuel assemblies with greatly different K_∞'s destroys the octant symmetry of the core flux distribution and would thus produce significant variations in the worths of symmetrically located CEAs. This asymmetry would be corroborated by symmetry checks performed for other symmetric rod groups thereby confirming and possibly even locating a fuel assembly misload.

In addition, many misloadings could be detected by either the ex-core detectors directly or the in-core detector channels which are analyzed at power levels

greater than 20 percent during the power ascension test at BOC and periodically throughout the cycle.

Thus most of the fuel assembly misloadings that can be postulated are easily detectable both during the rod symmetry checks and during power range operation. However, there are small number of misloadings which are undetectable during the rod symmetry testing or even early in the cycle with in-core instrumentation during power range operation. Of this small class the worst case is the interchange of a shimmed with an unshimmed one at the center of the core. This case, although not detectable at BOL, would cause local power power peaking as the shims burn out.

15.4.7.3 Analysis of Effects and Consequences

Several single assembly interchanges of this type were postulated and investigated using the fine-mesh neutronics methods discussed in Chapter 4.3. Most were shown to be detectable when estimates of the symmetric rod worths were calculated. Of those misloads which were not conclusively demonstrated to be detectable during startup at BOC1, the interchange of assemblies 9 and 50 was shown to result in the highest $F^n{}_R$ value (1.72) during subsequent full power operation over the first cycle. The associated power distribution shown in Figure 15.4.7-1 has a calculated minimum DNBR of 1.48. Since this is greater than the minimum acceptable DNBR of 1.19, no clad failure is expected to occur.

Furthermore even though these misloads may not be detected during startup at BOC, it is very probable that the anomaly would be detected early in the cycle before the maximum $F^n{}_R$ value is attained. This is because this type of interchange (i.e. shimmed with unshimmed) tends to produce an increasingly distorted power distribution which would alert the reactor engineer to the possibility of a fuel misloading.

15.4.7.4 Conclusion

Those Inadvertent Loading of a Fuel Assembly into the Improper Position Events which are not detected during startup at BOC1 do not result in fuel cladding consequences are within 10CFR100 guidelines

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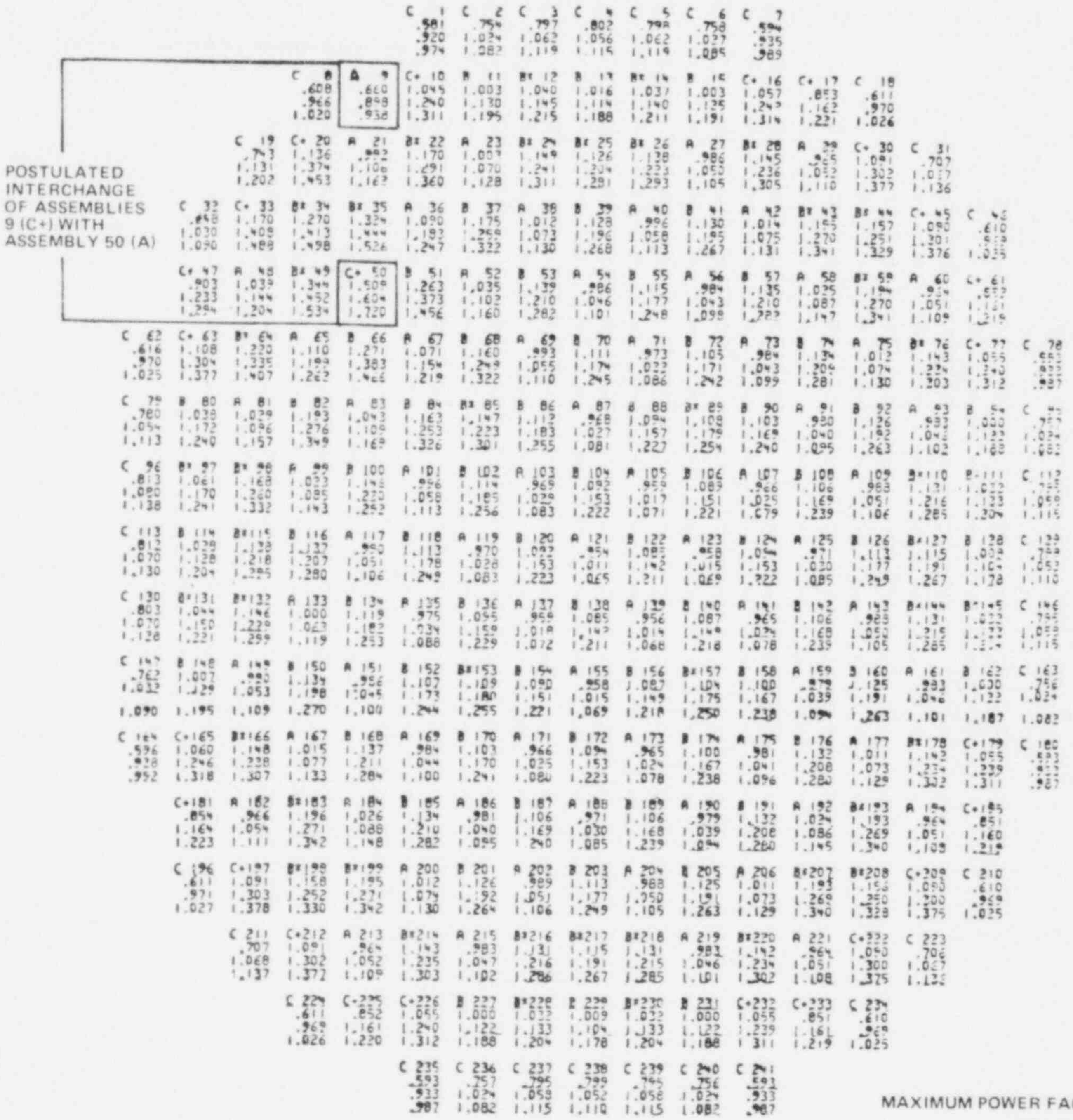
X.XX	BOX AVERAGE (BOX POWER/CORE AVERAGE POWER)
X.XX	MAX. ENTHALPY RISE FACTOR (MAX. OF AVERAGE POWER OF 4 NEIGHBORING PINS/CORE AVERAGE POWER)
X.XX	MAX. ONE-PIN FACTOR (MAX. PIN POWER/CORE AVERAGE POWER)



MAXIMUM POWER FACTORS

		VALUE IN BOX
BOX AVERAGE	1.5089	50
MAX 4-PIN	1.6045	50
MAX 1-PIN	1.7199	50

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C-E SYSTEM 80	PLANAR AVERAGE POWER DISTRIBUTION CORRESPONDING TO MAXIMUM F_R^N PRODUCED BY A FUEL ASSEMBLY MISLOADING THAT IS UNDETECTABLE DURING STARTUP AT BOC	Figure 15.4.7-1

15.4.8 CONTROL ELEMENT ASSEMBLY (CEA) EJECTION

15.4.8.1 Identification of Event and Causes

A CEA Ejection results from a circumferential rupture of the control element drive mechanism (CEDM) housing or of the CEDM nozzle.

15.4.8.2 Sequence of Events and Systems Operation

Table 15.4.8.-1 presents a chronological sequence of events which occur during a CEA ejection transient from the time the CEA and drive shaft are ejected until operator action is initiated. Figure 15.0-1, contains a glossary of SEA symbols and acronyms which may be used with the Sequence of Events Diagram, Figure 15.4.8-1, to trace the actuation and interaction of the systems utilized to mitigate the consequences of this event.

Table 15.4.8-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient.

Table 15.4.8-3 contains a matrix which summarize the utilization of safety systems as they appear in the sequence of events diagram.

The success paths in the Sequence of Events Diagram, Figure 15.4.8-1, are as follows:

Reactivity Control:

Following the CEA ejection a reactor trip is generated by the Reactor Protective System (RPS) on variable overpower-high power condition and the CEAs drop in the core. As Reactor Coolant System (RCS) pressure decreases an SIAS is generated adding additional boron to the core by means of the HPSI pumps. A Recirculation Actuation Signal (RAS) occurs on low Refueling Water Tank (RWT) level and opens the containment sump isolation valves to supply the HPSI pumps during the recirculation phase. The operator closes the RWT discharge valves.

Reactor Heat Removal:

All four RCPs coastdown following the loss of offsite power. The depressurization of the RCS brings it to a temperature and pressure below that of the steam generators. The turbine trip and loss of main feedwater pumps following the loss of offsite power, bottle the steam generators up until the operator commences plant cooldown.

A CIAS occurs on low pressurizer pressure. For plant cooldown, the operator uses the ADVs and auxiliary feedwater. The SCS is manually actuated when RCS temperature and pressure have been reduced to 350°F and 400 psia. This system provides sufficient cooling to bring the RCS to cold shutdown.

Primary System Integrity:

The Primary Safety Valves (PSVs) open to limit RCS pressure to an acceptable value. The PSV discharge is contained by the reactor drain tank. The operator throttles the HPSI pumps' isolation valves to control pressure during the cooldown.

Secondary System Integrity:

The turbine trips on a reactor trip signal. The MFW pumps are assumed to trip on the subsequent loss of offsite power. The Main Steam Safety Valves (MSSVs) open to disipate the heat transferred from the primary system until the primary system depressurizes. The steam generators then sit bottled up until the operator commences plant cooldown. Cooldown is accomplished by utilizing one feedwater pump designated as "auxiliary" and intended for normal startup and shutdown of the plant in conjunction with the ADVs. He may also let the ESFAS regulate the feedwater flow by issuing and withdrawing EFAS-1 and/or EFAS-2 signals down to cold shutdown entry conditions. See Applicant's FSAR for details of the Emergency and/or Auxiliary Feedwater Systems.

Containment Integrity:

A Containment Spray Actuation Signal (CSAS) is received on high-high containment pressure. The CS pumps spray water from the RWT into the containment to cool and reduce the pressure of the containment atmosphere. On low RWT level the containment sump isolation valves open to supply water to the containment spray pumps.

Combustible Gas Control:

Operator actuates BOP systems to control the hydrogen concentration in containment. See Applicant's SAR.

Control Room Habitability:

CIAS or SIAS or BOP signals may actuate control room habitability systems. See Applicant's FSAR for details.

Fuel Handling Building Habitability:

CIAS or SIAS or BOP signals may actuate fuel handling building habitability systems. See Applicant's FSAR for details.

Radioactive Effluent Control:

CIAS isolates various systems to reduce or terminate radioactive releases. CIAS actuates primary, secondary, and containment isolation equipment. Other actions may be initiated by BOP systems. See Applicant's FSAR for details.

Restoration of AC Power:

A loss of offsite power occurs following turbine trip. The diesel generatorssubsequently start and supply power to the ESF loads.

15.4.8.3 Analysis of Effects and Consequences

A. Mathematical Model

The NSSS response to a CEA Ejection was simulated using the method of analysis described in Reference 16 of Section 15.0. The procedure outlined in Figure 2.1 of Reference 16 was used to determine the energy deposition in the fuel rod. The number of fuel pins predicted to experience departure from nucleate boiling (DNB) was calculated using the STRIKIN-II computer program described in Section 15.0 with the CE-1 correlation described in Section 4. A matrix relating the initial and ejected CEA peaking factors to a pin census edit is obtained from Step 6 of the C-E Synthesis method and used to calculate the number of fuel pins experiencing DNB. Further conservatism is introduced by assuming that clad failure occurs when fuel rods experience DNB. The time dependent energy deposition in the RCS was determined from the above analysis and input into the CESEC-II computer program described in Section 15.0 to determine the overall NSSS response to this event.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a CEA Ejection are discussed in Section 15.0. A spectrum of initial reactor states (including conditions characteristic of the beginning and end of the fuel cycle) was considered. Table 15.4.8-4 contains assumptions regarding the initial reactor states analyzed for this event.

The initial conditions for the principal process variables were varied within the reactor operating space given in Table 15.0-5 to determine the set of conditions which produce the most adverse consequences following a CEA Ejection. Various combinations of initial core inlet temperature, core inlet flow rate, pressurizer pressure and axial power distribution were considered. The initial pressurizer and steam generator water level, as controlled within the operating space, have an insignificant effect on the consequences of the CEA ejection analysis.

For all cases analyzed, an axial power distribution was chosen to maximize the energy content in the hottest fuel pellet. The remaining parameters were chosen based on the results shown in Chapter 4 of Reference 16. These parameters were varied in the most adverse direction until a COLSS power operating limit was achieved.

C. Results

The spectrum of initial reactor states contained in Table 15.4.8-4 was analyzed to show that each case met the criteria established in Regulatory Guide 1.77. All cases resulted in a radial average fuel enthalpy less than 280 cal/gram at the hottest axial location of the hot fuel pin. The case that resulted in the greatest potential for off site dose consequences (i.e., the case resulting in the largest number of postulated fuel failures) was identified as the case initiated from full power (FP) beginning-of-cycle (BOC) initial conditions. The following paragraphs describe this event in detail. Refer to Table 15.4.8-5 for the initial conditions and assumptions used for this analysis.

Figures 15.4.8-2 through 15.4.8-6 show the reactor power, heat flux, and clad and fuel temperatures during the significant portion of transient. Table

15.4.8-1 contains the sequence of events that occur during a CEA Ejection initiated from full power BOC initial conditions.

Ejection of a CEA causes the core power to increase rapidly due to the almost instantaneous addition of positive reactivity. However, the rapid increase in core power is terminated by a combination of Doppler feedback and delayed neutron effects. This increase in power results in a high power trip and the reactor power begins to decrease as the CEA's enter the core. Reactivity effects are shown in Figure 15.4.8-7.

In the hot channel, the increase in heat flux is such that DNB is calculated to occur, resulting in:

1. A rapid decrease in the surface heat transfer coefficient.

2. A rapid decrease in heat flux.

3. A rapid increase in clad temperature.

The rapid increase in clad temperature is sufficient to override the decreased surface heat transfer coefficient, resulting in a second peak in the hot channel heat flux. At this time the CEAs are nearly fully inserted, resulting in a rapid reduction in the core power level. The heat flux continues to decrease for the remainder of the transient.

Initial RCS pressure for calculation of the limiting fuel performance and radiological release event was 2200 psia. RCS pressure vs. time for this case is given on Figure 15.4.8-8. The long term RCS pressure response is shown on Figure 15.4.8-10. Initial RCS pressure for the limiting peak pressure case is 2400 psia. RCS pressure vs. time for this case is given on Figure 15.4.8-9

Steam generator pressures, and steam generator safety valve flow rate following a FPBOC CEA ejection with a postulated loss of offsite power following turbine trip are shown in Figures 15.4.8-11 through 15.4.8-13.

The transient behavior of the NSSS following a postulated CEA Ejection is as follows. The steam generator pressure increases rapidly due to the closure of the turbine control valve following reactor and turbine trip. The steam bypass control system is inoperable on loss of offsite power and therefore is unavailable. The steam generator pressure reaching a maximum of 1348 psia at 4.8 seconds. The pressurizer pressure increases to a maximum of 2525 psia at 3.9 seconds due to the decreased heat removal of the steam generators.

Subsequently, the reduced reactor power following the reactor trip, in addition to the postulated break in the primary system, cause the RCS pressure and temperature to decrease.

The steam generator pressure decreases slowly until the main steam safety valves close. The total released through the safety valves is approximately 136,800 lbm.

Following a postulated CEA Ejection Event, 9.8% of the fuel is calculated to experience DNB. Regulatory Guide 1.77 recommends that the onset of DNB be used as the basis for predicting clad failure. C-E does not equate onset of DNB with cladding failure. Nevertheless, this criterion was used to determine the percentage of pins that suffer clad failure.

The activity released to the containment (through the ruptured CEDM pressure housing), is assumed to be mixed instantaneously throughout the containment and is available for leakage to the atmosphere.

The activity released from the secondary system is the activity released to the atmosphere from the main steam safety valves and from the atmospheric dump valves during cooldown.

The assumptions, parameters and calculational methods used to evaluate the radiological consequences of Chapter 15 events are discussed in Section 15.0-4. Assumptions and parameters that were unique to the evaluation of a CEA Ejection Event are itemized in Table 15.4.8-6. The following paragraphs provide additional clarification to some of the items contained in the table.

Item B.1-c Activity available for release from containment at time zero.

The activity available for leakage from containment is based on the following Regulatory Guide 1.77, Appendix B assumptions:

1. The activity in the fuel clad gap is 10% of the iodines and 10% of the noble gases accumulated in the fuel at the end of core life, assuming continuous maximum full power operation. All of the activity in the fuel gap for fuel rods that are calculated to experience DNB is assumed to be instantaneously available for release from containment.

2. The nuclide inventory of the fraction of fuel which reaches or exceeds the initiation temperature of fuel melting at any time during the transient was calculated; 100% of the noble gases and 25% of the iodines were assumed to be instantaneously available for release from the containment.

Item B.2.a-b Activity Release from the Secondary System.

Activity released from the secondary system is based upon the secondary activity initially in the steam generators plus primary activity resulting from technical specification steam generator tube leak. Table 15.4.8-7 contains the integrated mass releases from the main steam safety valves and the total primary to secondary leakage. The mass of steam released through the ADVs is given on Table 15.4.8-6.

Item B.2.c Reactor Coolant System Activity After Event

The RCS activity after the event was based on the assumptions given above, with the following exception. For the fraction of fuel which reaches or exceeds the fuel melting temperature at any time during the event, 50% of the iodines accumulated in the fuel at the end of core life were assumed to be uniformly mixed with the reactor coolant.

15.4.8.4 Conclusions

The rupture of a CEDM nozzle or housing and the subsequent ejection of a CEA will not result in a radial average fuel enthalpy greater than 280 cal/gram at any axial location in any fuel rod. The radiological consequences associated with secondary system steam releases have been conservatively analyzed using assumptions and models described in the preceeding sections. The whole-body dose due to immersion and the thyroid dose due to inhalation have been analyzed

for the two-hour dose at the exclusion area boundary and are presented in Table 15.4.8-8. The resultant doses are less than the allowable site boundary dose set forth in 10CFR Part 100. Doses due to containment leakage have not been included in this comparison and will be provided in the Applicant's FSAR.

The peak RCS pressure for the CEA Ejection event is 2757 psia. This is less than Service Limit C value as defined in the ASME code.

TABLE 15.4.8-1
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR
THE CEA EJECTION EVENT

Time (sec)	Event	Setpoint or Value	Success Path
0.0	Mechanical Failure of CEDM Causes CEA to Eject	--	
0.03	High Power Trip, % of design power	117	Reactivity Control
0.05	CEA Fully Ejected	--	
0.08	Maximum Core power, % of design power	138.3	
0.92	CEAs Begin to Drop	--	Reactivity Control
	Turbine Trip Occurs	--	Secondary Integrity
2.53	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity
2.6	Maximum Clad Surface Temperature in the Hot Node, F	936	
3.8	Maximum Fuel Centerline Temperature in the Hot Node, F	3779	
3.9	Pressurizer Safety Valves Open, psia	2525	Primary System Integrity

TABLE 15.4.8-1 (Cont'd) (Sheet 2 of 2)

SEQUENCE OF EVENTS FOR
THE CEA EJECTION EVENT

Time (Sec)	Event	Setpoint or Value	Success Path
3.9	Maximum Pressurizer Pressure, psia	2525	
4.7	Pressurizer Safety Valves Closed, psia	2462	Primary System Integrity
	Maximum Steam Generator Pressure, psia	1348	
5.3	CEAs Fully Inserted; Core Power Reduced to below 15% of design power	--	
40.2	Safety Injection Actuation Signal (SIAS), psia	1580	Reactor Heat Removal
850	Main Steam Safety Valves Closed, psia	1250	Secondary System Integrity
1800	Operator begins plant cooldown	--	Secondary System Integrity
12230	Shutdown cooling initiated, RCS pressure, temperature, ^{o}F	400/350	Reactor Heat Removal

TABLE 15.4.8-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR THE CEA EJECTION EVENT

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System			✓			1
2. Main Feedwater Pump Turbine Control System*			✓			1
3. Turbine-Generator Control System*			✓			1
4. Steam Bypass Control System				✓		1
5. Pressurizer Pressure Control System				✓		1
6. Pressurizer Level Control System				✓		1
7. Control Element Drive Mechanism Control System			✓			1
8. Reactor Regulating System				✓		1
9. Core Operating Limit Supervisory System			✓			1
10. Reactor Coolant Pumps			✓			1
11. Chemical and Volume Control System			✓			1
12. Secondary Chemistry Control System*			✓			1
13. Condenser Evacuation System*			✓			1
14. Turbine Gland Sealing System*			✓			1
15. Nuclear Cooling Water System*			✓			1
16. Turbine Cooling Water System*			✓			1
17. Plant Cooling Water System*			✓			1
18. Condensate Storage Facilities*			✓			1
19. Circulating Water System*			✓			1
20. Spent Fuel Pool Cooling and Clean-Up System*			✓			1
21. Non-Class 1E (Non-ESF) A.C. Power*			✓			1
22. Class 1E (ESF) A.C. Power*	✓					
*Balance-of-Plant Systems -						

TABLE 15.4.8-2 (CONTINUED) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR THE CEA EJECTION EVENT

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*	✓					
24. Class 1E D.C. Power*	✓					

NOTES:

1. Loss of offsite power following turbine trip results in loss of power to the Non-ESF loads. The diesel generators start and supply power to the ESF loads.

*Balance-of-Plant Systems

TABLE 15.4.8-3

UTILIZATION OF SAFETY SYSTEMS

FOR THE CEA EJECTION EVENT

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems	✓				
4. Supplementary Protection System					
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves	✓				
8. Main Steam Isolation System*			✓		
9. Emergency Feedwater System*	✓				1
10. Safety Injection System	✓				
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*	✓				
13. Containment Isolation System*	✓				
14. Containment Spray System*	✓				
15. Iodine Removal System*	✓				
16. Containment Combustible Gas Control System*	✓				
17. Diesel Generators and Support Systems*	✓				
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

Notes:

1. One auxiliary feedwater pump is used for cooldown.

*Balance-of-Plant Systems -

TABLE 15.4.8-4

INITIAL REACTOR STATES CONSIDERED
FOR THE CEA EJECTION EVENT*

Initial Rod Configuration	Ejected Rod Worth, (%$\Delta\rho$)	Ejected Radial Peaking Factor
Bank 5 Inserted	0.002	2.20
Banks 4 & 5 Inserted	0.003	2.65
Banks 3, 4, & 5 Inserted	0.004	4.90
Banks 2, 3, 4, & 5 Inserted	0.007	5.60
Banks 1,2,3,4 & 5 Inserted	0.010	8.00

*All cases were initiated from BOC and EOC initial conditions.

TABLE 15.4.8-5

ASSUMPTIONS USED FOR THE CEA EJECTION ANALYSIS
FULL POWER BEGINNING OF CYCLE INITIAL CONDITIONS

Parameters	Assumptions
Initial Core Power Level, Mwt	3876
Delayed Neutron Fraction, β	.00730
Moderator Temperature Coefficient	Section 15.0 Most positive value
Ejected CEA Worth, 10^{-2} $\Delta\rho$	0.2
Doppler Weighting Factor,	1.0
Initial Three-Dimensional Fuel Pin Peaking Factor	2.31
Ejected Three-Dimensional Fuel Pin Peaking Factor	3.30
Total CEA Worth Available for Insertion on Reactor Trip, 10^{-2} $\Delta\rho$	-3.81
Postulated CEA Ejection Time, sec	0.05
Core Inlet Coolant Temperature,° F	580
Core Mass Flow Rate, 10^6 lbm/hr	177.6
Reactor Coolant System Pressure, psia	2200
Break Size, ft^2	0.04

TABLE 15.4.8-6
(Sheet 1 of 4)

PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION

Parameter	Value
A. Data and Assumptions Used to Evaluate the Raioactive Source Term	
1. General	
a. Power Level, Mwt	3876
b. Burnup	EOC (Equilibrium)
c. Percent of Fuel Calculated to Experience DNB, %	9.8
d. Percent of Fuel Calculated to Experience Incipient Centerline Melt, %	0.0
e. Reactor Coolant Activity Before Event	Table 11.1-2
f. Secondary System Activity Before Event	Section 15.0.4
g. Primary System Liquid Inventory, lbm	533,700
h. Steam Generator Inventory	
- Liquid, lbm per steam generator	159,000
- Steam, lbm per steam generator	15,034
B. Data and Assumptions Used to Estimate Activity Released	
1. Containment Leakage	
a. Containment Volume, ft^3	Refer to Applicant's SAR
b. Containment Leak Rate, vol. %/day	Refer to Applicant's SAR
- 0 to 24 hours	
- 1 day to 30 days	

TABLE 15.4.8-6 (Cont'd.) (Sheet 2 of 4)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION

Parameters		Value
c.	Activity Available for Release from Containment at Time Zero, Ci	
	Isotope	
	I-131	1.55(+6)
	I-132	2.24(+6)
	I-133	3.0(+6)
	I-134	3.10(+6)
	I-135	2.79(+6)
	Kr-85M	3.19(+5)
	Kr-85	1.59(+4)
	Kr-87	5.66(+5)
	Kr-88	8.17(+5)
	Xe-131M	9.96(+3)
	Xe-133	3.03(+6)
	Xe-135	4.53(+5)
	Xe-138	2.30(+6)
d.	Percent of Core Fission Products Assumed Released to Containment	Refer to Paragraph 15.4.5.2.3.C
e.	Credit for Radioactive Decay	
	- Hold up in Containment	Yes
	- In Transit to Dose Point	No
2.	Activity Release from the Secondary System	
a.	Primary to Secondary Leak Rate, gal/min.	1.0 (total)
b.	Total Mass Release Through the Main Steam Safety Valves	136,800
c.	Total Mass Release Through the ADVs from 30 minutes to 2 hours, lbm	714,000

[1]Numbers in parenthesis indicate powers of 10

TABLE 15.4.8-6 (Cont'd.) (Sheet 3 of 4)

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION

Parameters		Value
d.	Reactor Coolant System Activity After Event, Ci	
	Isotope	
	I-131	1.55(+6)
	I-132	2.24(+6)
	I-133	3.0(+6)
	I-134	3.10(+6)
	I-135	2.79(+6)
	Kr-85M	3.19(+5)
	Kr-85	1.59(+4)
	Kr-87	5.66(+5)
	Kr-88	8.11(+5)
	Xe-131M	9.96(+3)
	Xe-133	3.03(+6)
	Xe-135	4.53(+5)
	Xe-138	2.30(+6)
e.	Percent of Core Fission Products Assumed Released to Reactor Coolant	Refer to Section 15.4.8.2.3.C
f.	Iodine Carryover Fraction in the Steam Generators	Section 15.0.4
g.	Credit for Radioactive Decay in Transit to Dose Point	No
h.	Loss of Offsite Power	Yes

C. Dispersion Data

1.	Distance to Exclusion Area Boundary, m	500

PARAMETERS USED IN EVALUATING THE
RADIOLOGICAL CONSEQUENCES OF A CEA EJECTION

Parameters	Value
2. Distance to Low Population Zone Outer Boundary, m	3000
3. Atmospheric Dispersion Factor, sec/m^3	2.00×10^{-3}
D. Dose Data	
1. Method of Dose Calculation	Section 15.0-4
2. Dose Conversion Assumptions	Section 15.0-4
3. Control Room Design Parameters	See Applicant's SAR

TABLE 15.4.8-7

SECONDARY SYSTEM MASS RELEASE
TO THE ATMOSPHERE

Time (Sec)	Integrated Safety Valve Flow	Integrated Primary to Secondary Leakage
0.0	0.0	0.0
2.0	0.0	0.2
3.0	460	0.3
5.0	5110	0.5
10.0	25490	1.0
20.0	53400	2.0
120.0	93400	12.0
220.0	110522	22.0
320.0	122120	32.0
420.0	127090	42.0
*850.0	136783	85.0
**1800.0	136783	180.0

* Main steam safety valve close

** Operator takes control of plant and begins cooldown utilizing atmospheric dump valves.

TABLE 15.4.8-8

RADIOLOGICAL CONSEQUENCES OF A POSTULATED CEA EJECTION EVENT

Result	From Containment Leakage	From Secondary System Steam Releases
Exclusion Area Boundary Dose (0-2 hours), rem:		
Thyroid	Refer to Applicant's	46.0
Whole-body	SAR	6.04

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SPECIFIC EVENT

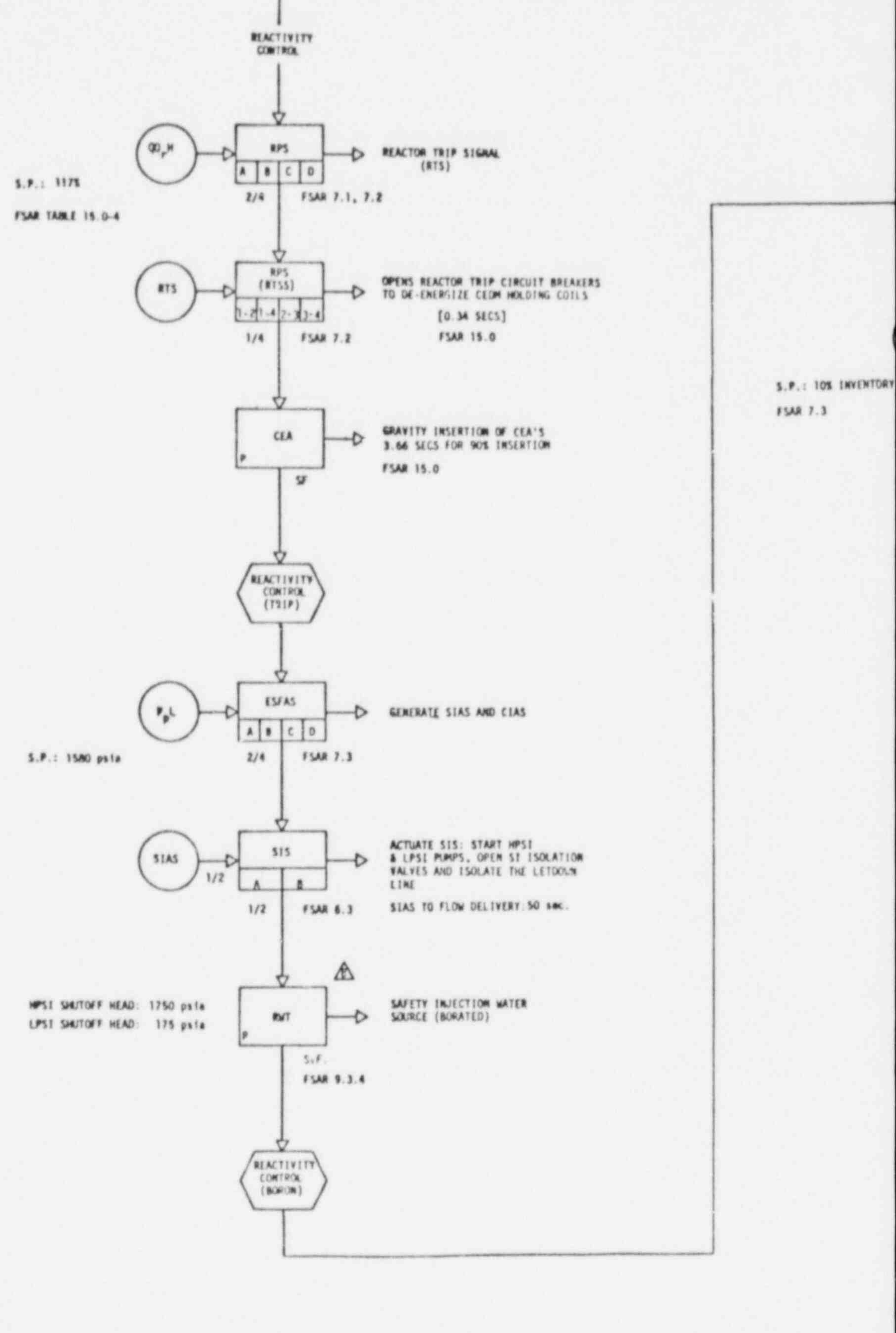
CONTROL ELEMENT ASSEMBLY EJECTION

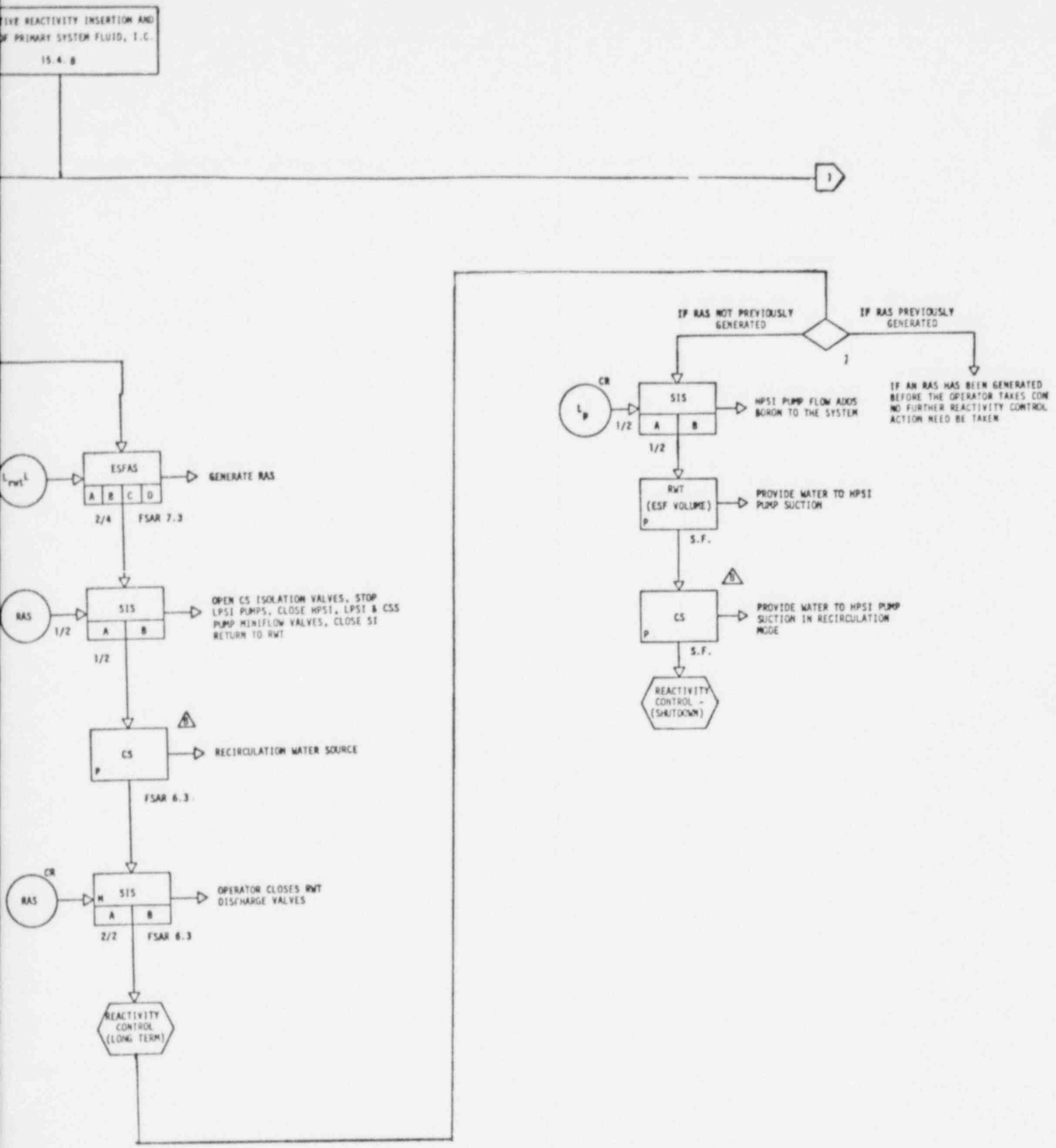
COINCIDENT OCCURRANCES

LOSS OF OFFSITE POWER

POSI

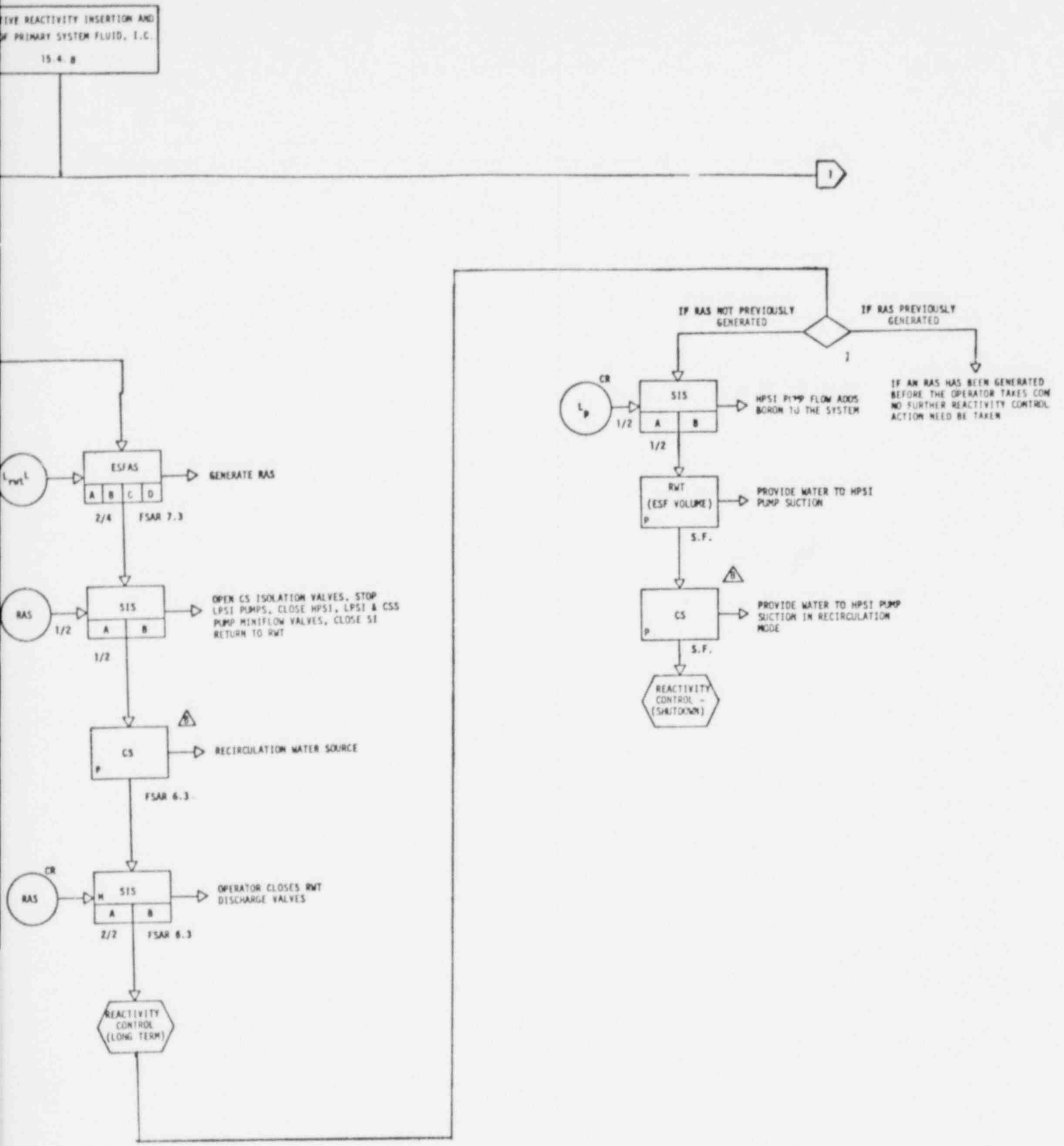
LOSS





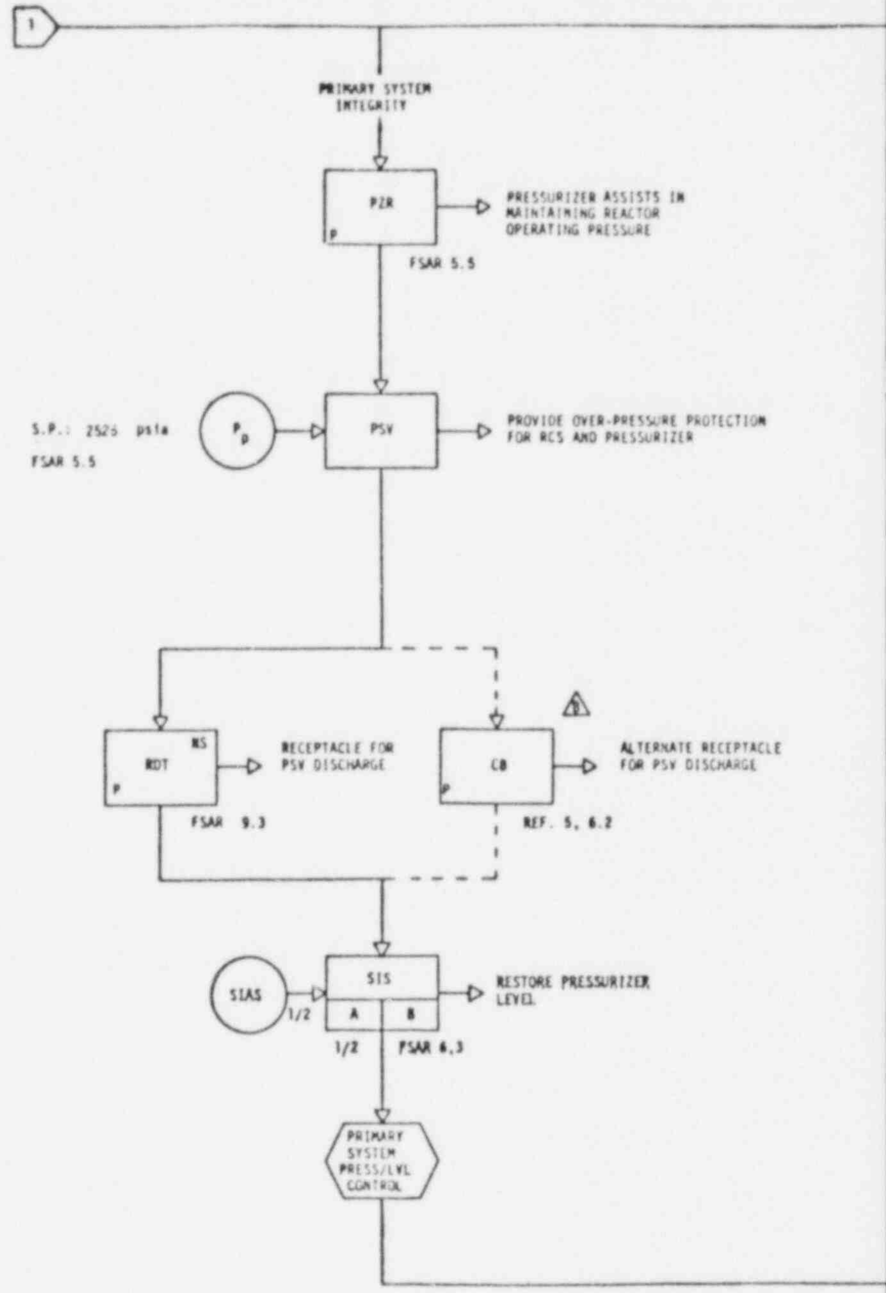
Amendment No. 7
March 31, 1982

C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8 -1A

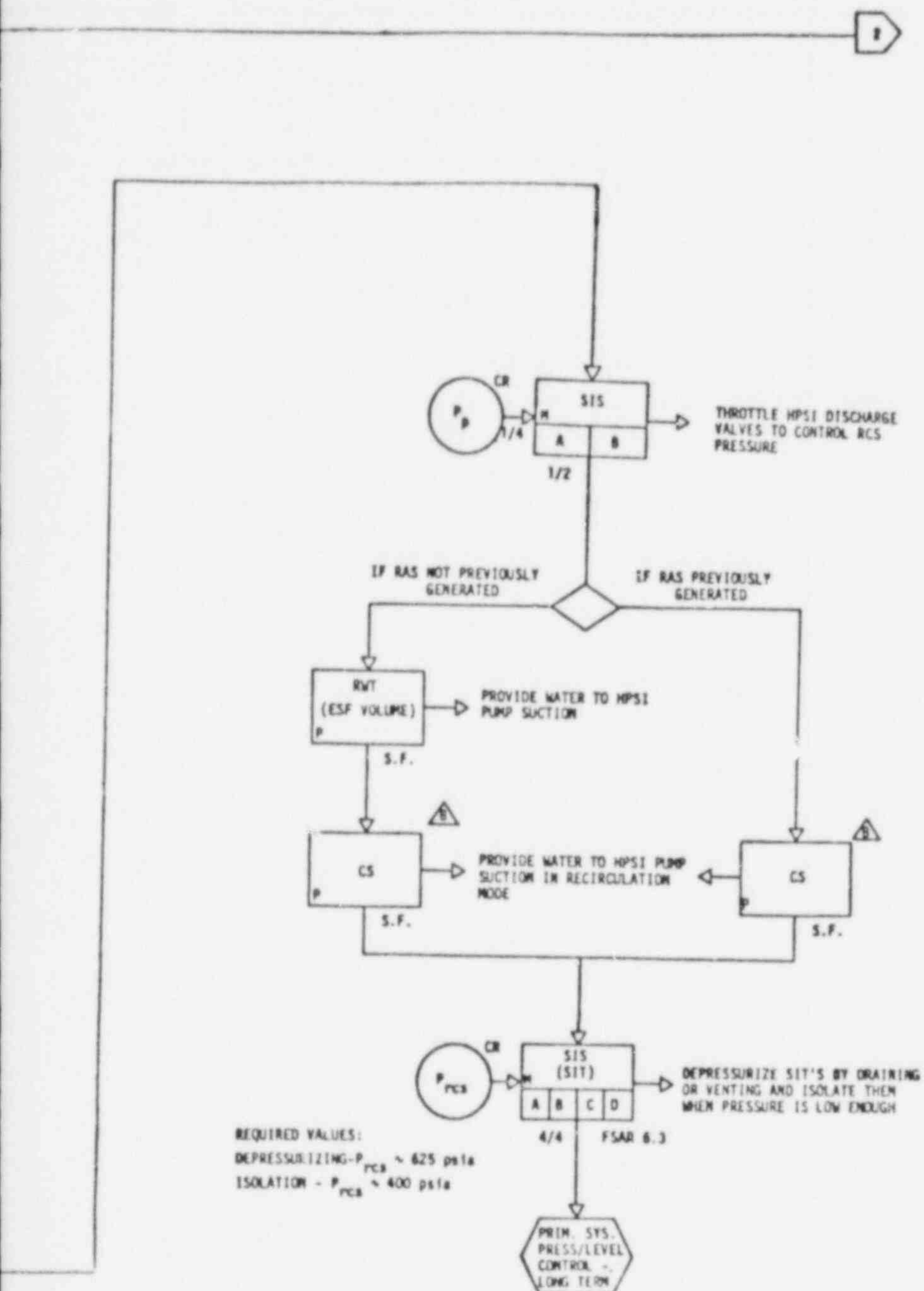


Amendment No. 7
March 31, 1982

C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8 -1A

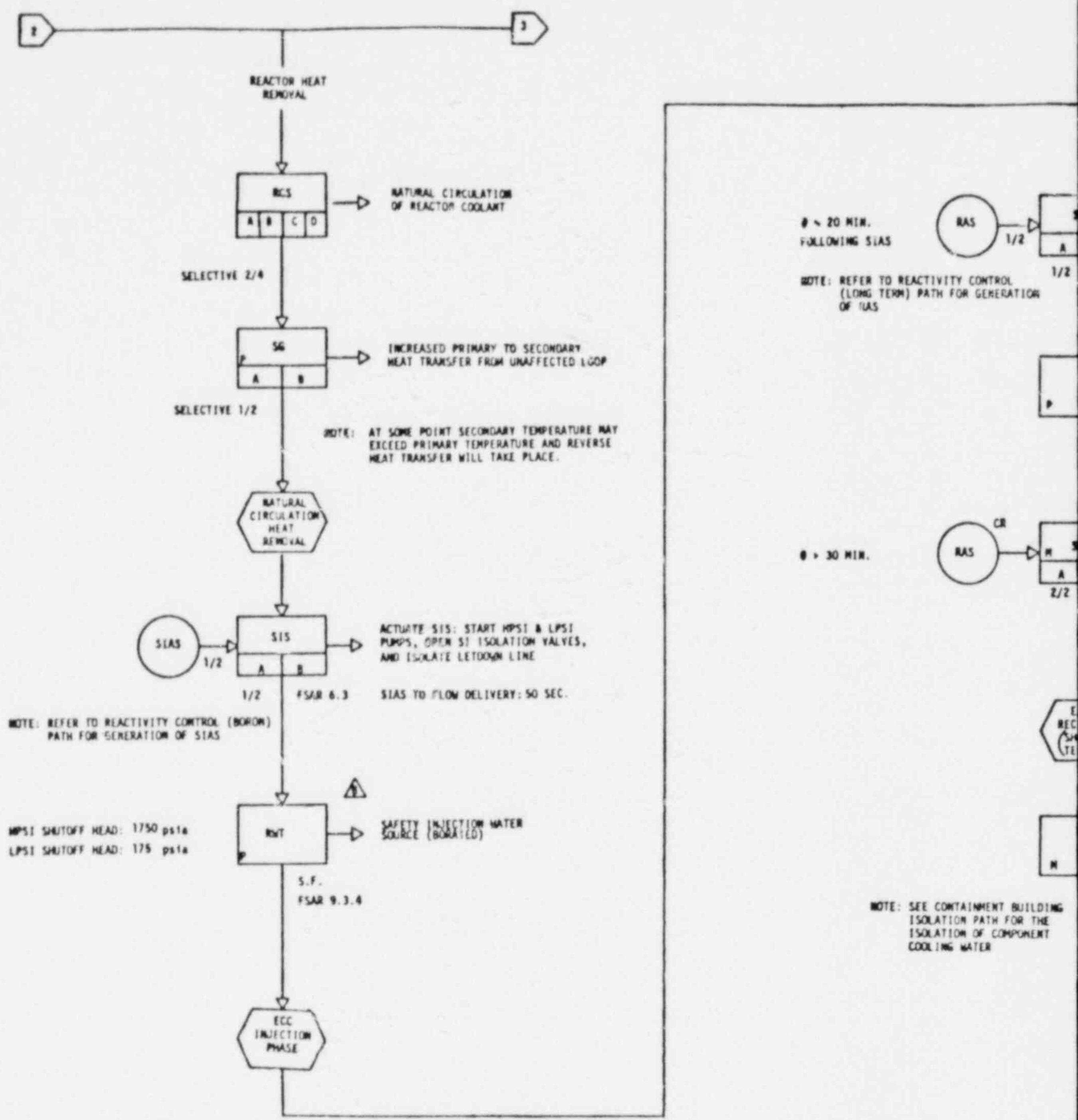


1
PRIMARY SYSTEM INTEGRITY
PZR
P
FSAR 5.5
PRESSURIZER ASSISTS IN MAINTAINING REACTOR OPERATING PRESSURE
S.P.: 2525 psia
FSAR 5.5
PSV
PROVIDE OVER-PRESSURE PROTECTION FOR RCS AND PRESSURIZER
RDT
NS
P
FSAR 9.3
RECEPTACLE FOR PSV DISCHARGE
CB
P
REF. 5, 6.2
ALTERNATE RECEPTACLE FOR PSV DISCHARGE
SIAS
1/2
SIS
A
B
1/2
FSAR 6.3
RESTORE PRESSURIZER LEVEL
PRIMARY SYSTEM PRESS/LVL CONTROL

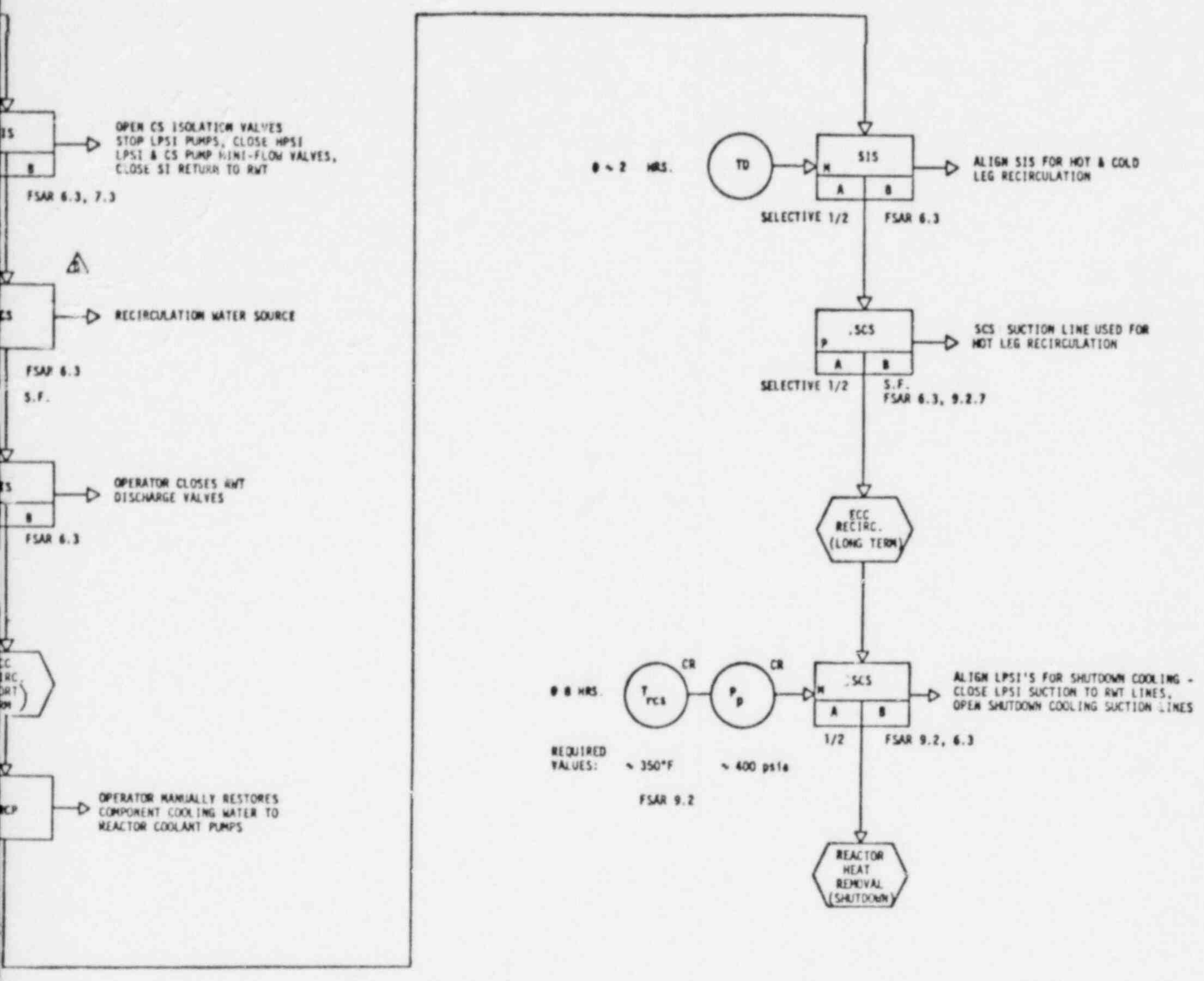


Amendment No. 7
March 31, 1982

C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8-1B



2
3
REACTOR HEAT REMOVAL
RCS
A B C D
NATURAL CIRCULATION OF REACTOR COOLANT
SELECTIVE 2/4
SG
P
A B
INCREASED PRIMARY TO SECONDARY HEAT TRANSFER FROM UNAFFECTED LOOP
SELECTIVE 1/2
NOTE: AT SOME POINT SECONDARY TEMPERATURE MAY EXCEED PRIMARY TEMPERATURE AND REVERSE HEAT TRANSFER WILL TAKE PLACE.
NATURAL CIRCULATION HEAT REMOVAL
SIAS
1/2
SIS
A B
ACTUATE SIS: START HPSI & LPSI PUMPS, OPEN SI ISOLATION VALVES, AND ISOLATE LETDOWN LINE
1/2
FSAR 6.3
SIAS TO FLOW DELIVERY: 50 SEC.
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF SIAS
1
HPSI SHUTOFF HEAD: 1750 psia
LPSI SHUTOFF HEAD: 175 psia
RWT
P
SAFETY INJECTION WATER SOURCE (BORATED)
S.F.
FSAR 9.3.4
ECC INJECTION PHASE
θ ~ 20 MIN. FOLLOWING SIAS
RAS
1/2
A
1/2
NOTE: REFER TO REACTIVITY CONTROL (LONG TERM) PATH FOR GENERATION OF RAS
P
CR
θ > 30 MIN.
RAS
M
A
2/2
M
NOTE: SEE CONTAINMENT BUILDING ISOLATION PATH FOR THE ISOLATION OF COMPONENT COOLING WATER



NOTE: IT WILL BE NECESSARY TO RESTORE THE SECONDARY HEAT SINK IN ORDER TO COOLDOWN TO SHUTDOWN COOLING INITIATION CONDITIONS.

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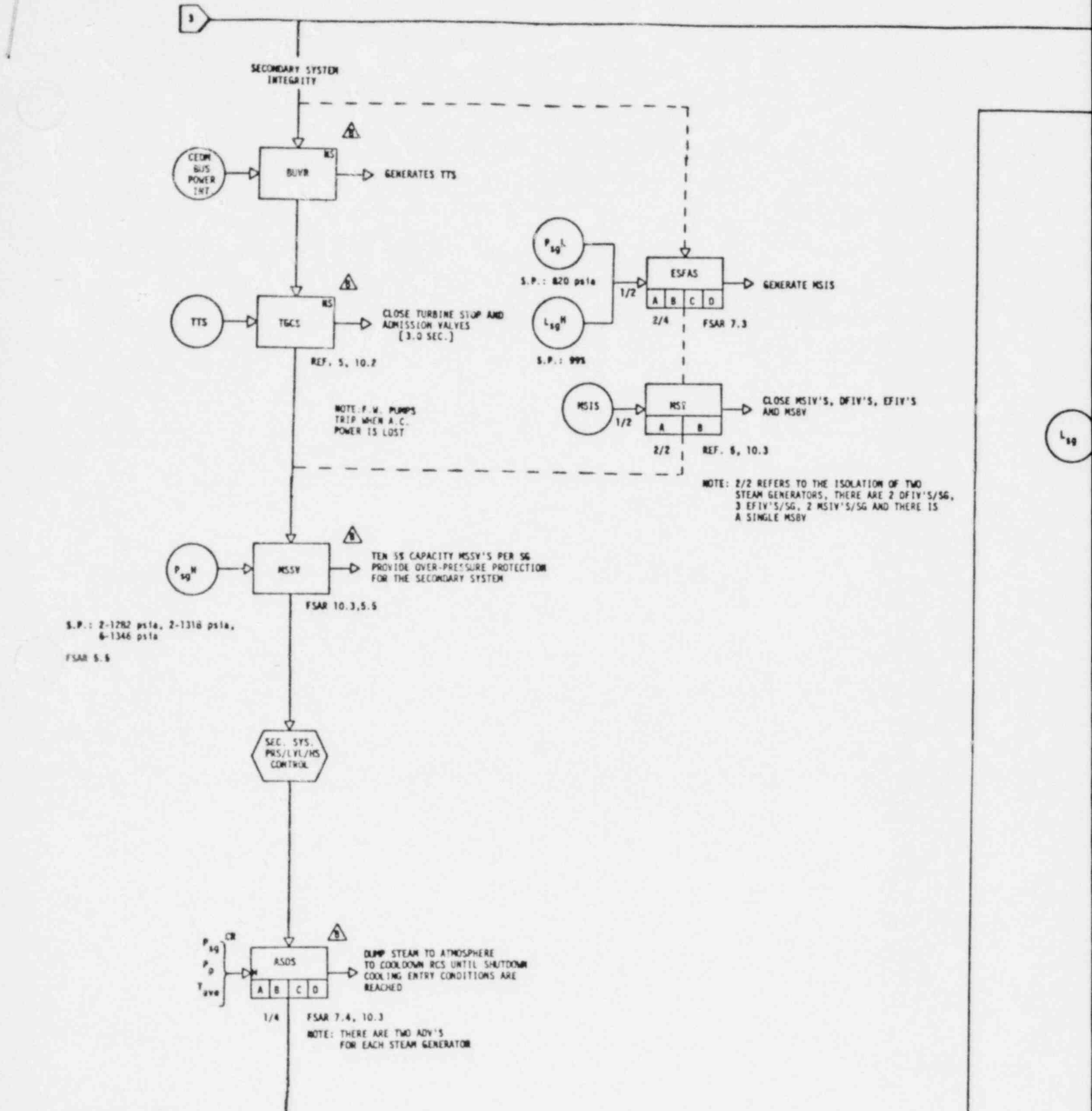
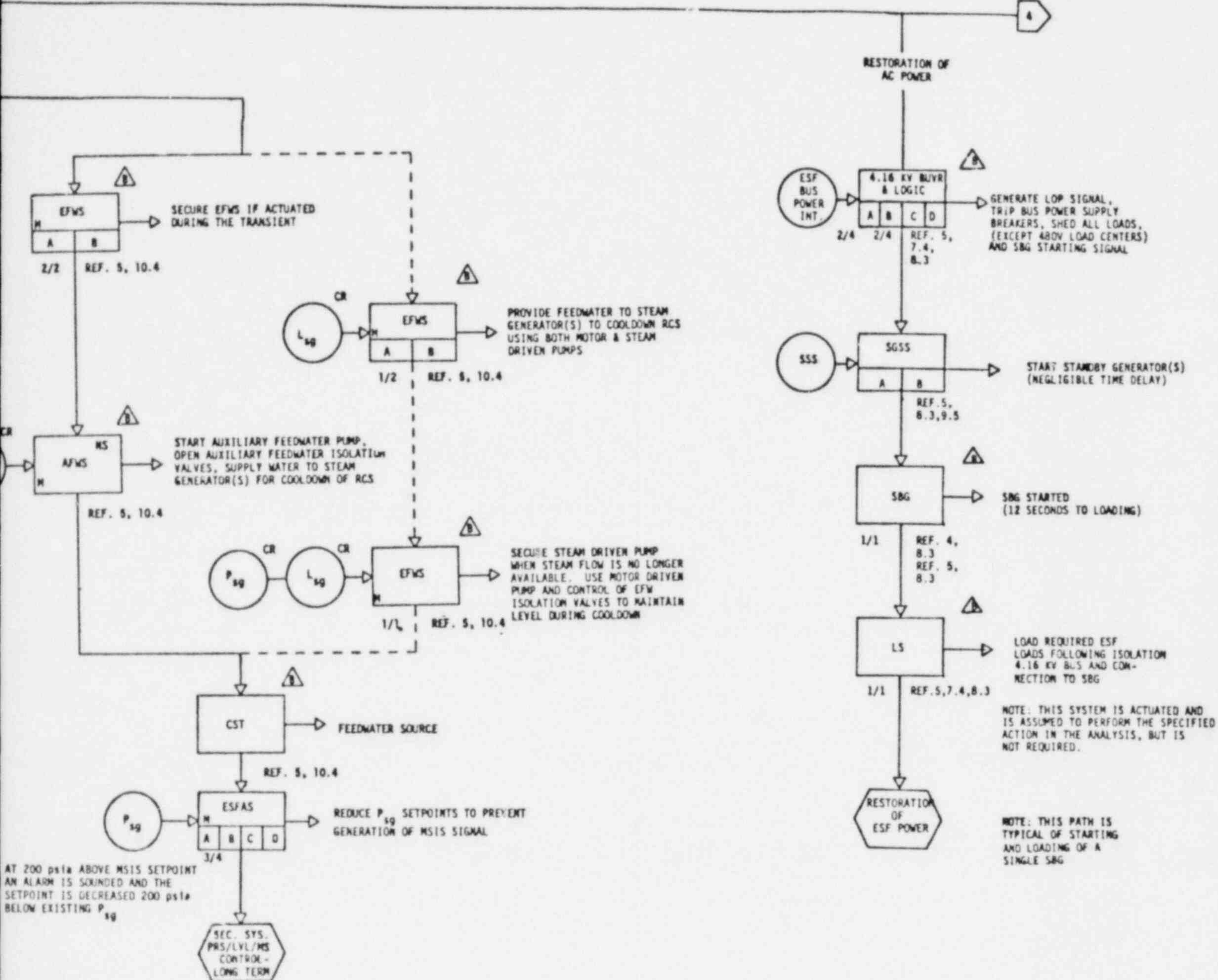
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8-1C



3
SECONDARY SYSTEM INTEGRITY
CEDM BUS POWER INT
BUVR
GENERATES TTS
TTS
TGCS
CLOSE TURBINE STOP AND ADMISSION VALVES [3.0 SEC.]
REF. 5, 10.2
NOTE: F.W. PUMPS TRIP WHEN A.C. POWER IS LOST
S.P.: 820 psia
ESFAS
A B C D
1/2
2/4
FSAR 7.3
GENERATE MSIS
S.P.: 99%
MSIS
1/2
A B
2/2
REF. 6, 10.3
CLOSE MSIV'S, DFIV'S, EFIV'S AND MSBV
NOTE: 2/2 REFERS TO THE ISOLATION OF TWO STEAM GENERATORS, THERE ARE 2 DFIV'S/SG, 3 EFIV'S/SG, 2 MSIV'S/SG AND THERE IS A SINGLE MSBV
MSSV
TEN 5% CAPACITY MSSV'S PER SG PROVIDE OVER-PRESSURE PROTECTION FOR THE SECONDARY SYSTEM
FSAR 10.3,5.5
S.P.: 2-1282 psia, 2-1318 psia, 6-1346 psia
FSAR 5.5
SEC. SYS. PRS/LVL/HS CONTROL
ASDS
A B C D
1/4
FSAR 7.4, 10.3
DUMP STEAM TO ATMOSPHERE TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
NOTE: THERE ARE TWO ADV'S FOR EACH STEAM GENERATOR



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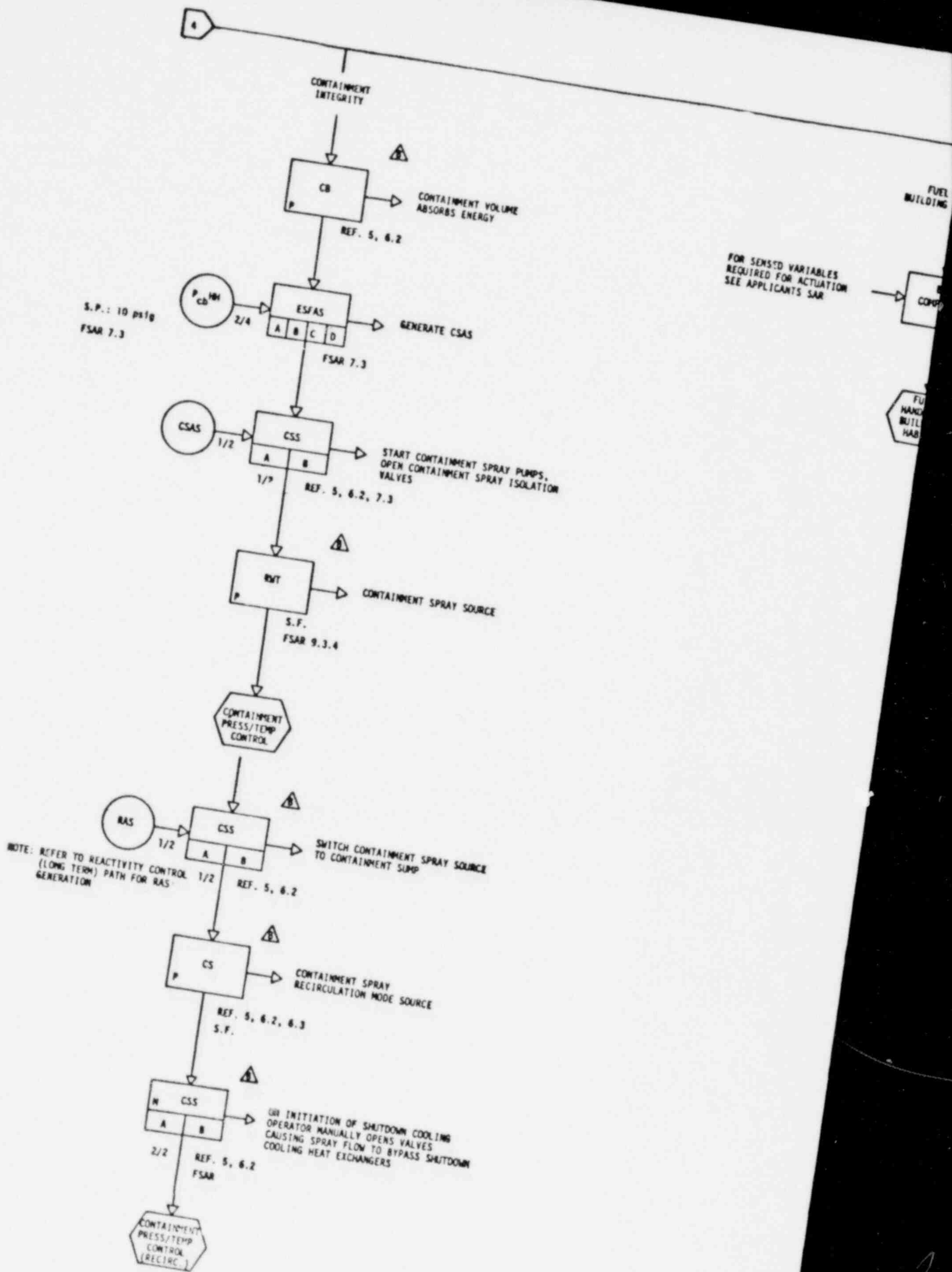
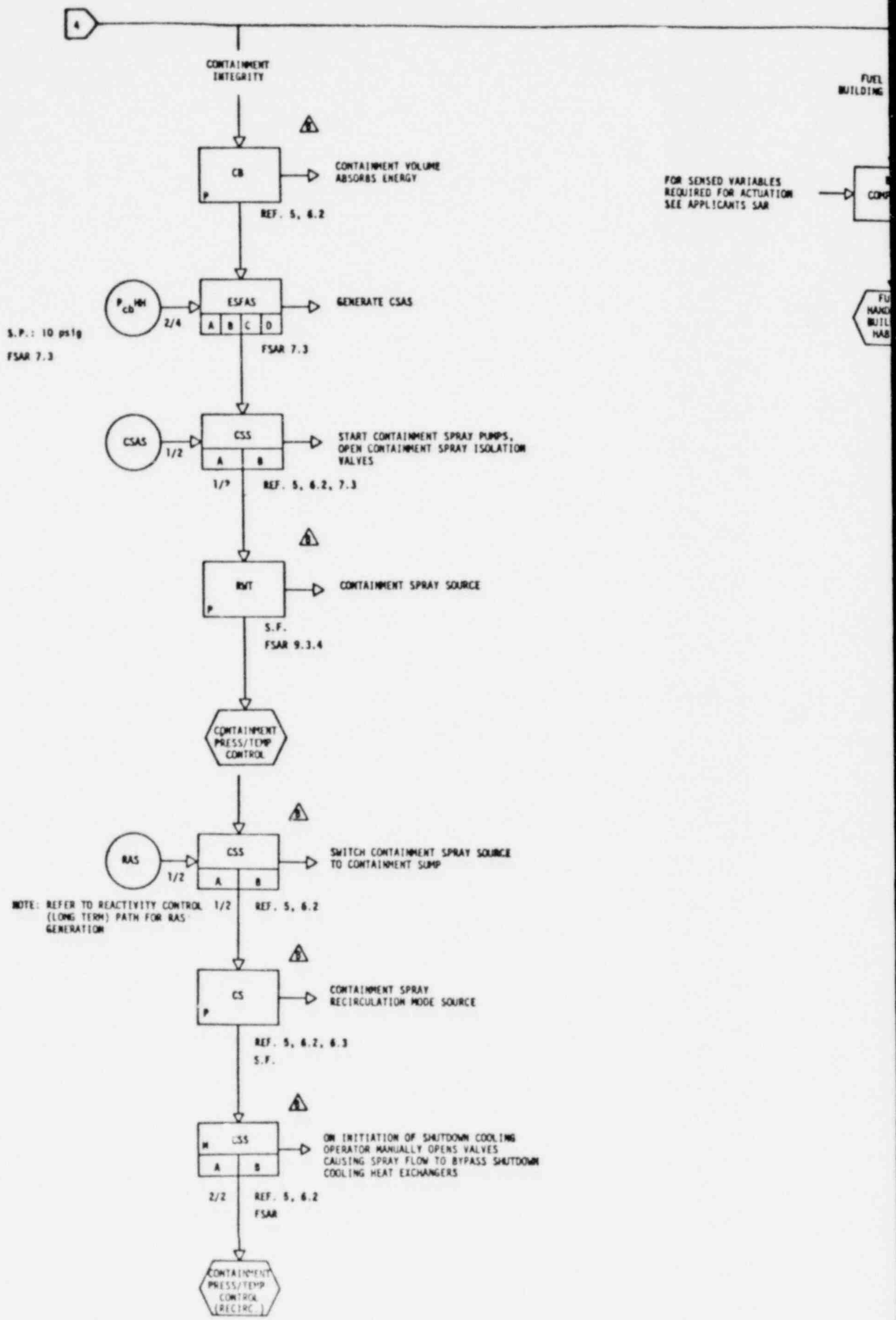
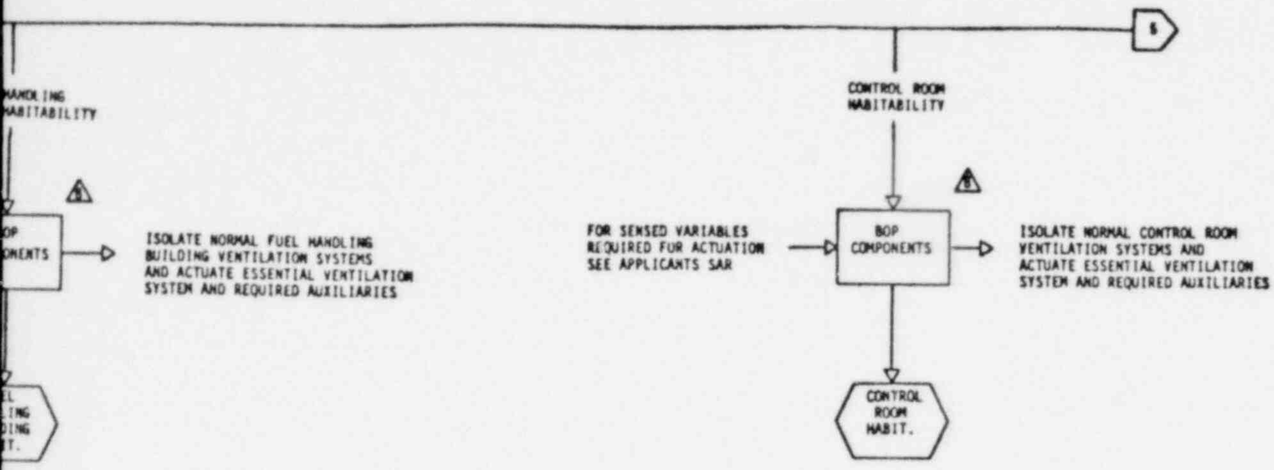
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8 -1D


4
CONTAINMENT INTEGRITY
CB
P
CONTAINMENT VOLUME ABSORBS ENERGY
REF. 5, 6.2
S.P.: 10 psig
FSAR 7.3
P_{cb}HH
2/4
ESFAS
A B C D
GENERATE CSAS
FSAR 7.3
CSAS
1/2
CSS
A B
START CONTAINMENT SPRAY PUMPS, OPEN CONTAINMENT SPRAY ISOLATION VALVES
REF. 5, 6.2, 7.3
RWT
P
CONTAINMENT SPRAY SOURCE
S.F.
FSAR 9.3.4
CONTAINMENT PRESS/TEMP CONTROL
RAS
1/2
CSS
A B
SWITCH CONTAINMENT SPRAY SOURCE TO CONTAINMENT SUMP
NOTE: REFER TO REACTIVITY CONTROL (LONG TERM) PATH FOR RAS GENERATION
1/2
REF. 5, 6.2
CS
P
CONTAINMENT SPRAY RECIRCULATION MODE SOURCE
REF. 5, 6.2, 6.3
S.F.
M CSS
A B
ON INITIATION OF SHUTDOWN COOLING OPERATOR MANUALLY OPENS VALVES CAUSING SPRAY FLOW TO BYPASS SHUTDOWN COOLING HEAT EXCHANGERS
2/2
REF. 5, 6.2
FSAR
CONTAINMENT PRESS/TEMP CONTROL (RECIRC.)
FUEL BUILDING
FOR SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR


4
CONTAINMENT INTEGRITY
FUEL BUILDING
CB
P
CONTAINMENT VOLUME ABSORBS ENERGY
REF. 5, 6.2
FOR SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
P cb HH
2/4
ESFAS
A B C D
GENERATE CSAS
S.P.: 10 psig
FSAR 7.3
FSAR 7.3
CSAS
1/2
CSS
A B
START CONTAINMENT SPRAY PUMPS, OPEN CONTAINMENT SPRAY ISOLATION VALVES
1/?
REF. 5, 6.2, 7.3
RWT
P
CONTAINMENT SPRAY SOURCE
S.F.
FSAR 9.3.4
CONTAINMENT PRESS/TEMP CONTROL
RAS
1/2
CSS
A B
SWITCH CONTAINMENT SPRAY SOURCE TO CONTAINMENT SUMP
NOTE: REFER TO REACTIVITY CONTROL (LONG TERM) PATH FOR RAS GENERATION
1/2
REF. 5, 6.2
CS
P
CONTAINMENT SPRAY RECIRCULATION MODE SOURCE
REF. 5, 6.2, 6.3
S.F.
M
CSS
A B
ON INITIATION OF SHUTDOWN COOLING OPERATOR MANUALLY OPENS VALVES CAUSING SPRAY FLOW TO BYPASS SHUTDOWN COOLING HEAT EXCHANGERS
2/2
REF. 5, 6.2
FSAR
CONTAINMENT PRESS/TEMP CONTROL (RECIRC.)



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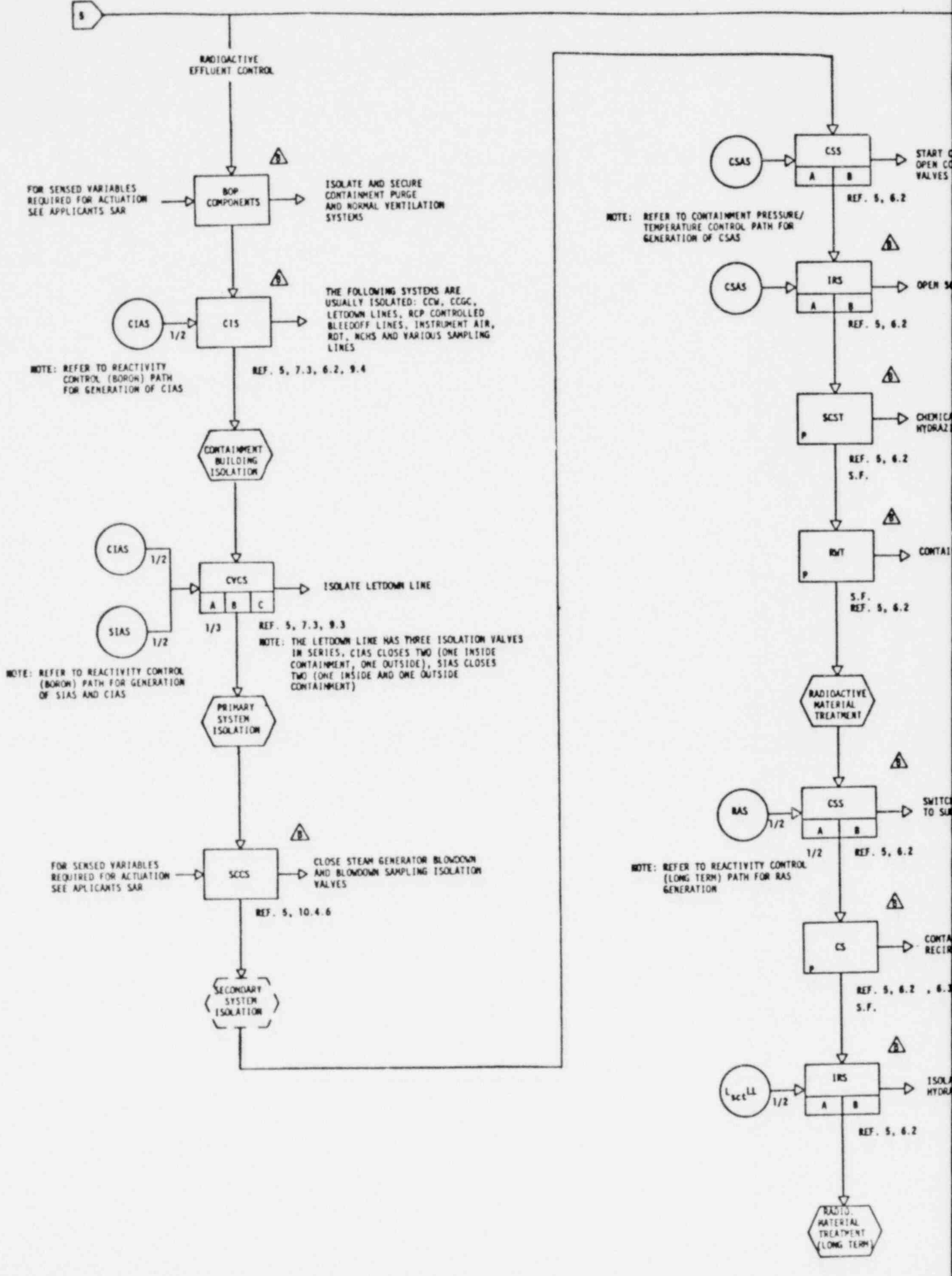
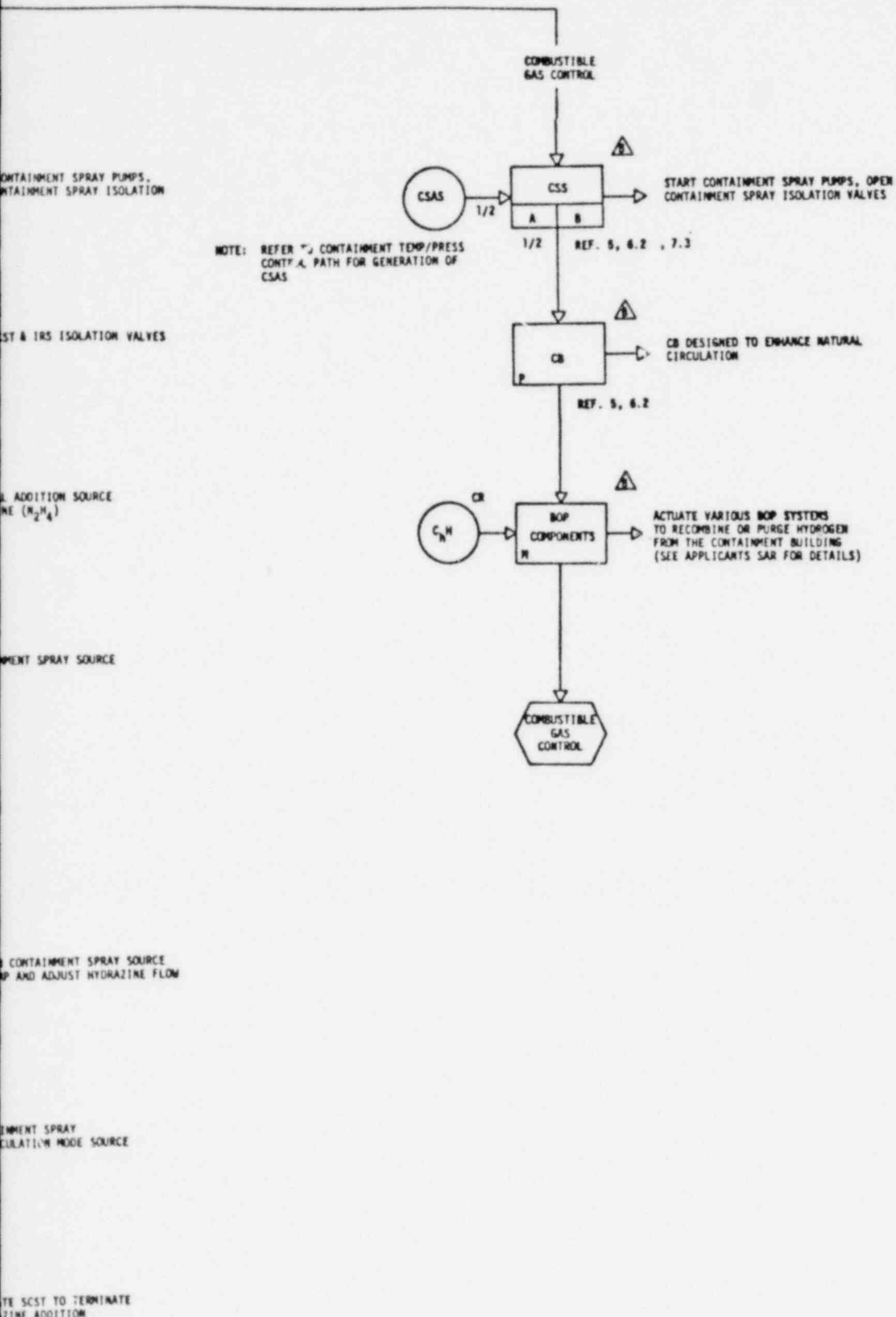
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8 -1E



5
RADIOACTIVE EFFLUENT CONTROL
FOR SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
BOP COMPONENTS
ISOLATE AND SECURE CONTAINMENT PURGE AND NORMAL VENTILATION SYSTEMS
CIAS
1/2
CIS
THE FOLLOWING SYSTEMS ARE USUALLY ISOLATED: CCW, CCGC, LETDOWN LINES, RCP CONTROLLED BLEEDOFF LINES, INSTRUMENT AIR, RDT, NCHS AND VARIOUS SAMPLING LINES
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF CIAS
REF. 5, 7.3, 6.2, 9.4
CONTAINMENT BUILDING ISOLATION
CIAS
1/2
SIAS
1/2
CVCS
A B C
1/3
ISOLATE LETDOWN LINE
REF. 5, 7.3, 9.3
NOTE: THE LETDOWN LINE HAS THREE ISOLATION VALVES IN SERIES. CIAS CLOSES TWO (ONE INSIDE CONTAINMENT, ONE OUTSIDE), SIAS CLOSES TWO (ONE INSIDE AND ONE OUTSIDE CONTAINMENT)
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF SIAS AND CIAS
PRIMARY SYSTEM ISOLATION
FOR SENSED VARIABLES REQUIRED FOR ACTUATION SEE APLICANTS SAR
SCCS
CLOSE STEAM GENERATOR BLOWDOWN AND BLOWDOWN SAMPLING ISOLATION VALVES
REF. 5, 10.4.6
SECONDARY SYSTEM ISOLATION
CSAS
CSS
A B
START C
OPEN CO
VALVES
REF. 5, 6.2
NOTE: REFER TO CONTAINMENT PRESSURE/TEMPERATURE CONTROL PATH FOR GENERATION OF CSAS
CSAS
IRS
A B
OPEN S
REF. 5, 6.2
SCST
P
CHEMICA
HYDRAZI
REF. 5, 6.2
S.F.
RWT
P
CONTAI
S.F.
REF. 5, 6.2
RADIOACTIVE MATERIAL TREATMENT
RAS
1/2
CSS
A B
1/2
SWITC
TO SU
REF. 5, 6.2
NOTE: REFER TO REACTIVITY CONTROL (LONG TERM) PATH FOR RAS GENERATION
CS
P
CONTA
RECIR
REF. 5, 6.2 , 6.
S.F.
$L_{sct}LL$
1/2
IRS
A B
ISOLA
HYDRA
REF. 5, 6.2
RADIO. MATERIAL TREATMENT (LONG TERM)



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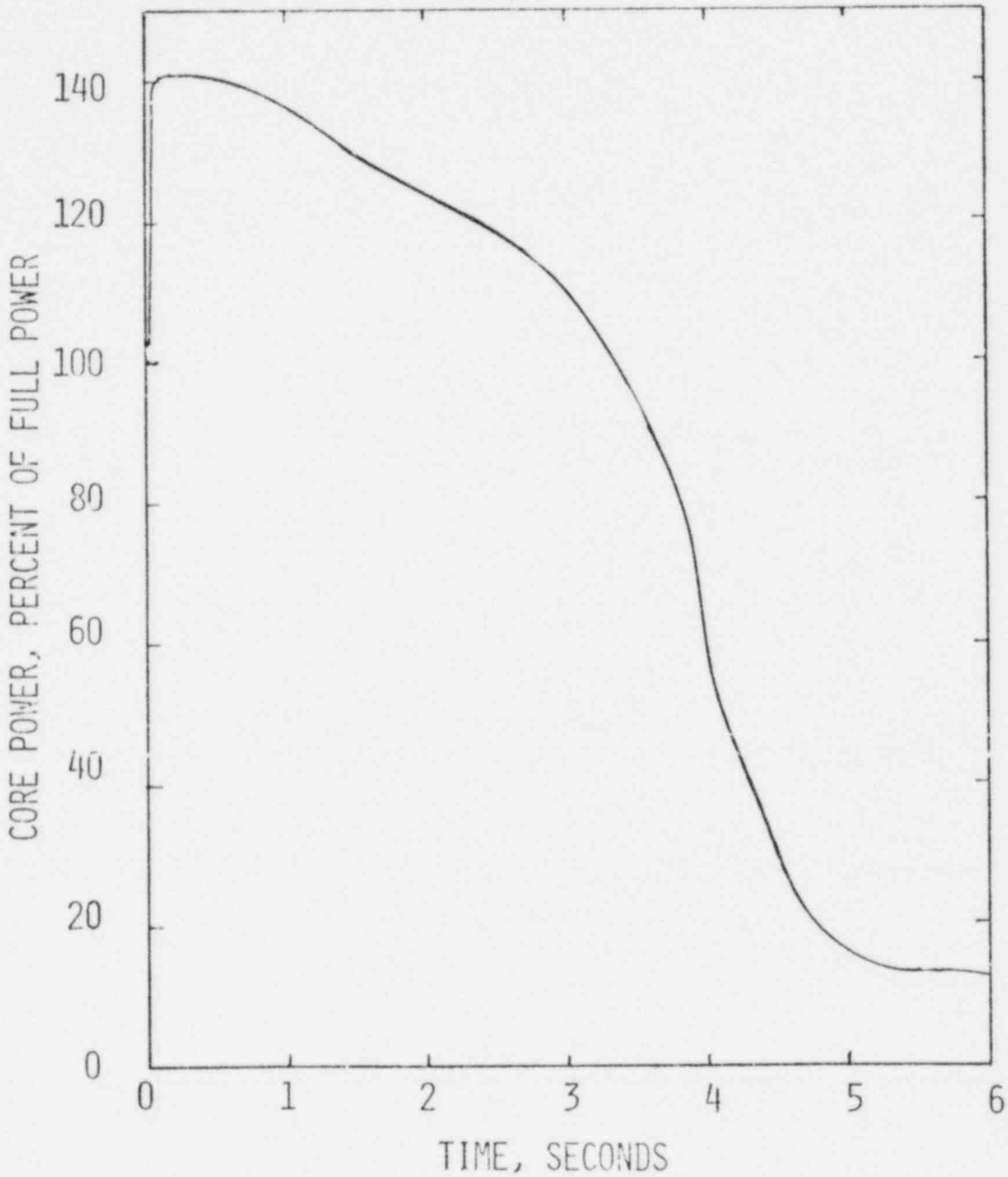
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8 -1F



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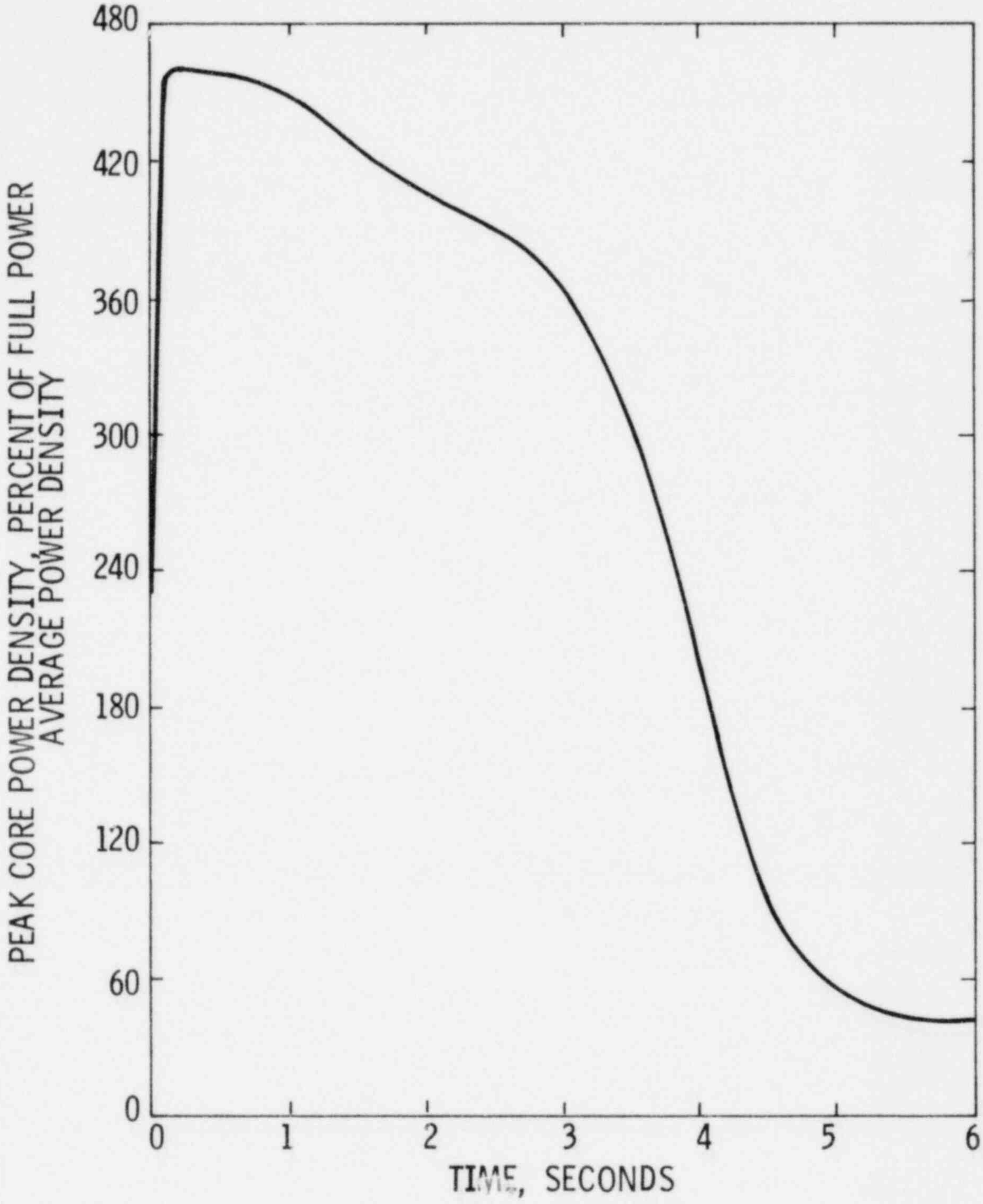
C - E SYSTEM 80	CEA EJECTION CORE POWER vs TIME	Figure 15.4.8-2



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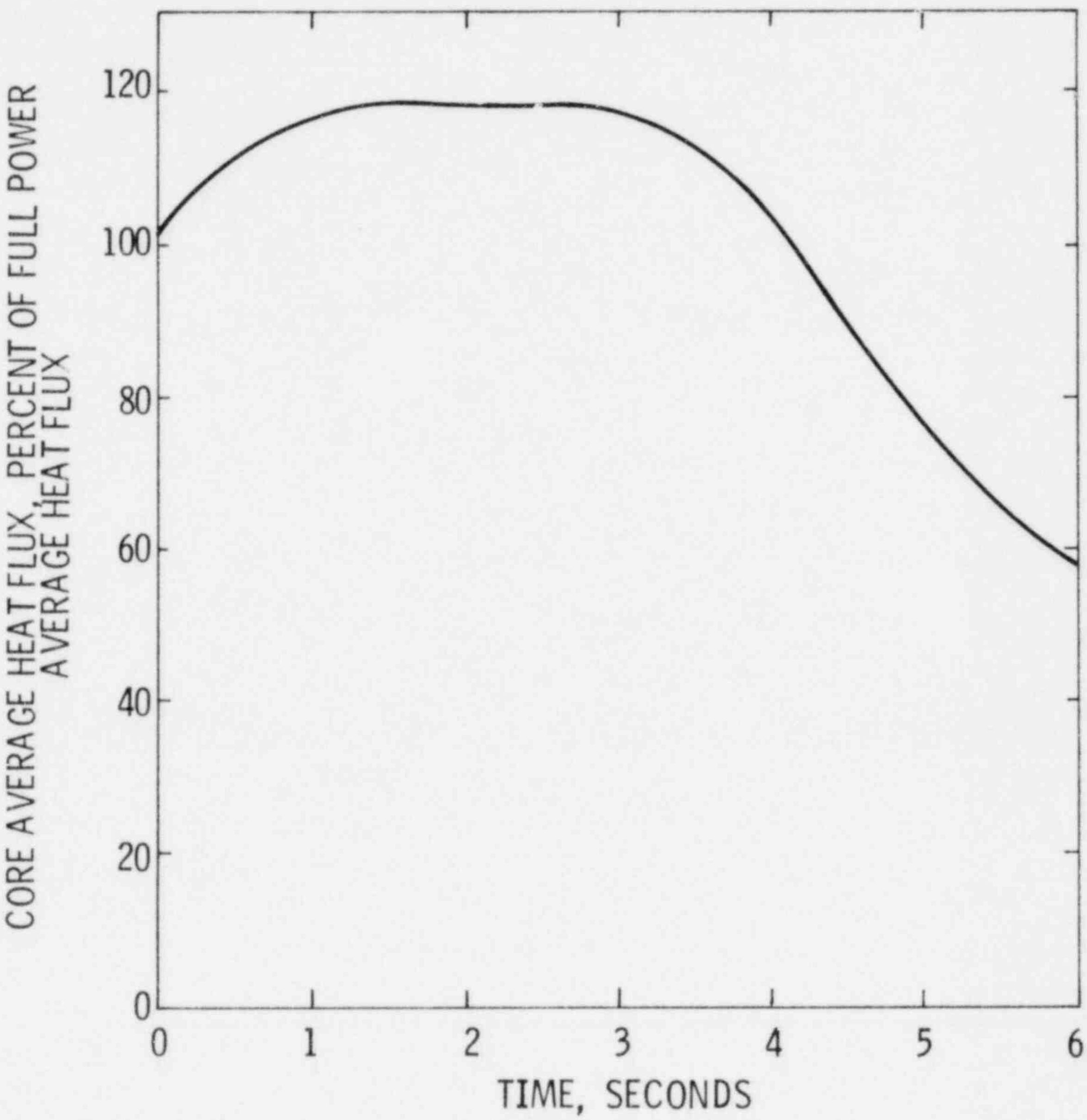
C - E SYSTEM 80	CEA EJECTION PEAK CORE POWER DENSITY vs TIME	Figure 15.4.8-3



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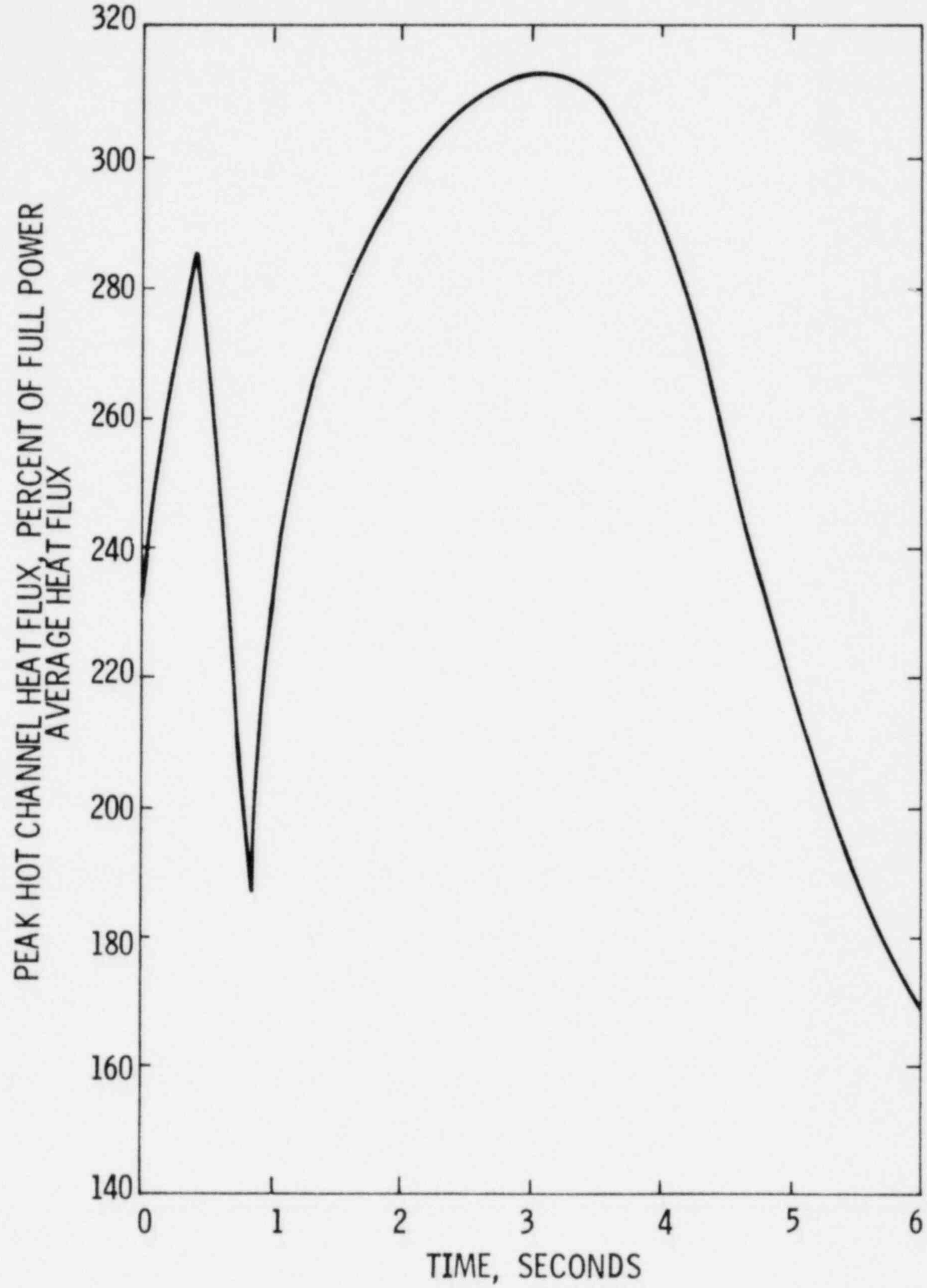
C - E SYSTEM 80	CEA EJECTION CORE AVERAGE HEAT FLUX vs TIME	Figure 15.4.8-4



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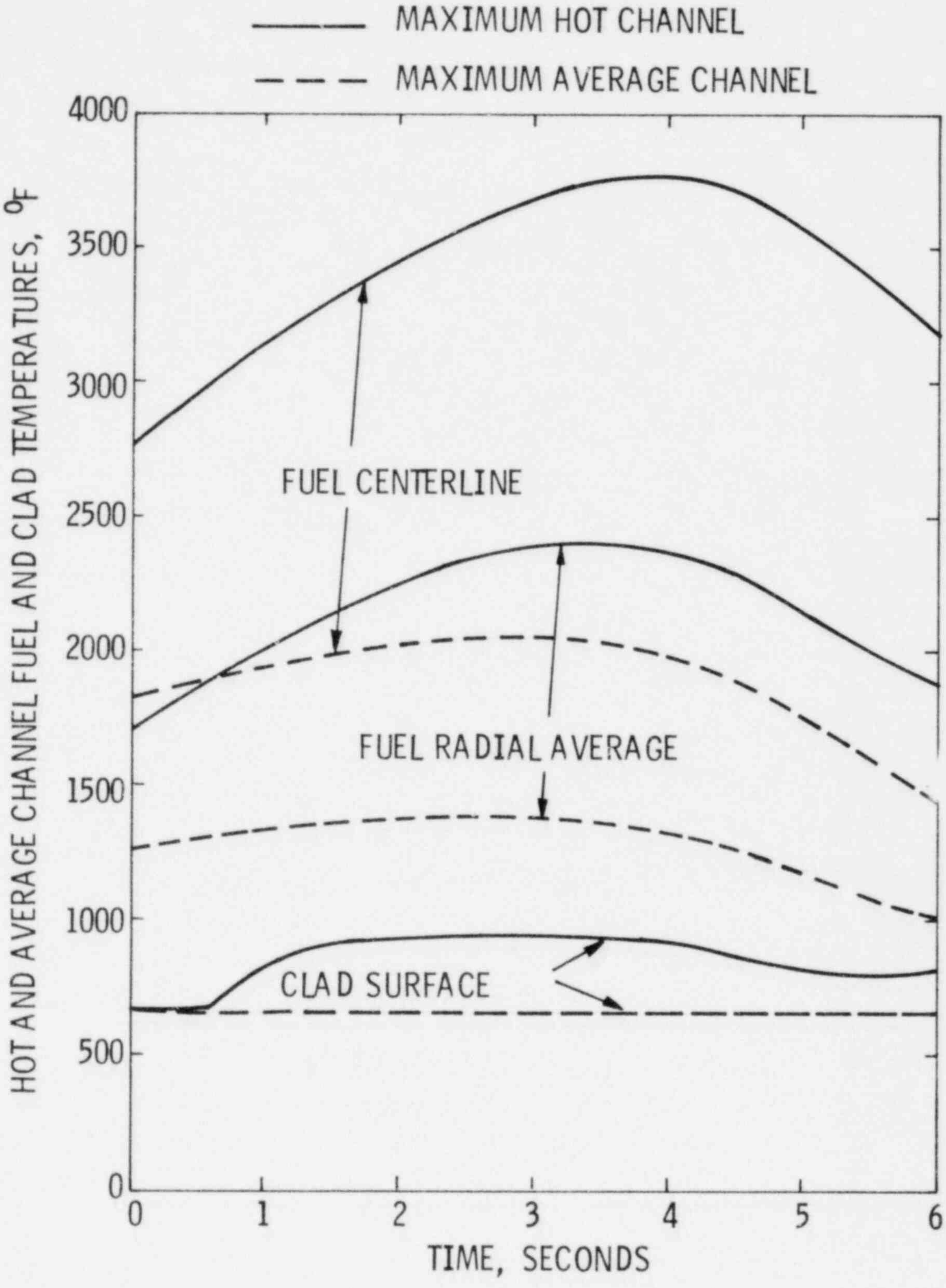
C-E SYSTEM 80	CEA EJECTION PEAK HOT CHANNEL HEAT FLUX vs TIME	Figure 15.4.8-5



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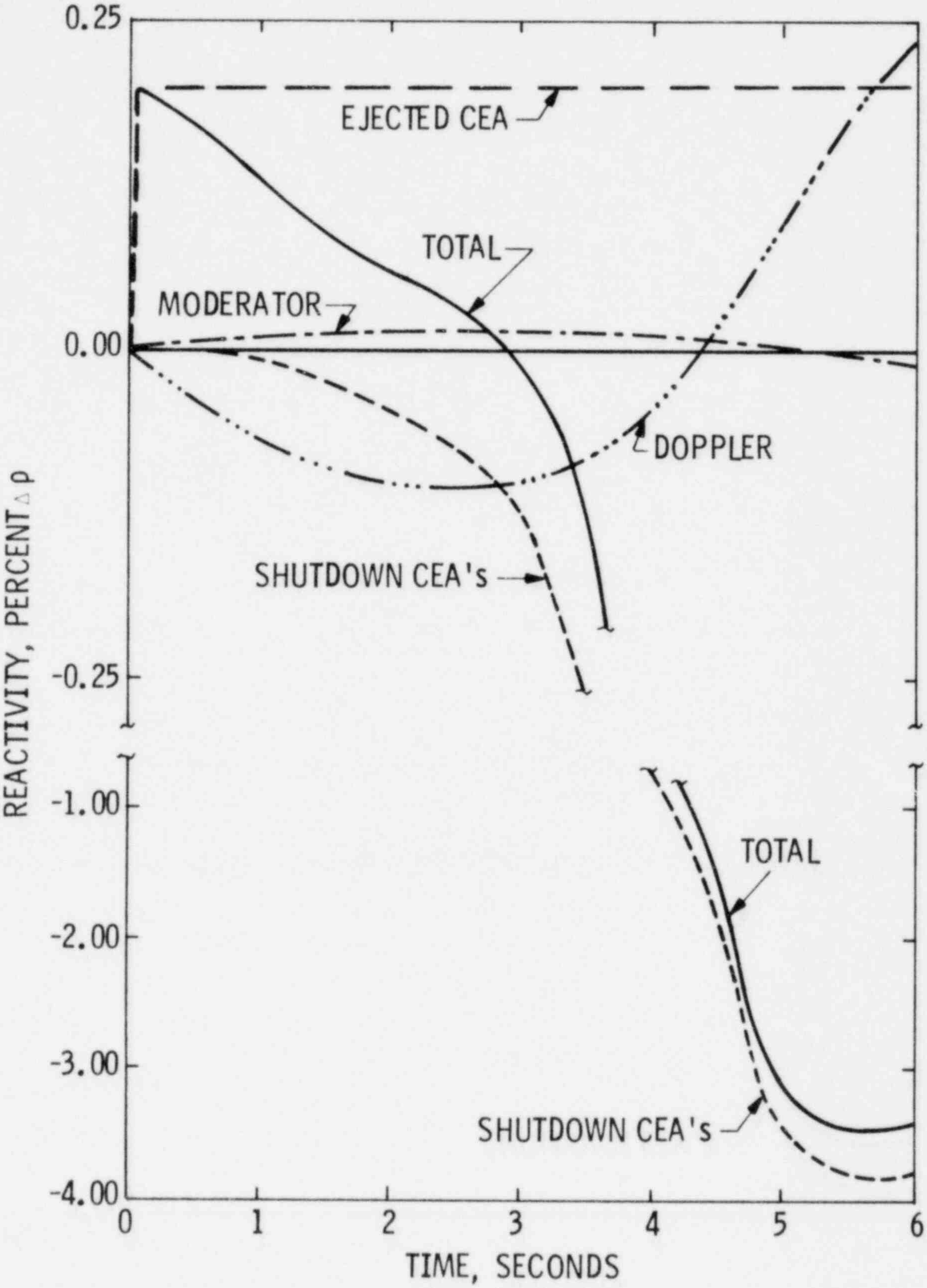
C-E SYSTEM 80	CEA EJECTION HOT AND AVERAGE CHANNEL FUEL AND CLAD TEMPERATURES vs TIME	Figure 15.4.8-6



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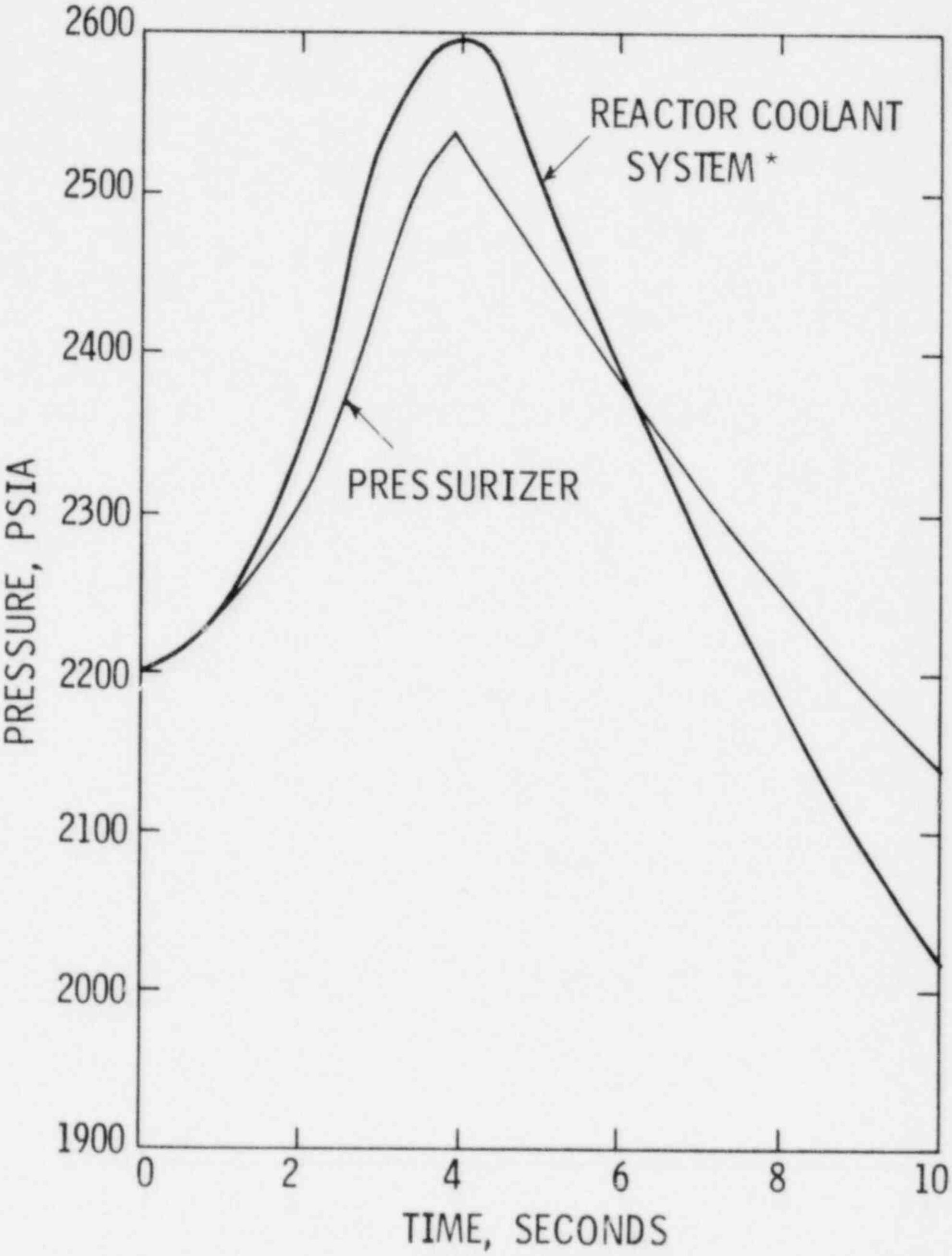
C - E SYSTEM 80	CEA EJECTION REACTIVITY vs TIME	Figure 15.4.8-7



* DOES NOT INCLUDE ELEVATION OR REACTOR COOLANT PUMP HEADS

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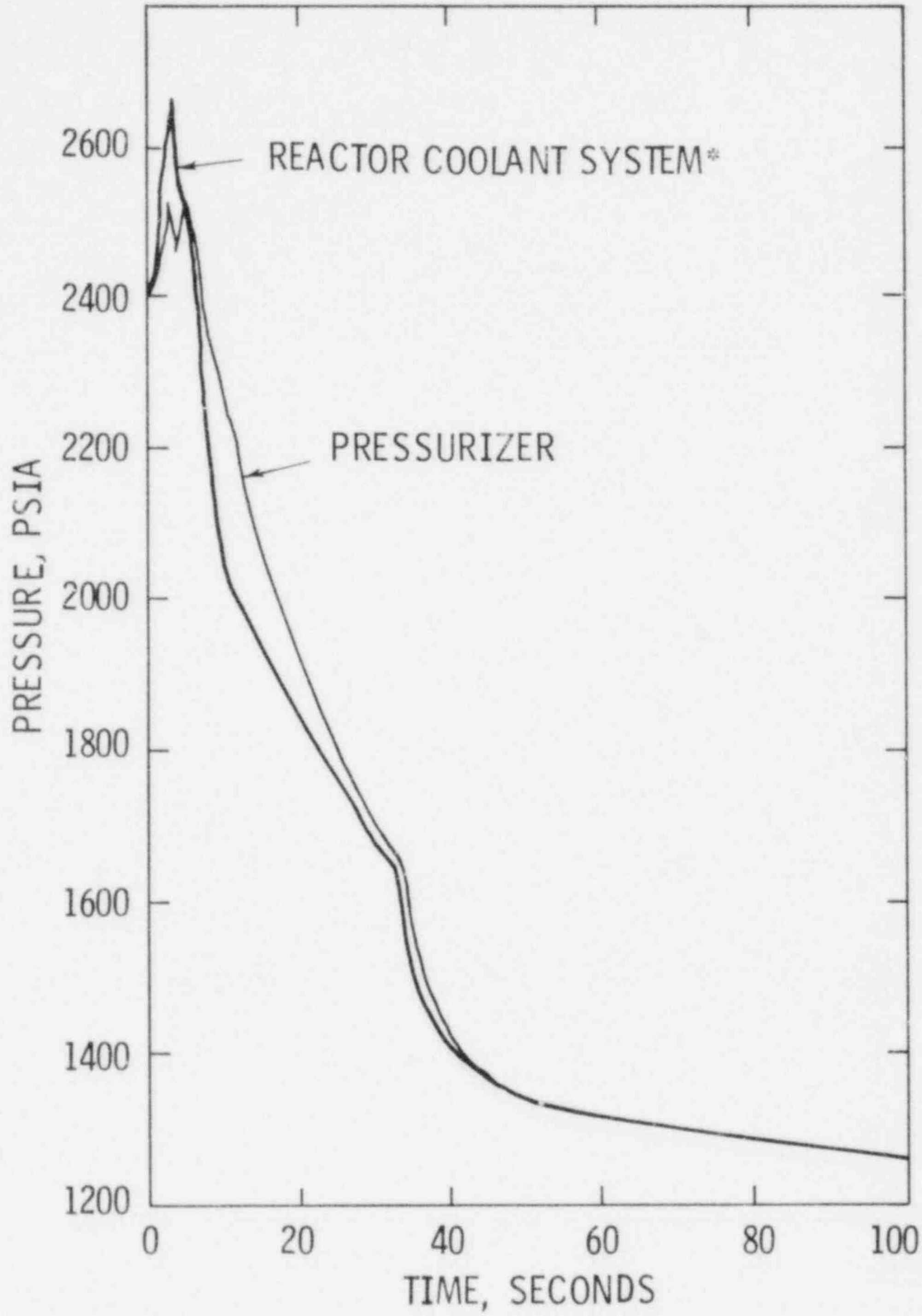
C-E SYSTEM 80	CEA EJECTION RCS AND PRESSURIZER PRESSURE vs TIME	Figure 15.4.8-8



* DOES NOT INCLUDE ELEVATION OR REACTOR COOLANT PUMP HEADS

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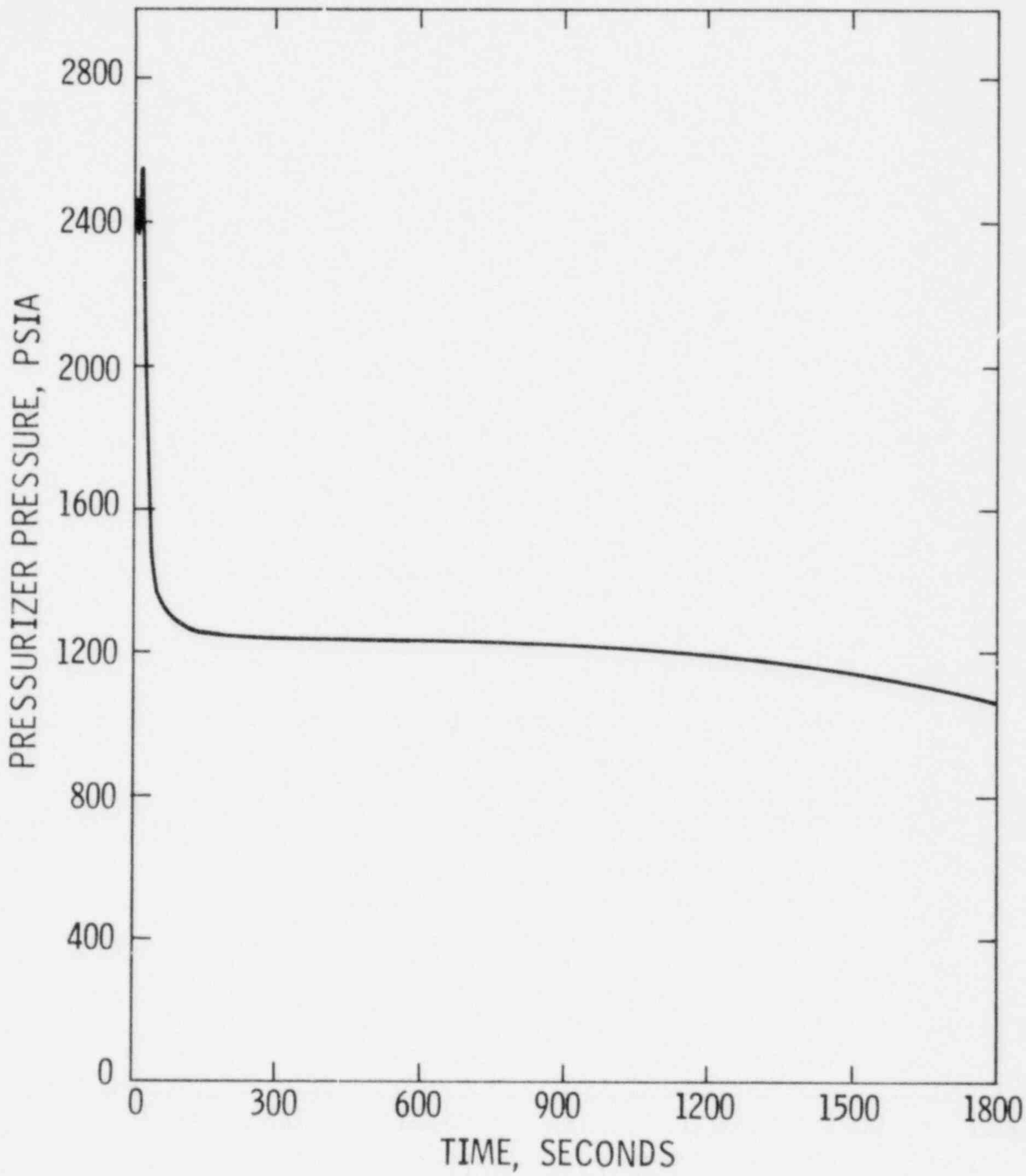
C - E SYSTEM 80	CEA EJECTION RCS AND PRESSURIZER PRESSURE vs TIME	Figure 15.4.8-9



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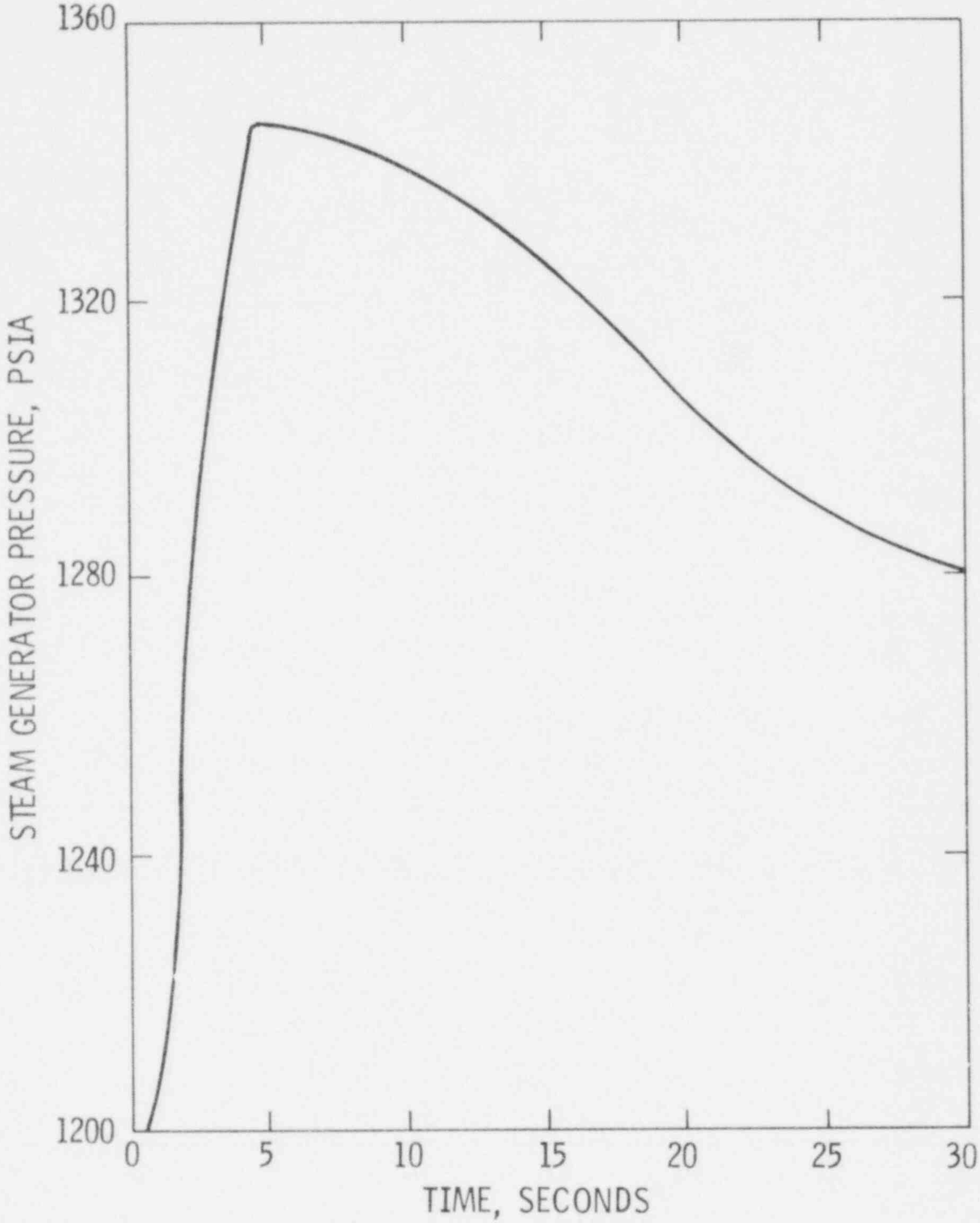
C-E SYSTEM 80	CEA EJECTION PRESSURIZER PRESSURE vs TIME	Figure 15.4.8-10



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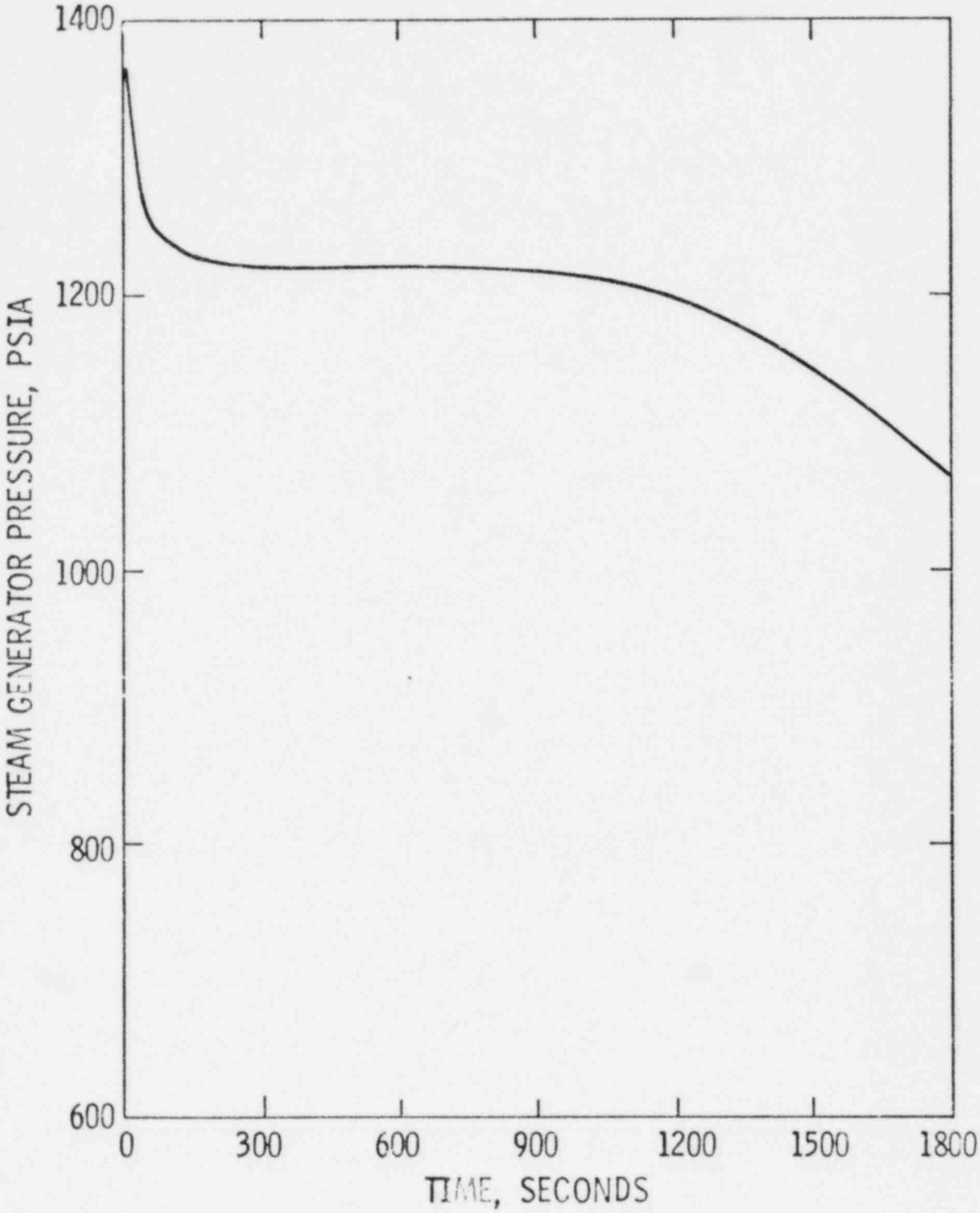
C - E SYSTEM 80	CEA EJECTION STEAM GENERATOR PRESSURE vs TIME	Figure 15.4.8-11



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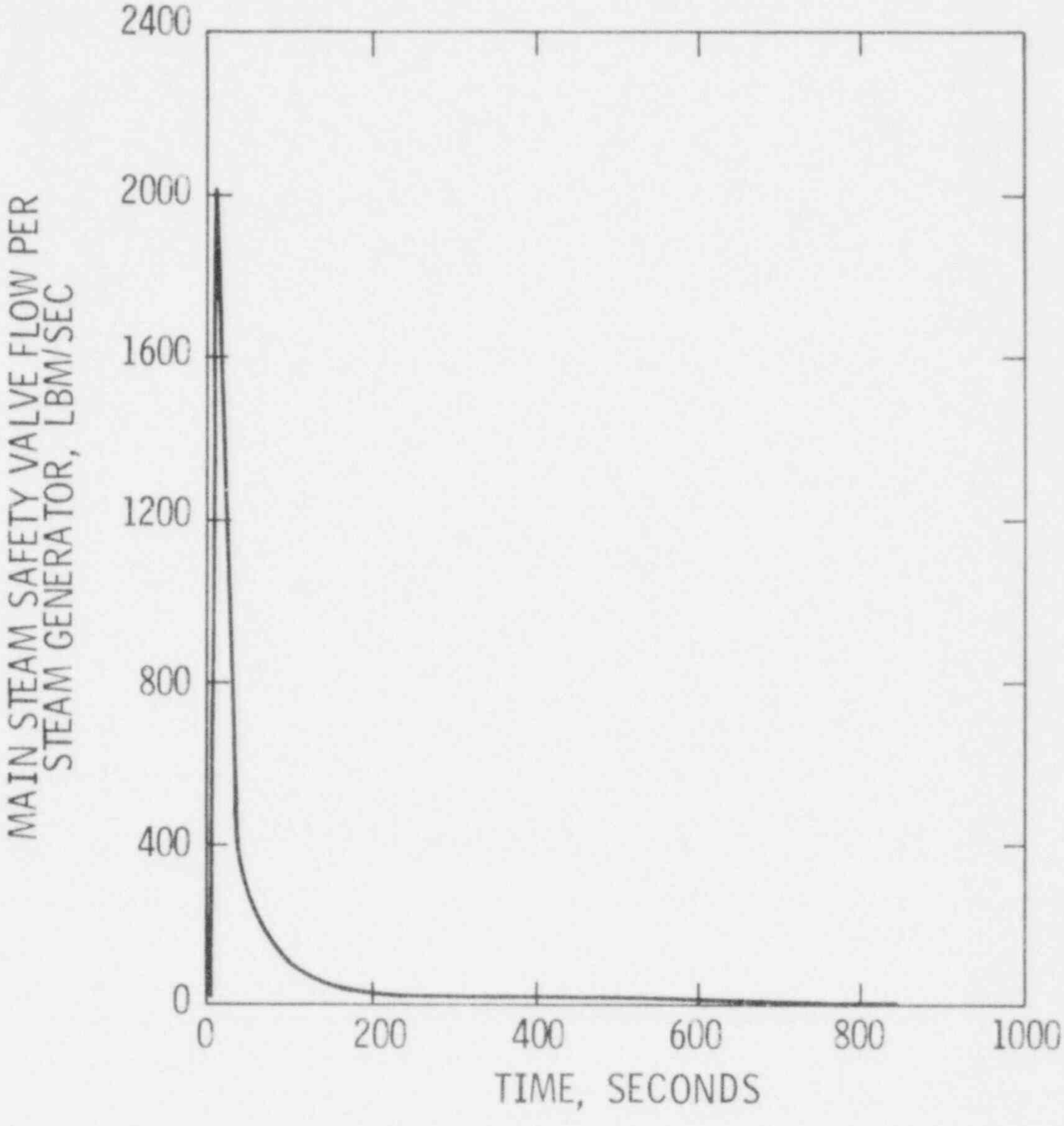
C - E SYSTEM 80	CEA EJECTION STEAM GENERATOR PRESSURE vs TIME	Figure 15.4.8-12



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C - E SYSTEM 80	CEA EJECTION MAIN STEAM SAFETY VALVE FLOW vs TIME	Figure 15.4.8-13

15.5 INCREASE IN RCS INVENTORY

15.5.1 INADVERTENT OPERATION OF THE ECCS

15.5.1.1 Identification of Event and Causes

The inadvertent operation of the emergency core cooling system (ECCS) is assumed to actuate the high pressure safety injection (HPSI) pumps (2) and open the corresponding discharge valves. This operation occurs as a result of a spurious signal to the system or operator error.

15.5.1.2 Sequence of Events and Systems Operation

Inadvertent operation of the ECCS is only of consequence when it occurs below the HPSI pump shutoff head pressure. Above that pressure there will be no injection of fluid into the system. Below the HPSI pump shutoff head pressure when the shutdown cooling system is isolated the HPSI flow will increase RCS inventory and pressure until the pressure reaches the pump shutoff head pressure. During shutdown cooling system operation the increase in RCS inventory and pressure will be mitigated by the shutdown cooling system relief valves.

15.5.1.3 Analysis of Effects and Consequences

Plant operation above the HPSI pump shutoff head pressure will not be impacted by the inadvertent operation of the ECCS. Below the HPSI pump shutoff head pressure when the shutdown cooling system is isolated, there will be an RCS inventory and pressure increase. This increase will be terminated when the pressure rises above the shutoff head pressure. Due to the pressure increase caused by this transient at low RCS temperatures, there is an approach to the brittle fracture limits of the RCS. Examination of Figure 16.3.4-2, RCS Temperature-Pressure Limitations, shows that the brittle fracture limits will not be violated for this transient. Should the ECCS inadvertently actuate during shutdown cooling operation, the shutdown cooling relief valves will mitigate the pressure transient so that the limits in Figure 16.3.4-2 are not exceeded. The shutdown cooling relief valves are only isolated when the shut off head of the HPSI pumps is below the pressure temperature limits for brittle fracture of the RCS.

15.5.1.4 Conclusion

The peak pressurizer pressure reached during the inadvertent operation of the ECCS is well within 110% of design pressure. Additionaly, the pressure-temperature limits for brittle fracture of the RCS are not violated by this transient. The fuel integrity is not challenged by this event.

15.5.2 CVCS MALFUNCTION-PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION WITH LOSS OF OFFSITE POWER

15.5.2.1 Identification of Event and Causes

All events and events plus single failures which cause an increase in RCS inventory were examined with respect to the Reactor Coolant System (RCS) pressure and fuel cladding performance. Pressurizer Level Control System

(PLCS) malfunction in combination with the loss of offsite power as a result of the assumed grid failure when the turbine trips was identified as the limiting event.

When in the automatic mode, the PLCS responds to changes in pressurizer level by changing charging and letdown flows to maintain the program level. Normally, one charging pump is running with two charging pumps available for automatic startup when a low level setpoint is reached. If the pressurizer level controller fails low or the level setpoint generated by the reactor regulating system fails high, a low level signal can be transmitted to the controller. In response, the controller will start all the charging pumps and close the letdown control valve to its minimum opening resulting in the maximum mass addition to the RCS.

The limiting single failure was determined with respect to its impact on fuel performance and system pressure.

Regarding the pressure criteria, the major factors which cause an increase in RCS pressure are:

a. increasing coolant temperature.
b. decreasing core flow.
c. decreasing primary to secondary heat transfer.

The PLCS malfunction causes a reactor trip, on high pressurizer pressure, resulting in the maximum RCS pressure in the first two to five seconds following reactor trip. Therefore, any single failure which would result in a higher RCS pressure during the transient would have to affect at least one of the above parameters during the first two to five seconds following reactor trip.

The single failures that have been postulated are listed in Table 15.0-6. The failures which affect the RCS behavior during this interval are (1) loss of normal AC, (2) failure of the pressurizer pressure control system, (3) failure of the steam bypass control system, (4) failure of the reactor regulating system and (5) failure of the feedwater control system. The loss of normal AC power results in loss of power to the reactor coolant pumps, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control system, the reactor regulating system, the feedwater control system, and the steam bypass control system.

The effect of losing normal AC power on the PLCS malfunction is as follows: Loss of the reactor regulating system will have no appreciable affect on the transient in the first five seconds. Loss of the steam bypass control system and feedwater control system results in a rapid build-up in secondary pressure and temperature. This reduces primary to-secondary heat transfer and a further decrease in heat transfer is experienced as the reactor coolant pump coast down. The resulting RCS pressure increase is further aggravated as the pressurizer sprays are not available due to the loss of power to the reactor coolant pumps and pressurizer pressure control system.

An individual loss of one of the control systems is bounded by the assumption of the loss of normal AC power with respect to RCS pressure increase. Thus none of the single failures listed in Table 15.0-6 will result in a higher RCS pressure than that predicted for a PLCS malfunction with a loss of offsite power as a result of turbine trip.

Regarding the approach to the fuel design limit, the major parameter of concern is the minimum hot channel DNBR. The major factors which cause a decrease in local DNBR are:

a. increasing coolant temperature.
b. decreasing coolant flow.
c. increasing local heat flux (including radial and axial power distribution effects).

The PLCS malfunction causes a reactor trip, and thus minimum DNBR occurs in the first two to five seconds following trip. No single failure was identified from Table 15.0-6 which would have a significant affect on DNBR prior to the reactor trip. Therefore, any single failure which would result in a lower DNBR during the transient would have to affect at least one of the above parameters during the first two to five seconds of the event.

The single failures that have been postulated are listed in Table 15.0-6. The failures which affect the RCS behavior during this interval are (1) a loss of normal AC power, (2) a failure of the pressurizer pressure control system, and (3) a failure of the reactor regulating system. The loss of normal AC power results in loss of power to the reactor coolant pumps, the circulating water pumps, the pressurizer pressure and level control system, the reactor regulating system, and the feedwater control system.

The effect of losing normal AC power on the PLCS malfunction is as follows: Loss of power to the condensate and circulating water pumps and the feedwater control system initially affect only the secondary system and, thus, do not affect DNBR in the first two to five seconds of the transient. Loss of power to the reactor regulating system pressurizer level and pressure control systems renders those systems inoperable. This inoperability will have no significant impact on DNBR during the first two to five seconds. Loss of power to the reactor coolant pumps is the only significant failure with regard to DNBR which results from a loss of normal AC power.

Failure of the pressurizer pressure control system or reactor regulating system cannot appreciably affect any of the major factors which determine DNBR during the first two to five seconds of the event. Thus, none of the single failures listed in Table 15.0-6 will result in a lower DNBR than that predicted for the PLCS malfunction with a loss of offsite power as a result of turbine trip.

15.5.2.2 Sequence of Events and Systems Operation

Table 15.5.2-1 presents a chronological sequence of events which occur during a PLCS malfunction in combination with loss of offsite power from the initial malfunction until the operator stabilizes the plant and initiates plant cooldown.

Table 15.5.2.-1 contains the sequence of events diagram which, together with Figure 15.0-1 (containing a glossary of SEA symbols and acronyms) may be used to trace the actuation and interaction of systems used to mitigate the consequences of the event. Table 15.5.2-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the course of the event.

The success paths on the Sequence of Events Diagram (Figure 15.5.2-1) are described below:

Reactivity Control:

The excess of charging over letdown and the assumed Pressurizer Pressure Control System operating mode results in the pressurizer pressure reaching the high pressure reactor trip set-point. A reactor trip and CEA insertion follow. Prior to initiating or during manual cooldown the opertor adjusts the boron concentration to insure that a proper negative reactivity shutdown margin is achieved. The boron concentration is adjusted manually using the charging pumps and letdown if normal power to the ESF buses has been reestablished or using the HPSI pumps and replacing RCS volume shrinkage if normal power to the ESF buses has not been reestabilished.

Primary System Integrity:

The closing of the turbine stop valves, the interruption of the feedwater flow, and reduction of reactor coolant flow due to loss of non-emergency AC, results in an increase in RCS pressure which opens the primary safety valves. The reactor drain tank serves as a receptacle for 796.5 lbm of steam released. If non-emergency AC power has been reestablished RCS pressure and level are manually reestablished utilizing the unfailed components in the pressurizer pressure and level control systems. If non-emergency AC power has not been reestablished, the HPSI discharge valves will be throttled to control the rate of change of RCS pressure. As the cooldown proceeds, the operator will reduce the safety injection actuation setpoint to prevent the inadvertent generation of an SIAS.

When the RCS pressure has been reduced to approximately 650 psia, the operator will vent or drain the SITs to reduce their pressure and will then isolate them.

Reactor Heat Removal:

Following loss of power to the non-ESF loads as a result of turbine trip and subsequent grid collapse the reactor coolant pumps coastdown. Reactor heat removal takes place by means of natural circulation.

The Shutdown Cooling System (SCS) is manually actuated when RCS temperture and pressure have been reduced to 350^{o}F and 400 psia respectively. This system provide sufficient cooling flow to cool the RCS to cold shutdown.

Secondary System Integrity:

Turbine trip results from the reactor trip on high pressurizer pressure. The external grid which the plant is feeding is assumed to collapse because this plant goes off line; therefore, no non-emergency AC is available within the plant. Condenser vacuum is lost therefore the steam bypass system is not available. This causes the main steam safety valves to open and stay open until the operator takes control at 30 minutes. Main feedwater is lost on loss of condenser vacuum. After 30 minutes the operator utilizes the AFWS and the atmospheric dump valves to cool the primary system.

The AFWS may be a separate system or may be one emergency feedwater pump designated as "auxiliary" and intended for normal startup and shutdown of the plant. He may also let the ESFAS regulate the feedwater flow by issuing and withdrawing EFAS-1 and/or EFAS-2 signals down to cold shutdown entry conditions. See Applicant's FSAR for details of the Emergency and/or Auxiliary Feedwater systems. As the cooldown proceeds, the operator reduces the main steam isolation actuation setpoint to prevent the inadvertent generation of an MSIS.

Restoration of AC Power:

A loss of normal power to ESF loads causes the loads to be shed from the 4.16 KV buses (except 480V load centers). The diesel generators are automatically started and sequentially connected to selected ESF load groups to restore essential AC power.

Spent Fuel Heat Removal:

Spent Fuel Pool (SFP) cooling is terminated on the loss of normal power to the ESF loads. Spent fuel heat removal is continuously accomplished by utilizing the heat capacity of the SFP water. Pool cooling is restored by manually loading the SFP cooling pumps onto the diesel generators and by aligning the SFP heat exchangers to receive essential cooling water.

Table 15.5.2-3 contains a matrix which summarizes the utilization of safety systems as they appear in this transient analysis.

15.5.2.3 Analysis of Effects and Consequences

A. Mathematical Mode

The Nuclear Steam Supply System (NSSS) response to PLCS malfunction with loss of offsite power at the time of turbine trip was simulated using the CESEC-II computer program described in Section 15.0.3.

B. Input Parameters and Initial Conditions

Table 15.5.2-4 lists the assumptions and initial condition used for this analysis in addition to those discussed in Section 15.0. Additional clarification to the assumptions and parameters listed in Table 15.5.2-4 is provided as follows:

Since the pressure transient is due to an increase in primary coolant inventory and not to thermal expansion, no power, coolant temperature, or DNB transient is produced prior to reactor trip. Therefore, the initial conditions for the principal process variables, with the exception of RCS pressure, have no effect on the consequences. Minimizing the initial RCS pressure maximizes time to reactor trip on high pressurizer pressure and maximizes increase in RCS inventory prior to trip. An initial pressure of 1785 psia was chosen which is the lowest possible RCS pressure of the operating range. Initial water volume in the pressurizer was chosen to be 60% of the total volume.

Since the charging flow through the regenerative heat exchanger exceeds the letdown flow, the temperature of the makeup water added to the RCS by the

charging pumps is decreased significantly. Therefore, the most negative value of MTC was selected to maximize the positive reactivity addition from injection of cold makeup water.

Total charging flow due to all three pumps is 132 GPM. Considering 16 GPM for the control bleed takeoff and 30 GPM for the minimum letdown flow, net flow increase to the RCS is 86 GPM. The Pressurizer Pressure Control System (PPCS) is assumed to be in the manual mode with the proportional sprays off preventing the PPCS from suppressing the resulting pressure transient.

C. Results

The dynamic behavior of NSSS parameters following PLCS malfunction with loss of offsite power at turbine trip is presented in Figures15.5.2-2 to 15.5.2-11.

Failure of the Pressurizer Level Control System (PLCS) causes an increase in reactor coolant sysem inventory initiated by the startup of the third charging pump coupled with the decrease in letdown flow to its minimum. With the PPCS in the manual mode and the proportional sprays turned off, increase in RCS inventory results in a pressurizer pressure increase to the high pressure trip setpoint of 2450 psia and trips the reactor at 1250.7 seconds.

Since the steam bypass control system is in the manual mode and the rate of closure of the turbine stop valves is faster than the rate of control rod insertion, pressurizer pressure increases to 2561 psia which opens the primary safety valves. Decreasing core heat flux and the opening of the primary safety valves causes the pressure to drop; however, the decrease in primary to secondary heat transfer due to four pump loss of flow causes pressurizer pressure to again increase, reaching a peak value of 2480 psia.

The unavailability of the steam bypass valves causes the steam generator pressure to increase, causing the main steam safety valves to open at 1265.5 seconds. The decreasing core power and the safety valves function to limit the steam generator pressure to 1298 psia.

The 796.5 lbs of steam discharged by the pressurizer safety valve is contained in the quench tank with no releases to the atmosphere. The main steam safety valves discharge 22,714 lbs of steam to the atmosphere prior to 1800 seconds. At 1800 seconds, the operator stabilizes the plant and initiates plant cooldown, using steam dump valves.

15.5.2.4 Conlcusion

The peak pressurizer pressure reached during the Pressurizer Level Control System malfunction with a loss of offsite power at turbine trip is 2561 psia and is less than 110% of the design pressure. Since this transient causes an increase in RCS pressure due to an increase in primary coolant inventory the DNBR increases. Therefore, the acceptance criterion regarding fuel performance is met.

TABLE 15.5.2-1

SEQUENCE OF EVENTS FOR THE PLCS MALFUNCTION WITH A LOSS OF OFFSITE POWER AT TURBINE TRIP

Time (Sec)	Event	Setpoint or Value	Success Path
0	Charging Flow Maximized & Letdown Flow Minimized	--	
1250.7	High Pressurizer Pressure Trip and Loss of A.C. at the Time of Turbine Trip, psia	2450	Reactivity Control
1252.7	Pressurizer Safety Valves open, psia	2525	Primary System Integrity
1253.2	Maximum Pressurizer Pressure, psia	2561	
1262.3	Pressurizer Safety Valves Close, psia	2525	Secondary System Integrity
1265.5	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity
1270.3	Maximum Steam Generator Pressure, psia	1298	
1800.0	Operator Initiates Plant Cooldown	--	Reactor Heat Removal

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR THE PLCS MALFUNCTION WITH LOSS OF OFF-SITE POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System			✓			
2. Main Feedwater Pump Turbine Control System*			✓			
3. Turbine-Generator Control System*			✓			
4. Steam Bypass Control System				✓		
5. Pressurizer Pressure Control System				✓		
6. Pressurizer Level Control System						1
7. Control Element Drive Mechanism Control System			✓			
8. Reactor Regulating System			✓			
9. Core Operating Limit Supervisory System			✓			
10. Reactor Coolant Pumps			✓			
11. Chemical and Volume Control System			✓			
12. Secondary Chemistry Control System*			✓			
13. Condenser Evacuation System*			✓			
14. Turbine Gland Sealing System*			✓			
15. Nuclear Cooling Water System*			✓			
16. Turbine Cooling Water System*			✓			
17. Plant Cooling Water System*			✓			
18. Condensate Storage Facilities*			✓			
19. Circulating Water System*			✓			
20. Spent Fuel Pool Cooling and Clean-Up System*			✓			
21. Non-Class 1E (Non-ESF) A.C. Power*			✓			
22. Class 1E (ESF) A.C. Power*	✓					

Balance-of-Plant Systems-

TABLE 15.5.2-2 (CONTINUED) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR THE PLCS MALFUNCTION WITH
LOSS OF OFF-SITE POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*			✓			
24. Class 1E D.C. Power*	✓					

Notes:

1. Failure in this system is the initiating event.

*Balance-of-Plant Systems

TABLE 15.5.2-3

UTILIZATION OF SAFETY SYSTEMS
FOR THE PLCS MALFUNCTION WITH
LOSS OF OFF-SITE POWER

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems			✓		
4. Supplementary Protection System					1
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves	✓				
8. Main Steam Isolation System*			✓		
9. Emergency Feedwater System*					
10. Safety Injection System			✓		
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*	✓				
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*	✓				
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

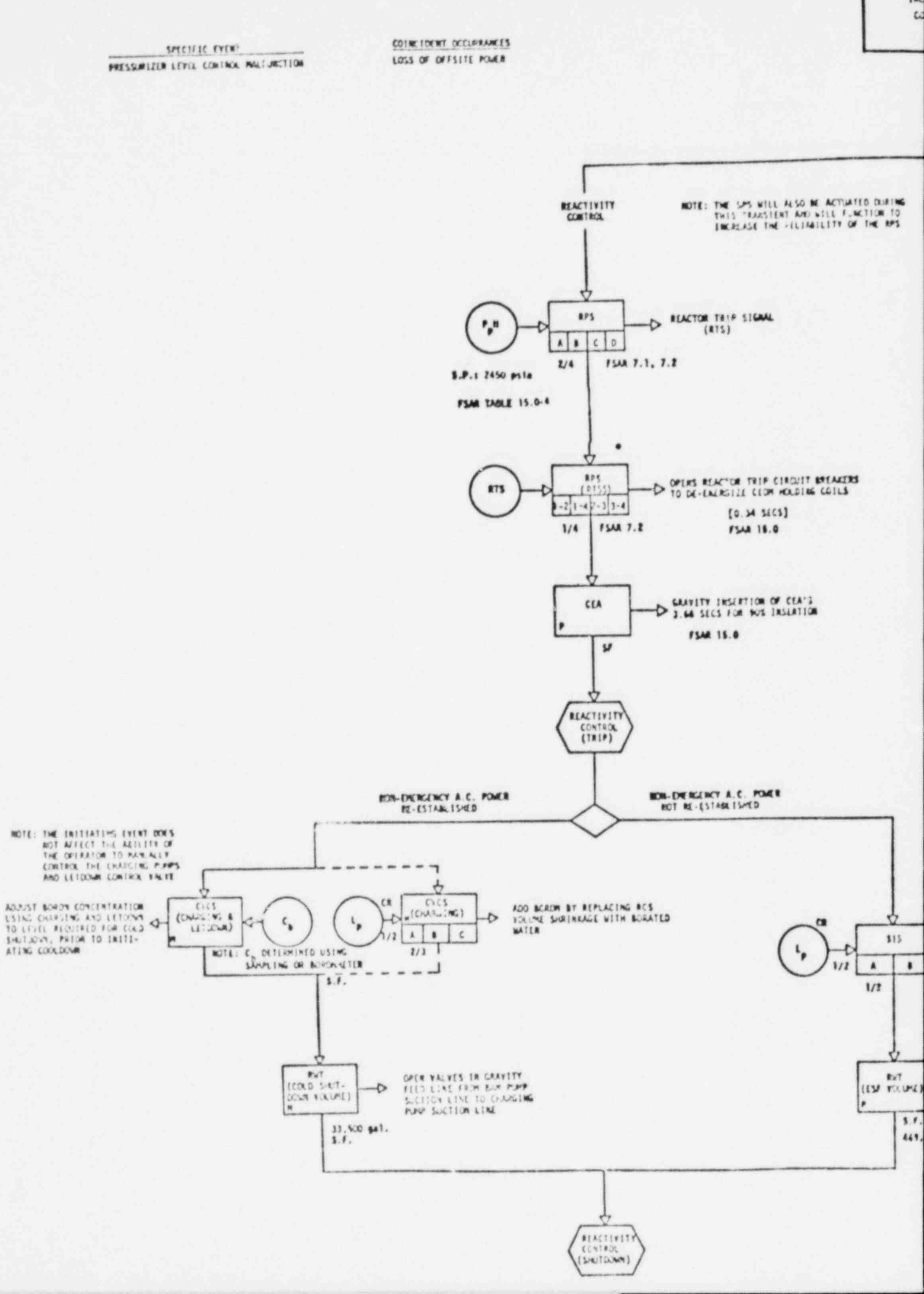
NOTES:

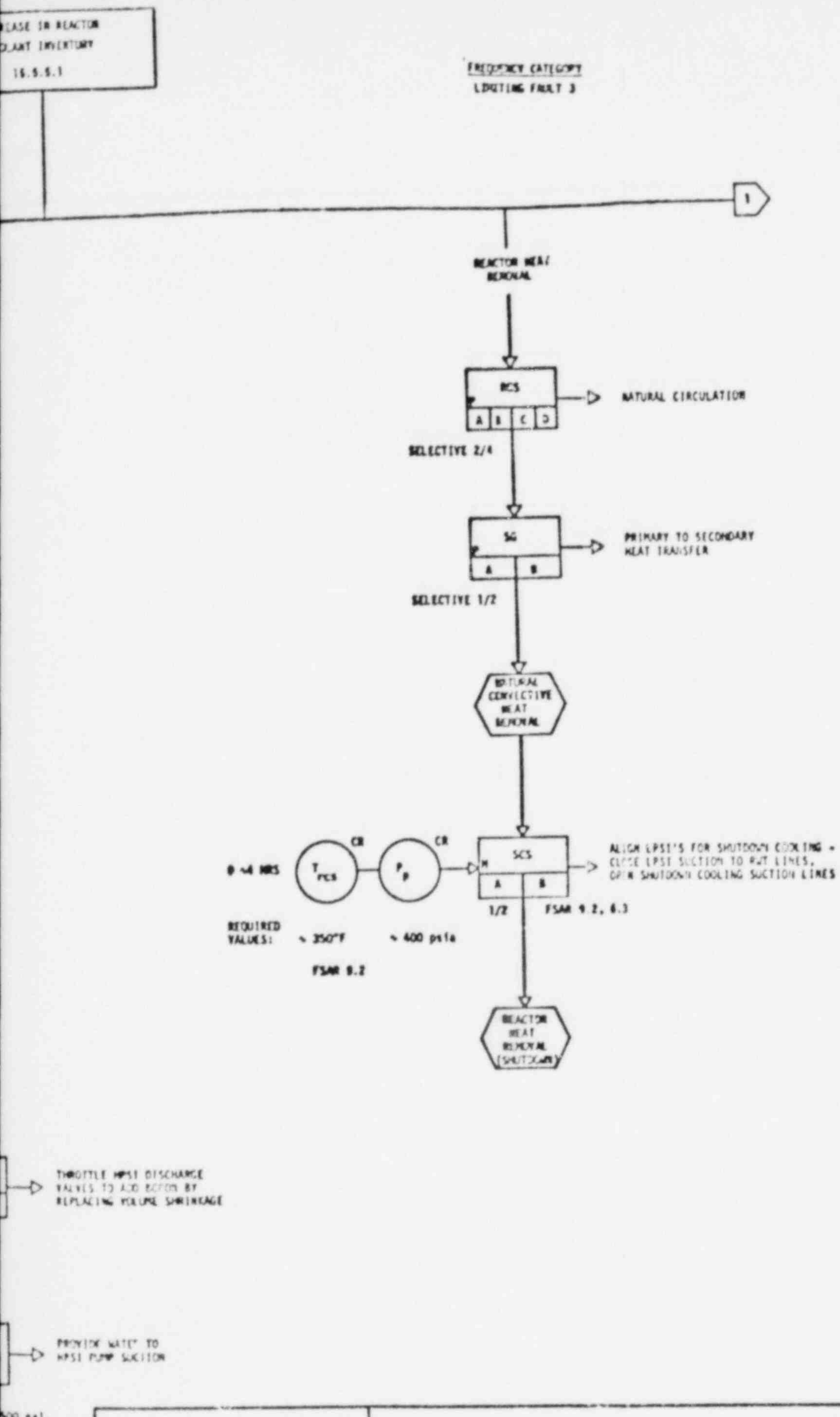
1. Safety backup to safety system.

*Balance-of-Plant Systems -

SPECIFIC EVENT
PRESSURIZER LEVEL CONTROL MALFUNCTION

COINCIDENT OCCURRANCES
LOSS OF OFFSITE POWER





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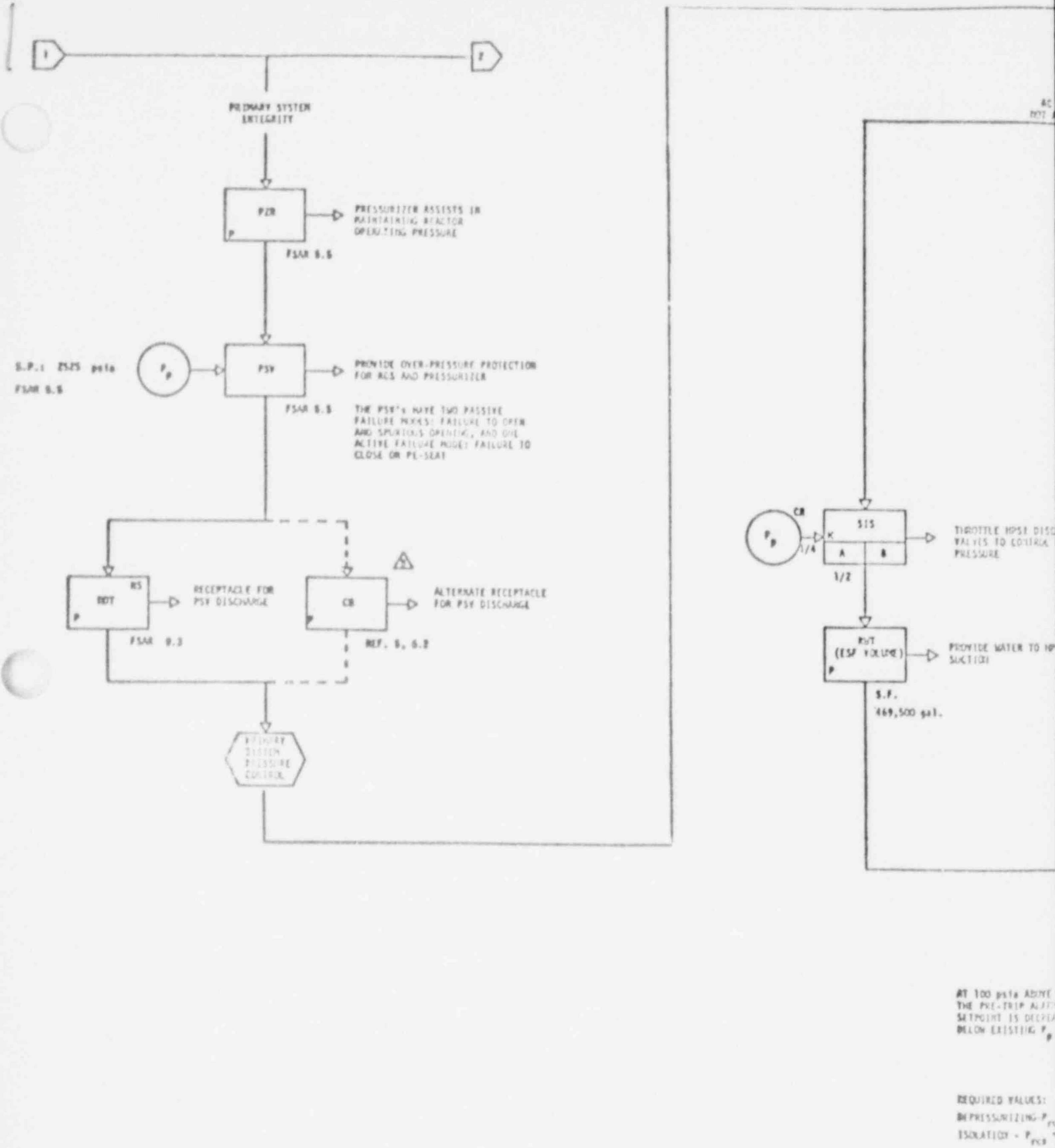
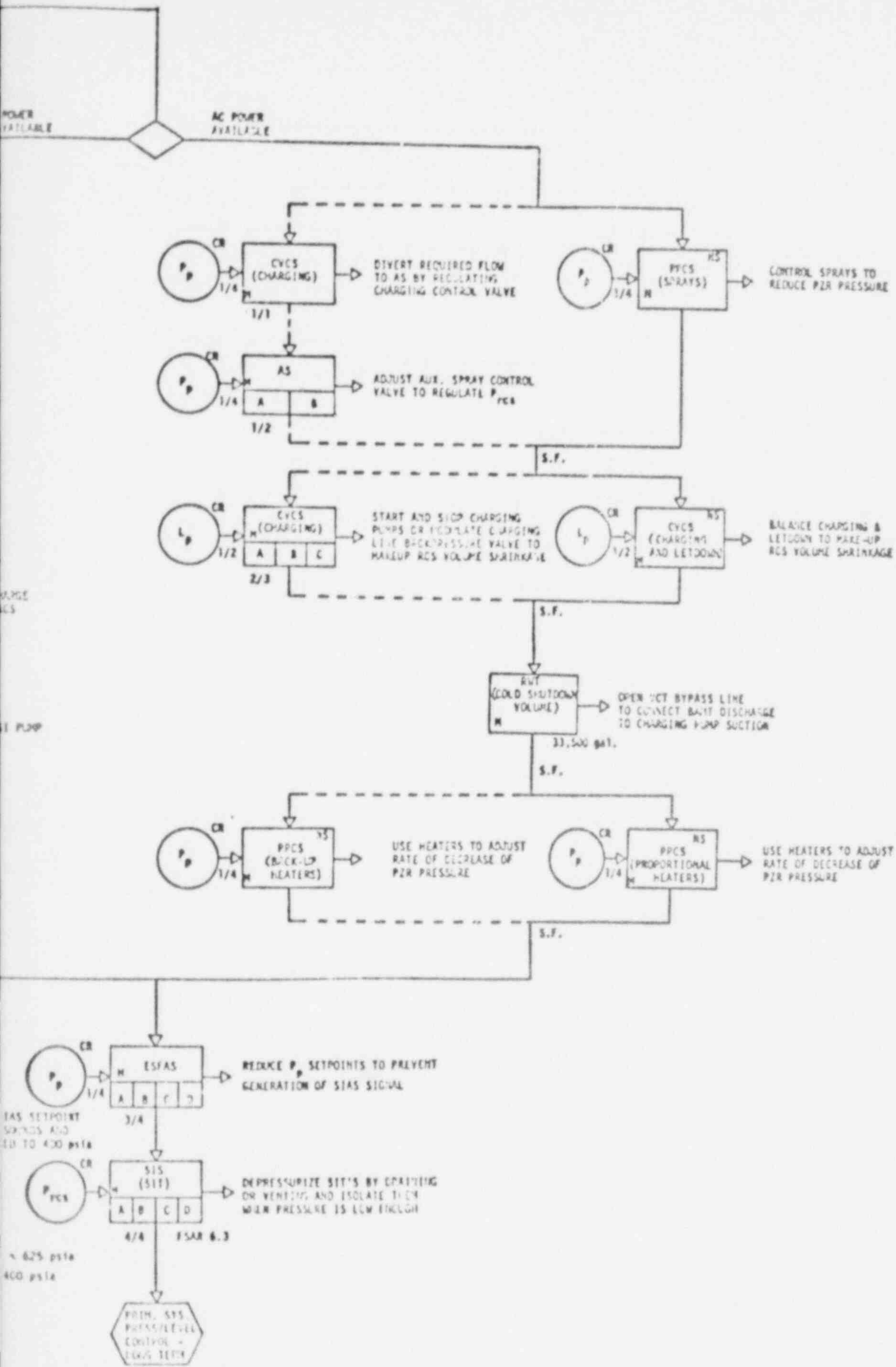
March 31, 1982

C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION WITH LOSS OF OFFSITE POWER FOLLOWING THE TURBINE TRIP	Figure 15.5.2-1A



1
2
PRIMARY SYSTEM INTEGRITY
PZR
P
PRESSURIZER ASSISTS IN MAINTAINING REACTOR OPERATING PRESSURE
FSAR 5.5
S.P.: 2525 psia
FSAR 5.5
PSV
PROVIDE OVER-PRESSURE PROTECTION FOR RCS AND PRESSURIZER
FSAR 5.5
THE PSV's HAVE TWO PASSIVE FAILURE MODES: FAILURE TO OPEN AND SPURIOUS OPENING, AND ONE ACTIVE FAILURE MODE: FAILURE TO CLOSE OR RE-SEAT
BDT
RS
P
RECEPTACLE FOR PSV DISCHARGE
FSAR 9.3
CB
P
ALTERNATE RECEPTACLE FOR PSV DISCHARGE
REF. 5, 6.2
PRIMARY SYSTEM PRESSURE CONTROL
CR
1/4
SIS
K
A
B
1/2
THROTTLE HPSI DISC VALVES TO CONTROL PRESSURE
RWT (ESF VOLUME)
P
PROVIDE WATER TO HP SUCTION
S.F.
469,500 gal.
AT 100 psia ABOVE
THE PRE-TRIP ALE
SETPOINT IS DECREA
BELOW EXISTING P_p
REQUIRED VALUES:
DEPRESSURIZING-P_{RC}
ISOLATION - P_{RCB}



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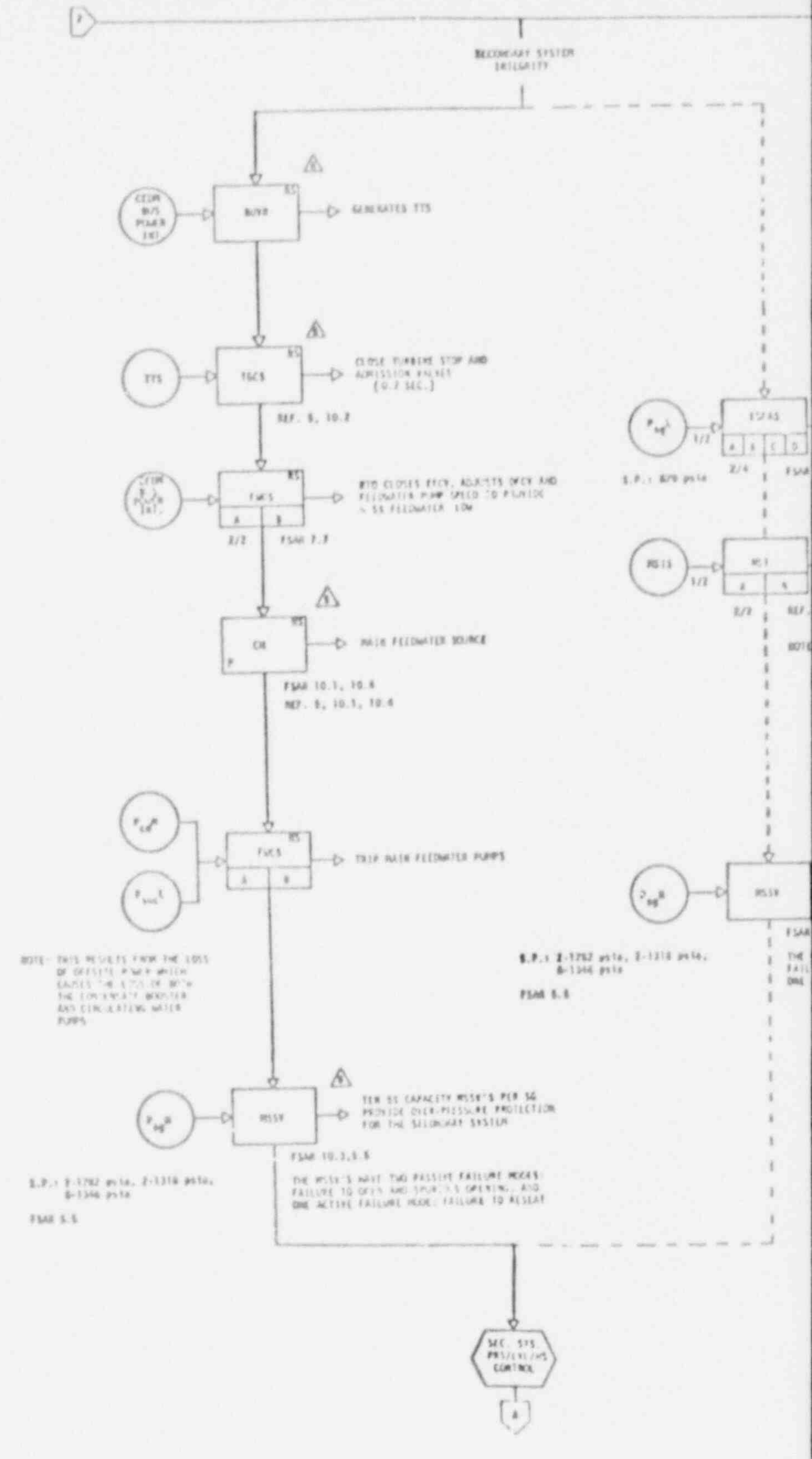
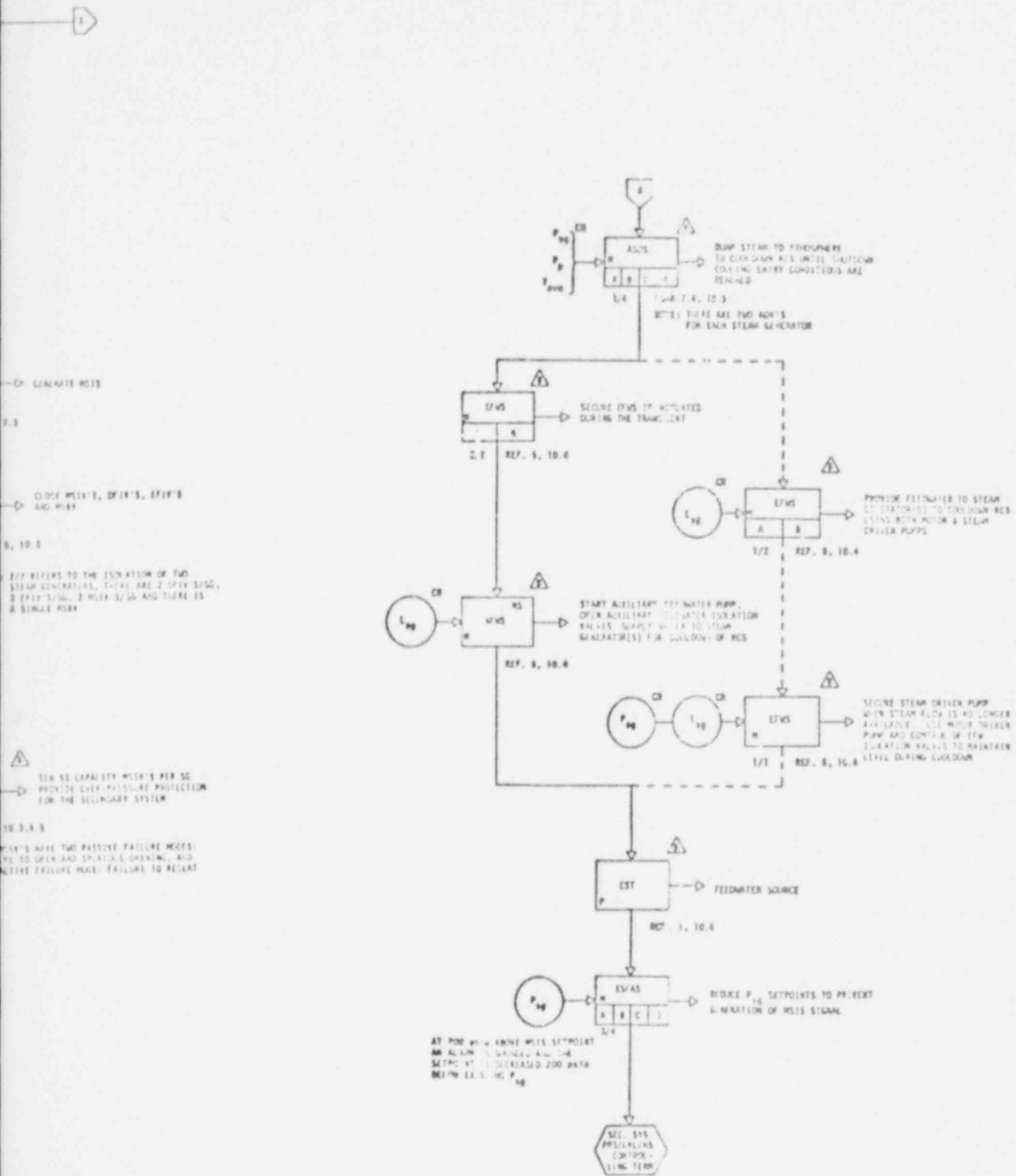
March 31, 1982

C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION WITH LOSS OF OFFSITE POWER FOLLOWING THE TURBINE TRIP	Figure 15.5.2-18



SECONDARY SYSTEM
INTEGRITY
GENERATES TTS
TTS
TGCS
CLOSE TURBINE STOP AND
ADMISSION VALVES
(0.2 SEC.)
REF. 5, 10.2
FWCS
2/2
FSAR 7.7
CH
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
FWCS
TRIP MAIN FEEDWATER PUMPS
NOTE- THIS RESULTS FROM THE LOSS
OF OFFSITE POWER WHICH
CAUSES THE LOSS OF BOTH
THE CONDENSATE BOOSTER
AND CIRCULATING WATER
PUMPS
MSSV
TEN 5% CAPACITY MSSV'S PER SG
PROVIDE OVER-PRESSURE PROTECTION
FOR THE SECONDARY SYSTEM
FSAR 10.3, 5.5
THE MSSV'S HAVE TWO PASSIVE FAILURE MODES:
FAILURE TO OPEN AND SPURIOUS OPENING, AND
ONE ACTIVE FAILURE MODE: FAILURE TO RESEAT
S.P.: 2-1282 psia, 2-1318 psia,
6-1346 psia
FSAR 5.5
ESFAS
2/4
MSIS
1/2
2/2
MSSV
S.P.: 2-1282 psia, 2-1318 psia,
6-1346 psia
FSAR 5.5
SEC. SYS.
PRS/LVL/HS
CONTROL
A



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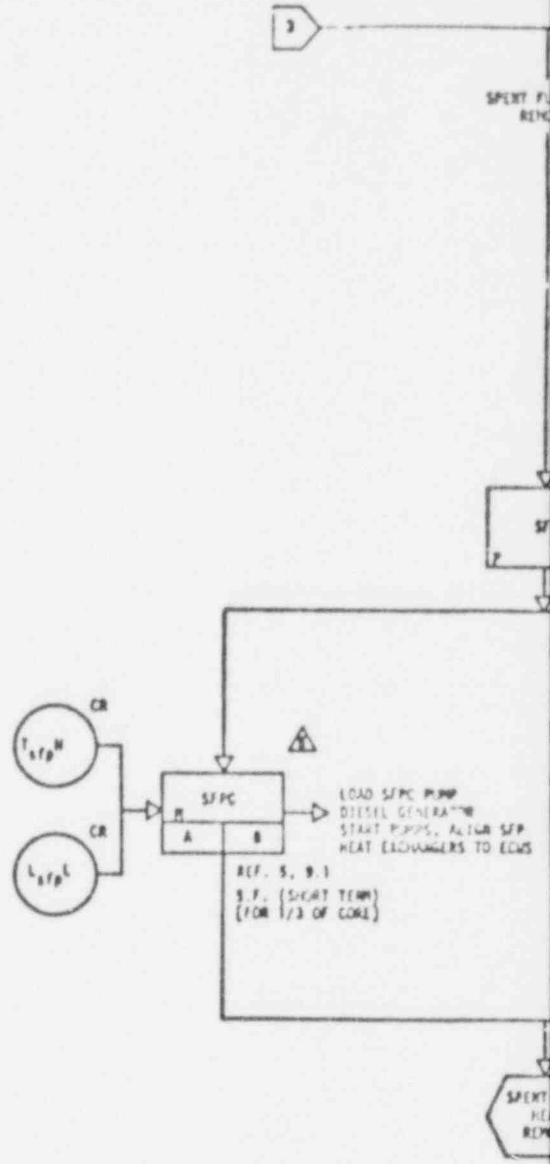
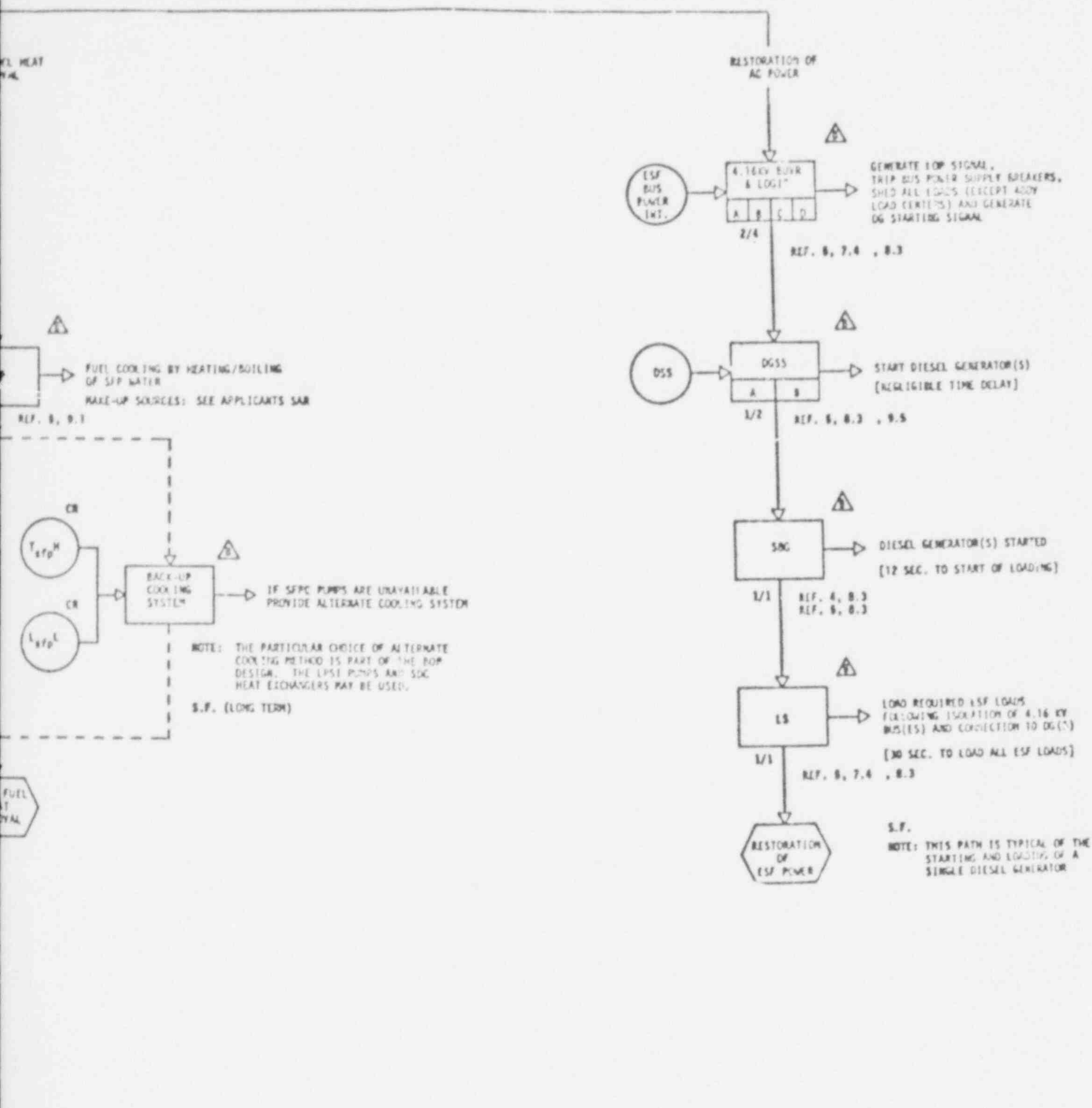
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION WITH LOSS OF OFFSITE POWER FOLLOWING THE TURBINE TRIP	Figure 15.5.2-1C



CR
CR
SFPC
A
B
LOAD SFPC PUMP
DIESEL GENERATOR
START PUMPS, ALIGN SFP
HEAT EXCHANGERS TO ECWS
REF. 5, 9.1
S.F. (SHORT TERM)
(FOR 1/3 OF CORE)



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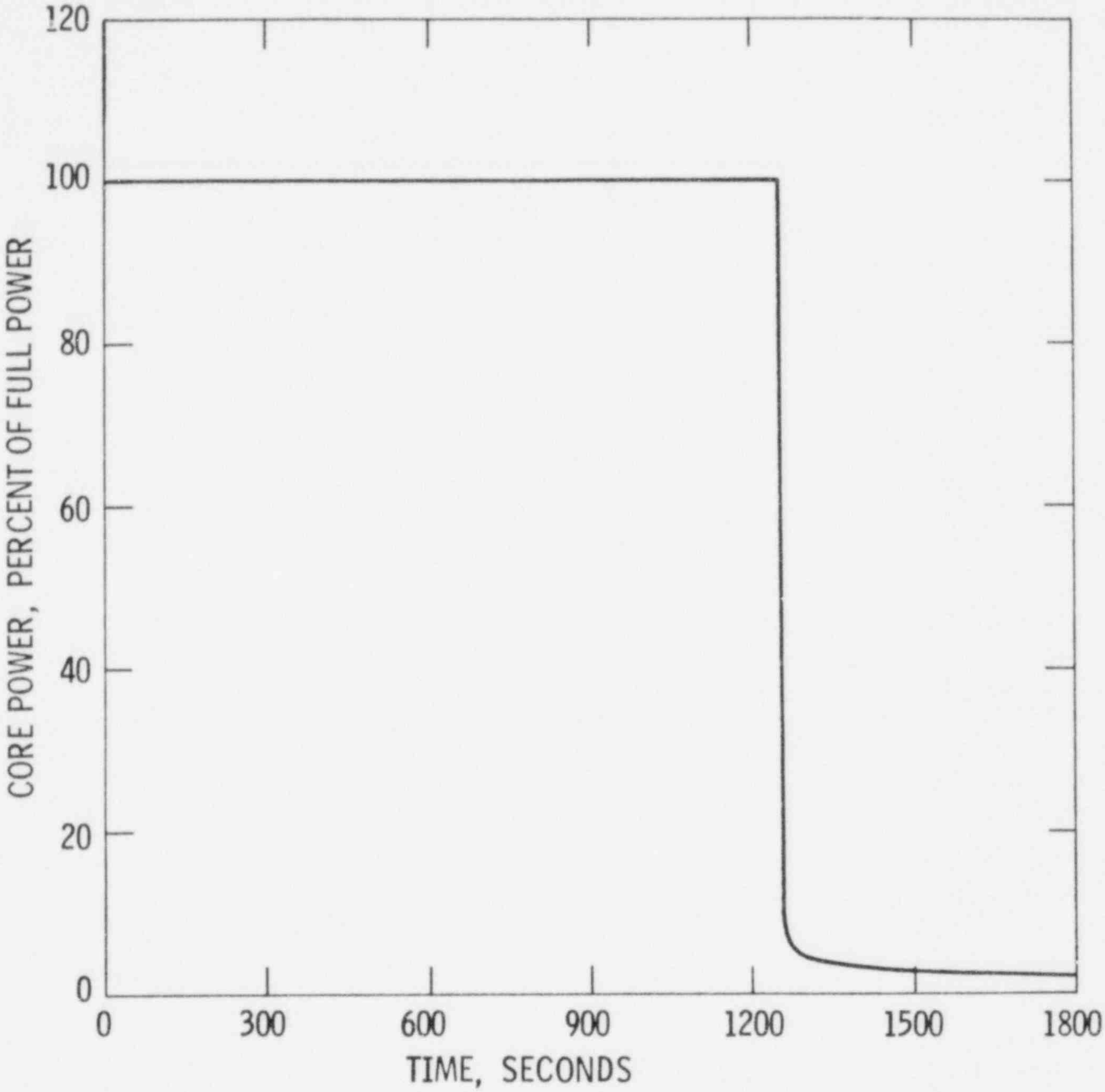
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR PRESSURIZER LEVEL CONTROL SYSTEM MALFUNCTION WITH LOSS OF OFFSITE POWER FOLLOWING THE TURBINE TRIP	Figure 15.5.2-1D



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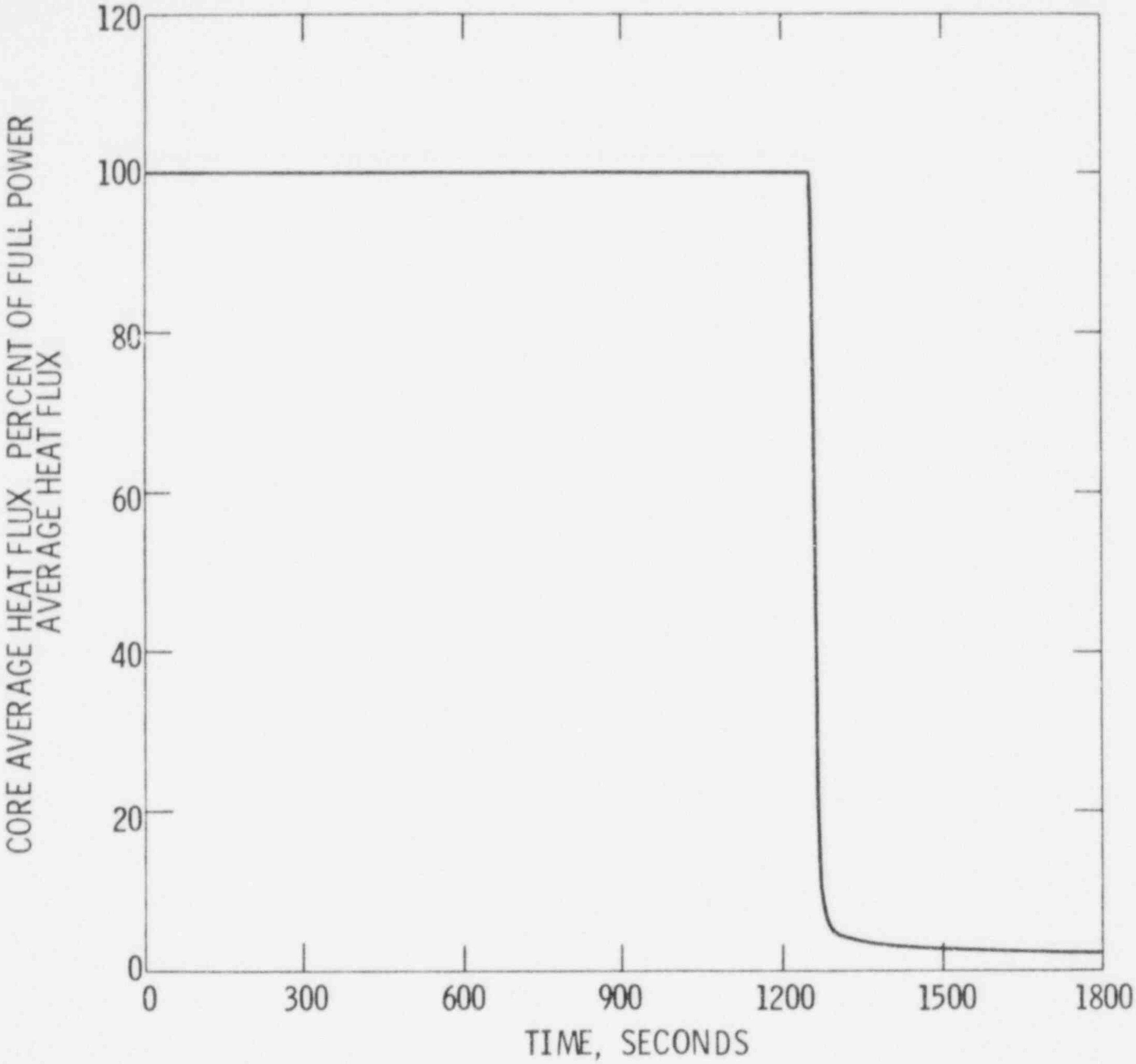
C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER CORE POWER vs TIME	Figure 15.5.2-2



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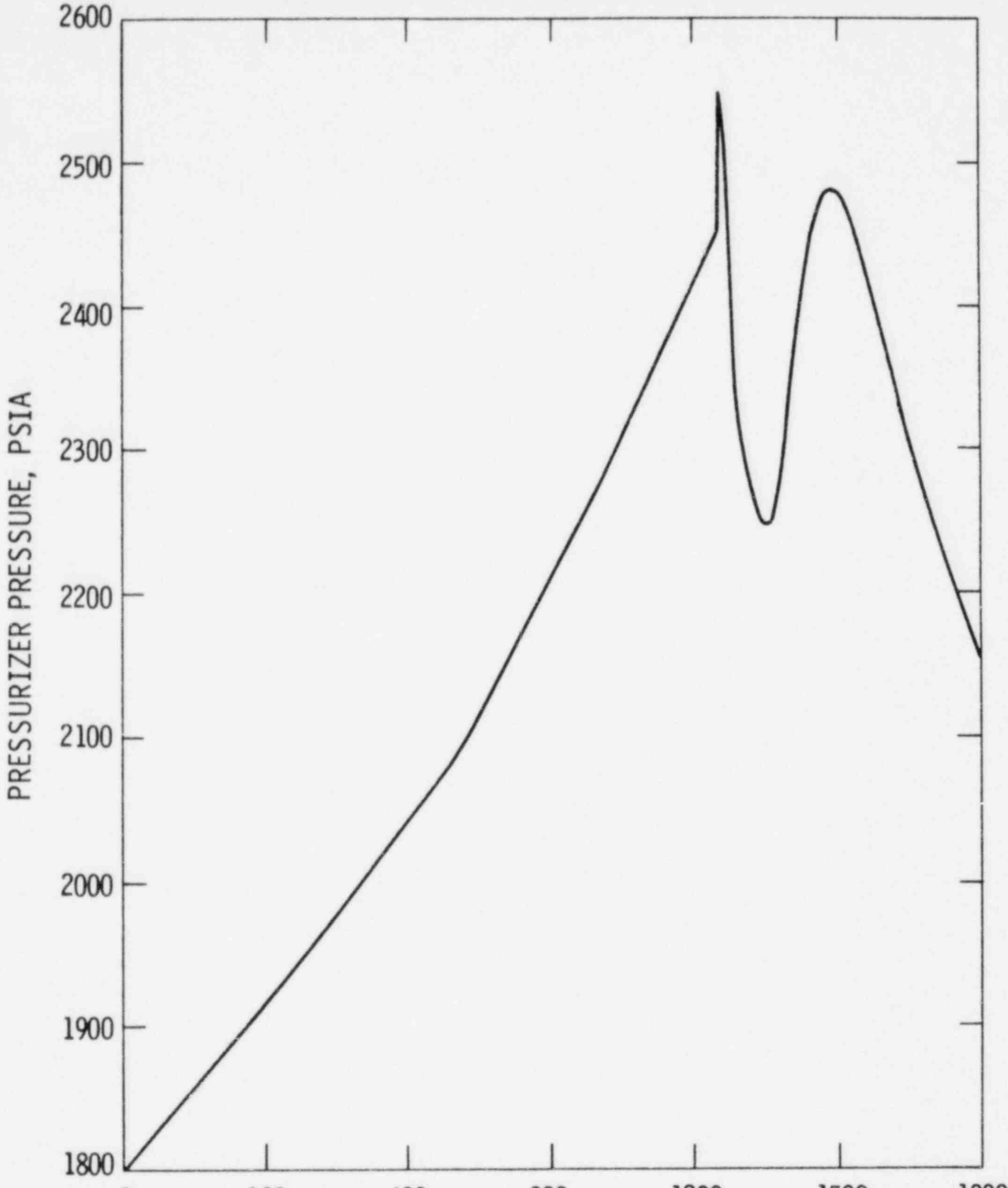
C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER CORE AVERAGE HEAT FLUX vs TIME	Figure 15.5.2-3



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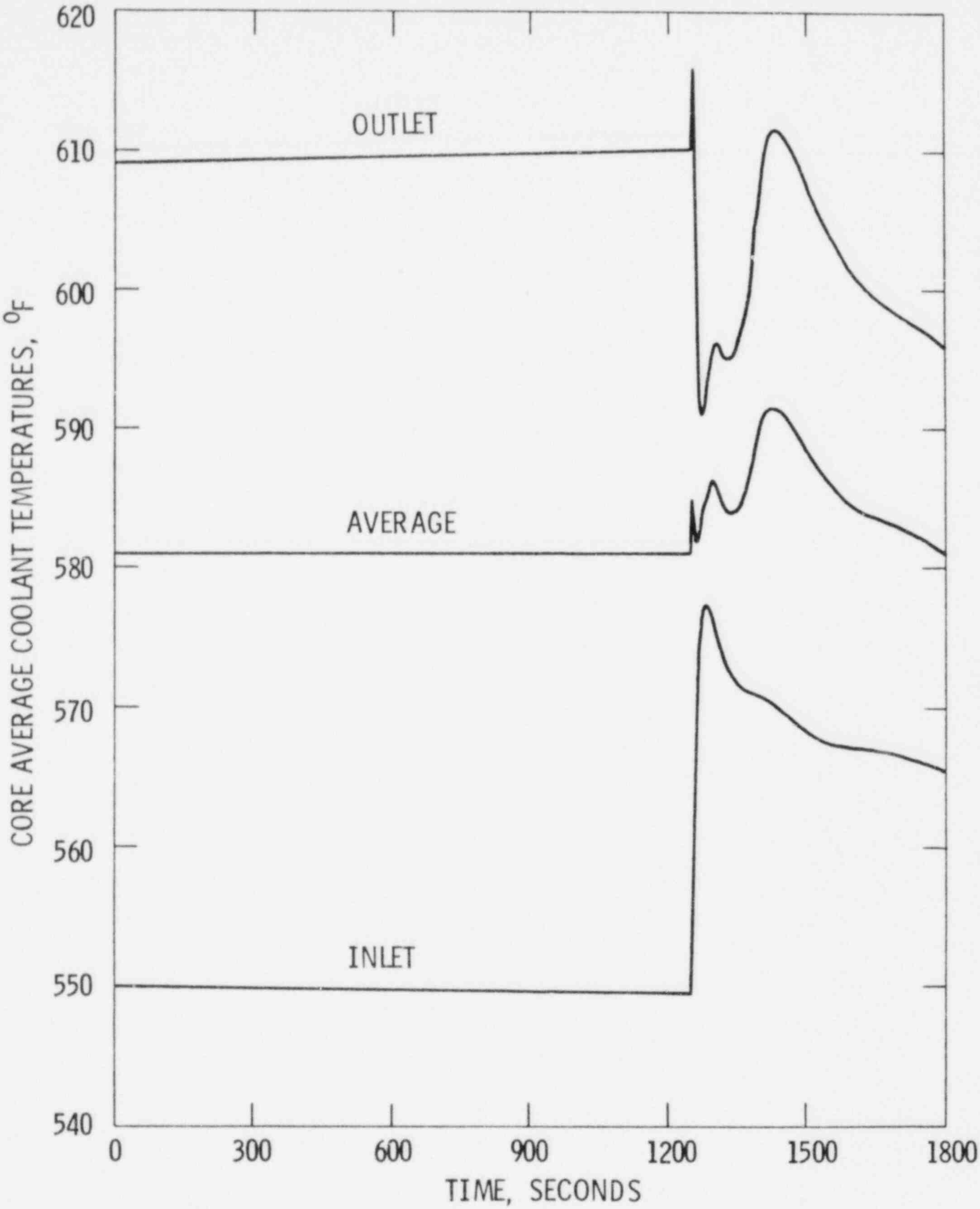
C-E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER PRESSURIZER PRESSURE vs TIME	Figure 15.5.2-4



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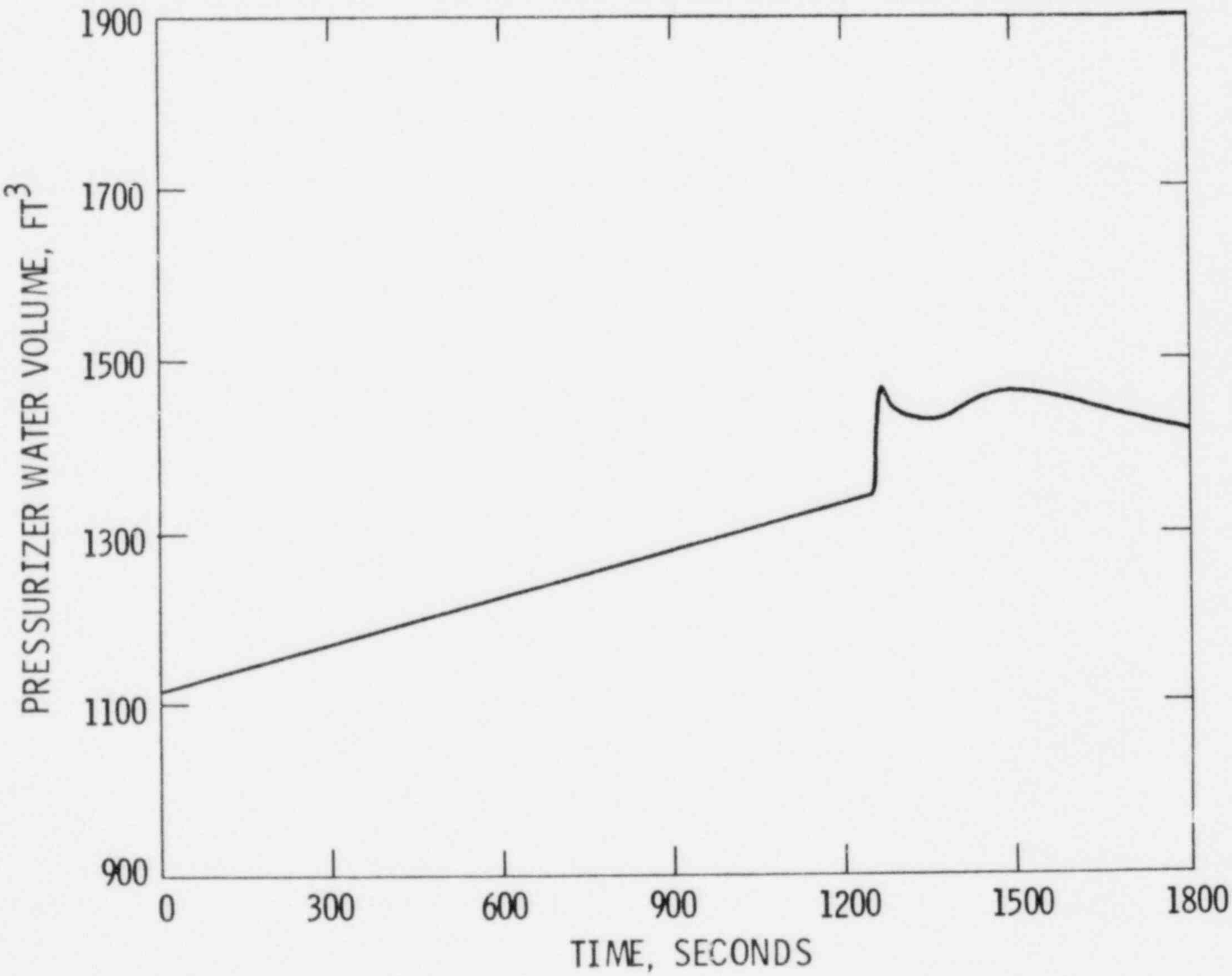
C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER CORE AVERAGE COOLANT TEMPERATURES vs TIME	Figure 15.5.2 -5



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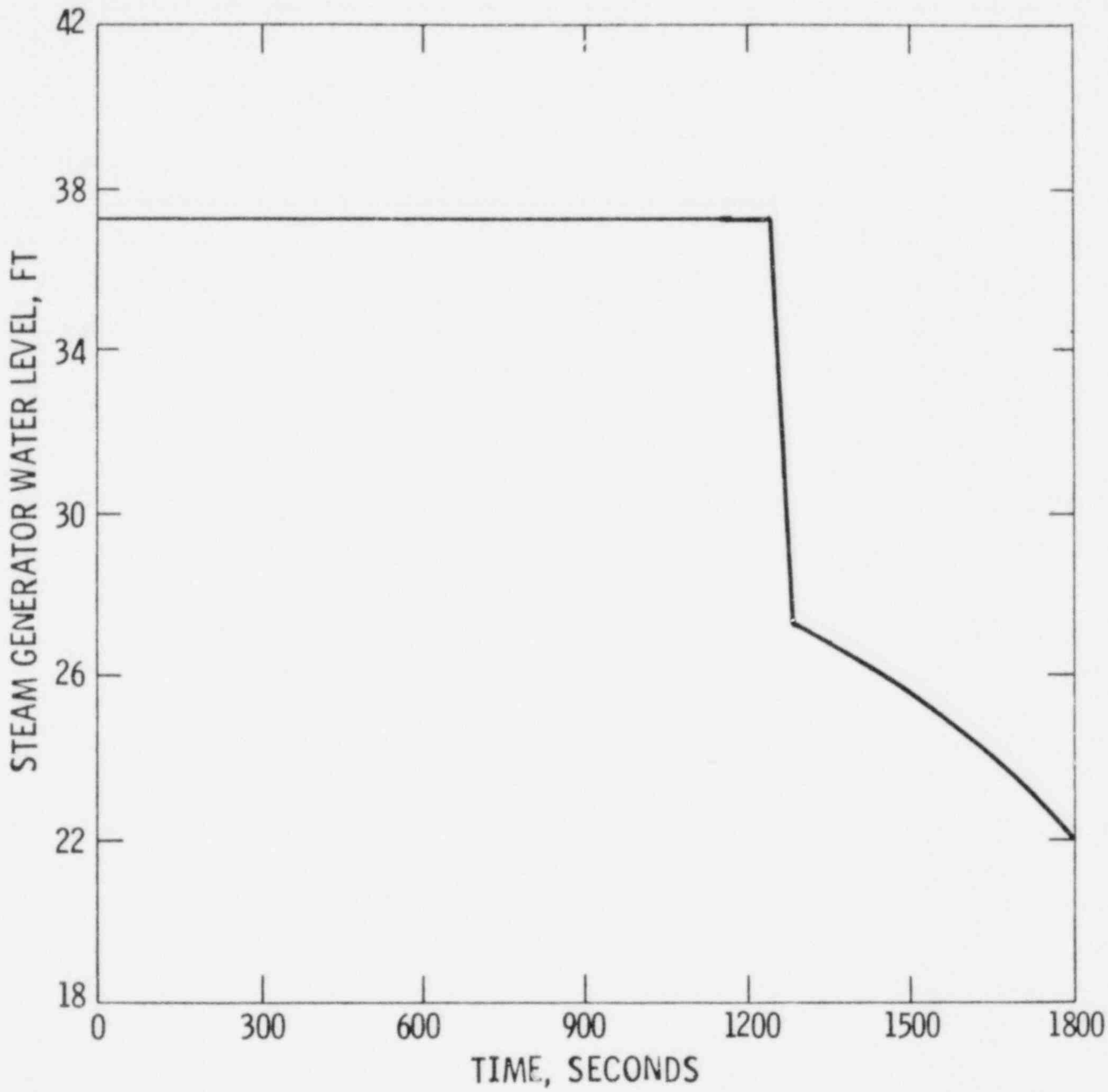
C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER PRESSURIZER WATER VOLUME vs TIME	Figure 15.5.2-6



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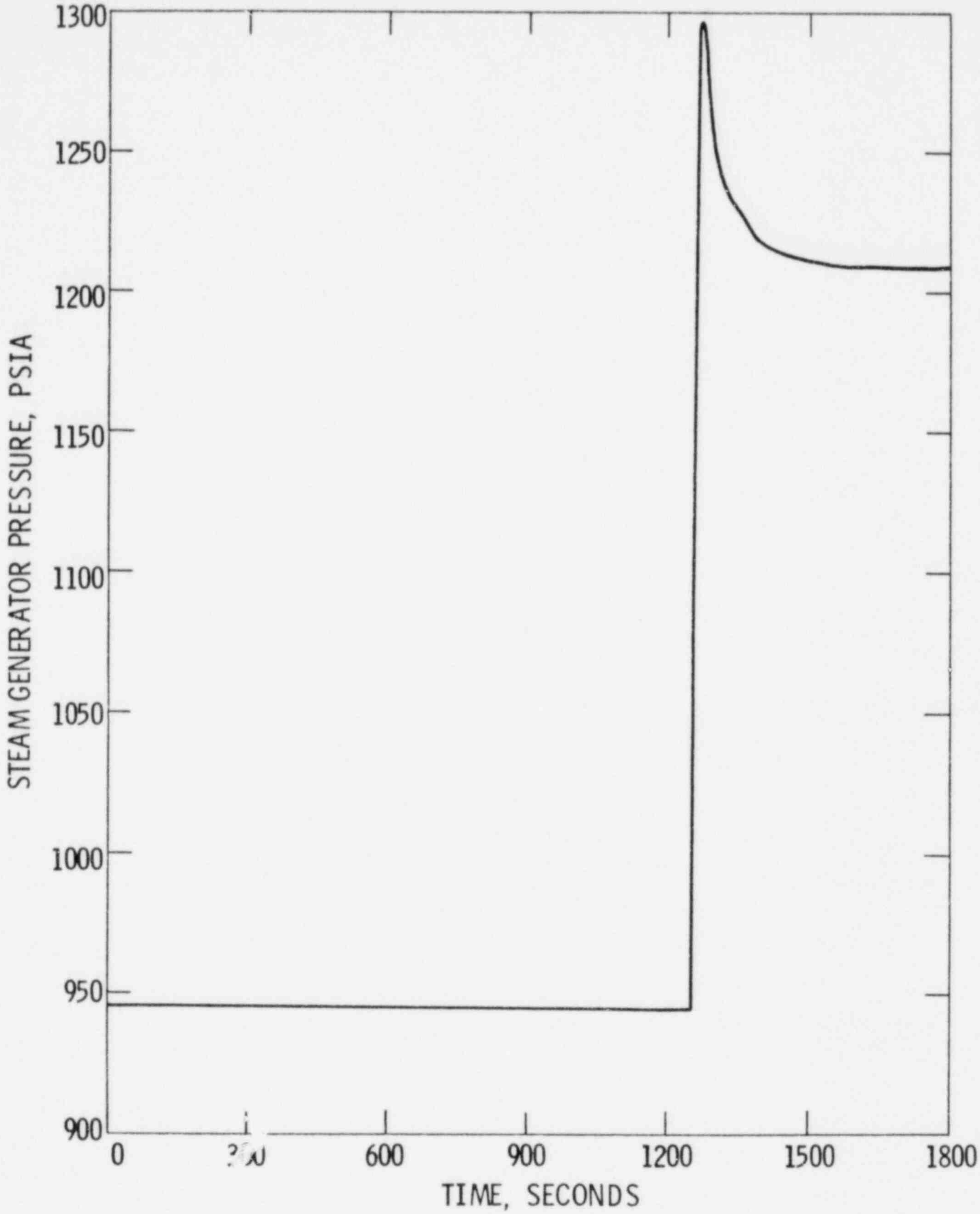
C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER STEAM GENERATOR WATER LEVEL vs TIME	Figure 15.5.2 -7



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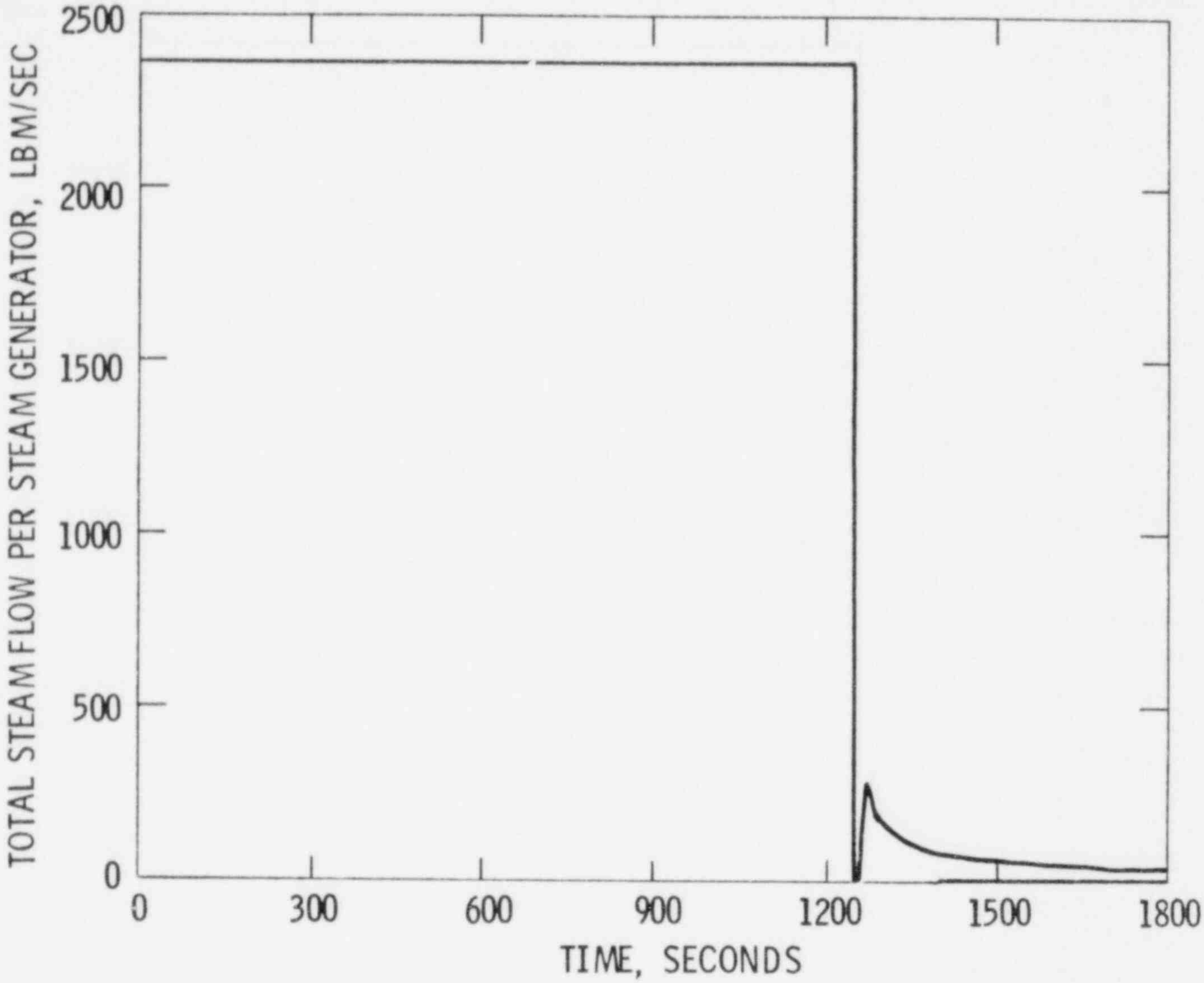
C-E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER STEAM GENERATOR PRESSURE vs TIME	Figure 15.5.2-8



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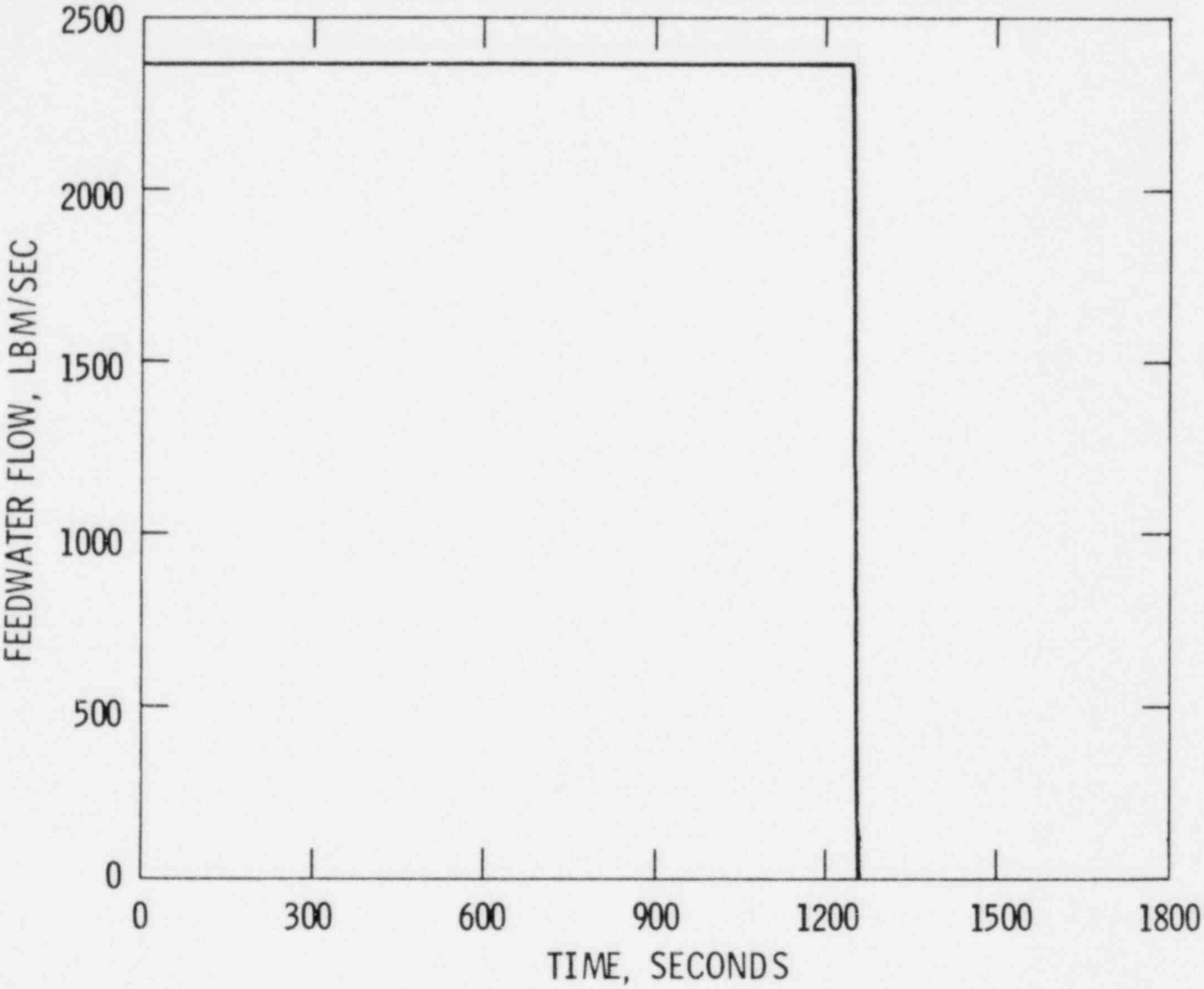
C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER TOTAL STEAM FLOW vs TIME	Figure 15.5.2-9



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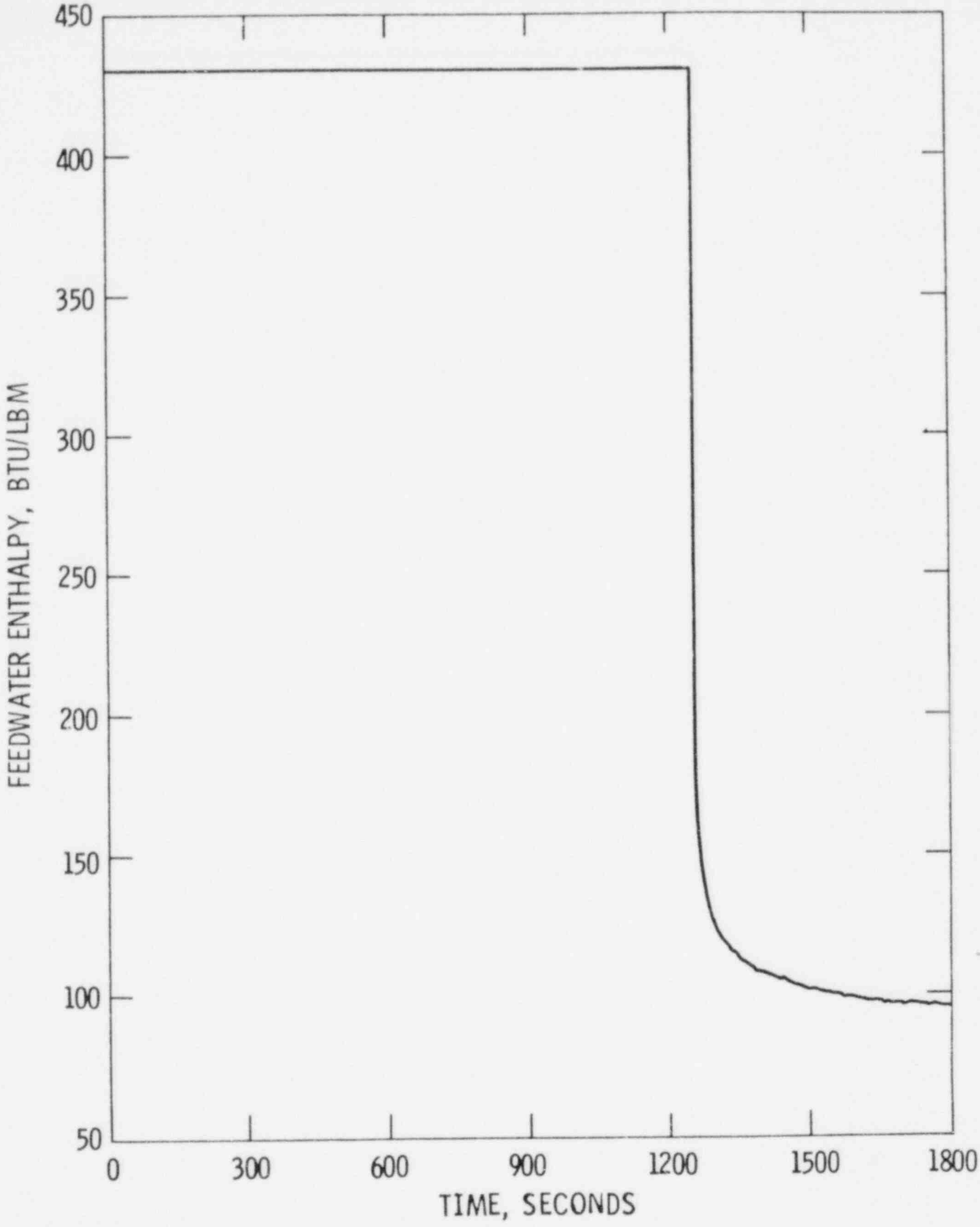
C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER FEEDWATER FLOW vs TIME	Figure 15.5.2 -10



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C - E SYSTEM 80	PLCS MALFUNCTION WITH LOSS OF OFFSITE POWER FEEDWATER ENTHALPY vs TIME	Figure 15.5.2 -11

15.6 DECREASE IN REACTOR COOLANT SYSTEM INVENTORY

15.6.1 INADVERTENT OPENING OF A PRESSURIZER SAFETY/RELIEF VALVE

The Inadvertent Opening of a Pressurizer Safety Valve event as described in SRP 15.6.1 is evaluated in the Emergency Core Cooling Systems analyses (Section 6.3).

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March 31, 1982

15.6.2 DOUBLE-ENDED BREAK OF A LETDOWN LINE OUTSIDE CONTAINMENT

15.6.2.1 Identification of Event and Causes

Direct release of reactor coolant may result from a break or leak outside containment in a letdown line, instrument line, or sample line. The double ended break of the letdown line outside containment, upstream of the letdown line control valve (DBLLOCUS) was selected for this analysis because it is the largest line and results in the largest release of reactor coolant outside the containment.

The single active failure of an isolation valve was not considered in the analysis because the letdown line includes two isolation valves in series situated inside the containment. Hence, failure of one isolation valve does not make the consequences of the event more severe.

A letdown line break can range from a small crack in the piping to a complete double ended break. The cause of the event may be attributed to corrosion which forms etch pits or to fatigue cracks resulting from vibration or inadequate welds.

15.6.2.2 Sequence of Events and Systems Operation

A double-ended break of the letdown line outside containment, upstream of the letdown line control valve releases primary fluid to the auxiliary building at a rate of approximately 50 lbs/sec. This is more than twice the maximum expected letdown flow. The event will set off a number of alarms. Table 15.6.2.-1 lists the alarms that would be noted by the reactor operator in the control room.

Of the alarms listed in Table 15.6.2-1 the first three, that is, the RHX exit high temperature alarm, the letdown line low flow and low pressure alarms, and the low flow alarms in the Process Radiation Monitor and the Borononeter, are going to immediately alert the operator after the initiation of the event. The high RHX outlet temperature alarm in addition to sounding the alarm also initiates isolation of the letdown line by closing one of the two letdown line isolation valves inside the containment. However, no credit is taken for this isolation action in the analysis. Secondly, the high temperature, high humidity and high radiation level alarms (see Table 15.6.2-1) in the auxiliary building are expected to be triggered within a few seconds after the event initiation. Thirdly, the pressurizer low level alarms (see Table 15.6.2-1) is expected to alert the operator within one minute after the initiation of the event. Finally, the auxiliary building sump high level alarm and the volume control tank low level alarms (see Table 15.6.2-1) are expected to be triggered within a few minutes after the initiation of the event.

The analysis assumes that ten minutes after the first three alarms resulting from the DBLLOCUS the operator isolates the letdown line thereby terminating any further release of primary flow to the auxiliary building. Subsequently, the operator is assumed to take appropriate steps for a controlled reactor shutdown. The assumption of operator action within 10 minutes after the first few alarms are triggered is based on ANS 58.8, ANSI N660, Rev. 2, 1981 ("Time Response Design Criteria for Safety-Related Operator Actions"). This is the

minimum time for the letdown line break event category that shall elapse from the time of the alarm until operator actions can be considered for initiation of safety functions.

Table 15.6.2-2 presents a chronological sequence of events which occur following a double-ended break of the letdown line until the operator takes action to terminate the primary system fluid loss 10 minutes after the initiation of the event. Figure 15.0-1, which contains a glossary of symbols and acronyms, may be used with Figure 15.6.2-1 to trace the actuation and interactions of the systems utilized to mitigate the consequences of this event.

Table 15.6.2-3 contains a matrix which shows the extent to which normally operating plant systems are assumed to function during the letdown line break transient.

Table 15.6.2-4 contains a matrix that summarizes the utilization of the safety systems as they appear in the transient analysis.

The success paths in the Sequence of Events Diagram in Figure 15.6.2-1 are as follows:

Reactivity Control:

The operator diagnoses the event based on alarms specified in Table 15.6.2-1, and generates, a manual reactor trip after isolating the letdown line. The CEAs fall into the core to provide a negative reactivity insertion. The boron concentration is adjusted to insure that a proper negative reactivity shutdown margin is achieved prior to cooldown. The boron concentration is adjusted by manually controlling the CVCS.

Reactor Heat Removal:

The SCS is manually actuated when RCS temperature and pressure have been reduced to 350 F and 400 psia, respectively. This system provides sufficient cooling flow to cool the RCS to cold shutdown.

Secondary System Integrity:

The turbine automatically trips on the manual reactor trip. The SBCS automatically actuates and opens the steam bypass valves to dump steam to the condense. The FWCS responds to the reactor trip and generates a Reactor Trip Override signal which reduces feedwater to 5% flow. The plant cooldown is controlled by manual operation of the SBCS. The main feedwater pumps are manually controlled and continue to supply feedwater until steam flow to the condenser becomes inadequate. The operator then starts the auxiliary feedwater pump and secures the main feedwater pumps (See Applicant's SAR for details).

Primary System Integrity:

RCS level is controlled by manual operation of the charging pumps. RCS pressure is reduced by manual operation of the pressurizer spray. As the cooldown proceeds, the operator will reduce the safety injection actuation

setpoint to prevent the inadvertent generation of an SIAS. When the RCS pressure is reduced to approximately 650 psia, the operator will vent or drain the SITs to reduce their pressure and will then isolate them.

Control Room Habitability:

BOP signals may actuate control room habitabiliy system due to the high radiation level in the auxiliary building. See Applicant's FSAR for details.

Fuel Handling Building Habitability:

BOP signals may actuate fuel handling building habitability systems due to the high radiation level in the auxiliary building. See Applicant's FSAR for details.

Radioactive Effluent Control:

The operator diagnoses the event based on alarms listed in Table 15.6.2-1. Ten minutes after receiving the alarms, the letdown line is manually isolated.

15.6.2.3 Analysis of Effects and Consequences

15.6.2.3.1 Core and System Performance

A. Mathematical Model

The Nuclear Steam Supply System (NSSS) response to a double-ended break of a letdown line outside containment, upstream of the letdown line control valve, was simulated with the CESEC-II computer program described in Section 15.0.3. The analysis assumes critical flow through the break and accounts for letdown line losses and for operation of the PPCS (Pressurizer Pressure Control System) and PLCS (Pressurizer Level Control System). The model of the letdown line break used is described in Reference 27 of Section 15.0.

B. Input Parameters and Initial Conditions

Table 15.6.2-5 lists the assumptions and initial conditions used for this analysis in addition to those discussed in Section 15.0. Conditions were chosen to maximize the primary system mass release for DBLLOCUS. This, in turn, leads to the most conservative predictions of radiological releases.

The initial conditions and NSSS characteristics used in this analysis of the maximum total radiological release for the letdown line break were based on parametric studies. The parameters evaluated were initial core inlet temperature, initial power level, initial pressurizer pressure, initial core inlet flow rate, initial pressurizer liquid inventory, and break size. The maximum total mas release is obtained when the transient is initiated with the following parameters from Table 15.0-5: The maximum core power, maximum allowed core inlet temperature, and a low core flow. All control systems are assumed to be in the automatic mode to maximize the total primary mass release. The break is assumed to be the full cross sectional area (double-ended) pipe break.

C. Results

The dynamic behavior of important NSSS parameters following a DBLLOCUS are presented in Figures 15.6.2-2 to 15.6.2-14. The decrease in the primary system mass causes the pressurizer pressure to decrease exponentially from the initial 2400 psia to about 2230 psia at 600 seconds. During the same time period the pressurizer level decreases from an initial level of 22.1 feet above the lower tap to a new level of 10.2 feet.

Ten minutes into the transient the operator isolates the letdown line, terminating the release of primary fluid outside the containment. During this time period no more than 30,766 pounds of primary system fluid is released into the auxiliary building. Some time shortly after the termination of the primary system mass release, the operator manually trips the reactor. The minimum DNBR does not decrease below 1.65 (as calculated using the CE-1 correlation) at any time during the transient (see Figure 15.6.2-14).

15.6.2.3.2 Radiological Consequences

A. Mathematical Model

The DBLLOCUS event is indicated by several alarms listed in Table 15.6.2-1. Ten minutes after the first three alarms, which take place immediately following the initiation of the event, the letdown line is isolated by the reactor operator. During this time 30,766 pounds of primary coolant is released into the auxiliary building.

The mathematical model used to calculate the inhalation doses at the exclusion area boundary (EAB) is discussed in Section 15.0.4.

B. Assumptions and Parameters

The letdown line break outside containment results in the discharge of radioactivity to the environment. There are some uncertainties in the calculation of resultant radiation doses. These principally arise from uncertainties in the reactor coolant activity levels, the quantity of coolant released, the fraction of radionuclides that become airborne, the fraction of airborne activity that escapes the auxiliary building, and meteorological conditions that exists at the time of the accident. These uncertainties are treated by taking worst case or conservative assumptions. These are:

a) The initial activity level of the primary coolant is assumed to be 4.6 Ci/gm. This corresponds to the maximum equilibrium value (with 1% failed fuel) given in the technical specifications.

b) An iodine activity spike with a spiking factor of 500 is assumed to occur coincident with the initiation of the transient.

c) The quantity of coolant released outside containment is maximized by assuming most adverse initial conditions and by assuming critical flow through the break.

d) The blowdown decontamination factor (DF) is assumed to be there. That is, one-third of all the iodine contained in the released primary mass

is assumed to be airborne. This is based on the fraction of primary fluid that flashes to steam in the auxiliary building based on the enthalpy of the escaping fluid.

e) The auxiliary building DF is assumed to be three. That is, credit is taken for the retention within the auxiliary building and filtration system of two-thirds of all the radioactivity contained in the released primary mass.

f) No credit is taken for ground deposition of the activity that escapes the auxiliary building or of decay in transit to the exclusion area boundary.

g) The meteorological conditions assumed to be present at the site during the course of the accident area based on X/Q values which are expected to be conservative 95% of the time. This condition results in the poorest values of atmospheric dispersion calculated for the exclusion area boundary or LPZ outer boundary. Furthermore, no credit has been taken for the transit time required for activity to travel from the point of release to the exclusion area boundary LPZ outer boundary. Hence, the radiological consequences evaluated under these conditions are conservative. The X/Q value conservatively assumed is 2.0×10^{-3} sec/M^3.

C. Results

The radiological consequences resulting from the occurrence of a postulated letdown line rupture have been conservatively analyzed using assumptions and models described in the preceding subsections. The thyroid inhalation dose has been analyzed for the 0 to 2-hour dose at the exclusion area boundary. The 2-hour thyroid inhalation dose is found to be no more than 23.7 rems.

15.6.2.4 Conclusions

The double-ended break of a letdown line outside containment upstream of the letdown line control valve results in gradual depressurization of the reactor coolant system. The minimum Departure From Nucleate Boiling Ratio (DNBR) stays above the value at which the fuel pins would be calculated to experience DNB.

During the 600 second duration of the transient no more than 30,766 pounds of primary system coolant is released outside the containment. This results in a two hour thyroid inhalation dose which is a small fraction of 10CFR100 guidelines.

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TABLE 15.6.2-1

ALARMS THAT WILL BE

ACTUATED FOR THE DBLLOCUS EVENT

1. Regenerative Heat Exchanger high exit temperature alarm

2. Letdown line low flow and low pressure alarms (downstream of the break)

3. Letdown line component low flow alarms
   a) Process Radiation Monitor
   b) Boronometer

4. Auxiliary building high radiation alarm

5. Auxiliary building high temperture and high humidity alarms

6. Pressurizer low level alarm

7. Auxiliary building sump high level alarm

8. Volume control tank low level alarm

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TABLE 15.6.2-2

SEQUENCE OF EVENTS FOR A DOUBLE-ENDED BREAK OF THE LETDOWN LINE OUTSIDE CONTAINMENT UPSTREAM OF THE LETDOWN CONTROL VALVE

Time (sec)	Event	Setpoint or Value	Success Path
0.0	Letdown Line Rupture Occurs Setting Off Alarms Listed in Table 15.6.2-1	--	
33	Third Charging Pump Starts	9" below Initial Pressurizer Level	Primary System Integrity
74	Pressurizer Backup Heaters Turned On, psia	2360	
600	Operator Isolates the Letdown Line And Takes Steps For A Controlled Shutdown Of The Reactor	--	Primary System Integrity and Reactivity Control

TABLE 15.6.2-3 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR THE DOUBLED ENDED BREAK OF A LETDOWN LINE, OUTSIDE CONTAINMENT, UPSTREAM OF THE LETDOWN CONTROL VALVES

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System	✓					
2. Main Feedwater Pump Turbine Control System*	✓					
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System	✓					
5. Pressurizer Pressure Control System	✓					
6. Pressurizer Level Control System	✓					
7. Control Element Drive Mechanism Control System	✓					
8. Reactor Regulating System	✓					
9. Core Operating Limit Supervisory System	✓					
10. Reactor Coolant Pumps	✓					
11. Chemical and Volume Control System	✓					
12. Secondary Chemistry Control System*	✓					
13. Condenser Evacuation System*	✓					
14. Turbine Gland Sealing System*	✓					
15. Nuclear Cooling Water System*	✓					
16. Turbine Cooling Water System*	✓					
17. Plant Cooling Water System*	✓					
18. Condensate Storage Facilities*	✓					
19. Circulating Water System*	✓					
20. Spent Fuel Pool Cooling and Clean-Up System*	✓					
21. Non-Class 1E (Non-ESF) A.C. Power*	✓					
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems -

TABLE 15.6.2-3 (CONTINUED) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR THE DOUBLED ENDED BREAK OF A
LETDOWN LINE, OUTSIDE CONTAINMENT,
UPSTREAM OF THE LETDOWN CONTROL VALVES

SYSTEM	NORMAL THROUGH-OUT TRANSIENT	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	MANUAL MODE INOPERATIVE ON LOSS OF A.C.	NORMAL AUTOMATIC MODE INOPERATIVE ON LOSS OF A.C.	MANUAL MODE WITHIN SYSTEM	SINGLE-FAILURE ASSUMED	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*	✓						
24. Class 1E D.C. Power*	✓						

*Balance-of-Plant Systems

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TABLE 15.6.2-4

UTILIZATION OF SAFETY SYSTEMS
FOR THE DOUBLED ENDED BREAK OF A
LETDOWN LINE, OUTSIDE CONTAINMENT,
UPSTREAM OF THE LETDOWN CONTROL VALVES

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems			✓		
4. Supplementary Protection System					
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*			✓		
7. Primary Safety Valves					
8. Main Steam Isolation System*			✓		
9. Emergency Feedwater System*			✓		
10. Safety Injection System			✓		
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*			✓		
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*					
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

*Balance-of-Plant Systems -

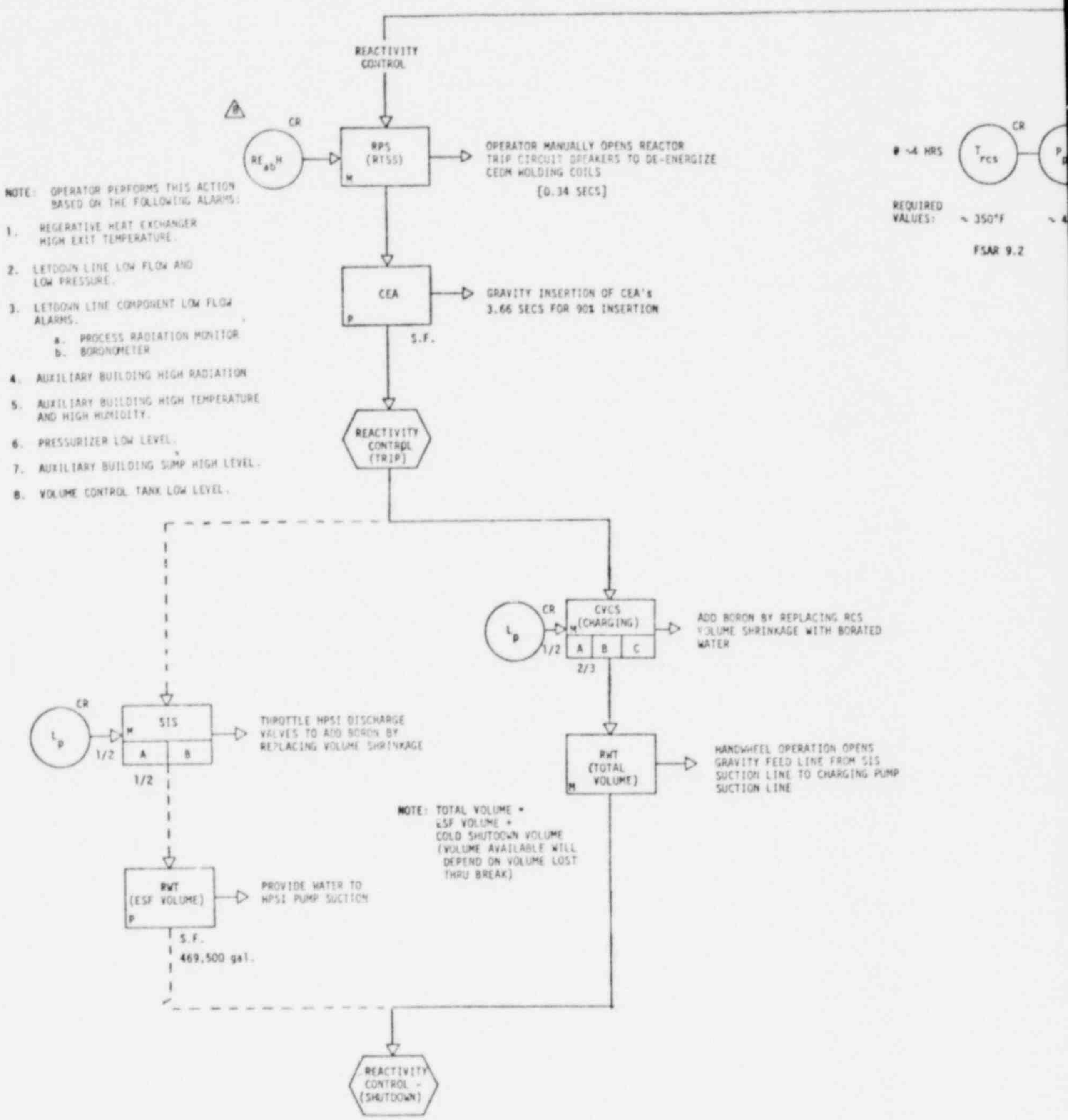
TABLE 15.6.2-5

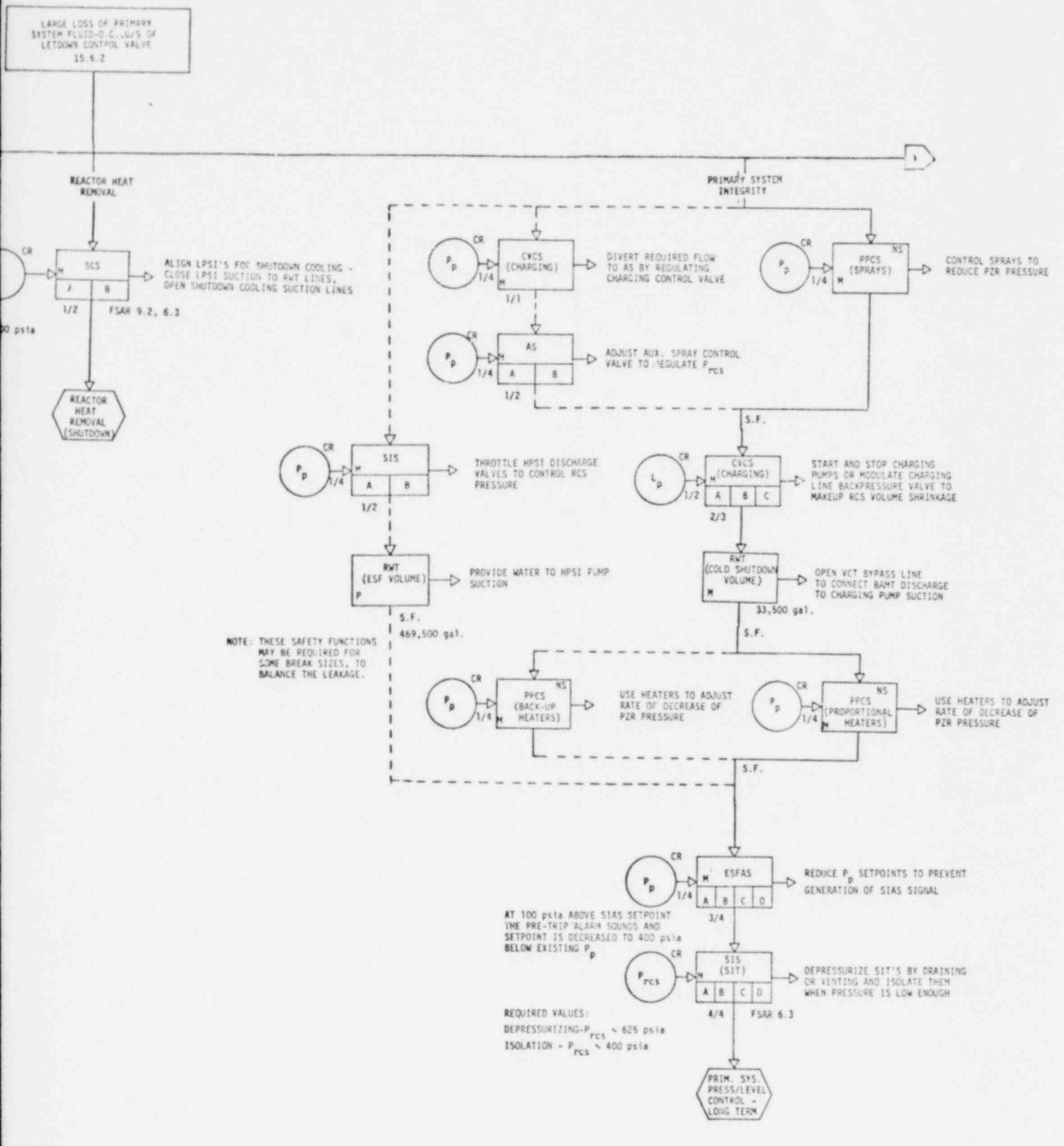
ASSUMED INPUT PARAMETERS AND INITIAL CONDITIONS FOR
THE DOUBLE-ENDED BREAK
OF THE LETDOWN LINE OUTSIDE CONTAINMENT
UPSTEAM OF THE LETDOWN LINE CONTROL VALVE

Parameters	Assumed Value
Core Power Level, Mwt	3876
Core Inlet Temperature, °F	580
Pressurizer Pressure, psia	2400
Core Mass Flow, 10^6 lbm/hr	153
Pressurizer Liquid Volume, ft^3	1116
Steam Generator Pressure, psia	1206
Doppler Coeffcient Multiplier	1.15
CEA Worth at Trip, $10^{-2}\Delta\rho$ (most reactive CEA fully withdrawn)	-10.0
Break Size (double-ended), ft^2	0.01556

SPECIFIC EVENT

LETDOWN LINE BREAK
OUTSIDE CONTAINMENT





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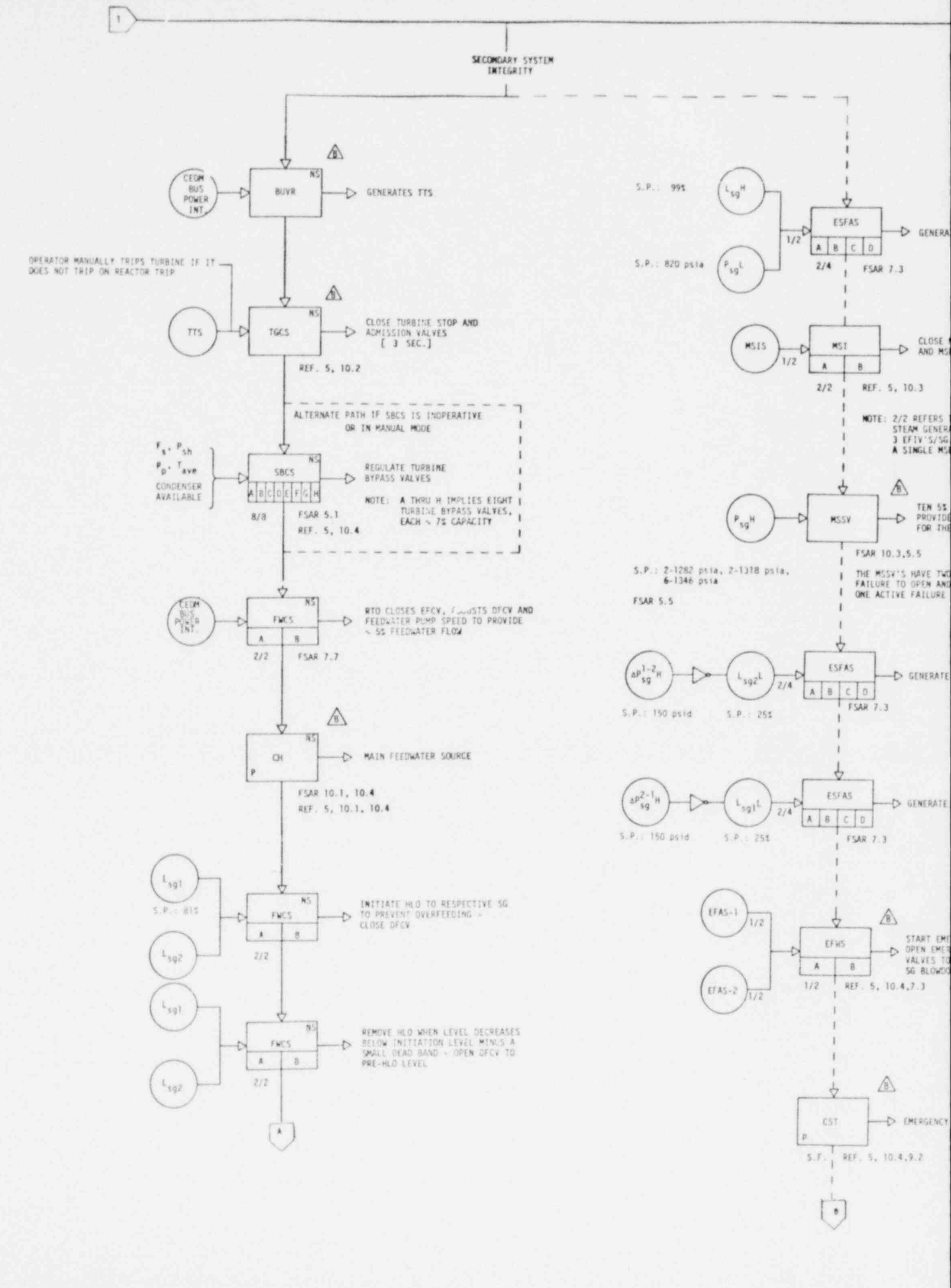
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR DOUBLE-ENDED LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN CONTROL VALVE	Figure 15.6.2 -1A


1
SECONDARY SYSTEM INTEGRITY
CEDM BUS POWER INT.
BUVR
NS
GENERATES TTS
OPERATOR MANUALLY TRIPS TURBINE IF IT DOES NOT TRIP ON REACTOR TRIP
TTS
TGCS
CLOSE TURBINE STOP AND ADMISSION VALVES [3 SEC.]
REF. 5, 10.2
ALTERNATE PATH IF SBCS IS INOPERATIVE OR IN MANUAL MODE
CONDENSER AVAILABLE
SBCS
A B C D E F G H
8/8
REGULATE TURBINE BYPASS VALVES
NOTE: A THRU H IMPLIES EIGHT TURBINE BYPASS VALVES, EACH ~ 7% CAPACITY
FSAR 5.1
REF. 5, 10.4
FWCS
RTO CLOSES EFCV, ADJUSTS DFCV AND FEEDWATER PUMP SPEED TO PROVIDE ~ 5% FEEDWATER FLOW
2/2
FSAR 7.7
CH
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
S.P.: 81%
INITIATE HLO TO RESPECTIVE SG TO PREVENT OVERFEEDING - CLOSE DFCV
REMOVE HLO WHEN LEVEL DECREASES BELOW INITIATION LEVEL MINUS A SMALL DEAD BAND - OPEN DFCV TO PRE-HLO LEVEL
A
S.P.: 99%
S.P.: 820 psia
ESFAS
1/2
2/4
FSAR 7.3
GENERA
MSIS
MSI
CLOSE
AND MS
REF. 5, 10.3
NOTE: 2/2 REFERS
STEAM GENER
3 EFIV'S/SG
A SINGLE MS
MSSV
TEN 5%
PROVIDE
FOR THE
FSAR 10.3,5.5
S.P.: 2-1282 psia, 2-1318 psia, 6-1346 psia
FSAR 5.5
THE MSSV'S HAVE TWO
FAILURE TO OPEN AND
ONE ACTIVE FAILURE
S.P.: 150 psid
S.P.: 25%
GENERATE
EFAS-1
EFAS-2
EFWS
START EM
OPEN EME
VALVES TO
SG BLOWDO
REF. 5, 10.4,7.3
CST
EMERGENCY
S.F.
REF. 5, 10.4,9.2
B

E MSIS

SIV'S, DFIV'S, EFIV'S
V

O THE ISOLATION OF TWO
TORS, THERE ARE 2 DFIV'S/SG,
2 MSIV'S/SG AND THERE IS
Y

CAPACITY MSSV'S PER SG
OVER-PRESSURE PROTECTION
SECONDARY SYSTEM

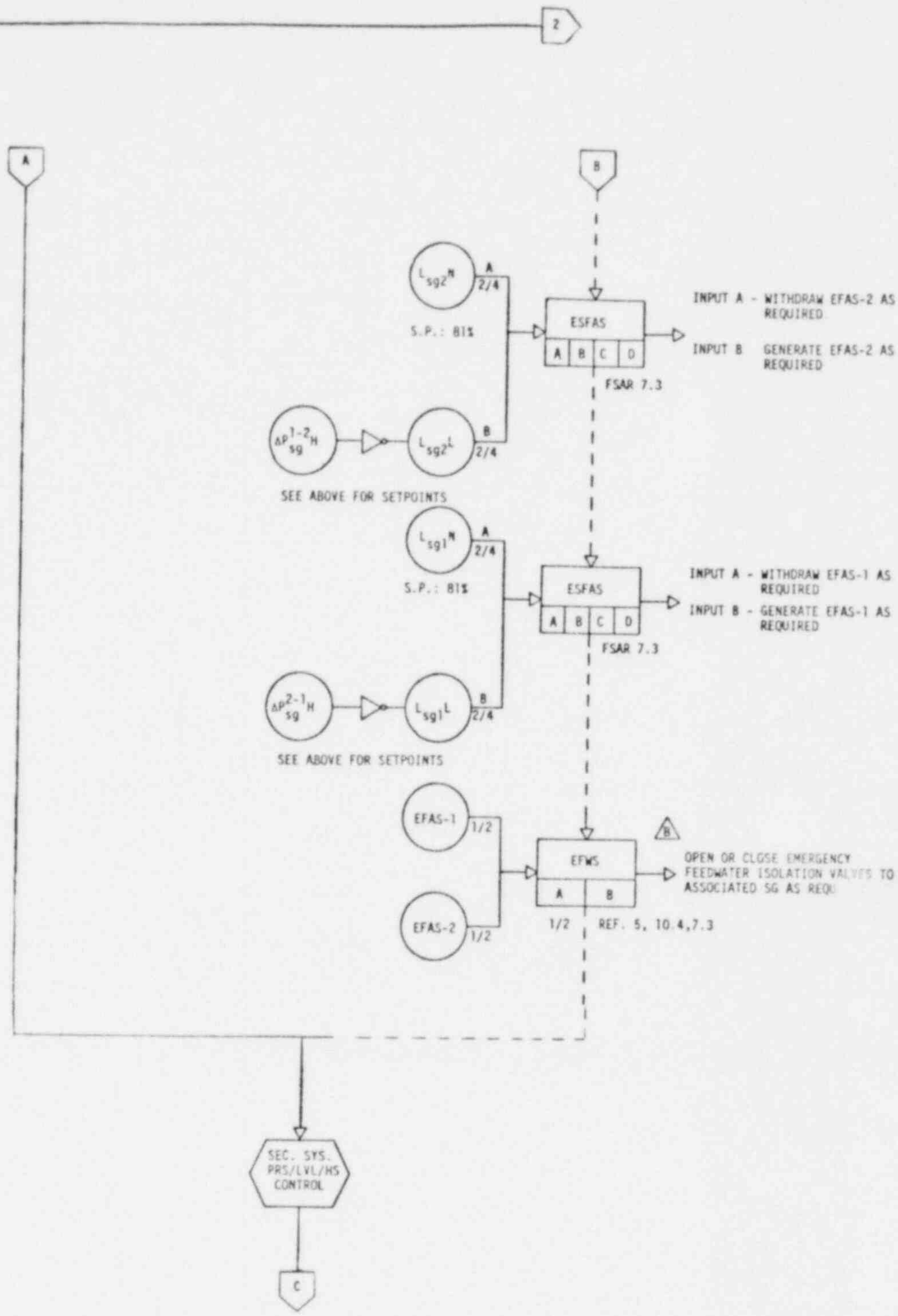
PASSIVE FAILURE MODES:
SPURIOUS OPENING, AND
MODE: FAILURE TO RESEAT

EFAS-2

EFAS-1

GENCY FEEDWATER PUMPS,
GENCY FEEDWATER ISOLATION
ASSOCIATED SG AND ISOLATE
N LINES

FEEDWATER SOURCE



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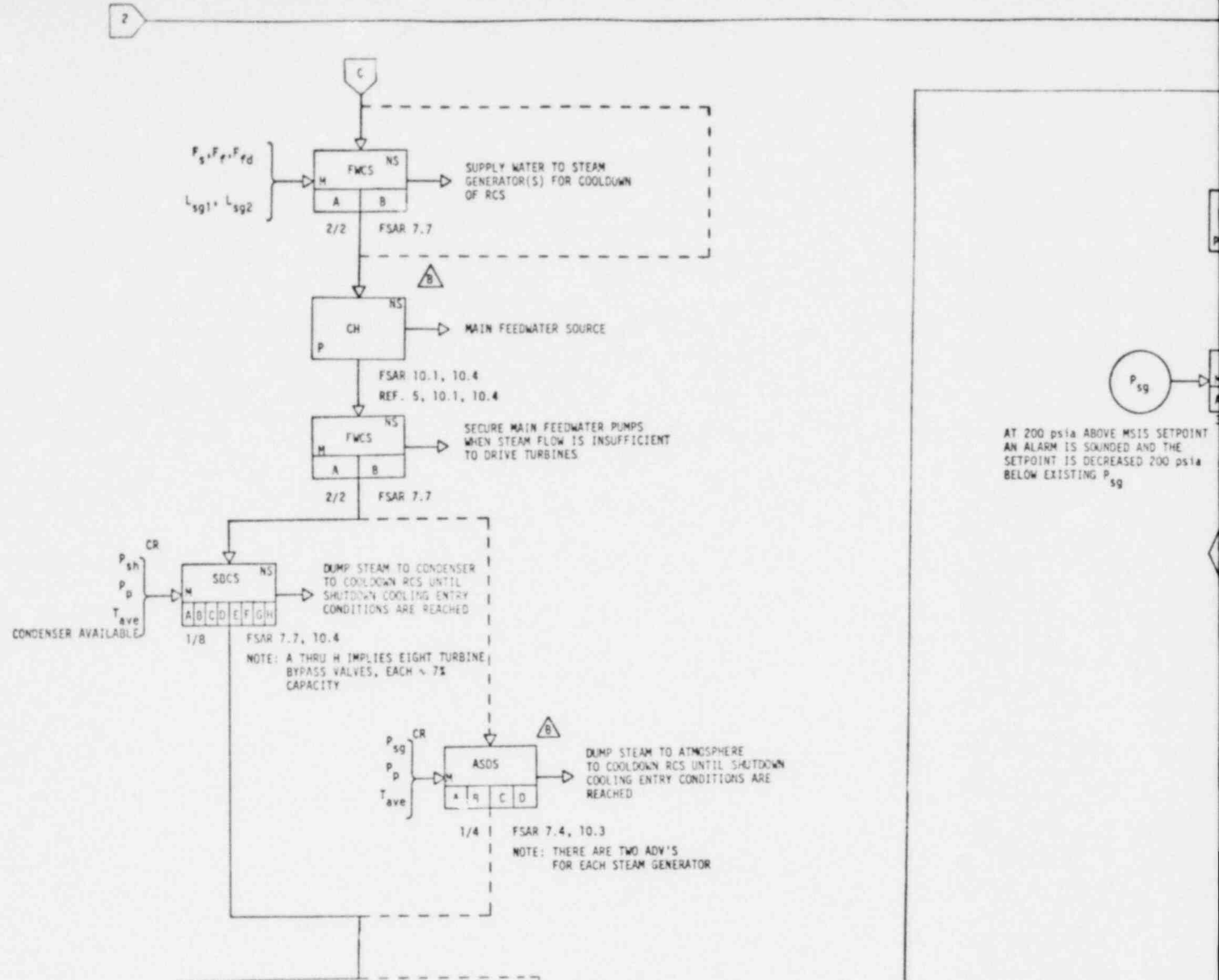
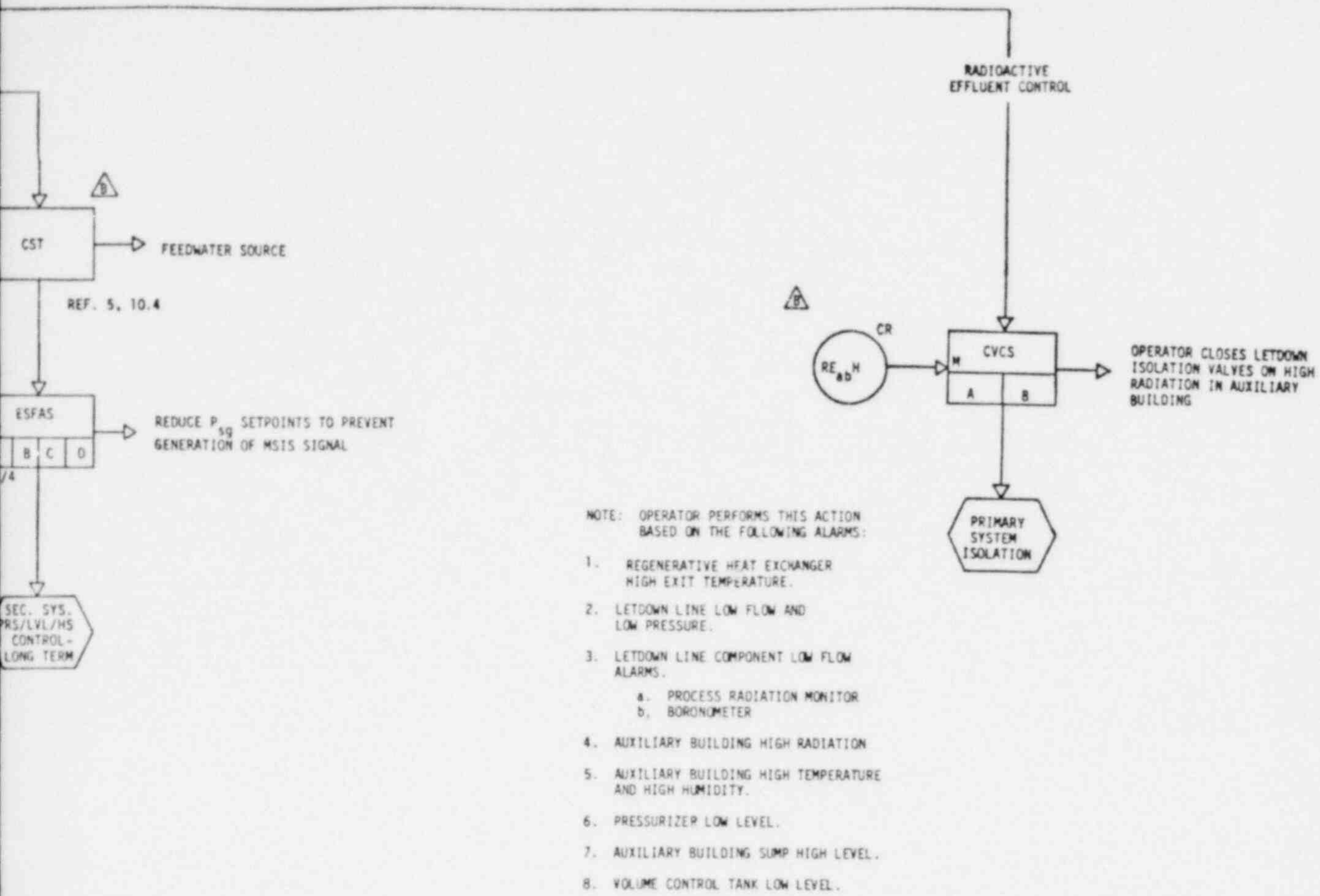
March 31, 1982

C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR DOUBLE-ENDED LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN CONTROL VALVE	Figure 15.6.2 -1B


2
C
F_s, F_f, F_{fd}
L_{sg1}, L_{sg2}
FWCS
NS
M
A
B
2/2
FSAR 7.7
SUPPLY WATER TO STEAM GENERATOR(S) FOR COOLDOWN OF RCS
B
CH
NS
P
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
FWCS
NS
M
A
B
2/2
FSAR 7.7
SECURE MAIN FEEDWATER PUMPS WHEN STEAM FLOW IS INSUFFICIENT TO DRIVE TURBINES
CR
P_{sh}
P_p
T_{ave}
CONDENSER AVAILABLE
SDCS
NS
M
A B C D E F G H
1/8
FSAR 7.7, 10.4
DUMP STEAM TO CONDENSER TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
NOTE: A THRU H IMPLIES EIGHT TURBINE BYPASS VALVES, EACH ~ 7% CAPACITY
B
CR
P_{sg}
P_p
T_{ave}
ASDS
M
A B C D
1/4
FSAR 7.4, 10.3
DUMP STEAM TO ATMOSPHERE TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
NOTE: THERE ARE TWO ADV'S FOR EACH STEAM GENERATOR
B
CR
L_{sg}
EFWS
M
A
B
1/2
REF. 5, 10.4
PROVIDE FEEDWATER TO STEAM GENERATOR(S) TO COOLDOWN RCS USING BOTH MOTOR & STEAM DRIVEN PUMPS
B
CR
L_{sg}
AFWS
NS
M
REF. 5, 10.4
START AUXILIARY FEEDWATER PUMP, OPEN AUXILIARY FEEDWATER ISOLATION VALVES, SUPPLY WATER TO STEAM GENERATOR(S) FOR COOLDOWN OF RCS
B
CR
CR
P_{sg}
L_{sg}
EFWS
M
1/1
REF. 5, 10.4
SECURE STEAM DRIVEN PUMP WHEN STEAM FLOW IS NO LONGER AVAILABLE. USE MOTOR DRIVEN PUMP AND CONTROL OF EFW ISOLATION VALVES TO MAINTAIN LEVEL DURING COOLDOWN
P_{sg}
AT 200 psia ABOVE MSIS SETPOINT AN ALARM IS SOUNDED AND THE SETPOINT IS DECREASED 200 psia BELOW EXISTING P_{sg}



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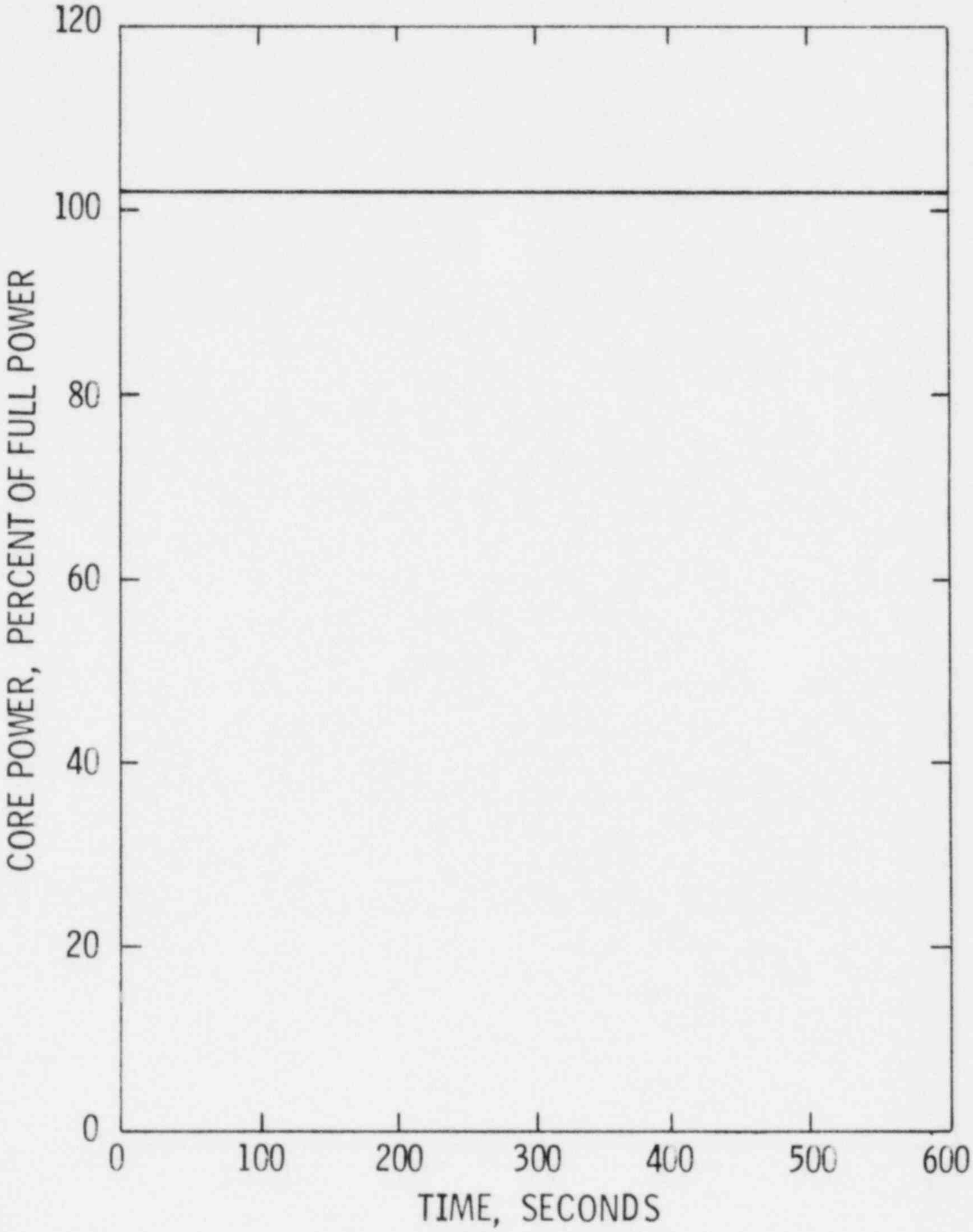
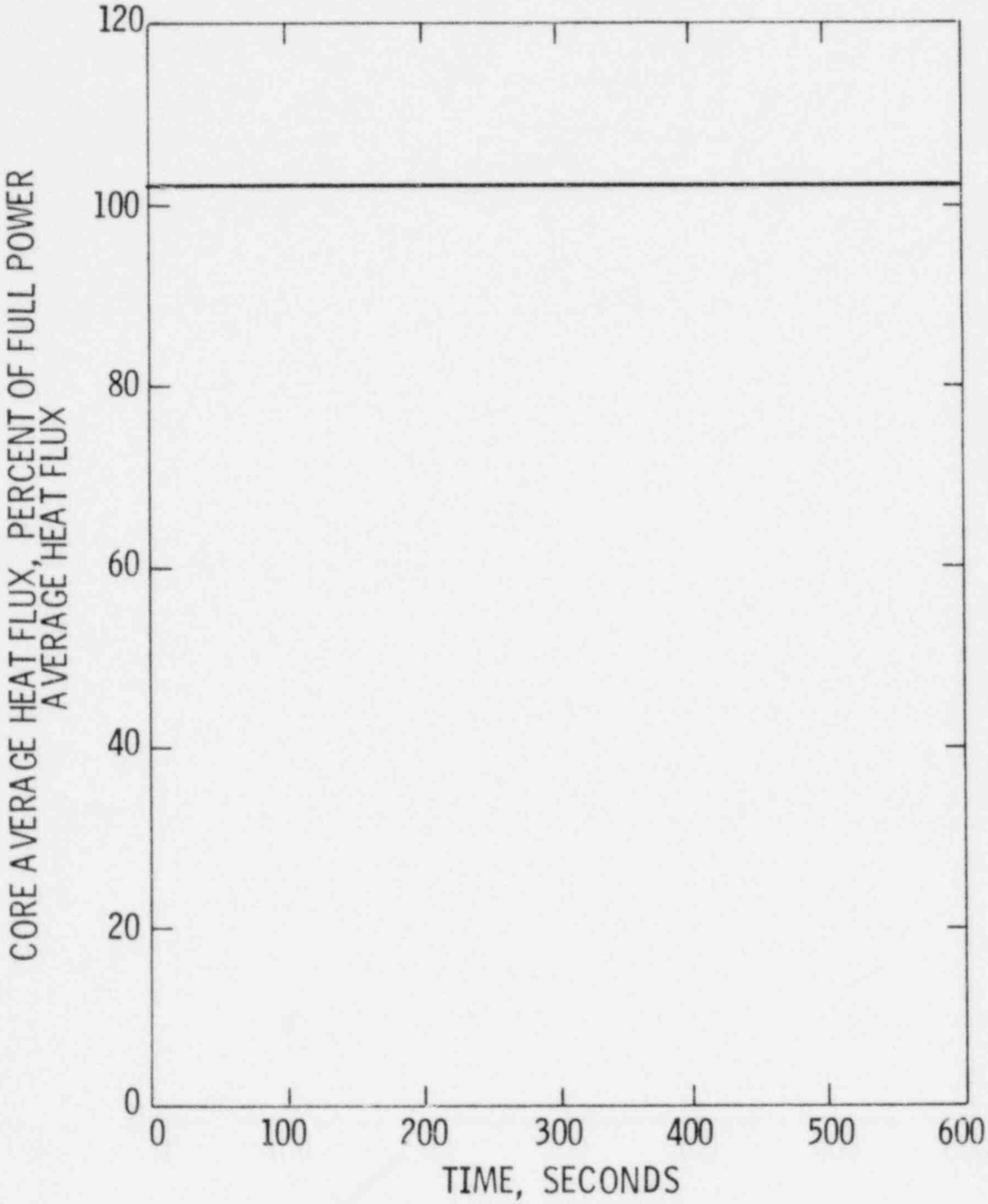
March 31, 1982

C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR DOUBLE-ENDED LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN CONTROL VALVE	Figure 15.6.2 -1C



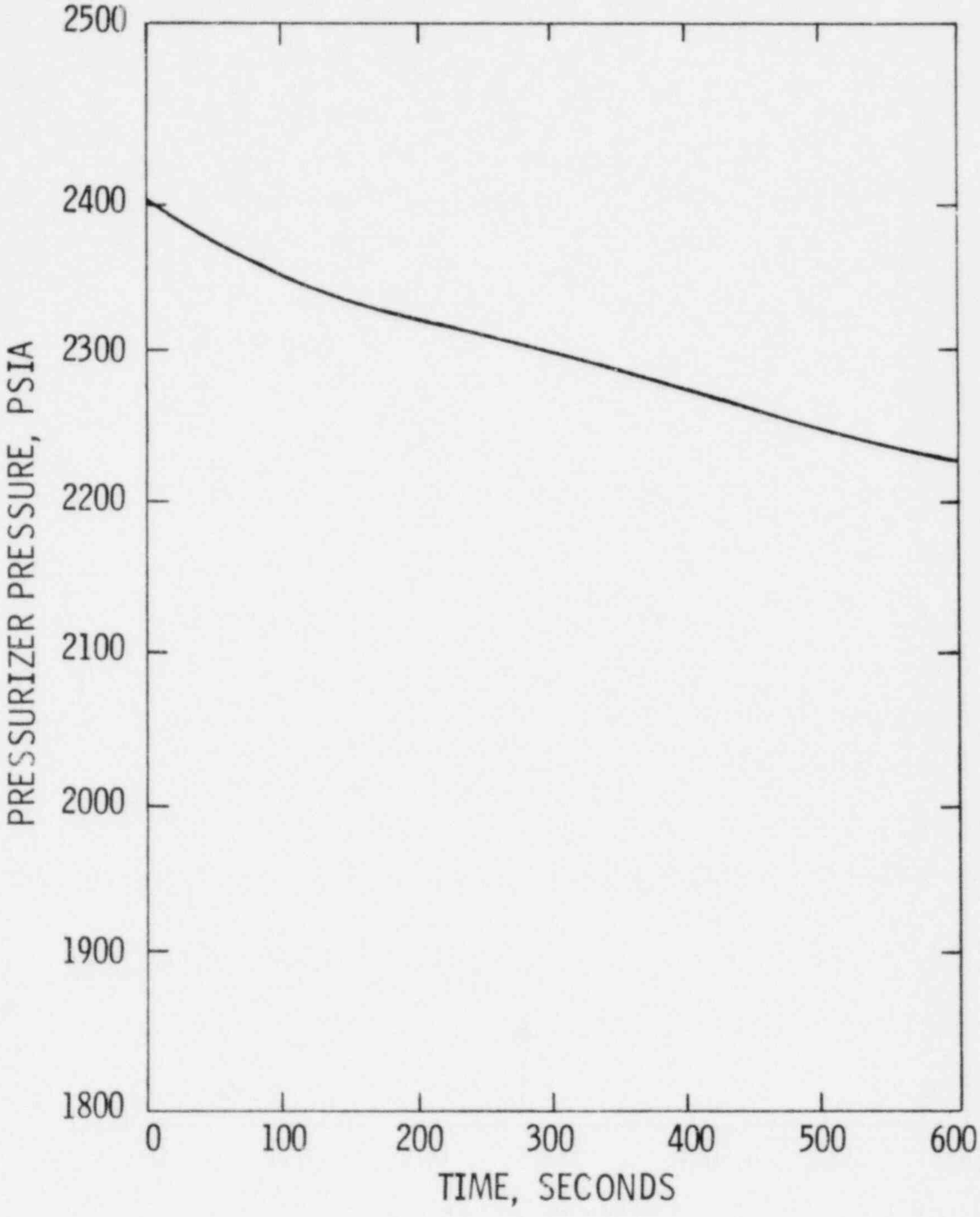
Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE CORE POWER vs TIME	Figure 15.6.2-2



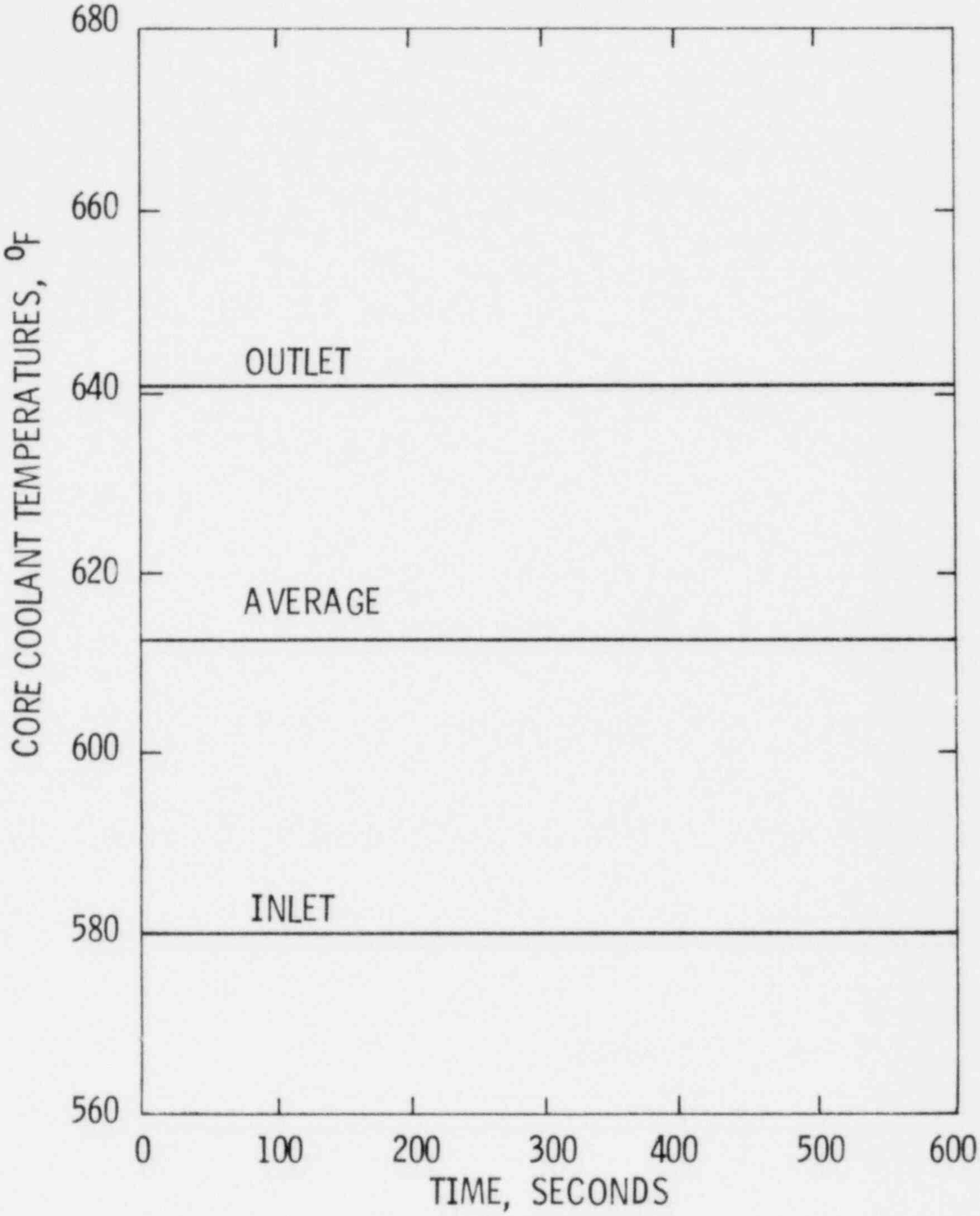
Amendment No. 7
March 31, 1982

C-E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE CORE AVERAGE HEAT FLUX vs TIME	Figure 15.6.2-3



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVES PRESSURIZER PRESSURE vs TIME	Figure 15.6.2-4



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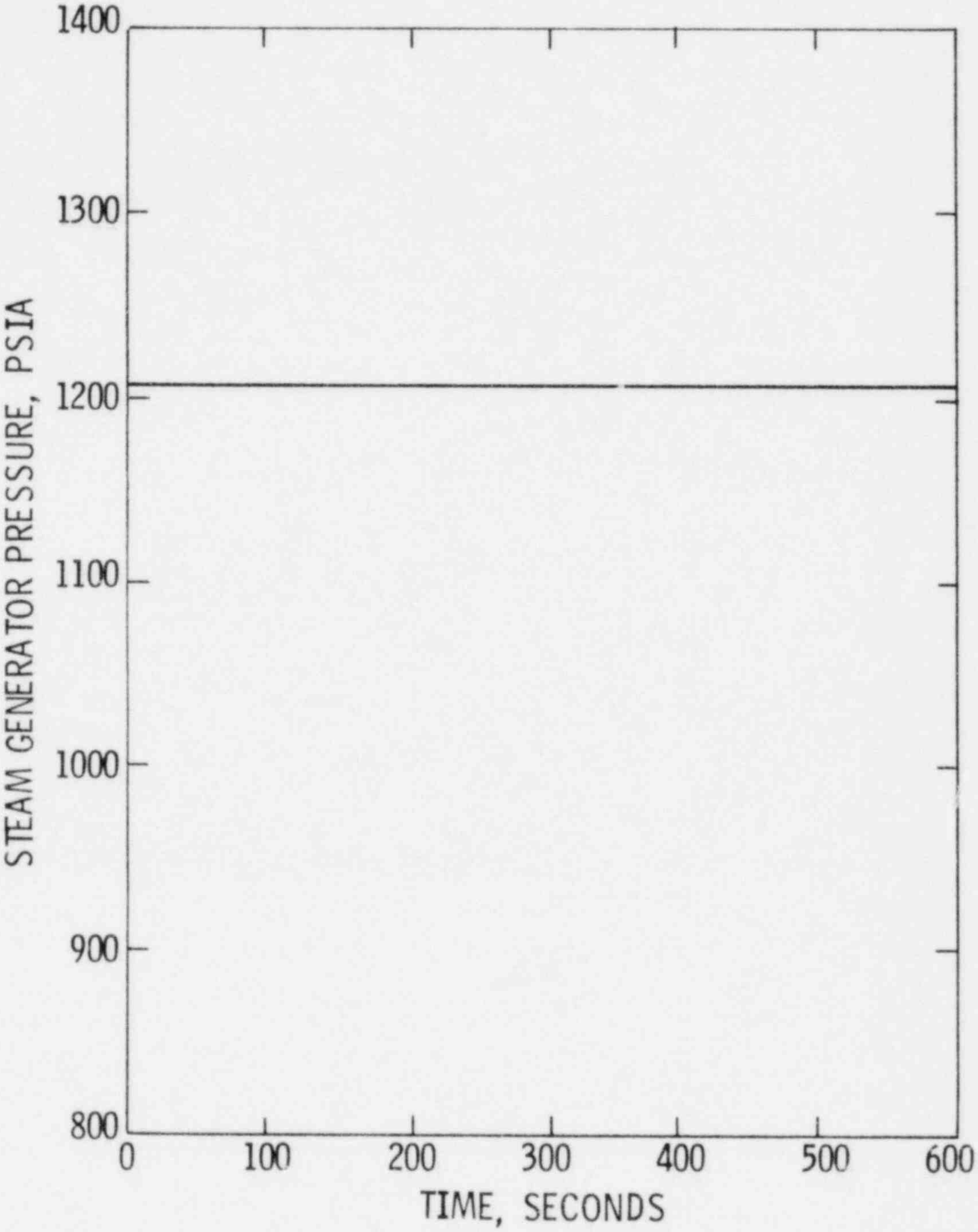
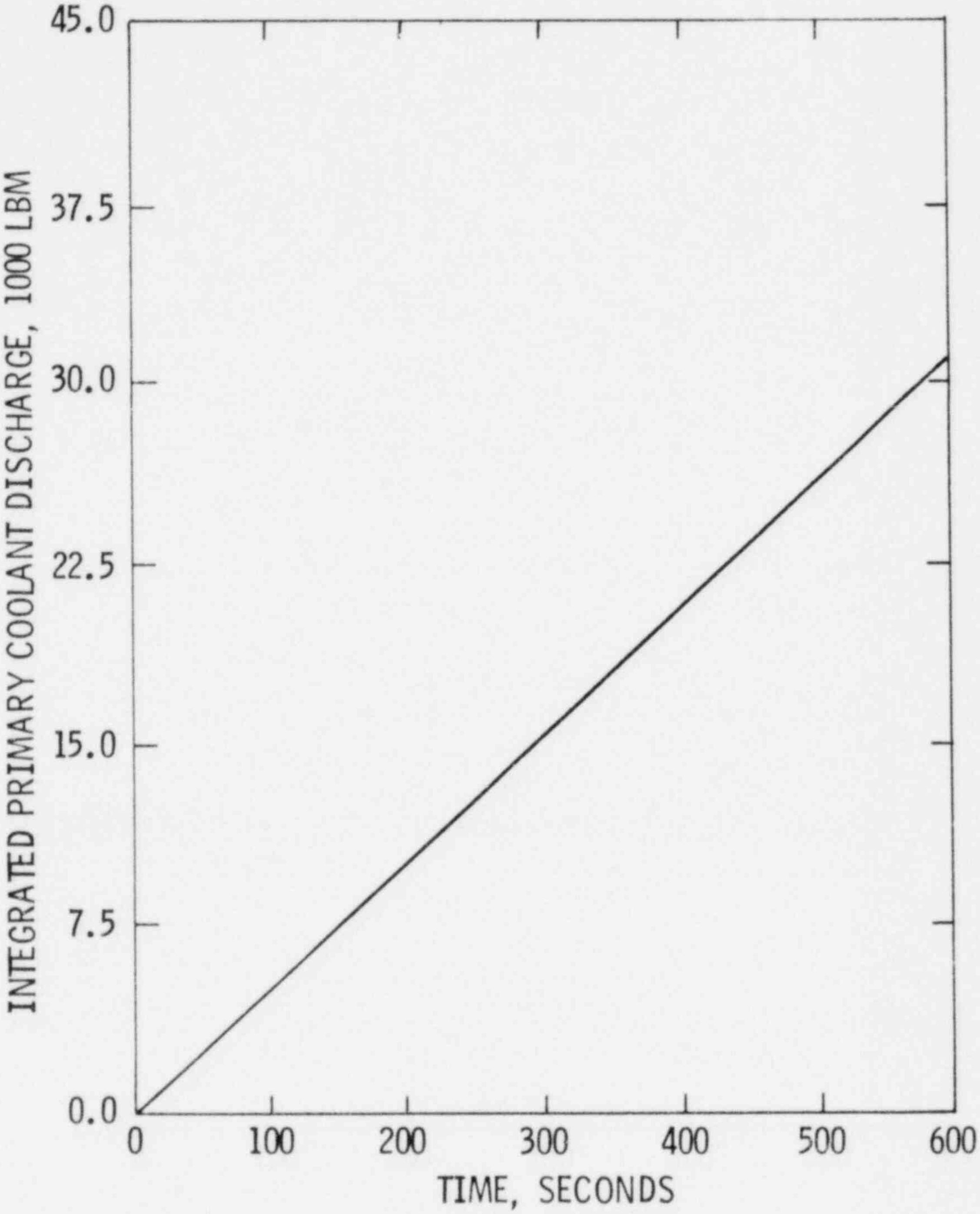
C-E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE CORE COOLANT TEMPERATURES vs TIME	Figure 15.6.2-5



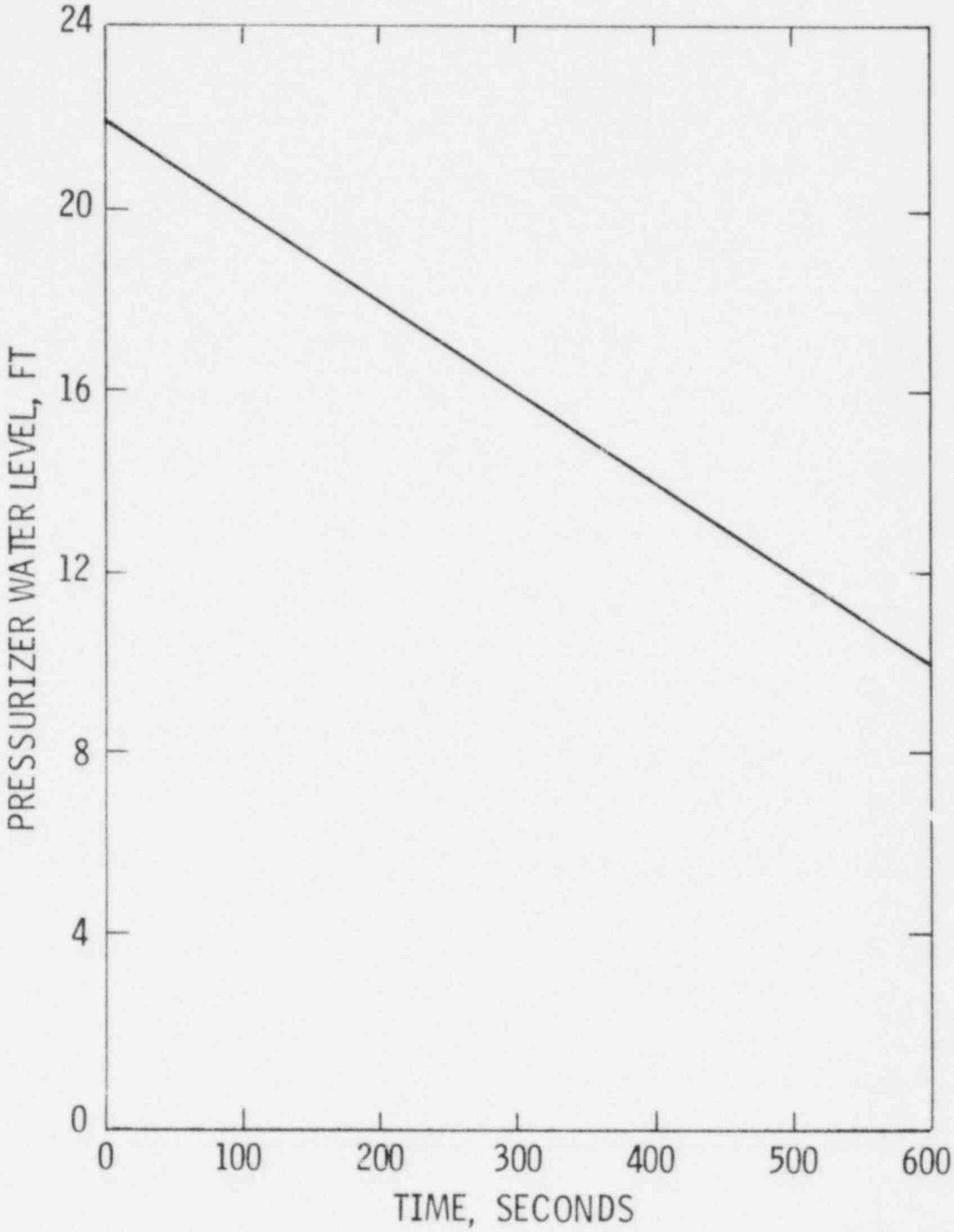
Amendment No. 7
March 31, 1982

C-E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE STEAM GENERATOR PRESSURE vs TIME	Figure 15.6.2-6



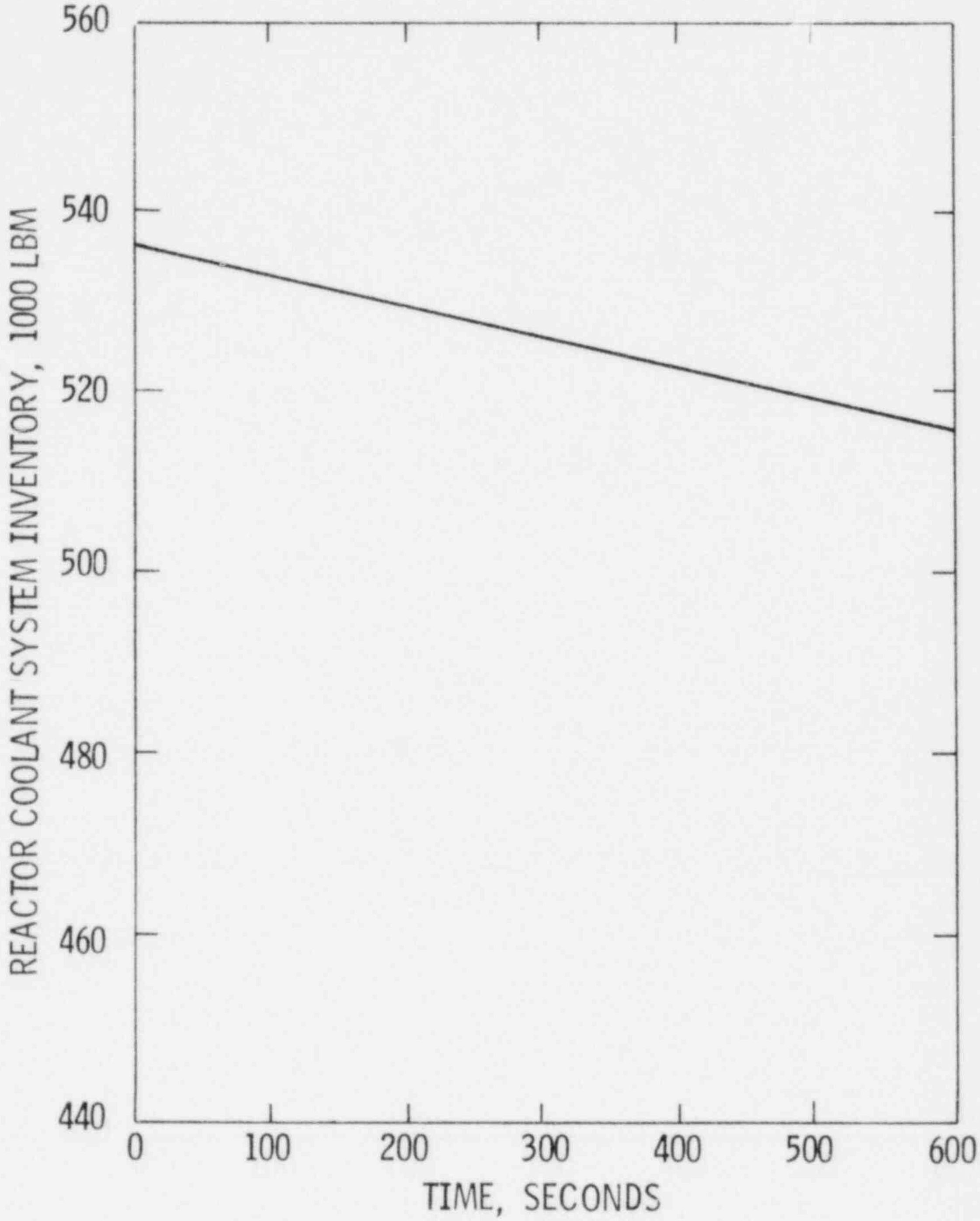
Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE INTEGRATED PRIMARY COOLANT DISCHARGE vs TIME	Figure 15.6.2-7



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE PRESSURIZER WATER LEVEL vs TIME	Figure 15.6.2-8



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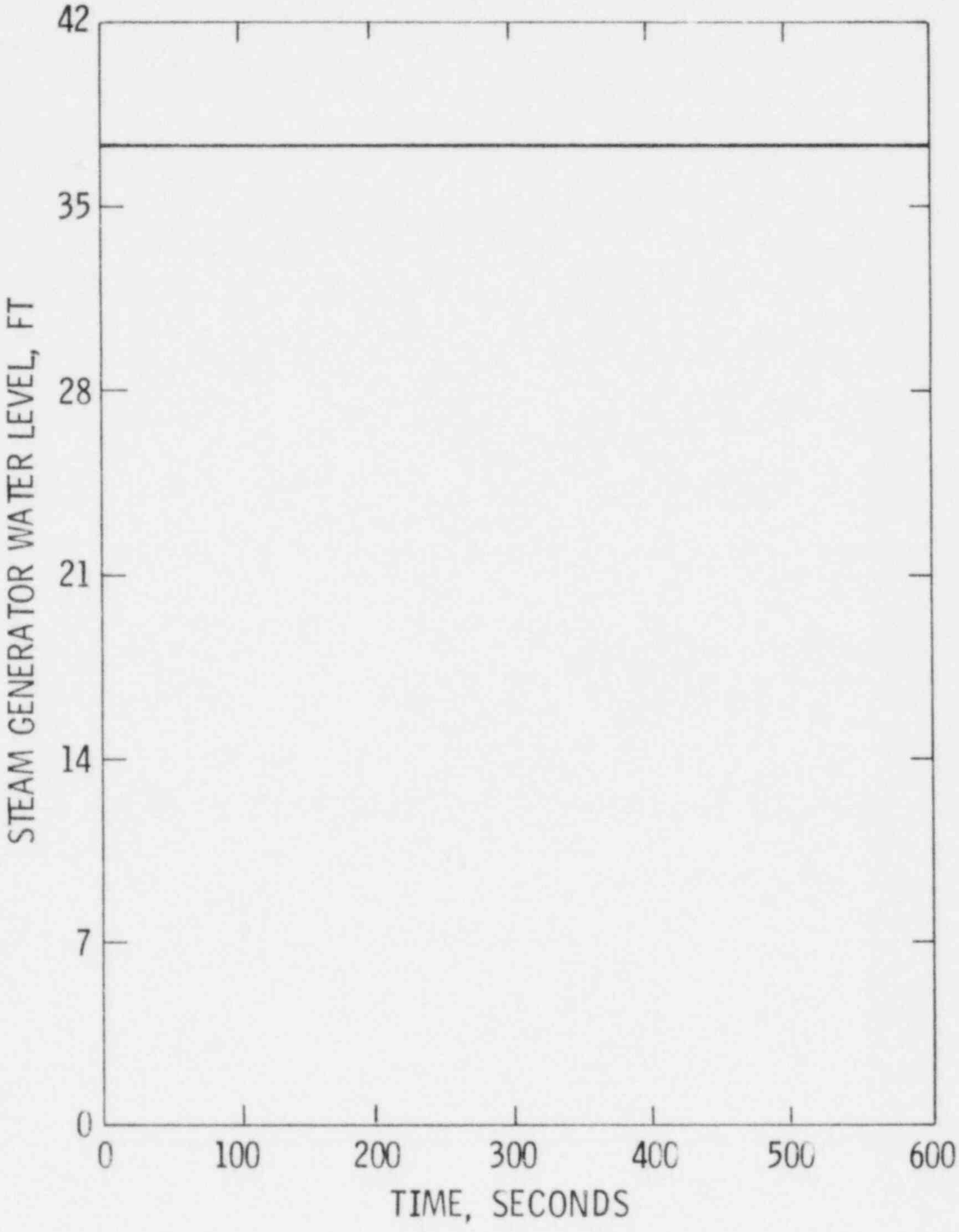
C-E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE REACTOR COOLANT SYSTEM INVENTORY vs TIME	Figure 15.6.2-9



Amendment No. 7
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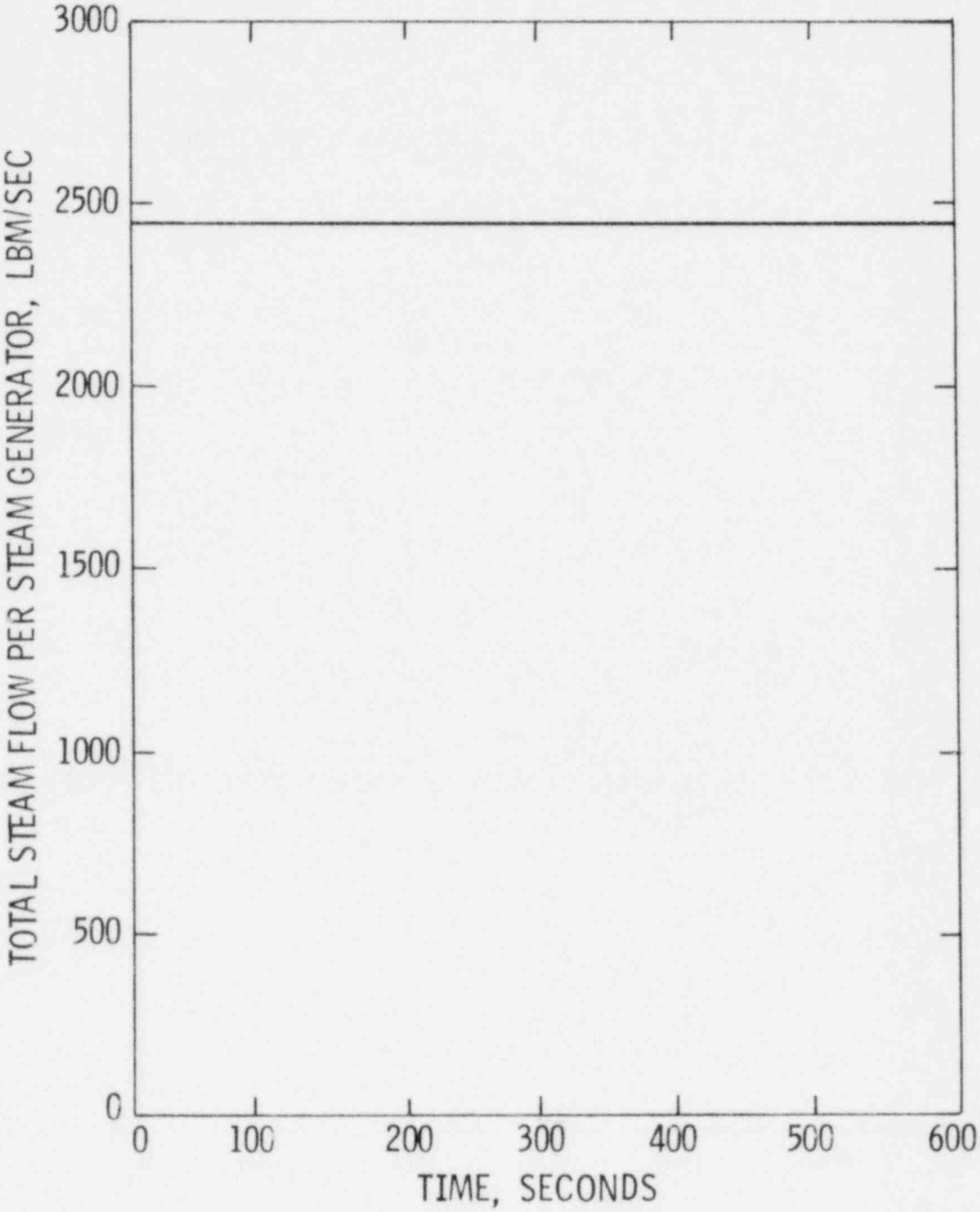
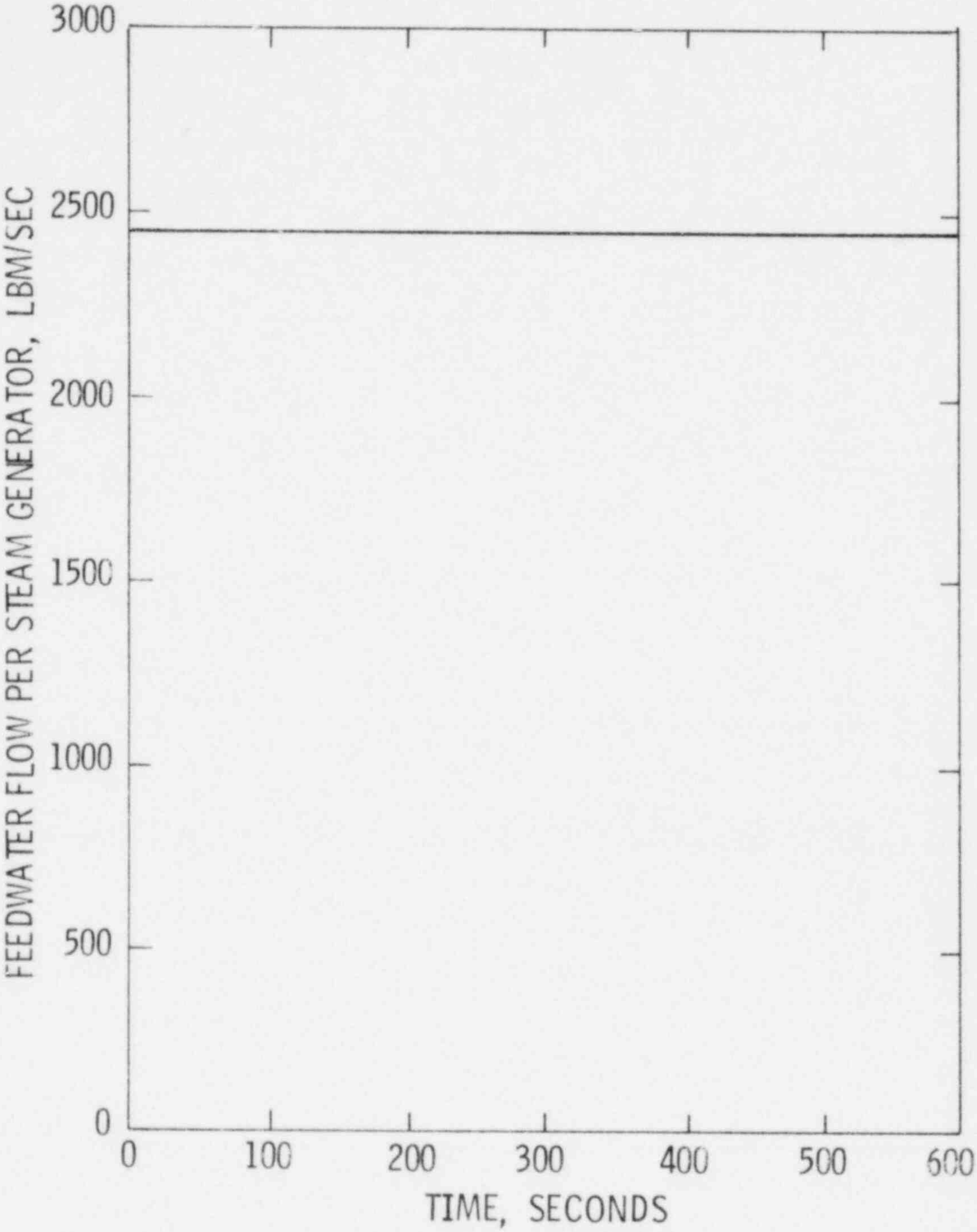
C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE STEAM GENERATOR WATER LEVEL vs TIME	Figure 15.6.2-10



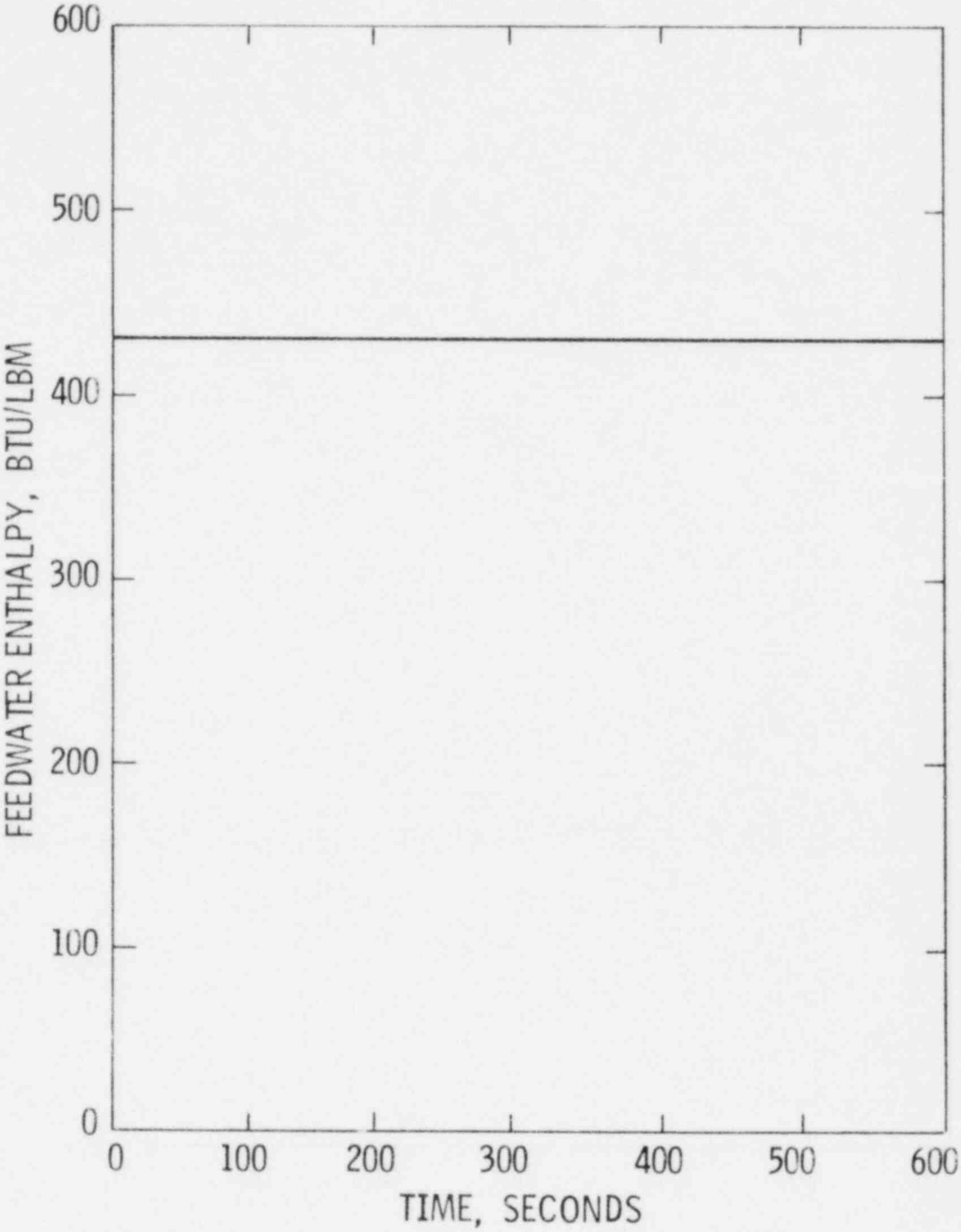
Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UP STREAM OF LETDOWN LINE CONTROL VALVE TOTAL STEAM FLOW vs TIME	Figure 15.6.2-11



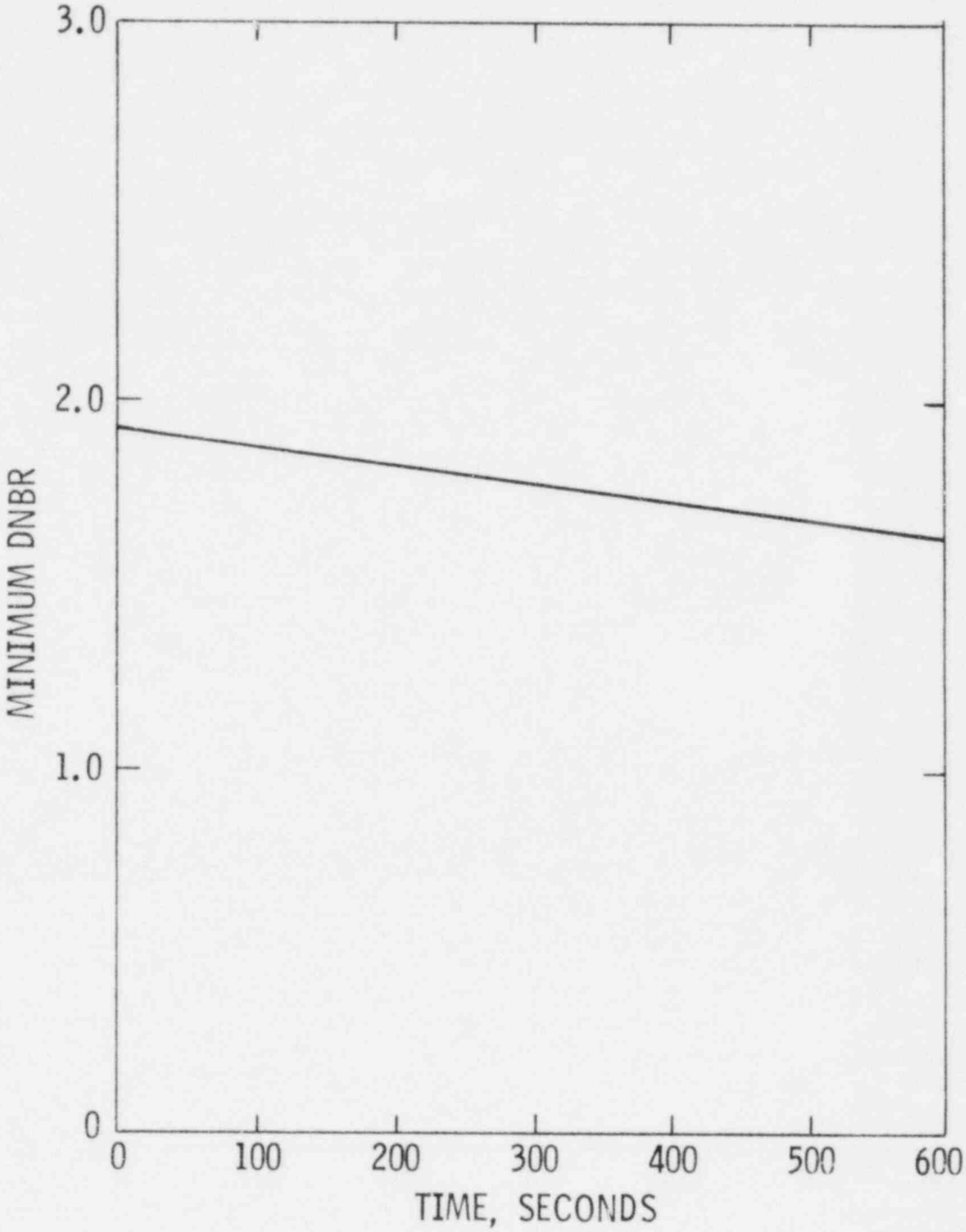
Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UP STREAM OF LETDOWN LINE CONTROL VALVE FEEDWATER FLOW vs TIME	Figure 15.6.2-12



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE FEEDWATER ENTHALPY vs TIME	Figure 15.6.2-13



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	LETDOWN LINE BREAK, OUTSIDE CONTAINMENT, UPSTREAM OF LETDOWN LINE CONTROL VALVE MINIMUM DNBR vs TIME	Figure 15.6.2-14

15.6.3 STEAM GENERATOR TUBE RUPTURE

15.6.3.1 Steam Generator Tube Rupture Without a Current Loss of Offsite Power

15.6.3.1.1 Identification of Event and Causes

The steam generator tube rupture (SGTR) accident is a penetration of the barrier between the reactor coolant system (RCS) and the main steam system and results from the failure of a steam generator U-tube. Integrity of the barrier between the RCS and main steam system is significant from a radiological release standpoint. The radioactivity from the leaking steam generator tube mixes with the shell-side water in the affected steam generator. Prior to turbine trip, the radioactivity is transported through the turbine to the condenser where the noncondensible radioactive materials would be released via the condenser air ejectors. Following reactor trip and turbine trip, with the steam bypass system in its manual mode, the steam generator safety valves open to control the main steam system pressure. The operator can isolate the damaged steam generator any time after reactor trip occurs. The cooldown of the NSSS can then be performed by manual operation of the emergency feedwater and the steam bypass control system (SBCS), and using the unaffected steam generator. The analysis presented herein conservatively assumes that operator action is delayed until 30 minutes after initiation of the event.

Diagnosis of the SGTR accident is facilitated by radiation monitors which initiate alarms and inform the operator of abnormal activity levels and that corrective operator action is required. These radiation monitors are located in the air ejector exhaust, steam generator blowdown lines, and turbine and auxiliary building ventilation ducts and stack. Additional diagnostic information is provided by RCS pressure and pressurizer level response indicating a leak and by level response in the affected steam generator.

Experience with nuclear steam generators indicates that the probability of complete severance of the Inconel vertical U-tubes is remote. No such double-ended rupture has ever occurred in a steam generator of this design. The more probable modes of failure result in considerably smaller penetrations of the pressure barrier. They involve the formation of etch pits or small cracks in the U-tubes or cracks in the welds joining the tubes to the tube sheet.

The most limiting steam generator tube rupture event is for a leak flow equivalent to a double-ended rupture of a U-tube at full power conditions.

15.6.3.1.2 Sequence of Events and Systems Operation

Table 15.6.3-1 presents a chronological list of events which occur during the steam generator tube rupture transient, from the time of the double-ended rupture of a steam generator U-tube to the attainment of cold shutdown conditions. The corresponding success paths are given in the Sequence of Events Diagram (SED), Figure 15.6.3-1. The Sequence of Events Diagram may be used together with Figure 15.0-1 (containing a glossary of SED symbols and acronyms) to trace the actuation and interaction of the systems used to mitigate the consequences of this event.

The sequence presented demonstrates that the operator can cool the plant down to cold shutdown during the event. 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 represents 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 15.6.3-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the course of the event.

Table 15.6.3-3 contains a matrix that summarizes the utilization of safety systems as they appear in the transient analyses.

The success paths in the Sequence of Events Dagram (Figure 15.6.3-1) are as follows:

Reactivity Control:

The pressurizer pressure decrease results in the generation of a CPC low pressure boundary trip and the CEAs drop into the core. Subsequently, the RCS pressure decreases more rapidly and a Safety Injection Actuation Signal (SIAS) is generated on low pressurizer pressure. As a result, additional negative reactivity is added to the system, in the form of borated water from the refueling water tank. Once the plant parameters have been stabilized, the operator adjusts the boron concentration to insure that a proper negative reactivity shutdown margin is achieved prior to cooldown. The boron concentration is adjusted by manually throttling the HPSI discharge valves to replace RCS volume shrinkage.

Reactor Heat Removal:

During the initial part of the transient, reactor heat removal is accomplished in the normal manner. Additional cooling capability is available through the injection of relatively low enthalpy RWT water, on the generation of the SIAS. On the initiation of the cooldown phase, the operator secures the Reactor Coolant Pumps (RCPs) in the loop associated with the affected steam generator to minimize heat transfer to the generator. Following the cooldown phase, the Shutdown Cooling System (SCS) is manually actuated when RCS temperature and pressure have been reduced to 350°F and 400 psia, respectively. This system provides sufficient cooling flow to cool the RCS to cold shutdown.

Primary System Integrity:

Prior to initiating cooldown procedures, the operator must reestablish the pressurizer water level. During the cooldown phase, the HPSI pump discharge valves are throttled to control RCS pressure.

When the RCS pressure has been reduced to approximately 650 psia, the operator will vent or drain the SITs to reduce their pressure and will then isolate them.

Secondary System Integrity:

Following the generation of a turbine trip on reactor trip, the Main Feedwater Control System (FWCS) enters the Reactor Trip Override (RTO) mode and reduces main feedwater flow to 5% of nominal full power flow. Since the Steam Bypass Control System (SBCS) is assumed to be in manual mode with all bypass valves closed, the Main Steam Safety Valves (MSSVs) open to limit secondary system pressure there by removing the heat generated and/or stored in the core and the RCS. Following closure of the MSSVs, the FWCS is prevented from over-feeding the steam generators by the High Level Override (HLO) which terminates feedwater flow until the steam generator level decreases to its nominal value. Due to the primary-to-secondary flow, the main feedwater flow to the affected steam generator is terminated before that of the unaffected steam generator. This time difference may be used by the operator to identify the affected steam generator. Once this has been accomplished, the operator will manually isolate the damaged steam generator and will initiate cooldown using main feedwater, the SBCS, and the unaffected steam generator.

When steam pressure decreases to a point where the main feedwater pump can no longer be used, the operator secures the main pumps. Cooldown is continued by utilizing one feedwater pump designated as "auxiliary" and intended for normal startup and shutdown of the plant in conjunction with the SBCS. The operator may let the ESFAS regulate the feedwater flow by issuing and withdrawing EFAS-1 and/or EFAS-2 signals down to cold shutdown entry conditions. See Applicant's FSAR for details of the Emergency and/or Auxiliary Feedwater Systems.

Radioactive Effluent Control:

A Containment Isolation Actuation Signal (CIAS) is generated subsequent to the SIAS. CIAS isolates various systems to reduce or terminate radioactive releases. CIAS actuates primary and containment isolation equipment. Other actions may be initiated by BOP systems. See Applicant's FSAR for details.

Upon identification of the affected steam generator, the operator isolates the steam generator and shuts off the reactor coolant pumps in that loop to minimize release from the affected generator.

15.6.3.1.3 Analysis of Effects and Consequences

15.6.3.1.3.1 Core and System Performance

A. Mathematical Model

The thermalhydraulic response of the Nuclear Steam Supply System (NSSS) to the steam generator tube rupture without a concurrent loss of offsite power was simulated using the CESEC III computer program described in Reference 27. The thermal margin on DNBR in the reactor core was determined using the TORC computer program described in Section 15.0.3 (Reference 18) with the CE-1 critical heat flux correlation described in CENPD-162 (Reference 19).

B. Input Parameters and Initial Conditions

The initial conditions and parameters assumed in the analyses of the system response to a steam generator tube rupture without a concurrent loss of offsite power are listed in Table 15.6.3-4. Additional discussion on the input parameters and the initial conditions are provided in Section 15.0. Conditions were chosen to maximize the primary to secondary mass releases during the SGTR transient. This, in turn, leads to the most conservative predictions of radiological releases.

The initial reactor operating conditions were varied over the operating space given in Table 15.0-5 to determine the set of conditions which would produce the most adverse consequences following a steam generator tube rupture without a concurrent loss of normal ac power. Various combinations of initial operating conditions were considered. These included, initial core inlet temperature, initial power level, initial RCS pressure, initial core coolant flow rate, initial pressurizer liquid level, initial steam generator liquid level, and fuel rod gap thermal conductivity. A scram reactivity consistent with the axial power distribution was employed in the parametric studies. Decreasing the initial core inlet temperature increases the primary to secondary leak rate and integrated leak, but reduces the releases via the main steam safety valves. Since the steam generator pressure and temperature would be initialized at lower values compatible with the lower core inlet temperature, the steam generator pressure may not increase enough to challenge the main steam safety valves. Decreasing the RCS pressure hastens the low pressurizer pressure reactor trip and results in lower releases due to a lower leak rate. Increasing the core inlet flowrate results in a lower enthalpy for the fluid entering the steam generator, resultant increased leak rate, and higher releases from the main steam safety valves. Thus, the parametric studies indicated that the maximum total mass release is obtained when the transient is initiated with the maximum allowed RCS pressure, maximum initial pressurizer liquid volume, maximum initial steam generator liquid volume, maximum core power, maximum core coolant flow, nominal core coolant inlet temperature, and a low fuel rod gap thermal conductivity.

The radiological consequences for the SGTR transient is also dependent on the break size. For break sizes resulting in a reactor trip during the first 30 minutes of the accident, the initial leak rate decreases from that value equivalent to a double-ended rupture, and the offsite dose also decreases due to the drop in the integrated leak. The decrease in break size also delays the time of reactor trip. As the break size is decreased further, the integral leak is reduced for the 30-minute operator action interval and the radiological consequences will be less severe. Therefore the most adverse break size is the largest assumed break of a full double ended rupture of a steam generator tube.

C. Results

The dynamic behavior of important NSSS parameters following a steam generator tube rupture is presented in Figures 15.6.3-2 to 15.6.3-17.

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For a double-ended rupture, the primary to secondary leak rate exceeds the capacity of the charging pumps. As a result, the pressurizer pressure gradually decreases from an initial value of 2400 psia. The primary to secondary leak rate and drop in pressurizer water level causes the third CVCS charging pump to turn on. Even with all three CVCS charging pumps on line the pressurizer pressure and level continue to drop. This results in the pressurizer heaters being de-energized at 560 seconds. At 1148 seconds a reactor trip signal is generated due to exceeding the CPC low pressure boundary of 1785 psia. The pressurizer empties at approximately 1151 seconds. At 1181 seconds a safety injection actuation signal is generated, and by 1231 seconds the safety injection flow is initiated. After the pressurizer empties, the reactor vessel upper head begins to behave like a pressurizer, and controls the reactor coolant system pressure until the pressurizer begins to refill at approximately 1447 seconds. Due to flashing caused by the depressurization, and the boiloff due to metal structure to coolant heat transfer, small amounts of voids form in the reactor vessel upper head at about 1151 seconds. Consequently, the RCS pressure begins to decay at a lower rate at this time. However, under the combined action of safety injection and charging flows, and reduced primary to secondary leakage, the upper head voids completely collapse at about 1447 seconds. Prior to this time, the RCS pressure begins to slowly increase helping to collapse the reactor vessel upper head voids. The pressurizer water level is reestablished at about the same time due to the net mass influx which increase the RCS inventory.

Following reactor trip and with turbine bypass assumed to be unavailable (i.e., in the manual mode), the main steam system pressure increases until the main steam safety valves open at 1209 seconds to control the main steam system pressure. A maximum main steam system pressure of 1283 psia occurs at 0.1 seconds after the MSSVs open. Subsequent to this peak in the pressure, the main steam system pressure decreases, resulting in the closure of the main steam safety valves at 1316 seconds.

Prior to reactor trip, the feedwater control system is assumed to be in the automatic mode and supplies feedwater to the steam generators such that steam generator water levels are maintained. Following reactor trip, the feedwater flow decreases to approximately 5% of the full power flow rate. Since the steam flow out of the steam generators is less than this feedwater flow, the liquid inventory in the steam generators gradually increases. At 1690 seconds a HLO mode terminates feedwater flow to the damaged steam generator. At 1778 seconds a HLO mode terminates feedwater flow to the intact steam generator.

After 1800 seconds, the operator identifies and isolate the affected steam generator by closing the main steam isolation valves and by securing the reactor coolant pumps in the affected loop. The operator then initiates an orderly cooldown via the steam bypass system and the condenser, and with manually-controlled feedwater flow to the unaffected steam generator. After the pressure and temperature of the reactor coolant are reduced to 400 psia and 350°F respectively, the operator activates the shutdown cooling system and isolates the unaffected steam generator.

The maximum RCS and secondary pressures do not exceed 110% of design pressure following a steam generator tube rupture event without concurrent loss of offsite power, thus, assuring the integrity of the RCS and main steam system. The minimum DNBR of 1.22 indicates no violation of the fuel thermal limits (see Figure 15.6.3-17).

Figure 15.6.3-12 gives the main steam safety valve integrated flow versus time for the steam generator tube rupture event without concurrent loss of offsite power. At 1800 seconds, when operator action is assumed, no more than 6617 lbm of steam from the damaged steam generator and 6609 lbm from the intact steam generator are discharged via the main steam safety valves. Also, during the same time period, approximately 75,275 lbm of primary system fluid is leaked to the damaged steam generator. Subsequently, the operator begins a plant cooldown at the technical specification cooldown rate (100°F/hr) using the intact steam generator, the steam bypass system, the feedwater system, and the condenser. For the first two hours following the initiation of the event, a total of 6.516×10^6 lbm (5.58×10^6 lbm) through the turbine and 936,000 lbm through the bypass system) of steam flows to the condenser from the steam generator. For the two to eight hour cooldown period, an additional 907,000 lbm of steam is discharged through the bypass system.

15.6.3.1.3.2 Radiological Consequences

A. Physical Model

The evaluation of the radiological consequences of a postulated steam generator tube rupture without a coincident loss of offsite power assumes a complete severance of a single steam generator tube while the reactor is operating at full rated power. Occurrence of the accident leads to an increase in contamination of the secondary system due to reactor coolant leakage through the tube break. A reactor trip occurs automatically as a result of low pressurizer pressure at approximately 1148 seconds after the event initiation. The reactor trip automatically trips the turbine.

Subsequent to reactor trip the steam generator pressure will increase rapidly, resulting in steam discharge as well as activity release through the main steam safety valves. Venting from the affected steam generator, i.e., the steam generator which experiences tube rupture, continues until the secondary system pressure is below the main steam safety valve setpoint. At this time, the affected steam generator is effectively isolated and, thereafter, no steam or activity is assumed to be released from the affected steam generator. After 1800 seconds the operator initiates a plant cooldown at the technical specification cooldown rate (100°F/hr) using the unaffected steam generator, steam bypass system, feedwater system, and the condenser.

The analysis of the radiological consequences of a steam generator tube rupture considers the most severe release of secondary system activity as well as primary system activity leaked from the tube break. The inventory of iodine and noble gas fission product activity

available for release to the environment is a function of the primary-to-secondary coolant leakage rate, the percentage of defective fuel in the core, and the mass of steam discharged to the environment. Conservative assumptions are made for all these parameters.

B. Assumptions and Conditions

The following assumptions and parameters are employed to determine the activity releases and offsite doses for a steam generator tube rupture (SGTR).

1. Accident doses are calculated for two different assumptions: (a) assumes a generated iodine spike (GIS) coincident with the initiation of the event and (b) assumes a pre-accident iodine spike (PIS).

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-accident 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 75,275 lbm.

12. The two hour steam flow to the condenser is 6.516×10^6 lbm, and an additional 907,000 lbm of steam flows to the condenser during the two to eight hour time period.

13. The atmospheric dispersion factors employed in the analyses are: 2×10^{-3} sec/m^3 for the exclusion area boundary and 1.5×10^{-4} sec/m^3 for the low population zone.

C. Mathematical Model

The mathematical model employed to analyze the activity released during the course of the transient is described in Section 15.0.4.

D. Results

The two-hour exclusion area boundary (EAB) inhalation doses and the eight-hour low population zone (LPZ) boundary inhalation doses for both the generated iodine spike (GIS) and the pre-existing iodine spike (PIS) are presented in Table 15.6.3-5. The calculated EAB and LPZ doses are well within the acceptance criteria.

15.6.3.1.4 Conclusions

The radiological releases calculated for the SGTR event without a concurrent loss of offsite power are well within the 10CFR100 guidelines. The RCS and secondary system pressures are well below 110% of the design pressure limits, thus, assuring the integrity of these systems. Additionally, no violation of the fuel thermal limits occurs, since the minimum DNR remains above the 1.19 value throughout the duration of the event.

The plant is maintained in a stable condition due to automatic actions, and after thirty minutes, the operator employs the plant emergency procedure for the steam generator tube rupture event to cool down the plant to shutdown cooling entry conditions.

15.6.3.2 Steam Generator Tube Rupture With a Concurrent Loss of Offsite Power

15.6.3.2.1 Identification of Event and Causes

The significance of a steam generator tube rupture accident is described in Section 15.6.3.1.1. 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 loss of offsite power subsequent to the time of reactor trip and turbine/generator trip is assumed in the analysis, since it produces the most adverse effect on the radiological releases. The plant is operating at full power for a period of approximately 20 minutes before the consequences of the primary-to-secondary leak cause the reactor trip. Thus, during this time period the radioactivity concentration in the steam generator increases before the main steam safety valves open, releasing radioactive materials to the atmosphere.

15.6.3.2.2 Sequence of Events and Systems Operation

Table 15.6.3-6 presents a chronological list of events which occur during the steam generator tube rupture event with a loss of offsite power, from the time of double-ended rupture of a steam generator U-tube to the attainment of cold shutdown conditions. The corresponding success paths are given in the sequence of events diagram (SED), Figure 15.6.3-18. The SED may be used together with Figure 15.0-1 (containing a glossary of SED symbols and acronyms) to trace the actuation and interaction of the systems used to mitigate the consequences of this event. Additionally, Table 15.6.3-7 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the course of the event. The utilization of safety systems as they appear in the transient analysis is summarized by the matrix contained in Table 15.6.3-8.

Prior to reactor trip, the systems and reactor operation are identical to that described in Section 15.6.3.1.2. As a result of the reactor trip, the turbine/generator trips within one second after the CPC low pressure boundary reactor trip signal. Subsequently, offsite power is assumed to be lost due to grid instability. A 3 second delay between the time of turbine trip and the time of loss of offsite power is conservatively assumed in the analysis, based on the discussion that follows.

The loss of a power generating unit causes frequency deviations in the electical power grid which normally operates at 60 Hz. Under certain conditions the resulting grid instability will cause loss of offsite power to that unit. The degree of instability is characterized by the rate of grid frequency degradation which is dependent on the magnitude of the load mismatch and the physical parameters of the grid. The physical response of the grid is dependent on the available spinning reserve and the stiffness of the grid, i.e., the ability to damp out frequency oscillations through load damping. Load shedding is also utilized to restore the balance between load and power generation and to return the grid frequency to 60 Hz. When the corrective action is not sufficient to avert frequency degradation, loss of off-site power to the plant can occur as a result of

that plant tripping off line. Most plants are automatically disconnected from the grid between 56-58 Hz, to prevent underfrequency damage to the plant components. For System 80 plants, a frequency of 57.6 Hz is taken as the setpoint at which a loss of offsite power occurs.

In order to determine the conservative lower bound for the time delay between turbine trip and loss of offsite power, the grid system for the Florida Penninsula was employed. This grid can tie into only the Georgia and Alabama grid systems, which can make up only 400 MWe through the transmission lines to Florida. Therefore, the Florida grid becomes an "electrical island" for a generation deficiency caused by the loss of a 1300 MWe unit. On the curves of grid frequency response for this grid system, the effects of a generation deficiency caused by the tripping of a System 80 plant was superimposed. Based on this evaluation, a 3.1 seconds time lag between turbine trip and loss of offsite power was calculated. This time delay is a conservative lower bound since the evaluation assumed:

(1) No credit for spinning reserve and load shedding,

(2) The Florida grid "island" conditions (no support from neighboring grid sytems),

(3) Loss of a System 80 plant as a 10% generation loss which is a much higher percentage than the actual loss (less than 3.5%), and

(4) Loss of offsite power at 57.6 Hertz for all System 80 plants.

Subsequent to reactor trip, stored and fission product decay energy must be dissipated by the reactor coolant and main steam systems. 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 released to atmosphere via the main steam safety valves. With the availability of standby power, emergency 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 emergency feedwater system and the atmospheric steam 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 first indication of the event.

The primary source of the emergency feedwater is the condensate storage tank. The capacity of the storage tank is 300,000 gallons which is sufficient feedwater to maintain the plant at hot standby for 8 hours. The condensate storage tank is provided with an atmospheric vent to maintain atmospheric pressure inside the tank. The maximum condensate radioactivity concentration is 0.1 μCi/lbm (2.2×10^{-4} μCi/gm) dose equivalent I-131.

15.6.3.2.3 Analysis of Effects and Consequences

15.6.3.2.3.1 Core and System Performance

A. Mathematical Model

The mathematical used for evaluation of core and system performance is identical to that described in Section 15.6.3.1.3.1.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used for the evaluation of core and systems performance are similar to those described in Section 15.6.3.1.3 and are given in Table 15.6.3-9. Both the initial core mass flow rates and the one pin radial peaking factor were chosen to: (1) maximize the primary-to-secondary integrated leak, and the steam releases through the main steam safety valves, and (2) at the same time, obtain a simultaneous reactor trip on a low DNBR (=1.19) as well as a low pressurizer pressure. Consequently, a slightly lower core mass flow rate (104% instead of 116%) as well as a slightly lower radial peaking factor (1.53 instead of 1.55) were employed in the analysis.

C. Results

The dynamic behavior of important NSSS parameters following a steam generator tube rupture with a loss of normal ac power are presented in Figures 15.6.3-19 through 15.6.3-34.

Prior to reactor trip, the dynamic behavior of the NSSS following a steam generator tube rupture with a loss of offsite power is similar to that following a steam generator tube rupture without a loss of offsite power which is described in Section 15.6.3.1.3. At about 1187 seconds after the initiation of the tube rupture the CPC low pressure boundary of 1785 psia is reached, resulting in a reactor trip signal.

Subsequent to the reactor trip, the RCS pressure begins to decrease rapidly, and the pressurizer empties at about 1201 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 1196 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 resulting in the generation of the safety injection actuation signal (SIAS) at 1613 seconds. The High Pressure Safety Injection (HPSI) pumps begin delivery of safety injection fluid to the

RCS in about 50 seconds after the SIAS, and as a result, the upper head voids begin to collapse at about 1677 seconds.

Following turbine trip and loss of offsite power, the main steam system pressure increases until the main steam safety valves open at about 1197 seconds to control the main steam system pressure. A maximum main steam system pressure of 1310 psia occurs at about 1205 seconds. Subsequent to this peak in pressure, the main steam system pressure decreases resulting in the closure of the safety valves at 1721 seconds.

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 1713 seconds. Subsequently, at about 1758 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 400 psia and 350°F, respectively, the operator activates the shutdown cooling system and isolates the unaffected steam generator.

The reduction in the RCS pressure due to the loss of primary coolant through the ruptured steam generator tube results in a reduction in the thermal margin to DNB (see Figure 15.6.3-34). The transient minimum DNBR of 1.19 occurs at the time of reactor trip. The DNBR shows an increasing trend after reactor trip due to the rapidly decreasing heat flux. The RCPs do not begin their normal coastdown until after the loss of offsite power three seconds after turbine trip. However, there is a slight decrease in the core flow during the three seconds immediately after turbine trip and prior to the loss of offsite power due to decreasing pump speed caused by frequency degradation (approximately 1 Hertz/second) of the electrical grid. The resultant calculation demonstrates that no violation of the fuel thermal limits occurs, since the minimum DNBR stays above the value of 1.19 throughout the transient.

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.

Figure 15.6.3-29 gives the main steam safety valve integrated flow rates versus time for the steam generator tube rupture event with a loss of offsite power. At 1800 seconds, when operator action is assumed, no more than 54,936 lbm of steam from the damaged steam generator and 54,730 lbm from the intact steam generator are discharged

via the main steam safety valves. Also, during the same time period approximately 80,500 lbm of primary system mass is leaked to the damaged steam generator. Subsequently, the operator begins a plant cooldown at the technical specification cooldown rate (100°F/hr) using the intact steam generator, the atmospheric dump valves,and emergency feedwater system. For the first two hours following the initiation of the event, a total of 5.76×10^6 lbms of steam flow to the condenser through the turbine (up to the time of loss of offsite power), and about 843,300 lbms of steam are released to the environment through the atmospheric dump valves. For the two to eight hour cooldown period an additional 1.81×10^6 lbms of steam are released via the atomspheric dump valves.

15.6.3.2.3.2 Radiological Consequences

A. Physical Model

The evaluation of the radiological consequences of a postulated steam generator tube rupture assumes a complete severance of a single steam generator tube while the reactor is operating at full rated power and a loss of offsite power three seconds after turbine trip. Occurrence of the accident leads to an increase in contamination of the secondary system due to reactor coolant leakage through the tube break. A reactor trip occurs automatically as a result of low pressurizer pressure at approximately 1187 seconds after the event initiation. The reactor trip automaticaly trips the turbine.

The steam generator pressure will increase rapidly, resulting in steam discharge as well as activity release through the main steam safety valves. Venting from the affected steam generator, i.e., the steam generator which experiences tube rupture, continues until the secondary system pressure is below the main steam safety valve setpoint. At this time, the affected steam generator is effectively isolated, and thereafter, no steam or activity is assumed to be released from the affected steam generator. After 1800 seconds, the operator initiates a plant cooldown at the technical specification cooldown rate (100°F/hr) using the unaffected steam generator, atmospheric dump valves, and the emergency feedwater system.

The analysis of the radiological consequences of a steam generator tube rupture considers the most severe release of secondary activity as well as primary system activity leaked from the tube break. The inventory of iodine and noble gas fission product activity available for release to the environment is a function of the primary-to-secondary coolant leakage rate, the percentage of defective fuel in the core, and the mass of steam discharged to the environment. Conservative assumptions are made for all these parameters.

B. Assumptions and Conditions

The assumptions and parameters employed for the evaluation of radiological releases are identical to those described in Section 15.6.3.1.3.2 with the following exceptions and/or additions.

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

2. The total amount of primary-to-secondary leakage through the rupture is 80,500 lbm.

3. The steam flow through the condenser is 5.76×10^6 lbms. The half hour to two hour steam flow through the atmospheric dump valves is 843,300 lbms. An additional 1.81×10^6 lbms of steam are discharged to the environment through the atmospheric dump valves during the two to eight hour time period.

C. Mathematical Model

The mathematical model employed in the evaluation of the radiological consequences during the course of the transient is described in Section 15.0.4.

D. Results

The two-hour exclusion area boundary (EAB) and the eight-hour low population zone (LPZ) boundary inhalation doses for both the event generated iodine spike (GIS) and the pre-existing iodine spike (PIS) are presented in Table 15.6.3-10. The calculated EAB and LPZ doses are well within the acceptance criteria.

15.6.3.2.6 Conclusions

The radiological releases calculated for the SGTR event with a loss of offsite power are well within the 10CFR100 guidelines. The RCS and secondary sy.tem pressures are well below the 110% of the design pressure limits, thus, assuring the integrity of these systems. Additionally, no violation of the fuel thermal limits occurs, since the minimum DNBR remains above the 1.19 value throughout the duration of the event.

Voids form in the reactor vessel upper head region during the transient, due to the thermal hydraulic decoupling of this region from the rest of the RCS. The upper head region liquid level remains well above the top of the hot leg throughout the transient. Therefore, natural circulation cooldown is not impaired during the transient. 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 cool down the plant to shutdown cooling entry conditions.

TABLE 15.6.3-1
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR THE
STEAM GENERATOR TUBE RUPTURE

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	Tube Rupture Occurs	--	
30.0	Third Charging Pump Started, feet below program level	-0.75	Primary System Integrity
30.0	Letdown Control Valve Throttled Back to Minimum Flow, feet below program level	-0.75	Primary System
53.8	Backup Heaters Energized, psia	2360	Primary System Integrity
560.0	Pressurizer Heaters De-energized due to Low Pressurizer Liquid Volume, ft^3	400	
1148	CPC Low Pressure Boundary Trip Signal, psia	1785	Reactivity Control
	Feedwater Flow Starts Ramp Down to 5% of Initial Full power Flow		
1149	CEAs Begin to Drop	--	Reactivity
	Turbine Trip: Stop Valves Start to Close	-- --	Control Secondary System Integrity
1151	Pressurizer Empties	--	--
1152	Turbine Stop Valves Closed	--	Secondary System Integrity
1181	Safety Injection Actuation Signal, psia	1578	Reactivity Control and Reactor Heat Removal
1181	Letdown Isolation Valves Closed on SIAS	--	Primary System Integrity

TABLE 15.6.3-1 (Cont'd.) (Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE STEAM GENERATOR TUBE RUPTURE

Time (Sec)	Event	Setpoint or Value	Success Path
1209	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity
1210	Maximum Steam Generator Pressure, psia	1283	
1231	Safety Injection Flow Intiated	--	
1316	Main Steam Safety Valves Close, psia	1218	Secondary System Integrity
1447	Pressurizer begins to refill	--	
1690	HLO Mode Terminates Feedwater Flow to Damaged Steam Generator, % wide range	80	Secondary System Integrity
1778	HLO Mode Terminates Feedwater Flow to Intact Steam Generator, % wide range	80	Secondary System Integrity
1800	Operator Isolates the Damaged Steam Generator and Initiates Plant Cooldown at 100°F/hr for the 1.5 hour time period	--	Reactor Heat Removal
28,800	Shutdown Cooling Entry Conditions are Assumed to be reached, RCS Pressure, psia/RCS Temperature, °F	400/350	Reactor Heat Removal

TABLE 15.6.3-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR

THE STEAM GENERATOR TUBE RUPTURE

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System	✓					
2. Main Feedwater Pump Turbine Control System*	✓					
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System		✓				
5. Pressurizer Pressure Control System	✓					
6. Pressurizer Level Control System	✓					
7. Control Element Drive Mechanism Control System	✓					
8. Reactor Regulating System		✓				
9. Core Operating Limit Supervisory System	✓					
10. Reactor Coolant Pumps	✓					
11. Chemical and Volume Control System	✓					
12. Secondary Chemistry Control System*	✓					1
13. Condenser Evacuation System*	✓					
14. Turbine Gland Sealing System*	✓					
15. Nuclear Cooling Water System*	✓					
16. Turbine Cooling Water System*	✓					
17. Plant Cooling Water System*	✓					
18. Condensate Storage Facilities*	✓					
19. Circulating Water System*	✓					
20. Spent Fuel Pool Cooling and Clean-Up System*	✓					
21. Non-Class 1E (Non-ESF) A.C. Power*	✓					
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems -

TABLE 15.6.3-2 (CONTINUED) (Sheet 2 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR THE STEAM GENERATOR TUBE RUPTURE

SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	MANUAL MODE THROUGH-OUT TRANSIENT	INOPERATIVE OR LOSS OF A.C. NORMAL AUTOMATIC MODE	INOPERATIVE ON LOSS OF A.C. MANUAL MODE	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*	✓					
24. Class 1E D.C. Power*	✓					

NOTES:

1. Portions of this system are isolated, either automatically (see applicant's SAR) or manually by the operator once he determines which steam generator contains the ruptured tube.

*Balance-of-Plant Systems

TABLE 15.6.3-3

UTILIZATION OF SAFETY SYSTEMS FOR THE STEAM GENERATOR TUBE RUPTURE

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems			✓		
4. Supplementary Protection System					
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves					
8. Main Steam Isolation System*	✓				1
9. Emergency Feedwater System*			✓		
10. Safety Injection System	✓				
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*			✓		
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*					
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

NOTES:

1. The operator manually isolates the affected steam generator.

*Balance-of-Plant Systems -

TABLE 15.6.3-4

ASSUMPTIONS AND INITIAL CONDITIONS FOR
THE STEAM GENERATOR TUBE RUPTURE

Parameter	Assumed Value
Core Power Level, MWT	3876
Core Inlet Coolant Temperature, °F	565
Reactor Coolant System Pressure, psia	2400
Core Mass Flow Rate, 10^6 lmb/hr	183.1
One Pin Integrated Radial Peaking Factor, with Uncertainty	1.55
Steam Generator Pressure, psia	1020
Moderator Temperature Coefficient, 10^{-4} $\Delta\rho$/°F	-3.5
Doppler Coefficient Multiplier	1.15
CEA Worth at Trip, % $\Delta\rho$ (most reactive CEA fully withdrawn)	-10.0

TABLE 15.6.3-5

RADIOLOGICAL CONSEQUENCES OF THE
STEAM GENERATOR TUBE RUPTURE

	Location	Offsite Doses, Rems	
		GIS	PIS
1.	Exclusion Area Boundary 0-2 hr Thyroid	2.0	2.7
2.	Low Population Zone Outer Boundary 0-8 hr Thyroid	0.19	0.21

TABLE 15.6.3-6
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR A
STEAM GENERATOR TUBE RUPTURE WITH A
LOSS OF OFFSITE POWER

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	Tube Rupture Occurs	--	
30.0	Third Charging Pump Started, feet below program level	-0.75	Primary System Integrity
30.0	Letdown Control Valve Throttled Back to Minimum Flow, feet below program level	-0.75	Primary System Integrity
53.8	Backup Heaters Energized, psia	2360	Primary System Integrity
560.0	Pressurizer Heaters De-energized due to Low Pressurizer Liquid Volume, ft^3	400	
1187	CPC Low Pressure Boundary Trip Signal, psia	1785	Reactivity Control
1188	Turbine/Generator Trip: Stop Valves Start to Close	--	Secondary System Integrity
	CEAs Begin to Drop	--	Reactivity Control
1191	Turbine Stop Valves Closed	--	Secondary System
	Loss of Offsite Power	--	Integrity
1197	LH Main Steam Safety Valves open, psia	1282	Secondary System Integrity
1197	RH Main Steam Safety Valves open, psia	1282	Secondary Sytem Integrity
1201	Pressurizer Empties	--	
1205	Maximum Steam Generator Pressures Both Steam Generator, psia	1310	
1563	Safety Injection Actuation Signal, psia	1578	Reactivity Control

TABLE 15.6.3-6
(Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE
STEAM GENERATOR TUBE RUPTURE WITH A
LOSS OF OFFSITE POWER

Time (Sec)	Event	Setpoint or Value	Success Path
1563	Letdown Isolation Valves Closed on SIAS	--	Primary System Integrity
1613	Safety Injection Flow Initiated	--	Reactivity Control Reactor Heat Removal
1714	Emergency Feedwater Actuation on Low Steam Generator Level Trip Signal, ft above tube sheet	19.76	Secondary System Integrity
1721	Main Steam Safety Values Closed, psia	1218	Secondary System Integrity
1759	Emergency Feedwater Flow Begins	--	Secondary System Integrity
1800	Operator Isolates the Damaged Steam Generator and Initiates Plant Cooldown	--	Reactor Heat Removal
28,800	Shutdown Cooling Entry Conditions are Assumed to be Reached, RCS Pressure, psia/Temperature, °F	400/350	Reactor Heat Removal

TABLE 15.6.3-7 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS
FOR
THE STEAM GENERATOR TUBE RUPTURE
WITH A LOSS OF OFFSITE POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System			✓			
2. Main Feedwater Pump Turbine Control System*	✓					
3. Turbine-Generator Control System*	✓					
4. Steam Bypass Control System				✓		
5. Pressurizer Pressure Control System			✓			
6. Pressurizer Level Control System			✓			
7. Control Element Drive Mechanism Control System				✓		
8. Reactor Regulating System				✓		
9. Core Operating Limit Supervisory System	✓					
10. Reactor Coolant Pumps				✓		
11. Chemical and Volume Control System			✓			
12. Secondary Chemistry Control System*			✓			1
13. Condenser Evacuation System*			✓			
14. Turbine Gland Sealing System*			✓			
15. Nuclear Cooling Water System*			✓			
16. Turbine Cooling Water System*			✓			
17. Plant Cooling Water System*			✓			
18. Condensate Storage Facilities*			✓			
19. Circulating Water System*			✓			
20. Spent Fuel Pool Cooling and Clean-Up System*			✓			
21. Non-Class 1E (Non-ESF) A.C. Power*			✓			
22. Class 1E (ESF) A.C. Power*	✓					

*Balance-of-Plant Systems -

DISPOSITION OF NORMALLY OPERATING SYSTEMS

FOR

THE STEAM GENERATOR TUBE RUPTURE

WITH A LOSS OF OFFSITE POWER

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.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
23. Non-Class 1E D.C. Power*			✓			
24. Class 1E D.C. Power*	✓					

NOTES:

1. Portions of this system are isolated, either automatically (see applicant's SAR) or manually by the operator once he determines which steam generator contains the ruptured tube.

*Balance-of-Plant Systems

TABLE 15.6.3-8

UTILIZATION OF SAFETY SYSTEMS

FOR

THE STEAM GENERATOR TUBE RUPTURE WITH A

LOSS OF OFFSITE POWER

SYSTEM	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACK-UP TO NON-SAFETY GRADE SYSTEM	SINGLE-FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	✓				
2. DNBR/LPD Calculator					
3. Engineered Safety Features Actuation Systems	✓				
4. Supplementary Protection System					
5. Reactor Trip Switch Gear	✓				
6. Main Steam Safety Valves*	✓				
7. Primary Safety Valves					
8. Main Steam Isolation System*	✓				1
9. Emergency Feedwater System*	✓				
10. Safety Injection System	✓				
11. Shutdown Cooling System	✓				
12. Atmospheric Dump Valve System*	✓				
13. Containment Isolation System*					
14. Containment Spray System*					
15. Iodine Removal System*					
16. Containment Combustible Gas Control System*					
17. Diesel Generators and Support Systems*	✓				
18. Component (Essential) Cooling Water System*	✓				
19. Station Service Water System*	✓				

NOTES:

1. The operator manually isolates the affected steam generator.

*Balance-of-Plant Systems -

TABLE 15.6.3-9

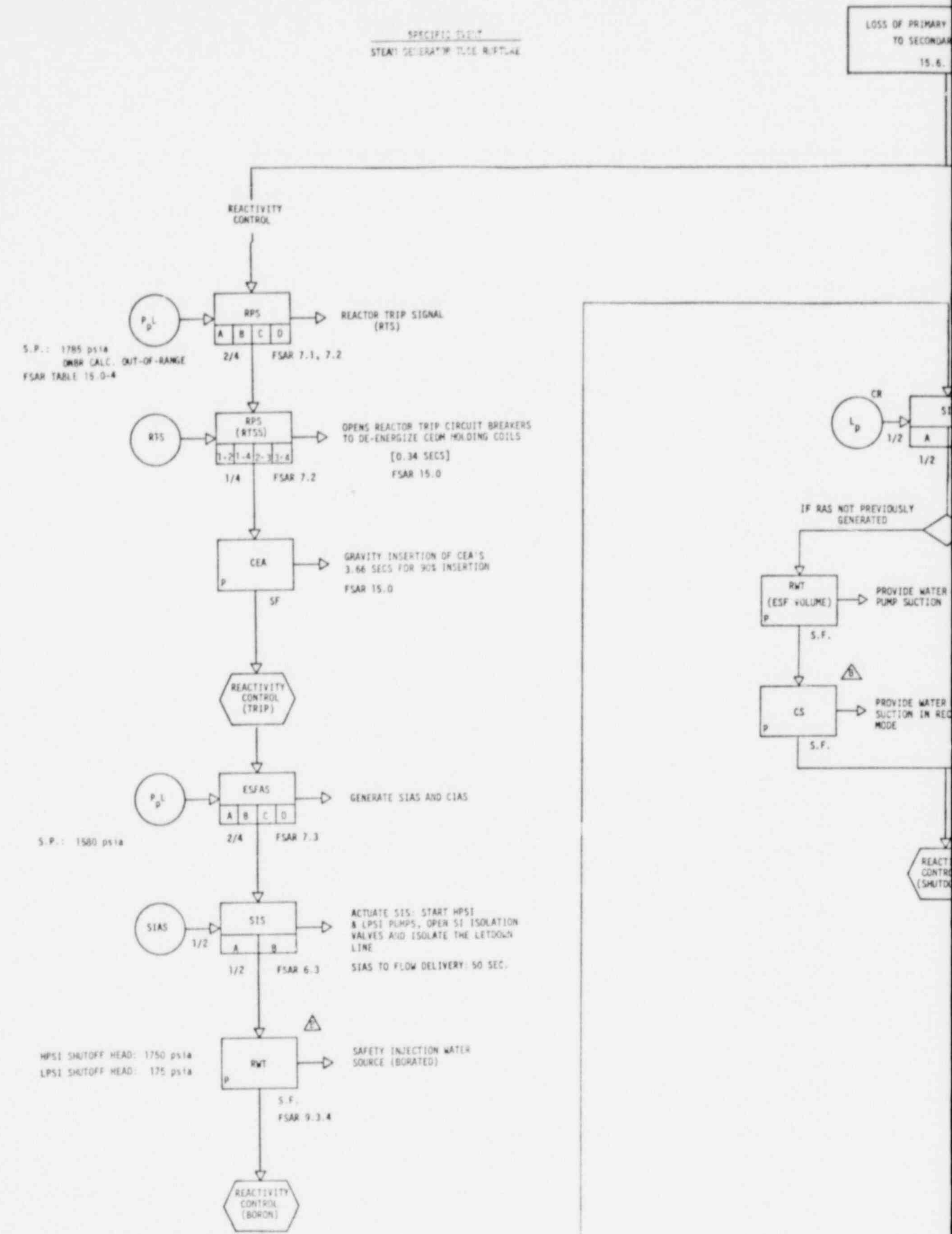
ASSUMPTIONS AND INITIAL CONDITIONS FOR THE STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER

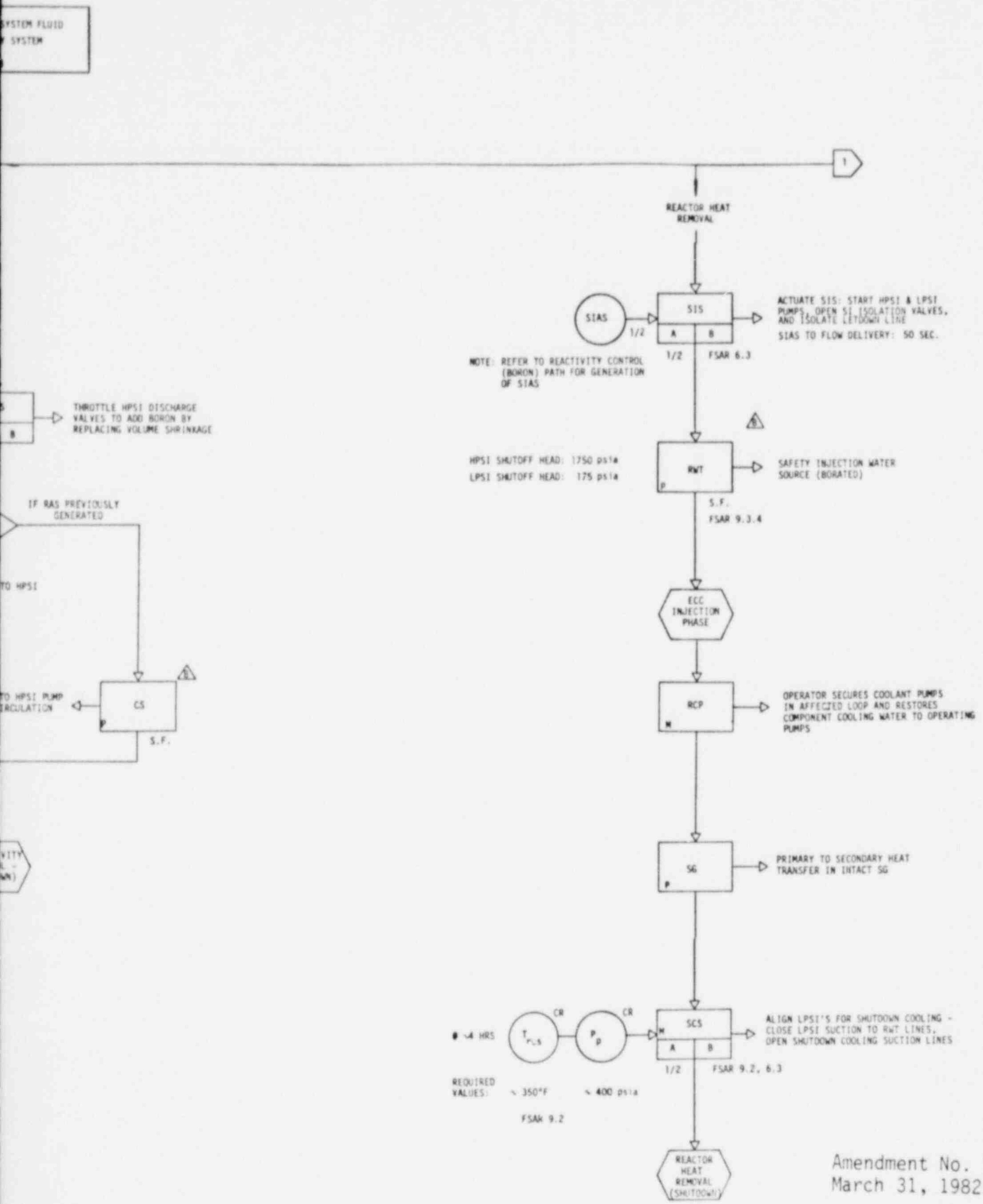
Parameter	Assumed Value
Core Power Level, MWt	3876
Core Inlet Coolant Temperature, °F	565
Reactor Coolant System Pressure, psia	2400
Core Mass Flow Rate, 10^6 lmb/hr	166
One Pin Integrated Radial Peaking Factor, with Uncertainty	1.53
Steam Generator Pressure, psia	1020
Moderator Temperature Coefficient, 10^{-4} $\Delta\rho$/°F	-3.5
Doppler Coefficient Multiplier	1.15
CEA Worth at Trip, % $\Delta\rho$ (most reactive CEA fully withdrawn)	-10.0

TABLE 15.6.3-10

RADIOLOGICAL CONSEQUENCES OF THE
STEAM GENERATOR TUBE RUPTURE
WITH A LOSS OF OFFSITE POWER

Location	Offsite Doses, Rems GIS	PIS
1. Exclusion Area Boundary 0-2 hr Thyroid	16.8	21.6
2. Low Population Zone Outer Boundary 0-8 hr Thyroid	8.2	2.4


SPECIFIC EVENT
STEAM GENERATOR TUBE RUPTURE
LOSS OF PRIMARY
TO SECONDAR
15.6.
REACTIVITY CONTROL
RPS
A B C D
REACTOR TRIP SIGNAL (RTS)
S.P.: 1785 psia
DNBR CALC. OUT-OF-RANGE
FSAR TABLE 15.0-4
2/4
FSAR 7.1, 7.2
RTS
RPS (RTSS)
1-2 1-4 2-3 3-4
OPENS REACTOR TRIP CIRCUIT BREAKERS TO DE-ENERGIZE CEDM HOLDING COILS
[0.34 SECS]
FSAR 15.0
1/4
FSAR 7.2
CEA
P
SF
GRAVITY INSERTION OF CEA'S
3.66 SECS FOR 90% INSERTION
FSAR 15.0
REACTIVITY CONTROL (TRIP)
ESFAS
A B C D
GENERATE SIAS AND CIAS
S.P.: 1580 psia
2/4
FSAR 7.3
SIAS
SIS
A B
1/2
ACTUATE SIS: START HPSI & LPSI PUMPS, OPEN SI ISOLATION VALVES AND ISOLATE THE LETDOWN LINE
1/2
FSAR 6.3
SIAS TO FLOW DELIVERY: 50 SEC.
HPSI SHUTOFF HEAD: 1750 psia
LPSI SHUTOFF HEAD: 175 psia
RWT
P
SAFETY INJECTION WATER SOURCE (BORATED)
S.F.
FSAR 9.3.4
REACTIVITY CONTROL (BORON)
CR
1/2
A
1/2
IF RAS NOT PREVIOUSLY GENERATED
RWT
(ESF VOLUME)
P
PROVIDE WATER
PUMP SUCTION
S.F.
CS
P
PROVIDE WATER
SUCTION IN REC
MODE
S.F.
REACTI
CONTRO
(SHUTDO

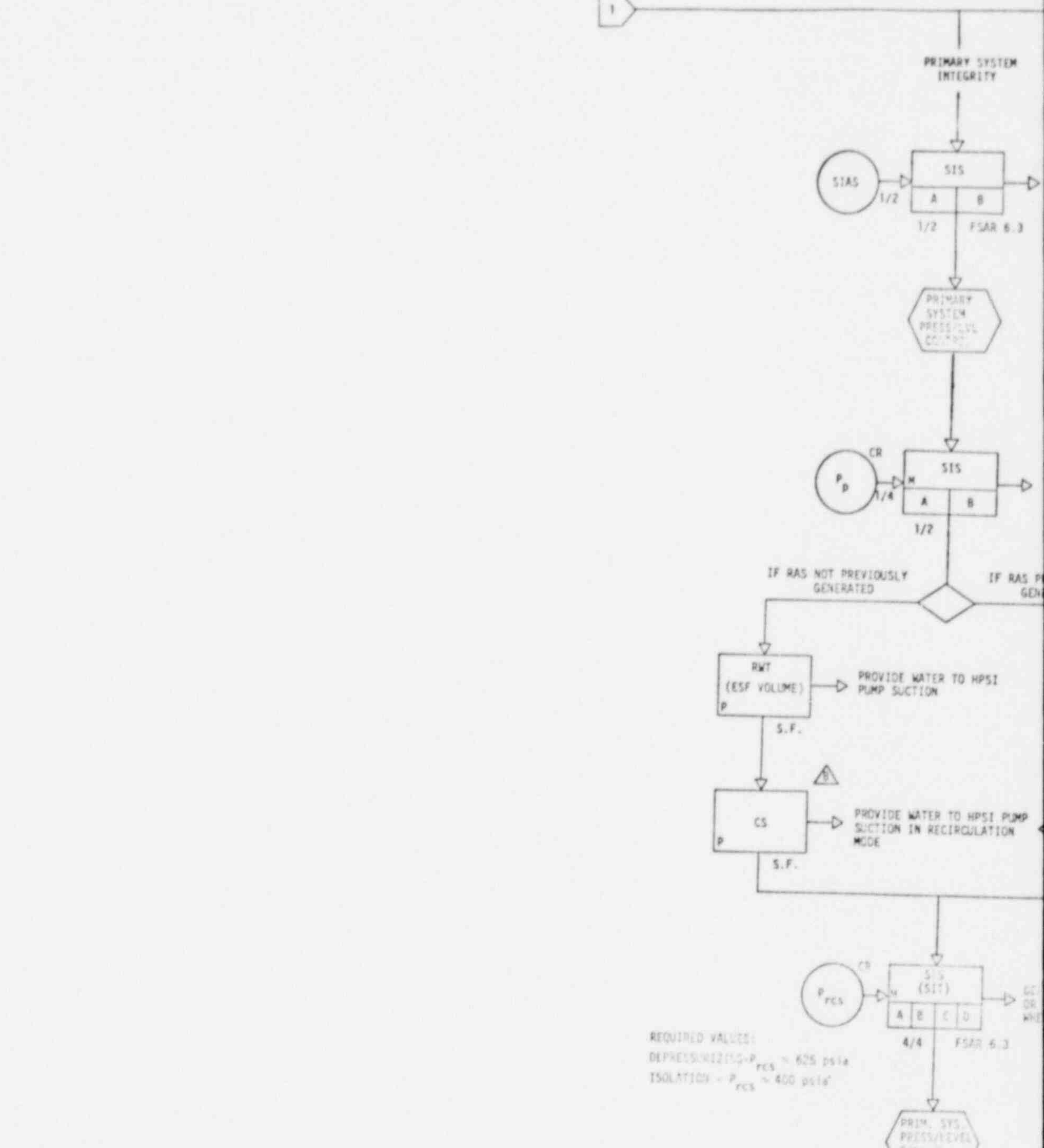


Amendment No. 7
March 31, 1982

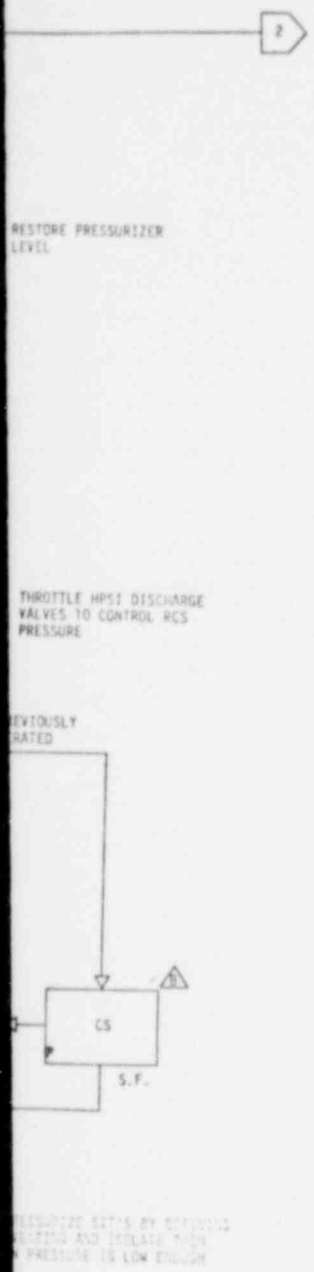
C-E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE

Figure 15.6.3-1A



1
PRIMARY SYSTEM INTEGRITY
SIAS
1/2
SIS
A
B
1/2
FSAR 6.3
PRIMARY SYSTEM PRESS/LVL CONTROL
CR
P
1/4
SIS
A
B
1/2
IF RAS NOT PREVIOUSLY GENERATED
RWT (ESF VOLUME)
P
PROVIDE WATER TO HPSI PUMP SUCTION
S.F.
CS
P
PROVIDE WATER TO HPSI PUMP SUCTION IN RECIRCULATION MODE
S.F.
P
SIS (SIT)
A
B
C
D
4/4
FSAR 6.3
REQUIRED VALUES:
PRIM. SYS. PRESS/LEVEL



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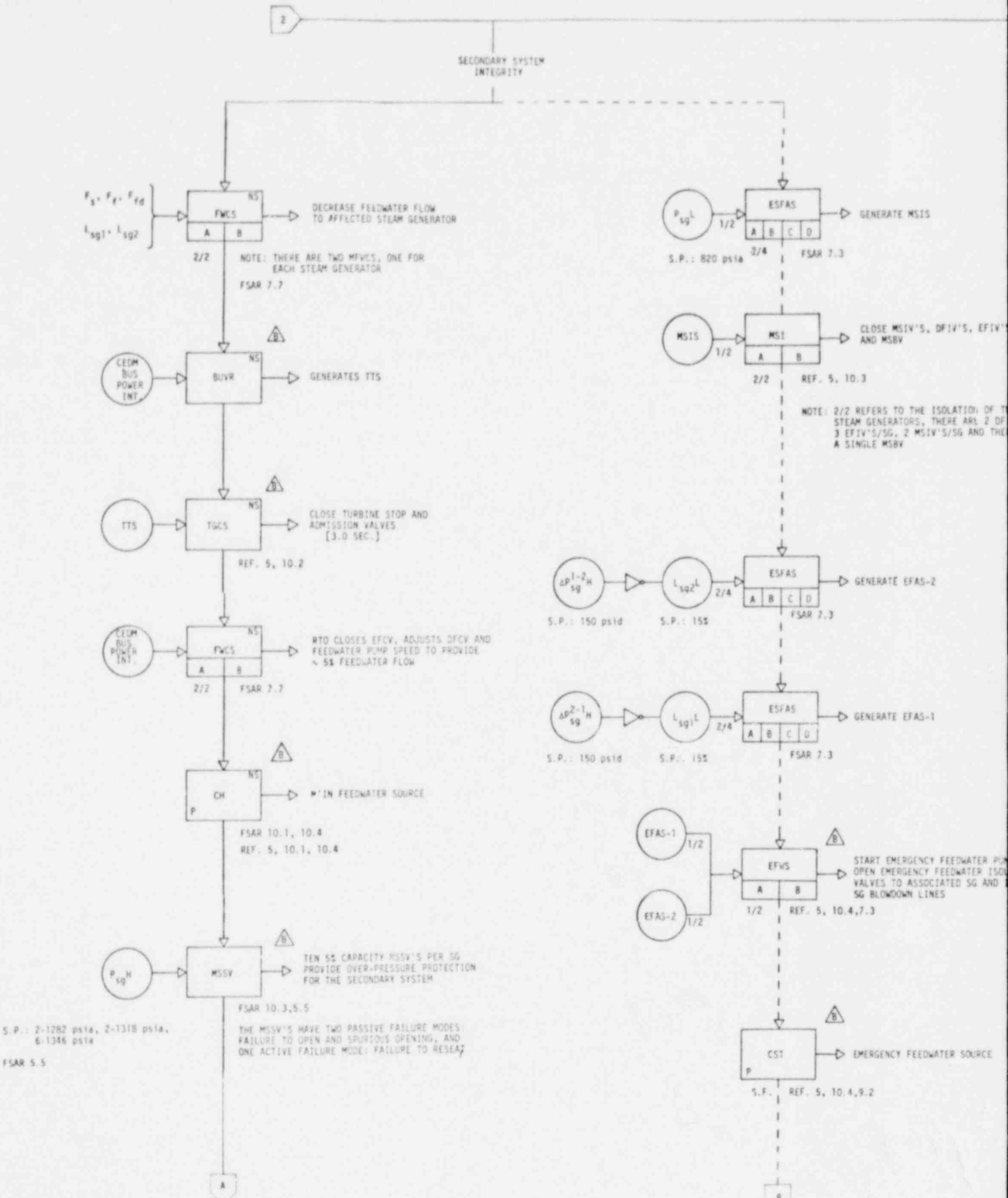
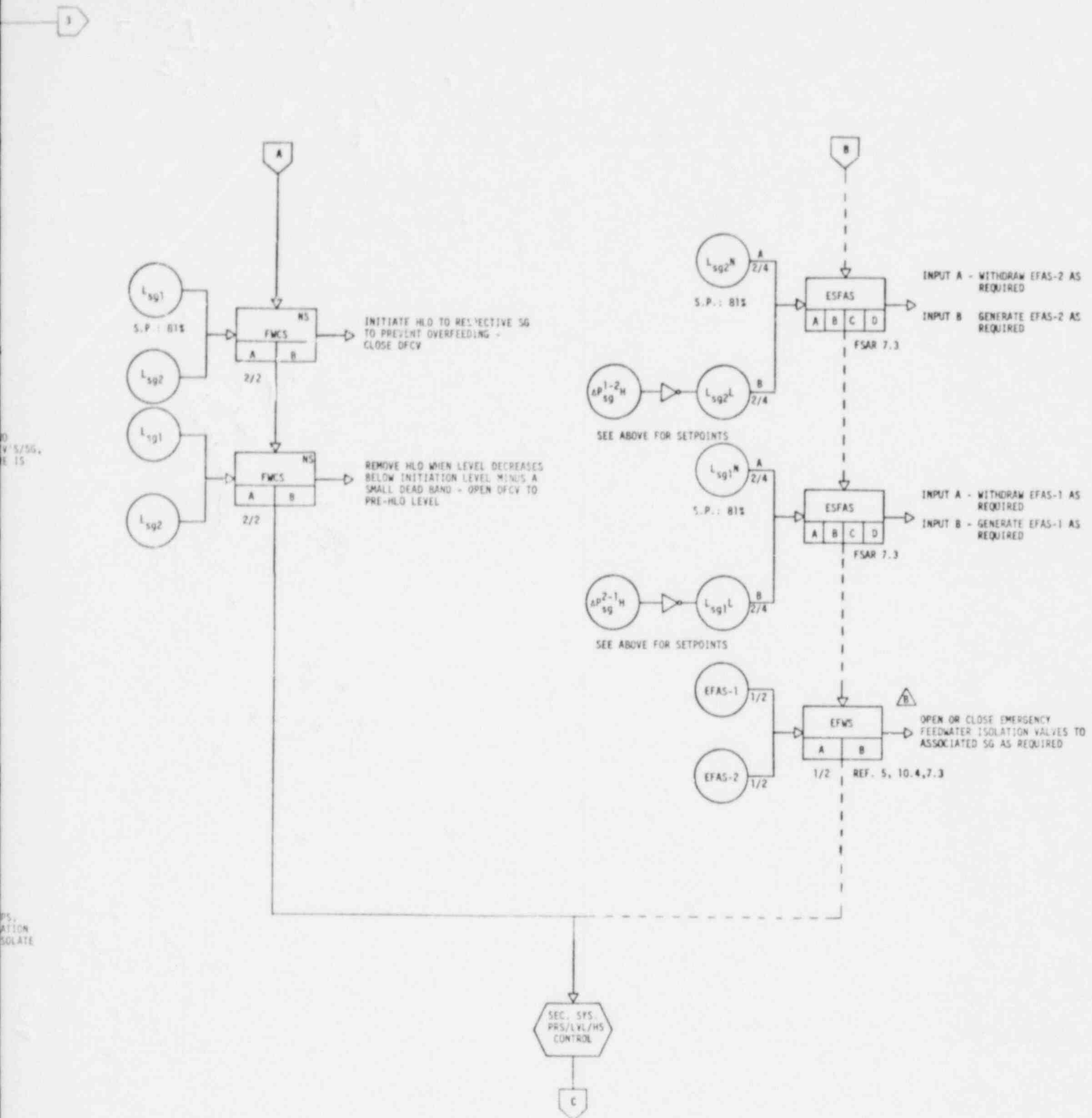
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE	Figure 15.6.3 -1B



2
SECONDARY SYSTEM INTEGRITY
FWCS
NS
A
B
DECREASE FEEDWATER FLOW TO AFFECTED STEAM GENERATOR
2/2
NOTE: THERE ARE TWO MFWCS, ONE FOR EACH STEAM GENERATOR
FSAR 7.7
CEDM BUS POWER INT.
BUVR
GENERATES TTS
TTS
TGCS
CLOSE TURBINE STOP AND ADMISSION VALVES [3.0 SEC.]
REF. 5, 10.2
RTO CLOSES EFCV, ADJUSTS DFCV AND FEEDWATER PUMP SPEED TO PROVIDE ~ 5% FEEDWATER FLOW
CH
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
MSSV
TEN 5% CAPACITY MSSV'S PER SG PROVIDE OVER-PRESSURE PROTECTION FOR THE SECONDARY SYSTEM
FSAR 10.3,5.5
THE MSSV'S HAVE TWO PASSIVE FAILURE MODES: FAILURE TO OPEN AND SPURIOUS OPENING, AND ONE ACTIVE FAILURE MODE: FAILURE TO RESEAT
S.P.: 2-1282 psia, 2-1318 psia, 6-1346 psia
FSAR 5.5
A
ESFAS
GENERATE MSIS
S.P.: 820 psia
2/4
FSAR 7.3
MSIS
MSI
CLOSE MSIV'S, DFIV'S, EFIV'S AND MSBV
REF. 5, 10.3
NOTE: 2/2 REFERS TO THE ISOLATION OF THE STEAM GENERATORS, THERE ARE 2 DF 3 EFIV'S/SG, 2 MSIV'S/SG AND THE A SINGLE MSBV
GENERATE EFAS-2
S.P.: 150 psid
S.P.: 15%
GENERATE EFAS-1
EFAS-1
EFAS-2
EFWS
START EMERGENCY FEEDWATER PU OPEN EMERGENCY FEEDWATER ISOL VALVES TO ASSOCIATED SG AND SG BLOWDOWN LINES
REF. 5, 10.4,7.3
CST
EMERGENCY FEEDWATER SOURCE
REF. 5, 10.4,9.2
B



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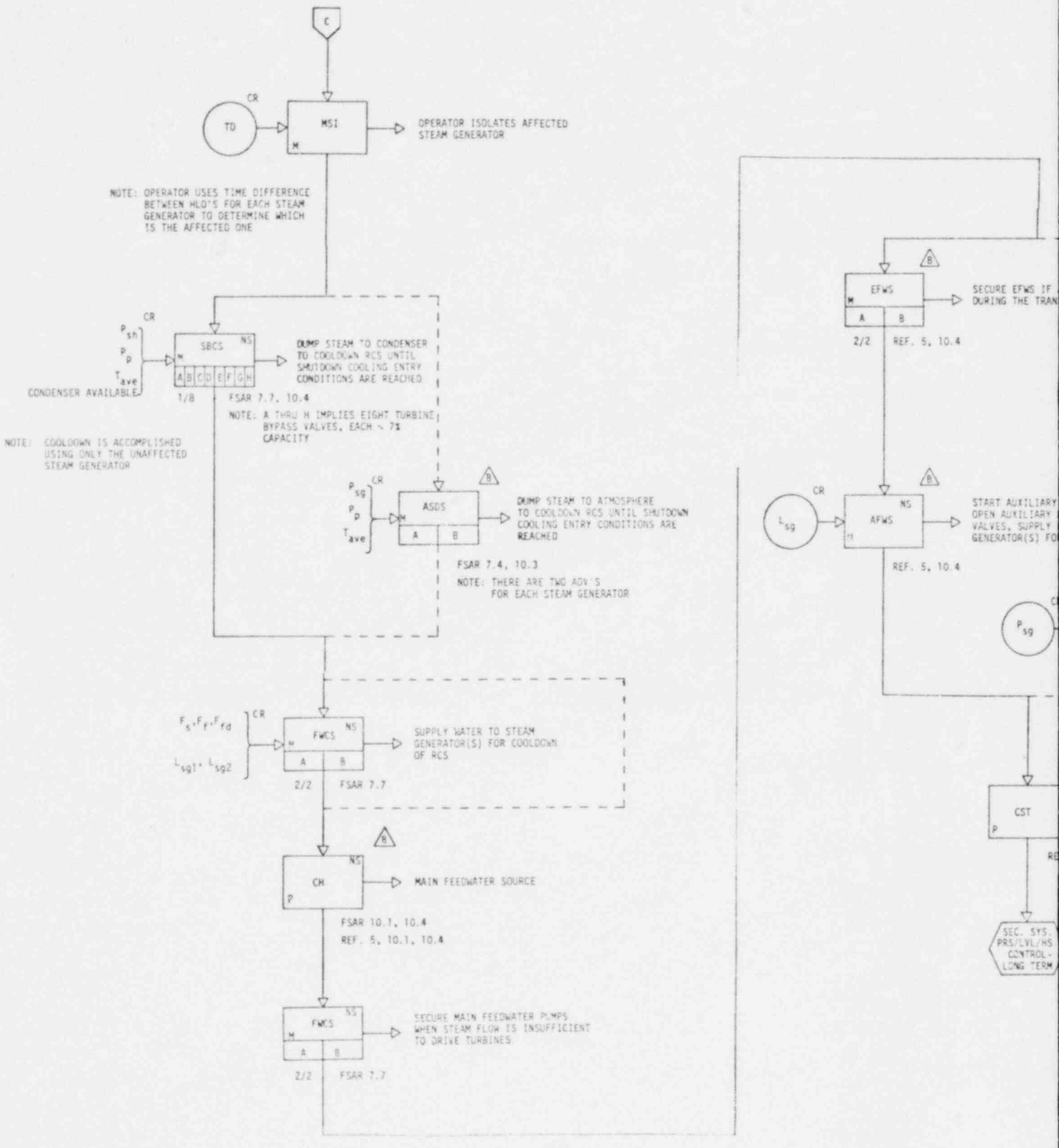
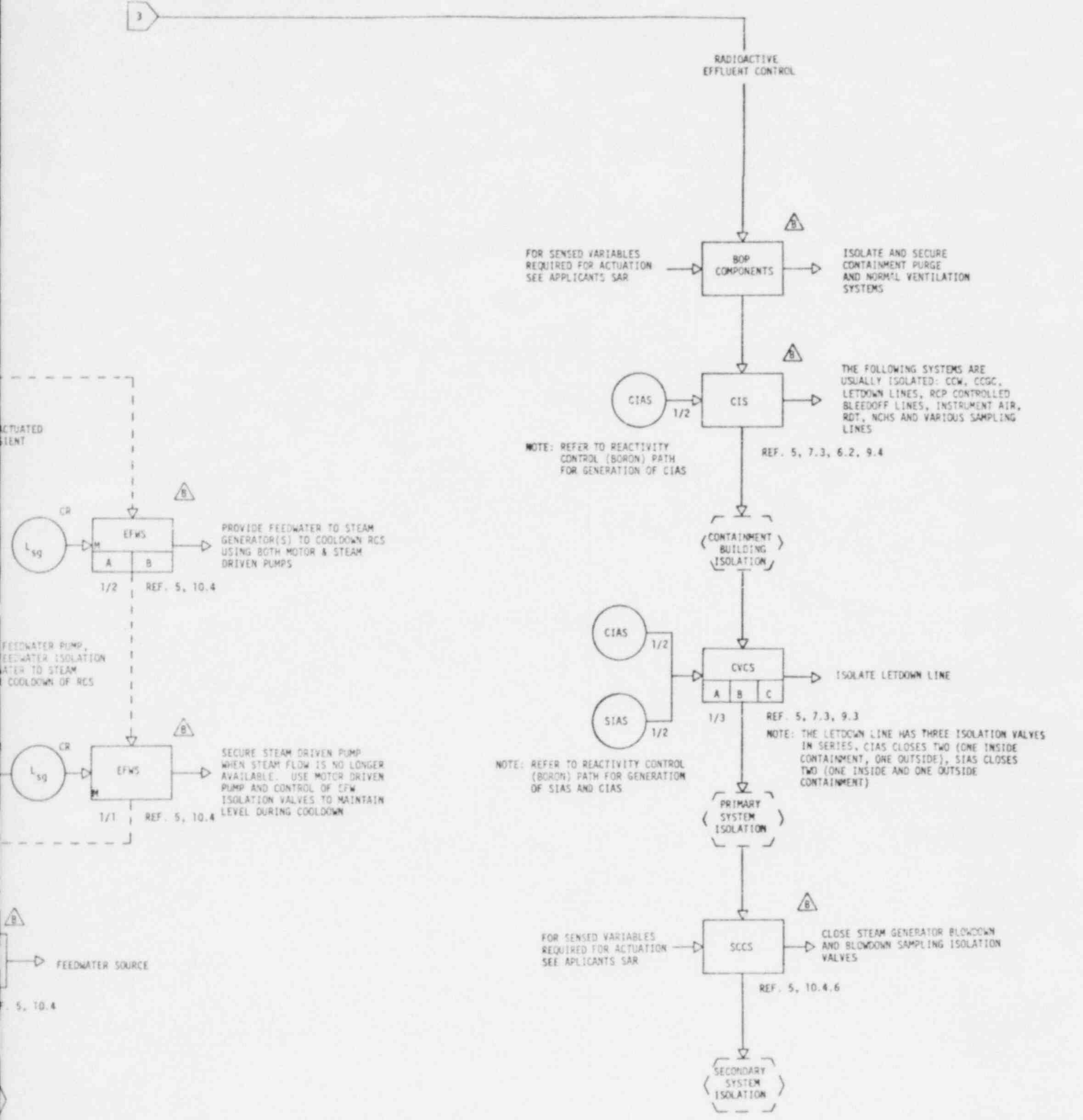
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE	Figure 15.6.3 -1C


C
TD
CR
MSI
M
OPERATOR ISOLATES AFFECTED STEAM GENERATOR
NOTE: OPERATOR USES TIME DIFFERENCE BETWEEN HLO'S FOR EACH STEAM GENERATOR TO DETERMINE WHICH IS THE AFFECTED ONE
P_{sh}
P_p
T_{ave}
CONDENSER AVAILABLE
SBCS
NS
A B C D E F G H
DUMP STEAM TO CONDENSER TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
1/8
FSAR 7.7, 10.4
NOTE: A THRU H IMPLIES EIGHT TURBINE BYPASS VALVES, EACH ~ 7% CAPACITY
NOTE: COOLDOWN IS ACCOMPLISHED USING ONLY THE UNAFFECTED STEAM GENERATOR
P_{sg}
ASDS
DUMP STEAM TO ATMOSPHERE TO COOLDOWN RCS UNTIL SHUTDOWN COOLING ENTRY CONDITIONS ARE REACHED
FSAR 7.4, 10.3
NOTE: THERE ARE TWO ADV'S FOR EACH STEAM GENERATOR
F_s, F_f, F_{fd}
L_{sg1}, L_{sg2}
FWCS
SUPPLY WATER TO STEAM GENERATOR(S) FOR COOLDOWN OF RCS
2/2
FSAR 7.7
CH
P
MAIN FEEDWATER SOURCE
FSAR 10.1, 10.4
REF. 5, 10.1, 10.4
SECURE MAIN FEEDWATER PUMPS WHEN STEAM FLOW IS INSUFFICIENT TO DRIVE TURBINES
EFWS
SECURE EFWS IF
DURING THE TRAN
REF. 5, 10.4
L_{sg}
AFWS
START AUXILIARY
OPEN AUXILIARY
VALVES, SUPPLY
GENERATOR(S) FO
CST
SEC. SYS. PRS/LVL/HS CONTROL-LONG TERM



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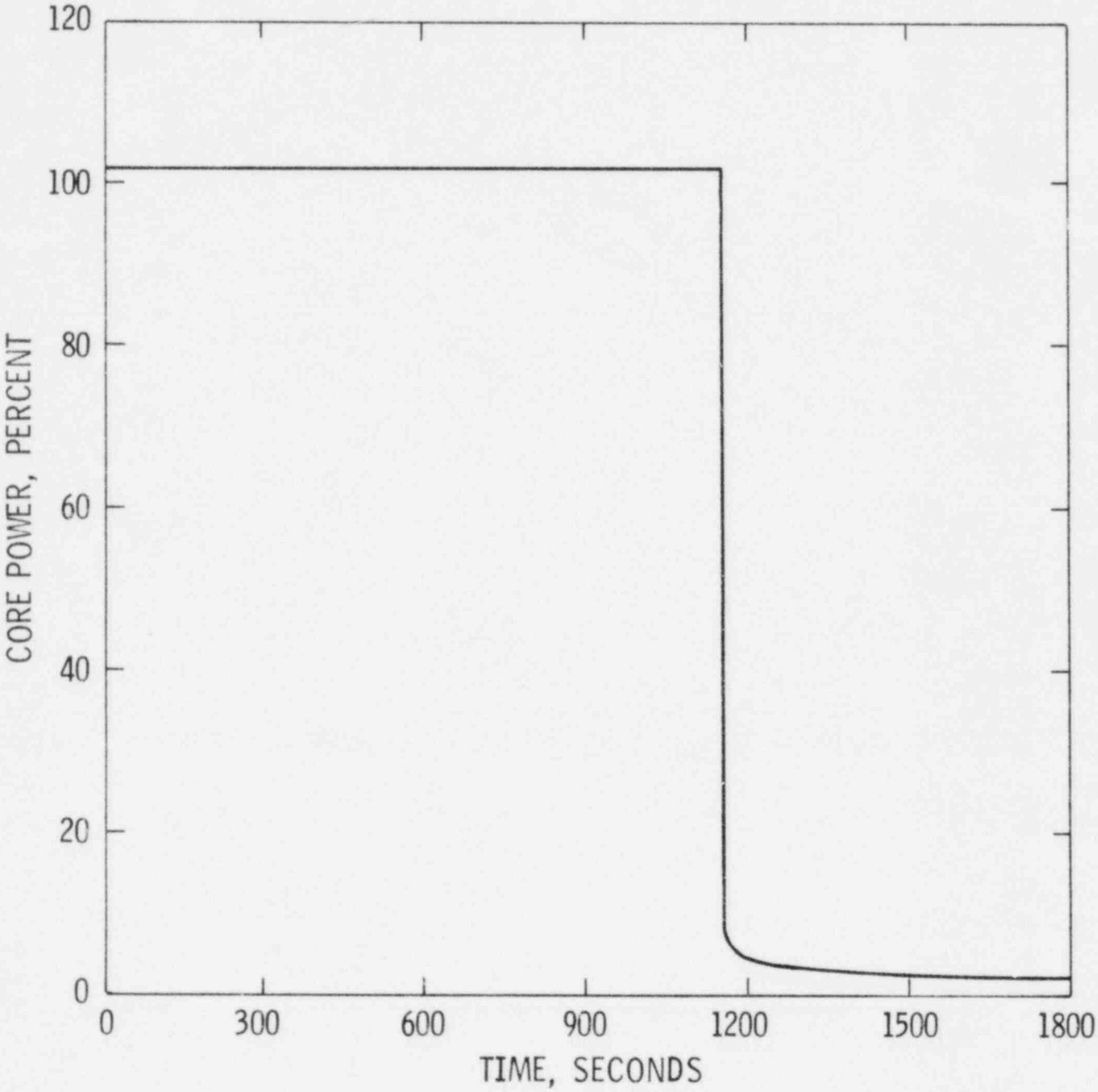
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE	Figure 15.6.3 -1D



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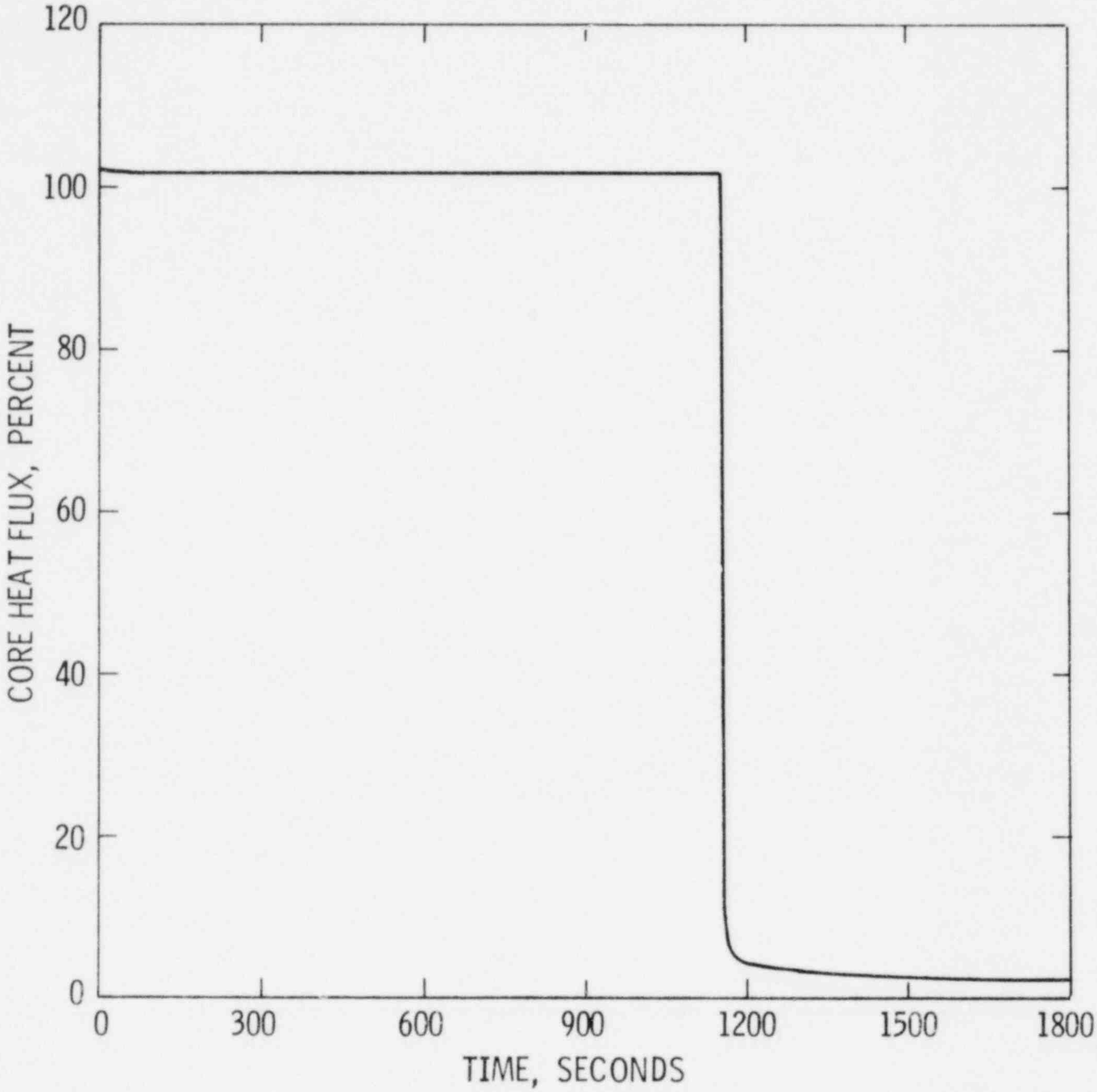
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER CORE POWER vs TIME	Figure 15.6.3-2



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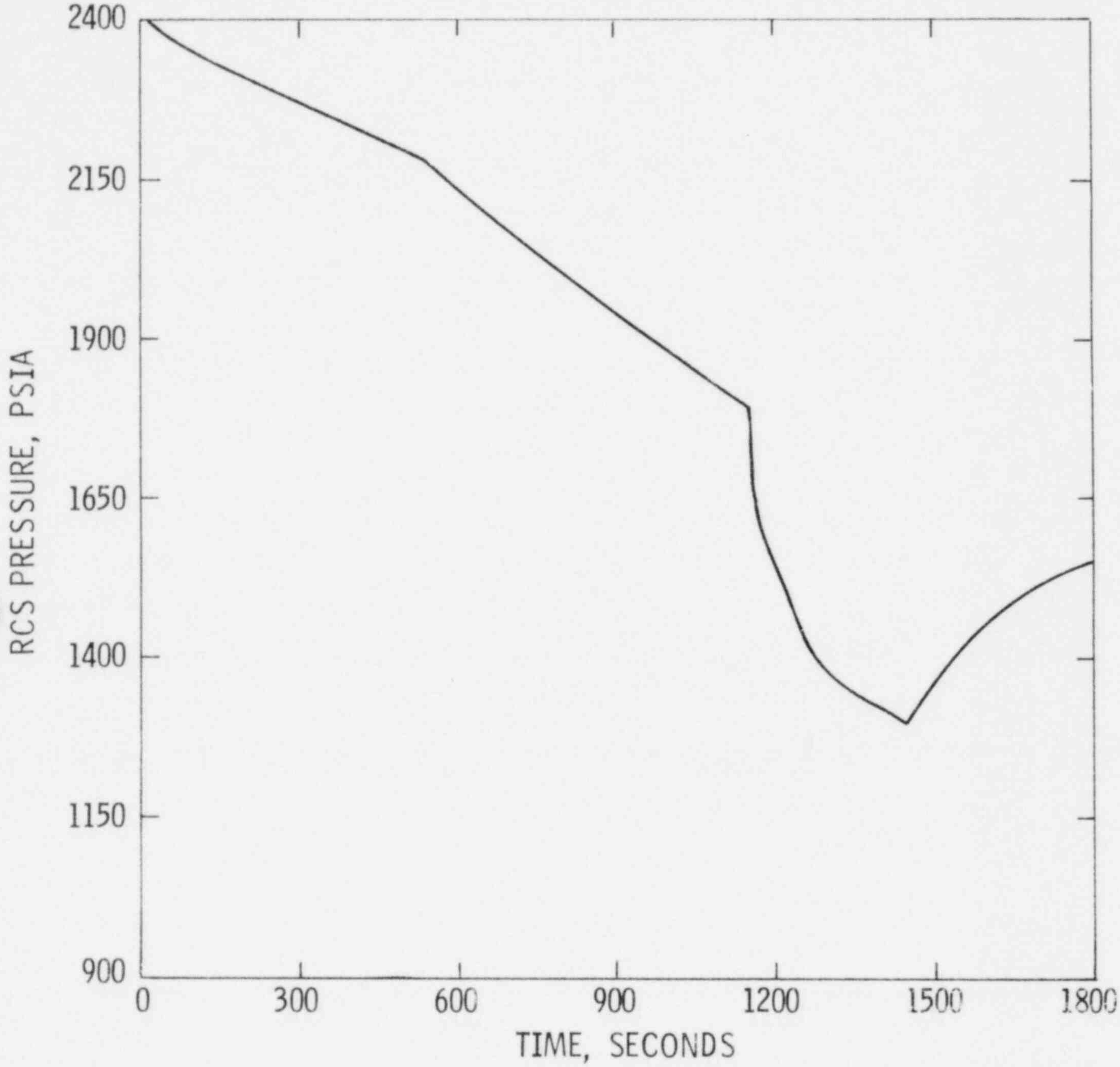
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER CORE HEAT FLUX vs TIME	Figure 15.6.3-3



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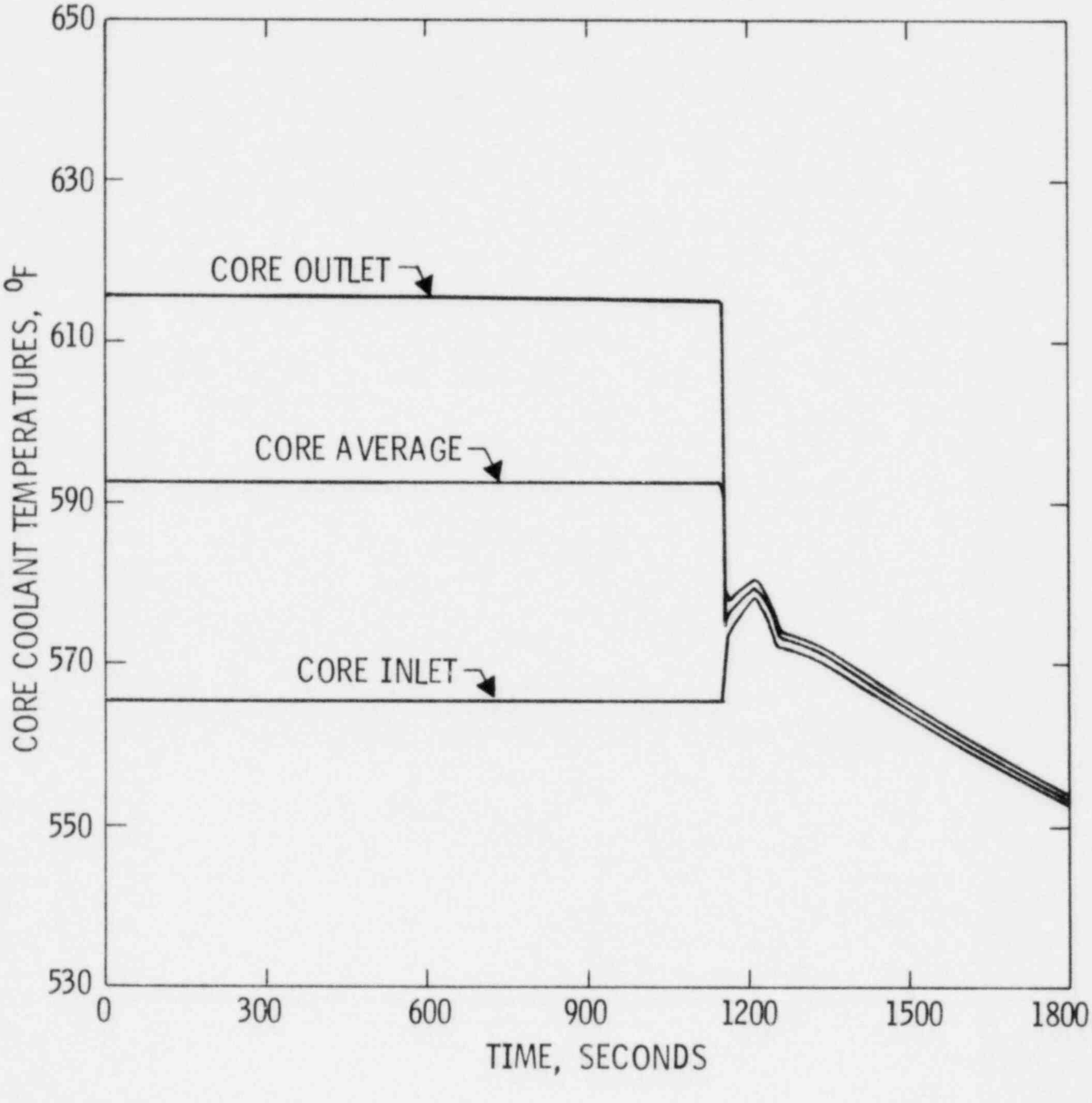
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER RCS PRESSURE vs TIME	Figure 15.6.3-4



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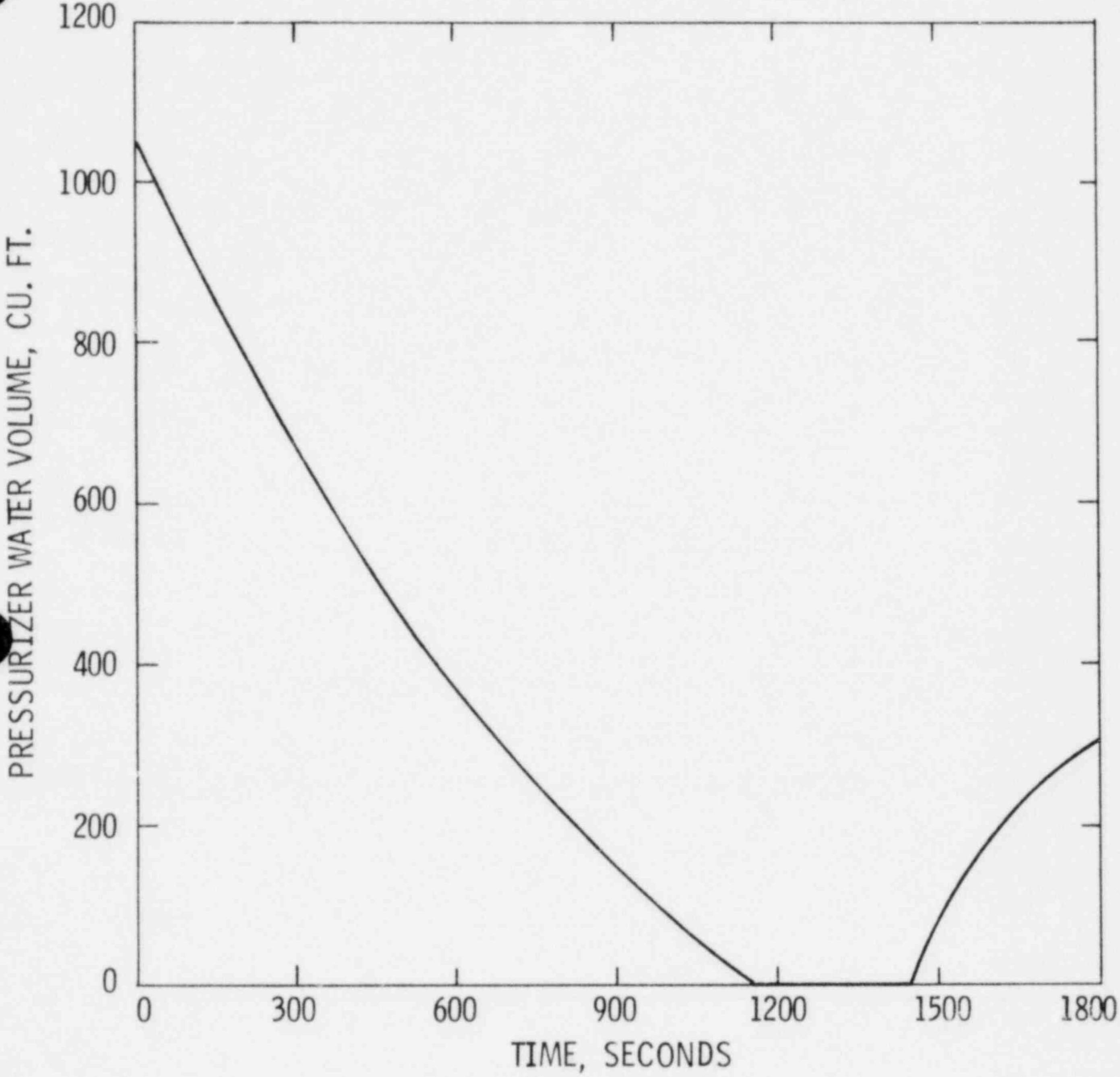
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER RCS TEMPERATURES vs TIME	Figure 15.6.3-5



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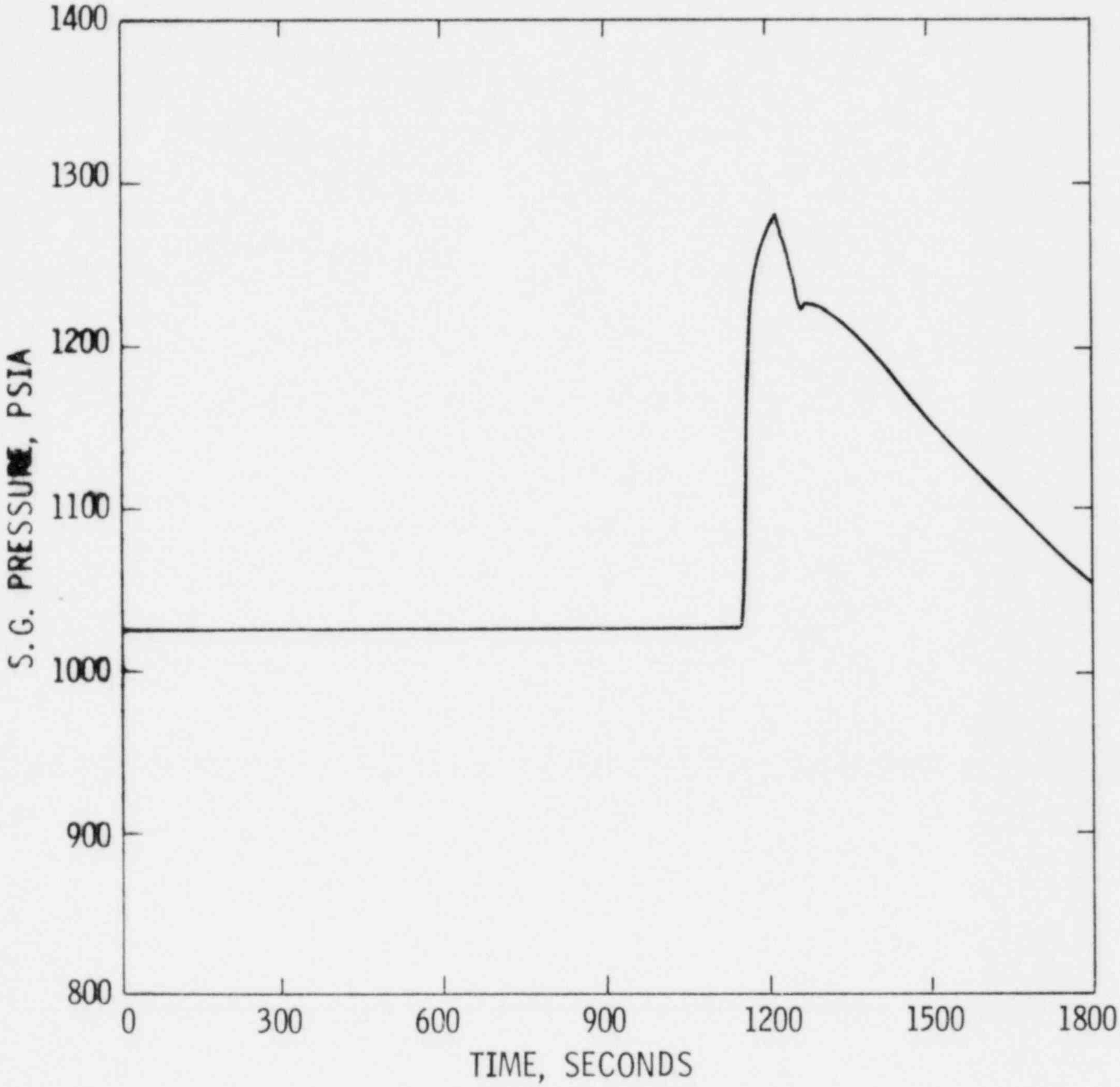
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER PRESSURIZER WATER VOLUME vs TIME	Figure 15.6.3-6



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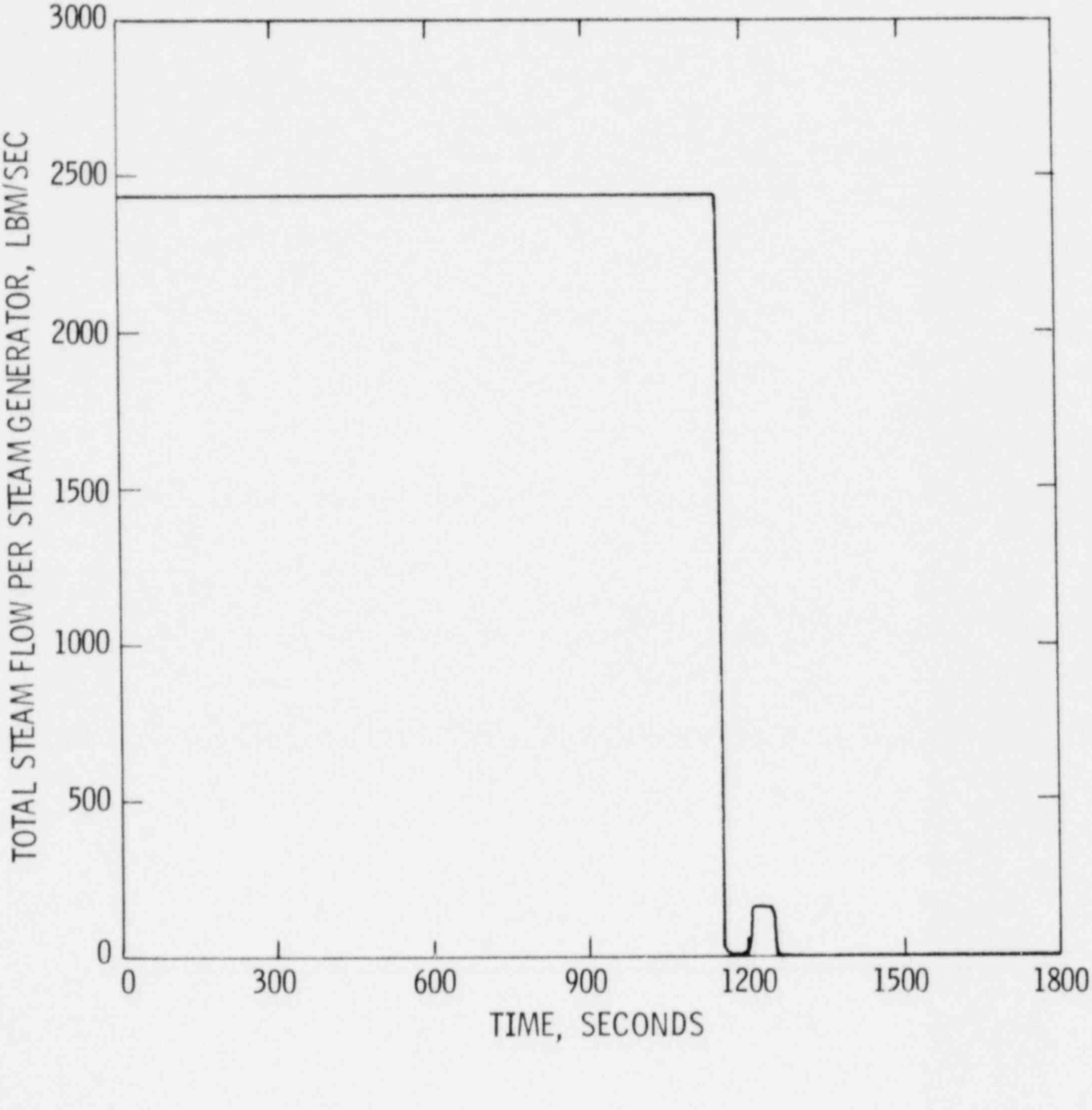
C-E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER S.G. PRESSURE vs TIME	Figure 15.6.3-7



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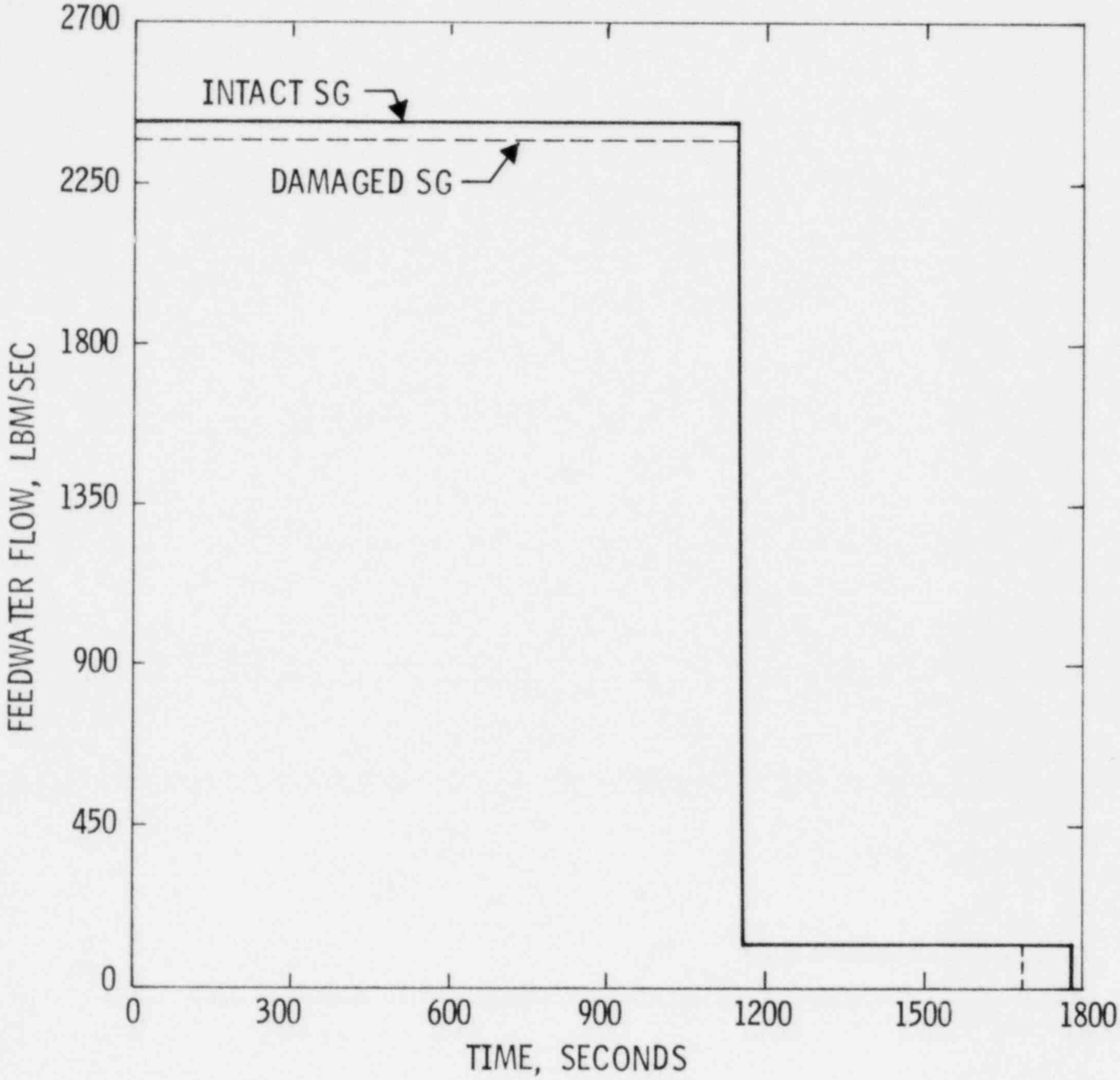
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER TOTAL STEAM FLOW vs TIME	Figure 15.6.3-8



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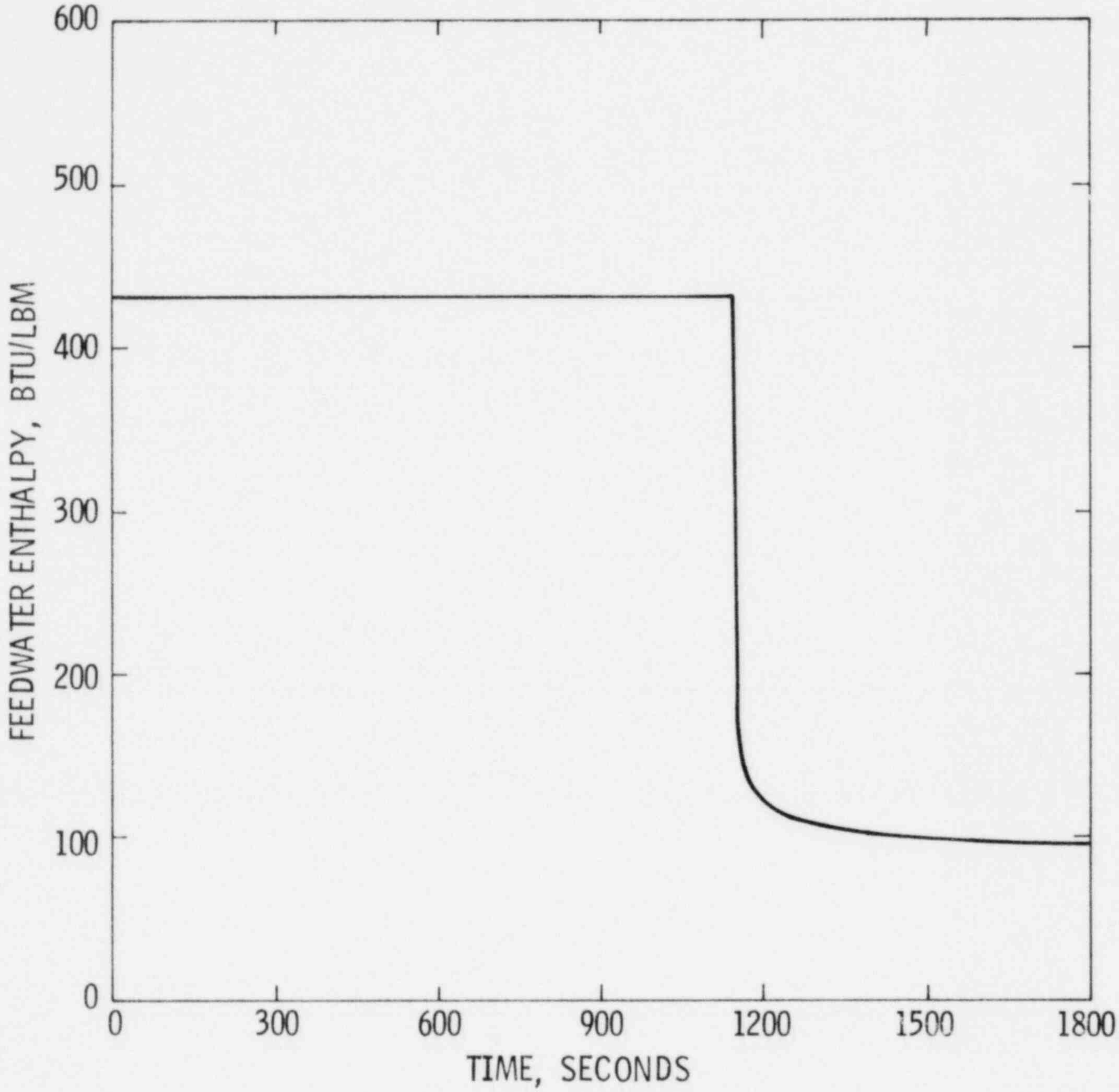
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER FEEDWATER FLOW vs TIME	Figure 15.6.3-9



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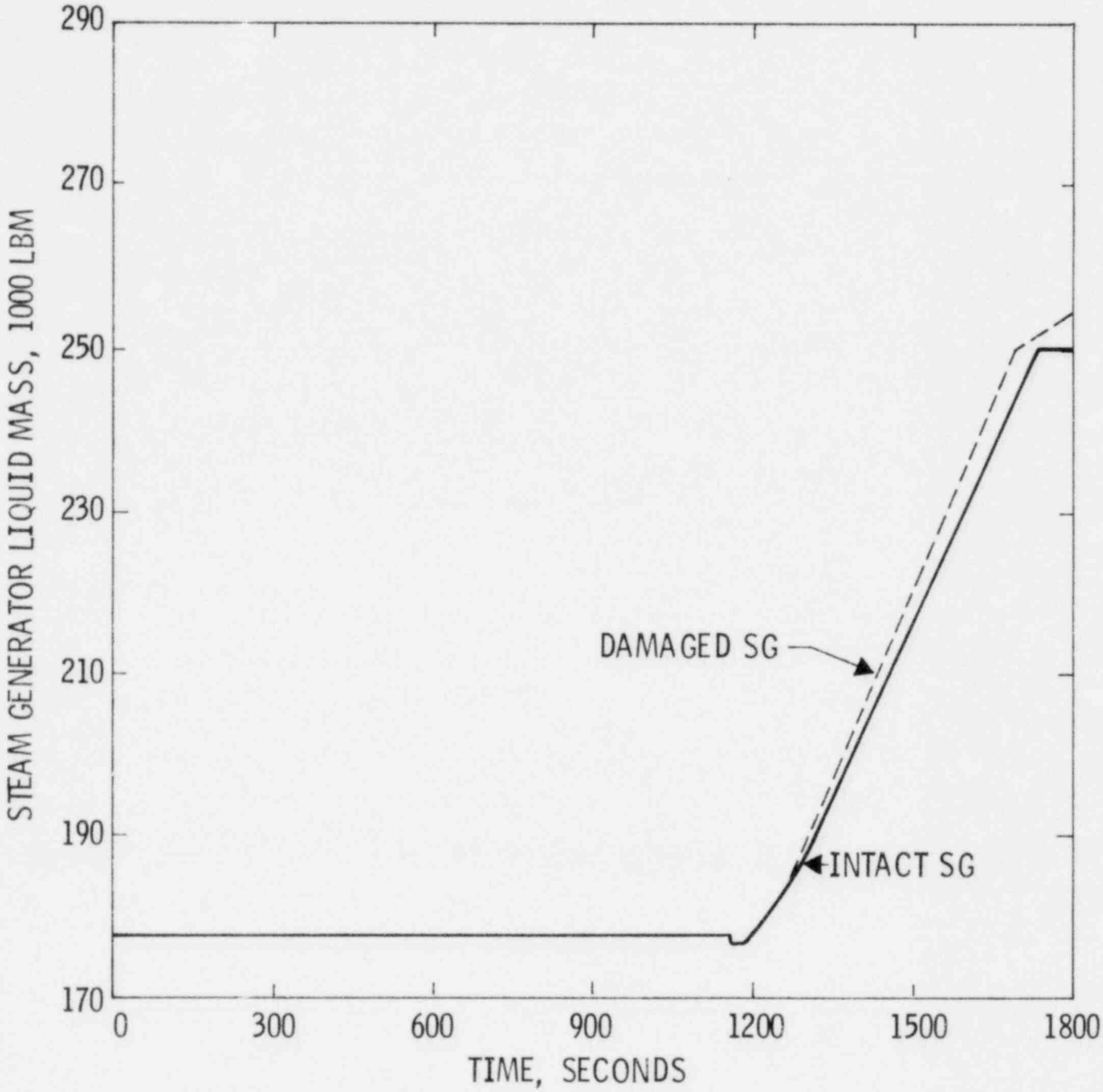
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER FEEDWATER ENTHALPY vs TIME	Figure 15.6.3-10



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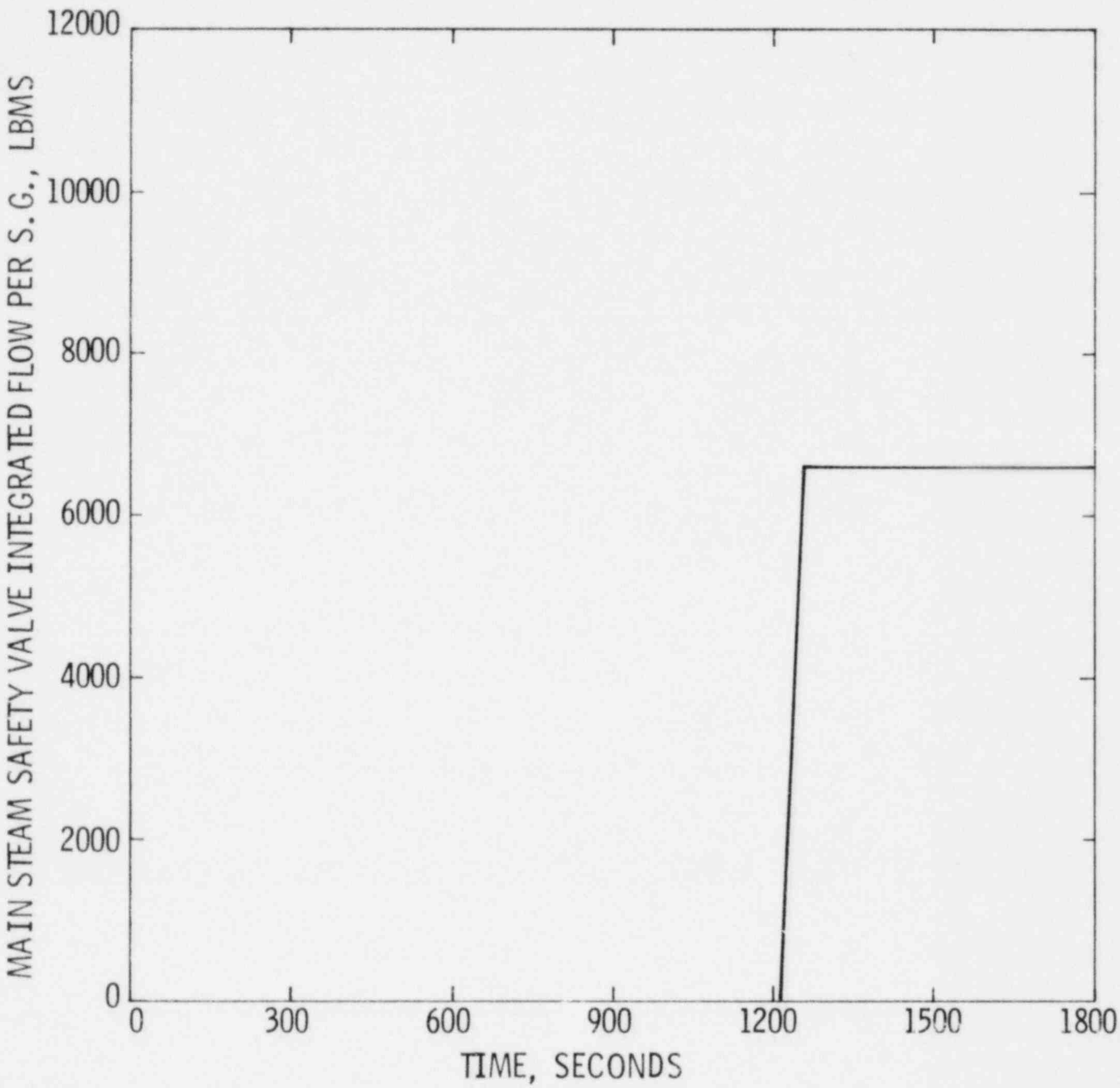
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER S.G. LIQUID MASS vs TIME	Figure 15.6.3-11



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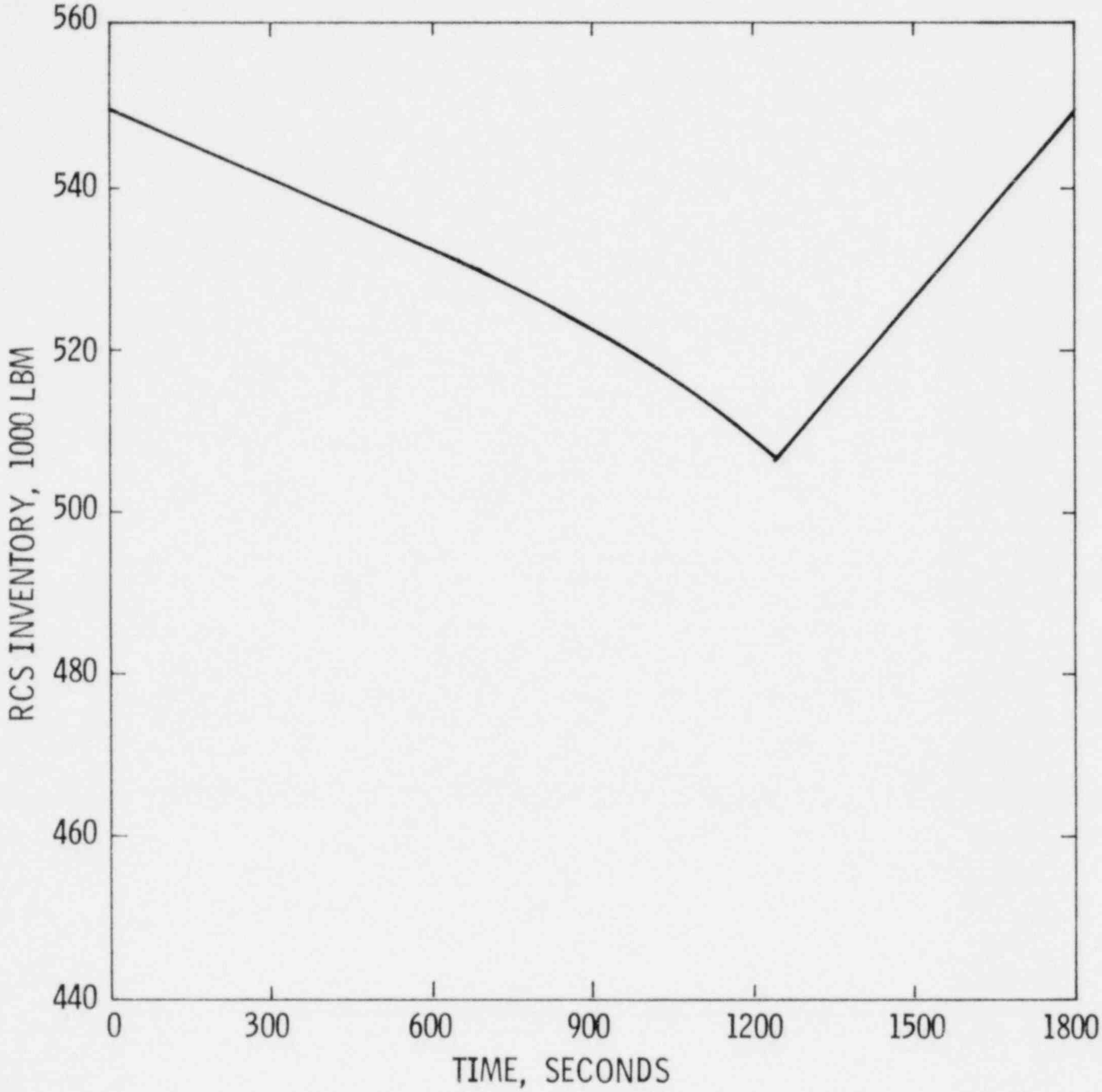
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER MAIN STM SAFETY VALVE INTEGRATED FLOW vs TIME	Figure 15.6.3-12



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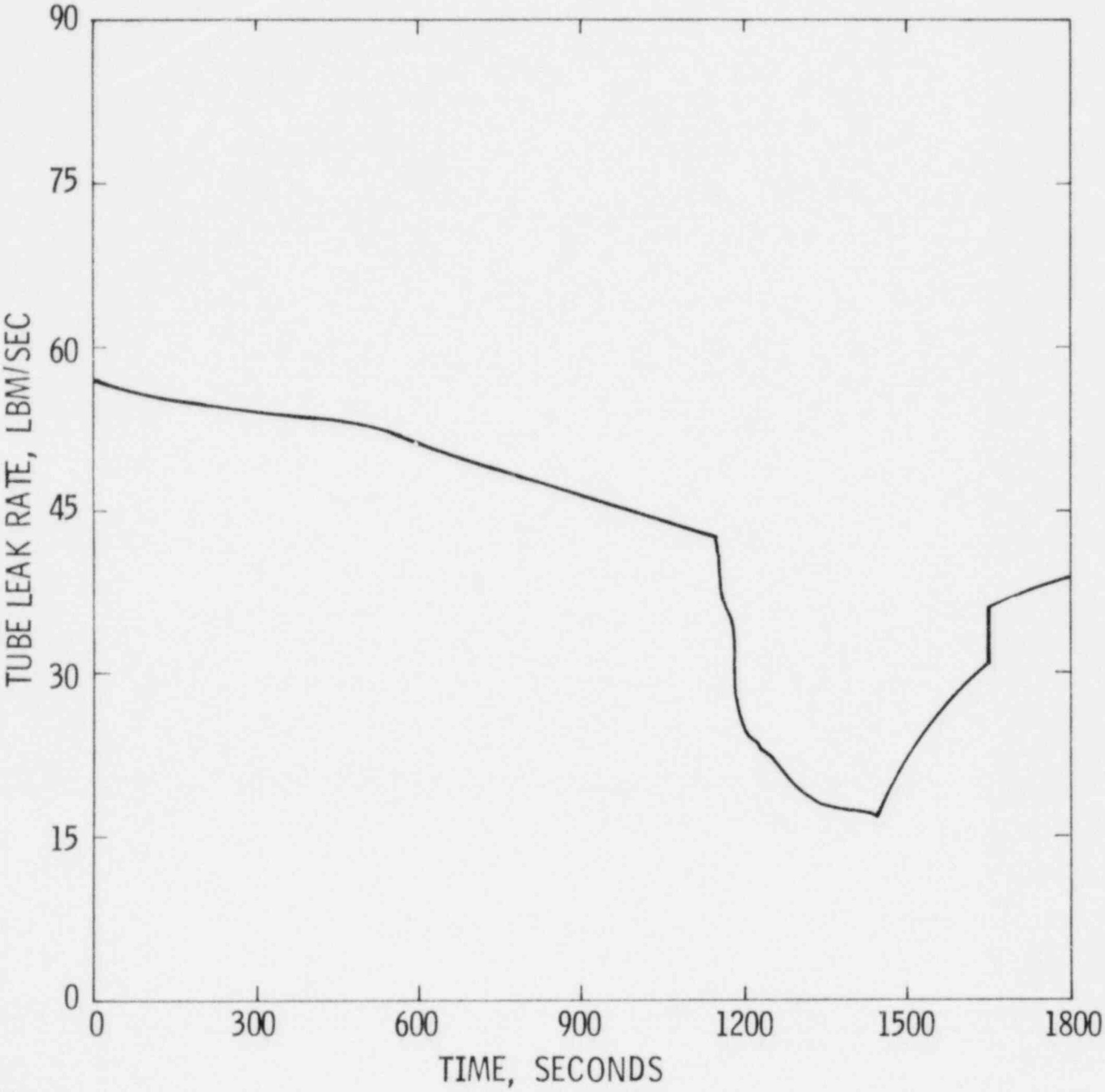
C-E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER RCS INVENTORY vs TIME	Figure 15.6.3-13



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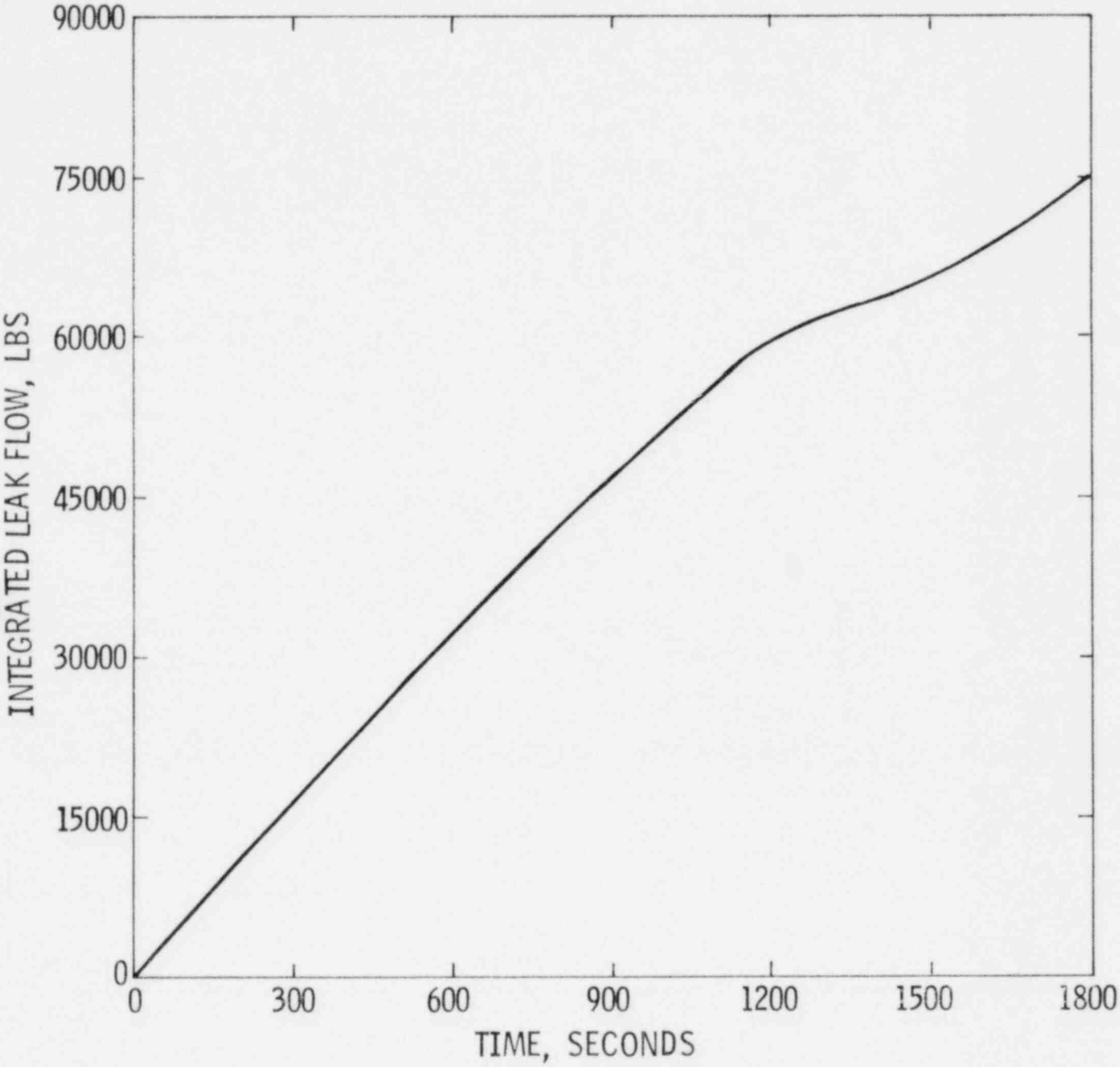
C-E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER TUBE LEAK RATE vs TIME	Figure 15.6.3-14



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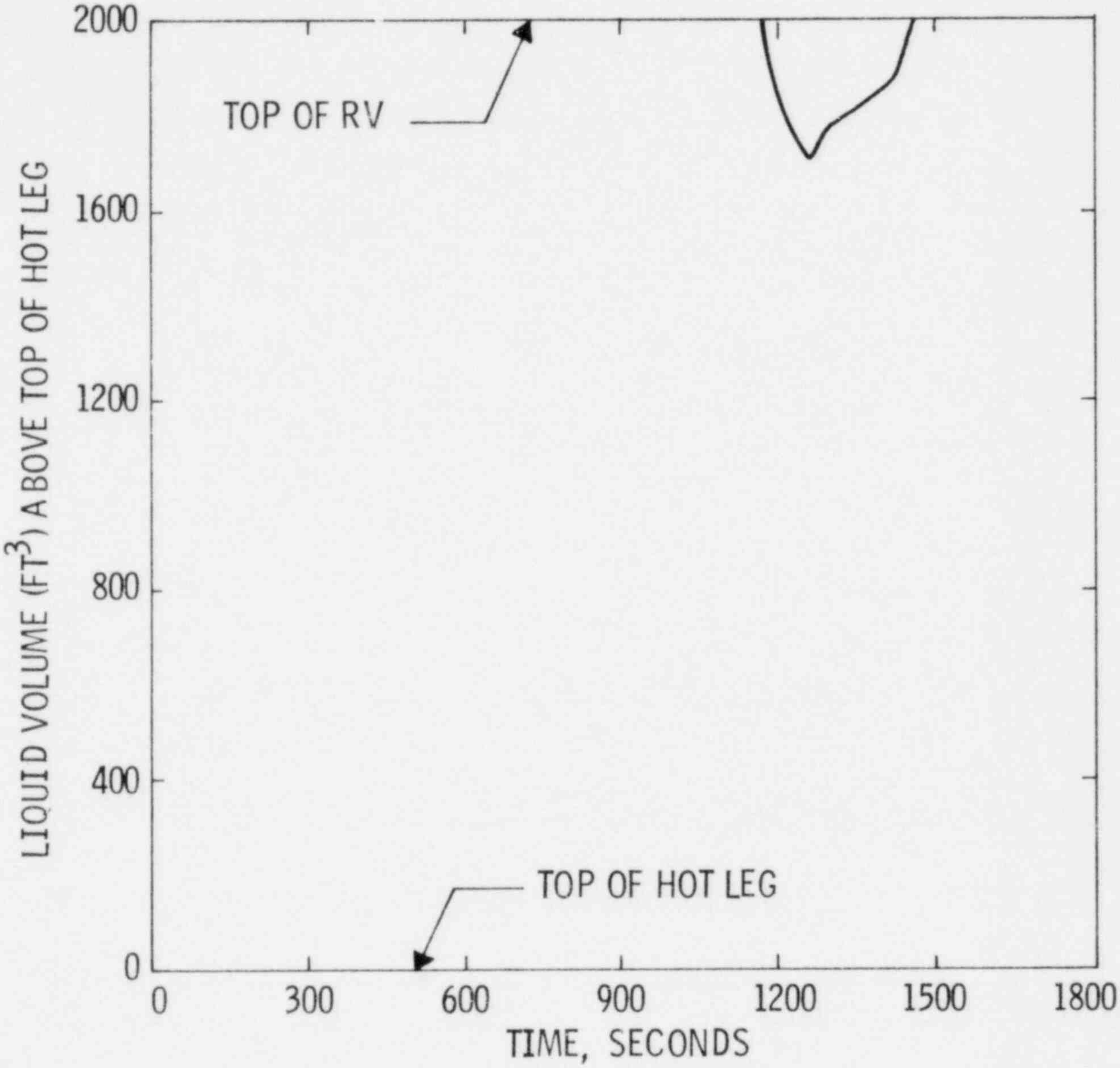
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER INTEGRATED LEAK FLOW vs TIME	Figure 15.6.3-15



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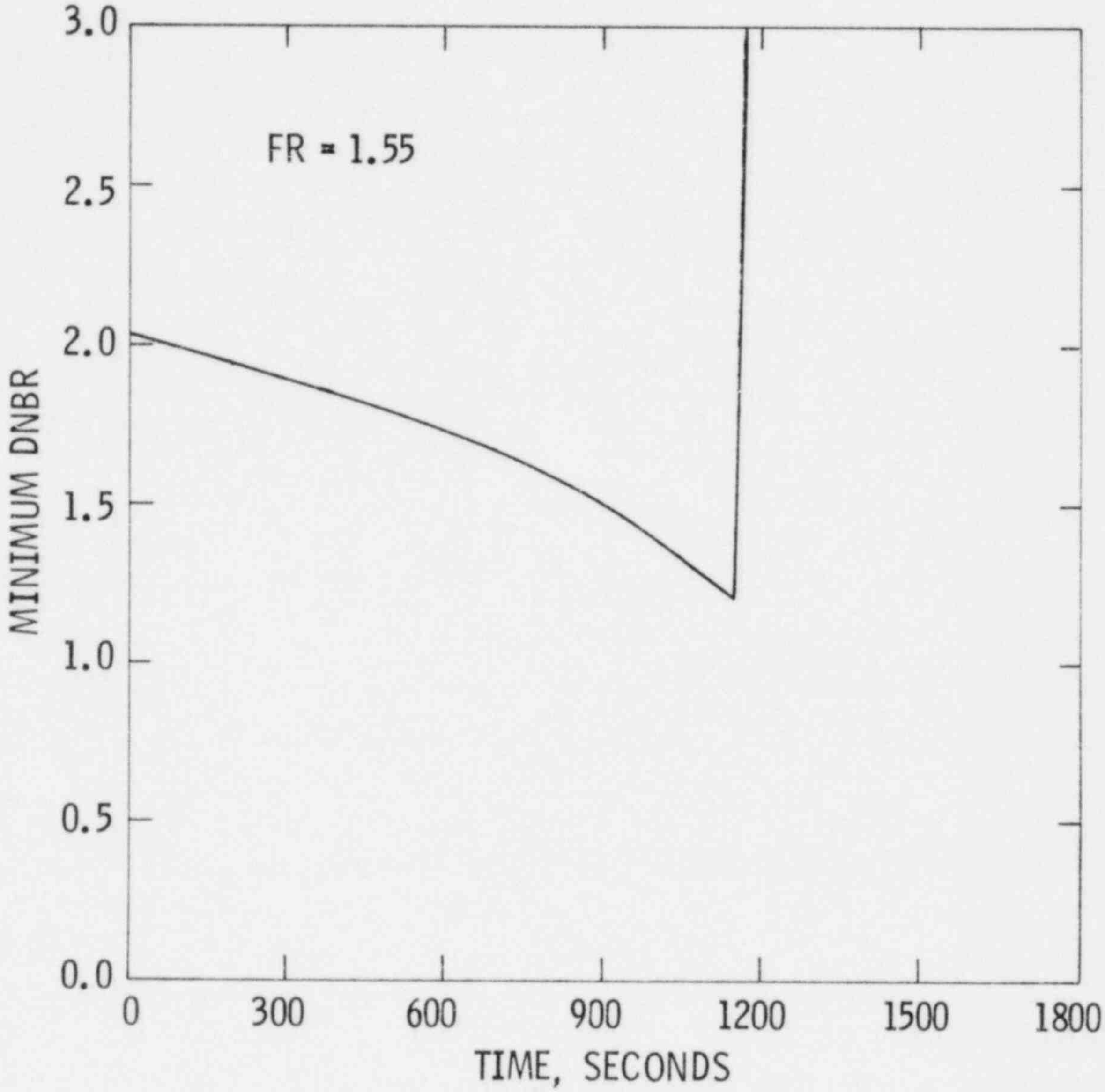
C-E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER LIQUID VOLUME ABOVE TOP OF HOT LEG vs TIME	Figure 15.6.3-16



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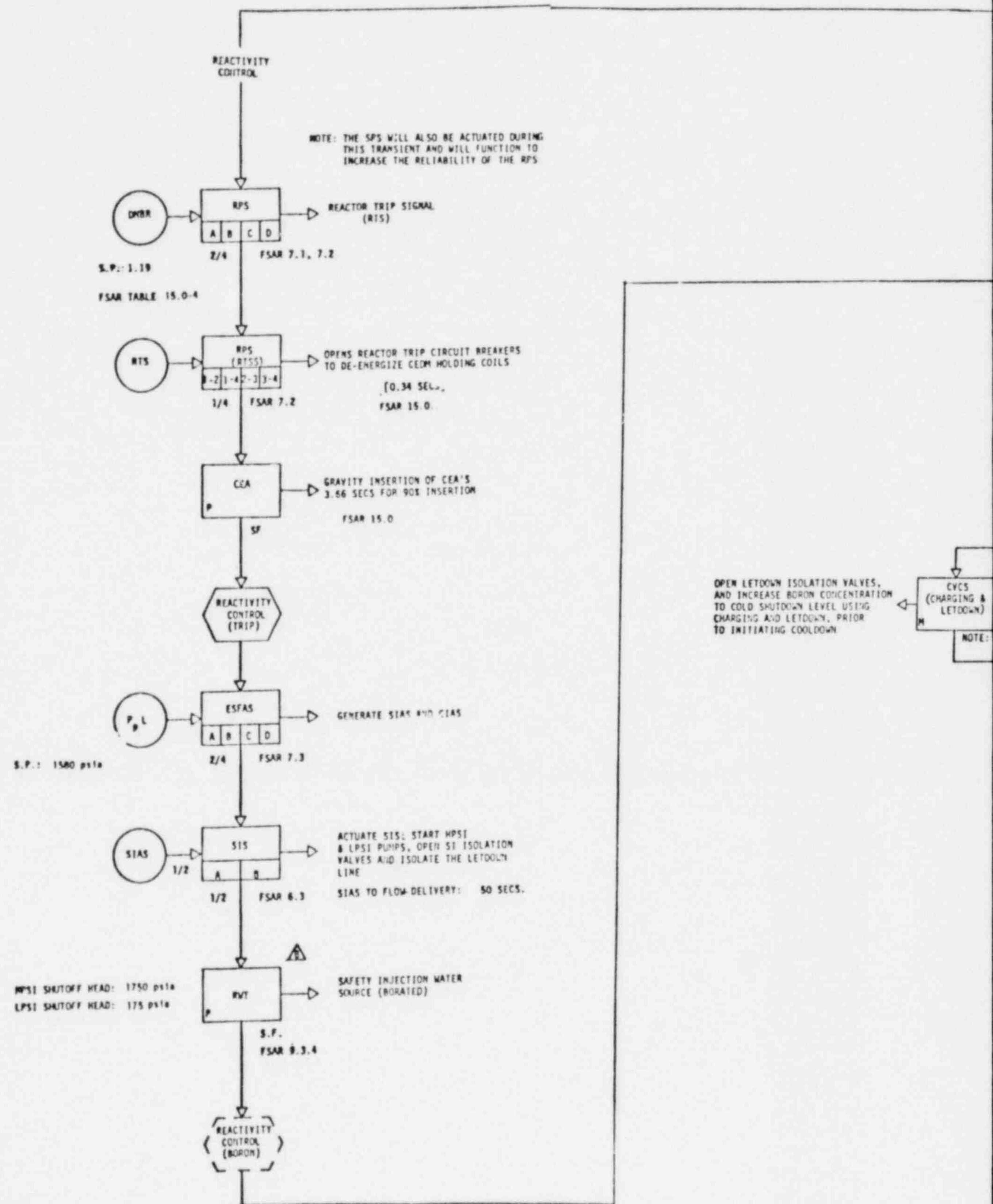
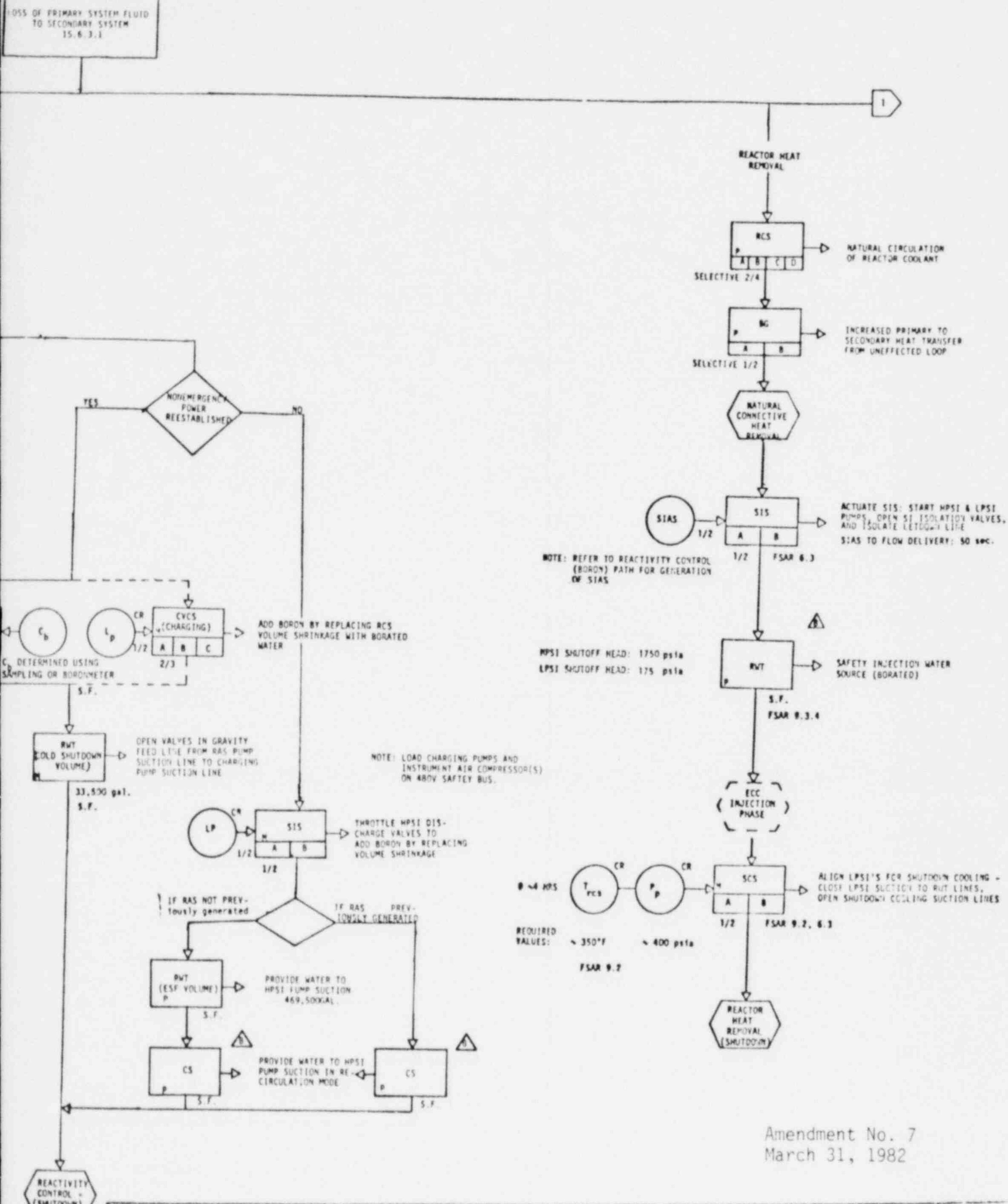
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITHOUT LOSS OF OFFSITE POWER MINIMUM DNBR vs TIME	Figure 15.6.3-17

SPECIFIC EVENT
STEAM GENERATOR TUBE RUPTURE

COINCIDENT OCCURRENCE
LOSS OF OFFSITE POWER AT
TIME OF REACTOR TRIP





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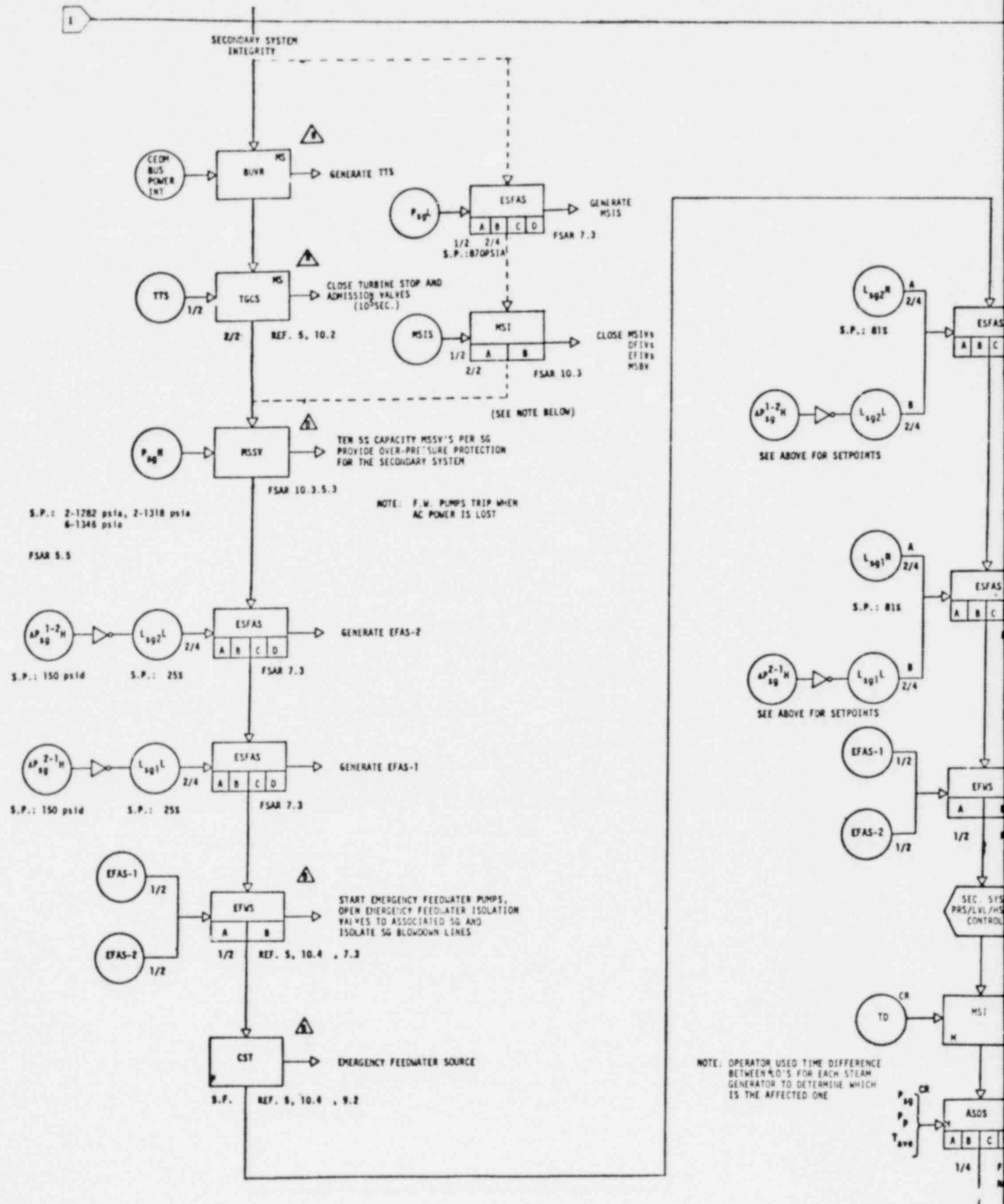
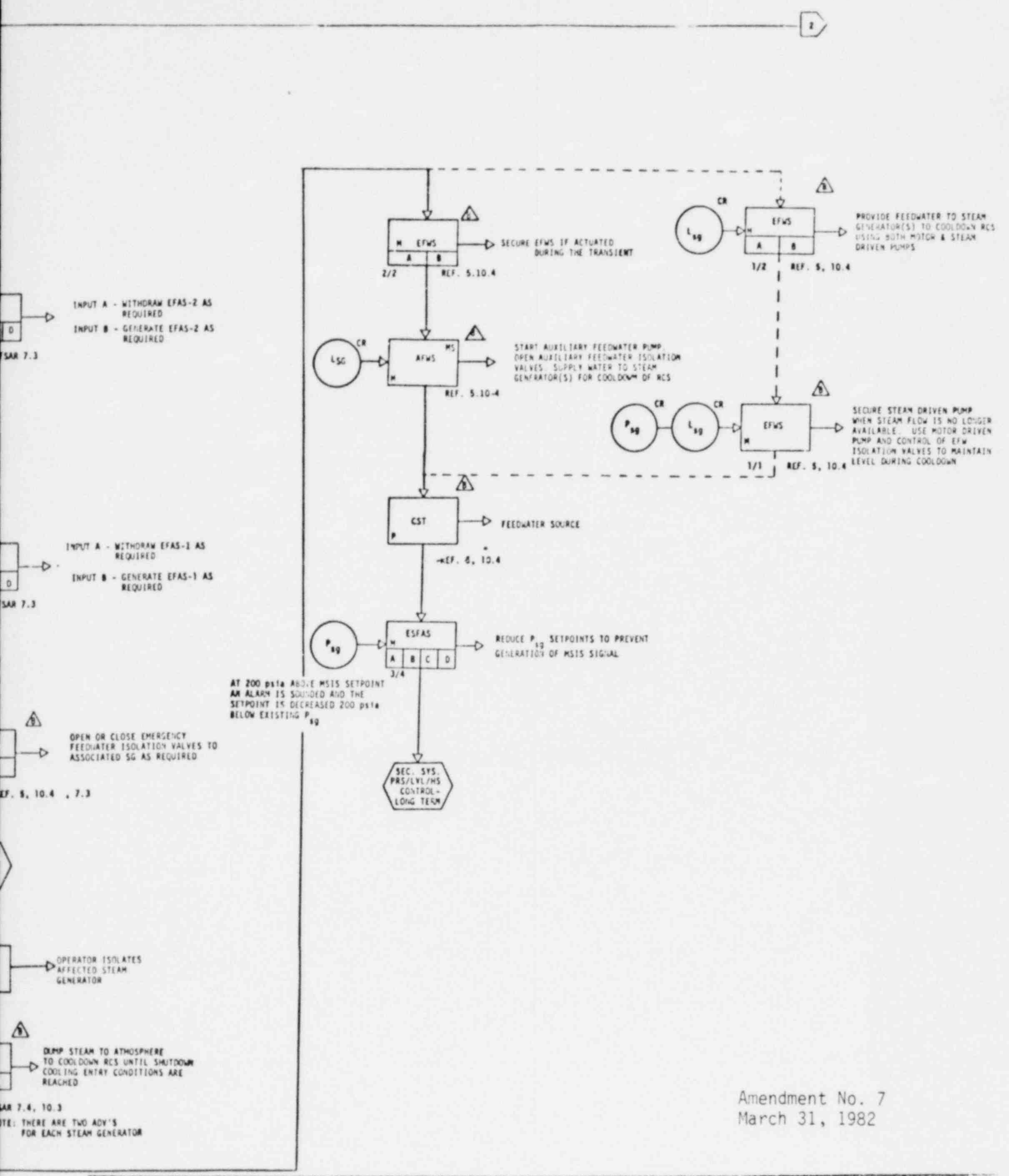
C-E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM
FOR STEAM GENERATOR TUBE RUPTURE
WITH LOSS OF OFFSITE POWER ON REACTOR TRIP

Figure 15.6.3-18A



I
SECONDARY SYSTEM INTEGRITY
CEDM BUS POWER INT
BUVR
MS
GENERATE TTS
TTS
1/2
TGCS
MS
CLOSE TURBINE STOP AND ADMISSION VALVES (10^5 SEC.)
2/2
REF. 5, 10.2
ESFAS
GENERATE MSIS
FSAR 7.3
1/2 2/4
S.P.: 870PSIA
MSIS
MSI
CLOSE MSIVs DFIVs EFIVs MSBV
2/2
FSAR 10.3
(SEE NOTE BELOW)
MSSV
TEN 5% CAPACITY MSSV'S PER SG PROVIDE OVER-PRESSURE PROTECTION FOR THE SECONDARY SYSTEM
FSAR 10.3.5.3
NOTE: F.W. PUMPS TRIP WHEN AC POWER IS LOST
S.P.: 2-1282 psia, 2-1318 psia 6-1346 psia
FSAR 5.5
ESFAS
GENERATE EFAS-2
S.P.: 150 psid
S.P.: 25%
2/4
FSAR 7.3
ESFAS
GENERATE EFAS-1
S.P.: 150 psid
S.P.: 25%
2/4
FSAR 7.3
EFAS-1
EFAS-2
1/2
EFWS
START EMERGENCY FEEDWATER PUMPS, OPEN EMERGENCY FEEDWATER ISOLATION VALVES TO ASSOCIATED SG AND ISOLATE SG BLOWDOWN LINES
1/2
REF. 5, 10.4 , 7.3
CST
EMERGENCY FEEDWATER SOURCE
S.F.
REF. 5, 10.4 , 9.2
S.P.: 81%
2/4
ESFAS
SEE ABOVE FOR SETPOINTS
S.P.: 81%
ESFAS
SEE ABOVE FOR SETPOINTS
EFAS-1
EFAS-2
1/2
EFWS
SEC. SYS PRS/LVL/HS CONTROL
TD
CR
MSI
NOTE: OPERATOR USED TIME DIFFERENCE BETWEEN LO'S FOR EACH STEAM GENERATOR TO DETERMINE WHICH IS THE AFFECTED ONE
ASDS
1/4



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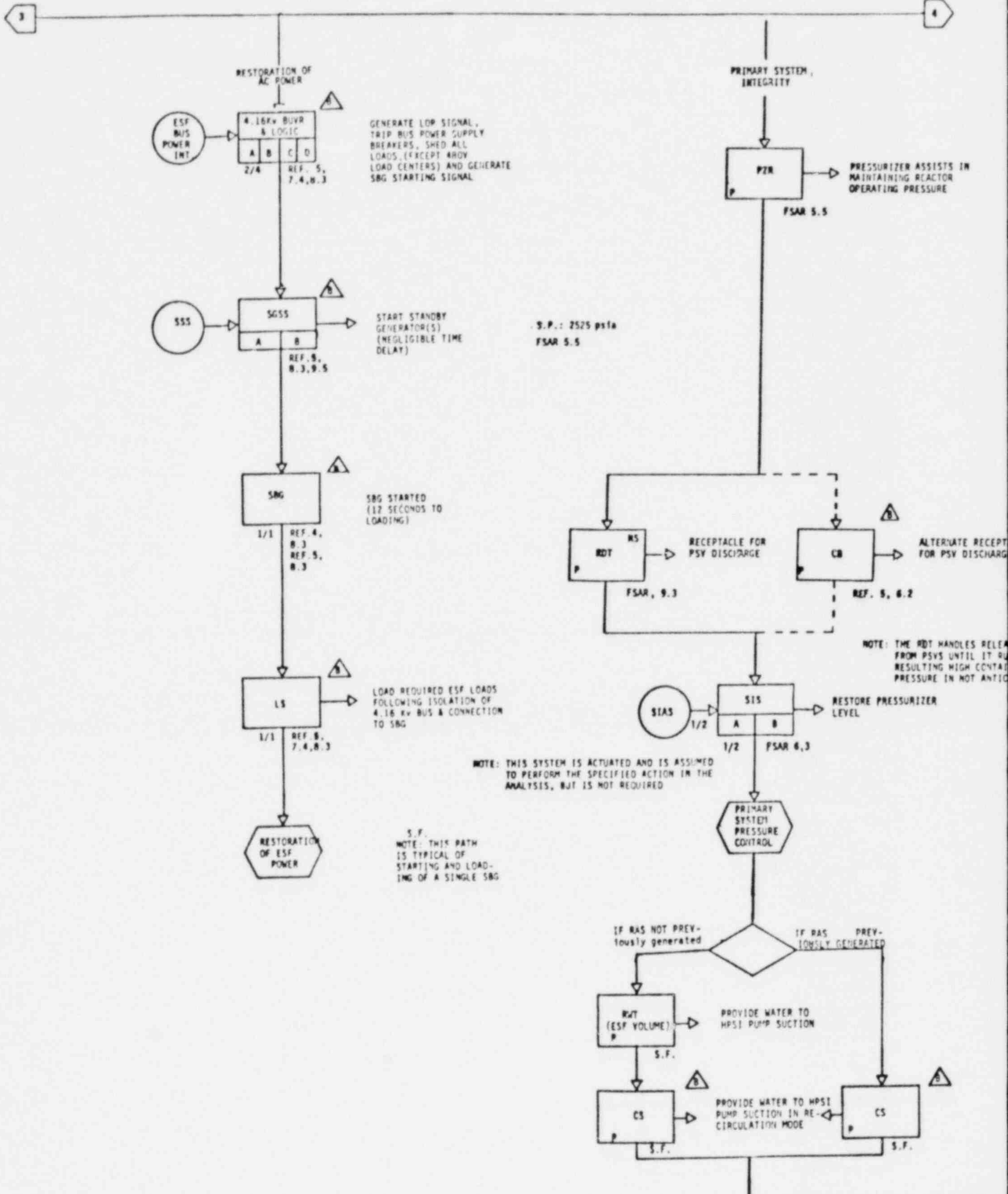
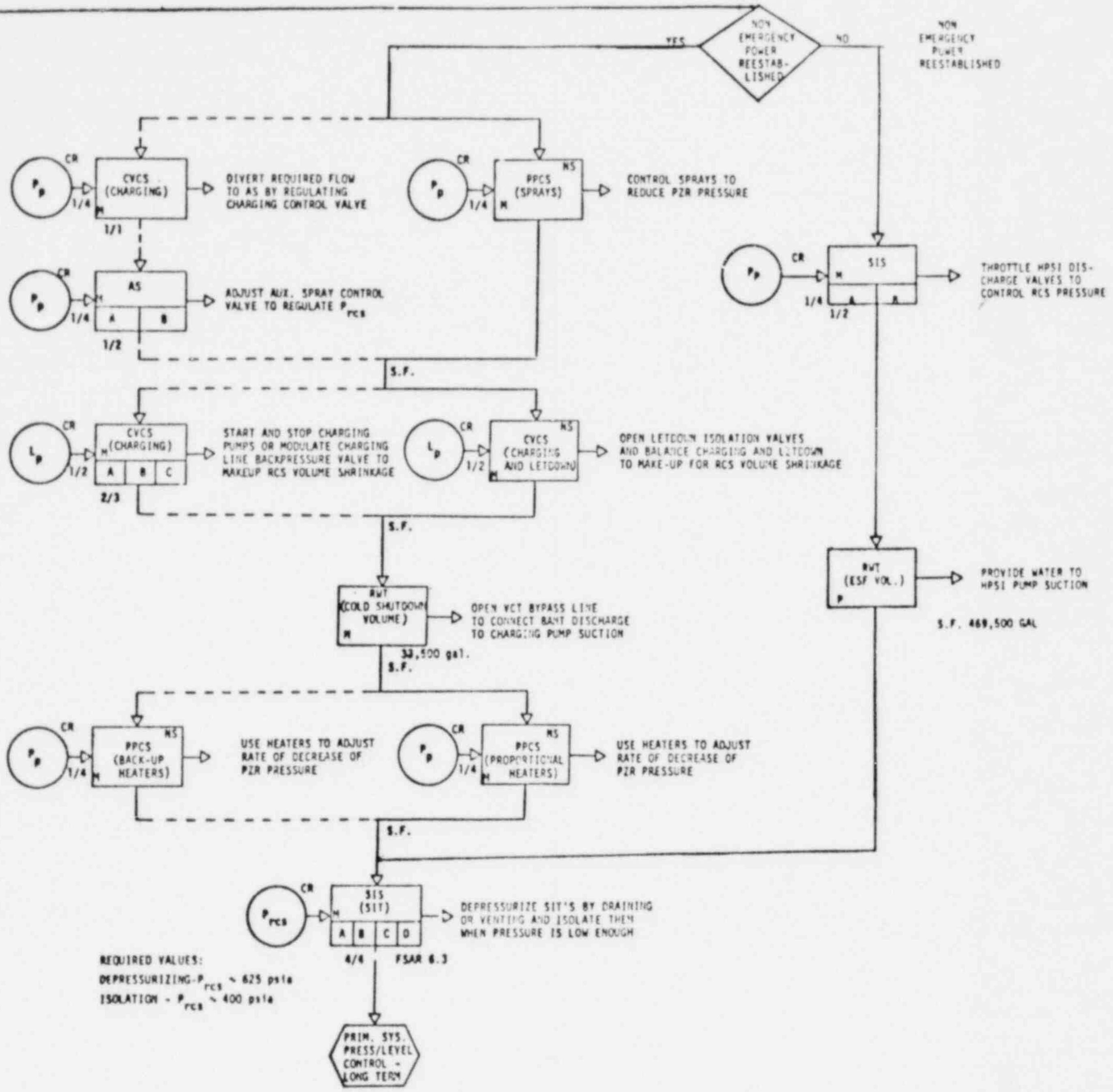
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER ON REACTOR TRIP	Figure 15.6.3 -18B



3
4
RESTORATION OF AC POWER
ESF BUS POWER INT
4.16Kv BUVR & LOGIC
A B C D
2/4
REF. 5, 7.4,8.3
GENERATE LOP SIGNAL, TRIP BUS POWER SUPPLY BREAKERS, SHED ALL LOADS,(EXCEPT 480V LOAD CENTERS) AND GENERATE SBG STARTING SIGNAL
SSS
SGSS
A B
REF.5, 8.3,9.5
START STANDBY GENERATOR(S) (NEGLIGIBLE TIME DELAY)
SBG
1/1
REF.4, 8.3 REF.5, 8.3
SBG STARTED (12 SECONDS TO LOADING)
LS
1/1
REF.5, 7.4,8.3
LOAD REQUIRED ESF LOADS FOLLOWING ISOLATION OF 4.16 Kv BUS & CONNECTION TO SBG
RESTORATION OF ESF POWER
S.F.
NOTE: THIS PATH IS TYPICAL OF STARTING AND LOADING OF A SINGLE SBG
PRIMARY SYSTEM INTEGRITY
PZR
P
FSAR 5.5
PRESSURIZER ASSISTS IN MAINTAINING REACTOR OPERATING PRESSURE
S.P.: 2525 psia
FSAR 5.5
RDT
RS
P
FSAR, 9.3
RECEPTACLE FOR PSV DISCHARGE
CB
P
REF. 5, 6.2
ALTERNATE RECEPT FOR PSV DISCHARG
NOTE: THE RDT HANDLES RELEA FROM PSVS UNTIL IT RU RESULTING HIGH CONTAI PRESSURE IN NOT ANTIC
SIAS
1/2
SIS
A B
1/2
FSAR 6,3
RESTORE PRESSURIZER LEVEL
NOTE: THIS SYSTEM IS ACTUATED AND IS ASSUMED TO PERFORM THE SPECIFIED ACTION IN THE ANALYSIS, BUT IS NOT REQUIRED
PRIMARY SYSTEM PRESSURE CONTROL
IF RAS NOT PREViously generated
IF RAS PREVIOUSLY GENERATED
RWT (ESF VOLUME)
P
S.F.
PROVIDE WATER TO HPSI PUMP SUCTION
CS
P
S.F.
PROVIDE WATER TO HPSI PUMP SUCTION IN RECIRCULATION MODE
CS
P
S.F.



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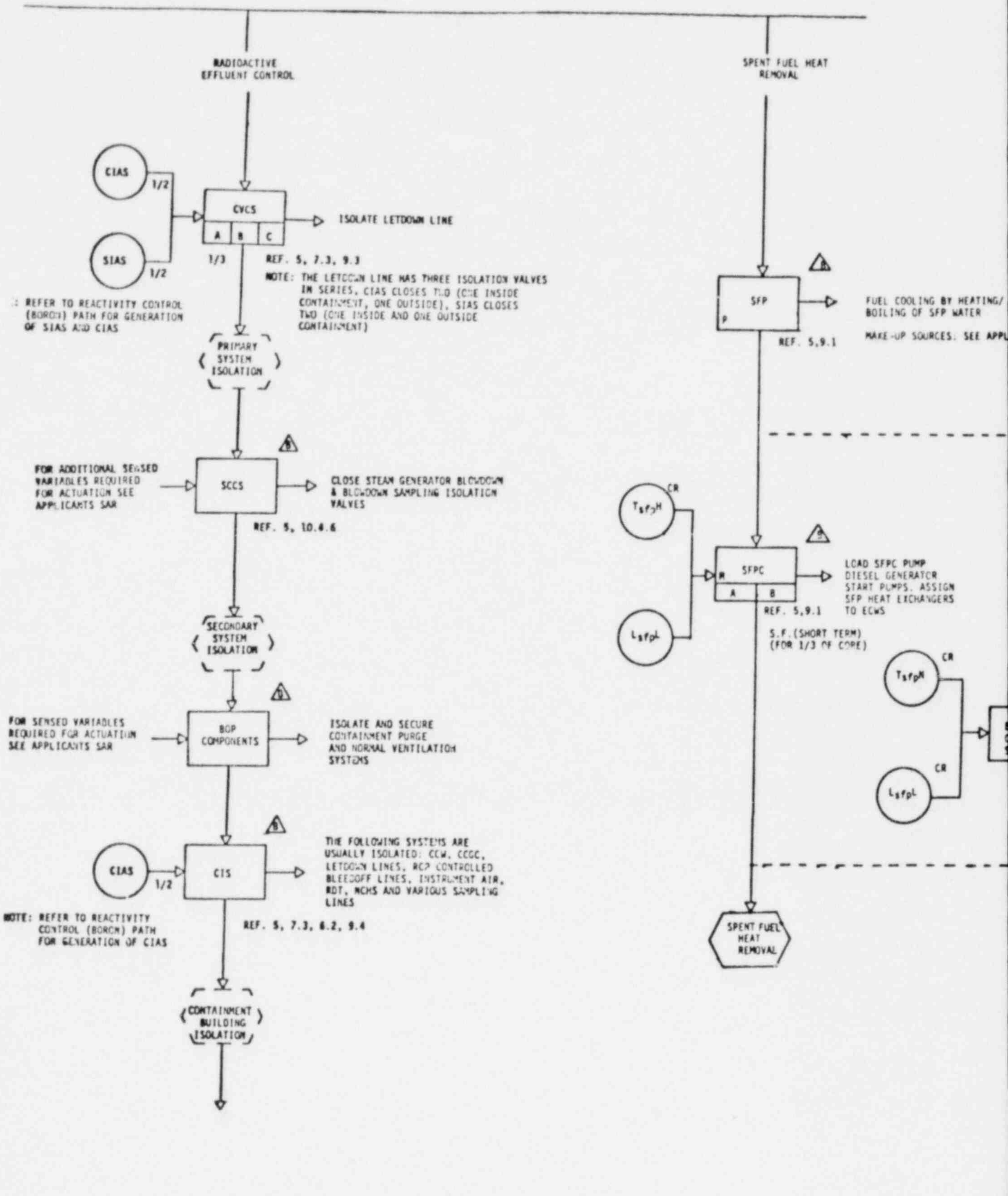
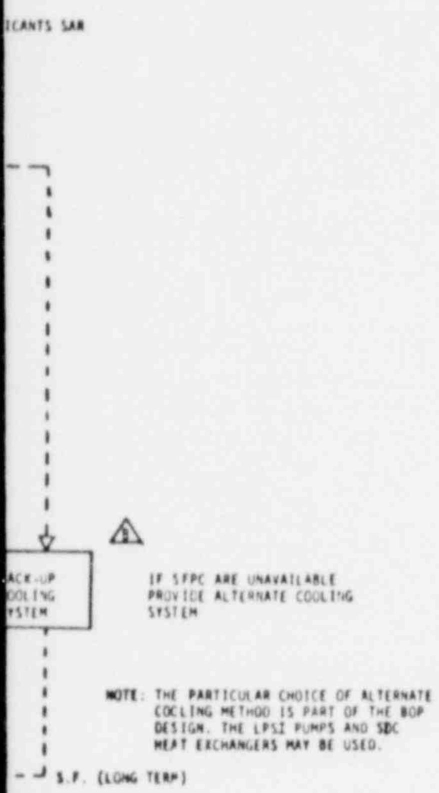
C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER ON REACTOR TRIP	Figure 15.6.3-18C



RADIOACTIVE EFFLUENT CONTROL
CIAS
1/2
SIAS
1/2
CVCS
A B C
ISOLATE LETDOWN LINE
1/3
REF. 5, 7.3, 9.3
NOTE: THE LETDOWN LINE HAS THREE ISOLATION VALVES IN SERIES, CIAS CLOSES TWO (ONE INSIDE CONTAINMENT, ONE OUTSIDE), SIAS CLOSES TWO (ONE INSIDE AND ONE OUTSIDE CONTAINMENT)
: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF SIAS AND CIAS
PRIMARY SYSTEM ISOLATION
FOR ADDITIONAL SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
SCCS
CLOSE STEAM GENERATOR BLOWDOWN & BLOWDOWN SAMPLING ISOLATION VALVES
REF. 5, 10.4.6
SECONDARY SYSTEM ISOLATION
FOR SENSED VARIABLES REQUIRED FOR ACTUATION SEE APPLICANTS SAR
BOP COMPONENTS
ISOLATE AND SECURE CONTAINMENT PURGE AND NORMAL VENTILATION SYSTEMS
CIAS
1/2
CIS
THE FOLLOWING SYSTEMS ARE USUALLY ISOLATED: CCW, CCGC, LETDOWN LINES, RCP CONTROLLED BLEEDOFF LINES, INSTRUMENT AIR, RDT, NCHS AND VARIOUS SAMPLING LINES
REF. 5, 7.3, 6.2, 9.4
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF CIAS
CONTAINMENT BUILDING ISOLATION
SPENT FUEL HEAT REMOVAL
SFP
P
FUEL COOLING BY HEATING/ BOILING OF SFP WATER
MAKE-UP SOURCES: SEE APPL
REF. 5,9.1
CR
SFPC
A B
LOAD SFPC PUMP DIESEL GENERATOR START PUMPS. ASSIGN SFP HEAT EXCHANGERS TO ECWS
REF. 5,9.1
S.F. (SHORT TERM) (FOR 1/3 OF CORE)
CR
CR
SPENT FUEL HEAT REMOVAL



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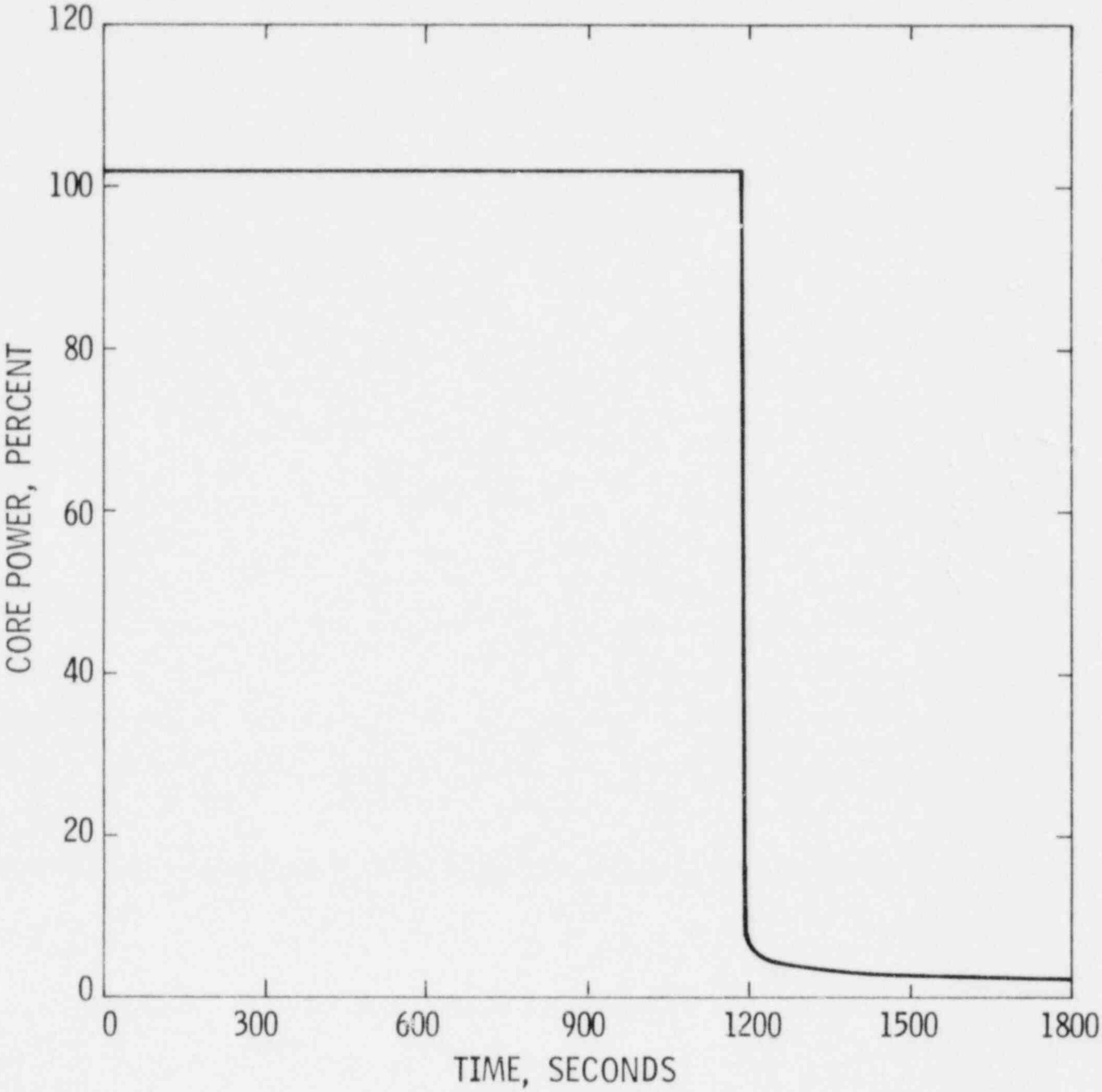
C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER ON REACTOR TRIP	Figure 15.6.3-18D



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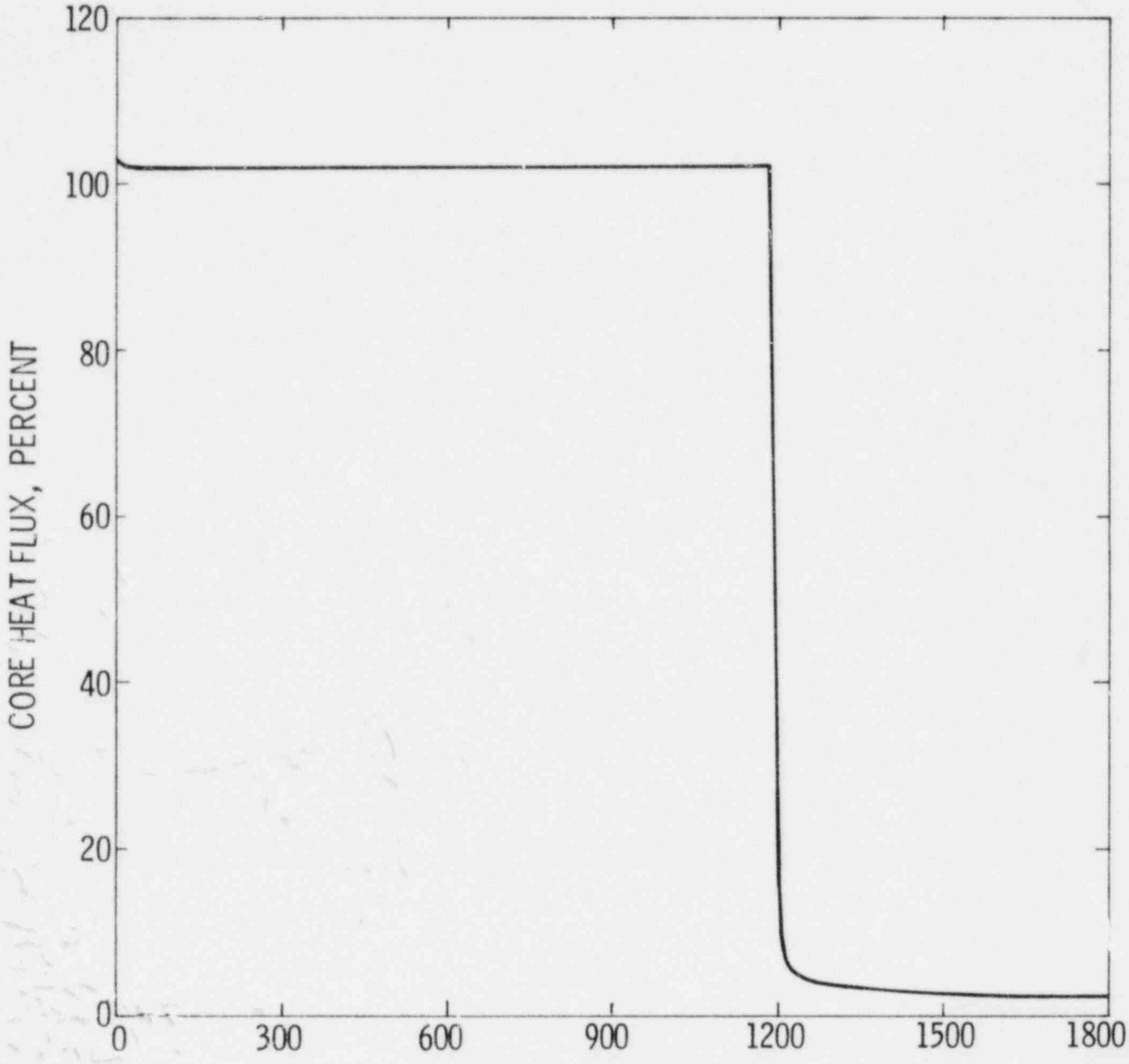
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER CORE POWER vs TIME	Figure 15.6.3-19



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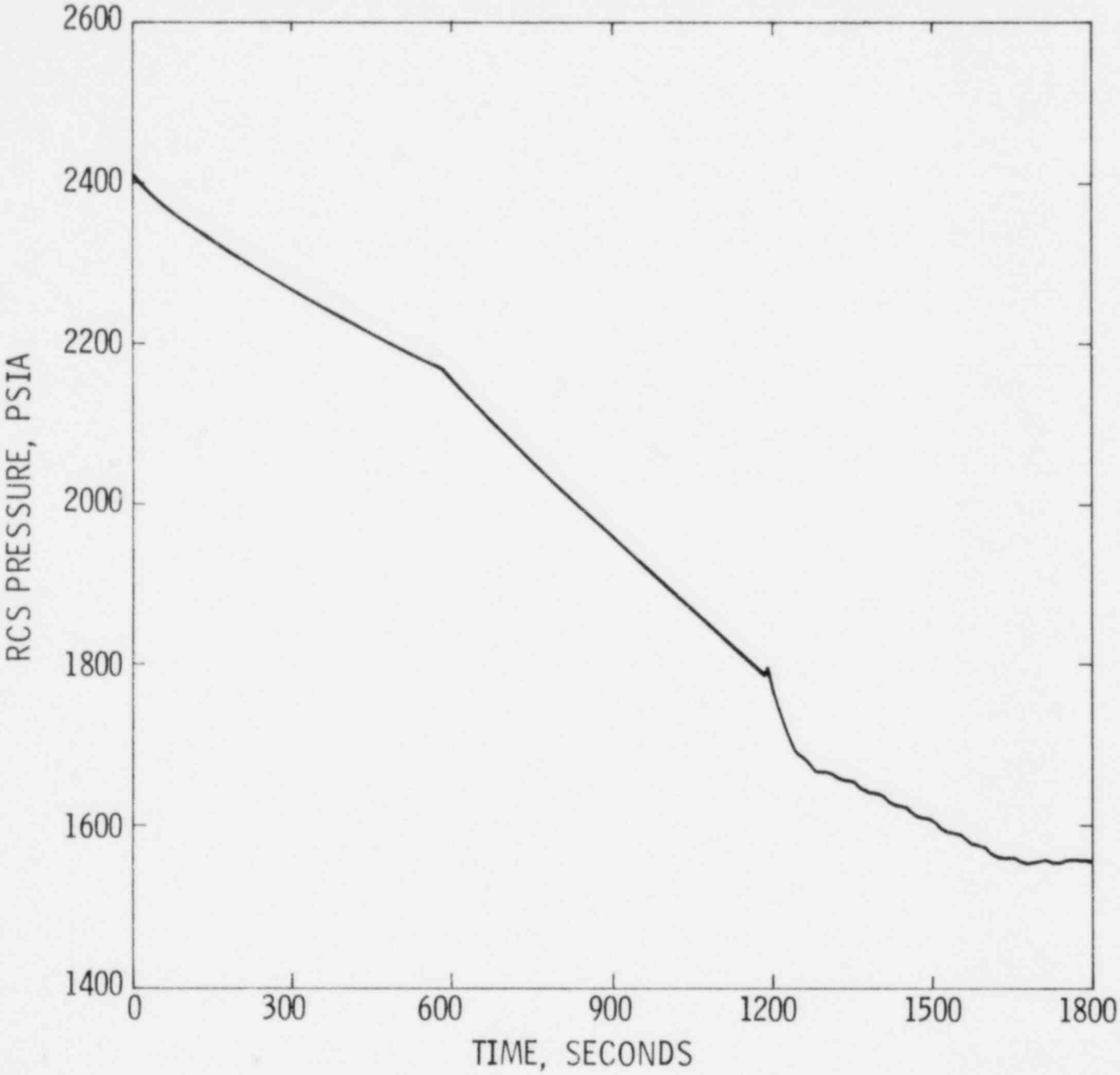
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER CORE HEAT FLUX vs TIME	Figure 15.6.3-20



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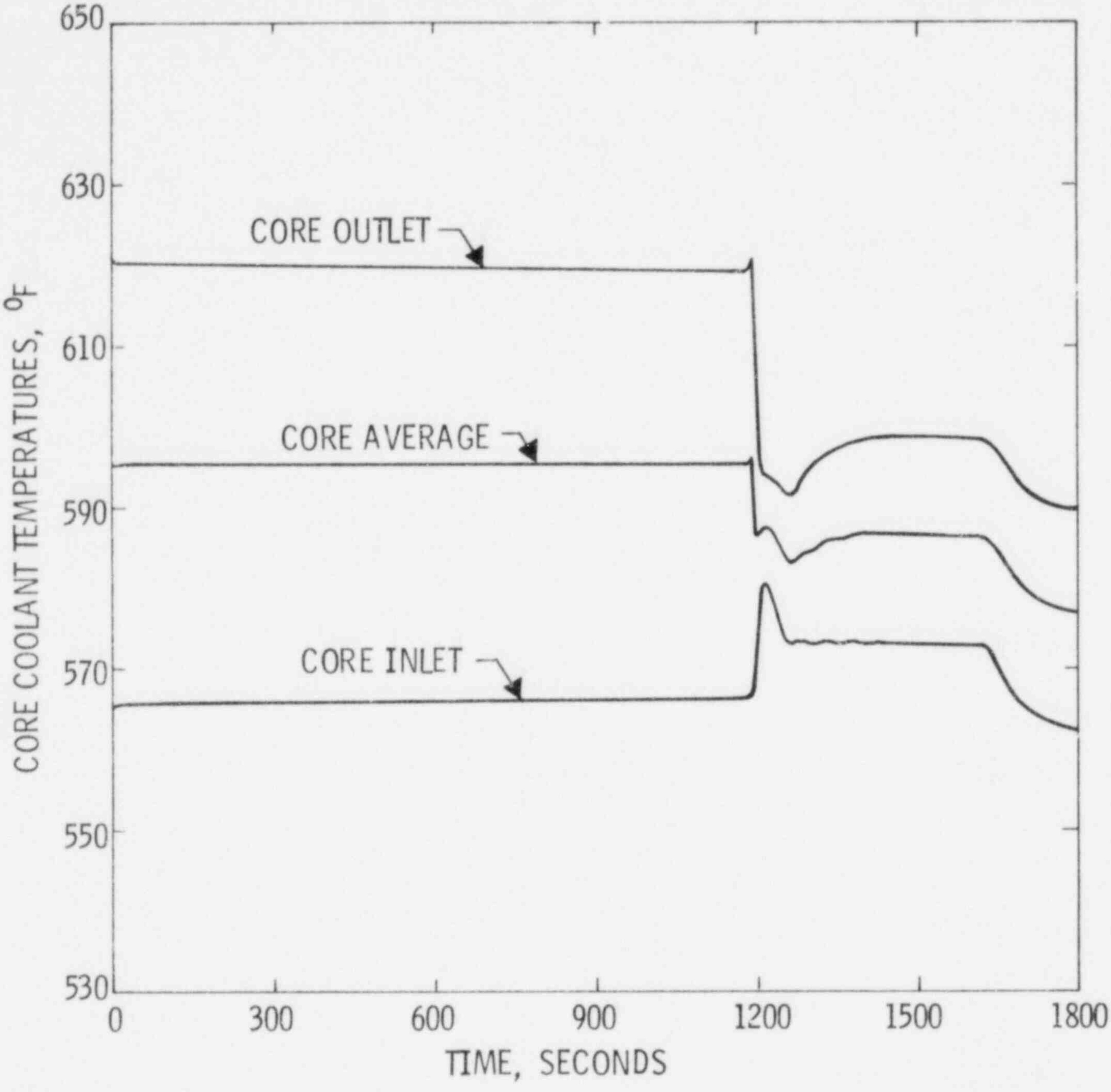
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER RCS PRESSURE vs TIME	Figure 15.6.3-21



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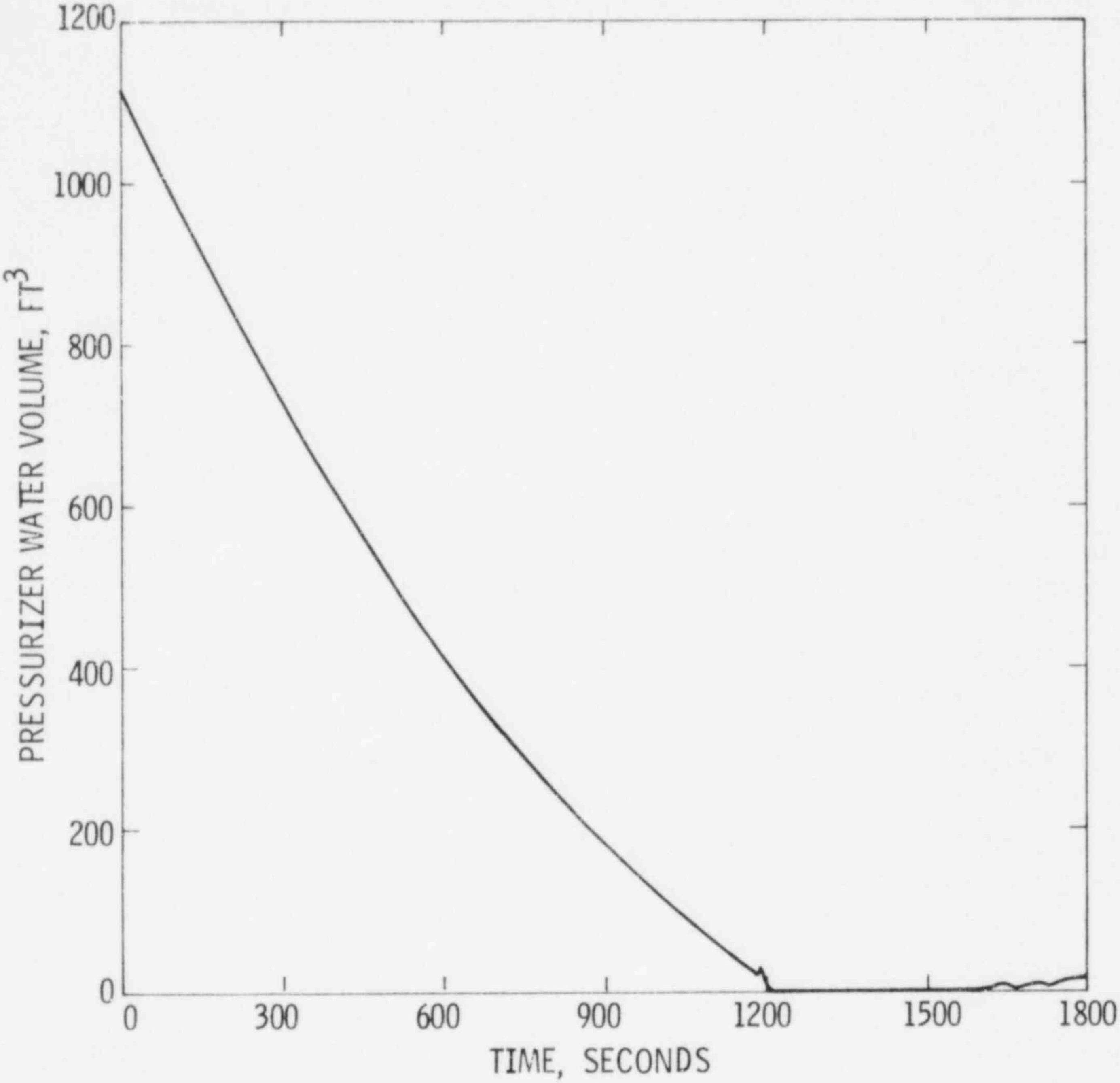
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER CORE COOLANT TEMPERATURES vs TIME	Figure 15.6.3-22



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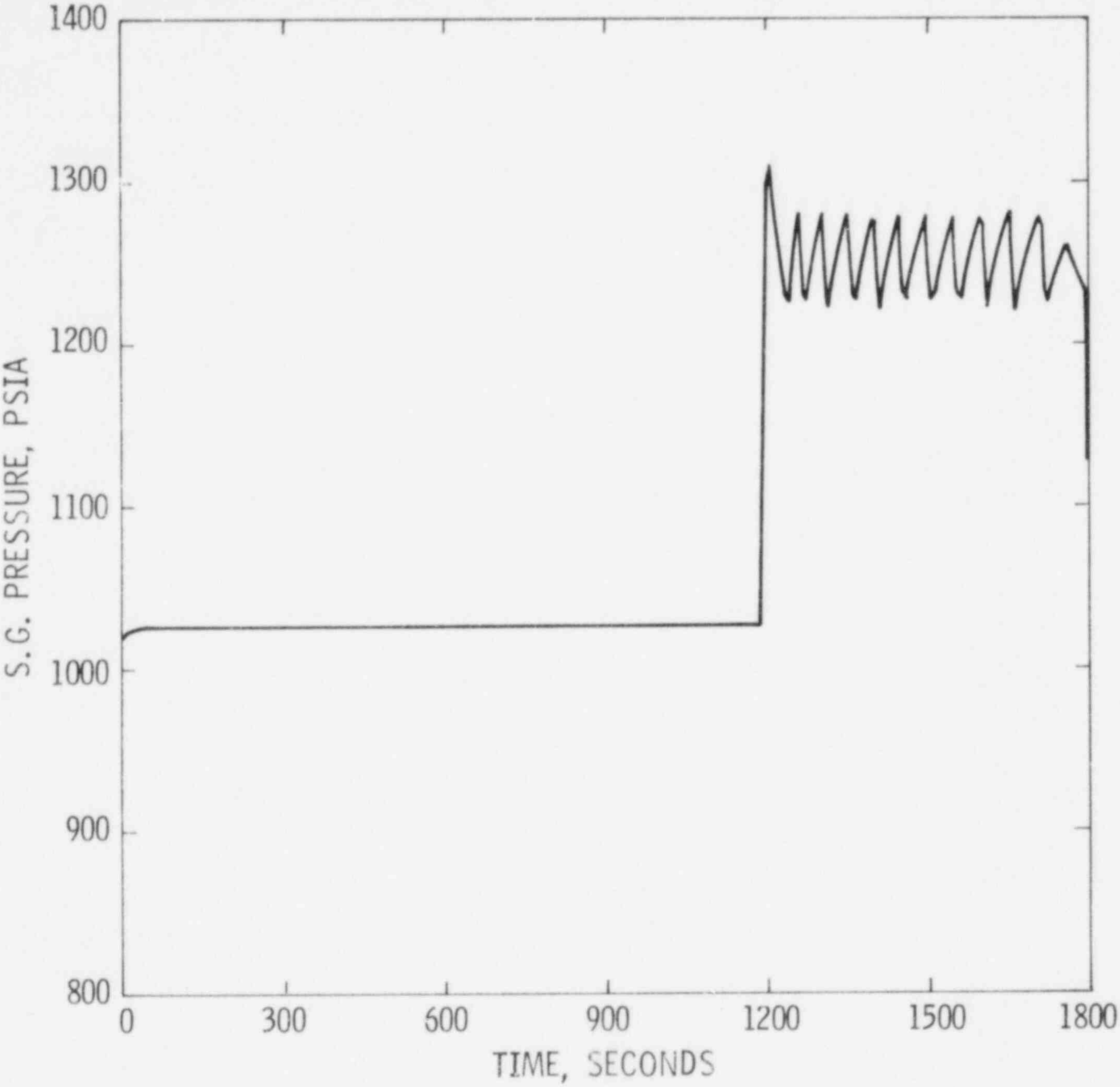
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER PRESSURIZER WATER VOLUME vs TIME	Figure 15.6.3-23



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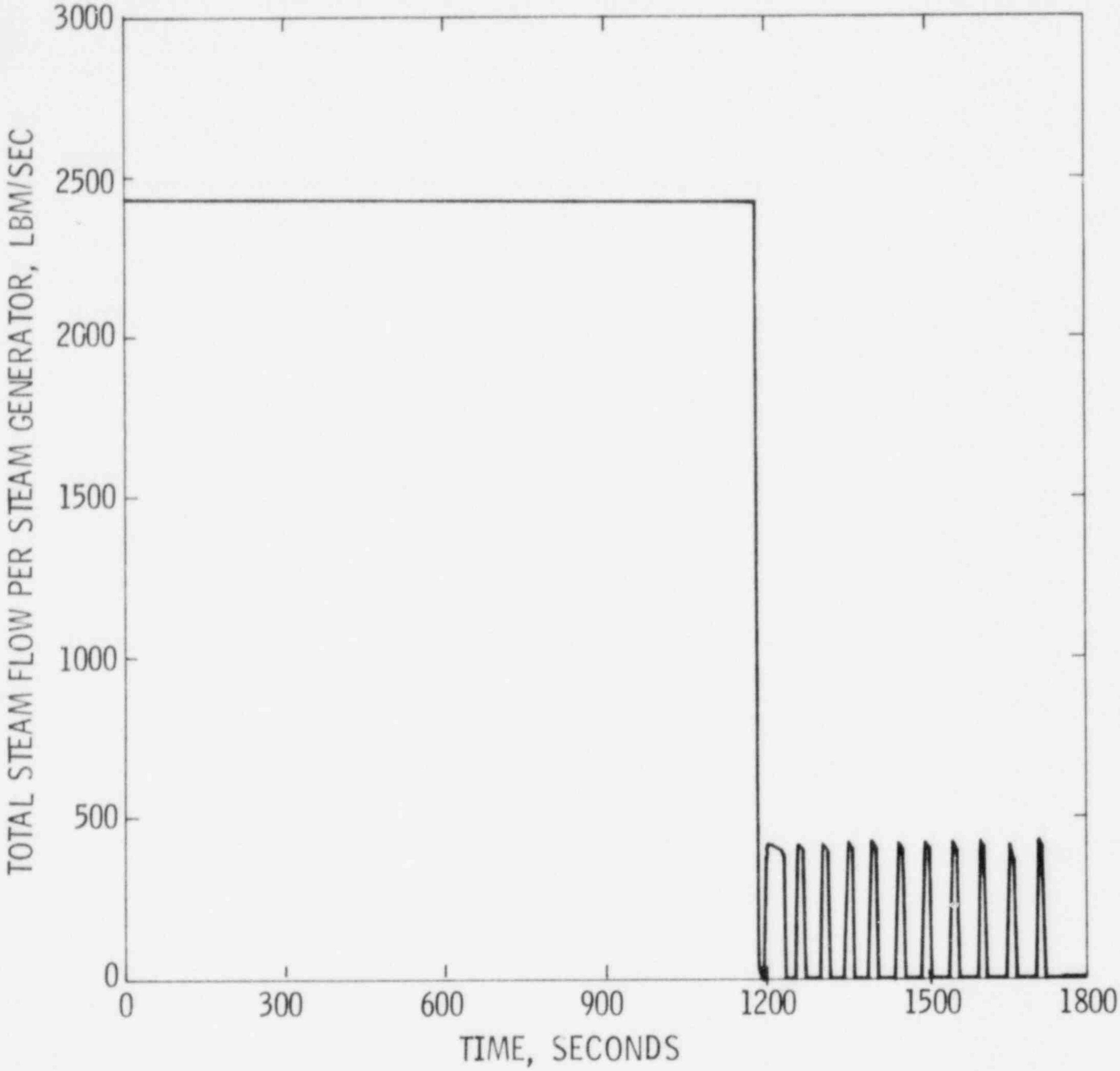
C-E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER STEAM GENERATOR PRESSURE vs TIME	Figure 15.6.3-24



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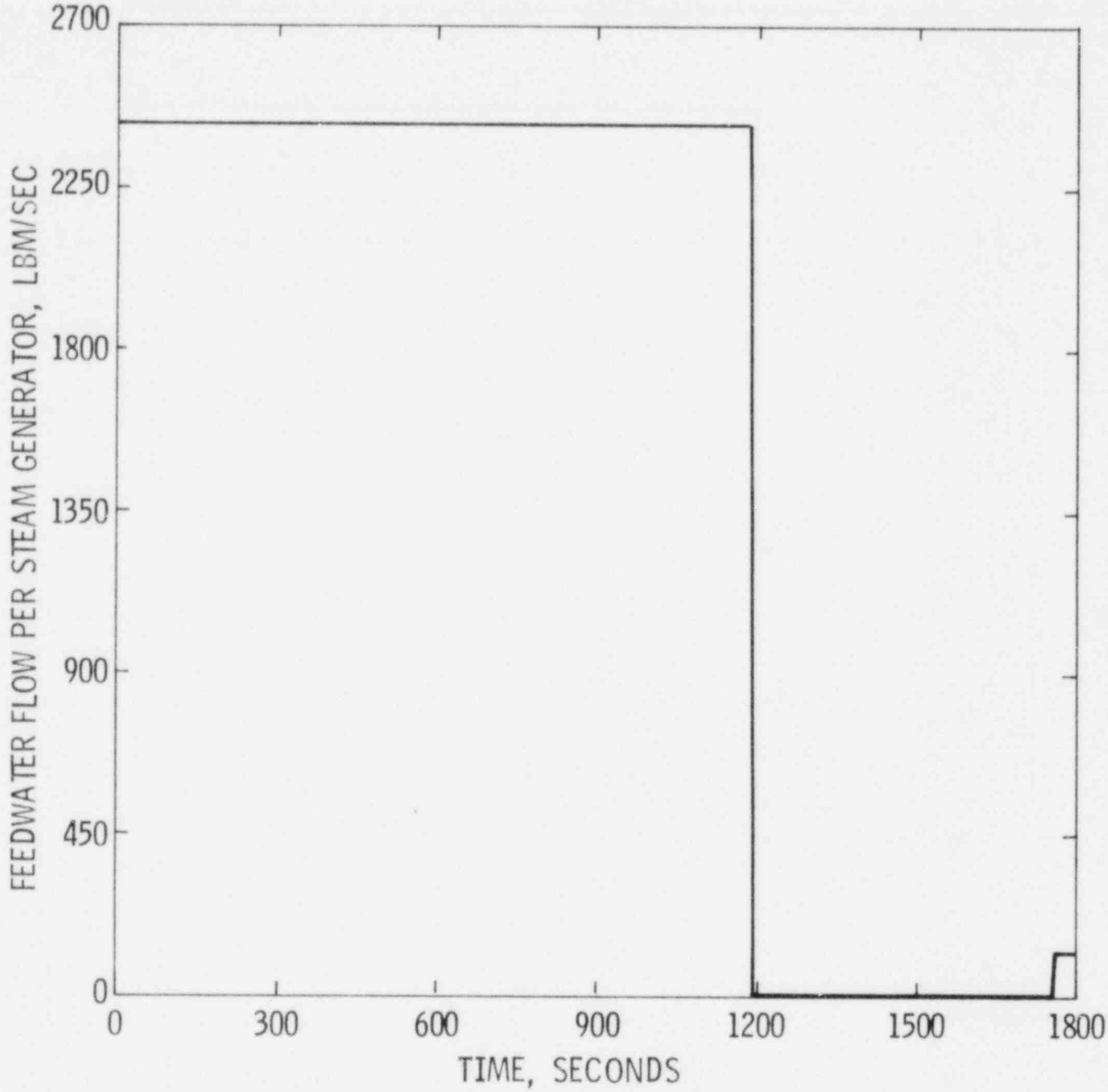
C-E SYSTEM 80

STEAM GENERATOR TUBE RUPTURE
WITH LOSS OF OFFSITE POWER
TOTAL STEAM FLOW PER S.G. vs TIME

Figure 15.6.3-25



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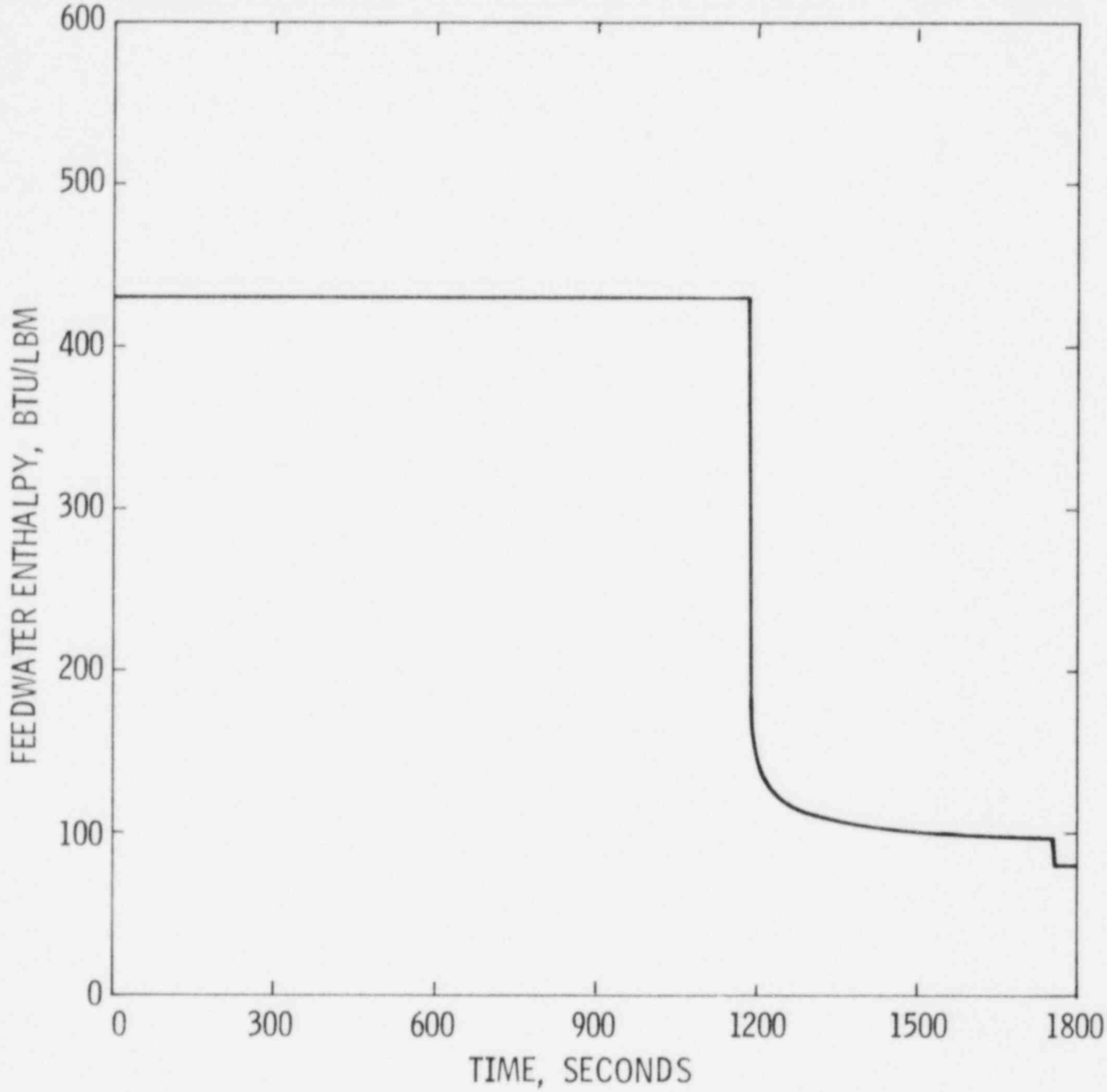
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WILL LOSS OF OFFSITE POWER FEEDWATER FLOW PER S.G. vs TIME	Figure 15.6.3-26



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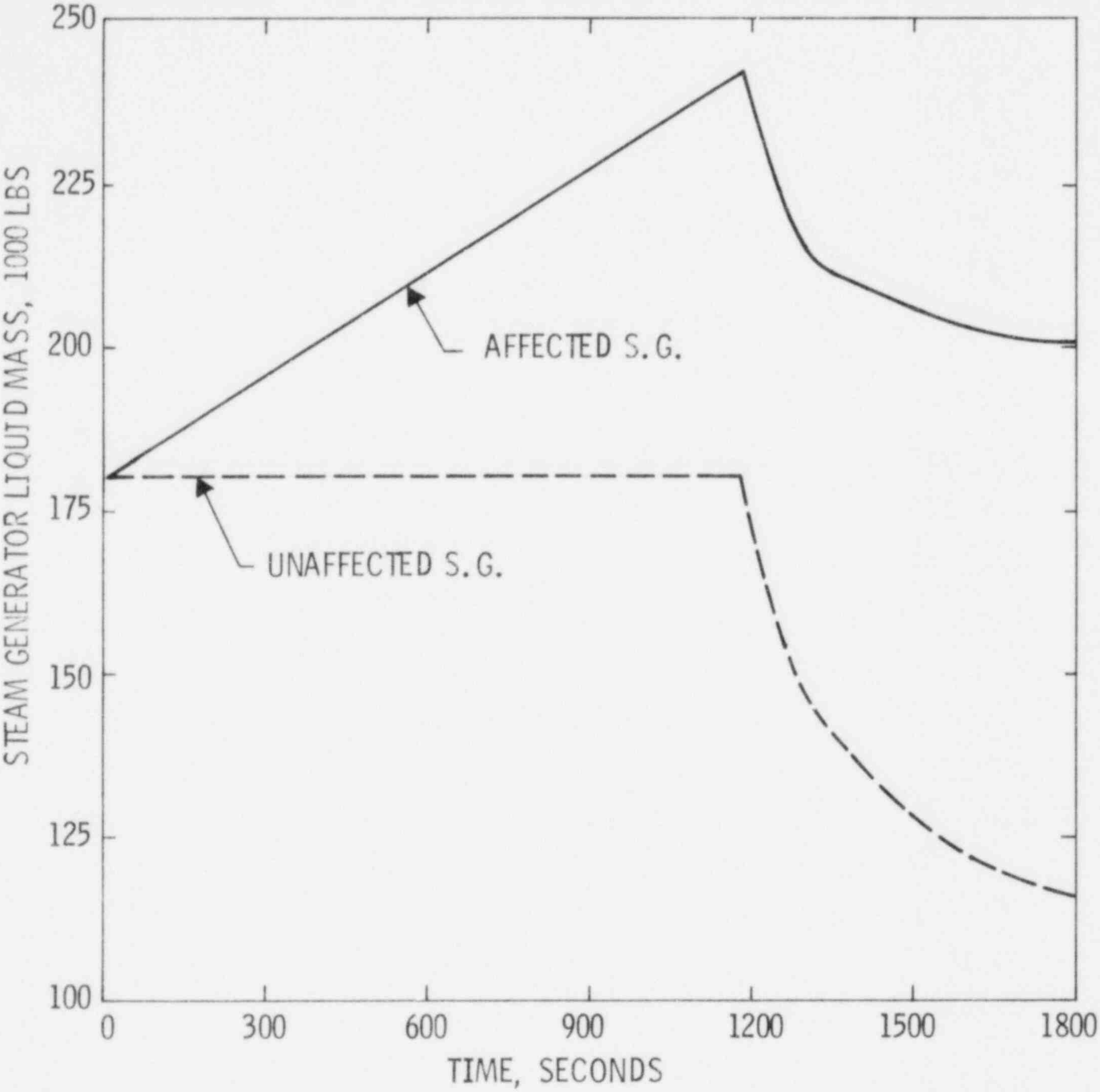
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER FEEDWATER ENTHALPY vs TIME	Figure 15.6.3-27



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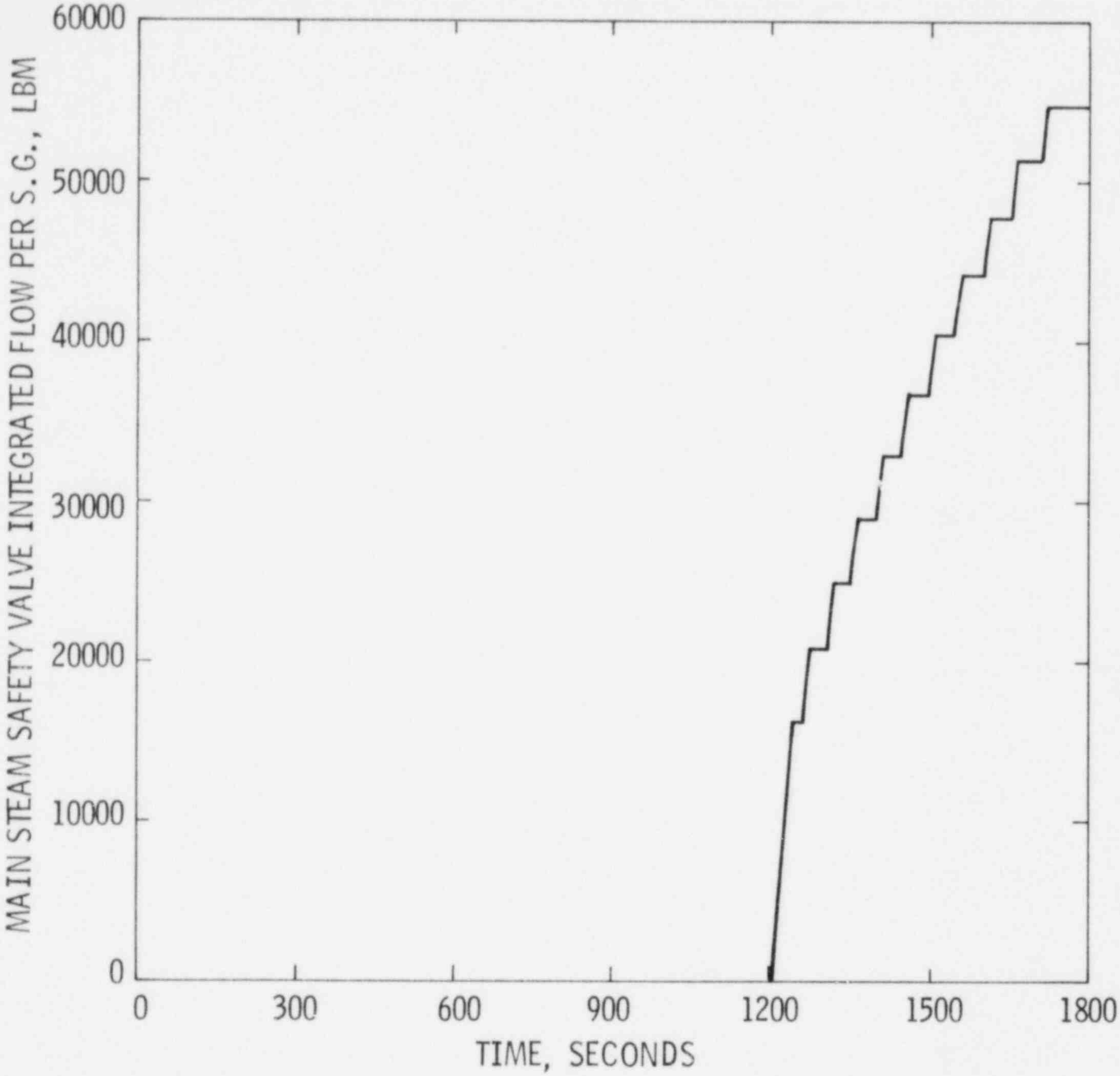
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER S.G. LIQUID MASS vs TIME	Figure 15.6.3-28



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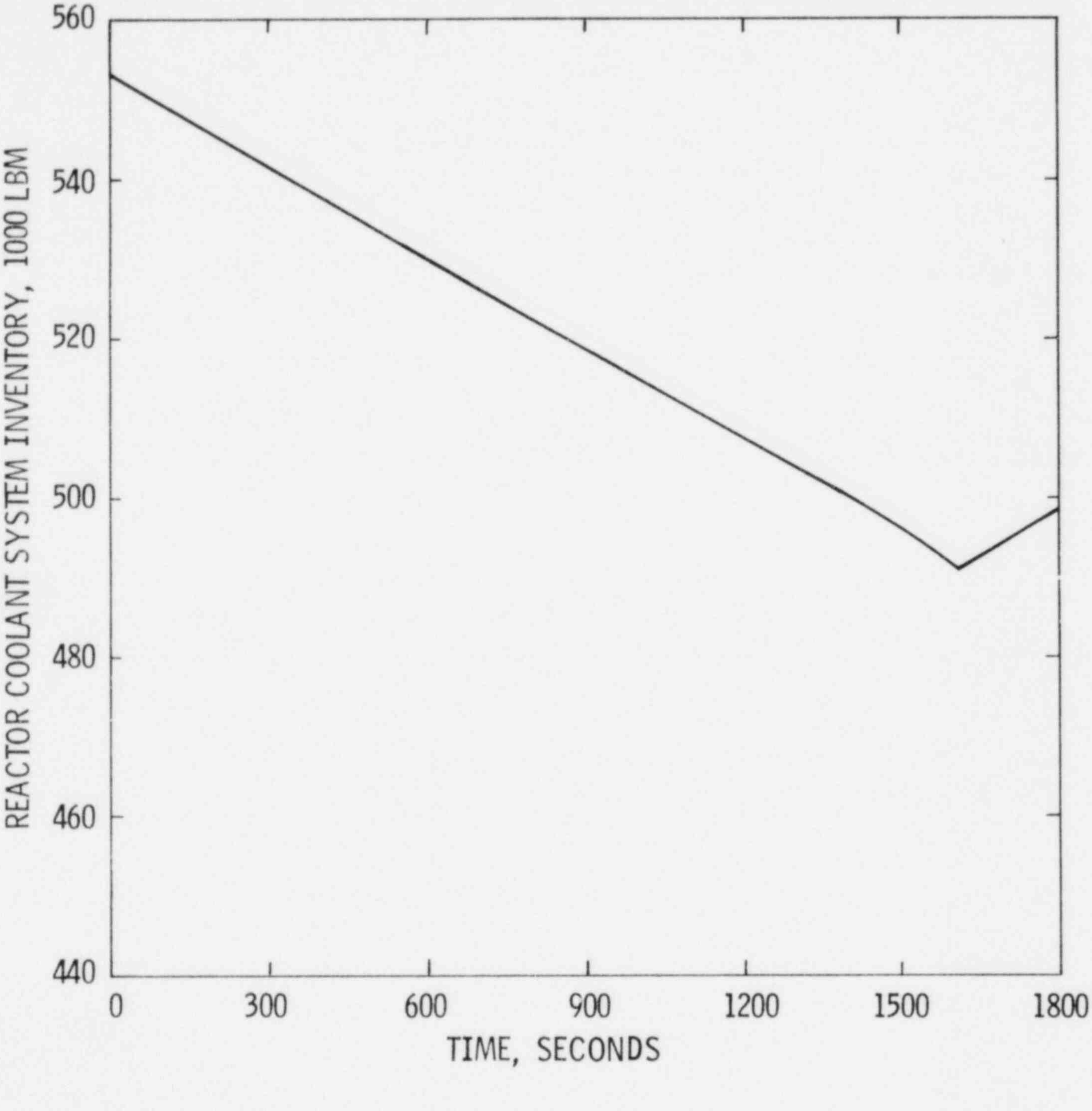
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER MSSV INTEGRATED FLOW PER S.G. vs TIME	Figure 15.6.3-29



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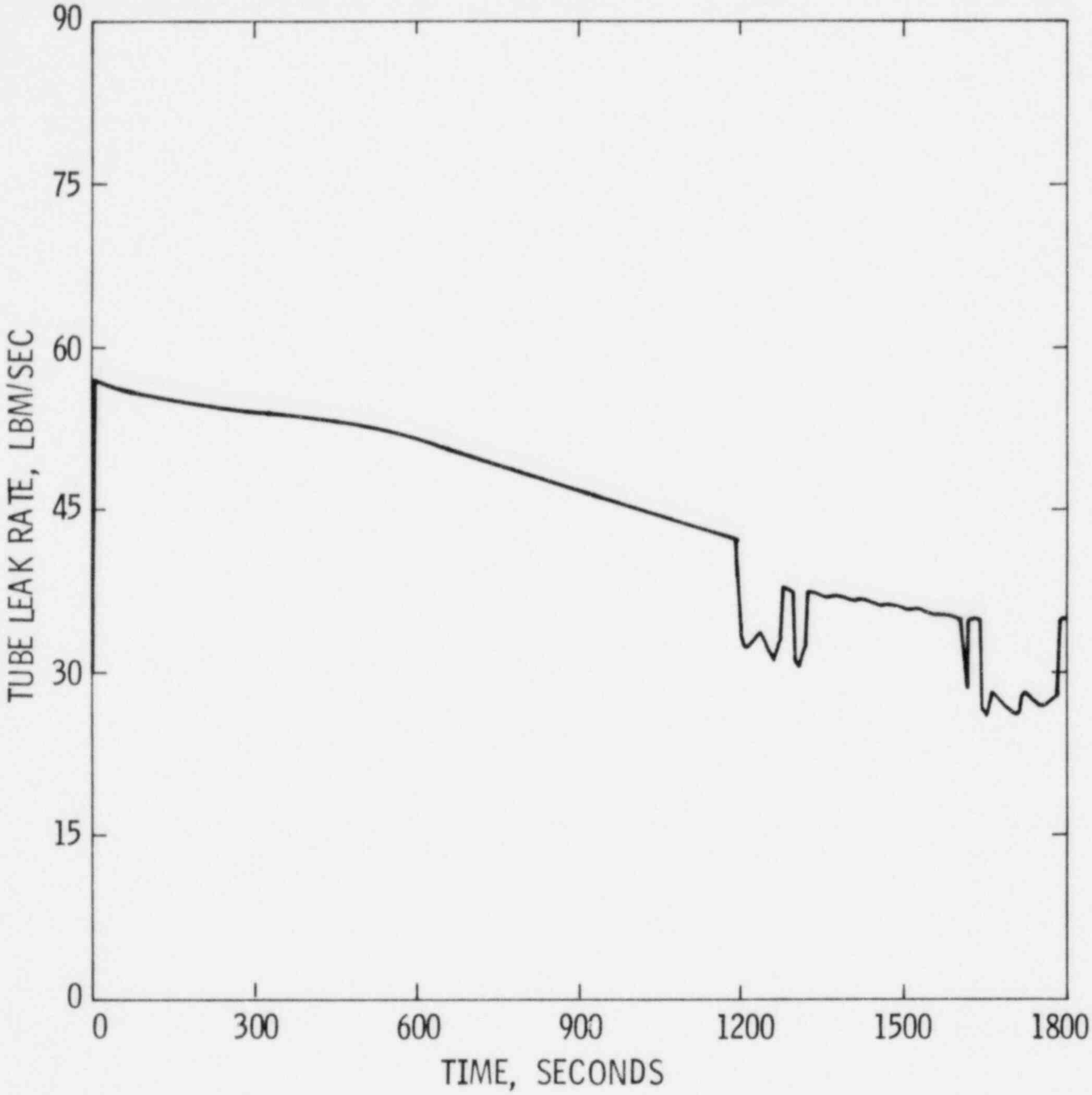
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER REACTOR COOLANT SYSTEM INVENTORY vs TIME	Figure 15.6.3-30



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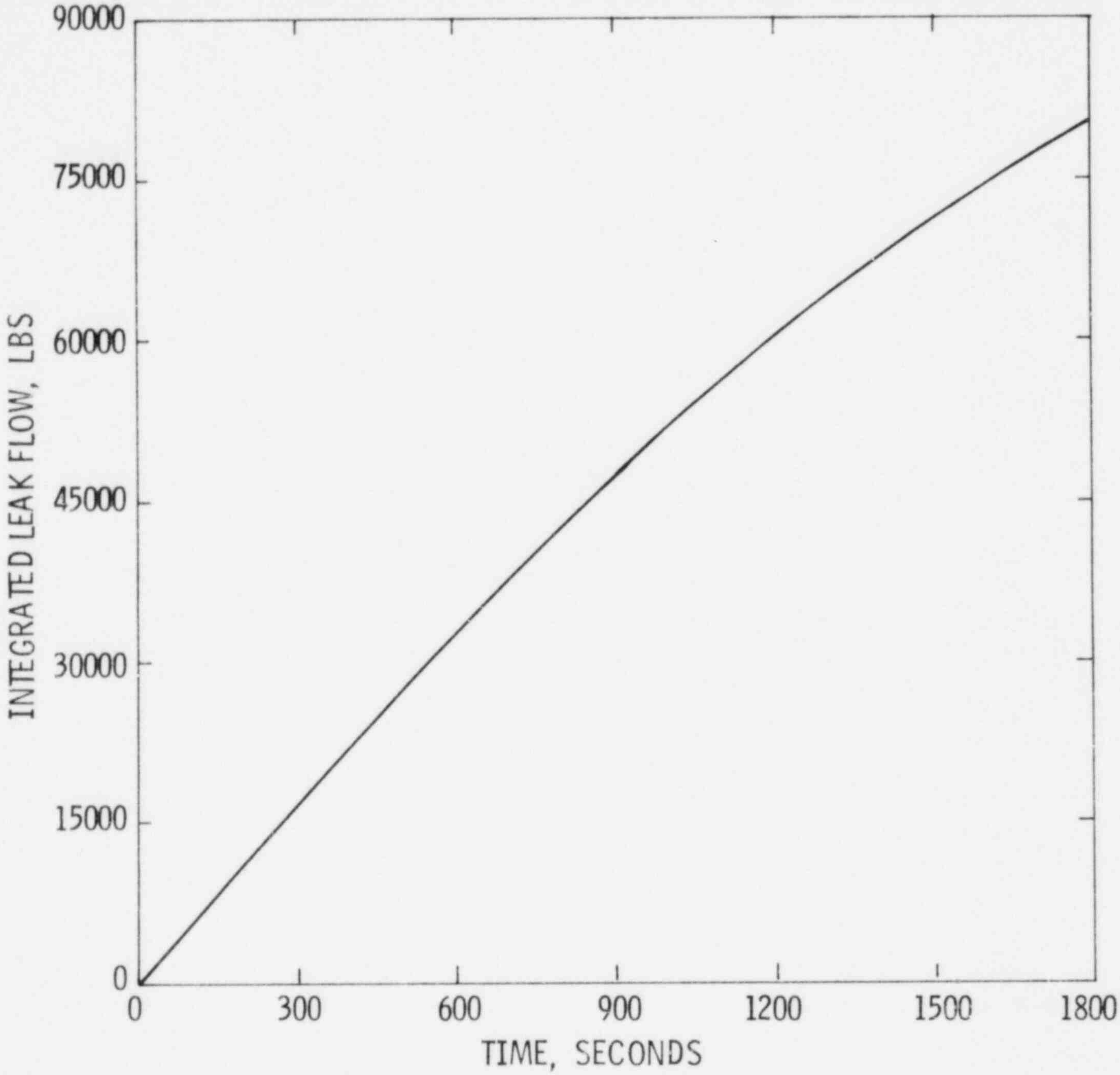
C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER TUBE LEAK RATE vs TIME	Figure 15.6.3-31



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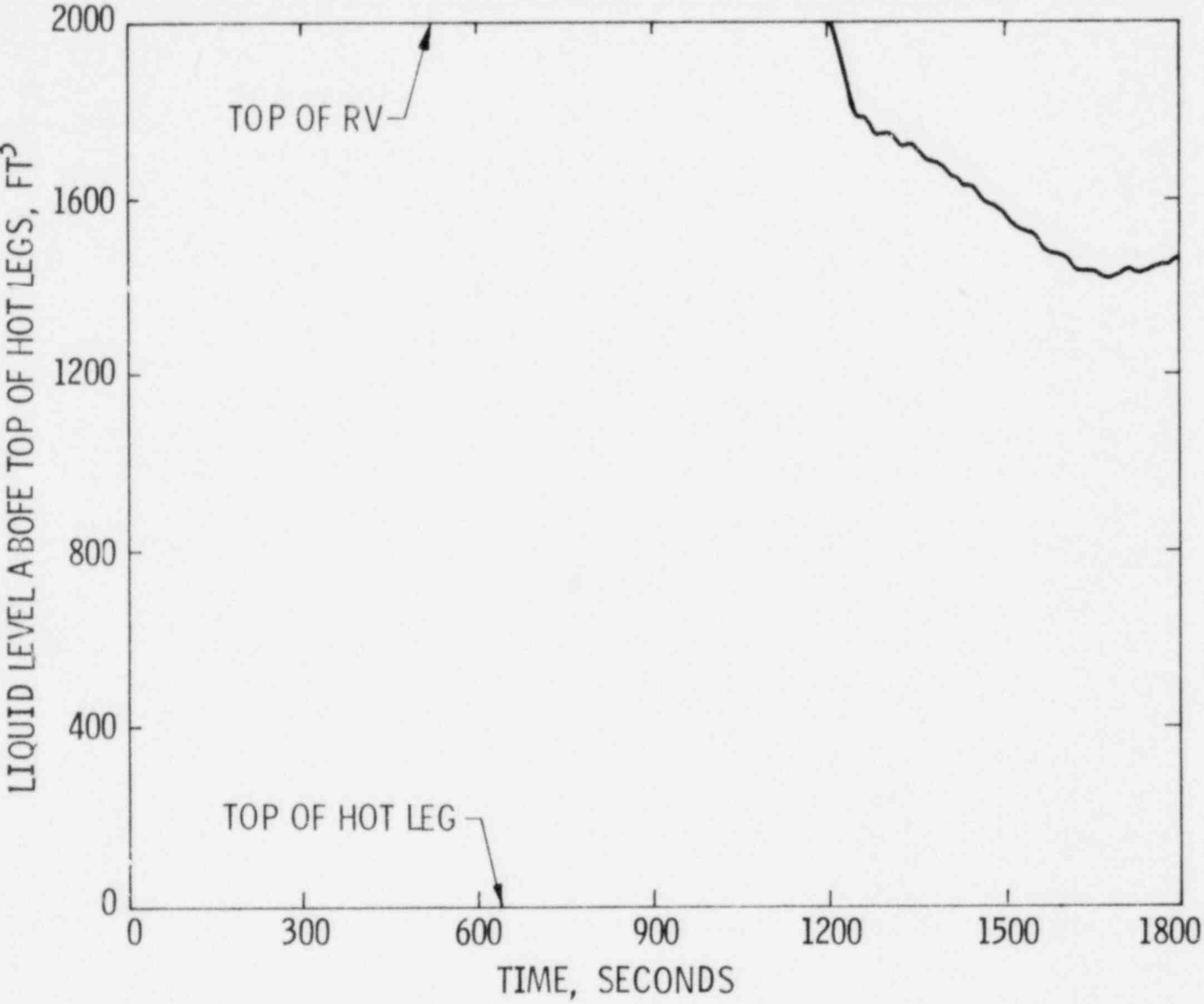
March 31, 1982

C-E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER INTEGRATED TUBE LEAK vs TIME	Figure 15.6.3-32



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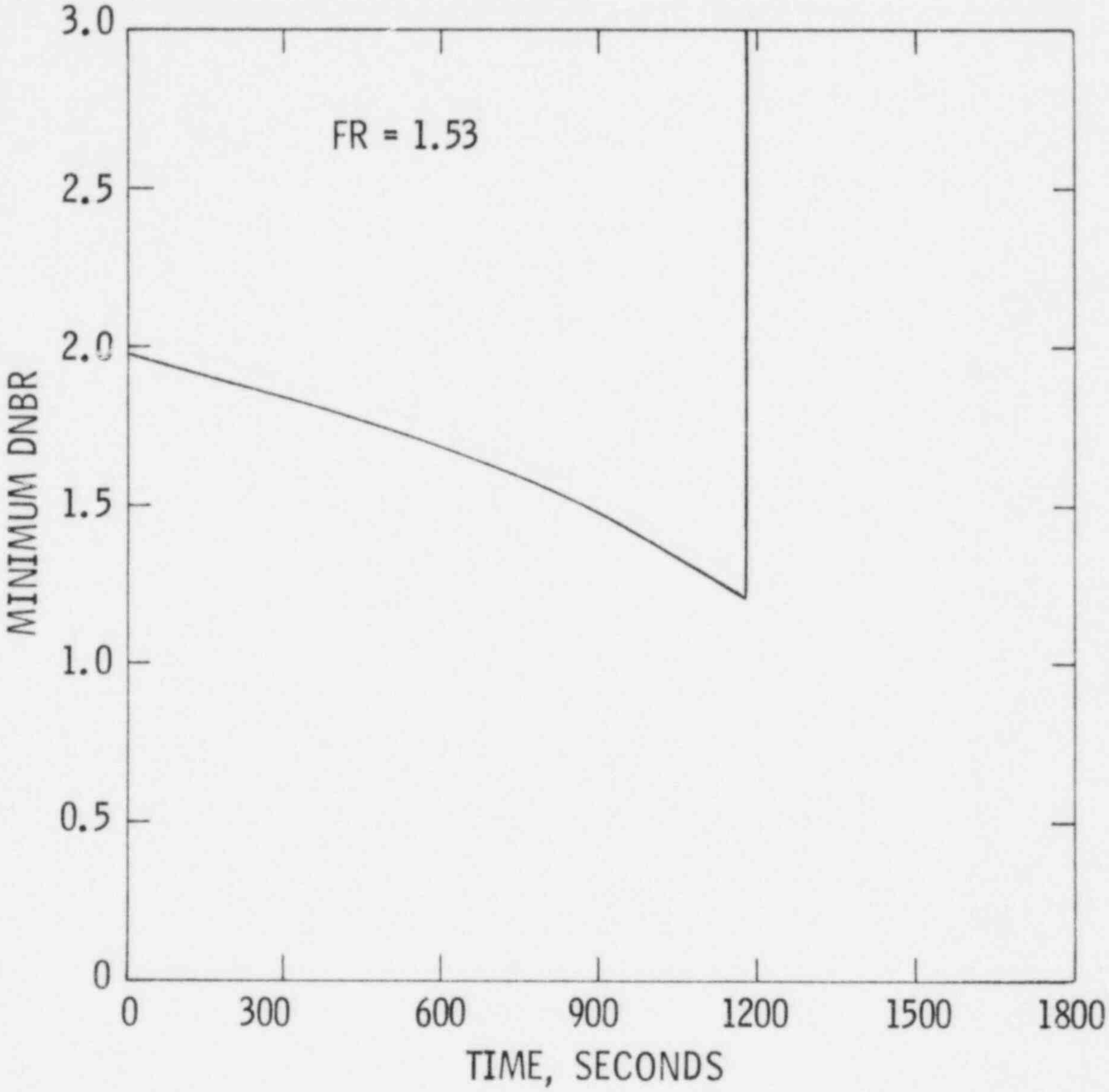
March 31, 1982

C-E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER LIQUID VOLUME ABOVE TOP OF HOT LEGS vs TIME	Figure 15.6.3-33



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C - E SYSTEM 80	STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER MINIMUM DNBR vs TIME	Figure 15.6.3-34

15.6.5 LOSS-OF-COOLANT ACCIDENT (LOCA)

15.6.5.1 Identification of Causes

Regulatory Guide 1.4 describes a design basis Loss of Coolant Accident (LOCA) as one of the hypothetical accidents used to evaluate the adequacy of various plant structures, systems, and components used to protect the public health and safety. Such an evaluation is required in Section 50.34 of 10CFR50 and is the subject of this analysis. LOCA analysis for the purpose of demonstrating the satisfactory performance of the Safety Injection System is given in Section 6.3.3 for a full spectrum of pipe break sizes.

15.6.5.2 Analysis of Events and Consequences

A LOCA is defined as a hypothetical break in a pipe in the reactor coolant pressure boundary resulting in the loss of reactor coolant at a rate in excess of the capability of the coolant makeup system. An immediate release of the core's radioactive inventory to the containment building is assumed. In accordance with the regulatory position of Regulatory Guide 1.4, the following are the fractions of the core's radioactive inventory assumed to be airborne within the containment and available for release by leakage to the environment:

100 percent of the noble gases

25 percent of the iodines

Table 15.6.5-1 gives the maximum total activity of the above isotopes in the containment atmosphere based upon 4200 Mwt core power level.

Results of the analysis of the site boundary doses from the design basis LOCA are to be provided by the Applicant. This analysis may include the reduction in the amount of radioactive material available for leakage to the environment by the Engineered Safety Feature Systems. It is the responsibility of the Applicant to indicate compliance with the offsite dose guidelines of 10CFR Part 100. In addition, due consideration must be given Regulatory Guide 1.4 regarding radionuclide release and dose modeling.

Table 15.6.5-1
System 80 Radioiodine and Noble Gas
Activity Inventory in Containment Atmosphere*

Nuclide	Activity (Curies)
Kr-85	9.36(+5)**
Kr-85m	2.95(+7)
Kr-87	5.41(+7)
Kr-88	7.73(+7)
Xe-131m	8.24(+5)
Xe-133	2.37(+8)
Xe-133m	- - -
Xe-135	4.24(+7)
Xe-135m	4.78(+7)
Xe-138	1.89(+8)
I-131	2.93(+7)
I-132	4.28(+7)
I-133	5.90(+7)
I-134	6.38(+7)
I-135	5.50(+7)

* 100% of the equilibrium noble gas and 25% of the equilibrium iodine in the reactor core.

**Numbers in parentheses denote powers of ten

15.7 RADIOACTIVE MATERIAL RELEASE FROM A SUBSYSTEM OR COMPONENT

15.7.1 WASTE GAS SYSTEM FAILURE
(see Applicant's SAR)

15.7.2 RADIOACTIVE LIQUID WASTE SYSTEM LEAK OR FAILURE
(see Applicant's SAR)

15.7.3 RADIOACTIVE RELEASE DUE TO LIQUID CONTAINING TANK FAILURE
(see Applicant's SAR)

15.7.4 FUEL HANDLING ACCIDENT

15.7.4.1 Identification of Event and Causes

The only event involving C-E scope components and resulting in radioactive release from a subsystem or component which was considered was the Fuel Handling Accident. The Fuel Handling Accident that is considered resulted from the dropping of a single fuel assembly during fuel handling. Interlocks and procedural and administrative controls involved in fuel handling are described in Section 9.1.4.

15.7.4.2 Sequence of Events and Systems Operation

All systems required to produce the safety functions necessary to mitigate the consequences of the Fuel Handling Accident are outside the CESSAR scope.

15.7.4.3 Analysis of Effects and Consequences

A. Mathematical Model

If a dropped assembly were damaged to the extent that one or more fuel rods were broken, the accumulated fission gases and iodines in the fuel rod gaps would be released to the surrounding water. Release of the solid fission products in the fuel would be negligible because of the low fuel temperature during refueling.

The fuel assemblies are stored within the spent fuel rack at the bottom of the spent fuel pool. The top of the rack extends above the tops of the stored fuel assemblies. A dropped fuel assembly could not strike more than one fuel assembly in the storage rack. Impact could occur only between the ends of the involved fuel assemblies, the lower end fitting of the dropped fuel assembly impacting against the upper end fitting of the stored fuel assembly. Analytical methods used to calculate the impact velocity and the resulting impact stress in the fuel rod cladding for the vertical drop are described below.

The analysis of the fuel assembly vertical drop employed a summation of the forces acting on the fuel assembly in the vertical direction to determine the equation of motion of the fuel assembly. The resulting equation of motion is given below:

$$F_{vert} = M \times a = F_D + F_B - F_W$$

where:

M = mass of a fuel assembly
a = acceleration
F_D = drag force of a fuel assembly [Drag Coeff. x (velocity)^2]
F_B = bouyant force of a fuel assembly
F_W = Weight (dry) of a fuel assembly

The analysis assumed the fuel assembly drop distance was sufficient for the fuel assembly to reach its terminal velocity (acceleration equals zero in the above equation), thus making the results conservative or applicable for any drop height. For this worst case, the terminal velocity, and therefore the assumed impact velocity of the fuel assembly, is 254.4 inches/second, and the resulting stress in the fuel rod cladding is 24,000 psi.

The equation employed in calculating the above impact stress in the fuel rod clad is as follows:

$$\sigma_I = V_I \quad E \times \rho$$

where:

σ = impact stress
V_I = impact velocity
E_I = modulus of elasticity
P = mass density

The yield stress of the fuel rod cladding is 49,000 psi. This is the minimum yield stress value for unirradiated Zircaloy-4 and is conservative for irradiated fuel. Thus, for the fuel assembly vertical drop, the impact stresses which result from absorbing the kinetic energy of the drop are below the yield stress of the clad and no fuel rod failures will occur.

Horizontal impact of a fuel assembly could result from a dropped fuel assembly falling in the horizontal position, or from a vertical fuel assembly rotating to the horizontal position. As in the vertical drop described above, worst case assumptions are made for the horizontal impact velocity (based on the terminal velocity) and the rotational impact velocity (based on an initial angular velocity of 5 radians/second). The worst case bundle impact results from the horizontal drop since the kinetic energy at impact is greater for the horizontal drop than for the rotational impact (3629 ft-lbs versus 2375 ft-lbs, respectively). During this horizontal drop, it is postulated that the assembly strikes a protruding structure. For this analysis, a localized loading of one grid span has been assumed.

An analysis of the fuel assembly drop has revealed that the most severe impact location is between the top two spacer grids since that impact area is within the fuel rod upper plenum region and the fuel pellets do not provide support for the cladding. To obtain an estimate of the number of fuel rods which might fail, the fuel assembly's grid span was modeled and calculations performed to relate the assembly's kinetic energy at impact to the resulting strain energy in the fuel rods and guide tubes.

B. Input Parameters and Initial Conditions

Input data to the analysis that described material properties and pool conditions were kept consistent with the circumstances of the event (i.e., irradiated fuel assembly material properties, water, and fuel rod cladding temperatures corresponding to spent fuel pool conditions). As a result of the fuel assembly drop, no more than four rows of fuel rods (60 rods) would fail due to the strain resulting from the fuel rods and guide tubes absorbing the bundle's kinetic energy at impact. Fuel rod cladding failure was assumed to occur if the maximum clad strain reached the ultimate strain of irradiated Zircaloy. The use of irradiated fuel rod properties for the horizontal impact is conservative because of the greater energy absorbing capability of unirradiated Zircaloy. The earliest anticipated time at which a spent fuel assembly would be handled is 3 days after shutdown.

C. Results

Assumptions and parameters used in evaluating the fuel handling accident are listed in Table 15.7. The radioactive inventory of the 60 fuel rods was obtained by multiplying the activity of the most radioactive fuel rod 72 hours after shutdown by a factor of 60. The calculational methods and assumptions described in Regulatory Guide 1.25 apply since: (1) the values for maximum fuel rod pressurization, (2) peak linear power density for the highest power assembly discharge, (3) maximum enterline operating fuel temperature for the assembly in item (2) above are less than the corresponding values in Regulatory Guide 1.25.

As described in the above presentation, the failure of all 236 fuel rods in one spent fuel assembly is not credible. However, the evaluation of the failure of all fuel rods in a fuel assembly (236 fuel rods) can be performed to demonstrate consistence with the recommendations of Regulatory Guide 1.13. This evaluation would be identical to the design basis accident with the exception that the radioactivity would be obtained by multiplying the activity of the most radioactive fuel rod 72 hours after shutdown by a factor of 236. In addition, a radial peaking factor of 1.65 can be used in place of the realistic assumption of 1.55 in order to demonstrate the consistency with the recommendations of Regulatory Guide 1.25.

15.7.4.4 Conclusion

The exclusion area boundary dose resulting from the fuel assembly drop event will be determined by the applicant.

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Table 15.7.4-1

PARAMETERS USED IN EVALUATING THE RADIOLOGICAL CONSEQUENCES OF A FUEL HANDLING ACCIDENT

Parameter	Design Basis Assumptions	Regulatory Guide 1.25 Assumptions
Source Data:		
Radial peaking factor	1.55	1.65
Burnup	3 full-power years at 80% plant factor	3 full power years at 80% plant factor
Decay time, hr.	72	72
Number of failed rods	60	236
Fraction of fission product gases contained in the gap region of fuel rods, %		
Kr-85	30	30
Other Noble Gases	10	10
Iodine	10	10
Activity Release Data:		
Percentage of gap activity released to pool	100	100
Activity released to fuel pool, Isotope	60 rods	236 rods
I-129	2.19×10^{-3}	9.95×10^{-3}
I-131	1.44×10^{4}	6.55×10^{4}
Xe-131m	1.17×10^{2}	5.34×10^{2}
Xe-133	2.91×10^{4}	1.32×10^{5}
KR-85	5.67×10^{2}	2.58×10^{3}

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APPENDIX 15A

LOSS OF PRIMARY COOLANT FLOW METHODOLOGY DESCRIPTION

15A.1 INTRODUCTION

This appendix describes the analytical methods used to determine the NSSS response to a loss of primary coolant flow (LOF) which could occur as a result of a loss of electrical power to the four reactor coolant pumps. This method, referred to hereafter as the Space-Time Kinetics LOF (ST-LOF) method, is used to support the conclusions and results in Section 15.3.1. A sample analysis of the four pump LOF using the ST-LOF method is provided in Section 15A.4.

The computer codes used in the ST-LOF method are; COAST, CESEC II, HERMITE and TORC. These codes are described in topical reports which are referenced in Section 15.0. The principal time dependent parameters calculated are the primary coolant flow rate, reactor core power, hot bundle heat flux and limiting channel Departure from Nucleate Boiling Ratio (DNBR).

15A.2 COMPUTER CODES

15A.2.1 Data Transfer

Given the postulated initiating event the COAST code is used to compute the core inlet volumetric flow rate as a function of time. This data is input to the CESEC code which is used to predict the overall system response. CESEC calculates Plant Protection System responses and valve actuations for assessing the long term consequences of the LOF. CESEC also computes the time dependent core inlet mass flux, core inlet coolant temperature and reactor coolant system pressure (however no credit is taken for pressure increases in computing the DNBR transient) which can be used for input to HERMITE. For those cases where a reactor trip occurs so rapidly that only the coolant flow rate changes, CESEC is bypassed and the flow coastdown is input directly to HERMITE.

HERMITE is used to predict the reactor core response during a LOF. HERMITE calculates the transient core power, core average heat flux and hot bundle heat flux. The time dependent core average and hot bundle heat fluxes along with the core inlet coolant mass flux, core inlet coolant temperature and reactor coolant system pressure are input to the TORC computer code. TORC computes the core average and limiting channel coolant conditions and the limiting channel DNBR. Figure 15A-1. depicts the transfer of data between the computer codes.

15A.2.2 COAST

The COAST code is used in the same manner as described in CENPD-183 (Section 15.0 Reference 20). COAST analyzes reactor coolant flow under any combination of active and inactive pumps in a two-loop four pump plant. The equation of conservation of momentum is written for each of the flow paths of the

COAST model assuming unsteady one-diminsional flow of an incompressible fluid. The equation of conservation of mass is written for the appropriate nodal points. Pressure losses due to friction, bends and shock losses are assumed proportional to the flow velocity squared. Pump dynamics are modelled using a head-flow curve for a pump at full speed and using four quadrant curves, which are parametric diagrams of pump head and torque on coordinates of speed versus flow, for a pump at other than full speed.

The COAST code has been verified by measurements of the flow coastdown at the Palisades plant. Additionally, the plant specific coastdown is measured and compared with the predicted values during the initial startup test program for each plant to verify that the coastdown used in the analysis is conservative. A further description of COAST is contained in CENPD-98 (Section 15.0 Reference 13).

15A.2.3 CESEC II

The CESEC II code is used to determine the long term response of the NSSS to primary coolant flow reductions resulting from postulated LOF events. Also, CESEC II may be used to predict the change in core inlet coolant temperature if this parameter changes before the time of minimum DNBR.

CESEC II computes key system parameters during a transient including core heat flux, pressures, temperatures, and valve actions. A partial list of the dynamic functions included in this NSSS simulation includes: point kinetics neutron behavior, Doppler and moderator reactivity feedback, boron and CEA reactivity effects, multi-node average channel reactor core thermal hydraulics, reactor coolant pressurization and mass transport, reactor coolant system safety valve behavior, steam generation, steam generator water level, main steam bypass, secondary safety and turbine valve behavior, as well as alarm, control, protection, and engineered safety feature system actions. The steam turbine and its associated controls are not included in the simulation. Steam generator feedwater enthalpy and flow rate are provided as input to CESEC II. For a further description of CESEC II see Section 15.0.

15A.2.4 HERMITE

One application of the HERMITE code is to determine the reactor core response during postulated LOF events. HERMITE can accept as input the transient boundary conditions of: coolant flow rate, inlet coolant temperature, reactor coolant system pressure and CEA position. In this application, HERMITE solves the few-group, space and time dependent neutron diffusion equation including feedback effects of fuel temperature, coolant temperature, coolant density and control rod motion for a one-dimensional average fuel bundle. The fuel temperature model explicitly represents the pellet, gap, and clad regions of an average fuel pin and representative hot bundle fuel pin. The hot bundle fuel pin power density is related to the average fuel pin power density by time dependent planar radial power peaking factors, which are discussed in more detail below. For the calculation of heat flux, heat conduction equations are solved by a finite difference method. Continuity and energy conservation equations are solved in order to determine the coolant temperature and density for the average and hot bundles. A further description of HERMITE is contained in CENPD-188-A.

The hot bundle fuel pin power density is equal to the core average fuel pin power density multiplied by the planar radial power peaking factor, $F_r(z)$. For times prior to the insertion of CEA's and for regions of the core that the CEA's have not penetrated, the $F_r(z)$ is equal to a conservativly chosen initial value. As the CEA's pass a plane of the core, the radial power peaking factor of that plane is increased as a function of time from the initial value to a final maximum value. This final maximum value of $F_r(z)$ has been at least a factor of 5 greater than that predicted by 2-D transient HERMITE calculations assuming the worst stuck CEA, over the time of interest. The radial peaking factor representation leads to the non-physical, but conservative, result that the local hot channel power density rises as the CEA's pass each plane.

The synthesis of the axial power distribution and the planar radial power peaking factors provides a conservative representation of the hottest fuel assembly during the LOF transient including maximum 3-D power peaking effects. This technique yields a conservative prediction of the minimum DNBR which can occur as a result of the LOF transient.

15A.2.5 TORC

The TORC code is used to calculate the limiting channel DNBR transient. TORC receives the core average fuel bundle heat flux, hot bundle heat flux, core inlet coolant mass flux, core inlet coolant temperature, and reactor coolant system pressure at selected times during the LOF transient. The code is used to perform static calculations of the axial coolant enthalpy distribution and DNBR at these times. No credit is taken for reactor coolant system pressure increases in calculating the DNBR. TORC solves the conservation of mass, energy and momentum equations for a 3-dimensional representation of the open-lattice core to determine the local coolant conditions at points in the core average fuel bundle and hot fuel bundle. Lateral transfer of mass, momentum and energy between neighboring flow channels (open-core effects) are accounted for in the calculations of local coolant conditions. These coolant conditions and the HERMITE calculated hot bundle heat flux are then used with the CE-1 critical heat flux correlation to compute the minimum DNBR value. A further description of TORC is contained in CENPD-161-P and CENPD-206-P.

15A.3 COMPARISON WITH PREVIOUS METHODS

CENPD-183, Appendix A describes the methodology used to predict the consequences of postulated LOF events for many previous Combustion Engineering NSSS designs. This section summarizes the fundamental differences between the ST-LOF method and that described in CENPD-183.

The primary difference between these methods is in the calculation of the core power. The CENPD-183 method uses the QUIX code to compute reactivity as a function of CEA position assuming the neutron flux and delayed neutron precursors are in equilibrium. Combining CEA position versus time data with the reactivity versus CEA position data produces the time dependent reactivity function which is input to the CESEC point kinetics equations.

The ST-LOF method uses HERMITE to calculate core power directly from CEA position versus time. HERMITE calculates the time dependent neutron flux in one dimension (axial) with the few group diffusion equation explicitly accounting for fission, absorption and transport cross section variations.

Other differences exist in the calculation of the hot channel heat flux. In the CENPD-183 methodology, it is assumed that the hot channel normalized heat flux decay is equivalent to the core average normalized heat flux decay for computing the time of minimum DNBR. Furthermore, it is assumed that the axial heat flux distribution is constant in time. The minimum DNBR value calculated with the CENPD-183 methodology assumes no decay of the hot channel heat flux.

In the ST-LOF method it is assumed that the hot bundle normalized power decay is equivalent to the core average normalized power decay, however the hot bundle power decay is modified upon the insertion of CEA's in that the planar radial power peaking factors are increased as the CEA's enter the core. The hot bundle and core average axial heat flux distributions are each time dependent. The minimum DNBR value calculated with the ST-LOF method is based on the decayed heat flux calculated by HERMITE at the time of minimum DNBR.

CENPD-183 describes both static and dynamic methods for computing the DNBR. The ST-LOF method uses the static method for calculating the DNBR as described in CENPD-183, Appendix A, except that TORC is used in place of COSMO.

15A.4 TOTAL LOSS OF PRIMARY COOLANT FLOW ANALYSIS

15A.4.1 Identification of Causes

A total Loss of Primary Coolant Flow (LOF) is caused by a simultaneous loss of electric power to all four reactor coolant pumps (RCP). A LOF will occur as part of the sequence of events following a loss of all AC power. The LOF is currently used as a design basis in determining the required margin to DNB for the Core Operating Limit Supervisory System (COLSS). Results of an analysis of a LOF are presented herein.

15A.4.2 Sequence of Events and Systems Operation

A loss of electric power to all reactor coolant pumps produces a reduction of coolant flow through the reactor core. The reduction in coolant flow rate causes an increase in the core average coolant temperature with a concurrent decrease in the margin to DNB. A low DNBR reactor trip is generated by the core protection calculators, as described in Section 7.2. The CEAs begin to drop into the core 1.09 seconds after the loss of electric power to the pumps. The 1.09 second delay conservatively includes the largest possible times for sensor delays, CPC calculation period, CEDM dead time, and CEDM coil decay time. The minimum DNBR of 1.19 occurs 2.56 seconds after the initiation of the event.

15A.4.3 Analysis of Effects and Consequences

15A.4.3.1 Mathematical Models

The NSSS response to a LOF was simulated using the methods described previously in this Appendix.

15A.4.3.2 Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a LOF are discussed in Section 15.0. The parameters, which are unique to the analysis discussed below, are listed in Table 15A-1.

The principal process variables that determine thermal margin to DNB in the core are monitored by COLSS. COLSS computes a power-operating limit which assists the operator in maintaining adequate thermal margin in the core. When this margin is initially available, the CPCs will prevent the minimum DNBR from being less than 1.19 during a LOF. COLSS is described in Section 7.7. The set of initial conditions chosen for the analysis presented in this section is one of a very large number of combinations within the reactor operating space given in Table 15.0-5 which would provide the minimum thermal margin required by the COLSS power operating limit. The consequences following a LOF initiated from any one of these combinations of conditions would be no more adverse than those presented herein.

15A.4.3.3 Results

The time dependent behavior of the core flow, reactor core power, hot bundle heat flux, and limiting channel DNBR is presented in Figures 15A-2 through 15A-5. The core coolant inlet temperature does not change prior to the time when the minimum DNBR is reached. For conservatism no credit is taken for the slight RCS pressure increase in computing this minimum DNBR.

15A.4.3.4 Conclusions

The minimum DNBR does not fall below 1.19. The maximum pressurizer pressure is less than 2500 psia, and there are no significant radiological releases.

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TABLE 15A-1

ASSUMED INITIAL CONDITIONS FOR THE TOTAL LOSS OF PRIMARY COOLANT FLOW CASE PRESENTED

Parameter	Assumed Value
Core Power Level, MWt	3876
Core Inlet Coolant Temperature, F	567
Core Mass Flow Rate, 10^6 lbm/hr	157.4
Reactor Coolant System Pressure, psia	1800
Initial Core Minimum DNBR	1.51
Maximum Radial Power Peaking Factor	1.62
Maximum Axial Power Peak	1.47
Axial Shape Index	.269
Doppler Coefficient Multiplier	0.0
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-10.0

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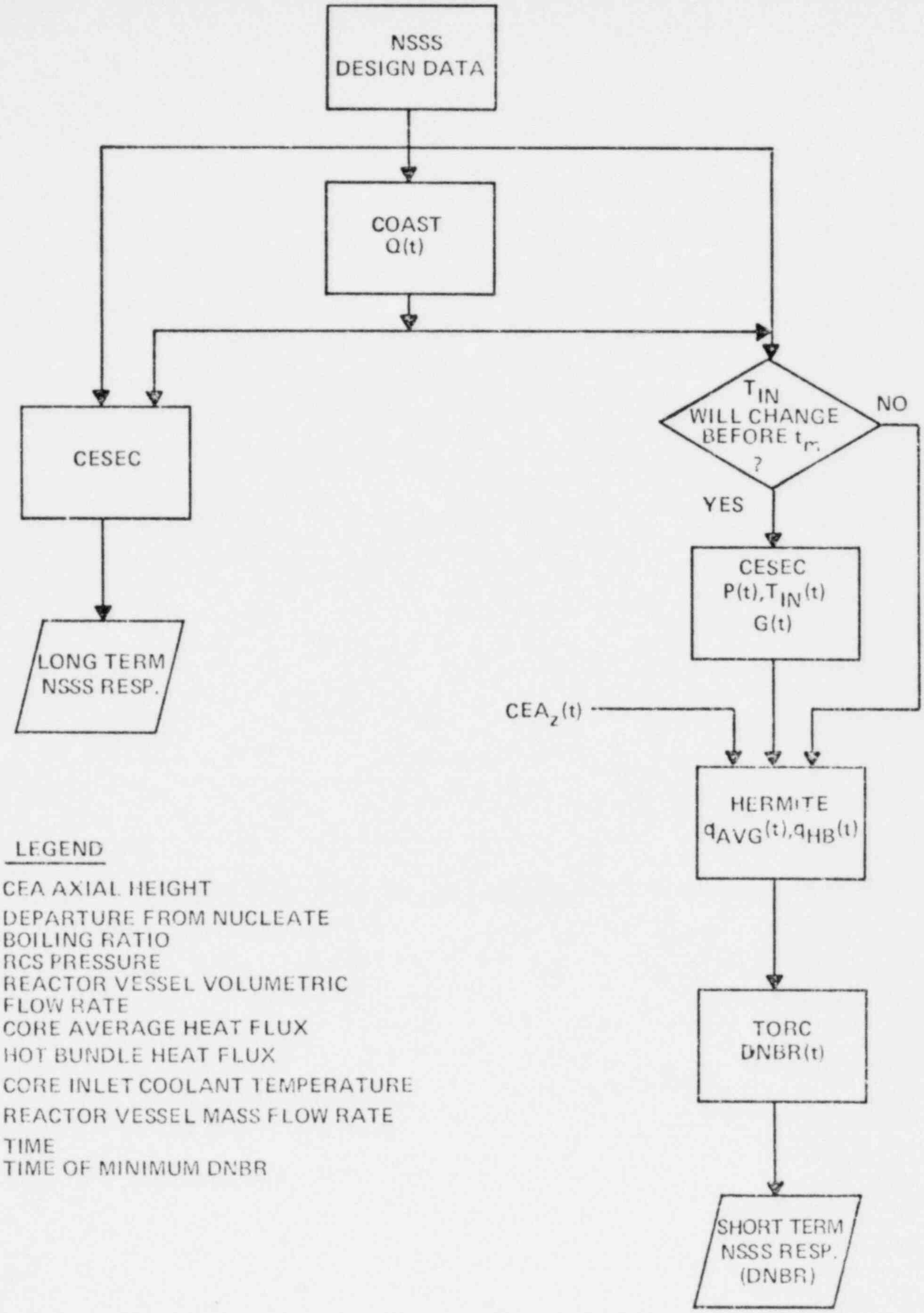
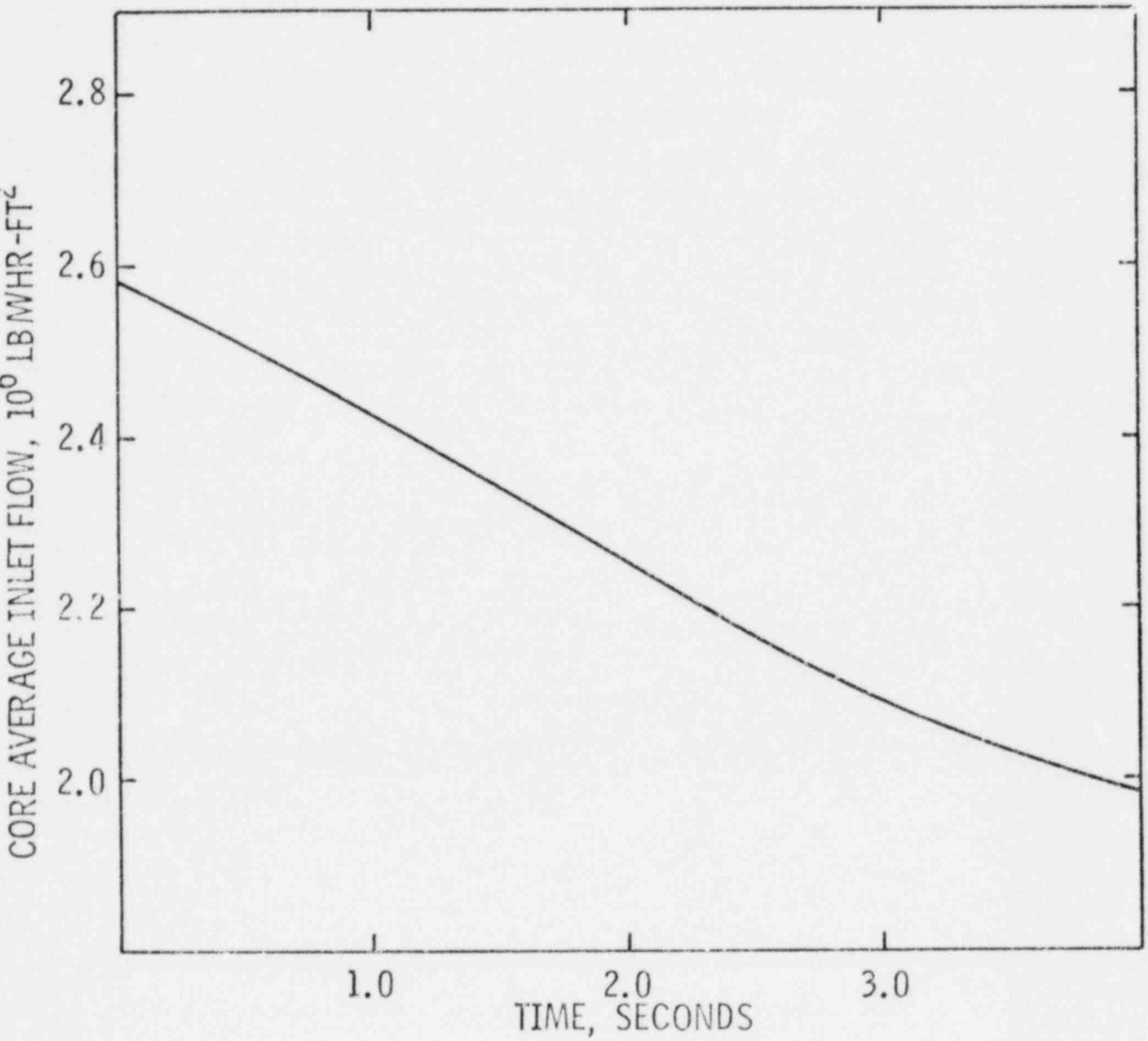


LEGEND

- CEA_z - CEA AXIAL HEIGHT
- DNBR - DEPARTURE FROM NUCLEATE BOILING RATIO
- P - RCS PRESSURE
- Q - REACTOR VESSEL VOLUMETRIC FLOW RATE
- q_{AVG} - CORE AVERAGE HEAT FLUX
- q_{HB} - HOT BUNDLE HEAT FLUX
- T_{IN} - CORE INLET COOLANT TEMPERATURE
- G - REACTOR VESSEL MASS FLOW RATE
- t - TIME
- t_m - TIME OF MINIMUM DNBR

Amendment No. 7
March 31, 1982

C-E SYSTEM 80	DATA TRANSFER BETWEEN COMPUTER CODES FOR THE SPACE-TIME KINETICS LOSS OF FLOW METHOD	Figure 15A-1



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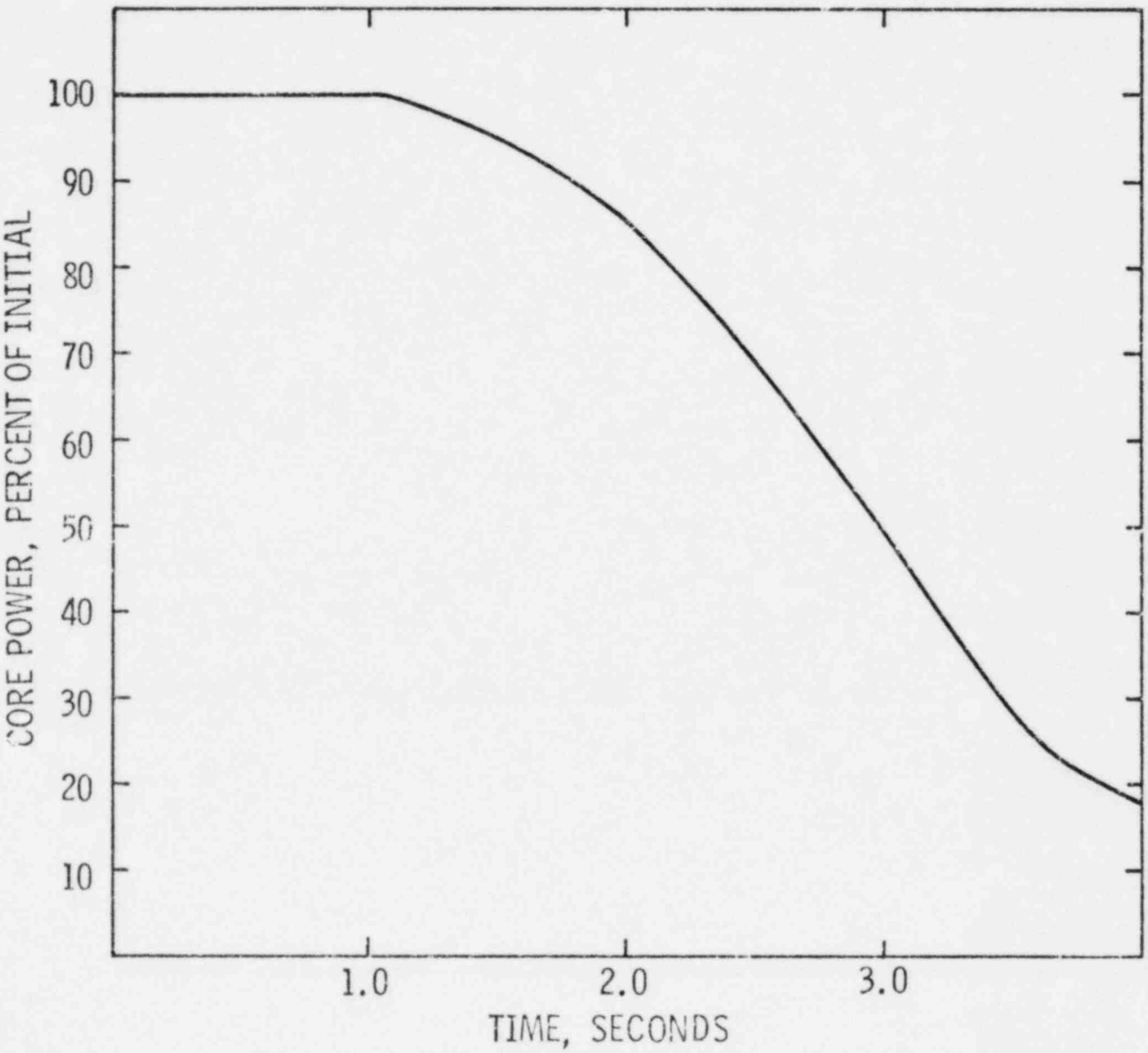
C-E SYSTEM 80	TOTAL LOSS OF FORCED REACTOR COOLANT FLOW CORE AVERAGE INLET FLOW vs TIME	Figure 15A-2



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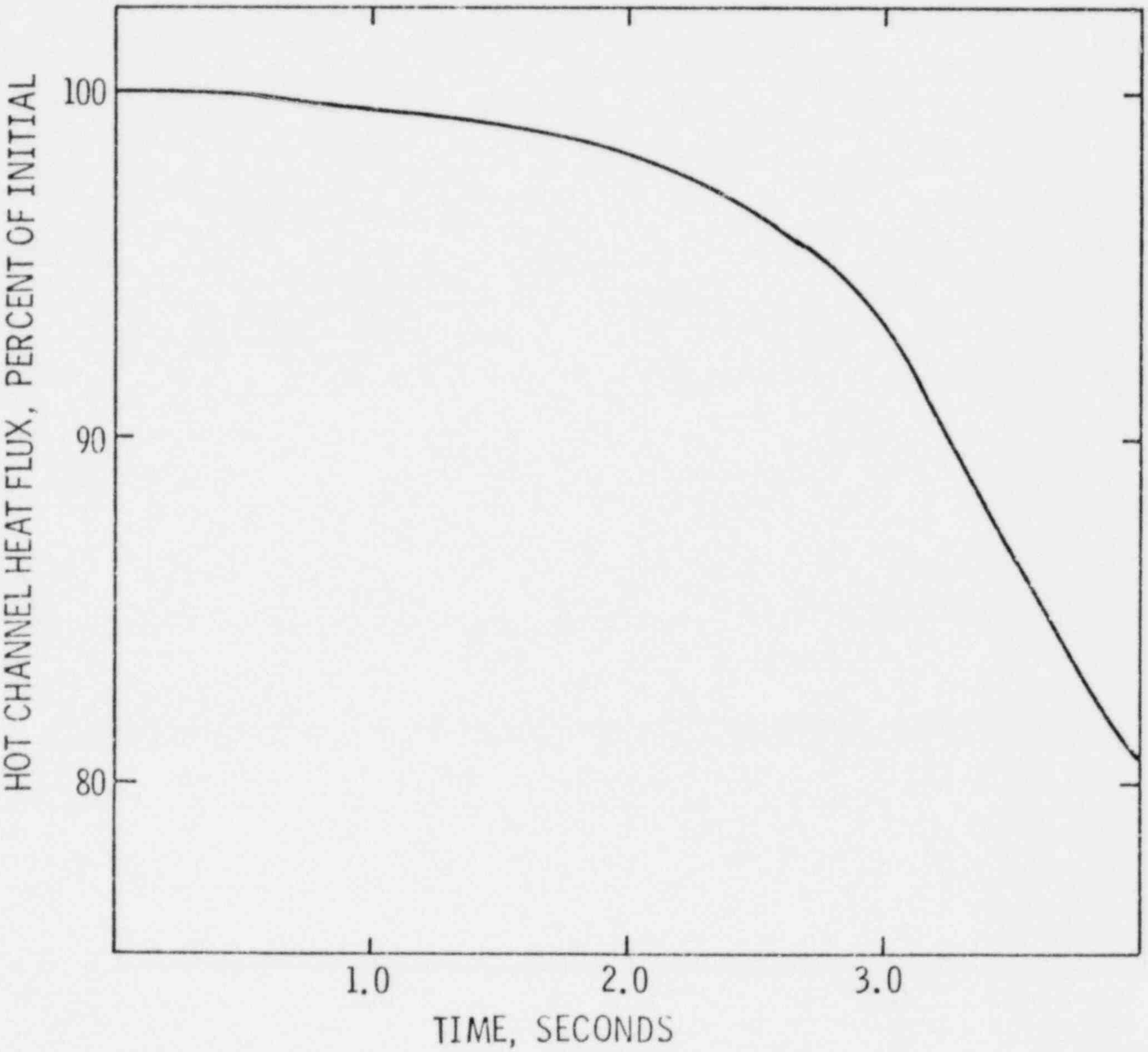
C - E SYSTEM 80	TOTAL LOSS OF FORCED REACTOR COOLANT FLOW CORE POWER vs TIME	Figure 15A-3



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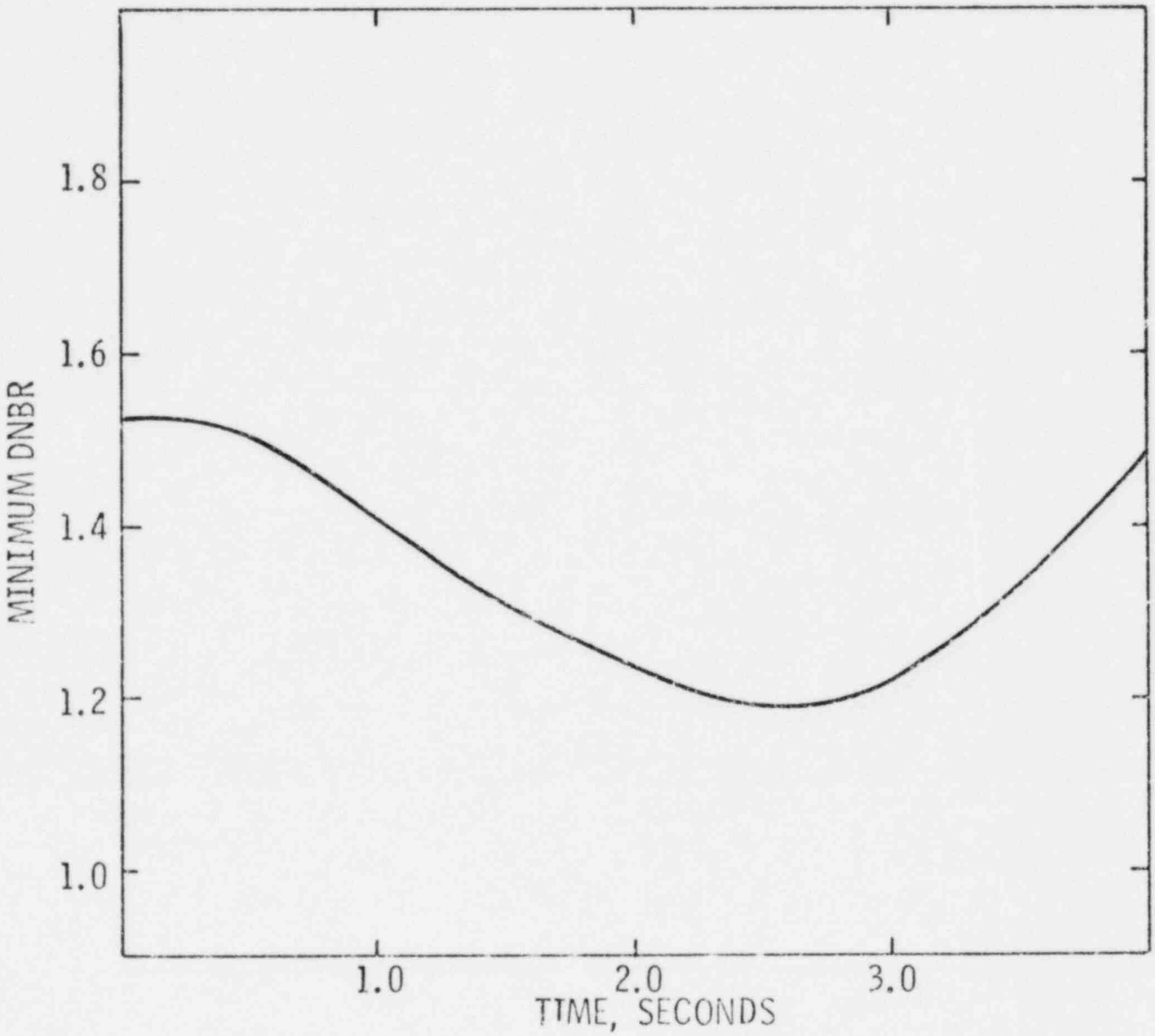
C - E SYSTEM 80	TOTAL LOSS OF FORCED REACTOR COOLANT FLOW HOT CHANNEL HEAT FLUX vs TIME	Figure 15A-4



Amendment No. 7
March 31, 1982

C - E SYSTEM 80	TOTAL LOSS OF FORCED REACTOR COOLANT FLOW MINIMUM DNBR vs TIME	Figure 15A-5

APPENDIX 15B

METHODS FOR ANALYSIS OF THE LOSS OF FEEDWATER INVENTORY EVENTS

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APPENDIX 15B

METHODS FOR ANALYSIS OF THE LOSS OF FEEDWATER INVENTORY EVENTS

15B.1 INTRODUCTION

This appendix describes the methods utilized in the transient analysis of Section 15 to envelope the overpressurization potential of the loss of feedwater inventory (LFI) event. The method involve simplifying, but conservative, modeling assumptions with respect to the feedwater line break mass and energy discharge rates and their affect on steam generator water level and heat transfer response. Using these assumptions sensitivity studies are performed to determine the most adverse set of initial plant operating conditions and transient parameters. The example used to demonstrate these methods corresponds to the limiting case feedwater line break defined in Reference 1 which includes consideration of the entire spectrum of break sizes and locations with the most adverse set of operating conditions, a loss of normal on-site and off-site electrical power at the most adverse time, the most adverse active single failure, and the failure of the most reactive control element assembly to insert following a reactor trip signal.

15B.2 DISCUSSION

The LFI event is initiated by a break in the main feedwater system (MFS) piping. Depending on the break size and location and the response of the MFS, the effects of a break can vary from a rapid heatup to a rapid cooldown of the Nuclear Steam Supply System (NSSS). In order to discuss the possible effects breaks are categorized as small, if the associated discharge flow is within the excess capacity of the MFS, and as large, otherwise. Break locations are identified with respect to the feedwater line reverse flow check valves which are located between the steam generator feedwater nozzles and the containment penetrations. Closure of these valves to reverse flow from the nearest steam generator maintains the integrity of that generator in the presence of a break upstream of the valves.

Breaks upstream of the check valves can initiate one of the following transients. If the MFS is unavailable following the pipe failure, a total loss of normal feedwater flow (LOFW) results. With the MFS remaining in operation no reduction in feedwater flow occurs for small breaks, while large breaks impose either a partial LOFW or a total LOFW, if the area is sufficient to discharge the entire feedwater pump flow capacity.

In addition to the possibility of partial or total LOFW events, breaks downstream of the check valves have the potential to establish reverse flow from the nearest steam generator (referred to as the "ruptured" generator) back to the break. Reverse flow occurs whenever the MFS is not operating subsequent to a pipe break or when the MFS is operating but without sufficient capacity to maintain pressure at the break above the steam generator pressure. It is only these breaks which develop reverse flow that are of interest in this analysis.

Depending on the enthalpy of the reverse flow and the ruptured steam generator's heat transfer characteristics, the reverse flow may induce either an RCS heatup or cooldown. However, excessive heat removal through the break is not considered in this analysis, because the cooldown potential is less than that of the loss of main steam inventory (LMSI) events. The maximum break size is smaller for the LFI events than for LMSI events. In addition, the LMSI breaks have a greater potential for discharging high enthalpy fluid due to the location of steam piping above feedwater piping within the steam generator. Furthermore, the LFI breaks cause an instant reduction in feedwater flow unlike LMSI breaks which results in a reduced heat removal capacity due to the lower liquid inventory. Since LFI breaks can cause a rapid depletion of ruptured steam generator liquid mass, reducing the heat transfer capability and causing a rapid RCS heatup and pressurization, it is the heatup pot tial which is emphasized in this study.

A general description follows of the LFI event assuming a break downstream of the check valves, inoperability of the MFS, and low enthalpy break discharge. The loss of subcooled feedwater flow to both steam generators causes increasing steam generator temperatures and decreasing liquid inventories and water levels. The rising secondary temperatures reduce the primary-to-secondary heat transfer and force a heatup and pressurization of the RCS. The heatup becomes more severe as the ruptured steam generator experiences a further reduction in its heat transfer capability due to insufficient liquid inventory as the break discharge continues. This initial sequence of events culminates with a reactor trip on high pressurizer pressure, low steam generator water level or high containment pressure. RCS heatup can continue after trip due to a total loss of heat transfer in the ruptured steam generator as it empties. Eventually the decreasing core power following reactor trip reduces the core heat rate to the heat removal capacity of the intact steam generator.

The analysis methods address the influence of the four major controlling parameters; discharge enthalpy and flow, low water level trip condition in the ruptured steam generator, and the heat transfer characteristics of the ruptured steam generator.

15B.3 Method of Analysis

Analysis of the LFI event is performed using the CESEC II computer program described in Section 15.0.3. along with several simplifying assumptions which, with respect to RCS overpressurization, conservatively model the break discharge flow and enthalpy and the ruptured steam generator water level and heat transfer. In addition, sensitivity of the RCS overpressurization to changes in various plant initial conditions is evaluated to determine the most adverse initial conditions for the LFI event.

Blowdown of the steam generator nearest the feedwater line break is modeled assuming frictionless critical flow as calculated by the Henry-Fauske correlation (Reference 2). Although the enthalpy of the blowdown physically depends upon the location of the break relative to fluid conditions within the ruptured steam generator, it is assumed that saturated liquid is discharged until no liquid remains at which time saturated steam discharge is assumed.

With respect to RCS overpressurization these assumptions result in conservatively high mass flow and conservatively low energy flow from the steam generator to the break, thereby minimizing the ruptured generator heat removal capacity.

In lieu of detailed steam generator modelling to calculate the redistribution of fluid under the influence of blowdown to the break, no credit is taken for a low water level trip condition in the ruptured steam generator until the generator is emptied of liquid. This conservatively delays the time of reactor trip, prolonging the RCS heatup and overpressurization. No credit is taken for the high containment pressure trip.

In order to determine the sensitivity of the RCS overpressurization to the ruptured steam generator heat transfer characteristics without implementing a detailed steam generator model, the effective heat transfer area is assumed to decrease linearly (from the design value to zero) as the steam generator liquid mass decreases (from a selected value to zero). The mass interval over which the rampdown is assumed to occur is referred to as "ΔM". Therefore, decreasing values of ΔM imply a more rapid loss of heat transfer in the ruptured steam generator.

Sensitivity studies are used to establish the most adverse set of initial operating and transient parameters with respect to RCS overpressurization. These parameters include break size, ΔM, initial core power, initial RCS pressure, initial reactor vessel flow, initial pressurizer liquid volume, pressurizer safety valve rated flow, core physics conditions, fuel gas gap heat transfer coefficient, initial core inlet temperature, initial feedwater enthalpy and initial steam generator inventory.

The first parametric analysis includes various combinations of break sizes and steam generator heat transfer characteristics (ΔM) with nominal full power beginning-of-cycle plant operating conditions assumed. At the time of turbine trip there is an assumed loss of both normal on-site and off-site electrical power. The break size is varied from 0.0 to the maximum area of 1.4 ft^2. The maximum area is restricted to the sum of the flow distribution holes in the steam generator economizer section. The value of ΔM is varied from 0 to 100,000 lbm to envelope all possible rates of decreasing the ruptured steam generator heat transfer. Results of this study are shown in Figure 15B-1.

For each value of ΔM the curve of peak RCS pressure versus break area is characterized by a relatively sharp rise in pressure with increasing break area followed by a gradual decline. Pressures for break area less than that corresponding to the inflection point are reduced due to a reactor trip on low water level in the intact steam generator before total heat transfer is lost in the ruptured steam generator. Larger breaks trip on high pressurizer pressure or low water level in the ruptured generator. The relationship between pressure and break area after the inflection point is due to a combination of more rapid loss of heat transfer with increasing area, off-set by greater steam relieving capacity of larger breaks once the ruptured steam generator empties which is important in reducing the RCS heatup following turbine trip.

Except for the range of small breaks, larger values of ΔM result in lower RCS pressures. The more gradual decrease in heat transfer associated with a larger ΔM allows for more reactivity feedback from the moderator temperature which reduces core power prior to trip, and also allows for a greater shift of secondary heat transfer from the ruptured steam generator to the intact generator prior to trip. Both of these phenomena minimize the rate of RCS heatup and pressurization after reactor trip. However, for the range of small breaks and small ΔM, no decrease in heat transfer occurs before trip, but as ΔM increases, heat transfer reduction begins prior to and continues after reactor trip.

The study shows that a break area of 0.2 ft^2 and ΔM equal to 0.0 is the most adverse combination. This combination is used as the base case for the rest of the sensitivity studies.

The sensitivity of peak RCS pressure to initial RCS pressure is shown in Figure 15B-2. For pressures to the right of peak in the figure, reactor trip occurs on high pressurizer pressure prior to the loss of heat transfer in the ruptured steam generator. Lower initial pressures trip on low water level in the ruptured steam generator (once emptied). And as the initial pressure is lowered the RCS pressure at reactor trip decreases reducing the peak pressure. The concavity of the curve up to 2200 psia is due to the limiting effects of the pressurizer safety valves.

Due to the sensitivity of the maximum RCS pressure to initial RCS pressure, each of the following parametric studies adjusts the initial RCS pressure within its full power operating band to provide a high pressurizer pressure trip signal coincident with the first reactor trip signal, if possible. This provides an equal basis for comparison.

The sensitivity of RCS pressure to initial core power is shown in Figure 15B-3. Lowering the core power reduces the RCS heatup associated with losing one steam generator heat transfer capability.

The sensitivity of RCS overpressurization to initial reactor vessel flow is negligible as shown in Figure 15B-4.

The initial pressurizer liquid volume shows no significant influence on the maximum RCS pressurization (Figure 15B-5). RCS pressurization prior to reactor trip is more rapid for larger initial liquid volumes, however, the volume does not affect the rate of RCS heatup nor the pressurizer safety valve opening and associated pressure required to accommodate the volumetric insurge flow due to the heatup. In the absence of significant sensitivity, the maximum pressurizer liquid volume is considered the most adverse due to the increased potential for completely filling the pressurizer with liquid during the course of the transient.

The rated flow of the four pressurizer safety valves is restricted to a minimum of 460,000 lbm/hr/valve to a maximum of 575,000 lbm/hr/valve. Figure 15B-6 shows that within this range the maximum RCS pressure decreases only slightly with increasing rated flow. This indicates that the maximum

volumetric insurge to the pressurizer during the maximum rate of RCS heatup is well within the relieving capacity of the safety valves (i.e., a valve with a lower rated flow must open proportionately further to provide the required flow, but not beyond its limit).

A multiplier applied to the Doppler reactivity feedback has negligible impact on the peak RCS pressure (see Figure 15B-7). This result is due to compensating effects which the Doppler feedback has on the core power transient before reactor trip relative to after trip. Increasing the feedback (multiplier) slightly reduces the core power before, but reduces the rate of core power decay after the reactor trip.

Figure 15B-8 shows the response of the maximum RCS pressure to relative changes in the core life. The decrease in RCS pressure is predominately due to decreasing moderator temperature coefficient of reactivity (nominally -1.13×10^{-4} $\Delta\rho$/F at beginning-of-cycle to -2.46×10^{-4} $\Delta\rho$/F at end-of-cycle, assuming equilibrium xenon and a core average temperature of 594°F). The more negative coefficient produces a greater reduction of core power prior to trip and thereby reduces the RCS heat up and pressurization following reactor trip.

The fuel gas gap heat transfer coefficient affects the initial fuel temperatures and the associated stored energy in the fuel. In the LFI event increased stored energy increases the core heat flux following reactor trip and hence the RCS heatup. Therefore, as shown in Figure 15B-9, the maximum RCS pressure reaches a peak for the lowest value of fuel gas gap heat transfer coefficient (corresponding to cold clean fuel).

Because the core power has a significant impact on the peak RCS pressure and can be influenced by moderator reactivity feedback prior to reactor trip, sensitivity studies on parameters which strongly affect moderator temperature (i.e., initial core inlet temperature, initial steam generator water mass and feedwater enthalpy) use the base case modified by implementing the most positive moderator reactivity versus temperature curve (beginning-of-cycle) including uncertainties.

The sensitivity of maximum RCS pressure to initial steam generator water mass shown in Figure 15B-10 has four characteristic segments. For initial masses between 90,000 lbm and 115,000 lbm, a reactor trip condition is first encountered on low water level in the intact steam generator event with an adjustment of the initial RCS pressure to the upper limit of operation (2400 psia). Within this range a decrease in initial mass forces an earlier reactor trip and lower RCS pressure at trip. Between 115,000 lbm and 135,000 lbm the initial RCS pressure can be adjusted to provide simultaneous reactor trip signals from high pressurizer pressure and low water level in the intact steam generator and hence the plateau of maximum RCS pressure. From 135,000 lbm to 155,000 lbm reactor trip still occurs on high pressurizer pressure and intact steam generator low water level, however heat transfer rampdown in the ruptured steam generator begins prior to reaching the maximum RCS pressure. Above 155,000 lbm the low water level trip condition is due to emptying of the ruptured steam generator. Therefore, all heat transfer is lost in the ruptured steam generator prior to reactor trip causing the most adverse RCS heatup initiated with the pressurizer pressure at the trip setpoint.

Figure 15B-11 shows the results of the parametric analysis on maximum RCS pressure versus initial feedwater enthalpy. Raising the degree of feedwater subcooling increases the rate of RCS heatup once main feedwater is terminated. The RCS pressurization is greater, therefore, for decreasing feedwater enthalpy.

The final sensitivity study on initial core inlet temperature indicates only a small dependence of peak RCS pressure on temperature. There are several off-setting influences of temperature. Lowering the core inlet temperature increases the initial moderator temperature coefficient of reactivity. It decreases the secondary side temperature, thereby reducing the degree of feedwater subcooling. The corresponding decrease in the steam generator pressure reduces the break discharge flow and also prevents opening of the main steam safety valves prior to reactor trip. The result of the interaction of these changes is shown in Figure 15B-12.

The results of these sensitivity studies provide a set of initial conditions and transient parameters which establish the limiting RCS overpressurization LFI event. In summary this set includes:

1. 0.2 ft^2 break area

2. Instantaneous loss of heat transfer in the ruptured steam generator ($\Delta M=0$)

3. Initial RCS pressure whi ...es a high pressurizer pressure trip coincident with the first reactor trip signal

4. Nominal reactor vessel flow

5. Maximum initial core power

6. Maximum initial pressurizer liquid volume

7. Minimum pressurizer safety valve rated flow

8. Nominal Doppler reactivity feedback

9. Most positive moderator temperature coefficient of reactivity

10. Minimum fuel gas gap heat transfer coefficient

11. Nominal initial steam generator water mass

12. Minimum initial feedwater enthalpy

13. Maximum initial core inlet temperature

15B.4 RESULTS

An example limiting analysis of the LFI transient suggested by Reference 1 was performed applying the conservative methods with the most adverse set of initial plant conditions and transient parameters discussed above. Table 15B-1 lists the assumptions utilized in this worst case. The sequence of events and the dynamic response of the important NSSS parameters are provided in Table 15B-2 and Figures 15B-13 through 15B-30, respectively.

A 0.2 ft^2 crack in the main feedwater line is assumed to instantaneously terminate feedwater flow to both steam generators and establish critical flow (~2000 lbm/sec of saturated liquid) from the generator nearest the break. The absence of subcooled feedwater flow causes a constant heatup and pressurization of the steam generators during the first 33.8 seconds which reduces the primary-to-secondary heat transfer rate. Rising reactor coolant temperatures and pressure result. Due to temperature reactivity feedback during this period the core power decreases slightly from 102 percent to 98 percent of design full power.

At 33.8 seconds the ruptured steam generator is assumed to instantaneously lose all heat transfer capability due to total depletion of its liquid inventory by boil-off and the break discharge flow. This initiates a rapid heatup and pressurization of the reactor coolant system and depressurization of the steam generators. Once emptied, credit is taken for a low water level trip condition in the ruptured steam generator which leads to a reactor trip signal at 34.4 seconds simultaneous with a high pressurizer pressure trip signal. The rate of reactor coolant system pressurization is further aggravated at 38.5 seconds. Closure of the turbine leaves the pipe break as the only steam relief path, thereby reducing the energy flow from the intact steam generator below that of the primary-to-secondary heat transfer rate. The resulting steam generator pressurization reduces the primary-to-secondary temperature difference. In addition, the loss of reactor coolant flow following the loss of electrical power decreases the heat transfer coefficient of the coolant in the steam generator tubes. A significant heat transfer reduction occurs.

Compression of the pressurizer steam volume due to the high insurge flow raises the pressure to the safety valve setpoint at 34.6 seconds. Thereafter every increase in the surge flow causes a slight pressurization which opens the safety valves such that their volumetric discharge rate matches that of the insurge. The reactor coolant system pressure continues to increase to a maximum of 2843 psia at 38.2 seconds. At that time the increased pressure establishes a surge line pressure gradient which provides sufficient flow to allow the reactor coolant to expand under the existing heatup with no further pressurization. Pressurizer pressure and surge line flow are also at their maxima of 2587 psia and 2205 lbm/sec, respectively.

The rate of heatup decreases subsequent to core heat flux decay causing the primary pressures to drop. By 40.5 seconds the main steam safety valves open thus stabilizing the secondary side temperature and allowing the

rising primary coolant temperature to develop greater heat transfer to the intact steam generator. The intact generator is forced to a maximum of 1318 psia before the heat transfer begins to decrease. However, the core-to-steam generator heat rate mismatch is reduced sufficiently by 45.4 seconds to allow closure of the pressurizer safety valves and by 45.8 seconds the reactor coolant system enters a cooldown. Under the influence of steam blowdown through the ruptured steam generator to the break, the cooldown proceeds even after the steam generator safety valves close at 73.8 seconds.

A main steam isolation signal is generated at 165.6 seconds on low steam generator pressure which closes the main steam isolation valves decoupling the intact steam generator from the ruptured steam generator and the break. The intact steam generator repressurizes, thereby reducing its heat transfer and eventually causing a primary system heatup by 300 seconds. With the main steam safety valves open by 314.2 seconds, the primary-to-secondary heat inbalance is eliminated by approximately 600 seconds. Thereafter the NSSS enters into a quasi-steady state with a very gradual cooldown and depressurization due to decreasing core decay heat and with emergency feedwater flow which was initiated at 89.6 seconds maintaining an adequate liquid inventory within the intact steam generator for heat removal. By 1800 seconds the operator initiates a controlled cooldown to shutdown cooling utilizing the atmospheric dump valves.

The minimum DNBR vs. Time as shown on Figure 15B-30 remains above 1.19 throughout the transient.

During the first 30 minutes following the initiation of this LFI event mass releases from the system amount to 2970 lbm of steam from the pressurizer safety valves to the reactor drain tank, 79,700 lbm of steam from the main steam safety valves to atmosphere, and 69,200 lbm of liquid and 34,200 lbm of steam from the feedwater line break to containment. Steam release to the reactor drain tank may burst the tank's rupture disc discharging its contents to containment.

During this event, two sources of radioactivity contribute to the site boundary dose, the initial activity in the steam generator inventory, and the activity associated with primary to secondary leakage from the steam generator tubes which are assumed to be at the technical specification limits of 0.1 μCi/gm and 4.6 μCi/gm dose equivalent I-131 respectively. During the first two hours of this event, the total activity from the steam generators includes 8.9 Ci from the affected steam generator to the containment building including 1.6 Ci associated with technical specification tube leakage (1 gpm) and 0.33 Ci total activity released from unaffected steam generator to the containment and atmosphere. Assuming all the radioactivity is released to the atmosphere, the offsite dose due to feedwater line break with loss of offsite power results in no more than 9.5 rem two hour inhalation thyroid dose at exclusion area boundary.

15B.5 CONCLUSION

These conservative methods,[(1)] even when applied to the limiting case of Reference 1, produce an NSSS transient with maximum pressures not greater than 2843 psia in the RCS and 1318 psia in the steam generators which is sufficiently low to ensure that the integrity of the pressure boundaries is maintained. This evaluation shows that feedwater line break with loss offsite power produces a radiological dose which is well within 10CFR100 guidelines. The minimum DNBR which remains above 1.19 indicates that no fuel cladding failure occurs.

FOOTNOTE:

(1) It must be reiterated that the analysis methods discussed and applied above to the LFI events utilize simplifying assumptions which are clearly conservative for the entire spectrum of break sizes, are intended to identify an upper limit for the associated RCS pressurization transient, and do not provide the expected RCS response. With respect to RCS pressurization, these methods are especially conservative for small line breaks. Based on a more realistic, yet still conservative reanalysis of the RCS response to a 0.2 ft^2 break, the maximum RCS pressure will not exceed 2700 psia following any small feedwater line break.

The reanalysis of the 0.2 ft^2 break was performed utilizing the same methods described in Section 15B.3, except that reactor trip on low water level in the ruptured steam generator was assumed prior to its emptying, and the ruptured steam generator's heat transfer was assumed to decrease more gradually. The event definition was not changed (i.e., a feed line break located between the steam generator and the nearest reverse flow check valve, a loss of offsite electrical power following turbine trip, etc.). Frictionless critical flow of saturated liquid from the ruptured generator to the break was assumed, and the most adverse set of plant initial conditions was selected based on the sensitivity studies described in Section 15B.3 (e.g., the initial RCS pressure was selected to provide a reactor trip on high pressurizer pressure coincident with the low steam generator water level trip signal).

However, reactor trip on low water level in the ruptured steam generator was assumed to occur with 22,000 lbm of liquid remaining in it, rather than delaying the trip until the generator empties. Under full power loss of feedwater conditions more than 60,000 lbm of liquid are calculated to be in the steam generator with the water level at the trip setpoint. This calculation considered the impact of the break discharge on the level measurement uncertainty. Since the steam generator pressure response during a small feed line break is similar to the total loss of feedwater transient, and the discharge flow to the line break is small relative to the recirculation flow within the generator (e.g., full power recirculation is approximately 10,000 lbm/sec, discharge from a 0.2 ft^2 break is approximately 2,000 lbm/sec), the full power loss of feedwater flow calculation is considered to be applicable to the small break analysis. However, a conservatively low value of 22,000 lbm was used.

Also, rather than instantaneously reducing heat transfer to the ruptured steam generator when it empties (i.e., $\Delta M = 0$), heat transfer was linearly reduced ($\Delta M = 22{,}000$). Calculations of steam generator behavior during the total loss of feedwater ATWS (anticipated transient without scram), Reference 3, event indicate that greater than 40,000 lbm of liquid remain in each generator when heat transfer begins to degrade (i.e., a shift from the nucleate boiling to liquid deficient heat transfer regime). Again, since the break discharge flow is small relative to the recirculation flow within the steam generators, the total loss of feedwater flow ATWS calculation is considered to be applicable to the small break analysis. However, a conservatively smaller value of ΔM was selected. See Figure 15B-1 for the relative sensitivity of maximum RCS pressure to the value of ΔM.

Based on these more realistic and still conservative assumptions the re-analysis of the 0.2 ft^2 feedwater line break showed that the maximum RCS pressure remains below 2700 psia.

References for Appendix 15B

1. "USNRC Standard Review Plan, Section 15.2.8, Feedwater System Pipe Breaks Inside and Outside Containment (PWR)", NUREG-75/087, November 24, 1975.

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

3. "Analyses of Anticipated Transients Without Reactor Scram in Combustion Engineering NSSSs," CENPD-158, Revision 1, May, 1976.

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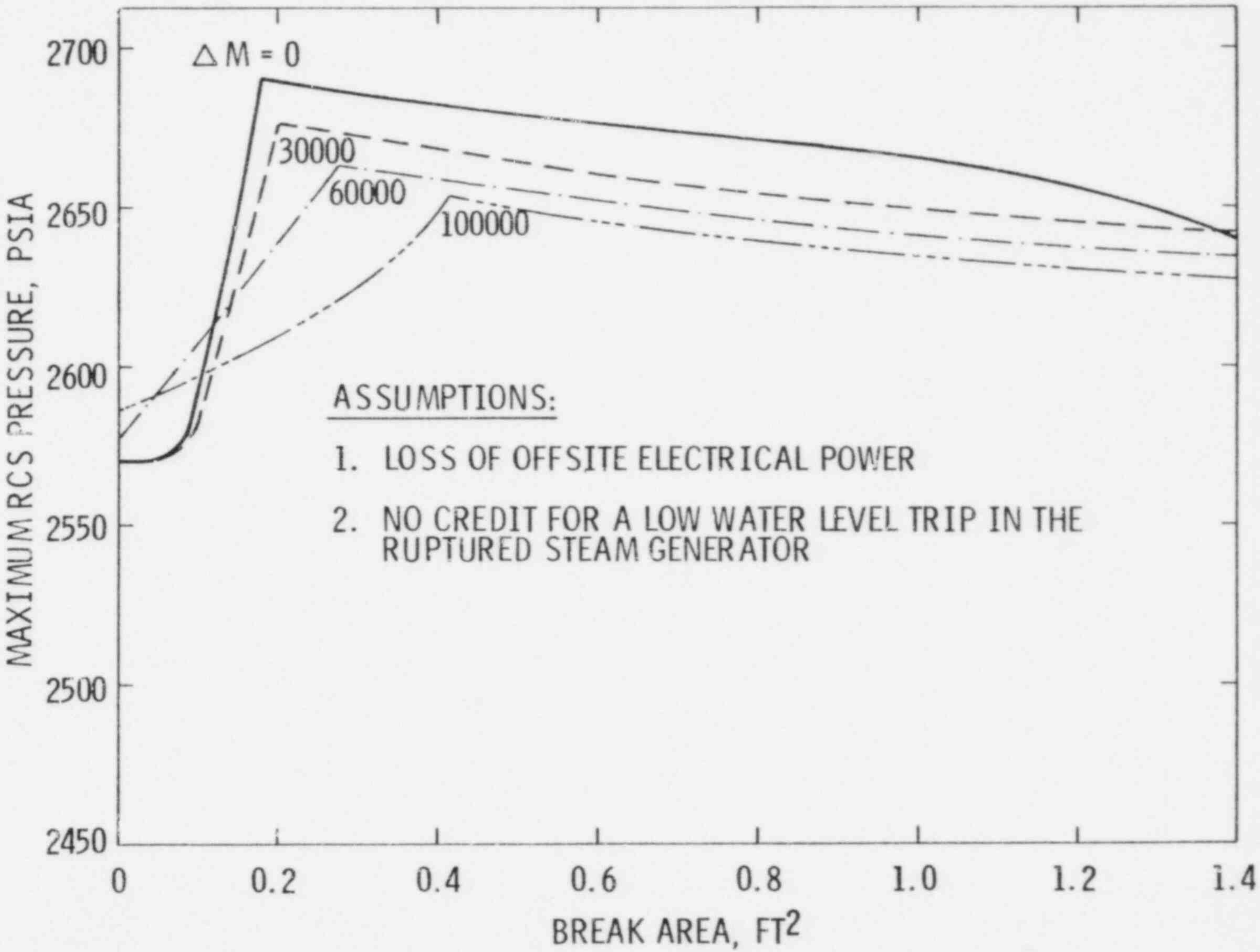

C-E SYSTEM 80

LOSS OF FEEDWATER INVENTORY
MAXIMUM RC SYSTEM PRESSURE
vs BREAK AREA

Figure 15B-1

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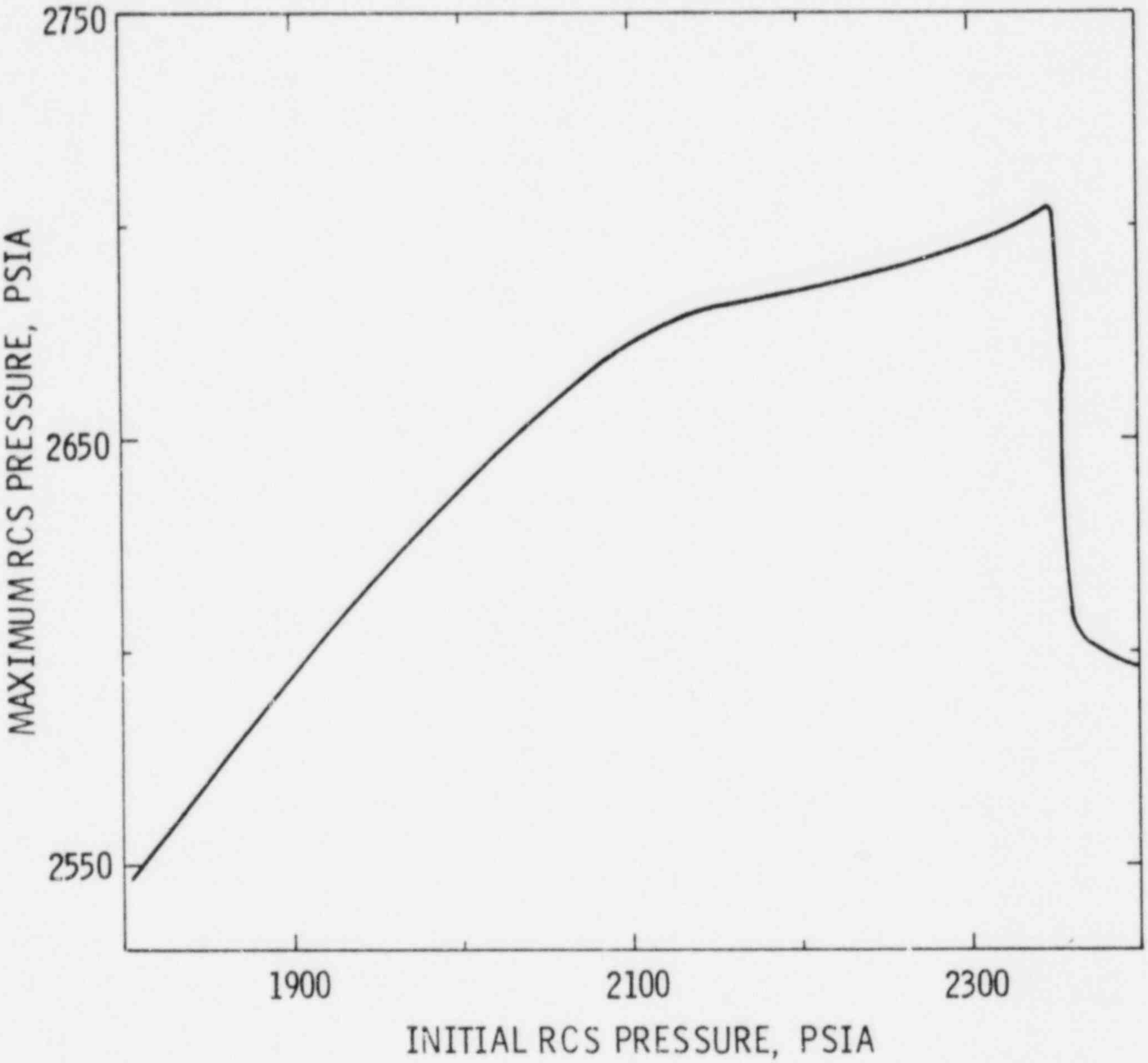

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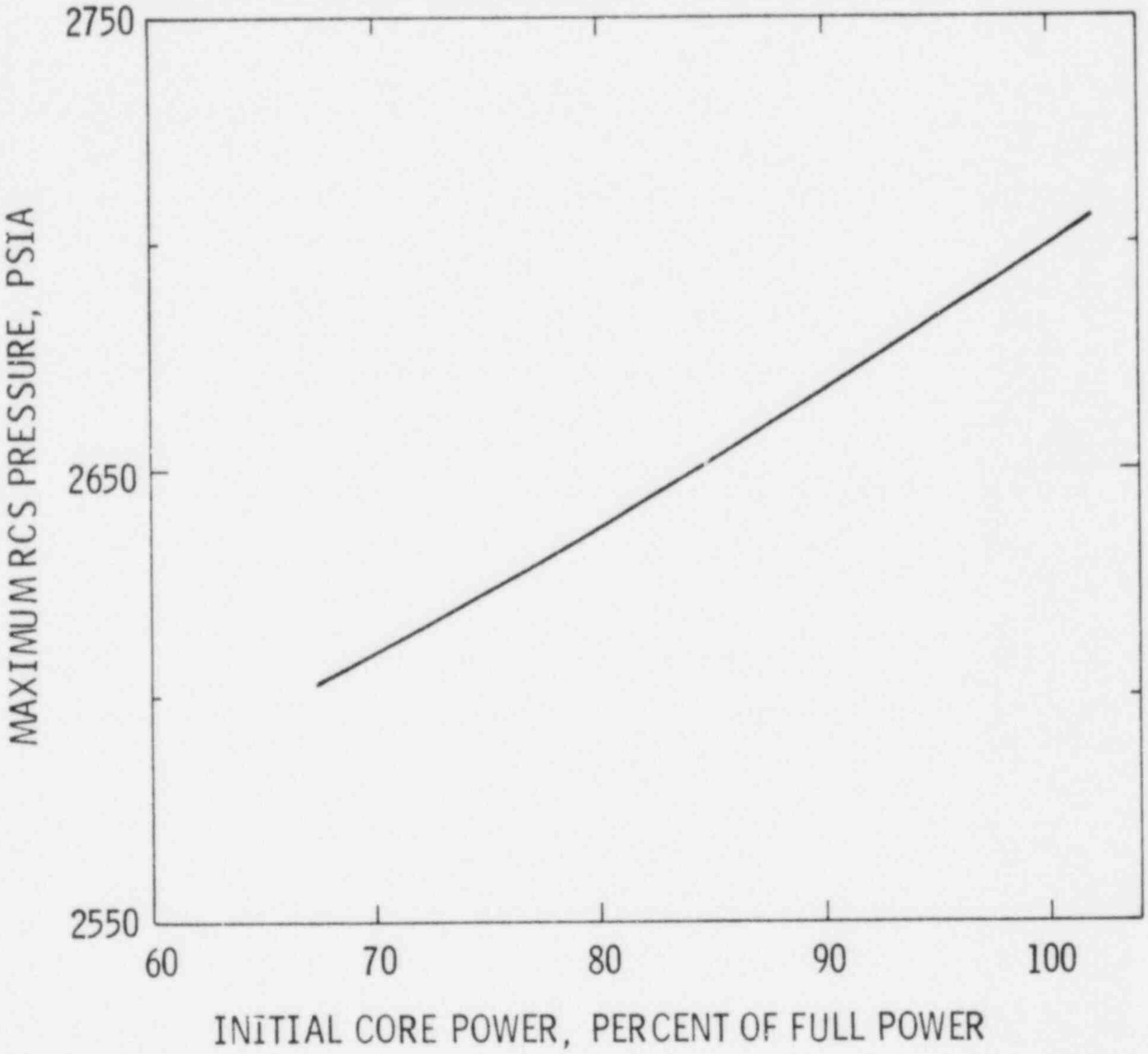
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs INITIAL RC SYSTEM PRESSURE	Figure 15B-2



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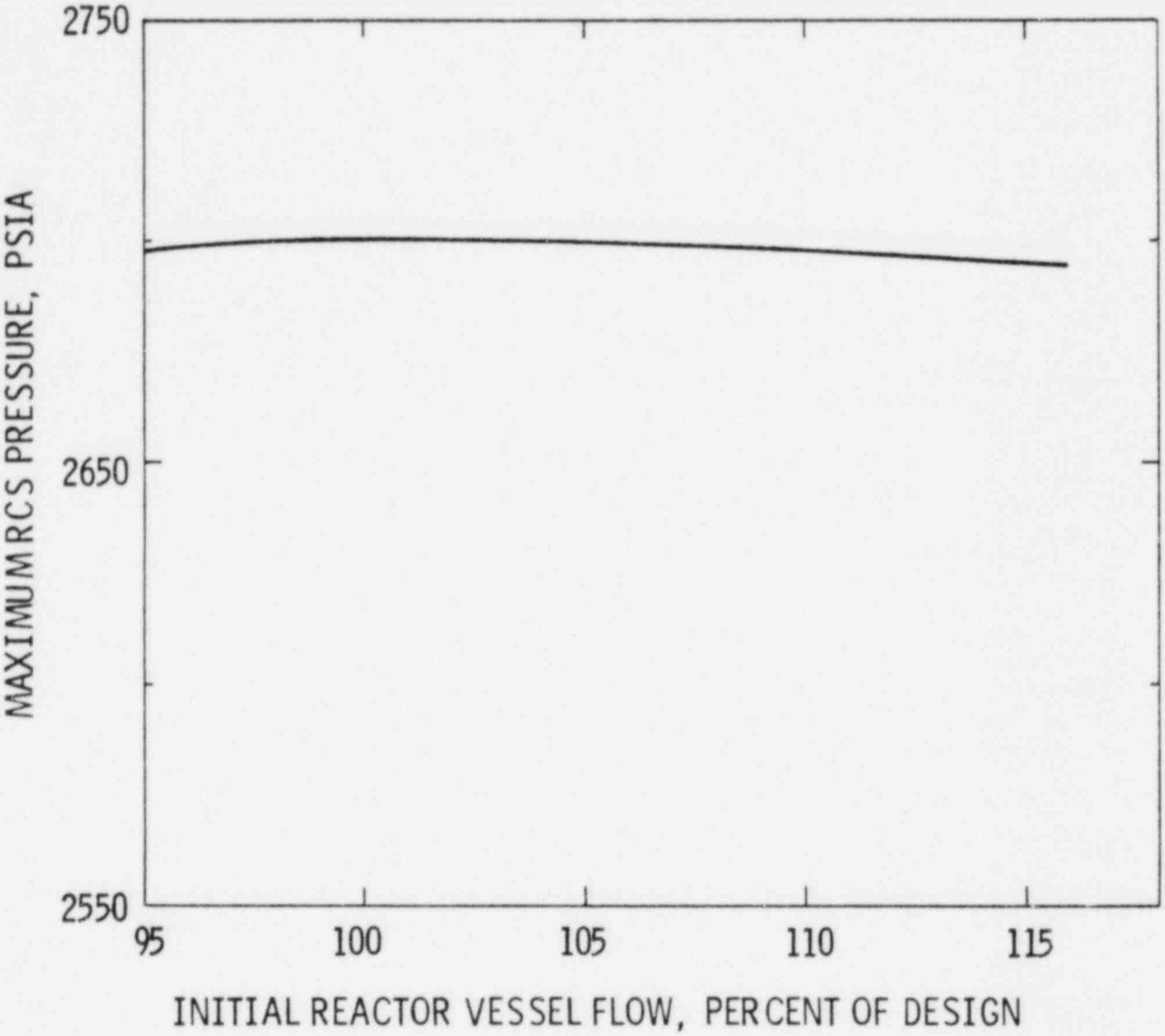
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs INITIAL CORE POWER	Figure 15B-3



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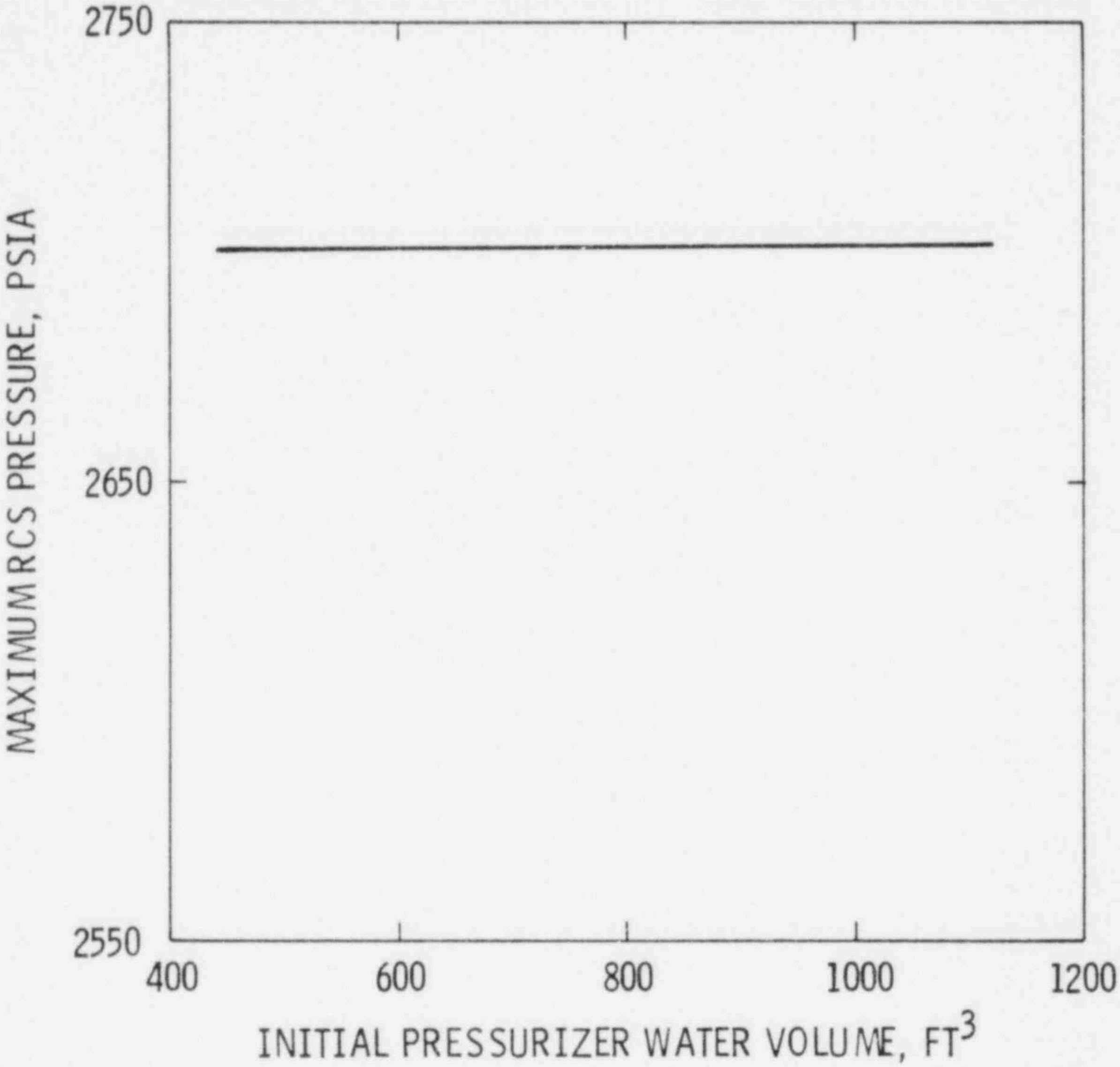
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs INITIAL REACTOR VESSEL FLOW	Figure 15B-4



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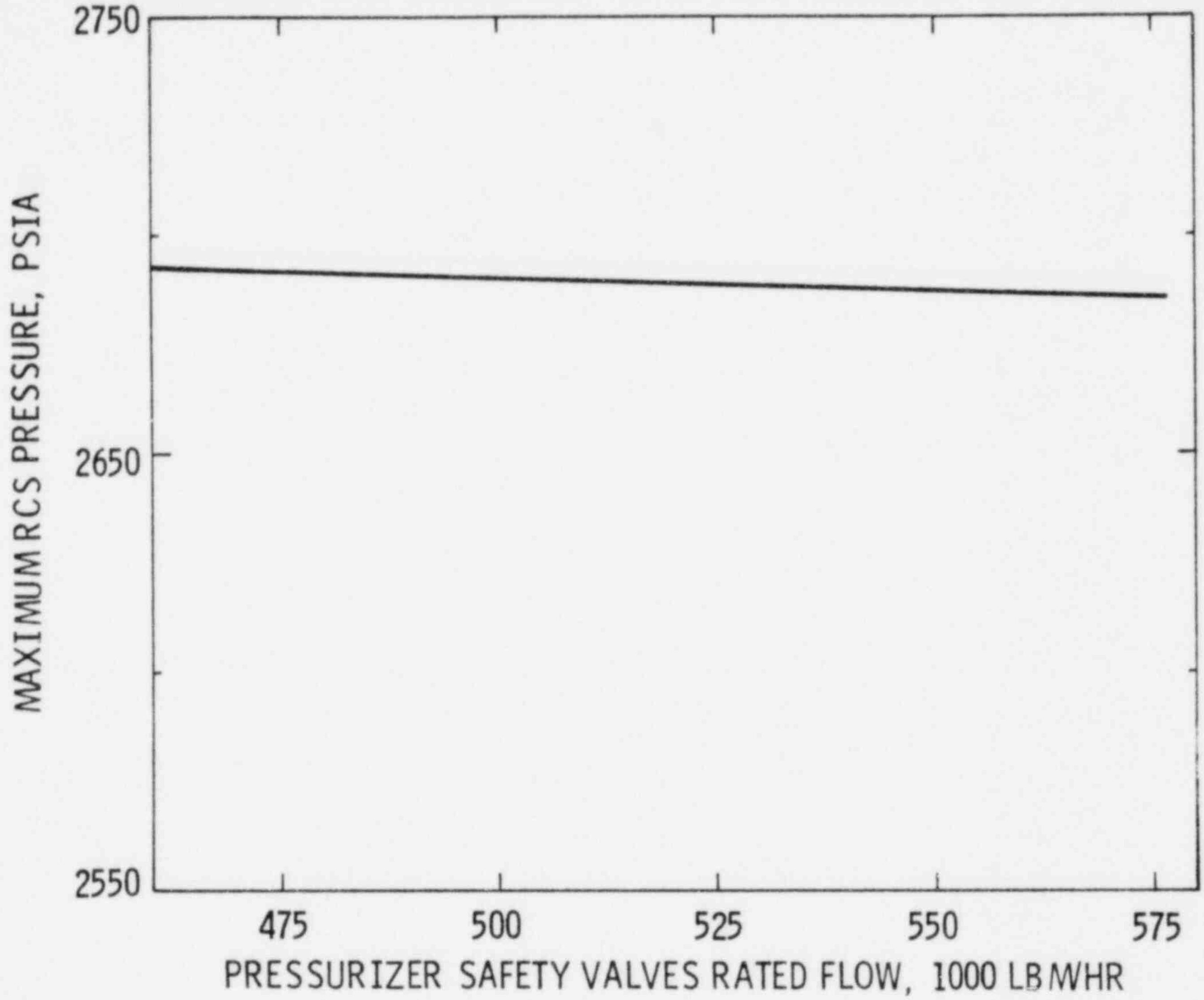
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs INITIAL PRESSURIZER WATER VOLUME	Figure 15B-5



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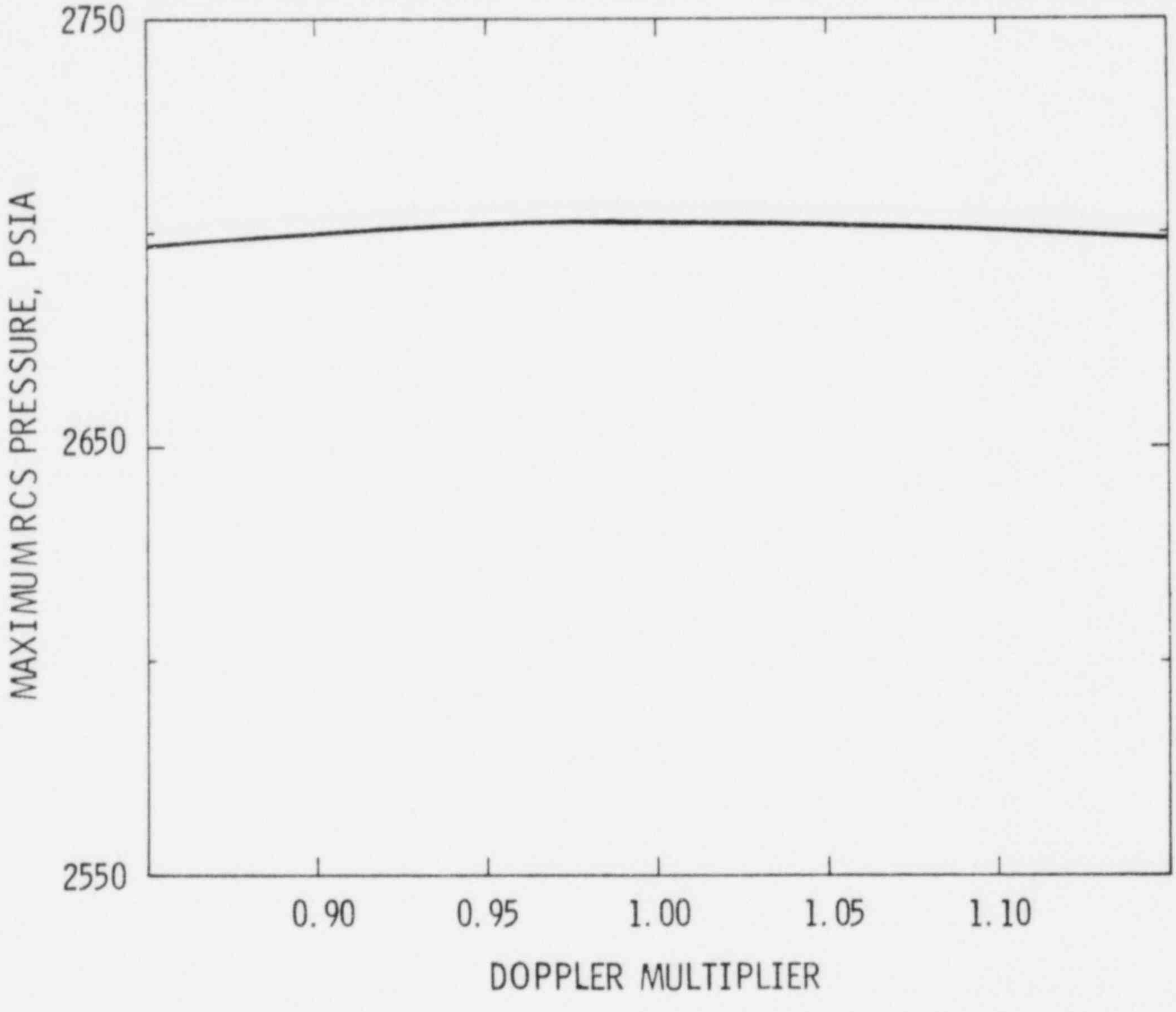
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs PRESSURIZER SAFETY VALVES RATED FLOW	Figure 15B-6



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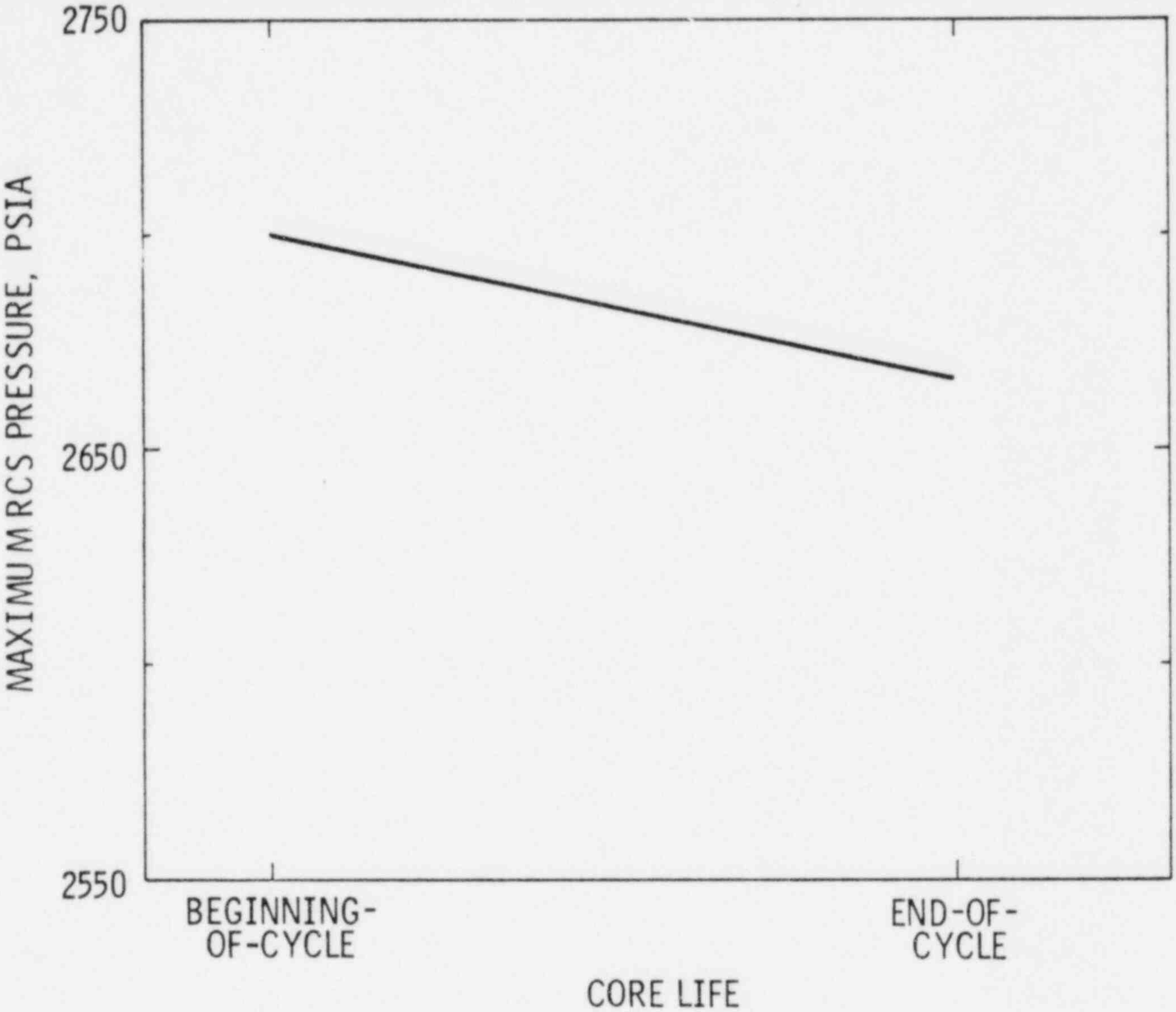
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM REACTOR COOLANT SYSTEM PRESSURE vs DOPPLER MULTIPLIER	Figure 15B-7



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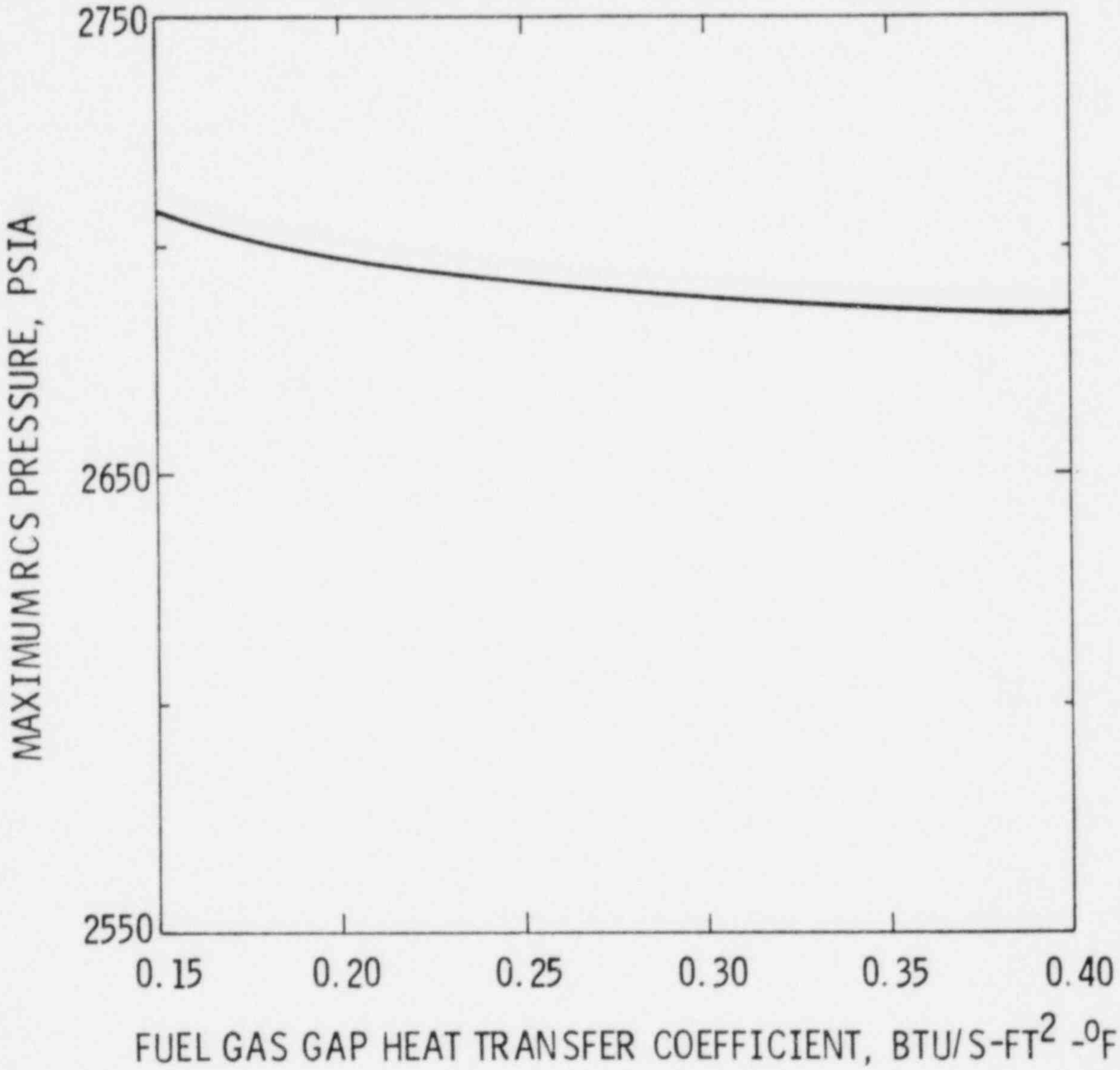
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM REACTOR COOLANT SYSTEM PRESSURE vs CORE LIFE	Figure 15B-8



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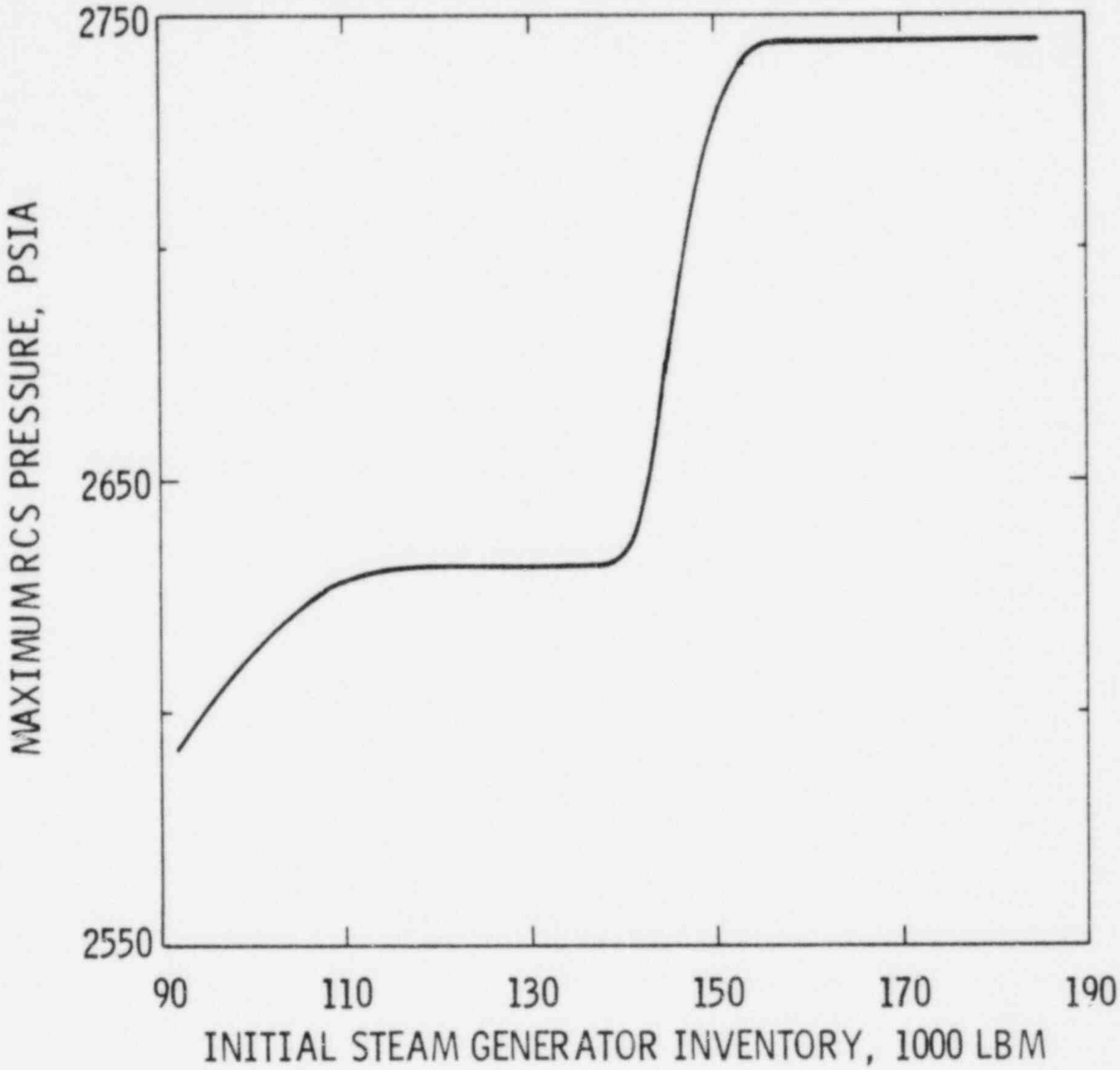
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs FUEL GAS GAP HEAT TRANSFER COEFFICIENT	Figure 15B-9



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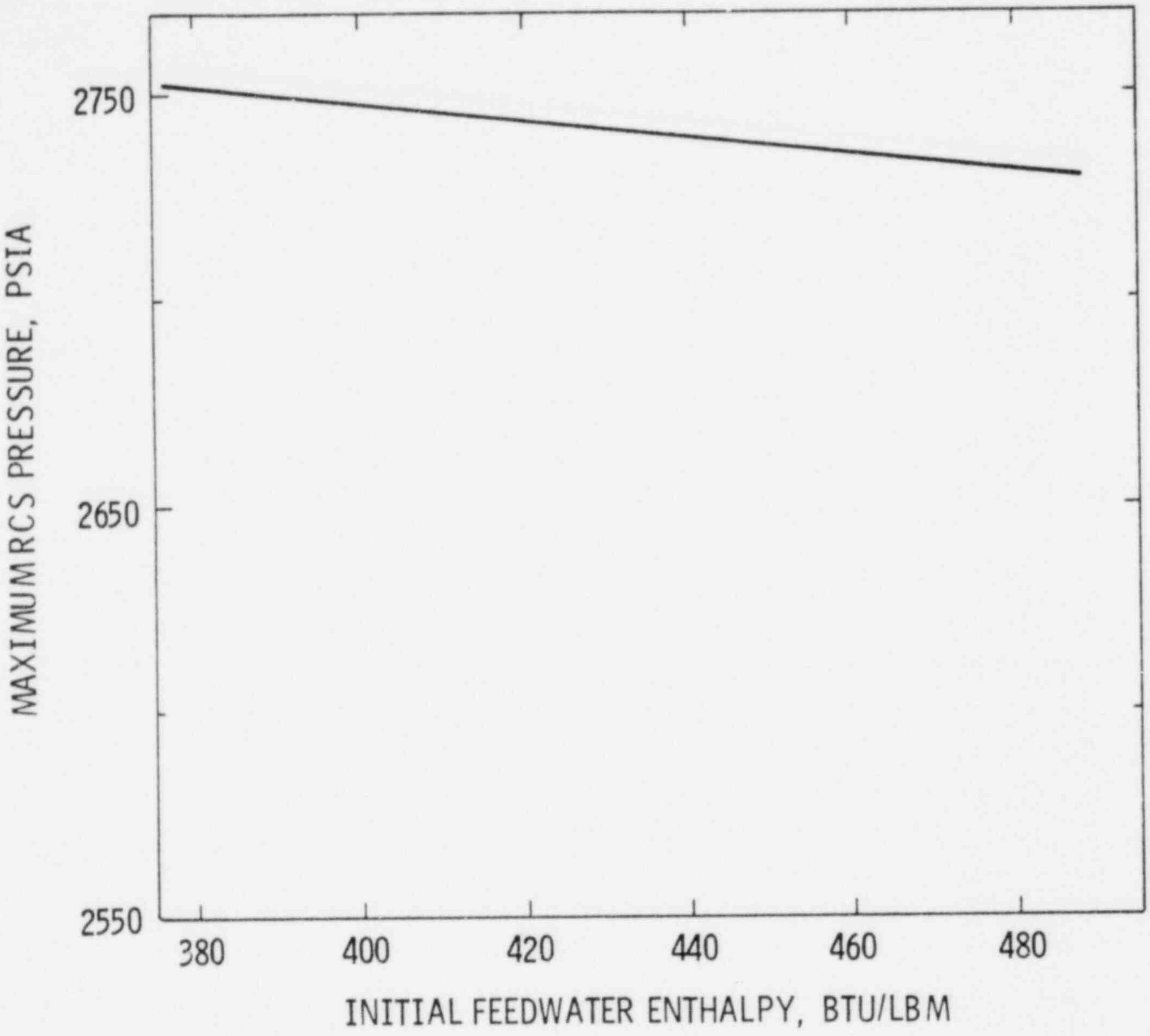
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs INITIAL STEAM GENERATOR INVENTORY	Figure 15B-10



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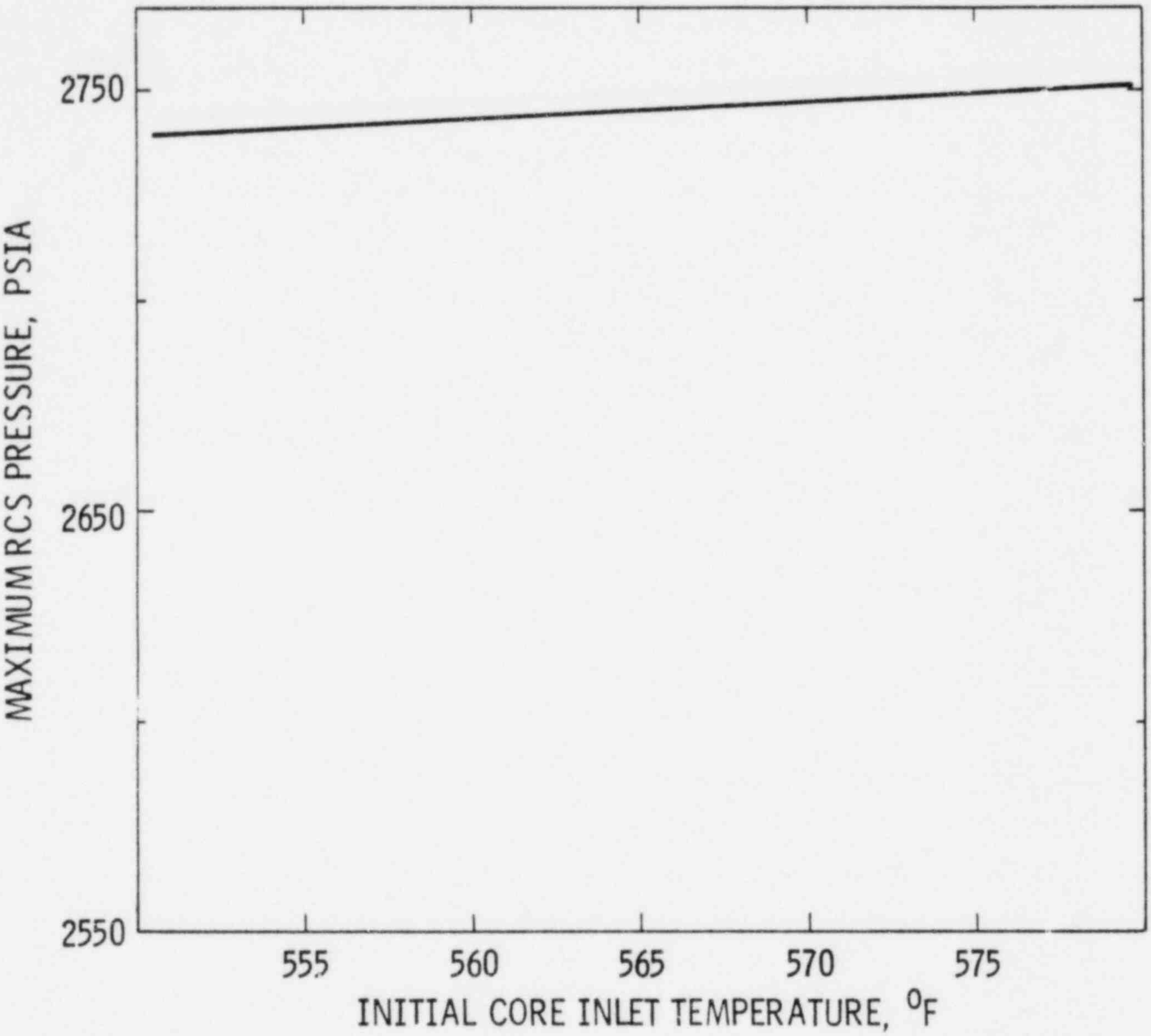
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs FEEDWATER ENTHALPY	Figure 15B-11



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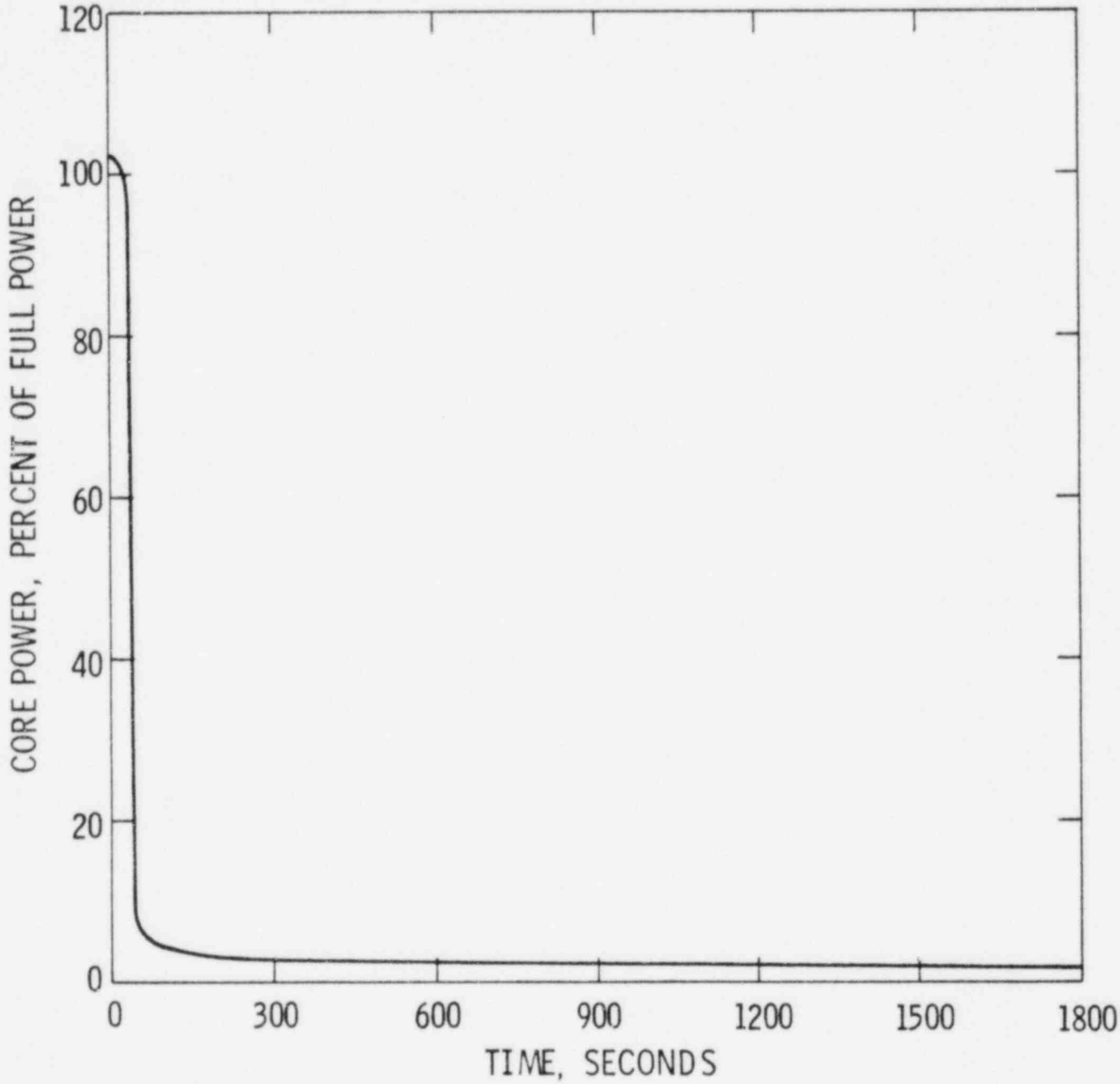
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY MAXIMUM RC SYSTEM PRESSURE vs INITIAL CORE INLET TEMPERATURE	Figure 15B-12



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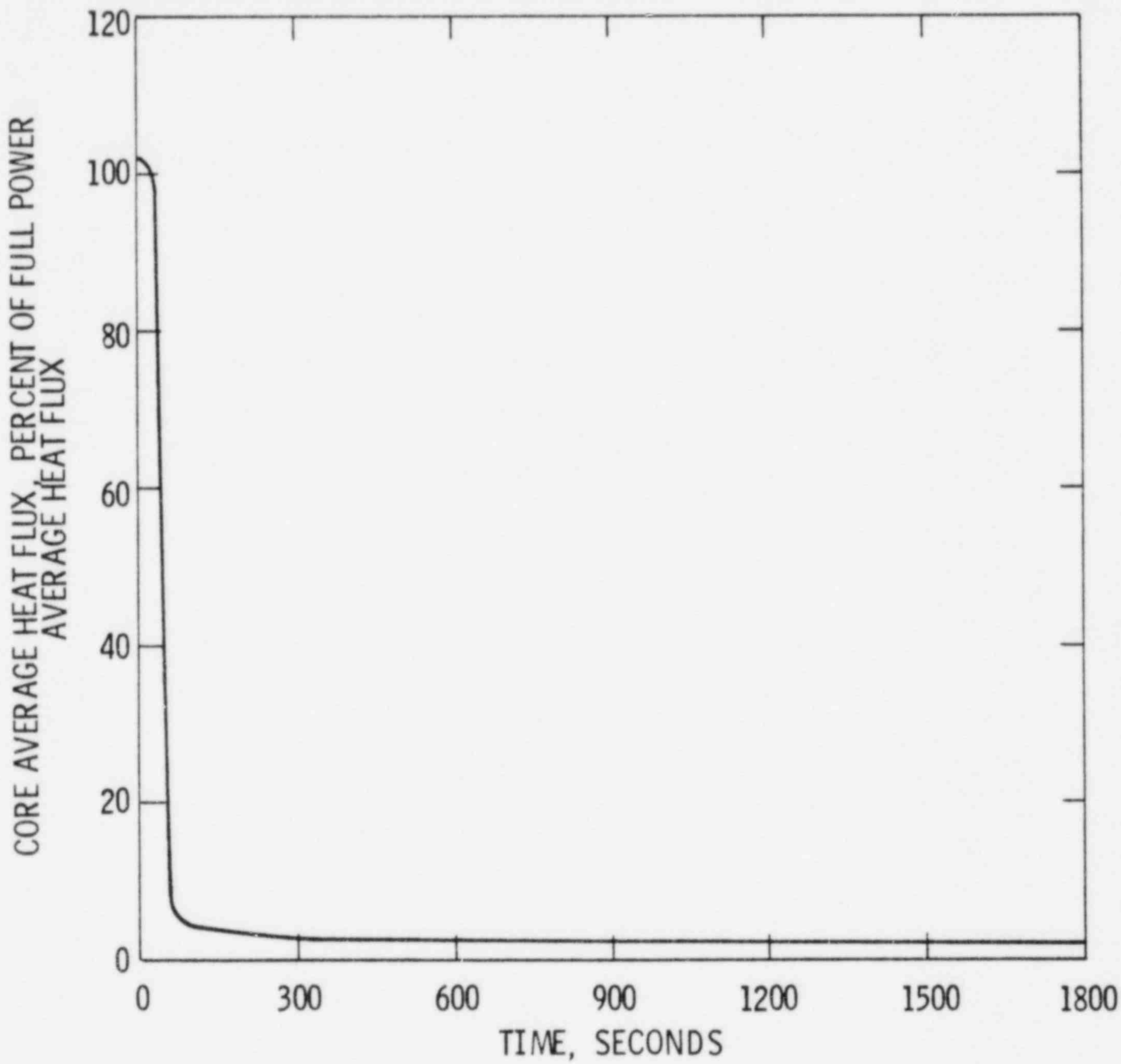
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE CORE POWER vs TIME	Figure 15B-13



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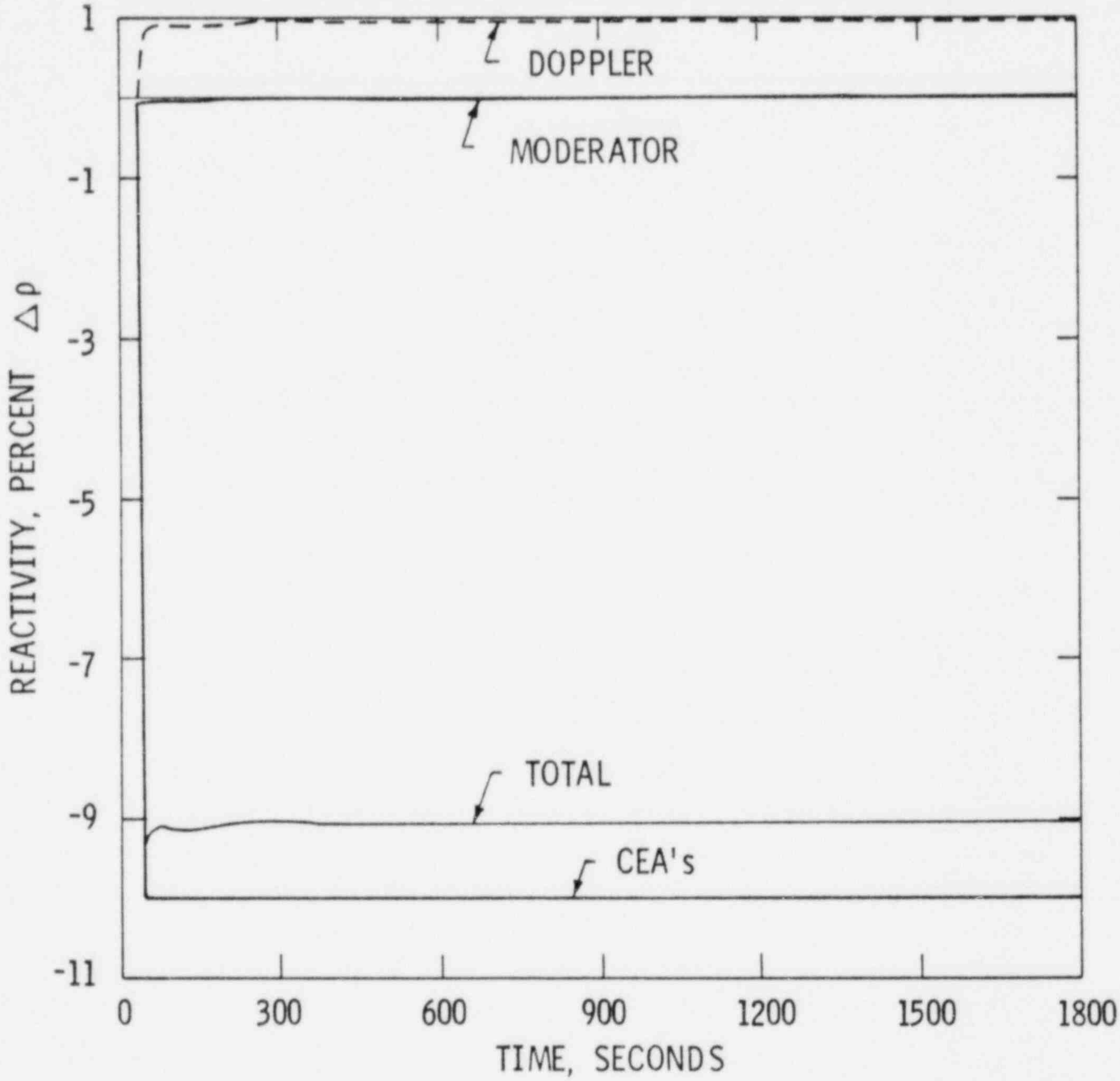
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE CORE AVERAGE HEAT FLUX vs TIME	Figure 15B-14



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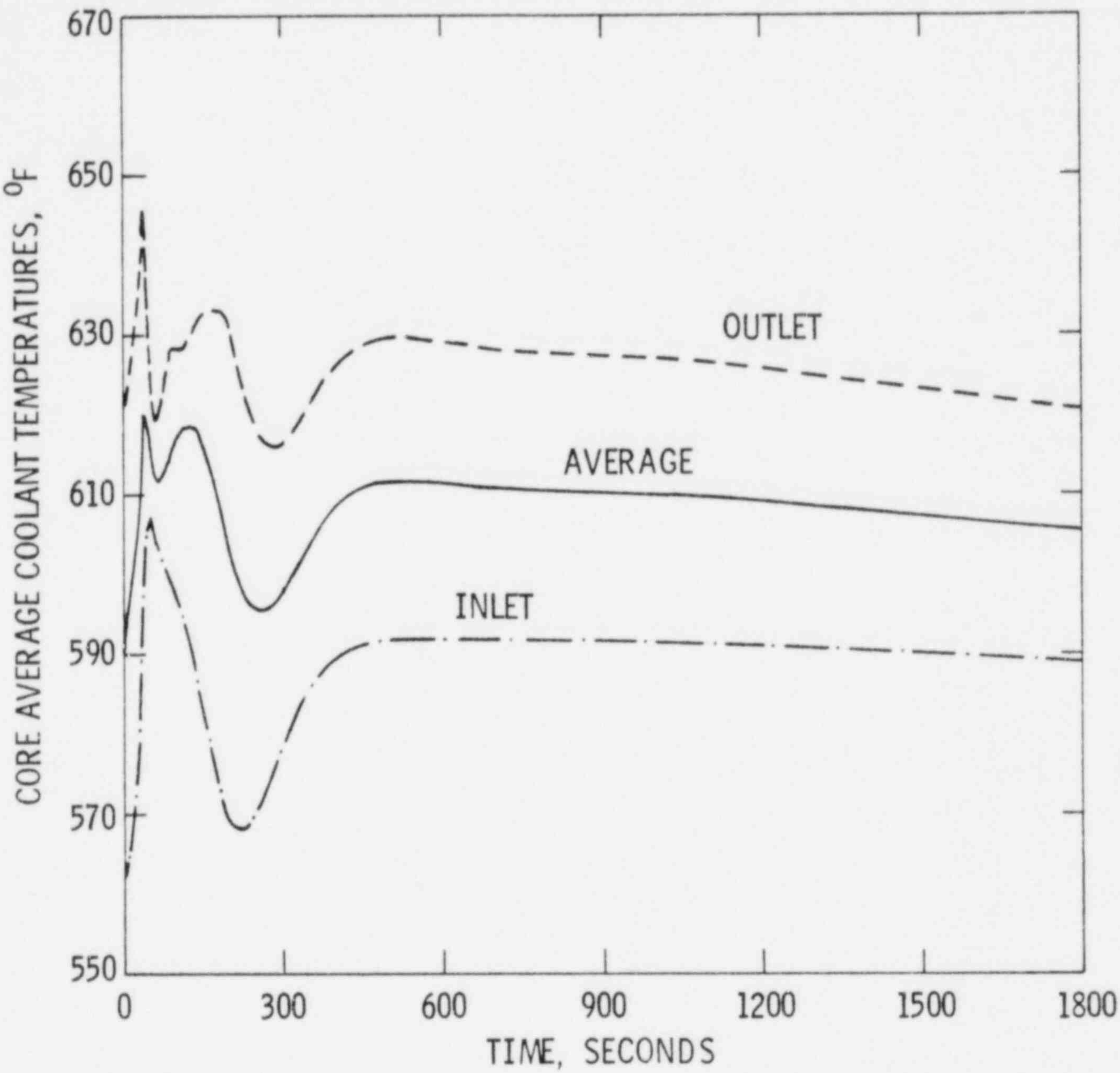
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE REACTIVITY vs TIME	Figure 15B-15



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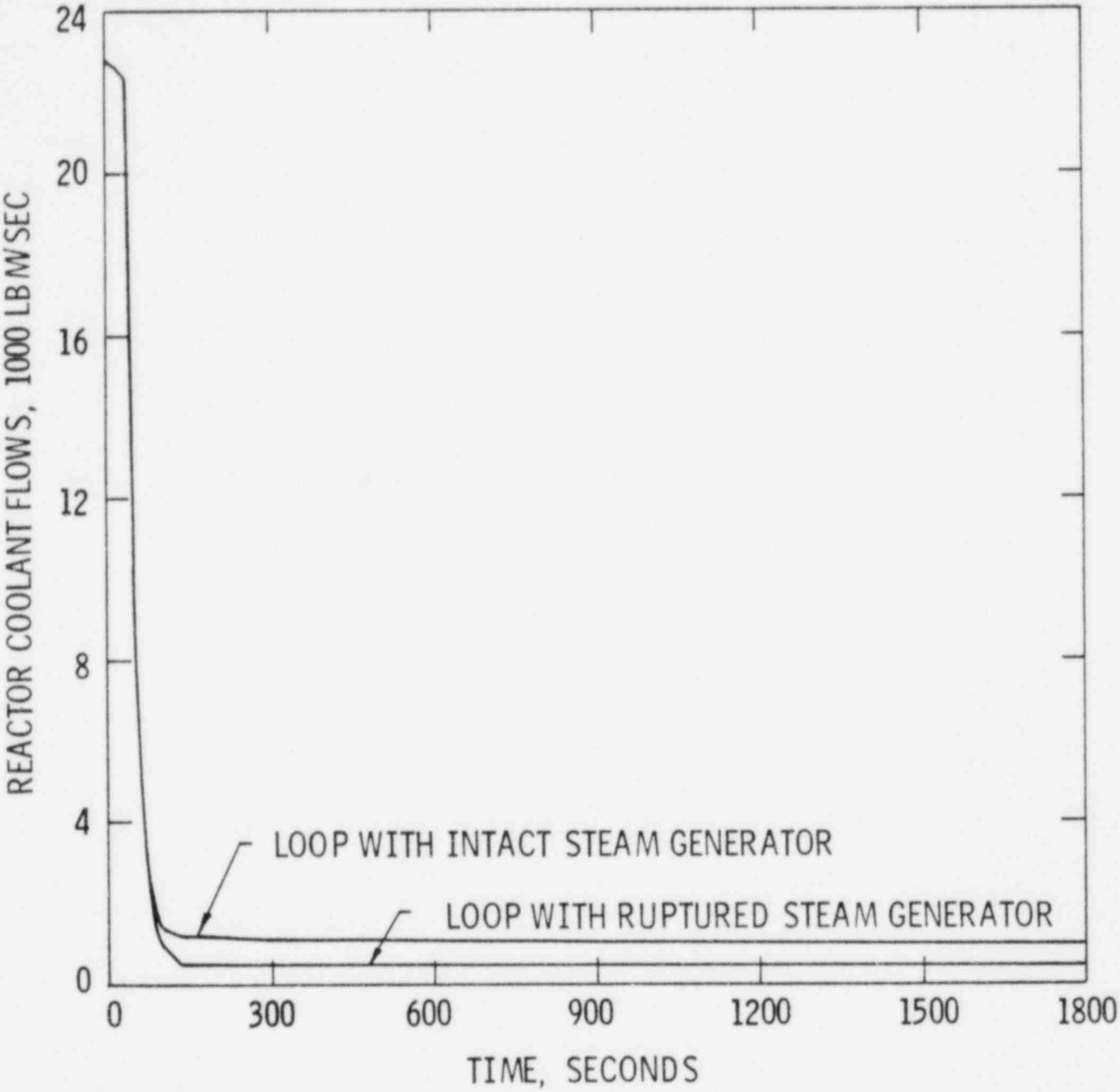
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE CORE AVERAGE COOLANT TEMPERATURE vs TIME	Figure 15B-16



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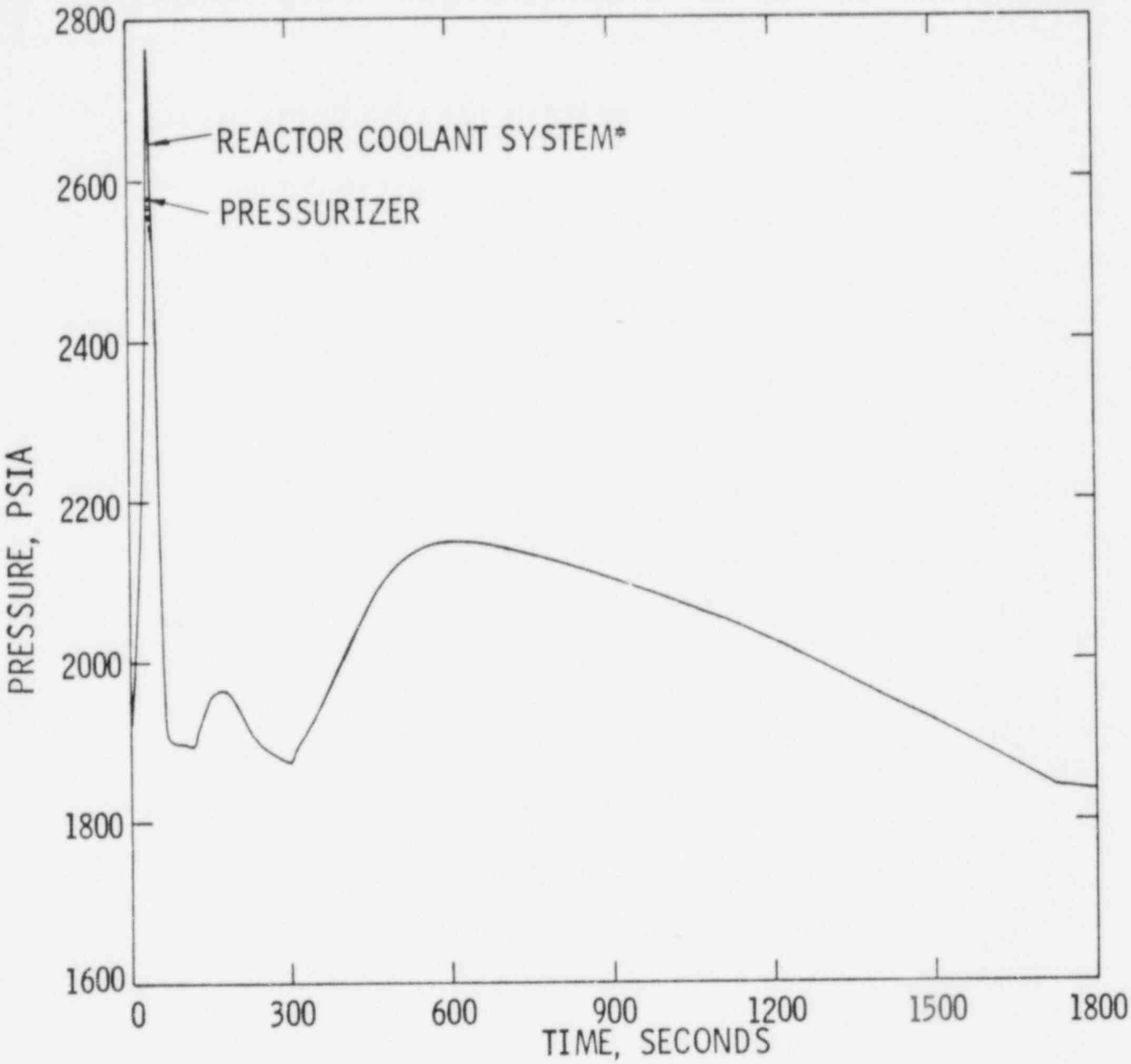
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE REACTOR COOLANT FLOWS vs TIME	Figure 15B-17



*DOES NOT INCLUDE ELEVATION OR REACTOR COOLANT PUMP HEADS

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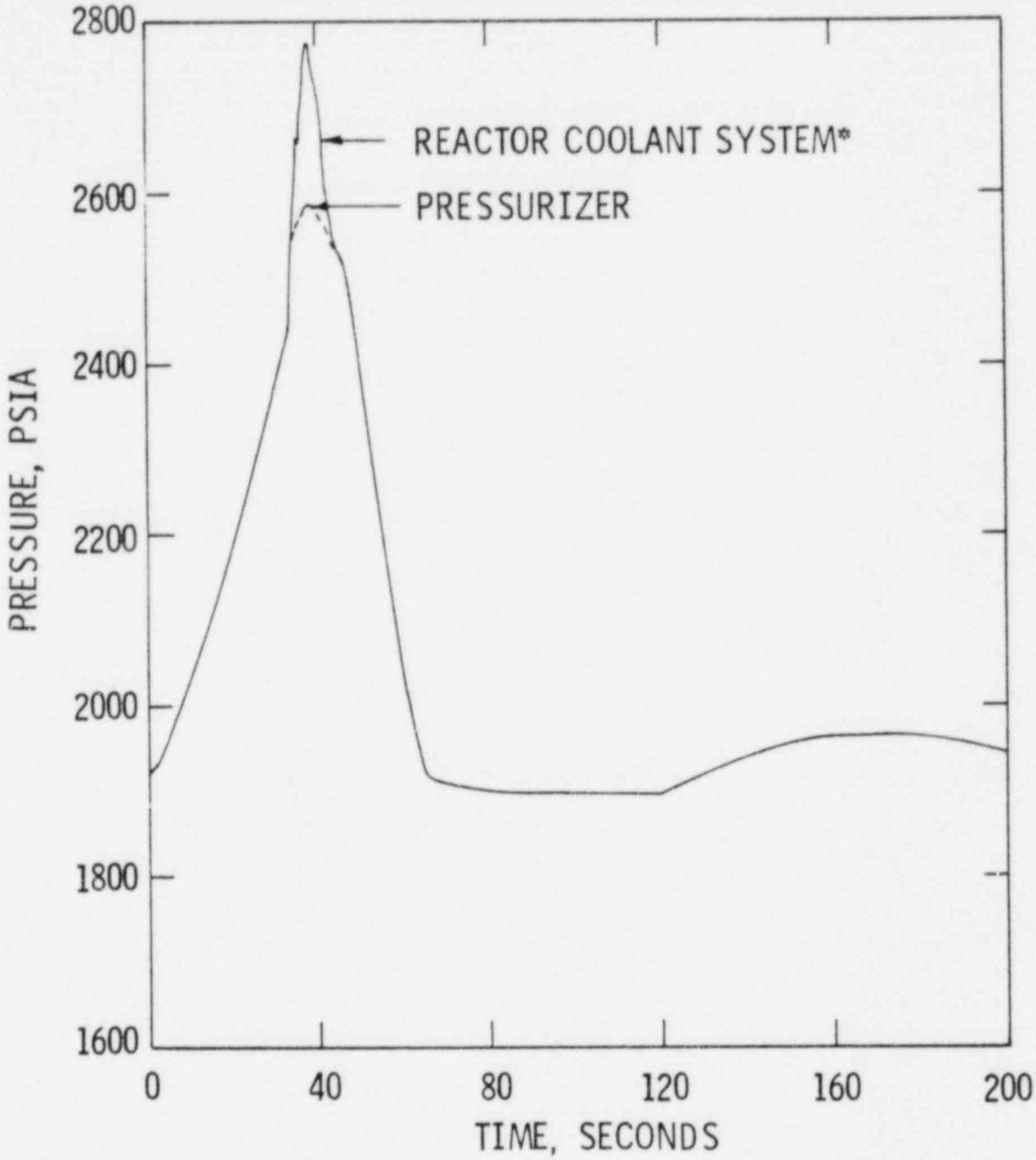
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE RCS AND PRESSURIZER PRESSURE vs TIME	Figure 15B-18



*DOES NOT INCLUDE ELEVATION OR REACTOR COOLANT PUMP HEADS

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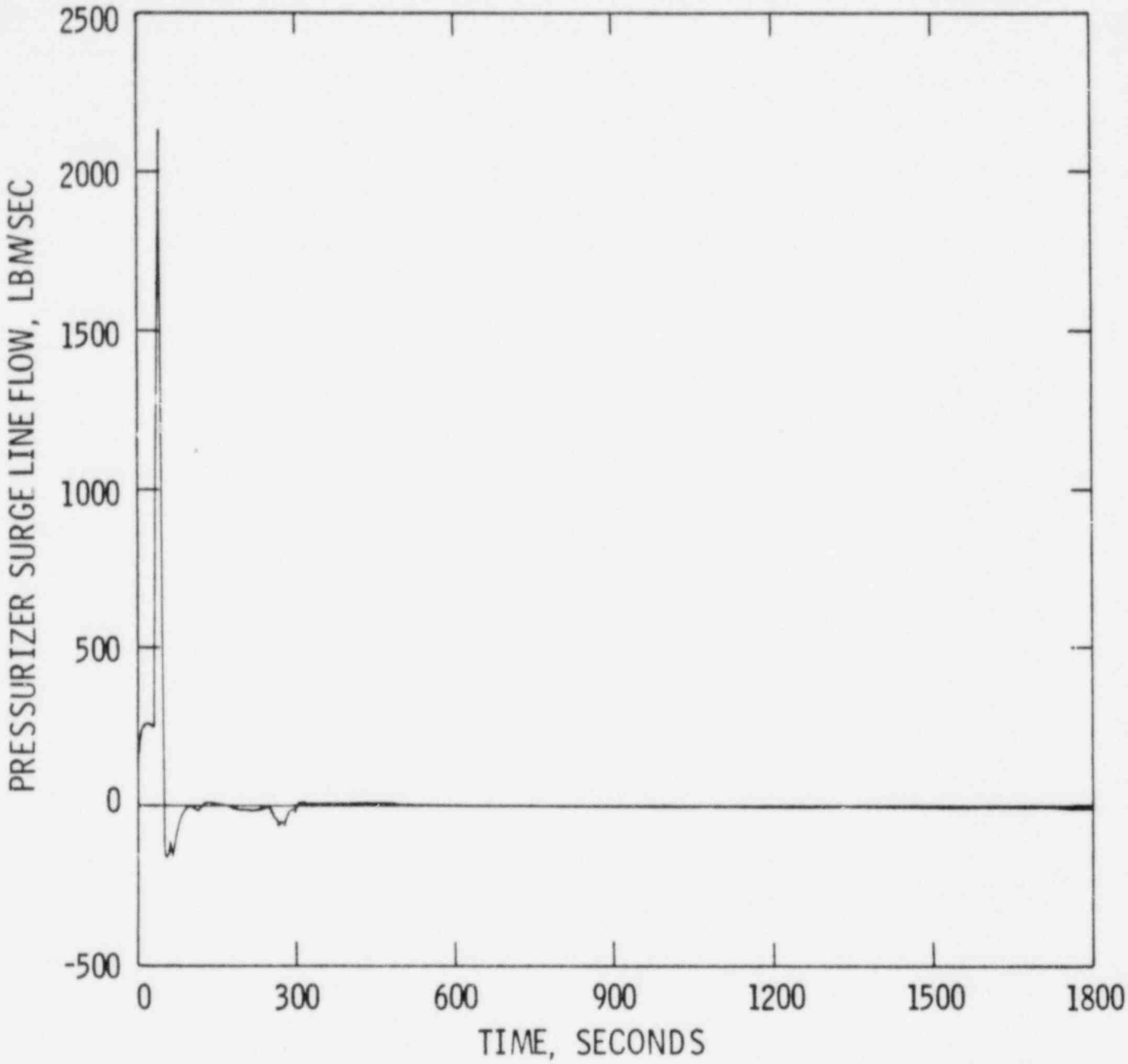
March 31, 1982

C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE RCS AND PRESSURIZER PRESSURE vs TIME	Figure 15B-19



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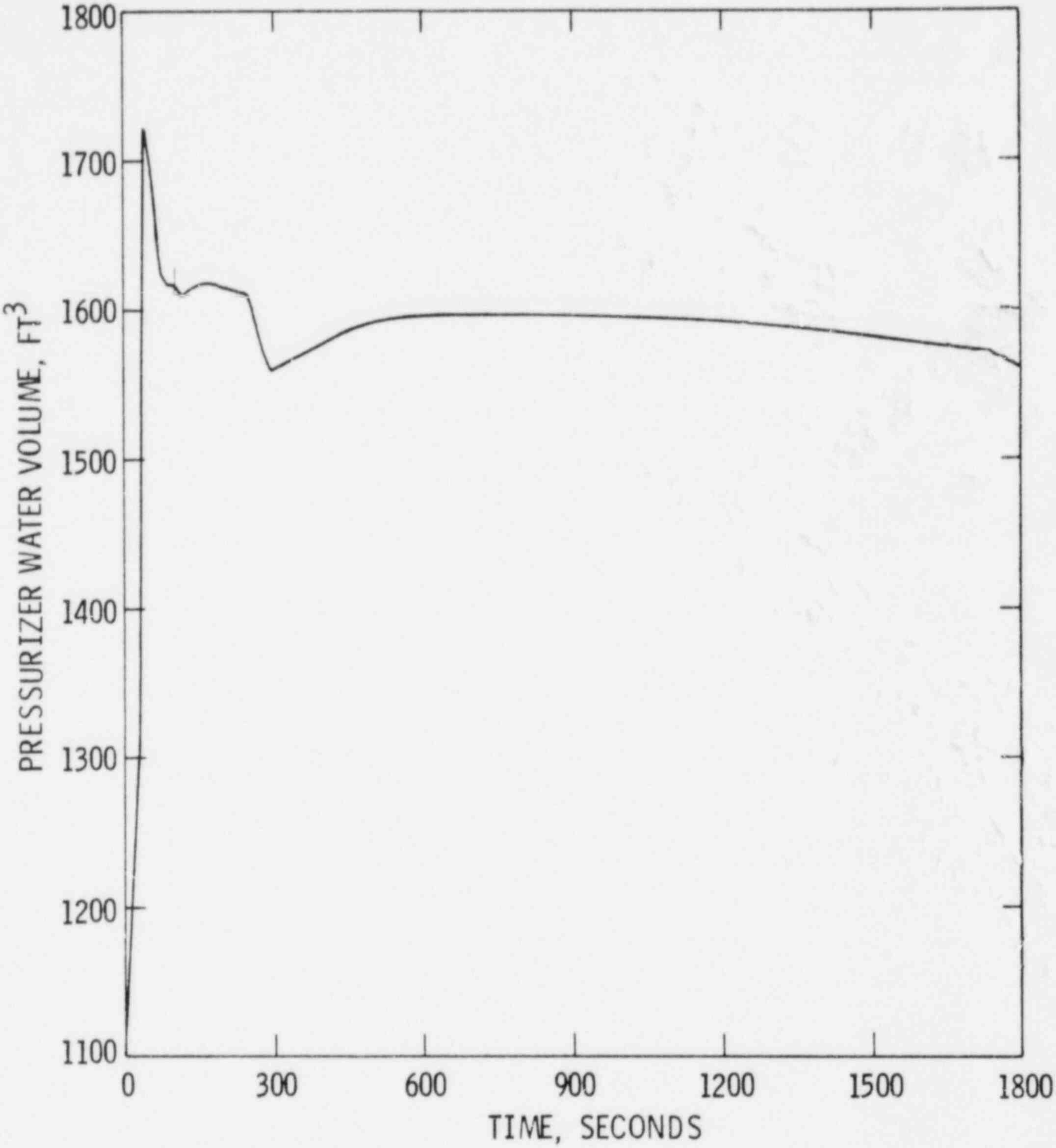
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE PRESSURIZER SURGE LINE FLOW vs TIME	Figure 15B-20



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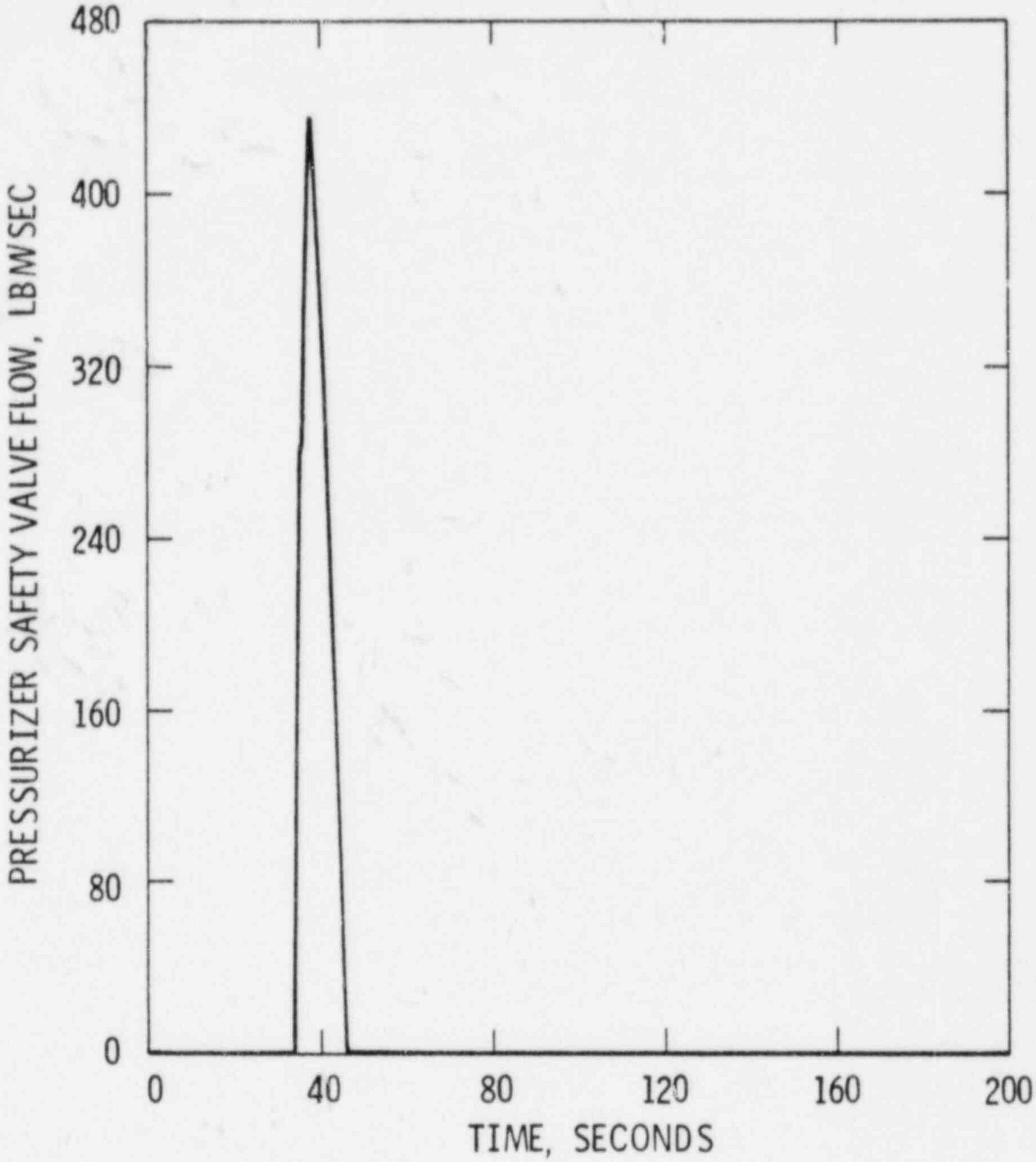
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE PRESSURIZER WATER VOLUME vs TIME	Figure 15B-21



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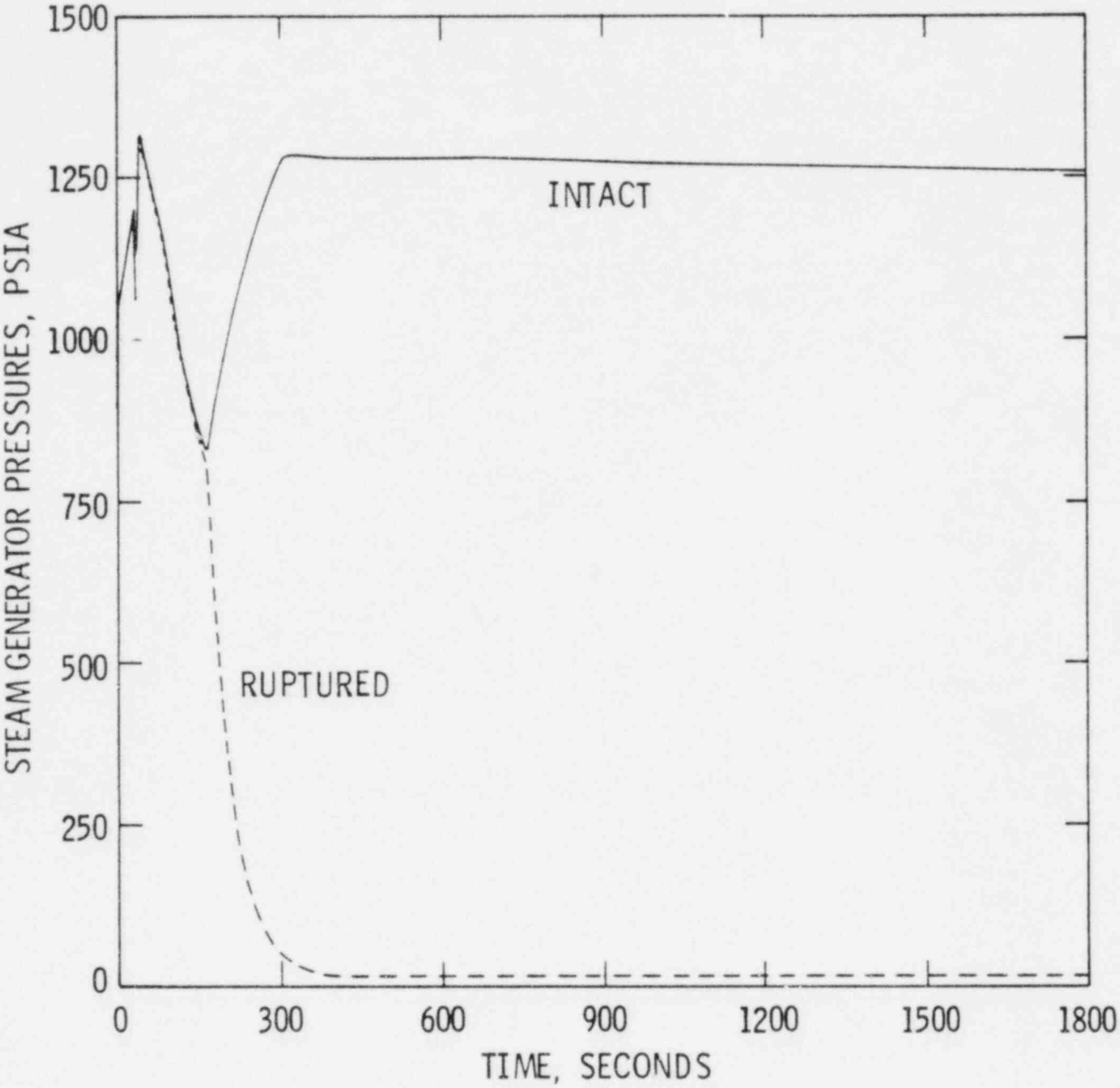
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE PRESSURIZER SAFETY VALVE FLOW vs TIME	Figure 15B-22



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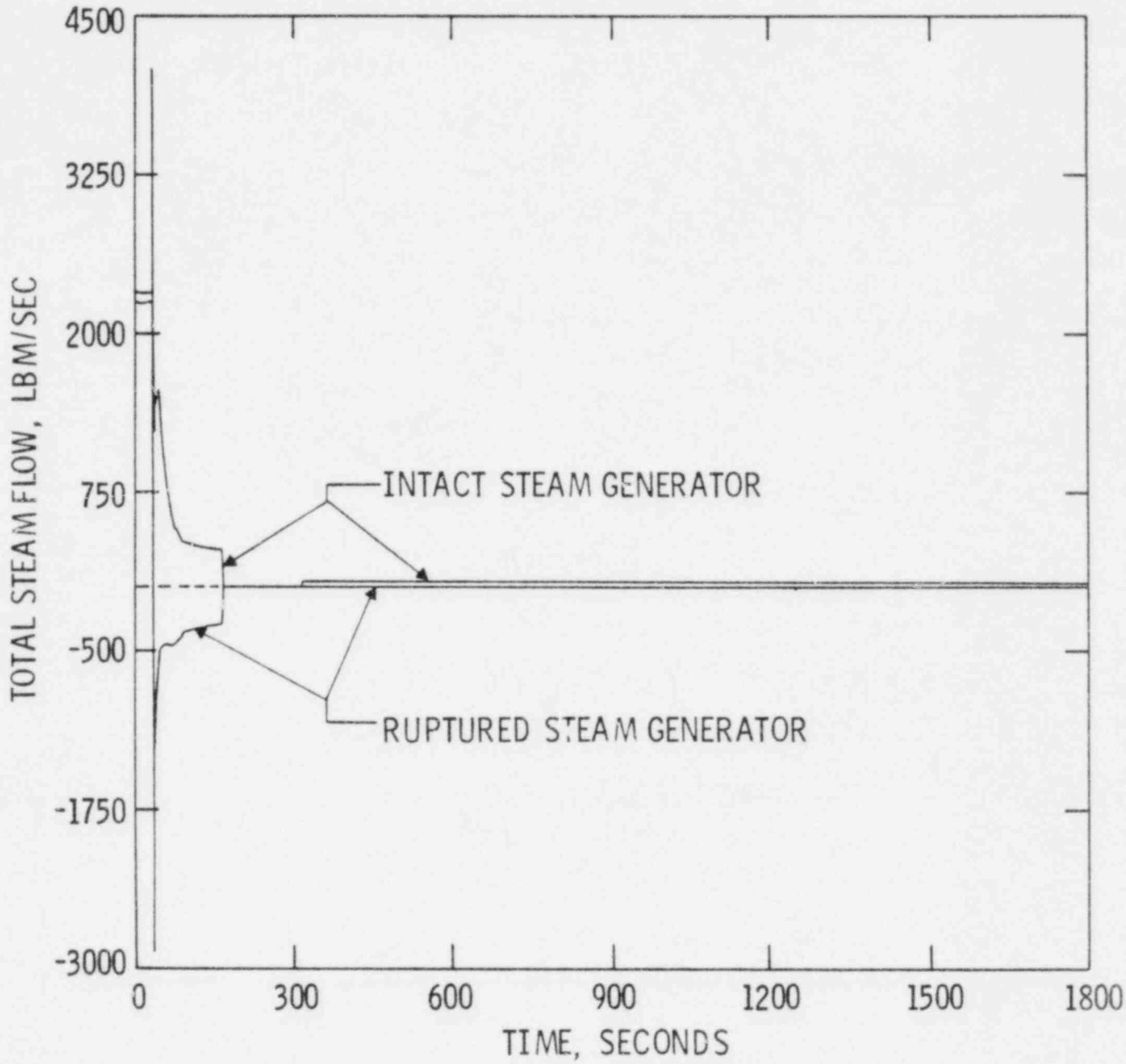
C-E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE STEAM GENERATOR PRESSURES vs TIME	Figure 15B-23



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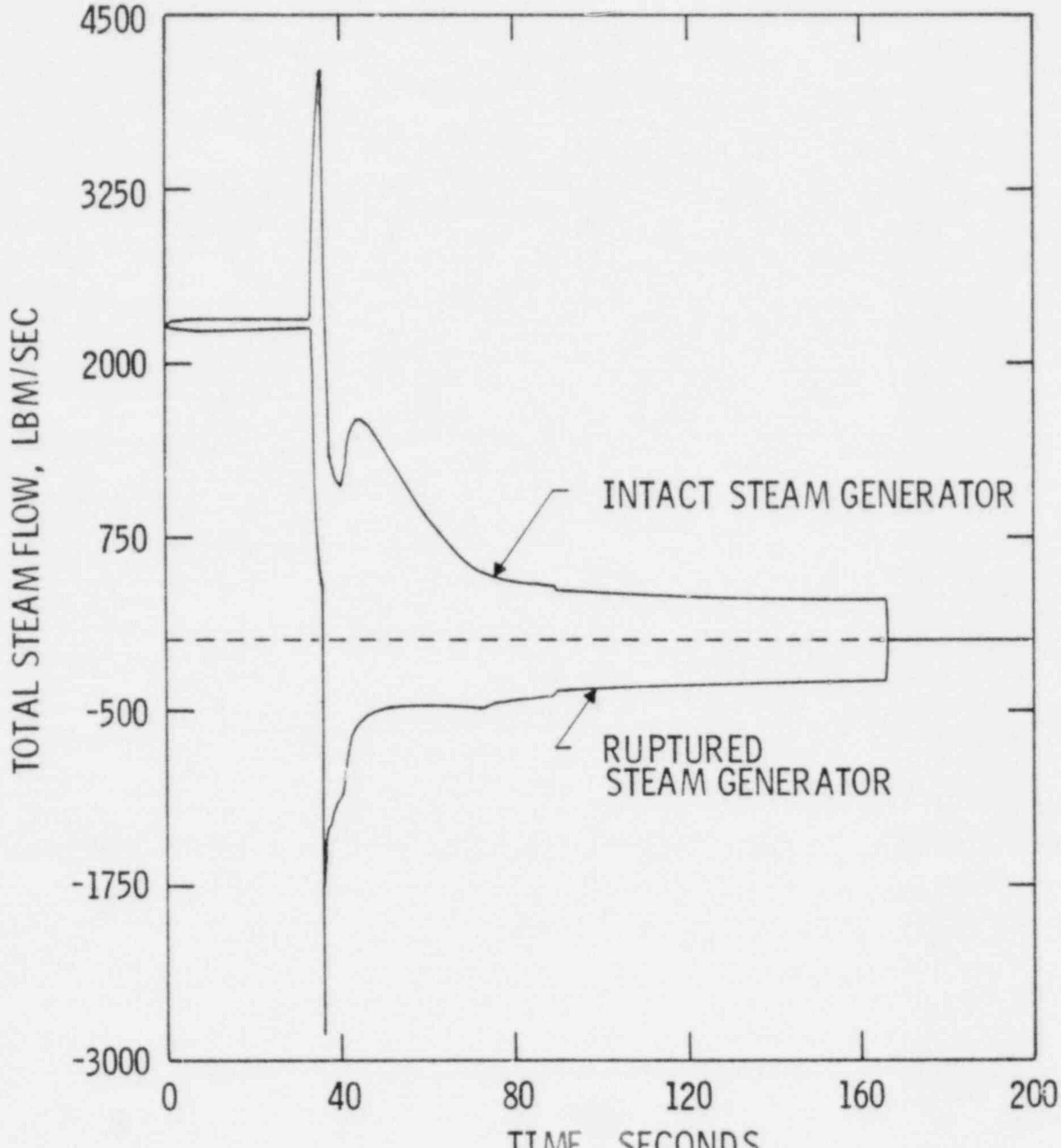
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE TOTAL STEAM FLOW vs TIME	Figure 15B-24



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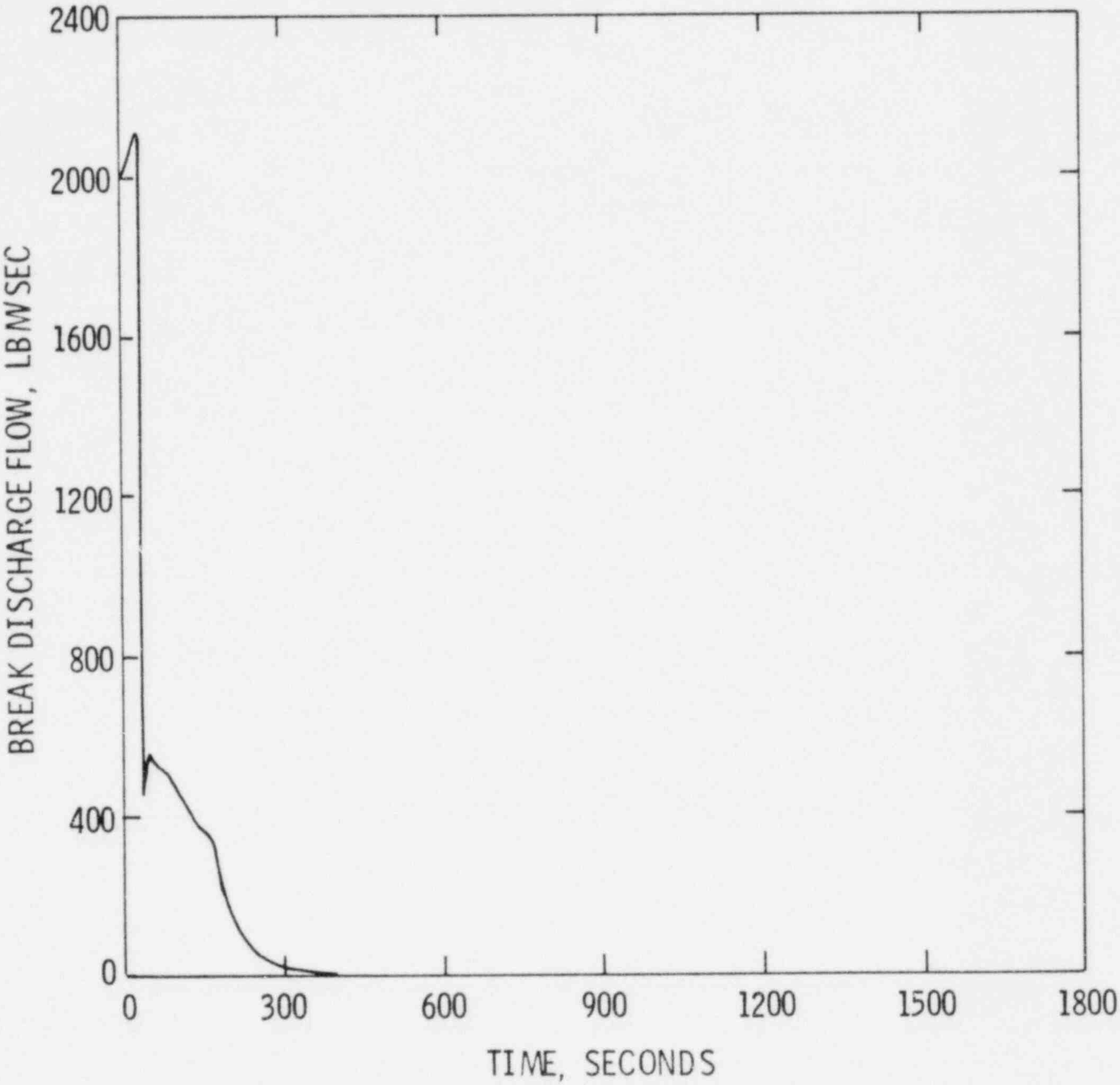
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE TOTAL STEAM FLOWS vs TIME	Figure 15B-25



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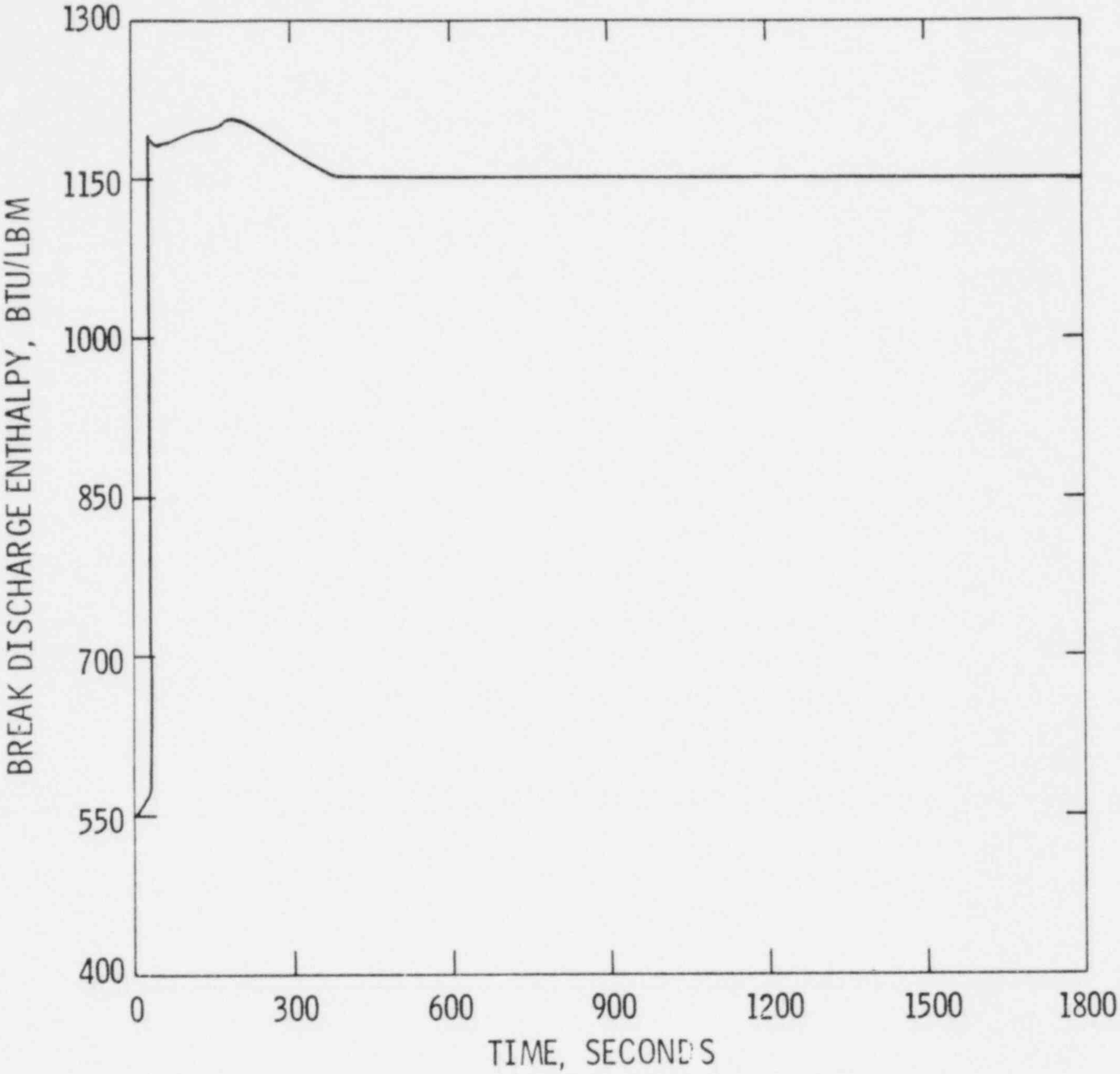
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE BREAK DISCHARGE FLOW vs TIME	Figure 15B-26



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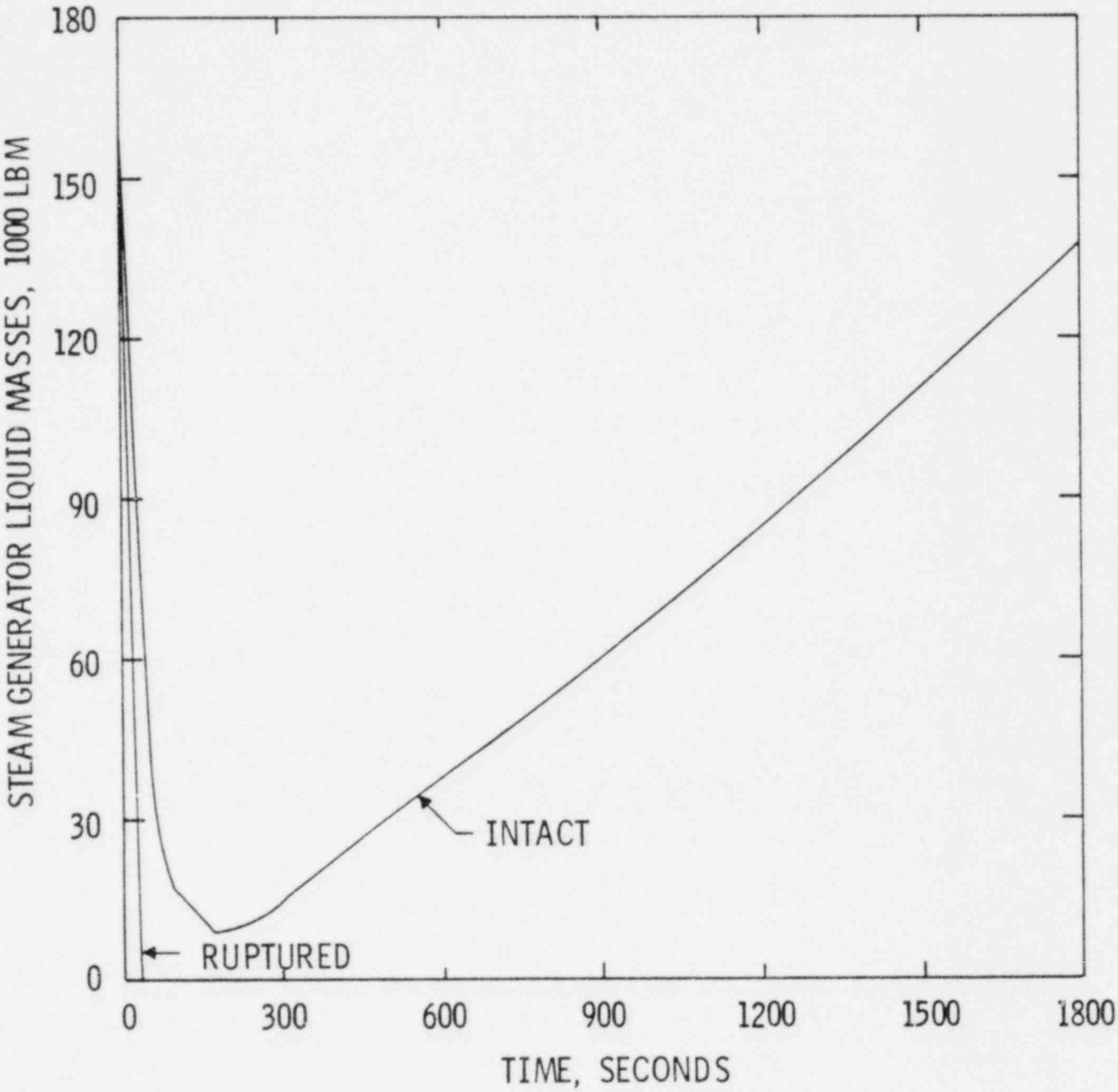
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE BREAK DISCHARGE ENTHALPY vs TIME	Figure 15B-27



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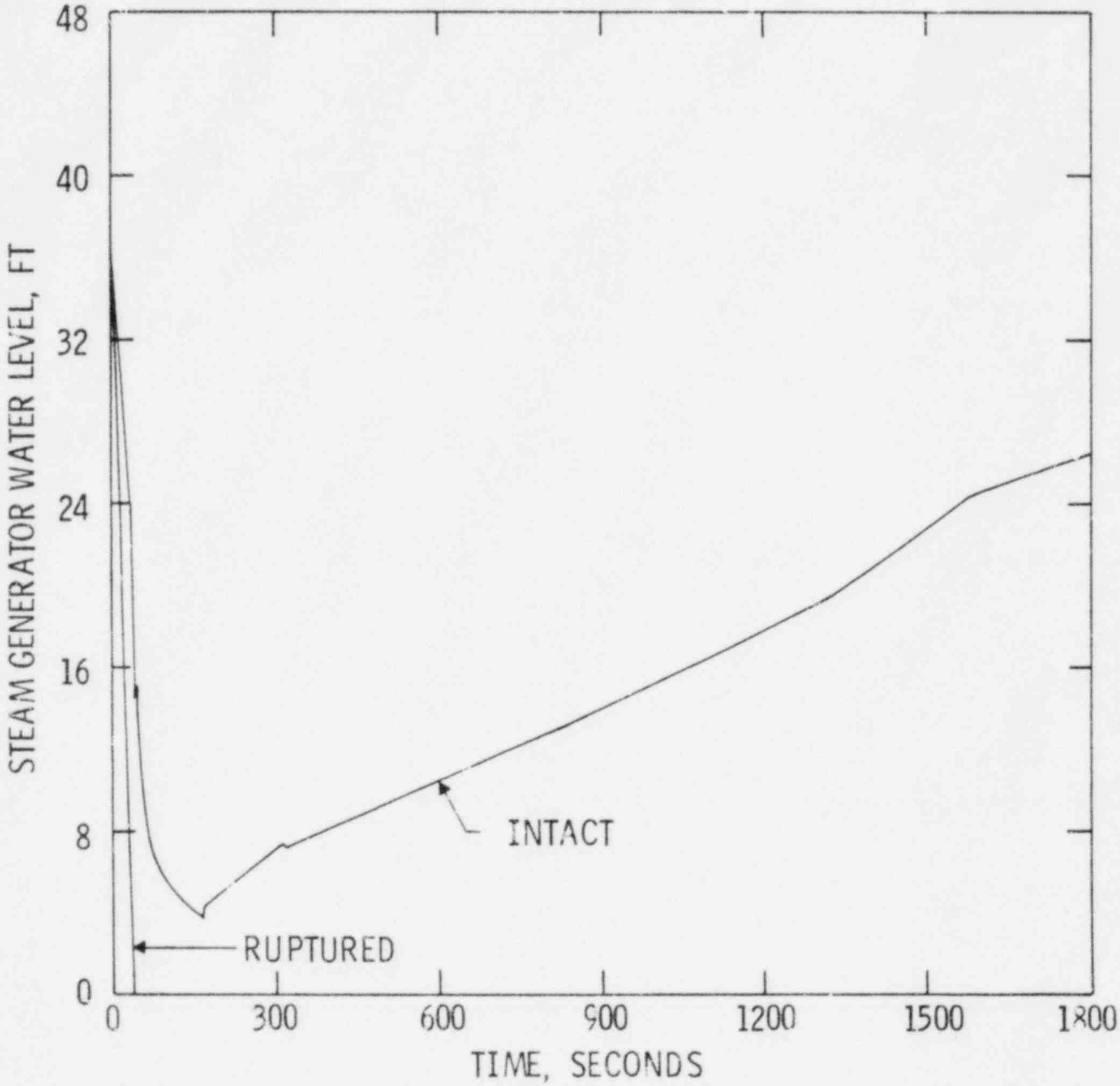
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE STEAM GENERATOR LIQUID MASS vs TIME	Figure 15B-28



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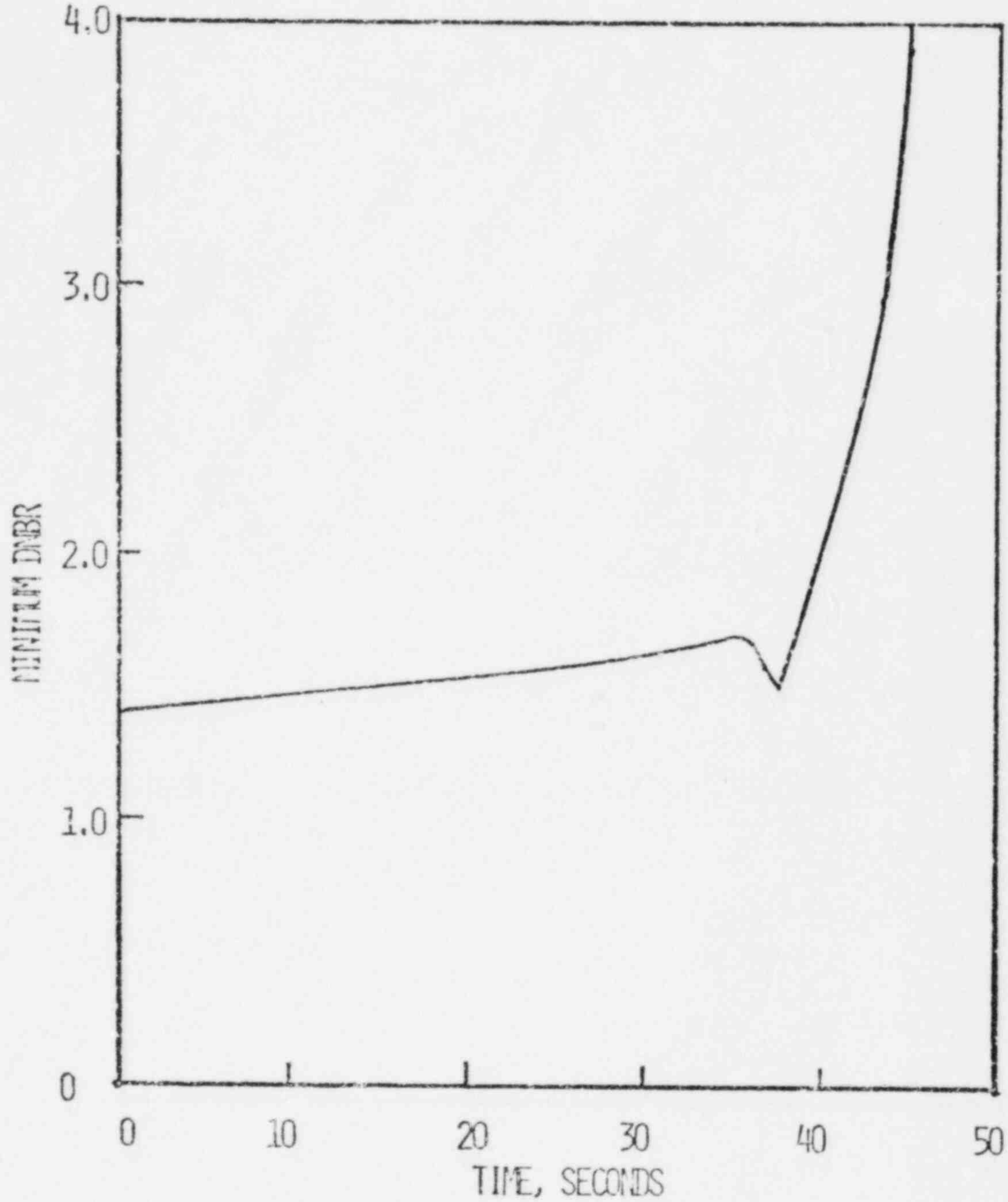
C - E SYSTEM 80	LOSS OF FEEDWATER INVENTORY LIMITING CASE STEAM GENERATOR WATER LEVEL vs TIME	Figure 15B-29



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C-E SYSTEM 80	MINIMUM DNBR vs TIME FOR THE LOSS OF FEEDWATER INVENTORY APPENDIX 15B	Figure 15B-30

APPENDIX 15C

ANALYSIS METHODS FOR STEAM LINE BREAKS

EFFECTIVE PAGE LISTING

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APPENDIX 15C

ANALYSIS METHODS FOR LARGE STEAM LINE BREAKS

15C.1 INTRODUCTION

This appendix provides a description of methods used in the analysis of nuclear steam supply system (NSSS) response to the steam line break (SLB) events presented in Section 15.1.5. Computer codes and supporting calculational methods used in the analysis are discussed in Section 15C.2. Analysis assumptions which were used to maximize the potential for degradation in fuel cladding performance and to maximize radiological releases are discussed in Section 15C.3.

15C.2 MATHEMATICAL MODELS

15C.2.1 PRIMARY AND SECONDARY SYSTEM THERMAL-HYDRAULIC MODEL

The NSSS response to the steam line break was simulated using the CESEC computer program version described in Reference 4. Major model changes relative to versions of CESEC used for earlier FSAR analyses include: (1) a more detailed reactor coolant system (RCS) thermal-hydraulic model to include the effect of temperature tilt in the reactor core during asymmetric transients and an explicit representation of the reactor vessel upper head region, (2) a reactor coolant pump model which, in combination with an RCS loop momentum model, explicitly calculates the time dependent reactor coolant mass flow rate, (3) a safety injection tank model, (4) an RCS metal heat transfer model, and (5) a three-dimensional reactivity feedback model.

The explicit representation of the reactor vessel upper head region, which nominally receives only about one percent of the total reactor vessel flow, produces a more accurate RCS pressure calculation for those transients which result in steam formation in the reactor vessel. In this region the RCS metal heat transfer model accounts for heat transfer between the upper head region fluid and metal (including the vessel wall and cladding, the upper guide structure and the control element assembly (CEA) guide tube shrouds).

The effect of decreasing reactor vessel downcomer fluid temperature on ex-core neutron detector response during steam line break is explicitly modeled in CESEC through the use of a decalibration factor. Ex-core detector decalibration, which is caused by increased neutron attenuation, delays the occurrence of the high core power reactor trip signal during steam line breaks.

15C.2.2 NUCLEAR MODEL

Core power as a function of time is calculated in CESEC using a six delayed group point kinetics model. Moderator, Doppler, boron, and scram rod reactivity contributor are explicitly modeled. The moderator and Doppler reactivity functions are based on two-dimensional PDQ-X (described in subsection 4.3.3.1.1) calculations. Moderator and Doppler reactivities are parameterized as functions of average moderator density and effective fuel temperature, respectively, for use by CESEC. Values used for scram rod worth (with one stuck CEA) as a function of scram rod insertion and for reciprocal boron worth were also calculated using PDQ-X. Reactivity coefficients

corresponding to end-of-cycle operation were used for the steam line breaks appearing in Section 15.1.5 to maximize post-trip reactivity insertion. Calculational uncertainty in the PDQ-X calculations was accounted for through the use of conservative multipliers on the CESEC reactivity functions.

The CESEC three-dimensional reactivity feedback option gives the capability of including three-dimensional reactivity feedback effects associated with core inlet plane temperature distribution, stuck CEA, and changes in core power distribution. The 3-D reactivity contribution is based on HERMITE (described in subsection 4.3.3.1.1) calculations, and is parameterized in CESEC as a function of core inlet plane temperature tilt (difference between hot and cold edge temperatures), core flow, and core fission power. This option was not used for the steam line breaks presented in Section 15.1.5.

15C.2.3 DNBR EVALUATION METHODOLOGY

For steam line breaks initiated from full power conditions, pre-trip DNBR in the hot channel was calculated using the TORC computer code discussed in Subsection 15.0.3.1.6, and the CE-1 critical heat flux correlation described in CENPD-162. The initial axial core power distribution was determined by selecting the most adverse* axial shape index (ASI) allowed by the core operating limit supervisory system (COLSS) for steady-state conditions. The allowed axial shapes for steady-state full power conditions were calculated using the QUIX computer program, which is discussed in Subsection 4.3.3.1.1. The initial power distribution was used from beginning of the transient until reactor trip. Average core heat flux, reactor coolant flow rate, RCS pressure, and core inlet temperature from CESEC are provided as input to TORC. The planar radial peaking factor provided as input to TORC corresponds to the most adverse* radial peak at the ASI for which the power operating limit (POL) is not exceeded.

The determination of DNBR for post-trip steam line break conditions requires methods which differ from those described above. This is due to the fact that the verified range of the CE-1 correlation dose not cover low pressures and low flow rates. Therefore the Macbeth DNBR correlation (References 1 and 2) has been selected to represent margin to DNB during periods of return-to-power.

Macbeth correlates critical heat flux to mass flux, inlet subcooling, pressure, heated diameter, and channel length. Application of a channel heat balance allows the correlation to be converted to a "local conditions" form. Using this local conditions form of the correlation, critical heat flux as a function of height in the hot channel (which is located near the stuck CEA location) is calculated, where the effect of non-uniform axial heating is incorporated using the method applied by Lee (Reference 3).

Open core calculations indicate that local quality in the hot channel during steam line break post-trip return-to-power conditions seldom exceeds a few percent, regardless of fission power rate or core average mass flux. This occurs due to the assembly cross-flow effects. The presence of low density liquid or of voids at the top of the hot channel causes post-trip power generation to occur near the bottom of the core. For return-to-power DNBR

*See Section 15C.3.2

calculations an integrated radial peaking factor of 15 and an axial peaking factor of 3 are used to bound all possible power distributions unless explicit 3-D HERMITE calculations are performed. Enthalpy as a function of height is computed by performing a closed channel heat balance. Hot channel inlet enthalpy is set equal to the average enthalpy predicted by CESEC for the fluid at the core inlet for that half of the core on the side associated with the affected steam generator. Maximum enthalpy is limited to that corresponding to 20% quality at the system pressure, to account for the cross-flow effect.

15C.3 INPUT PARAMETERS AND INITIAL CONDITIONS

15C.3.1 GENERAL

The consequences of steam line breaks are evaluated with respect to criteria on:

a. over-pressure

b. fuel performance, and

c. radiological releases

Steam line breaks are initially depressurization events. During the portion of the transient after steam generator dryout and before operator action, some repressurization can occur due to safety injection pump flow, decay heat addition, and heat transfer from the hotter walls and structure of the RCS. However, the emergency feedwater system and the primary and secondary system safety valves are designed to relieve in excess of the energy available from these sources while maintaining primary and secondary pressures at, or below, design pressure. Therefore, input parameters and initial conditions were not chosen to maximize over-pressure for the analyses of SLB initiated transients.

Degradation in fuel performance can occur during SLB initiated events either during the portion of the transient prior to and during reactor trip (henceforth referred to as the pre-trip portion) or during the post-trip return-to-criticality, or approach-to-criticality, portion of the transient (henceforth referred to as the post-trip portion). Input parameters and initial conditions which maximize the potential for pre-trip degradation in fuel performance are discussed in Section 15C.3.2. Input parameters and initial conditions which maximize the potential for post-trip degradation in fuel performance are discussed in Section 15C.3.3. The departure from nucleate boiling ratio (DNBR) provides a measure of fuel performance. Therefore the discussions of potential for degradation in fuel performance will be in terms of those parameters which can decrease local DNBR (i.e., degrade fuel performance) for the conditions present in a PWR during SLBs:

a. increase in local heat flux,

b. decrease in coolant flow,

c. decrease in coolant pressure, and

d. increase in coolant temperature.

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If there is a potential for degradation in fuel performance such that more than a very small fraction (on the order of 0.1% for System 80) of the fuel pins in the core must be assumed to fail, then offsite doses are sufficiently dominated by the contribution from primary system activity that assumptions which maximize the potential for degradation in fuel performance also maximize the radiological releases. If there is not a potential for degradation in fuel performance such that more than a very small fraction of the fuel pins in the core must be assumed to fail, then offsite doses are sufficiently dominated by the contribution from secondary system activity that assumptions which affect the contribution of the secondary system activity to the offsite dose must be considered. The input parameters and initial conditions which maximize the contribution of the secondary system activity to the offsite dose are discussed in Section 15C.3.4.

15C.3.2 PARAMETERS AND CONDITIONS FOR MAXIMIZING PRE-TRIP DEGRADATION IN FUEL PERFORMANCE

Due to the protective action of the core protection calculators (CPCs) the pre-trip minimum transient DNBR will be nearly the same for a wide spectrum of steam line break sizes, initial conditions, and analysis assumptions. The CPC low DNBR trip ensures that no more than 0.7% of the fuel pins will be calculated to experience DNB during any outside containment SLB. In the SLB transient presented for pre-trip degradation in fuel performance in Section 15.1.5 (Case 5), the CPC trip is taken at a time which illustrates an approach to this limit on fraction of fuel which will be calculated to experience DNB. The initial conditions chosen for RCS pressure and temperature, core flow, and power are such as (a) to make the initial state near a power operating limit for the values of ASI and radial peaking factors used and (b) to achieve a transient minimum DNBR less than 1.19, thus requiring the protective action of the CPCs. The value of ASI and radial peaking factor, F_R, are chosen to maximize the fraction of fuel pins calculated to experience DNB for a given transient minimum DNBR. The most negative ASI (-0.3) and the lowest F_R (1.4) were found to yield the largest fraction of fuel pins calculated to experience DNB for a given minimum DNBR. Assumptions concerning initial pressurizer water level and initial steam generator water level have little or no impact on the transient DNBR.

One analysis assumption does impact the minimum transient DNBR: For cases initiated from a power operating limit and where loss of offsite power is assumed to occur concurrent with the SLB, there will be a CPC trip on projected DNBR within the first 0.6 second of the initiation of the event. Thus the CPC trip occurs much earlier in the transient for cases with concurrent loss offsite power than for cases with offsite power available. The loss of flow (LOF) due to RCP coastdown causes a more rapid rate of reduction in DNBR for the SLB cases with concurrent loss of offsite power. However the power operating limit is determined such that the CPC trip will prevent the transient minimum DNBR due to a LOF from being less than 1.19. The only significant additional effect of the SLB, over that of the LOF, up to the time of minimum transient DNBR will be a reduction in RCS pressure. Therefore for SLBs with concurrent loss of offsite power the transient minimum DNBR will be only incrementally lower than 1.19. Analyses done to determine the transient minimum DNBR for SLBs with concurrent loss of offsite power have shown that

this minimum DNBR is not less than 1.13. Thus the minimum DNBR for SLBs with concurrent loss of offsite power is less adverse than the minimum DNBR for the SLB events with offsite power available discussed in Case 5 of Section 15.1.5.

15C.3.3 PARAMETERS AND CONDITIONS FOR MAXIMIZING POST TRIP DEGRADATION IN FUEL PERFORMANCE

15C.3.3.1 Background

Degradation in fuel performance during the post-trip portion of SLB initiated transients can only occur if there is a return-to-power (R-t-P). Therefore the primary consideration for maximizing post-trip degradation in fuel performance is to select those parameters and conditions which will maximize R-t-P. The magnitude of R-t-P is primarily determined by the value of the maximum post-trip reactivity, the timing of this reactivity, and the duration of the reactivity peak. (Other parameters which can affect the R-t-P, such as delayed neutron fraction, have a minor effect within the range of values of the parameters. These other parameters are therefore chosen to be appropriate to the core burnup which yields the maximum transient post-trip total reactivity.) The timing of the maximum post-trip reactivity has an important effect on the post-trip R-t-P: the same reactivity will produce less R-t-P later in a transient since (a) fission power will have decreased to a lower value prior to R-t-P, requiring more multiplication to reach a given power level, and (b) the delayed neutron background will be lower, requiring more reactivity to produce a given, positive rate of change of power. The duration of the reactivity peak is important in that this parameter determines how long the post-trip power will continue to rise (if a R-t-P occurs) before being turned around by decreasing reactivity.

For transients which result in R-t-P, degradation in post-trip fuel cladding performance (measured by the DNBR) is impacted strongly by core flow at the time of R-t-P. Core flow at the time of R-t-P is primarily a function of the analysis assumption on time of reactor coolant pump coastdown. Initial conditions and possible single failures have little or no effect on this core flow. For the range of pressure and temperature involved, the direct effect of pressure and temperature upon post-trip DNBR is small compared with the impact of these parameters upon fuel performance through their effect on the magnitude of the R-t-P via the reactivity feedbacks.

Initial conditions which impact the R-t-P are discussed in Section 15C.3.3.2. The effect of analysis assumptions on the R-t-P and the core flow at time of R-t-P are presented in Section 15C.3.3.3. A discussion of the effect of possible single failures on R-t-P is presented in Section 15C.3.3.4.

15C.3.3.2 Plant Initial Conditions

The impact of initial conditions on the potential for post-trip degradation in fuel performance is through their effect on R-t-P via the magnitude, timing, and duration of the post-trip total reactivity peak. These effects act through their contributions to the moderator reactivity, the Doppler reactivity, and the safety injection boron reactivity.

The ranges of the parameters given in Table 15.0-5 (with the restriction on core inlet coolant temperature given in footnote 2 of that table) were

considered in establishing the most adverse initial plant state for R-t-P. (The radial peaking factors given in Table 15.0-5 are not used for post-trip analysis. See the discussion in Section 15C.2.3.) For System 80 this most adverse state has been found to be the maximum core power, most positive ASI, minimum core flowrate, maximum pressurizer water level, maximum core inlet coolant temperature, maximum reactor coolant system pressure, and maximum water level in the affected steam generator with the water level in the unaffected steam generator at the maximum value which can exist initially and still result in emergency feedwater actuation at the time of main steam isolation valve closure (i.e., the transient time of minimum level).

Maximizing the core power and core inlet temperature and minimizing the core flow impact the R-t-P adversely via their effect of maximizing RCS average temperature and core outlet temperature. Maximizing RCS average temperature maximizes the rate of cooldown since it maximizes steam generator pressure. Maximizing RCS (core) average temperature also causes the cooldown to occur over a more adverse portion of the moderator reactivity function, i.e. the portion having the greatest rate of change of reactivity with temperature. Maximizing core outlet temperature maximizes the energy stored in the water and metal of the upper head region of the reactor vessel and also maximizes the saturation pressure of the water in this region. As the RCS pressure falls below the saturation pressure of the liquid in the upper head region, the stored energy provides the energy necessary to vaporize this liquid, resulting in a low rate of decrease of RCS pressure below the saturation pressure of the liquid in the upper head. This in turn minimizes the safety injection boron reactivity at the time of R-t-P, since the safety injection actuation signal is delayed and the safety injection pump flow is impeded by the higher transient pressures.

Use of the most positive ASI maximizes the delay in insertion of CEA reactivity following trip. This has little effect on the R-t-P. Maximizing pressurizer water level and pressure maximizes the energy stored in the pressurizer. This maximizes transient RCS pressures, delaying and impeding safety injection flow.

Maximizing steam generator water level in the affected steam generator maximizes the amount of cooldown, thus maximizing the moderator reactivity. Maximizing the water level in the unaffected steam generator maximizes the amount of steam blowdown from that steam generator before MSIS, since a higher initial steam generator water level results in a lower rate of decrease of steam generator pressure causing a lower rate of decrease in steam blowdown flow rate. Thus increasing the initial water level in the unaffected steam generator increases the cooldown due to steam blowdown from this steam generator, also. However, if the initial water level in the unaffected steam generator is above some minimum level, the level in this steam generator will not fall below the EFAS low level setpoint during the transient. It has been found that, for System 80, the cooldown provided by emergency feedwater is more than the additional cooldown that would result from initializing the water level at the maximum possible level in the unaffected steam generator. Therefore cooldown by the intact steam generator is maximized by using the maximum initial water level which will result in EFAS at the time of MSIV closure (the point at which level stops decreasing).

15C.3.3.3 Analysis Assumptions

The impact of analysis assumptions on the potential for post-trip degradation in fuel performance is through their effect on core flow at the time of R-t-P and their effect on R-t-P via the magnitude and timing of the maximum post-trip reactivity.

The analysis assumption which affected core flow at time of R-t-P was the time of reactor coolant pump (RCP) trip. Early RCP trip yields low flow at time of R-t-P and therefore low minimum DNBR. The time of RCP trip (initiation of four-pump coastdown) also affects the magnitude of the R-t-P, primarily via the timing of the maximum post-trip total reactivity -- but also via the magnitude of this reactivity. Higher flow tends to produce a larger R-t-P. However, the magnitude of the core flow, itself, at the time of R-t-P has more effect upon the minimum DNBR than does the less direct effect via the magnitude of the R-t-P. Therefore, loss of offsite power concurrent with the steam line break yields the greatest potential for degradation in post-trip fuel performance, since the RCPs begin to coastdown at the beginning of the transient. Table 15C-1 shows, for System 80, the effect of time of RCP trip on post-reactor-trip R-t-P, maximum total reactivity, and minimum DNBR for RCP trip concurrent with the break and at time of SIAS as well as for cases with no RCP trip.

A number of analysis assumptions affect the magnitude of the R-t-P. Conservative analysis assumptions which affect the R-t-P and which were used in the System 80 SLB analysis include:

a) The CEA of maximum worth stuck in the fully withdrawn position after reactor trip.

b) End of equilibrium burnup cycle core conditions to yield the most negative moderator coefficient.

c) Saturated steam blowdown with no moisture carryover from the steam generators to yield the maximum energy removal.

d) A 10 percent increase for the slope of the moderator reactivity versus coolant temperature function to assure that the calculation of the reactivity increase due to cooldown of the moderator is conservative.

e) A 15 percent increase in the slope of the Doppler reactivity versus fuel temperature function to assure that the calculation of the reactivity increase due to cooldown of the fuel is conservative.

f) A 10 percent decrease in the slope of the boron reactivity versus boron concentration to assure that the calculation of SI reactivity is conservative.

g) The steam line breaks were initiated by a postulated double-ended rupture of one steam line upstream of the MSIV. This break location results in an initial blowdown area for each steam generator (until the MSIVs close) equivalent to two flow restrictor areas (since there are two steam lines per steam generator). As the MSIVs close, steam blowdown from the unaffected steam generator terminates and the

effective blowdown area for affected steam generator is reduced to one flow restrictor area (i.e., blowdown through the other steam line for the affected steam generator is terminated by the closed MSIVs). A smaller break delays the time of maximum post-trip reactivity and therefore decreases the magnitude of the R-t-P generated.

h) Heat transfer areas in the reactor vessel upper head region were increased by 10% to assure that the heat added by the walls and structure in this region was conservatively large, causing the transient pressures to be higher and, as a result, the safety injection reactivity to be less.

i) Heat transfer areas in the RCS, other than those in the reactor vessel upper head region, were decreased by 10% to assure that the heat added by the walls and structure in these regions was conservatively small, causing the RCS cooldown to be increased.

j) Moderator reactivity was determined as a function of the lowest cold leg temperature to account conservatively for the effect of uneven temperature distribution on the moderator reactivity. Asymmetric heat removal causes unequal cold leg temperatures at the reactor vessel inlets for the two steam generator loops. Unequal reactor vessel inlet temperatures in combination with incomplete mixing of coolant in the reactor vessel downcomer and lower plenum results in a temperature distribution at the core inlet plane. The effect of this temperature distribution is included by basing moderator reactivity on core cold edge moderator density.

15C.3.3.4 Single Failures

Of the single failures possible for System 80 (Table 15.0-6) only the failure of one MSIV to close and failure of one HPSI pump can affect the potential for post-trip R-t-P and consequent possible degradation in fuel performance. (The failure of the most reactive CEA to insert and a loss of offsite power are assumed, additionally, for SLB analyses). Whether the additional cooldown provided by the failure of an MSIV on the unaffected steam generator or the decreased safety injection boron reactivity resulting from the failure of a HPSI pump is more adverse for a transient depends upon a number of factors. In general the failure of a HPSI pump will be more adverse unless transient characteristics (e.g., RCS pressure, time of R-t-P) are such that little or no safety injection boron reaches the core before R-t-P, even when both HPSI pumps are assumed to be operative.

Table 15C-2 shows the maximum post-trip reactivities, core average powers, and minimum DNBRs with an assumed MSIV failure and with an assumed HPSI pump failure for double-ended guillotine SLBs for System 80. Cases are presented for SLBs initiated at full power and at zero power, with and without loss of offsite power. For all cases except the SLB initiated at full power with offsite power present, the HPSI failure produces the most adverse transient results.

15C.3.4 PARAMETERS AND CONDITIONS FOR MAXIMIZING SECONDARY SYSTEM CONTRIBUTION TO RADIOLOGICAL RELEASES

The contribution of the secondary system to radiological releases is maximized by (a) the maximum initial steam generator inventory in the affected steam generator, (b) a loss of condenser availability, and (c) the maximum amount of post-accidient heat to be removed.

(a) Assuming that the initial steam generator water level is at the highest permissible operating level maximizes the potential for radiological release due to the discharge to atmosphere of the contents of the affected steam generator. Further, cases initiated from zero power operating conditions will have the maximum initial steam generator water inventory for a given water level.

(b) A loss of condenser availability (due to loss of offsite power, e.g.) requires that the plant be cooled down by use of the atmospheric dump valves. This causes additional radiological releases due to the discharge to atmosphere of water from the unaffected steam generator.

(c) Maximizing the amount of post-accident heat to be removed maximizes the amount of liquid from the unaffected steam generator that must be vaporized and released to the atmosphere (in the absence of condenser availability of (b) above) to achieve cold shutdown. The amount of post-accident heat to be removed is maximized by assuming the maximum initial plant temperature and by assuming that the decay heat to be removed is that appropriate to full power operation, even for cases initiated at zero power: It is assumed that the event occurred at zero power, but that within the previous half hour the plant had been at equilibrium full power conditions.

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TABLE 15C-1

EFFECT OF TIME OF REACTOR COOLANT PUMP TRIP ON MAXIMUM POST-TRIP REACTIVITY, CORE AVERAGE POWER, AND DNBR FOR DOUBLE-ENDED GUILLOTINE MAIN STEAM LINE BREAKS WITH A STUCK CEA AND A SINGLE FAILURE.

Post-Reactor-Trip:	Time of Reactor Coolant Pump Trip	Initial Power Level FULL	ZERO
Maximum* core average power (% of 3800 MW)	0	5.5	0.007
	at SIAS	4.1	0.018
	no trip	5.1	0.017
Maximum reactivity (% $\Delta\rho$)	0	+0.09	-0.64
	at SIAS	-0.28	-0.52
	no trip	-0.18	-0.19
Minimum DNBR	0	2.7	>10
	at SIAS	>10	>10
	no trip	>10	>10

* or value at time of maximum reactivity, if no return-to-power occurs.

TABLE 15C-2

EFFECT OF SINGLE FAILURE OF MSIV OR ONE HPSI PUMP ON MAXIMUM POST-TRIP REACTIVITY, CORE AVERAGE POWER, AND DNBR FOR DOUBLE-ENDED GUILLOTINE MAIN STEAM LINE BREAKS WITH A STUCK CEA.

INITIAL POWER LEVEL	OFF-SITE POWER	SINGLE FAILURE	MAXIMUM POST-TRIP: REACTIVITY (%$\Delta\rho$)	CORE AVERAGE POWER* (% OF 3800 MWt)	DNBR
FULL	LOSS OF	ONE HPSI PUMP	+0.087	5.5	2.7
		MSIV	-0.005	4.5	>10
	AVAIL-ABLE	ONE HPSI PUMP	-0.64	2.4	>10
		MSIV	-0.18	5.1	>10
ZERO	LOSS OF	ONE HPSI PUMP	-0.64	0.007	>10
		MSIV	-1.3	0.007	>10
	AVAIL-ABLE	ONE HPSI PUMP	-0.19	0.017	>10
		MSIV	-0.39	0.007	>10

*Maximum value or value at time of of maximum reactivity, if no return-to-power occurs.

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