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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
8	May 10, 1983
9	February 27, 1984
10	June 28, 1985

Chapter 3
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A-36	A-36

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SAFETY CLASS 1, 2 & 3 VALVES
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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	7
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	
CH-231P	Seal Injection Isolation	2	I	1	
CH-239	Charging Line Backpressure	2	I	1	10
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	7
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	7
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	

3.9.5.1.2 Upper Guide Structure Assembly

The UGS assembly aligns and laterally supports the upper end of the fuel assemblies, maintains the control element spacing, holds down the fuel assemblies during operation, prevents fuel assemblies from being lifted out of position during a severe accident condition and protects the control elements from the effects of coolant cross flow in the upper plenum. The upper guide structure (UGS) assembly is handled as one unit during installation and refueling.

The UGS assembly consists of the UGS support barrel assembly and the CEA shroud assembly (Figure 3.9.5-6). The UGS support barrel assembly consists of UGS support barrel fuel alignment plate, UGS base plate and control element shroud tubes. The UGS support barrel consists of a right circular cylinder welded to a ring flange at the upper end and to a circular plate (UGS base plate) at the lower end. The flange, which is the supporting member for the entire UGS assembly, seats on its upper side against the pressure vessel head during operation. The lower side of the flange is supported by the holddown ring, which seats on the core support barrel upper flange. The UGS flange and the holddown ring engage the core support barrel alignment keys by means of four accurately machined and located keyways equally spaced at 90 degree intervals. This system of keys and slots provides an accurate means of aligning the core with the closure head and thereby with the CEA drive mechanisms. The fuel alignment plate is positioned below the UGS base plate by cylindrical control element shroud tubes. These tubes are attached to the UGS base plate and the fuel alignment plate by rolling the tubes into the plates and welding. The fuel alignment plate is designed to align the lower ends of the control element shroud tubes which in turn locate the upper ends of the fuel assemblies. The fuel alignment plate also has four equally spaced slots on its outer edge which engage with Stellite hardfaced lugs protruding from the core shroud to provide alignment. The control element shroud tubes bear the upward force on the fuel assembly holddown devices. This force is transmitted from the alignment plate through the control element shroud tubes to the UGS barrel base plate.

The CEA shroud assembly limits cross flow and provides separation of the CEA assemblies. The assembly consists of an assemblage of large vertical tubes connected by vertical plates in a grid pattern. The shroud assembly is mounted on the UGS base plate and is held in position by eight tie rod tube assemblies which are threaded into the UGS base plate at their lower end. The tie rods are bolted against plates located at the top of the CEA shroud assembly and are pretensioned. The vertical tubes and vertical connecting plates are furnished with multiple holes to permit hydraulic
communication. Lateral movement of the vertical tube and plate assembly is 10
minimized by four snubbers symmetrically located between this assembly and the top of the UGS support barrel.

The holddown ring provides axial force on the flanges of the upper guide structure assembly and the core support structure in order to prevent movement of the structures under hydraulic forces. The holddown ring is designed to accommodate the differential thermal expansion between the pressure vessel and the internals in the vessel ledge region.

3.9.5.1.3 Flow Skirt

The Inconel flow skirt is a right circular cylinder, perforated with flow holes, and reinforced with two stiffening rings. The flow skirt is used to reduce inequalities in core inlet flow distributions and to prevent formation of large vortices in the lower plenum. The skirt is supported by nine equally spaced machined sections that are welded to the bottom head of the pressure vessel.

3.9.5.1.4 In-Core Instrumentation Support System

The complete in-core neutron flux monitoring system includes self-powered in-core detector assemblies, supporting structures and guide paths, an external movable detector drive system and an amplifier system to process detector signals. The self-powered in-core detector assemblies and the amplifier system are described in Section 7.7. The external movable detector drive system and the instrumentation supporting structures and guide paths are described in this section and shown in Figure 3.9.5-7.

The support system begins outside the pressure vessel, penetrates the bottom of the vessel boundary and terminates in the upper end of the fuel assembly. Each in-core instrument is guided over its full length by the external guidance conduit, the pressure vessel nozzles, the lower support structure ICI nozzles and the instrument guide tube of the fuel assembly. Figure 3.9.5-4 shows the in-core instrument support structure. The in-core instrumentation support system routes the instruments so that detectors are located in selected fuel assemblies throughout the core. An equal instrument length exists for all locations. The guide tube routing outside the reactor vessel is a simple 180° bend to the seal table. The pressure boundaries for the individual instruments are at the out-of-reactor seal table, where the external electrical connections to the in-core instruments are made (Figure 3.9.5-7).

The in-core instrument assemblies contain a movable detector guide tube to allow insertion of a miniature movable flux detector. The assemblies have an integral seal plug which forms a seal at the instrument seal table and through which the signal cables and movable guide tube pass. Static O-ring seals are used to seal against operating pressure.

The movable detector drive system consists of two drive machines, two transfer machines, two drive cables with detectors and the interconnecting tubing. Because the two halves of the system are identical with only several connections between them (leak detection and gas purge), only half of the system is described below.

A fission chamber is used as the movable flux detection device. The detector signal cable is wound with an edgewise helical steel wrap to form the drive cable. This cable construction allows a hobbed wheel in the drive machine to drive the cable in either direction. The drive machine consists of a cable reel, a drive motor, gear reducer, hobbed drive wheel and a shaft postion encoder. The detector may be positioned from the control room by use of the plant computer or a separate control box.

TABLE 3.9.1-1

TRANSIENTS USED IN STRESS ANALYSIS OF CODE CLASS 1 COMPONENTS
(Sheet 3 of 3)

Test Condition

Occurrence	Conditions	
Primary system hydrostatic	10 primary side cycles from 15 $lb/in.^2$ to 3,125 $lb/in.^2$ at a temperature between 120F to 400F. These cycles are based on one initial hydrostatic test plus a major repair every 4 years for 36 years which includes equipment failure and normal plant cycles. The secondary side of the steam generator is at atmospheric pressure during this test.	10
Primary system leak	200 cycles from 15 $lb/in.^2$ to 2250 $lb/in.^2$ at a temperature between 120F to 400F. These cycles are based on a normal plant maintenance operation involving 5 shutdowns per year for 40 years.	10

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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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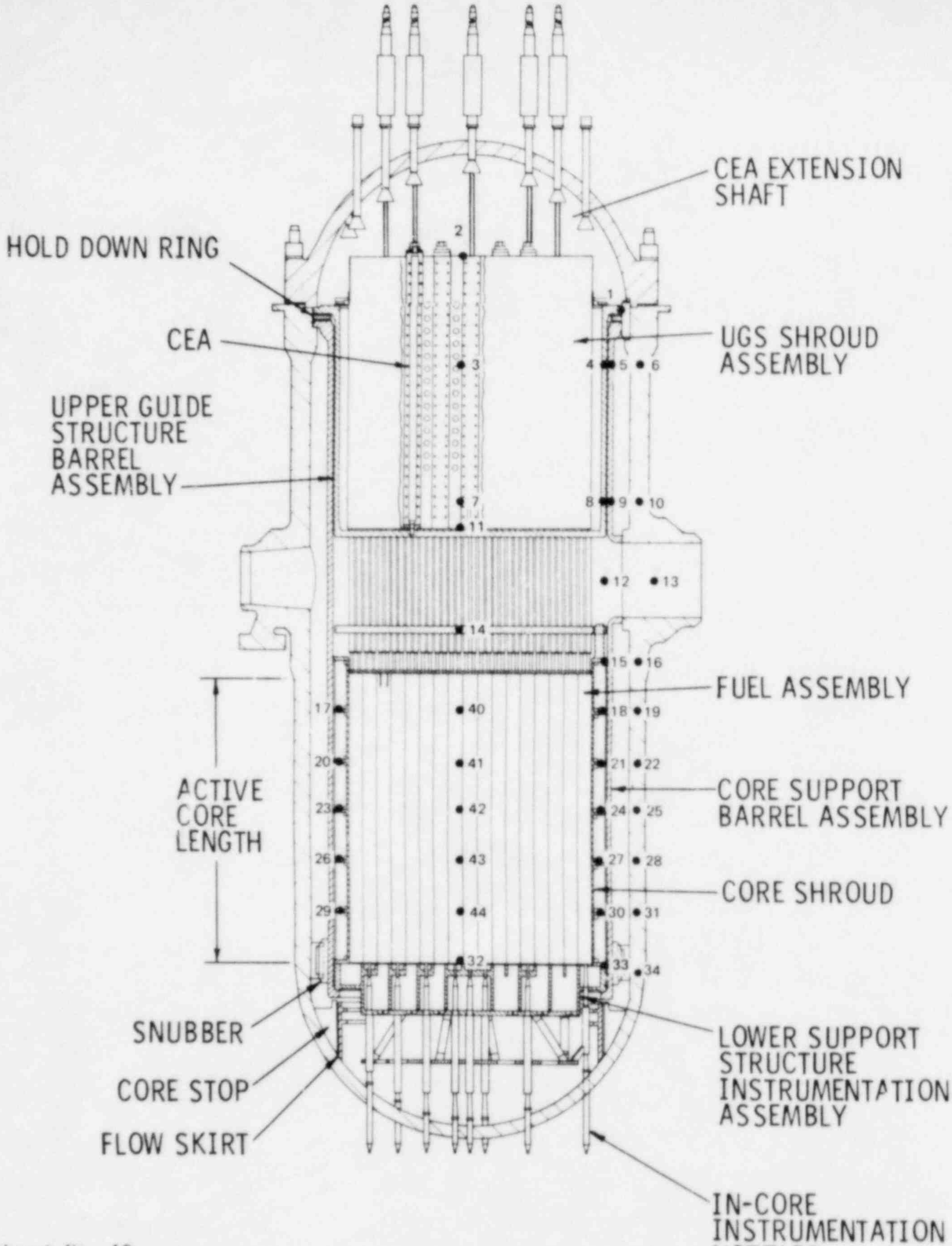
TABLE 3.9.3-3

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	7
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	
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 239	Charging Line Backpressure (Close)	2-1/2	Globe	2	Pneumatic	10
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	7
CH 305	RWT Suction Check (Operate)	20	Swing Check	2	None	
CH 306	RWT Suction Check (Operate)	20	Swing Check	2	None	



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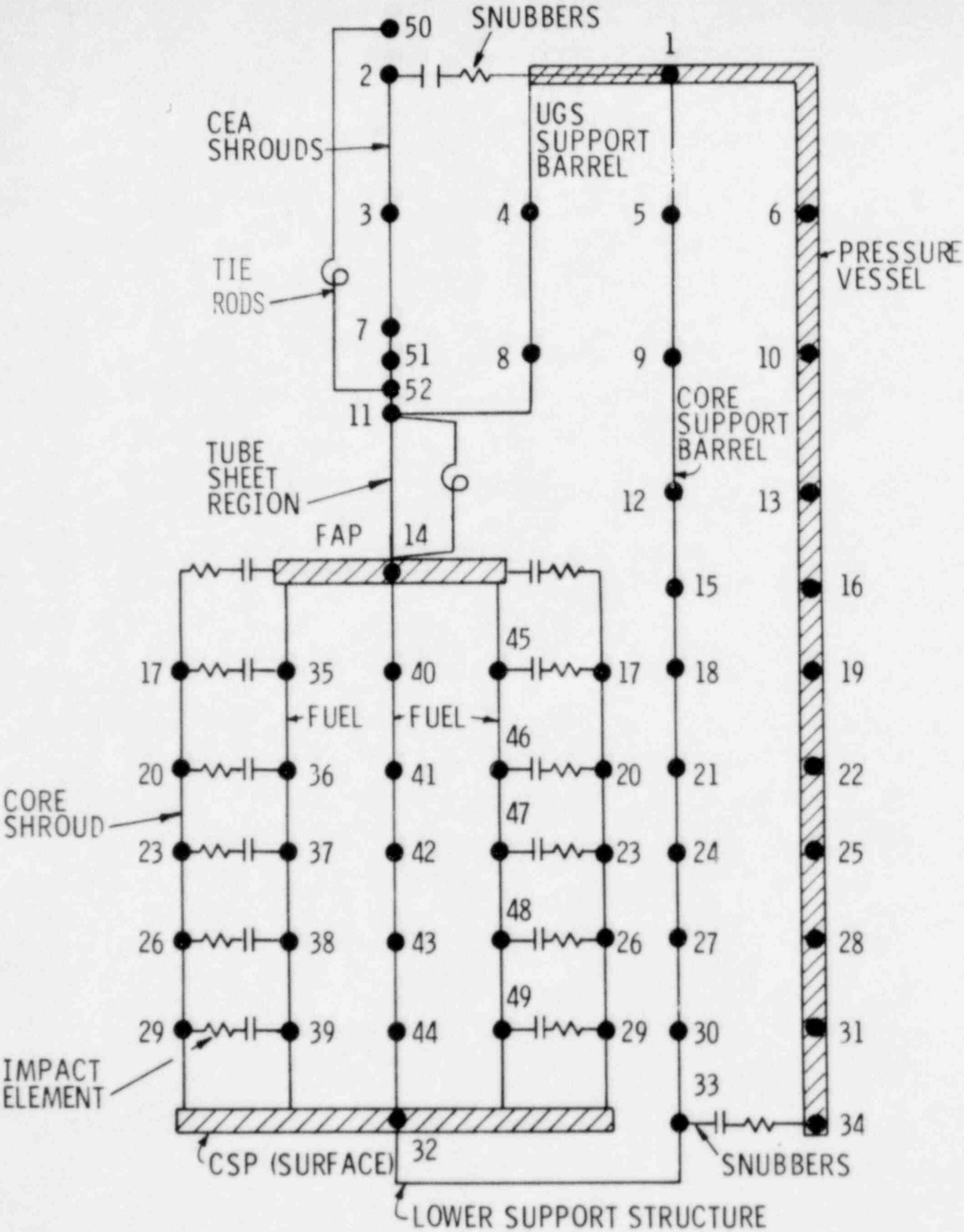
C - E SYSTEM 80	REACTOR INTERNALS HORIZONTAL SEISMIC MODEL	Figure 3.7.3-1



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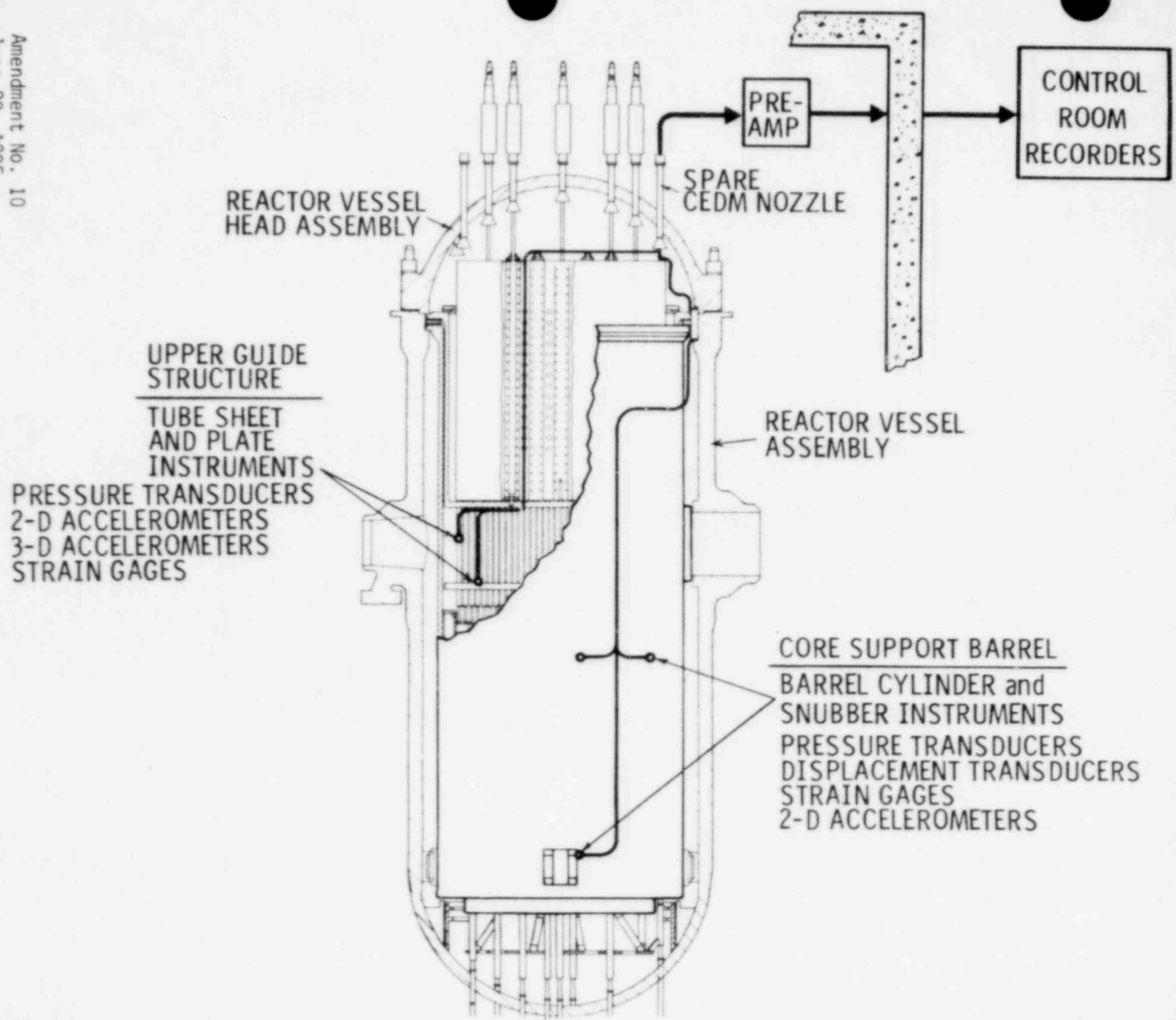
C-E SYSTEM 80	REACTOR INTERNALS NONLINEAR HORIZONTAL SEISMIC MODEL	Figure 3.7.3-4



C-E SYSTEM 80

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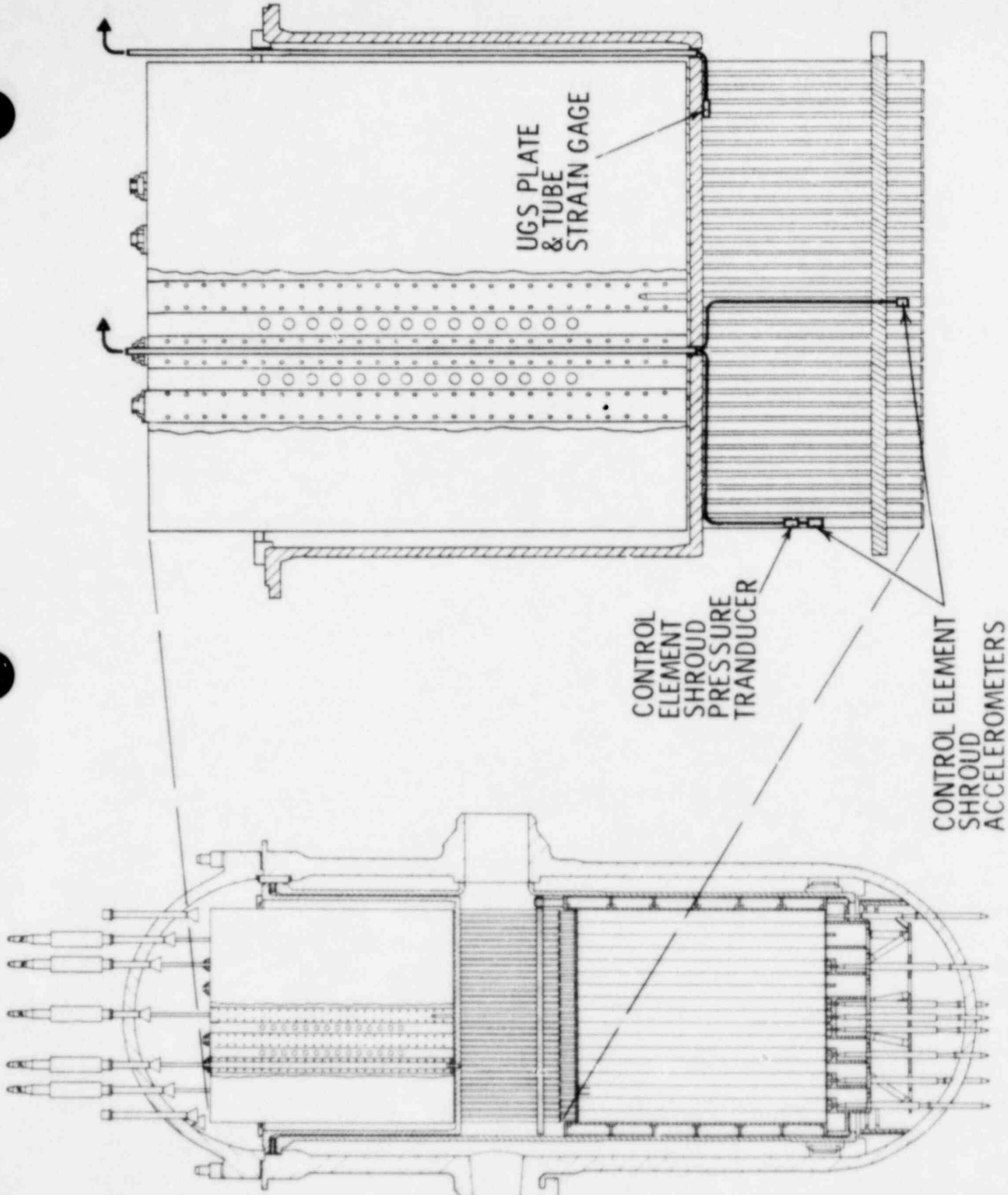
PVMP INTERNALS ASSEMBLY

Figure 3.9.2-7



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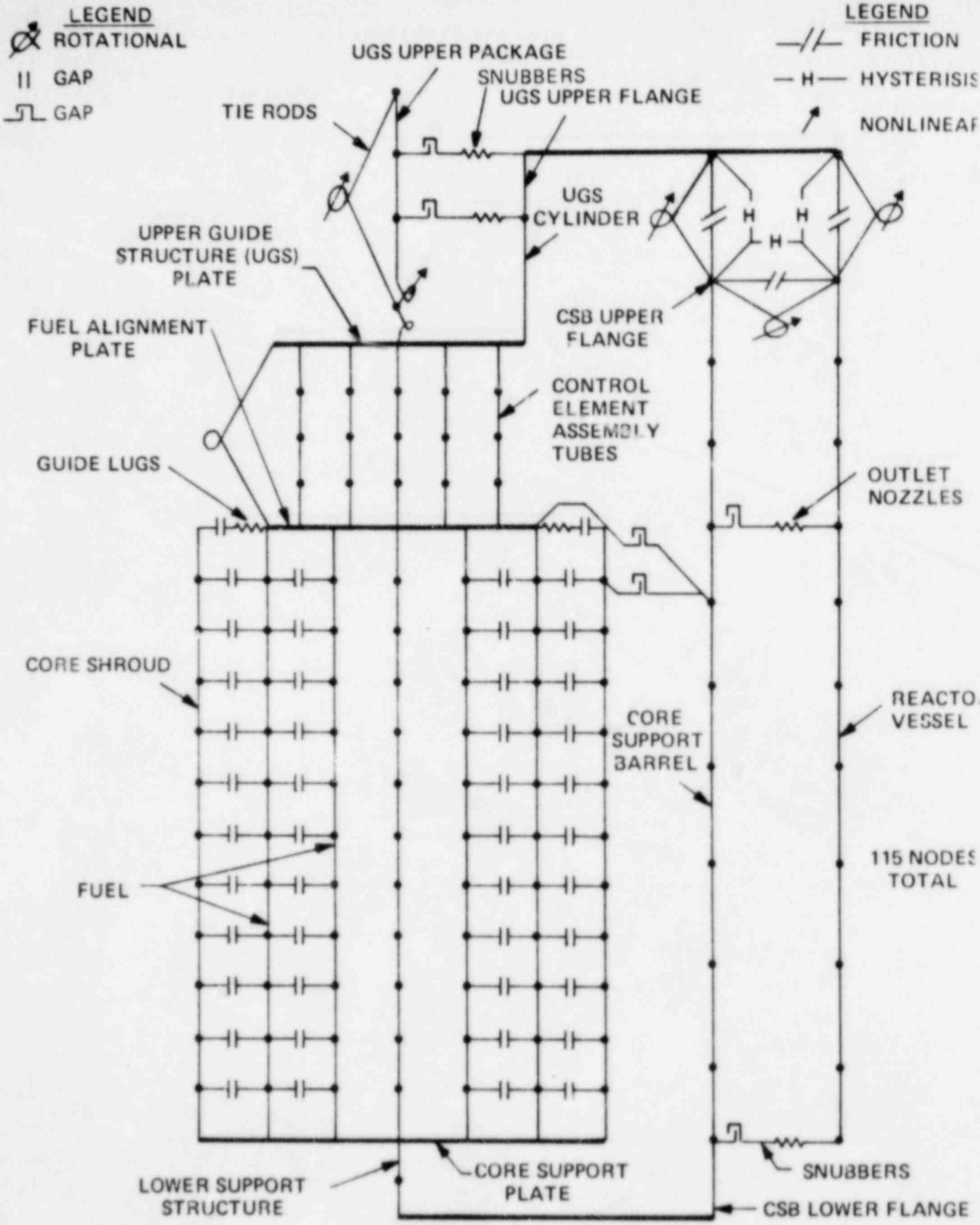
C - E SYSTEM 80	UPPER GUIDE STRUCTURE TYPICAL PVMP INSTRUMENTATION	Figure 3.9.2-9



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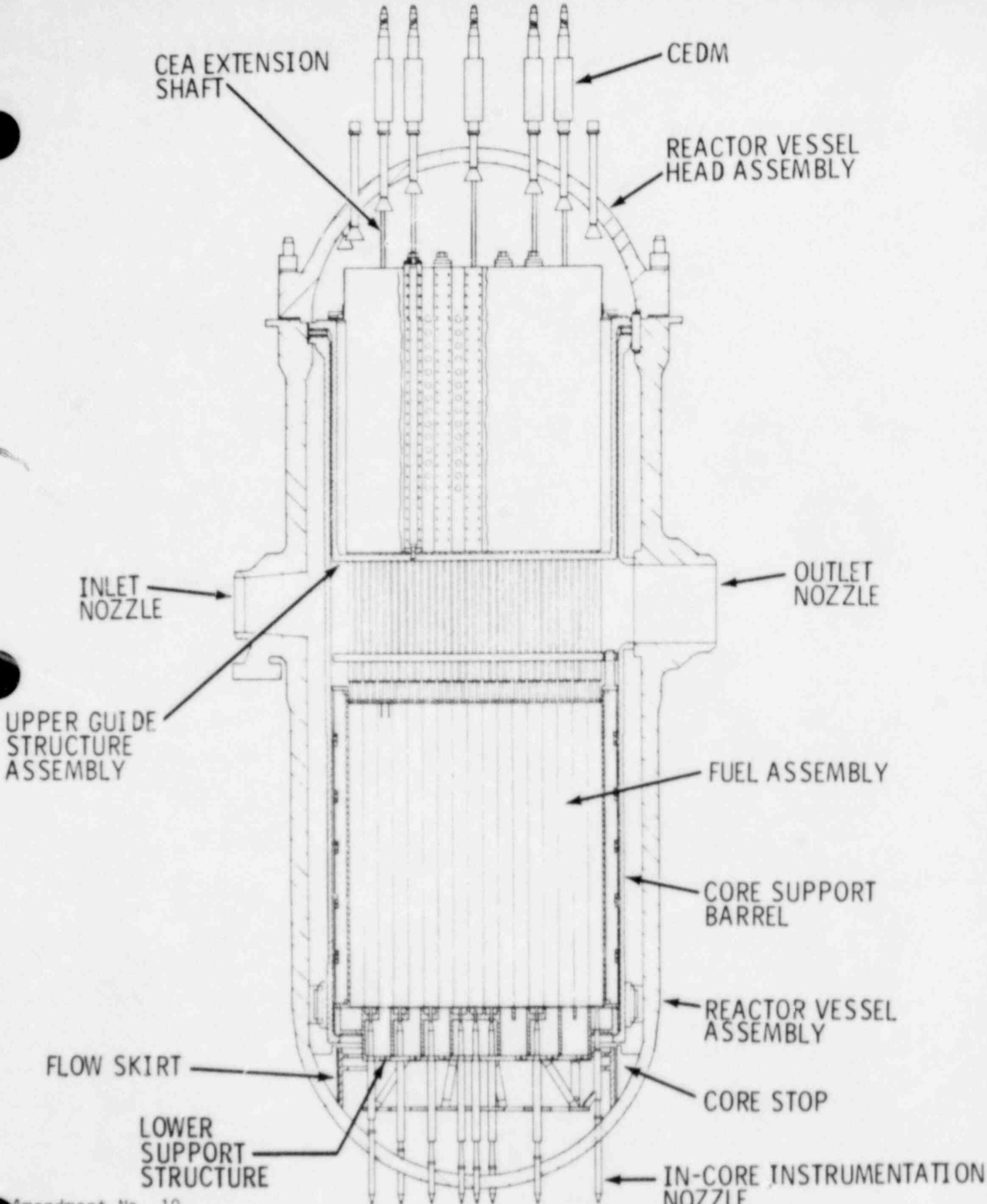
C-E SYSTEM 80	DETAILED LATERAL INTERNALS CESHOCK MODEL	Figure 3.9.2-11



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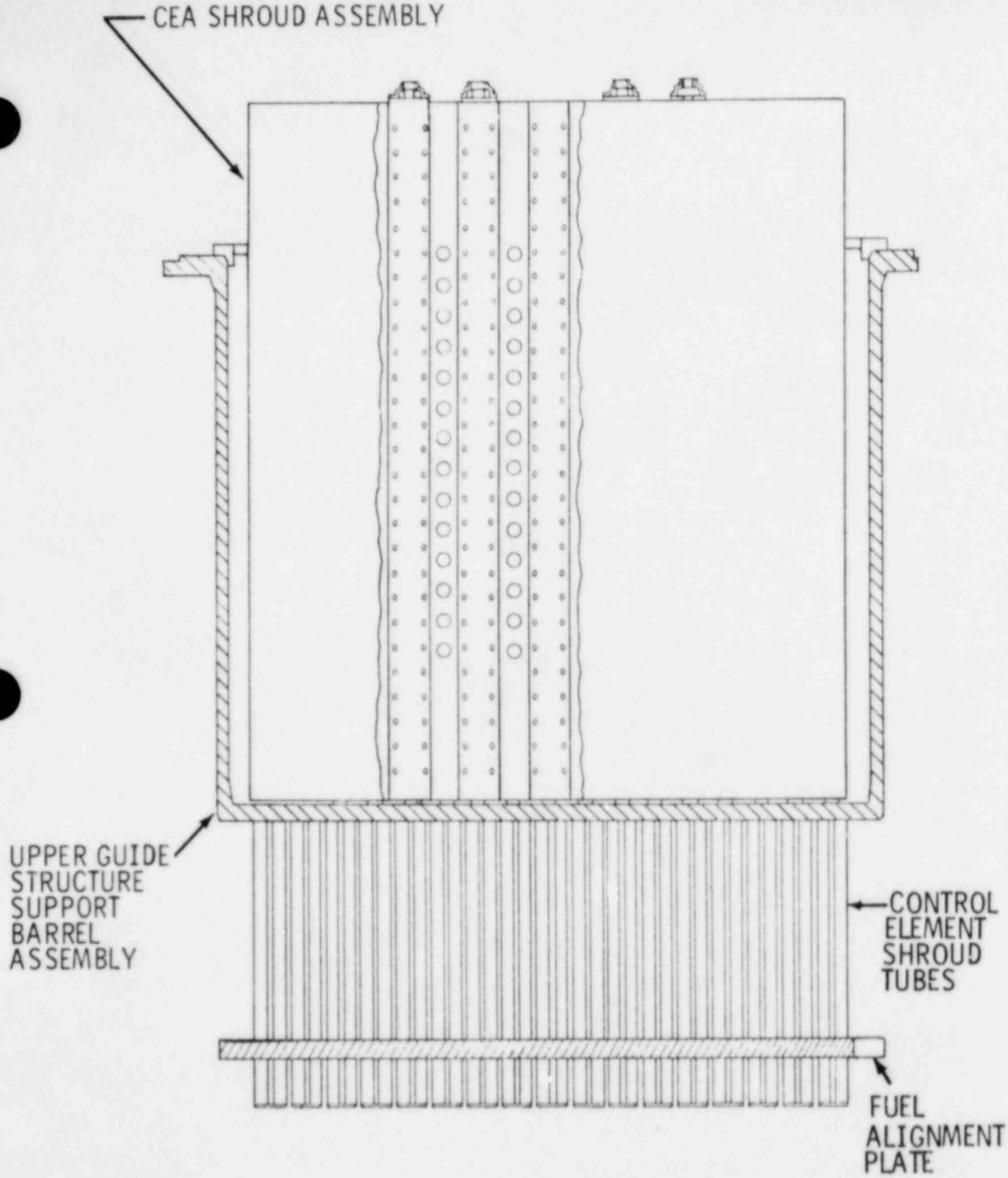
C-E SYSTEM 80	REACTOR VERTICAL ARRANGEMENT	Figure 3.9.5-1



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C-E SYSTEM 80	UPPER GUIDE STRUCTURE ASSEMBLY	Figure 3.9.5-6

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TABLE 3.11B-1
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MECHANICAL EQUIPMENT QUALIFICATION REQUIREMENTS

SYSTEM	REQUIRED DURATION OF OPERATION OF 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-239 Charging Line Backpressure 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	Passive	C	CH-521 PRM and Boronometer Bypass Valve		9.3.4

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COLSS determinations of F^n_q. The uncertainty analysis provided for SYSTEM 80 is described in Section 7.7.1.5. In addition, a power level uncertainty factor of 1.02, an engineering factor of 1.03, and an augmentation factor to account for power spiking associated with fuel densification are customarily included. The latter factor varies axially, but can be expected to have a
value on the order of 1.03 at the elevation of the axial peak. It has been 3
demonstrated in Reference 32, for cores similar to SYSTEM 80, that an uncertainty of 4.6% is associated with the thermal margin calculation performed by COLSS.

4.3.2.2.5 Comparisons Between Limiting and Expected Power Distributions

As was discussed in Section 4.3.2.2.3, Expected Power Distributions, the
maximum expected unrodded F^n_q that occurs during the first cycle at full 3
power is 1.88. Augmenting this value by the uncertainties and allowances discussed above provides an upper limit on F^n_q of 2.19 which is well below the design target of 2.28. Additionally, the calculations described in Section 4.3.2.2.3 show that, with proper use of the part-length CEAs, no appreciable increase in the peak linear heat rate occurs during these maneuvering transients. In the event that the part-length CEAs were not moved properly, the power distribution could have become unacceptable. In this case, the monitoring system would indicate if insufficient margin to indicate that action has to be taken to improve the core power distribution, to improve the coolant conditions, or to reduce core power.

Similarly, even allowing for the 4.6% uncertainty on the monitoring of thermal margin, the maximum expected unrodded F^n_r that occurs at full power is well below the design limit stated in Section 4.3.2.2.2 of 1.55. Again, as demonstrated by the calculations of the power distributions expected to occur during maneuvering transients, no appreciable loss in thermal margin is expected to occur during these transients.

4.3.2.3 <u>Reactivity Coefficients</u>

Reactivity coefficients relate changes in core reactivity to variations in fuel or moderator conditions. The data presented in this section and associated tables and figures illustrate the range of reactivity coefficient
values calculated for a variety of operating and accident conditions. 3
Section 4.3.3 presents comparisons of calculated and measured moderator temperature coefficients and power doefficients for operating reactors. The good agreement shown in that subsection provides confidence that the data presented in this section adequately characterize the SYSTEM 80 reactors. Table 4.3-3 presents a comparison of the reactivity coefficients calculated for SYSTEM 80 reactors with those used in the safety analyses
described in Chapters 6 & 15. For each accident analysis, suitably 3
conservative reactivity coefficient values are used. Since uncertainties in the coefficient values, as discussed in Section 4.3.3.1.2, and other conservatisms are taken into account in the safety analyses, values used in the safety analyses may fall outside the ranges in a conservative direction of the data presented in this section. A more extensive list of reactivity coefficients is given in Table 4.3-4.

The calculational methods used to compute reactivity coefficients are discussed in Section 4.3.3.1.1. All data discussed in subsequent paragraphs

are calculated with two-dimensional, quarter-core nuclear models. Spatial distributions of materials and flux weighting are explicitly performed for the particular conditions at which the reactivity coefficients are calculated. The adequacy of this method is discussed in Section 4.3.3.1.2.

4.3.2.3.1 Fuel Temperature Coefficient

The fuel temperature coefficient is the change in reactivity per unit change in fuel temperature. A change in fuel temperature affects the reaction rates in both the thermal and epithermal neutron energy regimes. Epithermally, the principal contributor to the change in reaction rate with fuel temperature is the Doppler effect arising from the increase in absorption widths of the resonances with an increase in fuel temperature. The ensuing increase in absorption rate with fuel temperature causes a negative fuel temperature coefficient. In the thermal energy regime, a change in reaction rate with fuel temperature arises from the effect of temperature dependent scattering properties of the fuel matrix on the thermal neutron spectrum. In typical PWR fuels containing strong resonance absorbers such as U-238 and Pu-240, the magnitude of the component of the fuel temperature coefficient arising from the Doppler effect is more than a factor of 10 larger than the magnitude of the thermal energy component.

Figure 4.3-45 shows the dependence of the calculated fuel temperature coefficient on the fuel temperature, both at the beginning and the end of the first cycle.

4.3.2.3.2 Moderator Temperature Coefficient

The moderator temperature coefficient relates changes in reactivity to uniform changes in moderator temperature, including the effects of moderator density changes with changes in moderator temperature. Typically, an increase in the moderator temperature causes a decrease in the core moderator density and, therefore, less thermalization, which reduces the core reactivity. However, when soluble boron is present in the moderator, a reduction in moderator density causes a reduction in the content of soluble boron in the core, thus producing a positive contribution to the moderator temperature coefficient. In order to limit the dissolved boron concentration, burnable poison rods (shims) are provided in the form of cylindrical pellets of alumina with uniformly dispersed boron carbide particles. The number of shims is given in Table 4.3-1 and their distribution in one quadrant of the core is shown in Figure 4.3-1. The distribution is identical for the other three quadrants. The reactivity control provided by the shims is given in Table 4.3-1. This control makes possible a reduction in the dissolved boron concentration to the values given in Table 4.3-1.

The calculated moderator temperature coefficients for various core conditions at beginnings and end of first cycle are given in Table 4.3-4. The moderator temperature coefficients are more negative at end-of-cycle because the soluble boron in the coolant is reduced. The buildup of equilibrium xenon produces a
net negative change of $-0.4 \times 10^{-4}\ \Delta\rho/°F$ in the moderator temperature | 10
coefficient; this change is due mainly to the accompanying reduction in critical soluble boron. The changing fuel isotopic concentrations and the changing neutron spectrum during the fuel cycle depletion also contribute a small negative component to the moderator temperature coefficient.

TABLE 4.4-8

REACTOR COOLANT SYSTEM GEOMETRY

Component	Flow Path Length (ft)	Top Elevation (d) (ft)	Bottom Elevation (d) (ft)	Minimum Flow Area (ft^2)	Volume (ft^3)
Hot Leg	14.06	2.38	-1.75	9.62	135.27
Suction Leg	24.32	0.58	-9.97	4.91	119.38
Discharge Leg	19.30	1.25	-1.25	4.91	94.74
Pressurizer	-----	(f)	----	----	1800
Liquid level (full power)	-----	(f)	(f)	50.07[a]	900
Surge line (e)	77.99	(f)	1.75	0.56	43.62
Steam generator					
Inlet nozzle	3.07	3.90	-0.48	9.62	31.30
Outlet nozzle	2.79	2.41	-1.19	4.91	13.70
Inlet plenum	4.74[b]	6.48	-0.10	19.07	332.41
Outlet plenum	4.74[b]	6.48	-0.10	9.74	332.41
Tubes (Active & Inactive)	61.15	40.94	6.48	0.002[c]	1634.20
Reactor Vessel					
Inlet nozzle (ea)	3.7	1.4	-1.5	4.9	21.7
Downcomer	21.4	11.7	-22.6	33.8	1157.1
Lower plenum	3.2	-20.5	-25.9	32.5	430.2
Lower support structure & inactive core	2.8	-17.7	-20.5	44.4	239.2
Active core	12.5	-5.3	-17.8	60.8	888.2
Upper inactive core	2.8	-2.5	-5.3	46.3	262.9
Outlet plenum	5.7	2.1	-2.4	26.6	459.4
Core shroud bypass	15.9	-2.7	-19.6	0.1	240.6
CEA shroud assembly & tie tubes	17.9	15.6	-3.5	0.4	1352.5
UGS, CEA shroud annulus	10.6	12.7	2.1	1.6	226.0
Top head	3.2	19.9	12.7	7.8	422.6
Outlet nozzle	4.0	1.7	-1.8	9.6	32.2

a. For the cylinder.

b. Represents a geometrical rather than an actual flow path length.

c. Flow path area per tube.

d. Reactor Vessel nozzle centerline is the reference elevation. It has an elevation of 0.0 ft.

e. Surge line routing for each System 80 plant will be different. Nominal valves are given.

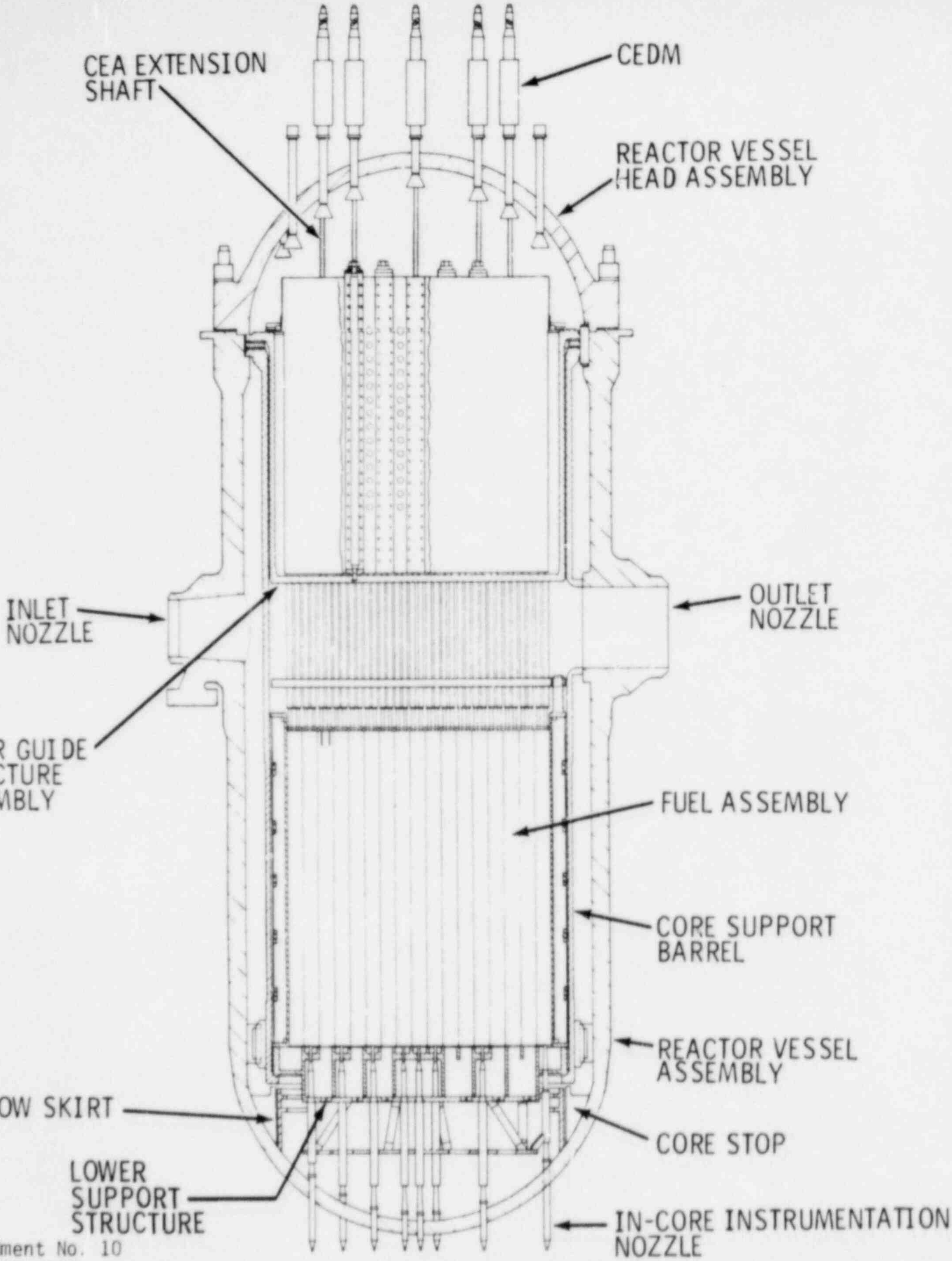
f. Depends on individual plant surge line height.

TABLE 4.4-9

REACTOR COOLANT SYSTEM COMPONENT THERMAL AND HYDRAULIC DATA[a]
(Sheet 1 of 2)

Component	Data	
Reactor Vessel		
Rated core thermal power, MWt	3,800	
Design pressure, lb/in.^{2}a	2,500	
Operating pressure, lb/in.^{2}a	2,250	
Coolant outlet temperature, °F	621.2	
Coolant inlet temperature, °F	564.5	
Coolant outlet state	Subcooled	
Total coolant flow, 10^6 lb/h	164	
Average coolant enthalpy		10
Inlet, Btu/lb	565	
Outlet, Btu/lb	645	
Average coolant density		
Inlet, lb/ft^3	45.9	
Outlet, lb/ft^3	41.2	
Steam Generators		
Number of units	2	
Primary Side (or tube sides)		
Design pressure/temperature, lb/in.^{2}a/°F	2,500/650	
Operating pressure, lb/in.^{2}a	2,250	
Inlet temperature, °F	621.2	
Outlet temperature, °F	564.5	
Secondary (or shell side)		
Design pressure/temperature, lb/in.^{2}a/°F	1270/575	
Full load steam pressure/temperature, lb/in.^{2}/°F	1070/552.86	
Zero load steam pressure, lb/in.^{2}a	1,170	
Total steam flow per gen., lb/h	8.59×10^6	10
Full load steam quality, %	99.75	
Feedwater temperature, full power, °F	450	
Pressurizer		
Design pressure, 1/bin.^{2}a	2,500	
Design temperature, °F	700	
Operating pressure, lb/in.^{2}a	2,500	
Operating temperature, °F	653	
Internal volume (ft^3)	1,800	
Heaters		
Type and rating of heaters, kW	Immersion/50	
Installed heater capacity, kW	1,800	

a. Full power conditions



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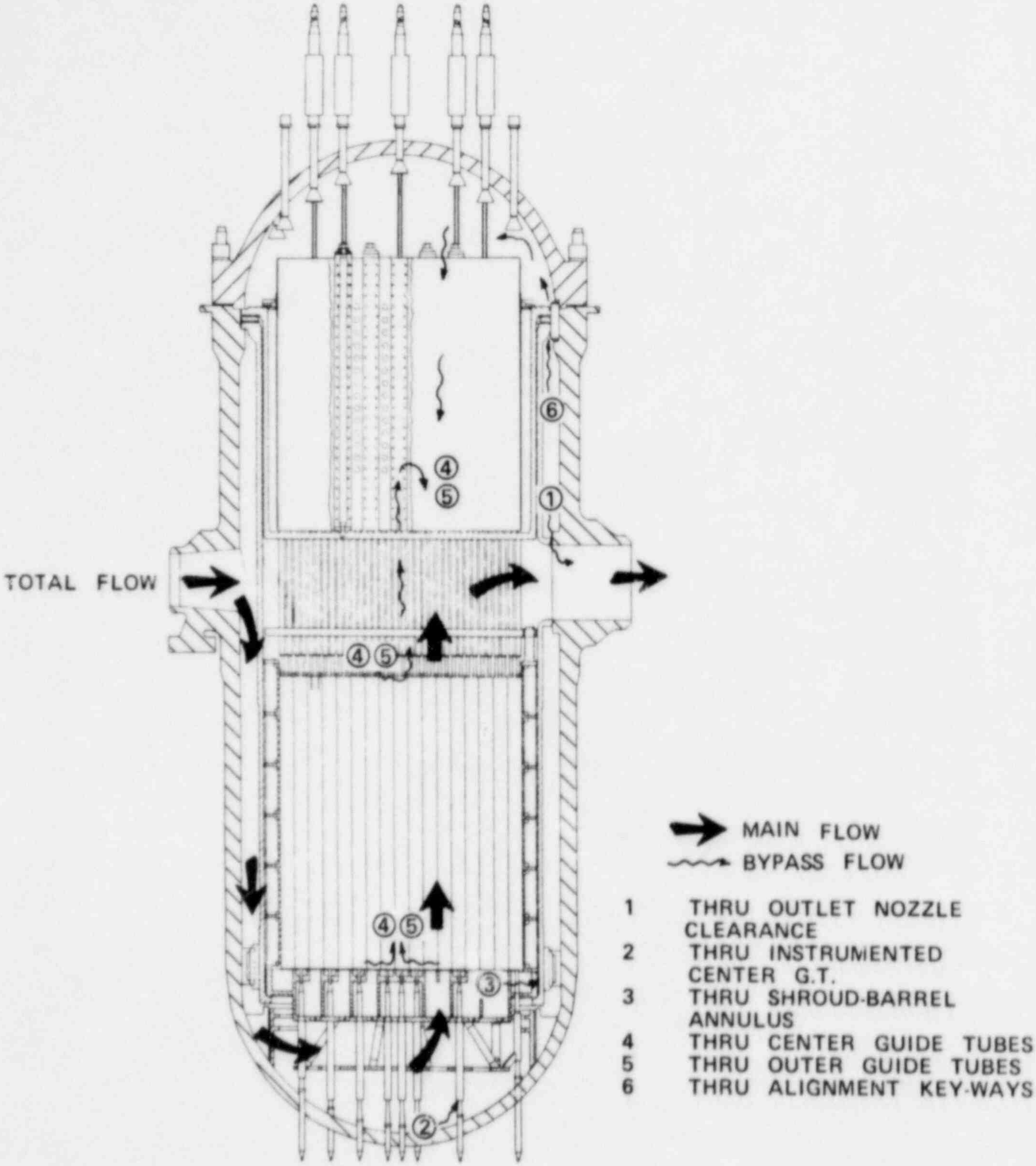
C - E SYSTEM 80	REACTOR VERTICAL ARRANGEMENT	Figure 4.1-1



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C-E SYSTEM 80	REACTOR FLOW PATHS	Figure 4.4-6

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5.1.4 NUCLEAR STEAM SUPPLY SYSTEM - BALANCE OF PLANT INTERFACE REQUIREMENTS

Below are detailed the interface requirements that the Nuclear Steam Supply System (NSSS) places on certain aspects of the Balance of Plant, listed by categories. In addition, applicable General Design Criteria (GDC) and Regulatory Guides, which C-E utilizes in its design of the Reactor Coolant System (RCS), 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, 5, 14, 15, 26, 27, 28, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 54, 55, 56, 57.
Relevant Reg. Guides:	1.1, 1.2, 1.4, 1.14, 1.24, 1.26, 1.29, 1.31, 1.34, 1.36, 1.38, 1.42, 1.43, 1.44, 1.45, 1.46, 1.47, 1.48, 1.49, 1.50, 1.51, 1.54, 1.61, 1.64, 1.65, 1.66, 1.67, 1.71, 1.73, 1.74, 1.79, 1,83, 1.84, 1.85.

A. <u>Power</u>

See Chapters 7 and 8 for power information.

B. <u>Protection from Natural Phenomena</u>

1. The containment shall remain functional for the full range, per GDC 2, of natural phenomena (earthquakes, tornadoes, tornado missiles, flooding conditions, hurricanes, winds, snow, and ice) and external environmental conditions.

2. The steam piping and associated supports from the steam generators up to and including the Main Steam Isolation Valves (MSIV's), the ADVs and their associated isolation valves, and any auxiliary steam supply systems up to the isolation valves which connect upstream of the MSIV's shall be seismic category I and designed to ASME B&PV Code, Section III, Class 2 requirements. 10

3. The valves, piping, and associated supports of the Feedwater System from and including the Main Feedwater Isolation Valves (MFIV's) to the steam generator feed nozzles shall be Seismic Category I and designed to ASME B&PV Code Section III, Class 2 requirements.

4. All components and piping of the Emergency Feedwater System between the steam generators and the containment isolation valves shall be Seismic Category I and designed to ASME B&PV Code Section III, Class 2 requirements.

5. All components, piping and associated supports in the condensate storage facilities for Emergency Feedwater shall be Seismic Category I and designed in accordance with ASME B&PV Code Section III, Class 3.

6. All components and piping associated with steam generator blowdown between the steam generator and the containment isolation valves shall be Seismic Category I and designed to ASME B&PV Code Section III, Class 2 requirements.

C. Protection from Pipe Failure

1. The following valves shall be protected against internally generated missiles or the effects resulting from a high energy pipe rupture (e.g., pipe whip, jet impingement and steam environment) such that these events will not prevent the valves from performing their requisite safety functions.

   a. MSIV's.

   b. Secondary Safety Valves.

   c. Atmospheric Dump Valves (ADV's).

   d. MSIV Bypass Valves.

   e. MFIV's.

   f. Blowdown Isolation Valves.

2. Pipe whip stops shall be provided for the RCS piping. (See Section 3.9.1.4).

3. The MSIV's shall be supported such that the valve body and actuator will not be distorted or displaced as a result of pipe break thrust loadings to such a degree that the valve cannot close.

4. Feedwater piping shall be routed, protected and restrained such that in the case of a rupture of a feedwater line or any other system pipeline, a single failure criteria will not be exceeded with regard to safe shutdown of the plant.

5. A containment shall be provided to limit the release of energy and radioactivity to the environs in the event of a rupture of the RCS and to protect the public health and safety.

6. The containment, including penetrations, shall not be subject to loss of function from dynamic effects (e.g., missiles, pipe reactions, fluid reaction forces) resulting from failure of RCS equipment or piping within the containment.

7. The design pressure and temperature of the containment shall, as a minimum:

   a. Be equal to the peak pressure and temperature resulting frcm either (1) complete blowdown of the reactor coolant through any rupture of the RCS piping, up to and including a postulated double-ended severence of the largest reactor coolant pipe or, (2) a complete blowdown of the unisolated steam generator plus attached steam lines up to the respective main steam isolation valves through any rupture of the steam line piping, up to and including a postulated double-ended severance of the largest main steam line pipe, assuming a sequence of events for either case which leads to the peak transient accumulation of energy in the building atmosphere. To meet this end, a spectrum of loss-of-coolant accidents (LOCA) and main steam line breaks (MSLB) have been analyzed. They shall be used by the applicant to establish the design pressure and temperature of the containment. (Refer to Sections 6.2.1.3 and 6.2.1.4). 8

   b. Take into account all credible post-blowdown energy additions to the containment atmosphere, such as core residual heat, thin and thick structural metal stored energy, steam generator reverse heat transfer, metal-water reactions and other possible chemical reactions resulting from a loss-of-coolant accident.

8. Compartments within the containment including the reactor vessel cavity shall be designed for the maximum pressure differential between the compartment and the remainder of the containment based on the maximum RCS pipe break that can occur in the compartment as defined in Section 3.6.

D. Missiles

1. The RCS, which is a potential source of missiles, shall to the extent possible, be either surrounded by barriers or restrained to prevent missiles from reaching other parts of the RCS, the containment lines, the secondary steam and feedwater piping or the engineered safeguards systems. See Section 3.5 for additional discussion of missiles.

2. A containment structure shall be provided to protect the RCS from loss of function due to missiles generated outside the containment, including those resulting from equipment failure, and weather induced forces such as tornadoes and hurricanes.

E. Separation

1. Adequate physical separation shall be maintained between the redundant electrical and instrumentation systems used for emergency control and safe shutdown of the reactor, and between the multiple instrumentation channels in the Plant Protection System.

2. Each MSIV shall have two physically separate and electrically independent closure solenoids in order to provide redundant means of valve operation. A Main Steam Isolation Signal (MSIS) shall be provided to each solenoid.

3. Redundant feedwater system isolation valves in each feedwater line meeting the single failure criteria shall be provided in piping interconnecting the steam generators to preclude blowdown of both steam generators following a pipe rupture.

4. Each ADV shall be provided with an isolation valve in the piping which connects each ADV to the main steam lines. 10

F. Independence

1. The provisions of General Design Criteria 54 and 57 for containment isolation valves shall be met.

2. The feedwater system piping, Emergency Feedwater System piping, and main steam piping and all of their associated supports and restraints shall be designed so that a single adverse event, such as a ruptured feedwater line, emergency feedwater line, main steam line inside containment, or a closed isolation valve can occur without:

   a. Initiating a Loss-of-Coolant incident.

   b. Causing failure of the other steam generator's safety class steam and feedwater lines, MSIV's, safety valves, MFIV's blowdown line isolation valves, or ADV's.

   c. Reducing the capability of any of the Engineered Safety Features systems or the Plant Protective System.

   d. Transmitting excessive loads to the containment pressure boundary.

   e. Compromising the function of the plant control room.

   f. Precluding orderly cooldown of the RCS.

3. An electrical or mechanical malfunction of one solenoid shall not prevent a MSIV from closing.

4. No single failure in the control circuits shall prevent closure of the MSIV bypass valves.

5. The MSIV bypass valve control circuits shall be designed, or precautions shall be taken, such that no single electrical failure would result in the spurious motion of the valves.

6. The ADV control circuits shall be designed or precautions taken, such that no single electrical failure would result in the opening of valves with a total combined capacity greater than 1.9×10^6 lb/hr at 1000 psia.

7. No single failure in the control circuits shall prevent operation of at least one ADV on each steam generator.

8. Each MFIV actuator shall be physically and electrically independent of the other such that failure of one will not cause failure of the other.

9. No single active or passive component failure, single passive or active electrical component failure, or power supply failure shall preclude adequate operation of the Emergency Feedwater System (acceptable guidelines for implementing these criteria can be found 8
in ANSI N658-1976), assuming the following events:

   a. Loss of normal feedwater with or without a concurrent loss of normal onsite or offsite AC power.
   b. Minor secondary system pipe breaks with or without a concurrent loss of normal onsite or offsite AC power.
   c. Steam generator tube rupture with or without a concurrent loss of normal onsite or offsite AC power.
   d. Major secondary system pipe breaks with or without a concurrent loss of normal onsite or offsite AC power.
   e. Small LOCA with or without a concurrent loss of normal onsite or offsite AC power.

10. The ability of the Emergency Feedwater System to perform its design function considering a power supply failure, a single active or passive mechanical component failure, a single active or passive failure or an electrical component, or the effects of a high or moderate energy pipe rupture shall be demonstrated. Acceptable guidelines for implementing these criteria can be found in ANSI 8
N658-1976.

11. The Emergency Feedwater System shall provide double isolation from the Main Feedwater System during plant conditions when the Emergency Feedwater System is not required.

12. Blowdown piping exiting containment shall have redundant blowdown line isolation valves which shall be actuated by an Emergency Feedwater Actuation Signal (EFAS).

13. The Emergency Feedwater System (EFWS) shall have an unavailability in the range 10^{-4} to 10^{-5} per demand based on an analysis using methods and data presented in NUREG-0611 and NUREG-0635. Compensating factors such as other methods of accomplishing safety 8
functions of the EFWS or other reliable methods for cooling the reactor core during abnormal conditions may be considered to justify a larger unavailability of the EFWS.

G. Thermal Limitations

1. A component cooling system (CCS) shall provide cooling water to each RCP as shown in Figure 5.1.2-2.

2. RCP heat load and flow data presented in Table 5.1.4-1 shall be utilized in the design of the cooling water system.

3. The maximum and minimum temperature of the component cooling water during normal operation shall be 105°F and 65°F respectively.

4. Power operated atmospheric dump valves shall be provided in each of the four main steam lines to allow cooldown of the steam generators when the main steam line isolation valves are closed, or when the main condenser is not available as a heat sink. Each ADV shall be capable of holding the plant at hot standby dissipating core decay and reactor coolant pump heat, and allowing controlled cooldown from hot standby to Shutdown Cooling System initiation conditions. Each valve shall be sized to allow a rupture, which renders one steam generator unavailable for heat removal, concurrent with a loss of normal A.C. power and single failure of one of the remaining two ADV's. To accomplish the above, each ADV (considering all line losses) shall have sufficient capacity to meet the saturated 10
steam flow conditions in Figure 5.1.4-1. Also no single valve shall have a maximum capacity greater than 1.9×10^6 lb/hr at 1000 psia.

5. Following the events stated in Section 5.1.4.F.9, the emergency feedwater system shall maintain adequate inventory in the steam generator(s) for residual heat removal and be capable of the following:

   a. Maintaining the NSSS at hot standby with or without normal offsite and normal onsite power available.

   b. Facilitating NSSS cooldown at the maximum administratively controlled rate of 75°F/hr from hot standby to shutdown cooling initiation with or without normal offsite or onsite power available. (The Shutdown Cooling System becomes available for plant cooldown when the RCS temperature and pressure are reduced to approximately 350°F and 400 psia.)

6. The Emergency Feedwater System shall be available to deliver flow to the steam generator(s) automatically upon receipt of an EFAS as follows:

   a. Within 10 seconds when normal offsite or normal onsite power is available.

   b. Within 45 seconds when both normal onsite and normal offsite power are not available.

7. The required emergency feedwater flow, based on residual heat removal requirements is 875 gpm delivered to the steam generator(s) downcomer feedwater nozzle. Maximum expected steady state steam generator pressure at the downcomer nozzle is approximately 1275 psia.

8. Emergency feedwater temperature shall be at least 40F and no greater than 180F.

9. A minimum of 300,000 gallons of secondary quality makeup water as defined in Section 10.3.4 shall be available to the Emergency Feedwater System for delivery to the intact steam generator(s).

This amount ensures sufficient feedwater to allow an orderly plant cooldown to shutdown cooling initiation conditions.

10. Each MSIV leak flow shall not exceed 0.001 percent of nominal flow at 1270 psia in the forward direction and shall not exceed 0.1 percent of nominal flow at 1270 psia in the reverse direction.

11. No single MSIV bypass valve or bypass valve line shall have a capacity greater than 1.9×10^6 lb/hr of saturated steam at 1000 psia.

12. No single turbine bypass valve shall have a capacity greater than 1.9×10^6 lb/hr at 1000 psia.

13. The total reverse leak rate of feedwater check valves to each steam generator shall not exceed 1000 cc/hr.

H. Monitoring

1. Means shall be provided for detection of reactor coolant leakage into the secondary side of the steam generators and cooling water systems associated with components containing reactor coolant.

2. Applicant supplied component designs and RCS construction procedures shall ensure that RCS leakage from known sources will not exceed 10 gpm; from steam generator tubes will not exceed 1.0 gpm; and from unknown sources will not exceed 1 gpm, to minimize in-plant airborne and surface activity levels and activity releases to the environs at system normal operating temperature and pressure.

3. Capability for monitoring each MSIV, MFIV, ADV and blowdown line isolation valve position shall be provided locally and in the control room.

4. The required accuracy of the feedwater temperature measurement devices shall be $\pm 1^{\circ}F$ for any calorimetric measurement.

I. Operational/Controls

1. A power-operated MSIV capable of establishing shutoff under conditions of design pressure, design temperature, and flow conditions resulting from a break just upstream or downstream shall be provided in each main steam line outside of containment.

2. Capability for controlling MSIV position shall be provided in the control room and remote from the control room.

3. The MSIV and MSIV bypass valve shall be either a fail close valve or a valve that is shown by the applicant to close upon receipt of a MSIS.

4. The full open to close stroke time of each MSIV and MSIV bypass valve shall be 4.6 seconds or less upon receipt of an MSIS. | 10

5. The ADV's shall be fail close and shall be capable of being remote manually positioned to control the plant cooldown rate.

6. The ADV's shall be provided with manual operators such that the valves may be hand operated from the control room and remote shutdown panel in the event of a loss of normal power supply.

7. In the combined event of either a steam line break or steam generator tube rupture and the loss of power operation of the ADV's, personnel access to the manual operators of the intact valves on the other steam generator shall be possible.

8. A MSIS actuation signal shall close the MSIV's, MSIV bypass valve, MFIV's and the steam generator blowdown valves.

9. Redundant feedwater system isolation valving shall be provided in both the economizer feedlines and the downcomer feedlines such that the following criteria are met when the effects of single failure criteria are imposed:

   a. Complete termination of forward feedwater flow is assumed within 4.6 seconds after receipt of an MSIS. | 10

   b. Abrupt complete termination of reverse feedwater flow with the existence of a reverse flow condition. Check valves are considered to be an acceptable means of achieving the above.

10. The economizer and downcomer feedwater line isolation valves (MFIV's) in each main feedwater line shall be remote-operated and be capable of maintaining leak rate of less than 1000 cc/hr under the main feedwater line pressure, temperature and flow resulting from the transient conditions associated with a pipe break on either side of the valves.

11. The Emergency Feedwater System shall be controllable in a post-accident environment from either the control room or a remote shutdown station.

12. The Emergency Feedwater System shall be controllable such that post accident operation will not result in overfilling the intact steam generator(s).

13. If the Emergency Feedwater System is used as an auxiliary feedwater system, the emergency feedwater pumps shall be designed for operation when steam generator pressure is negligible and not result in damage to the pumps or effect the ability of the system to deliver the required emergency feedwater flow. Such a condition can exist during startup or shutdown operation subsequent to an EFAS which starts the emergency feedwater pumps and fully opens the system isolation and control valves.

14. Personnel access to the isolation valve upstream of the ADV shall be possible at all times during operation. | 10

15. If the isolation valves upstream of the ADV's are electrically controlled and operated, the valve operator and control systems shall be designed to the same IEEE standards as applied to the ADV's. 10

J. Inspection and Testing

1. All ASME B&PV Code, Section III, Class 1 and 2 valves shall be designed, fabricated and installed such that they are capable of being periodically tested in accordance with ASME Code, Section XI.

2. Adequate clearances shall be provided for inservice inspection of the Reactor Coolant Pressure Boundary and the ASME B&PV Code Section III, Class 2 portions of the Main Steam, Main Feed, Emergency Feed, and Blowdown systems' piping, in accordance with the provisions of Section XI of the ASME Boiler and Pressure Vessel Code.

3. Biological shielding and all other insulation, if installed around the Reactor Coolant Pressure Boundary, shall be designed to afford access for inservice inspection as defined by Section XI of the ASME Boiler and Pressure Vessel Code.

4. The pressurizer manway shall be accessible for internal examination of the pressurizer.

K. Chemistry/Sampling

1. A sampling system which provide a means of obtaining remote liquid samples from the RCS for chemical and radiochemical laboratory analysis shall be provided. The sampling system shall be designed to allow for the following tests: corrosion product activity levels, dissolved gas, fission product activity, chloride concentration, coolant pH, conductivity levels and boron concentration. The pressurizer steam space sample lines shall contain 7/32" x 1" orifice as close to the pressurizer as possible. The sample system shall be as shown on Figure 5.1.2-1.

2. A system or systems shall be provided to maintain the steam generator secondary water chemistry within Section 10.3.4 specifications during plant operation. The system or systems shall incorporate steam generator blowdown, chemical addition, and monitoring.

3. Provisions shall be made to allow sampling of the RCS during Shutdown Cooling System operation.

4. Provisions shall be made to allow sampling of the RCS during startup.

L. Materials

1. The materials used for the containment and its internal structures shall be compatible with both the normal operating environment and the most severe thermal, chemical, and radiation environment expected during post-accident conditions (refer to Section 3.11

for the environmental parameters). Consideration shall be given to compatability with spray water chemistry and recirculating water chemistry to ensure that containment materials will withstand this exposure without causing deleterious or undesirable reactions, or significantly altering the existing water chemistry of recirculating ECCS water.

2. The following elements and components shall not come in contact with surfaces which will later be in contact with reactor coolant, at any stage of manufacture, assembly or inspection. These are: (a) lead or lead compounds, (b) mercury or mercury compounds, (c) halogen containing solvents or other halogen compounds.

3. The use of the following materials shall be minimized on surfaces normaly in contact with reactor coolant:

   a. sulfonated cutting oils,

   b. zinc metal or zinc compounds,

   c. magnesium metal,

   d. asbestos,

   e. aluminum,

   f. copper acid etchants,

   g. penetrants.

   If the above materials are intended to be used, the use shall first be approved by C-E.

4. The sample lines in contact with the reactor coolant, including welds shall be designed such that the material is compatible with the fluid chemistry described in Section 9.3.4.

5. Construction materials or protective coatings containing low melting point elements, particularly lead, mercury and sulfur, shall not be used if they could come in contact with the secondary systems. This is required to reduce to a minimum the potential for stress corrosion cracking of Inconel material in the steam generators.

6. The secondary system piping shall be designed to allow cleaning for the removal of foreign material and rust prior to operation and to prevent introduction of this material into the steam generator. Chemical cleaning or hand cleaning may be employed. During chemical cleaning, no fluid shall enter the steam generators. Suitaple bypass piping shall be provided if required.

TABLE 5.1.1-1

PROCESS DATA POINT TABULATION*

Parameter	Pressurizer	S.G. 1-A Midpoint	Pump 1-B Outlet	R.V. Midpoint	Pump 1-A Outlet	S.G. 2-A Midpoint	Pump 2-A Outlet	Pump 2-B Outlet	
Data Point Fig. 5.1.2-1	1	2	3	4	5	6	7	8	
Pressure, psia	2250	2235.3	2325.1	2292.2	2325.1	2235.3	2325.1	2325.1	
Temperature °F	652.7	592.8	564.5	595.8	564.5	592.8	564.5	564.5	
Mass Flow Rate lbm/hr	-	82.0×10^6	41.0×10^6	164.0×10^6	41.0×10^6	82×10^6	41.0×10^6	41.0×10^6	10
Volumetric Flow Rate, gpm	-	233.6×10^6	111.4×10^3	467.18×10^3	111.4×10^3	233.6×10^3	111.4×10^3	111.4×10^3	

*For normal steady state 100% power conditions

TABLE 5.1.1-2

DESIGN PARAMETERS OF REACTOR COOLANT SYSTEM

Design Thermal Power, Mwt (Including Net Heat Addition from Pumps	3817
Thermal Power, Btu/hr	1.303×10^{10}
Design Pressure, psig	2485
Design Temperature (Except Pressurizer), °F	650
Coolant Flow Rate, lb/hr	164×10^{6}
Cold Leg Temperature, Operating, °F	564.5
Average Temperature, Operating, °F	592.85
Hot Leg Temperature, Operating, °F	621.2
Normal Operating Pressure, psig	2235
System Water Volume, Ft^3 (Without Pressurizer)	12,353
Pressurizer Water Volume, Ft^3 (Full Power)	900
Pressurizer Steam Volume, Ft^3 (Full Power)	900

d) 75°F to 653°F and return to 75°F at a rate of 200°F/hr with pressures at saturation levels for 500 cycles. (Plant heat up and cool down).

Note: Heat up and cool down are separate transients, each beginning at steady state conditions.

e) Pressurize to 1.5 times set pressure at 100°F-200°F for 10 cycles plus number of hydros conducted prior to valve shipment. (Hydrostatic test).

f) 480 cycles from closed to full open to closed. (Turbin Trip)

5.2.2.4.2 Environment

The primary safety valves are designed to operate in the following environmental conditions.

5.2.2.4.2.1 Normal Environment

a) 122°F maximum

b) Relative humidity of 95% at 60°F to 80°F.

c) Fixed moisture content eqivalent to 95% relative humidity at 80°F, up to 122°F.

5.2.2.4.2.2 Main Steam Line Break (One occurrence)

350°F maximum Superheated steam/air mixture for 12 minutes followed by saturated steam/air mixture.

5.2.2.4.3 Main Steam Safety Valves

The main steam safety valves are direct acting, spring loaded, carbon steel valves. The valves are mounted on each of the main steam lines upstream of the steam line isolation valves, and outside containment. A schematic drawing of the main steam safety valves is given in Figure 5.4.13-2. The valve parameters are given in Table 5.4.13-2. For a description of overpressure protection equipment and components for the main steam system refer to Subsection 10.3.2.

5.2.2.4.3.1 Main Steam Safety Valve Operation. The operation of these valves is similar to the primary safety valves, Section 5.2.2.4.2.

5.2.2.4.3.2 Transients. The main steam safety valves are designed to withstand the following transients without failure or malfunction.

a) 565°F to 75°F in 60 seconds for 5 cycles (loss of secondary pressure).

b) Pressure changes form 0 psig to 1375 psig, at a temperature range of between 100°F to 200°F for 200 cycles (secondary side leak test).

c) ± 10°F step change from 553°F, 10^6 cycles (normal plant variations).

d) 75°F to 565°F and return to 75°F at a rate of 100°F/hr with pressures at saturation levels for 500 cycles (plant heatup and cool down).

Note: Heat up and cool down are separate transients, each beginning at steady state conditions.

e) Pressurize to 1.5 times set pressure at 100°F - 200°F for 10 cycles plus number of hydros conducted prior to valve shipment (hydrostatic test).

f) 480 opening and closing cycles to full stem movement (turbine trip).

5.2.2.4.3.3 Environment. The main steam safety valves are designed to operate in the following environmental conditions:

5.2.2.4.3.3.1 Normal Environment

a) 104°F maximum

b) Relative humidity 95% at 60°F to 80°F.

c) Fixed moisture content equivalent to 95% relative humidity at 80°F, up to 104°F.

5.2.2.4.3.3.2 Main Steam Line Break (One Occurrence)

a) 330°F maximum for 3 minutes

b) Relative humidity of 100%.

5.2.2.4.4 Safety Injection System Relief Valves SI-169 and SI-469 10

These relief valves are direct acting, spring loaded, stainless steel valves with enclosed bonnets. The design parameters of these valves are: 10

set pressure	2485 psig	10
rated flow	15 gpm	
water chemistry	0 - 4 weight percent boric acid	10
throat area	.023 in^2	
design temperature	650°F	

10

5.2.2.4.4.1 Valve Operation. As the set pressure is reached, the disc raises off the nozzle seat. This lift continues until the valve is fully open at 10 percent accumulation. The lift decreases as pressure drops until the seat and disc contacts and seals closed. The valve is fully closed at a maximum of 10% below set pressure (10% blowdown).

5.2.2.4.4.2 Transients. These relief valves are designed to withstand the following transients without failure or malfunction. 10

a) 60°F to 400°F in 5 seconds, 400°F to 60°F in 15 minutes for 55 cycles.

b) 60°F to 350°F in 15 minutes, 350°F to 60°F in 2.9 hours for 500 cycles. 10

c) 120°F to 60°F in 5 seconds, 60°F to 120°F in 15 minutes for 660 cycles.

5.2.2.4.4.3 Environment. These relief valves are designed to operate in the following environmental conditions. 10

a) 122°F maximum

b) 95% relative humidity at 60°F to 80°F.

c) Fixed moisture content equivalent to 95% RH at 80°F at temperatures above 10

5.2.2.4.4.4 Material Specifications. Material specifications for the primary safety valves are given in Table 5.4.13-1.

Material specifications for the main steam safety valves are given in Table 5.4.13-2. 10

Typical materials used for these relief valves are: 10

Body	ASME SA351 GR. CF 8M
Disc	Stellite No. 6B
Nozzle	ASME SA 479 Type 316 with Stellite Seat.
Inlet Stud	ASME SA 193 GR. B6.

5.2.2.5 Mounting of Pressure-Relief Devices

See Applicant's SAR

5.2.2.6 Applicable Codes and Classification

The applicable codes and classifications for the overpressurization protection system are contained in Table 3.2-1. The applicable codes and classification for the secondary safety valves are identified in Section 5.1.4.

5.2.2.7 Process Instrumentation

Process instrumentation for the overpressurization protection equipment that is associated with the Reactor Coolant System is shown in Figure 5.1.2-1 and described in Chapter 7. Instrumentation associated with pressurizer relief discharge is described in Section 5.4.11. Process instrumentation for Secondary System Overpressurization Protection will be identified in the Applicant's SAR.

5.2.2.8 System Reliability

Reliability of the main steam system reliefs is discussed in the interface Section 5.1.4. The primary safety valves are passive, spring actuated mechanisms, and cannot fail closed if setpoint pressure is exceeded. The operational reliability of the primary safety valves is assured by:

- Stringent compliance with ASME III and XI Code for safety valves.
- Conservative design criteria.
- Selection of a vendor with proven experience and expertise.
- Accounting for thermal cycling during valve operation.
- Technical Specifications

5.2.2.9 Testing and Inspection

Testing and inspection of the primary, and secondary valves is governed by ASME Section XI.

5.2.2.10 Overpressure Protection During Low Temperature Conditions

Overpressure protection of the RCS during low-temperature conditions is provided by the relief valves located in the shutdown cooling system (SCS) suction lines. Section 5.4.7 provides a description of the SCS. The SCS is schematically shown on the RCS P&ID (Figure 5.1.2-1) and on the Safety Injection System (SIS) P&ID (Figure 6.3.2-1B). The electrical schematic for the SCS isolation valves is provided in the SIS P&ID (Figure 6.3.2-1B). The SCS relief valves are shown on Figure 6.3.2-1B and described in paragraph 5.4.7.2.2.

Alignment of the SCS relief valve to the RCS is provided via plant procedures to ensure RCS overpressure protection for all temperatures below the pressure-temperature (P-T) operating curve limits corresponding to the pressurizer safety valve set pressure of 2500 $lb/in.^2a$. The P-T curves are shown in the Technical Specifications, Figure 3.4-2. For temperatures above the temperature limit which corresponds to the pressurizer safety valve setpoint, overpressure protection is provided by the pressurizer safety valves described in subsection 5.2.2. 6

5.2.2.10.1 Design Criteria

A discussion follows of the criteria considered in the design of the overpressure mitigating system to provide low temperature overpressure protection (LTOP) for the RCS.

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5.2.2.10.1.1 Credit for Operator Action

No credit is taken for operator action for 10 minutes after the operator is made aware that a transient is in progress.

5.2.2.10.1.2 Single Failure

In the LTOP mode, each SCS relief valve is designed to protect the reactor vessel given a single failure in addition to a failure that initiated the pressure transient. The event initiating the pressure transient is considered to result from either an operator error or equipment malfunction. The SCS relief valve system is independent of a loss of offsite power. Each SCS relief valve is a self actuating spring-loaded liquid relief valve which does not require control circuitry. The valve opens when the RCS pressure exceeds its setpoint.

The redundant SCS suction line trains between the RCS and SCS relief valves meet the single failure criteria as described in paragraph 5.4.7.1.2 and table 5.4.7-3. No single failure of an isolation valve or its associated interlock will prevent one relief valve from performing its intended function.

5.2.2.10.1.3 Testability

Periodic testing of the SCS isolation valves is defined in the Technical Specifications, paragraph 16.3/4.5.2. 6

5.2.2.10.1.4 Seismic Design and IEEE 270 Criteria

The SCS suction line relief valves, isolation valves, associated interlocks, and instrumentation are designed to Seismic Category I requirements as discussed in subsections 3.2.1, paragraph 5.4.7.2.5 and table 3.2-1. The interlocks and instrumentation associated with the SCS suction isolation valves satisfy the appropriate portions of IEEE 279 criteria as discussed in paragraphs 5.4.7.2.5, 7.6.2.1.1 and 7.6.2.2.1.

5.2.2.10.2 Design and Analysis

In demonstrating that the SCS relief valves meet the criteria listed in paragraph 5.2.2.10.1, the following additional information is provided.

5.2.2.10.2.1 Limiting Transients

Transients during the low temperature operating mode are more severe when the RCS is operated in the water-solid condition. Addition of mass or energy to an isolated water-solid system produces increased system pressure. The 10
severity of the pressure transients depends upon the rate and total quantity of mass or energy addition. The choice of the limiting LTOP transients was based on evaluations of potential transients for System 80 plants. The most limiting transients initiated by a single operator error or equipment failure are: 6

a) An inadvertent safety injection actuation (mass input).
b) A reactor coolant pump start when a positive steam generator to reactor vessel Δ T exists (energy input).

The transients were determined as most limiting by conservative analyses which maximize mass and energy additions to the RCS. In addition, the RCS is assumed to be in a water-solid condition at the time of the transient; such a condition has been noticed to exist infrequently during plant operation since the operator is instructed to avoid water-solid conditions whenever possible.

Figure 5.2-1 shows the result of the inadvertent safety injection actuation 6
transient analysis when the RCS is in the LTOP mode. The mass addition due to the simultaneous operation of two HPSI and three charging pumps was considered, along with the simultaneous addition of energy from decay heat and the pressurizer heaters.

Figures 5.2-2 shows the result of the transient analysis of reactor coolant
pump start when a steam generator to reactor vessel Δ T of 100°F exists. This 10
Δ T is the maximum allowed by technical specification during the LTOP mode. In addition to considering the energy addition to the RCS from the steam generator secondary side, energy addition from decay heat, the reactor coolant pump and all pressurizer heaters were also included. In this analysis the steam generators were assumed to be filled to the zero power, normal water level. For conservatism, the secondary water, both around and above the
U-tubes, was assumed to be thermally mixed in order to maximize the energy 6
input to the primary side. This assumption is conservative since as a result of the temperature distribution within the steam generator during the transient, the water inventory above the tubes is practically isolated thermally from the heat transfer region. Therefore the heat transfer rate, and thus the primary side pressure, is not sensitive to the secondary side water level as long as the tubes are covered.

On the basis of experience, the ΔT value of 100°F used in the analysis is much 10
larger than any ΔT that might be expected during plant operation. This 6
maximum allowable ΔT of 100°F will prevent pressurizer pressure from exceeding
the minimum P-T limit allowed for the lowest system temperature during the 10
LTOP mode of operation. (See Technical Specification Figure 3.4-2). During RCS cooldown using the shutdown cooling system, coolant circulating with the reactor coolant pumps serves to cool the steam generator to keep the temperature difference between the reactor vessel and the steam generator minimal. Procedures will direct the operator to maintain the ΔT below approximately 20°F.

6

LTOP transients have not been analyzed for the simultaneous startup of more than one reactor coolant pump (RCP). Such operation is procedurally precluded since the operator starts only one RCP at a time and a second RCP is not started until system pressure is stabilized. Additionally, there is an LTOP transient alarm that should indicate that a pressure transient is occurring. Accordingly, the second RCP would not be started.

Technical Specification section 16.3/4.4.1.3 requires that the operator not
start an RCP if the ΔT exceeds 100°F. However, as mentioned above, adminis- 10
trative procedures will ensure that the ΔT is maintained below approximately 20°F.

The results of the analyses provided in Figures 5.2-1 and 5.2-2 show that the 6
use of either SCS relief valve will provide sufficient pressure relief capacity to mitigate the most limiting LTOP events identified above.

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 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). 7

These LTOP conditions are within the SCS operating range. Technical Specification section 16.3/4.4.8.3 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. 10 7

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 liquid relief valves with sufficient capacity to mitigate the most limiting overpressurization event. Pertinent valve parameters are as follows: 10

Parameter 6

Nominal Setpoint 450 lb/in.^{2} absolute 10
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. 6

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 6
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 meets the minimum required relief 10
capacity of 4000 gpm which contains 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

Administrative controls necessary to implement the LTOP provisions are limited 6
- 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-deposited 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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5.4.3 REACTOR COOLANT PIPING

5.4.3.1 Design Basis

Applicable design codes are found in Table 5.2-1. The reactor coolant loop piping is designed and analyzed for all transients specified in Section 3.9.1. In addition, those nozzles subjected to local thermal transients, caused by fluid entering the Reactor Coolant System from an auxiliary system, are analyzed to ensure that the nozzles can accommodate the additional transients. 10

In addition to being specified as Seismic Category I, the piping is designed to ensure that critical vibration frequencies are well out of the range expected during normal operation and during abnormal conditions. Additional presentations relating to seismic and dynamic analysis and criteria for the reactor coolant piping is contained in Sections 3.7.2 and 3.9.2, respectively.

5.4.3.2 Description

Each of the two heat transfer loops contains five sections of pipe: one 42-in. internal diameter pipe between the reactor vessel outlet nozzle and steam generator inlet nozzle, two 30-in. internal diameter pipes from the steam generator's two outlet nozzles to the reactor coolant pumps suction nozzle, and two 30-in. internal diameter pipes from the pumps discharge nozzle to the reactor vessel inlet nozzles. These pipes are referred to as the hot leg, the suction legs, and the cold legs, respectively. The other major pieces of reactor coolant piping are the surge line, a 12-in. pipe between the pressurizer and the hot leg, and the spray line, a 4-inch pipe at the pressurizer end reduced to a 3-inch pipe and connected to two (2) cold legs.

The 42-in. and 30-in. pipe diameter are selected to obtain coolant velocities which provide a reasonable balance between erosion-corrosion, pressure drop, and system volume. The surge line is sized to limit the frictional pressure loss through it during the maximum in-surge so that the pressure differential between the pressurizer and the heat transfer loops is no more than 5 percent of the system design pressure. The spray line sizing is discussed in Section 5.4.10.

To reduce the amount of field welding during plant fabrication, the 42-in. and 30-in. pipes are supplied in major pieces, complete with shop-installed instrumentation nozzles and connecting nozzles to the auxiliary systems. Where required, the nozzles are supplied with safe ends to facilitate field welding of the connecting piping. 10

Flow restricting orifices (7/32" dia. x 1" long) are provided in the nozzles for the RCS instrumentation and sampling lines to limit flow in the event of a break downstream of a nozzle.

5.4.3.3 Materials

The materials used in the fabrication of the piping are listed in Table 5.2-2. These materials are in accordance with the ASME Code, Section III. The provisions taken to control those factors that contribute to stress corrosion cracking are discussed in Section 5.2.3.

Fracture toughness of the reactor coolant piping is discussed in Section 5.2.3.

5.4.3.4 Tests and Inspections

Prior to, during and after fabrication of the reactor coolant piping, nondestructive tests based upon Section III of the ASME Code were performed. In addition, the fully assembled reactor coolant system is hydrostatically tested in accordance with the Code.

Inservice inspection of the reactor coolant system piping is discussed in Section 5.2.4.

5.4.4 MAIN STEAM LINE RESTRICTIONS

The steam generator outlet nozzles are one piece forgings with an integral venturi type flow restrictor. The venturi section of the nozzle is designed to reduce the flow area by 70%.

5.4.5 MAIN STEAM LINE ISOLATION SYSTEM

The main steam line isolation system is composed of portions of the main steam system and the engineered safety features actuation system. Discussed here are those portions of these systems that respond to a Main Steam Isolation Signal, as defined in Section 7.3. A discussion of radiological considerations is provided in Section 12.3.

5.4.5.1 Design Bases

A. The main steam line isolation valves are designed to isolate the steam generators and the main steam lines in the event of a main steam line rupture.

B. The main steam line isolation valves are designed to perform containment isolation functions for the main steam lines in the event of a design basis accident, as discussed in Section 6.2.4. In the event of a steam line break outside the containment, the isolation function serves to reduce the potential leakage of radioactivity to the environment.

C. The main steam isolation valves are designed to isolate the main steam lines and the steam generators as required for maintenance.

   C-E interface requirements for the main steam isolation valves are listed in Subsection 5.1.4.

5.4.5.2 System Design

5.4.5.2.1 General Description

Each of the four main steam lines is provided with a power-actuated main steam isolation valve designed to stop flow from either direction when it is tripped closed. Each valve is located outside containment and is provided with means of actuation from the engineered safety features actuation system, meeting the requirements of IEEE Standard 279.

The logic circuitry required to isolate the main steam lines is discussed in Section 7.3. The main steam system valves and arrangement will be discussed in the Applicant's SAR.

5.4.5.2.2 Component Description

The main steam isolation system consists of the main steam isolation valves and their associated controls and instrumentation. The main steam isolation valves are remotely operated valves designed to either fail closed or be guaranteed to close upon receipt of Main Steam Isolation Signal. The main steam isolation valves can be monitored and controlled locally and in the control room.

5.4.5.2.3 System Operation

The main steam isolation valves are designed to isolate the main steam lines and the steam generators as required during operation and under accident conditions.

A steam line break inside containment would result in a pressure rise in the containment. Reverse flow protection is also achieved through the main steam isolation valves. To achieve reverse flow protection in the case of the main steam pipe rupture, the valve is fully closed within 5 seconds from receipt of the initiating signal.

The main steam line isolation system components are qualified to serve in the environment specified in Section 3.11.

5.4.5.3 Design Evaluation

Design evaluations are listed to correspond with the design bases listing.

A. The main steam isolation valves are capable of isolating the steam generators within 4.6 seconds after receiving a signal from the engineered safety features actuation system. In the event of a steam line break, this action prevents continuous uncontrolled steam release from more than one steam generator. Protection is offered for breaks inside or outside the containment. 10

B. The main steam isolation valves, their operators, and associated circuitry are Seismic Category I, and are protected against missiles and the effect of high-energy line breaks.

5.4.5.4 Tests and Inspections

All main steam isolation valves are designed, fabricated, tested, and installed in accordance with the codes and standards identified in the interface requirements described in Section 5.1.4. Assurance of operability is discussed in Section 3.9.3 of the Applicant's SAR.

5.4.6 REACTOR CORE ISOLATION COOLING SYSTEM

This system is not applicable to a Pressurized Water Reactor.

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

5.4.7.1 Design Bases

5.4.7.1.1 Summary Description

The Shutdown Cooling System (SCS) is used in conjunction with the Main Steam and Main or Emergency Feedwater Systems (see Sections 10.1 and 10.4.7) to reduce the temperature of the Reactor Coolant System (RCS) in post shutdown periods from normal operating temperature to the refueling temperature. The initial phase of the cooldown is accomplished by heat rejection from the steam generators (SG) to the condenser or atmosphere. After the reactor coolant temperature and pressure have been reduced to approximately 350°F and 400 psia, the SCS is put into operation to reduce the reactor coolant temperature to the refueling temperature and to maintain this temperature during refueling.

The Shutdown Cooling Heat Exchangers (SDCHX) are also used during the recirculation mode following a Loss-Of-Coolant Accident (LOCA) or Main Steam Line Break (MSLB) for containment spray purposes as described in Section 6.3.

The SCS is used in addition to the S.G. atmospheric steam release capability and the Emergency Feedwater System to cooldown the RCS following a small break LOCA (see Section 6.3). The SCS would also be used subsequent to steam and feedline breaks, steam generator tube ruptures, and is used to maintain flow through the core during plant startup.

5.4.7.1.2 Functional Design Bases

The following functional design bases apply to the Shutdown Cooling System:

a. No single active failure prevents at least one complete train of the SCS from being brought on line from the control room, whether this is during normal plant cooldown or following a Design Basis Event.

b. The functional requirements defined in Paragraph 5.4.7.1.1 are met assuming the failure of a single active component during shutdown cooling or a single active or limited leakage passive failure of a component during the recirculation mode following a Design Basis Event.

c. For all conditions, cooling water shall be supplied as follows:

Parameter	Required Value Per Heat Exchanger
Normal Allowable Delivery Pressure	100 psig
Maximum Allowable Delivery Pressure	150 psig
Required Flowrate	11,000 gpm
Maximum Allowable Flowrate	13,000 gpm

d. Cooling water piping supplying the shutdown cooling heat exchangers shall be designed and fabricated in accordance with ASME B&PVC, Section III, Class 3, as a minimum, and shall be designed as Seismic Category I, Safety Class 3, as a minimum.

e. The cooling water system which services the SCS shall be designed with sufficient redundancy and diversity such that one SCS heat exchanger train will always be supplied cooling water.

f. The cooling water system which services the SCS shall be designed consistent with the cooling water chemistry.

3. Containment Spray System (CSS)

a. The CSS shall be designed to allow use of the containment spray pumps can augment the SCS during the later stage of plant cooldown when plant temperature is less than 200°F. The spray system shall provide 4000 gpm per train at a head which can be set between 250-300 feet.

b. The CSS shall be designed such that the containment spray pumps can be aligned for automatic spray initiation concurrent with shutdown cooling operation of the LPSI pumps. When shutdown cooling is in operation and the containment spray pumps are aligned for automatic initiation, the containment spray alignment shall bypass the shutdown cooling heat exchangers.

4. Reactor Coolant Gas Vent System (RCGVS)

The RCGVS shall be designed as safety grade and shall meet the single failure criterion of IEEE 279. 10

Q. Environmental

1. The proper operating environmental conditions for the equipment of one train of the SCS shall be maintained independently of the environment of the other train of the SCS, e.g., failure or isolation of the ventilation capability to one train of the SCS shall not cause the environmental limits of the other SCS train to be exceeded.

2. The auxiliary building ventilation system shall control ambient air conditions in the proximity of all C-E supplied motor driven or diaphragm operated equipment in the SCS in accordance with the requirements of Section 3.11.

5.4.7.2 System Design

5.4.7.2.1 System Schematic

The SCS is shown on the RCS P&ID (Figure 5.1.2-1) and on the SIS P&ID (Figure 6.3.2-1A, 1B). Figures 6.3.2-1I, 1J, 1K, and 1L, and Tables 6.3.2-4d and 4e show flow rates at various locations during system operation. The pressure and temperature of the RCS system vary from 400 psia and 350°F at initiation of shutdown cooling to atmospheric pressure and 135°F at refueling conditions. SCS design parameters are given in Table 5.4.7-1. The SCS suction side pressure and temperature follow RCS conditions. The discharge side pressure is higher by an amount equal to the pump head and the temperature is lower at the shutdown cooling heat exchanger outlet.

The SCS contains two shutdown cooling heat exchangers and employs the two low pressure safety injection pumps throughout shutdown cooling. The applicant may utilize the flow of the containment spray pumps through the shutdown cooling heat exchangers to achieve an increased cooldown rate during the latter stages of shutdown cooling. During initial shutdown cooling, a portion of the reactor coolant flows out the shutdown cooling nozzles located on the reactor vessel outlet (hot leg) pipes and is circulated through the shutdown cooling heat exchangers by the LPSI pumps. The return to the RCS is through the four LPSI lines.

The SCS suction line isolation valves are interlocked to prevent overpressurization of the SCS by the RCS. These interlocks are described in Sections 5.4.7.2.3 and 7.6.

Shutdown cooling and LPSI flow are measured by orifice meters installed in each LPSI header. The information provided by these flow elements is used by the operator for flow control during shutdown cooling operation.

The cooldown rate is controlled by adjusting flow through the heat exchangers with throttle valves on the discharge of each heat exchanger. The operator maintains a constant total shutdown cooling flow to the core by adjusting the heat exchanger bypass flow to compensate for changes in flow through the heat exchangers.

5.4.7.2.2 Component Description

1. Shutdown Cooling Heat Exchangers

   The shutdown cooling heat exchangers are used to remove decay, sensible and safeguards pump heat during cooldown, and decay and pump heat during cold shutdown. The units are sized to maintain a refueling water temperature of 135°F with the design component cooling water temperature 105°F at 27-1/2 hours after shutdown following an assumed

level, resulting in a transient pressure below normal operating pressure. To minimize the extent of this transient, the backup heaters are energized, contributing more heat to the water. Backup heaters are deenergized in the event of concurrent high-level error and high-pressurizer pressure signals. A low-low pressurizer water level signal deenergizes all heaters before they are uncovered to prevent heater damage. The pressure control program is shown in Figure 5.4.10-5.

5.4.10.3 Evaluation

It is demonstrated by analysis in accordance with requirements for ASME Code, Section III, Class 1 vessels that the pressurizer is adequate for all normal operating and transient conditions expected during the life of the facility. Following completion of fabrication, the pressurizer is subjected to the required ASME Code, Section III hydrostatic test and post-hydrostatic test non-destructive testing.

During hot functional testing, the transient performance of the pressurizer is checked by determining its normal heat losses and maximum depressurization
rate. This information is used in setting the pressure controllers. 10

Further assurance of the structural integrity of the pressurizer during plant life will be obtained from the inservice inspections performed in accordance with ASME Code, Section XI, and described in Section 5.2.

Overpressure protection of the Reactor Coolant System is provided by four ASME Code spring-loaded safety valves. Refer to Section 5.4.12 and 5.4.13.

5.4.10.4 Tests and Inspections

Prior to and during fabrication of the pressurizer, non-destructive testing is performed in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code. Table 5.4.10-2 summarizes the pressurizer inspection program, which also includes tests not required by the Code. Refer to Section 5.2.1 for inservice inspections of the pressurizer.

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5.4.13 SAFETY AND RELIEF VALVES

5.4.13.1 Design Basis

The safety valves on the pressurizer are designed to protect the system, as required by the ASME B&PV Code, Section III.

The design basis for establishing the relieving capacity of the pressurizer safety valves is presented in Appendix 5A. For the postulated transients presented in Chapter 15, the results indicate that relieving capacity of the safety valves is sufficient to provide overpressure protection in accordance with Section III of the ASME Code.

Safety valves on the steam side of each steam generator are designed to protect the steam system, as required by the ASME Code, Section III. They are conservatively sized to pass a steady flow equivalent to the maximum expected power level at the design pressure of the steam system.

5.4.13.2 Description

The RCS has four safety valves to provide overpressure protection. A typical safety valve is illustrated in Figure 5.4.13-1. The design parameters are given in Table 5.4.13-1. These valves are connected by piping to the top of the pressurizer. They are direct acting, spring-loaded safety valves meeting ASME Code requirements. They have an enclosed bonnet and have a balanced bellows to compensate for backpressure. The safety valves pass sufficient pressurizer steam to limit the reactor coolant system pressure to 110% of design pressure (2750 psig) following a complete loss of turbine generator load without simultaneous reactor trip. A delayed reactor trip is assumed on a high-pressurizer pressure signal. To determine maximum steam flow through the pressurizer safety valves, the main steam safety valves are assumed to be operational. Values for the system parameters, delay times, and core moderator coefficient are given in Chapter 15.

Overpressure protection for the shell side of the steam generators and the main steam line up to the inlet of the turbine stop valve is provided by the secondary safety valves.

These valves are each sized to pass a steam flow of 945,292 lb/hr at 1308 psia. This limits steam generator pressure to less than 110% of steam generator design pressure during worst case transients. The secondary safety valves consist of two banks of 10 valves with staggered set pressures. The valves are spring-loaded safety valves procured in accordance with ASME Boiler and Pressure Vessel Code, Section III (see Table 5.2-1). Parameters for the secondary safety valves are given in Table 5.4.13-2.

5.4.13.3 Evaluation

Overpressure protection is discussed in Section 5.2.2. The ASME Code report on Overpressure Protection is included as Appendix 5A.

5.4.13.4 Tests and Inspections

The valves are inspected during fabrication in accordance with ASME III Code requirements.

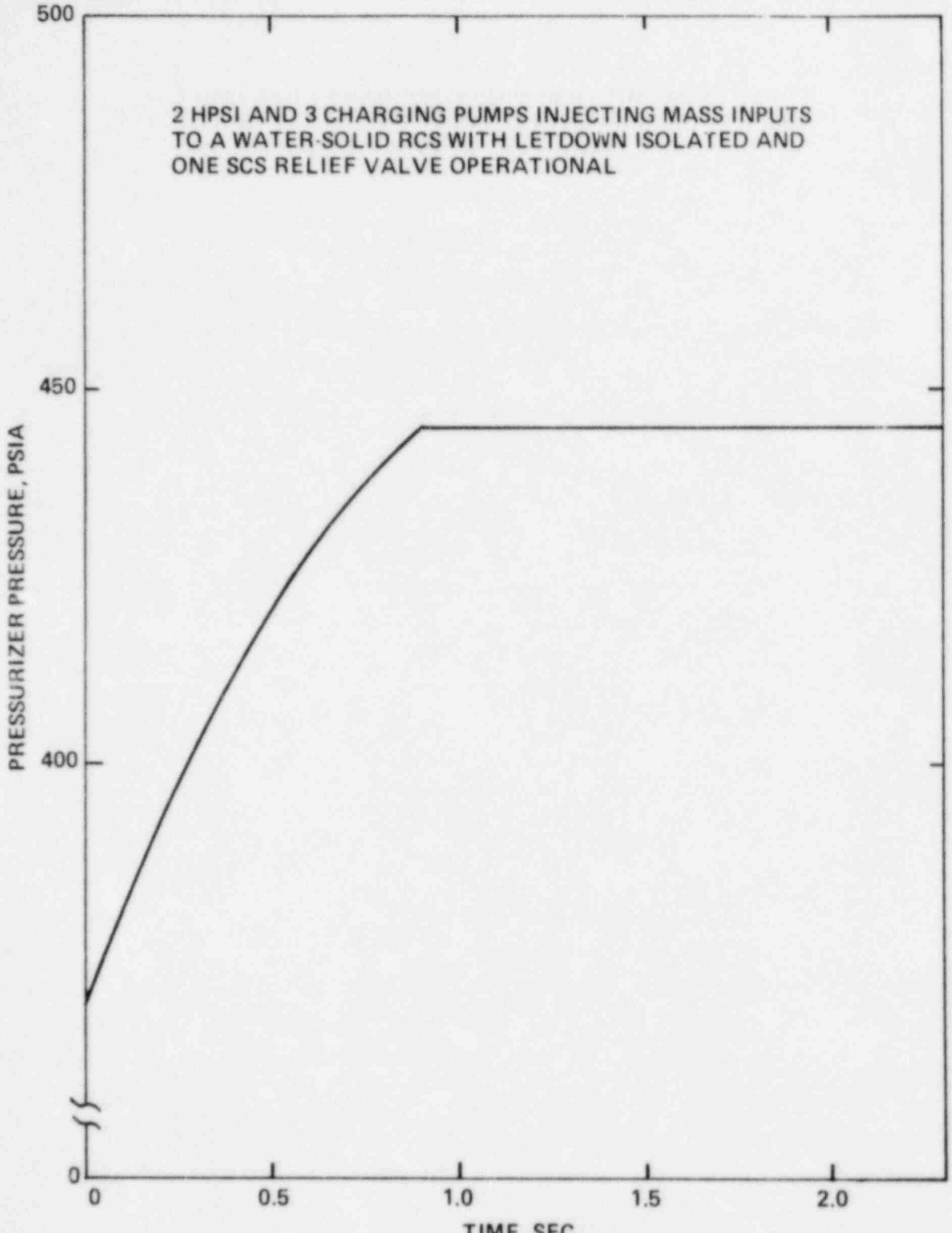
5.4.13.4.1 Pressurizer Safety Valves

The inlet and outlet portions of the valves are hydrostatically tested with 9
water at the appropriate pressures required by the applicable section of
the ASME Code. Set pressure and seat leakage tests can be performed with 10
steam using a pro-rated spring. Final set pressure tests are performed 9
with the final springs using either high pressure steam or low pressure steam 10
with an assist device. Final seat leakage tests are performed prior to
shipment with the final springs using either hot air or hot nitrogen. Valve
adjustment shall be made to a valve ring setting combination selected to 9
provide stable valve operation on the basis of the EPRI Safety Valve Test
Program results.(1)

5.4.13.4.2 Main Steam Safety Valves

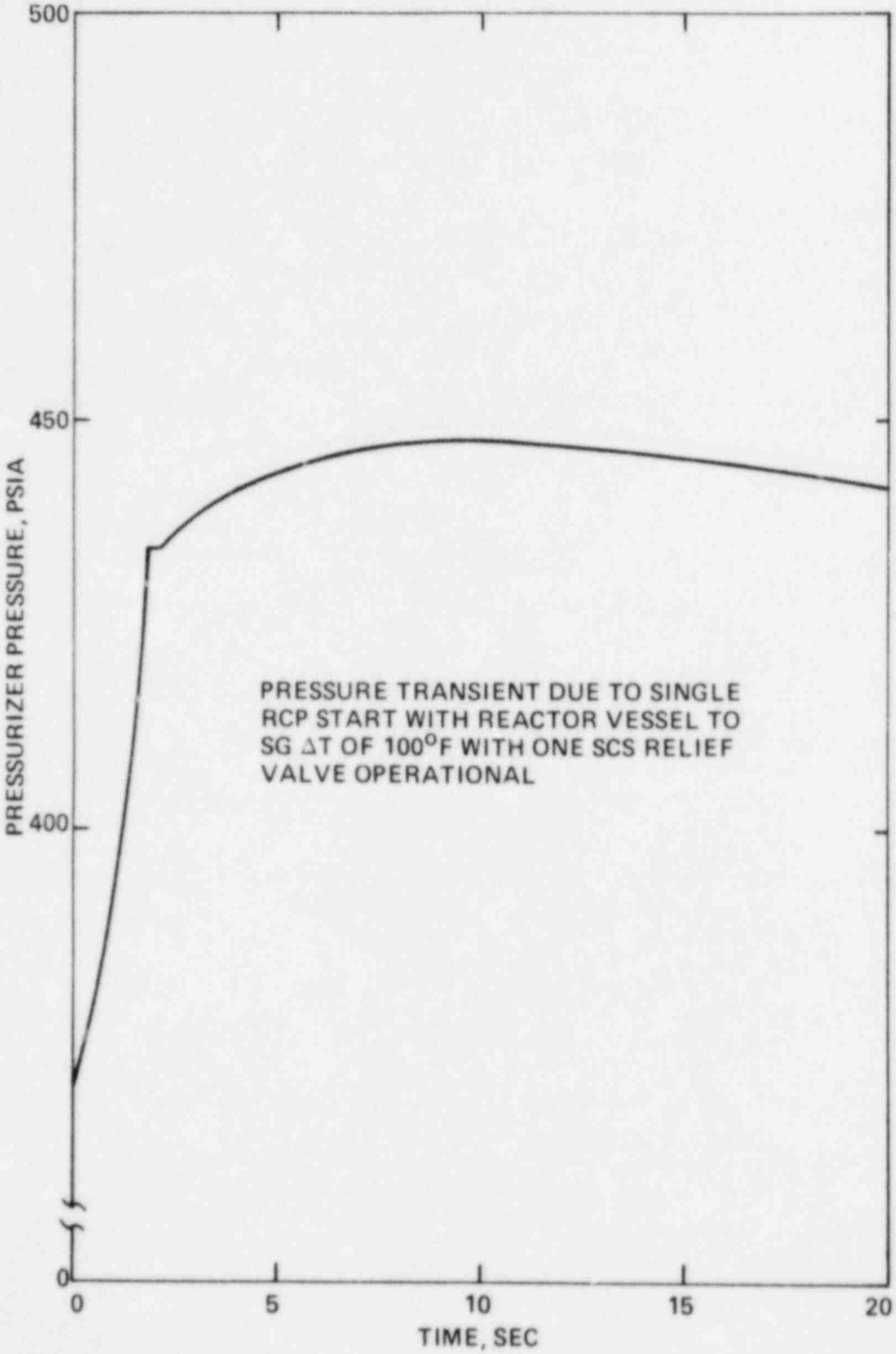
The inlet portion of the valve is hydrostatically tested with water in
accordance with the ASME Code. Set pressure and set leakage tests are
performed using steam. Adjustment is made to provide a valve blowdown 9
meeting the requirement specified in Table 5.4.13-2.

(1) CEN-227 "Summary Report on the Operability of Pressurizer Safety
Relief Valve in C-E Designed Plants". December 1982. 9



Amendment No. 10
June 28, 1985

C - E SYSTEM 80	PRESSURIZER PRESSURE DURING INADVERTENT SAFETY INJECTION ACTUATION	Figure 5.2-1



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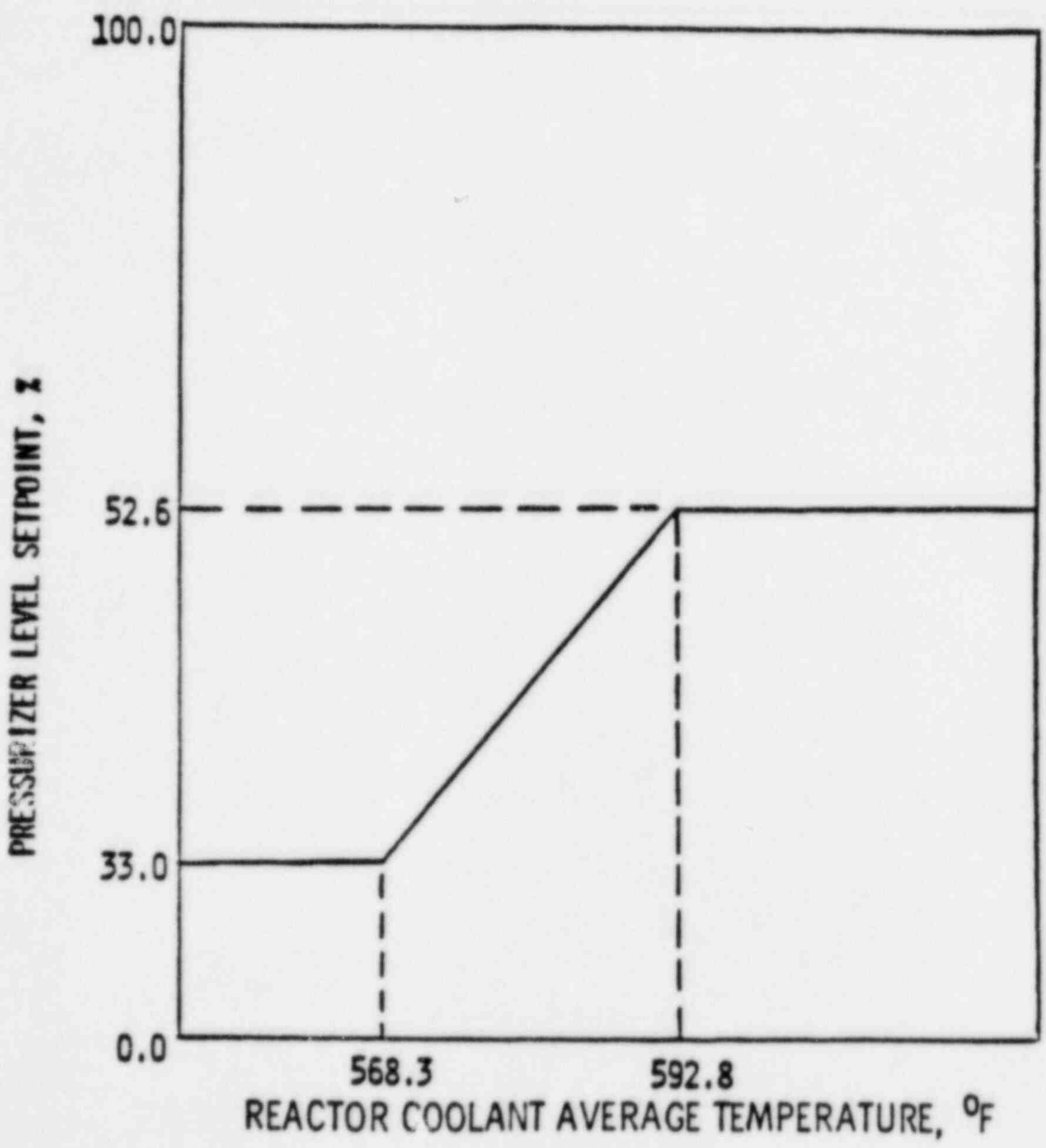
C - E SYSTEM 80	PRESSURIZER PRESSURE DURING RCP START WITH RCS ΔT	Figure 5.2-2



Amendment No. 10
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C-E SYSTEM 80	TYPICAL PRESSURIZER LEVEL SETPOINT PROGRAM	Figure 5.4.10-2

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Figure 5A-2 depicts the steam generator pressure transient for this worst case loss-of-load incident. As can be seen in Figure 5A-2, the steam generator pressure remains below 110 percent of design pressure during the incident.

2.2.2 PRIMARY SAFETY VALVE SIZING

The reactor drain tank, inlet and discharge piping are sized to preclude unacceptable pressure drops and backpressure which would adversely affect valve operation.

Primary safety valve backpressure is limited by the design pressure of the valve bellows. These bellows prevent any accumulated backpressure from being imposed on the valve spring, thus allowing valve operation at its design setpoint rather than at its setpoint plus backpressure.

The design basis incident for sizing the primary safety valves is a loss of turbine-generator load in which the reactor is not immediately tripped. No credit is taken for any pressure-reducing devices except the primary and secondary safety valves. In reality, the incident would be terminated by a number of reactor trips. These include: 9

a. Steam generator low level trip;

b. High pressurizer pressure trip;

c. Manual trip.

If the high primary pressure trip were to become inoperative, other reactor trips would proceed to shut the reactor down as their setpoints are exceeded.

A series of loss-of-load studies are run with various sizes of primary safety valves. As can be seen in Figure 5A-1, after the safety valve capacity increases to a certain size, additional increase in capacity has negligible effect in reducing the maximum system pressure experiences during the loss-of-load transient. C-E's primary safety valves are chosen so as to minimize the maximum pressure experienced during the loss-of-load transient. The minimum specified safety valve capacity is identified on Figure 5A-1.

Figures 5A-2, 5A-3 and 5A-4 present curves of steam generator pressure, maximum Reactor Coolant System pressure and core power versus time for the worst case loss of turbine-generator load. As can be seen on Figures 5A-2 and 5A-3, the maximum steam generator pressure and reactor coolant loop pressures remain below 110% of design during this worst case transient.

The first, second, and third banks of secondary safety valves open at approximately 3.7, 5, and 6.2 seconds, respectively. The secondary safety valves remove energy from the Reactor Coolant System and thus mitigate the pressure surge. The primary safety valves are conservatively assumed to open at 1 percent above the normal Reactor Coolant System design pressure 5.7 seconds after the initiation of the upset condition.

Amendment No. 9
February 27, 1984

The analysis of a complete loss of load incident is described in Chapter 15, Section 15.2. As demonstrated in this analysis, if a complete loss of load occurs without a simultaneous reactor trip, the protection provided by the high pressurizer pressure trip, primary safety valves and secondary safety valves is sufficient to assure that the integrity of the RCS and main steam system is maintained and that the minimum DNB ratio is not less than 1.19. 10

2.2.3 ACCEPTABILITY OF SAFETY VALVE BLOWDOWN

2.2.3.1 Background

Full scale, full pressure prototypical testing of pressurizer safety valves was performed by EPRI in 1981.(1) The blowdown settings required to insure stable valve operation during the blowdown from the set pressure were above the 5% setting specified in the ASME Code. In order to insure that the extended blowdown would not adversely affect overpressure protection or plant operation, analyses were performed to evaluate the NSSS response. The analyses described below demonstrate that a blowdown setting, including associated uncertainties, of 18.5% is acceptable.

2.2.3.2 Results of Evaluation

An extended blowdown of the safety valves could result in swelling of the pressurizer liquid level due to flashing and possible liquid carryover through the safety valves. since the safety valve design specification specifies dry saturated steam flow conditions, it is desirable to show that these conditions are maintained during the extended blowdown. It is also desirable to verify that the RCS remains in a subcooled condition in order that the steam bubble formation in the RCS is precluded. 9

A computer analysis was performed of the Loss-of-load event with delayed reactor trip, similar to that used in safety valve sizing, except that a conservative 20% safety valve blowdown and initial conditions biased to maximize pressurizer liquid level were assumed. The purpose of this analysis was to determine the pressurizer liquid level response and the RCS subcooling under these conservative conditions. For additional conservatism, an additive adjustment was made to the computer-calculated pressurizer levels on the basis of a very conservative pressurizer model. This model assumed that the initial saturated pressurizer liquid did not mix with the cooler insurge liquid, that the initial liquid remained in equilibrium with the pressurizer steam space, and that the steam which flashed during blowdown remained dispersed in the liquid phase and caused the liquid level to swell. The adjusted pressurizer water level vs time curve showed a maximum of 98%(2) (1730 ft^3), below the safety valve nozzle elevation of 100%, so that dry saturated steam flow to the safety valves is assured throughout the blowdown. The computer analysis also showed that adequate subcooling was maintained in the RCS during the blowdown, so that steam bubble formation is precluded. 10

(1) CEN-227, "Summary Report on the Operability or Pressurizer Safety Relief Valves in C-E Designed Plants", December 1982. 9

(2) Water level expressed as the percentage of the distance from the lower Level nozzle to the upper level nozzle.

In addition, the System 80 safety analyses of pressurization events were
re-evaluated to determine the impact of assuming an 18.5% blowdown below
nominal set pressure (to 2040 psia) for the pressurizer safety valves in lieu
of the 5% specified by the ASME Code. The evaluation indicated that, for the
FWLB event analysis, which produces the greatest increase in pressurizer
level, the increased blowdown would not result in the pressurizer liquid level 9
reaching the safety valve nozzle elevation and thus normal safety valve
operation would be assured. Further, subcooling in the RCS was maintained
during the blowdown.

In summary, analyses show that adequate plant overpressure protection and RCS subcooling are ensured during a blowdown of 18.5% below nominal pressurizer safety valve set pressure.

3.0 CONCLUSIONS

C-E's System 80 pressurized water reactor, steam generators, and Reactor
Coolant System are protected from overpressurization in accordance with the
guidelines set forth in the ASME Boiler and Pressure Vessel Code, Section III.
Peak Reactor Coolant System and Secondary System pressures are limited to less 10
than 110% of design pressures during worst case loss of turbine-generator
load. Overpressure protection is afforded by primary safety valves, secondary
safety valves, and the Reactor Protection System.

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For MSLB cases with small break areas, steam can escape fast enough from the two-phase region of the affected steam generator so that the level swell does not reach the steam line nozzle. A pure steam blowdown results. Because of the pressure reducing effects of active and passive containment heat sinks, the highest peak containment pressure resulting from a MSLB for a given set of initial steam generator conditions occurs for that case where the break area is the maximum at which a pure steam blowdown can occur. The potential for steam generator two-phase level swell following a MSLB increases as power level decreases; therefore, a spectrum of power levels must be analyzed to determine which one results in the peak MSLB containment pressures.

The feedwater distribution box is below the steam generator water level; therefore, MFLB cases always result in two-phase blowdowns and do not produce peak containment pressures as severe as MSLB cases.

To permit a determination of the effect of MSLB upon containment pressure, analyses are performed with SGNIII (described in Appendix 6B of Reference 1) at 102, 75, 50, 25, and 0 percent power. The largest slot and guillotine breaks at which a pure steam blowdown can occur are determined. The breaks are conservatively assumed to be at the nozzle of one of the steam generators. The cases analyzed are listed in Table 6.2.1-1.

The System 80 plants have integral flow restrictors in the nozzles of the steam generators. Credit for the flow restrictors is taken in the analysis.

In the plant, the main steam isolation signal (MSIS) of the engineered safety features actuation system (ESFAS) closes the MSIV's, MFIV's and the emergency feedwater isolation valves. MSIS is generated either by a steam generator low pressure signal or a containment high pressure signal. The
MSIV's close in 4.6 seconds. The valve closures have been considered in the analysis. 10

The main steam line isolation interface requirements are discussed in Section 5.1.4. The main feedwater line isolation interface requirements are discussed in Section 5.1.4. The emergency feedwater line isolation interface requirements are discussed in Section 5.1.4.

The emergency feedwater system functions automatically during MSLB to ensure that a heat sink is always available to the reactor coolant system by supplying cold feedwater to maintain an adequate water inventory in the unaffected steam generator. The affected steam generator is identified and isolated while a controlled flow path is provided to the unaffected steam generator. No credit for emergency feedwater flow to the unaffected steam generator is taken in the MSLB analysis.

Interface requirements on the maximum steam line and feedwater line volumes are discussed in Section 5.1.4. The total volume of fluid between the MSIV's and each steam generator is assumed to be 2000 cubic feet (total for two steam lines). The volume of fluid between the MSIV's and the turbine stop valves is assumed to be 14000 cubic feet maximum. The maximum volumes

are considered in the MSLB analysis. There are two MFIV's in each feedwater line. The maximum volume of fluid between the upstream MFIV and each steam generator is assumed to be 500 cubic feet. The flashing of this fluid into the affected steam generator and then into the containment is considered in the analysis.

6.2.1.4.1 Mass and Energy Release Data

Mass/energy release data for the MSLB cases listed in Table 6.2.1-1 are given in Part A of Tables 6.2.1-11 through 6.2.1-20.

6.2.1.4.2 Single Failure Analysis

Assuming the availability of non-emergency power is conservative since it allows the continuation of reactor coolant pump operation. This maximizes the rate of heat transfer to the affected steam generator which maximizes the rate of mass/energy release. With non-emergency power, a diesel failure need not be postulated.

There is an MSIV in each main steam line. The MSIV's have been designed to close based on a conservative calculation which maximizes the dynamic pressure loading on the valve for all possible flow rates and qualitites. Each valve has dual solenoid valves to assure closure even with a single failure in the control system. Single failure of the actuation signal will not prevent valve closure since both trains of MSIS actuation are provided to each MSIV. Any failure would result in the valve going to the closed position so that no additional steam could be added to the containment. The other MSIV isolates the unaffected steam generator. Each valve is tested periodically. Therefore, the failure of an MSIV is not considered to be a credible event.

There are two MFIV's in series in each main feedwater line. If one MFIV fails, the second MFIV would provide isolation. All cases analyzed considered the flashing of the fluid in the lines from the upstream MFIV's to the affected steam generator; therefore, there is no need to do a separate analysis assuming MFIV failure.

Data in Table 6.2.1-11 through 6.2.1-20 assume no failure in C-E supplied equipment. The data is to be used with the assumption of a failure in the CHRS. The effect of a single active failure in the CHRS is shown in the Applicant's SAR.

6.2.1.4.3 Initial Conditions

Nominal full load for System 80 is 3800 Mwt. Reactor coolant system parameters at 102 percent of full power are given in Table 6.2.1-22. The steam generator pressure varies from 1070 psia (nominal full load) to 1170 psia (no load). The initial steam generator inventory is calculated assuming manufacturing tolerances which maximize the initial inventory. The increase in the initial inventory resulting form thermal expansion of the steam generator is included.

TABLE 6.2.1-11

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
102% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART C: Energy Balance (continued)

Energy Description	Energy (10^6 Btu) Prior to MSLB	At Peak Pressure	End of Blowdown
Feedwater To Steam Generator 1	0.0	A*	0.0
Feedwater To Steam Generator 2	0.0	A*	32.946
Steam Flow To Turbine	0.0	A*	23.130
Energy Generated During Shutdown From Decay Heat	0.0	A*	44.948
Break Flow	0.0	A*	354.239
Energy Content Of RCB Atmosphere	A*	A*	A*
Energy Content Of RCB Internal Structures	A*	A*	A*
Energy Content Of Recirculation Intake Water (Sump)	A*	A*	A*
Energy content Of RWST Water	A*	A*	A*
Energy Removed By Shutdown Heat Exchangers	A*	A*	A*
Energy Removed By Containment Building Emergency Fan Coolers	A*	A*	A*

* See Applicant's SAR

TABLE 6.2.1-11

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
102% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART D. Accident Chronology

Time (Seconds)	Event	Setpoint
0.00	Break Occurs	
3.80	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
3.80	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
4.80	High Containment Pressure Reactor Trip Signal and MSIS Generated	
4.95	Reactor Trip Breakers Open	
4.95	Turbine Admission Valves Closed	
9.70	Main Steam Isolation Valves Closed	
9.70	Main Feedwater Isolation Valves Closed	
A*	Containment Spray Actuation Signal	
A*	Peak Containment Temperature	
A*	Peak Containment Pressure	
170.00	End Of Blowdown	

10

* See Applicant's SAR

TABLE 6.2.1-12

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
102% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 9 of 9

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
5.25	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
5.25	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	10
6.25	High Containment Pressure Reactor Trip Signal and MSIS Generated		
6.40	Reactor Trip Breakers Open		
6.40	Turbine Admission Valves Closed		
11.15	Main Steam Isolation Valves Closed		
11.15	Main Feedwater Isolation Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
175.00	End Of Blowdown		

*See Applicant's SAR

TABLE 6.2.1-13

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
75% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 1 of 7

PART A: Mass/Energy Release Data

	Time (Sec)	Mass Release Rate (Lbm/Sec)	Enthalpy (Btu/Lbm)	Energy Release Rate (Million Btu/Sec)
1	0.000	10045.77	1189.06	11.945012
2	.200	9792.61	1190.00	11.653239
3	.600	9455.70	1191.28	11.264352
4	1.000	9222.11	1192.17	10.994316
5	2.000	8771.84	1193.88	10.472546
6	3.000	8396.03	1195.24	10.035297
7	4.000	8076.16	1196.35	9.661894
8	5.000	7985.31	1196.74	9.556317
9	6.000	7976.86	1196.82	9.546877
10	7.000	7916.07	1197.03	9.475779
11	8.000	7867.45	1197.19	9.418842
12	9.000	7826.58	1197.33	9.370980
13	9.500	7805.16	1197.40	9.345891
14	10.000	2434.44	1196.63	2.913136
15	10.500	2460.54	1196.34	2.943638
16	11.000	2481.18	1196.10	2.967729
17	11.500	2496.99	1195.92	2.986191
18	12.000	2508.38	1195.78	2.999468
19	12.500	2515.50	1195.70	3.007771
20	13.000	2518.42	1195.68	3.011176
21	15.000	2489.33	1196.01	2.977259
22	20.000	2250.63	1198.63	2.697672
23	25.000	2089.48	1200.20	2.507798
24	30.000	2037.13	1200.67	2.445917
25	35.000	1961.56	1201.31	2.356448
26	40.000	1884.55	1201.95	2.265131
27	50.000	1778.21	1202.73	2.138705
28	60.000	1670.15	1203.40	2.009857
29	70.000	1571.96	1203.89	1.892474
30	80.000	1467.46	1204.27	1.767219
31	90.000	1351.24	1204.49	1.627557
32	100.000	1213.64	1204.46	1.461777
33	110.000	1020.29	1203.78	1.228208
34	120.000	912.88	1202.97	1.098169
35	130.000	860.53	1202.42	1.034719
36	140.000	779.05	1201.37	.935926
37	150.000	661.10	1199.27	.792837

TABLE 6.2.1-13

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
75% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART C: Energy Balance (continued)

Energy Description	Prior to MSLB	At Peak Pressure	End of Blowdown
	Energy (10^6 Btu)		
Feedwater To Steam Generator 1	0.0	A*	0.0
Feedwater To Steam Generator 2	0.0	A*	25.365
Steam Flow To Turbine	0.0	A*	16.390
Energy Generated During Shutdown From Decay Heat	0.0	A*	33.311
Break Flow	0.0	A*	357.629
Energy Content Of RCB Atmoshpere	A*	A*	A*
Energy Content Of RCB Internal Structures	A*	A*	A*
Energy Content Of Recirculation Intake Water (Sump)	A*	A*	A*
Energy Content Of RWST Water	A*	A*	A*
Energy Removed By Shutdown Heat Exchangers	A*	A*	A*
Energy Removed By Containment Building Emergency Fan Coolers	A*	A*	A*

* See Applicant's SAR

TABLE 6.2.1-13

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
75% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 7 of 7

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
3.70	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
3.70	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	10
4.70	High Containment Pressure Reactor Trip Signal and MSIS Generated		
4.85	Reactor Trip Breakers Open		
4.85	Turbine Admission Valves Closed		
9.60	Main Steam Isol. Valves Closed		
9.60	Main Feedwater Isol. Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
185.00	End Of Blowdown		

* See Applicant's SAR

TABLE 6.2.1-14

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
75% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
5.15	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
5.15	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	
6.15	High Containment Pressure Reactor Trip Signal and MSIS Generated		10
6.30	Reactor Trip Breakers Open		
6.30	Turbine Admission Valves Closed		
11.05	Main Steam Isol. Valves Closed		
11.05	Main Feedwater Isol. Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
190.00	End of Blowdown		

* See Applicant's SAR

TABLE 6.2.1-15

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
50% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART A: Mass/Energy Release Data

	Time (Sec)	Mass Release Rate (Lbm/Sec)	Enthalpy (Btu/Lbm)	Energy Release Rate (Million Btu/Sec)
1	0.000	10446.05	1187.44	12.404087
2	.200	10196.87	1188.41	12.118105
3	.600	9867.10	1189.73	11.739160
4	1.000	9629.02	1190.69	11.465164
5	2.000	9145.30	1192.59	10.906580
6	3.000	8733.71	1194.12	10.429136
7	4.000	8377.19	1195.39	10.013996
8	5.000	8210.99	1196.01	9.820038
9	6.000	8065.23	1196.52	9.650210
10	7.000	7925.36	1196.98	9.486324
11	8.000	7810.73	1197.36	9.352225
12	9.000	7714.35	1197.66	9.239183
13	9.500	2368.11	1197.35	2.835462
14	10.000	2390.81	1197.10	2.862037
15	10.500	2408.70	1196.90	2.882984
16	11.000	2422.99	1196.75	2.899704
17	11.500	2434.12	1196.62	2.912715
18	12.000	2442.26	1196.53	2.922232
19	12.500	2447.43	1196.47	2.928254
20	13.000	2449.48	1196.45	2.930669
21	15.000	2425.10	1196.72	2.902170
22	20.000	2207.84	1199.01	2.647220
23	30.000	1984.55	1201.03	2.383504
24	40.000	1843.32	1202.16	2.215958
25	50.000	1738.52	1202.87	2.091212
26	60.000	1633.30	1203.46	1.965612
27	70.000	1540.13	1203.87	1.854114
28	80.000	1448.73	1204.15	1.744494
29	90.000	1347.52	1204.31	1.622838
30	100.000	1241.59	1204.30	1.495252
31	110.000	1116.31	1204.03	1.344067
32	120.000	942.15	1202.99	1.133401
33	130.000	685.34	1199.52	.822078
34	140.000	588.88	1197.30	.705067
35	150.000	576.13	1196.99	.689620
36	160.000	557.31	1196.45	.666795
37	180.000	480.31	1194.02	.573498

TABLE 6.2.1-15

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
50% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART C: Energy Balance (continued)

	Energy (10^6 Btu)		
Energy Description	Prior to MSLB	At Peak Pressure	End of Blowdown
Feedwater To Steam Generator 1	0.0	A*	0.0
Feedwater To Steam Generator 2	0.0	A*	18.189
Steam Flow To Turbine	0.0	A*	10.050
Energy Generated During Shutdown From Decay Heat	0.0	A*	23.972
Break Flow	0.0	A*	363.560
Energy Content Of RCB Atmoshpere	A*	A*	A*
Energy Content Of RCB Internal Structures	A*	A*	A*
Energy Content Of Recirculation Intake Water (Sump)	A*	A*	A*
Energy Content Of RWST Water	A*	A*	A*
Energy Removed By Shutdown Heat Exchangers	A*	A*	A*
Energy Removed By Containment Building Emergency Fan Coolers	A*	A*	A*

* See Applicant's SAR

TABLE 6.2.1-15

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
50% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint
0.00	Break Occurs	
3.55	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
3.55	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
4.55	High Containment Pressure Reactor Trip Signal and MSIS Generated	
4.70	Reactor Trip Breakers Open	
4.70	Turbine Admission Valves Closed	
9.45	Main Steam Isol. Valves Closed	
9.45	Main Feedwater Isol. Valves Closed	
A*	Containment Spray Actuation Signal	
A*	Peak Containment Temperature	
A*	Peak Containment Pressure	
215.00	End of Blowdown	

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* See Applicant's SAR

TABLE 6.2.1-16

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
50% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONT. COOLING

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
5.00	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
5.00	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	10
6.00	High Containment Pressure Reactor Trip Signal and MSIS Generated		
6.15	Reactor Trip Breakers Open		
6.15	Turbine Admission Valves Closed		
10.90	Main Steam Isol. Valves Closed		
10.90	Main Feedwater Isol. Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
220.000	End of Blowdown		

* See Applicant's SAR

TABLE 6.2.1-17

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
25% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 1 of 7

PART A: Mass/Energy Release Data

	Time (Sec)	Mass Release Rate (Lbm/Sec)	Enthalpy (Btu/Lbm)	Energy Release Rate (Million Btu/Sec)
1	0.000	10647.52	1188.53	12.654933
2	.500	10162.02	1190.51	12.097984
3	1.000	9862.16	1191.76	11.753282
4	2.000	9373.49	1193.73	11.189431
5	3.000	8948.13	1195.36	10.696230
6	4.000	8572.44	1196.72	10.258833
7	5.000	8314.98	1197.64	9.958393
8	6.000	8079.90	1198.45	9.683645
9	7.000	7877.40	1199.12	9.445821
10	8.000	7709.37	1199.65	9.248573
11	9.000	7569.26	1200.09	9.083808
12	9.500	2326.44	1199.77	2.791193
13	10.000	2338.70	1199.64	2.805589
14	10.500	2348.67	1199.53	2.817296
15	11.000	2356.87	1199.44	2.826929
16	11.500	2363.51	1199.37	2.834727
17	12.000	2368.58	1199.32	2.840674
18	14.500	2362.92	1199.38	2.834032
19	17.000	2293.70	1200.11	2.752690
20	22.000	2078.73	1202.20	2.499042
21	32.000	1909.23	1203.63	2.298013
22	42.000	1774.28	1204.62	2.137331
23	52.000	1676.29	1205.21	2.020282
24	62.000	1578.21	1205.70	1.90284[illegible]
25	72.000	1490.25	1206.02	1.[illegible]7276
26	82.000	1406.94	1206.22	1.697078
27	92.000	1325.07	1206.31	1.598441
28	102.000	1240.64	1206.29	1.496575
29	112.000	1154.99	1206.13	1.393064
30	122.000	1061.35	1205.76	1.279732
31	132.000	946.34	1205.00	1.140342
32	142.000	782.41	1203.14	.941352
33	150.800	582.65	1199.13	.698671
34	160.800	299.62	1247.95	.373910
35	170.800	264.86	1183.42	.313440
36	220.800	255.69	1182.71	.302407
37	250.800	226.79	1187.96	.269418

TABLE 6.2.1-17

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
25% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART C: Energy Balance (continued)

Energy Description	Energy (10^6 Btu) Prior to MSLB	At Peak Pressure	End of Blowdown
Feedwater To Steam Generator 1	0.0	A*	0.0
Feedwater To Steam Generator 2	0.0	A*	11.479
Steam Flow To Turbine	0.0	A*	4.507
Energy Generated During Shutdown From Decay Heat	0.0	A*	15.254
Break Flow	0.0	A*	386.914
Energy Content Of RCB Atmoshpere	A*	A*	A*
Energy Content Of RCB Internal Structures	A*	A*	A*
Energy Content Of Recirculation Intake Water (Sump)	A*	A*	A*
Energy Content Of RWST Water	A*	A*	A*
Energy Removed By Shutdown Heat Exchangers	A*	A*	A*
Energy Removed By Containment Building Emergency Fan Coolers	A*	A*	A*

* See Applicant's SAR

TABLE 6.2.1-17

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
25% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 7 of 7

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
3.45	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
3.45	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	10
4.45	High Containment Pressure Reactor Trip Signal and MSIS Generated		
4.60	Reactor Trip Breakers Open		
4.60	Turbine Admission Valves Closed		
9.35	Main Steam Isol. Valves Closed		
9.35	Main Feedwater Isol. Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
315.8	End of Blowdown		

* See Applicant's SAR

TABLE 6.2.1-18

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
25% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
4.86	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
4.86	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	10
5.86	High Containment Pressure Reactor Trip Signal and MSIS Generated		
6.01	Reactor Trip Breakers Open		
6.01	Turbine Admission Valves Closed		
10.76	Main Steam Isol. Valves Closed		
10.76	Main Feedwater Isol. Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
315.80	End of Blowdown		

* See Applicant's SAR

<u>TABLE 6.2.1-19</u>

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
0% POWER/SLOT/4.00 SQ. FT./LOSS OF CONTAINMENT COOLING

PART A: Mass/Energy Release Data

	Time (Sec)	Mass Release Rate (Lbm/Sec)	Enthalpy (Btu/Lbm)	Energy Release Rate (Million Btu/Sec)
1	0.000	8050.50	1185.45	9.543502
2	.200	7945.94	1186.03	9.424123
3	.600	7795.76	1186.93	9.252999
4	1.000	7665.28	1187.70	9.104040
5	2.000	7379.66	1189.37	8.777119
6	3.000	7128.94	1190.78	8.489018
7	4.000	6902.62	1192.02	8.228057
8	5.000	6697.06	1193.10	7.990269
9	6.000	6513.64	1194.04	7.777532
10	7.000	6352.76	1194.84	7.590511
11	8.000	6213.54	1195.51	7.428353
12	9.000	6094.49	1196.08	7.289471
13	9.500	6041.53	1196.32	7.227623
14	10.000	5992.75	1196.55	7.170645
15	10.500	2446.76	1196.73	2.928120
16	11.000	2437.84	1196.83	2.917691
17	11.500	2428.95	1196.94	2.907302
18	12.000	2420.22	1197.03	2.897078
19	12.500	2411.60	1197.13	2.886994
20	13.000	2403.01	1197.22	2.876940
21	15.000	2365.51	1197.64	2.833024
22	20.000	2211.96	1199.23	2.652653
23	30.000	1946.80	1201.62	2.339312
24	40.000	1812.92	1202.65	2.180302
25	50.000	1705.08	1203.35	2.051804
26	60.000	1611.08	1203.84	1.939488
27	70.000	1526.07	1204.20	1.837699
28	80.000	1443.99	1204.45	1.739218
29	90.000	1365.33	1204.58	1.644655
30	100.000	1292.46	1204.62	1.556926
31	110.000	1225.00	1204.58	1.475612
32	120.000	1159.71	1204.44	1.396805
33	130.000	1093.55	1024.22	1.316870
34	140.000	1028.17	1203.90	1.237812
35	150.000	960.57	1203.43	1.155980
36	160.000	885.70	1202.76	1.065287
37	170.000	739.10	1201.63	.953010

TABLE 6.2.1-19

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
0% POWER/SLOT/4.00 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 6 of 7

PART C: Energy Balance (continued)

Energy Description	Energy (10^6 Btu) Prior to MSLB	At Peak Pressure	End of Blowdown
Feedwater To Steam Generator 1	0.0	A*	0.0
Feedwater To Steam Generator 2	0.0	A*	0.371
Steam Flow To Turbine	0.0	A*	0.006
Energy Generated During Shutdown From Decay Heat	0.0	A*	0.013
Break Flow	0.0	A*	378.769
Energy Content Of RCB Atmoshpere	A*	A*	A*
Energy Content Of RCB Internal Structures	A*	A*	A*
Energy Content Of Recirculation Intake Water (Sump)	A*	A*	A*
Energy Content Of RWST Water	A*	A*	A*
Energy Removed By Shutdown Heat Exchangers	A*	A*	A*
Energy Removed By Ccntainment Building Emergency Fan Coolers	A*	A*	A*

* See Applicant's SAR

TABLE 6.2.1-19

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
0% POWER/SLOT/4.00 SQ. FT./LOSS OF CONTAINMENT COOLING

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
4.55	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
4.55	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	
5.55	High Containment Pressure Reactor Trip Signal and MSIS Generated		10
5.70	Reactor Trip Breakers Open		
5.70	Turbine Admission Valves Closed		
10.45	Main Steam Isol. Valves Closed		
10.45	Main Feedwater Isol. Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
210.00	End of Blowdown		

* See Applicant's SAR

TABLE 6.2.1-20

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
0% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

PART D: Accident Chronology

Time (Seconds)	Event	Setpoint	
0.00	Break Occurs		
4.75	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig	
4.75	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig	
5.75	High Containment Pressure Reactor Trip Signal and MSIS Generated		10
5.90	Reactor Trip Breakers Open		
5.90	Turbine Admission Valves Closed		
10.65	Main Steam Isol. Valves Closed		
10.65	Main Feedwater Isol. Valves Closed		
A*	Containment Spray Actuation Signal		
A*	Peak Containment Temperature		
A*	Peak Containment Pressure		
210.00	End of Blowdown		

* See Applicant's SAR

TABLE 6.2.1-21

SUMMARY OF CALCULATED ENERGY RELEASES

Sheet 1 of 1

LOCA Results	Time Of End Of Blowdown Seconds	Energy Released During Blowdown 10^6 BTU	Time Of End Of Reflood Seconds	Energy Released During Reflood 10^6 BTU
1.0 DEHLS	12.0	376.000	NA	NA
1.0 DESLS				
Maximum ECCS, 70 psia	22.4	378.100	119.1	70.886
Minimum ECCS, 70 psia	22.4	378.100	126.9	72.667
Maximum ECCS, 55 psia	22.4	378.100	136.5	85.907
Minimum ECCS, 55 psia	22.4	378.100	167.3	91.478
1.0 DEDLS				
Maximum ECCS, 70 psia	19.3	382.900	217.0	133.461
Minimum ECCS, 70 psia	19.3	382.900	425.7	151.884
Maximum ECCS, 55 psia	19.3	382.900	254.0	147.543
Minimum ECCS, 55 psia	19.3	382.900	492.8	152.137

MSLB Results

Power (%)	Break* Type		
102	S	170.00	354.239
102	G	175.00	350.171
75	S	185.00	357.629
75	G	190.00	352.205
50	S	215.00	366.560
50	G	220.00	360.240
25	S	315.80	386.914
25	G	315.80	379.397
0	S	210.00	378.769
0	G	210.00	377.809

* S: Slot Break
G: Guillotine Break

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 or C	FAI	None	5	EB	10
			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 7
emergency generators (emergency power).

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 is delivered to the RCS within a maximum of 29 seconds after SIAS is generated. 10
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

Criterion (5) Long Term Cooling. "After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core".

The spectrum analysis shows that the rapid insertion of borated water from the ECCS will suitably limit the peak clad temperature and cool the core within a short period of time. Subsequently, the safety injection pumps will supply cooling water from the refueling water tank or the containment sump to remove decay heat resulting from the long-lived radioactivity remaining in the core. A detailed analysis and description of the long term cooling performance is given in paragraph 6.3.3.4.

6.3.3.2 Large Break Analysis

6.3.3.2.1 Mathematical Model

The calculations reported in this section were performed using the C-E large break evaluation model which is described in reference 2. In the C-E model, the CEFLASH-4A[4] computer program is used to determine the primary system flow parameters during the blowdown phase, and the COMPERC-II[5] computer program is used to determine the system behavior during the refill and reflood phases. The core flow and thermodynamic parameters from these two codes are used as input to the STRIKIN-II[6] computer, which is used to calculate the hot rod clad temperature transient. The peak clad temperature and peak local clad oxidation percentage are therefore obtained from the STRIKEN-II calculation. The core-wide clad oxidation percentage is obtained from the results of both the STRIKIN-II and COMZIRC[5, Suppl. 1] computer programs.

6.3.3.2.2 Safety Injection System Assumptions

The safety injection system (SIS) consists of two high pressure pumps, two low pressure pumps and four safety injection tanks. Automatic operation of the pumps is actuated by either a low pressurizer pressure signal or a high containment pressure signal. Flow is initiated from the safety injection tanks by the opening of a check valve when the cold leg pressure drops below the tank pressure.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of safety injection flow. It is assumed that offsite power is lost and all pumps must await diesel startup before they can begin to deliver flow. (It is assumed, however, that offsite power is available for the containment spray system). For breaks in the pump discharge leg, it is also assumed that all safety injection flow delivered to the broken cold leg spills into the containment.

An analysis of the possible single failures that can occur within the SIS has shown that the worst single failure for the large break spectrum is the

failure of one of the low pressure pumps to start[2]. This results in a minimum amount of safety injection water, available to the core, without affecting the operation of the containment spray system.

Therefore, based on the above assumptions, the following safety injection flows are credited for the large break analysis:

Two high pressure safety injection pumps (HPSIP's) are piped so that each one can feed all four cold leg injection points. Thus:

a. for a break in the pump discharge leg, the safety injection flow credited is 75% of the flow from two HPSIP's since it is assumed that all injection in the broken cold leg is spilled.

b. for breaks in other locations, the safety injection flow credited is 100% of two HPSIP's.

Two low pressure safety injection pumps (LPSIP's) are piped so that each one feeds two cold leg injection points. Thus:

a. for a break in the pump discharge leg, the safety injection flow credited is 50% of the flow from one LPSIP. The bases for this flow is that only the LPSIP is operable (worst single failure) and one of the two injection points for the operable pump is located in the broken loop and thus that flow is spilled.

b. for breaks in other locations, the safety injection flow is 100% of one LPSIP.

Four safety injection tanks (SIT's) are piped so that each SIT feeds a single cold leg injection point. Thus:

a. for a break in the pump discharge leg, the safety injection flow credited is 100% flow from three SIT's since it is assumed that all injection in the cold leg is spilled.

b. for breaks in other locations, the safety injection flow credited is 100% flow from four SIT's.

The rate at which emergency cooling water is delivered to the reactor vessel
downcomer for the limiting break is shown in Figure 6.3.3.2-5L. System 4
delivery data for the high and low pressure pumps are presented in
Section 6.3.3.3. As shown in Table 6.3.3.2-1, no credit is taken for pump
flow until the tanks are empty, resulting in a minimum effective delay of over
55. seconds from the time the SIAS setpoint is reached until pump flow is
delivered to the RCS. The actual delay time will not exceed 29 seconds 10
following a SIAS. In the large break analysis, no operator action has been
assumed.

6.3.3.2.3 Core and System Parameters

The significant core and system parameters used in the large break calculations are presented in Table 6.3.3.2-2. The peak linear heat generation

6.3.3.3 Small Break Analysis

6.3.3.3.1 Evaluation Model

The calculations reported in this section were performed using the C-E small
break evaluation model which is described in Reference 3 and was approved by
the NRC in Reference 12. In the C-E model, the CEFLASH-4AS[10] computer program 4
is used to determine the primary system hydraulic parameters during the blow-
down phase, and the COMPERC-II[5] computer program is used to determine the 4
system behavior during the reflood phase. Fuel rod temperatures and clad
oxidation percentages are calculated using the STRIKIN-II[6] and PARCH[11] 4
computer programs. The interfacing between these programs is discussed in
detail in Reference 3. 4

6.3.3.3.2 Safety Injection System Assumptions

As discussed in Section 6.3.3.2.2, the safety injection system (SIS) includes 4
two high pressure pumps, two low pressure pumps and four safety injection
tanks. It is conservatively assumed that offsite power is lost upon reactor
trip and therefore all safety injection pumps must await diesel startup and
load sequencing before they can start. The total time delay assumed is 29
seconds from the time that the SIAS is generated to the time that SI flow is 10
delivered to the RCS. For breaks in the pump discharge leg, it is also assumed
that all safety injection flow delivered to the broken cold leg spills out the
break.

An analysis of the possible single failures that can occur within the SIS
has shown that the worst single failure for the small break spectrum is the
failure of one of the emergency diesels to start[3]. This failure causes a 4
loss of both a high pressure pump and a low pressure pump and results in a
minimum of safety injection water being available to cool the core. Therefore,
based on the above assumptions, the following safety injection flows are
credited for the small break analysis.

Since each high pressure safety injection pump (HPSIP) is piped so that it
can feed all four cold leg injection points: 4

a. for a break in the pump discharge leg, the HPSIP flow credited is 75% of the flow from one HPSIP. The remaining 25% is assumed to spill out the break.

b. for breaks in other locations, the HPSIP flow credited is 100% of one HPSIP.

Since each low pressure safety injection pump (LPSIP) is piped so that it feeds two of the cold leg injection points:

a. for a break in the pump discharge leg, the LPSIP flow credited is 50% of the flow from one LPSIP. The remaining 50% is assumed to spill out the break.

b. for breaks in other locations, the LPSIP flow credited is 100% of one LPSIP.

The four safety injection tanks (SITs) are piped so that each SIT feeds a single cold leg injection point. Thus:

a. for a break in the pump discharge leg, the SIT flow credited is 100% of the flow from three SITs. The remaining SIT is assumed to spill out the break.

b. for breaks in other locations, the SIT flow credited is 100% of four SITs.

Table 6.3.3.3-1 presents the high and low pressure safety injection pump flow rates assumed at each of the four injection points as a function of reactor coolant system pressure.

6.3.3.3.3 Core and System Parameters

The significant core and system parameters used in the small break calculations are presented in Table 6.3.3.3-2. The peak linear heat generation rate (PLHGR) of 15.0 kw/ft was assumed to occur 15% from the top of the active core. A conservative beginning-of-life moderator temperature coefficient of 0.0 $\Delta\rho/^{\circ}F$ was used in all small break calculations.

The ECCS performance analyses as performed, do not account for steam generator 4
tube plugging which may occur over the plant's lifetime.

The initial steady state fuel rod conditions were obtained from the FATES[7] computer program. Like the large break, the small break analyses employed a hot rod average burnup which maximized the amount of stored energy in the fuel. Since the small break analysis used a higher PLHGR than did the large 4
break analysis (15.0 kw/ft vs 14.0 kw/ft) the fuel rod parameter values given in Table 6.3.3.3-2 differ from those on Table 6.3.3.2-2.

Because the large break results are always more limiting than the small break results, the small break analysis is run at a higher PLHGR to prevent requiring a reanalysis should the large break results improve. Since the small break results are governed mainly by the core liquid level transient (see Results Section below) which is a function of the total core decay heat generation rate, the higher PLHGR does not significantly affect the small break results.

6.3.3.3.4 Containment Parameters

The small break analysis does not credit any rise in containment pressure. Therefore, other than the initial containment pressure, which is assumed to remain constant, no containment parameters are employed for this analysis. The initial containment pressure was assumed to be 0.0 psig.

6.3.3.3.5 Break Spectrum

Six breaks were analyzed to characterize the small break spectrum. Five breaks, ranging in size from 0.5 ft^2 to 0.02 ft^2 were postulated to occur in the pump discharge leg. The 0.5 ft^2 break was also analyzed for the large break spectrum (Section 6.3.3.2) and is defined as the transition
break size[3]. One break, equal in area to a fully open pressurizer safety 4

valve, (.03 ft^2) was postulated to occur in the top of the pressurizer. Table 6.3.3.3-3 lists the various break sizes and locations examined for this analysis.

6.3.3.3.6 Results

The transient behavior of important NSSS parameters is shown in the figures listed in Table 6.3.3.3-4. Table 6.3.3.3-5 summarizes the improtant results of this analysis. Times of interest for the various breaks analyzed are presented in Table 6.3.3.3-6. A plot of peak clad temperature (PCT) versus break size is presented in Figure 6.3.3.3-7. The o.05 ft^2 break results in the highest clad temperature (1557°F) of the small breaks analyzed, which is over 600°F lower than that reported in Section 6.3.3.1 for the limiting large break. The break resulting in the next highest PCT of the small break spectrum is the 0.2 ft^2 break with a PCT of 1030°F.

It is important to note the differences in the transient behavior of these two break sizes, because each characterizes different controlling features of small breaks. The larger breaks (between 0.2 ft^2 and 0.5 ft^2) temperature transients are terminated by the action of the safety injection tanks (SIT) whereas the temperature transients for the smaller breaks (< 0.05 ft^2) are terminated solely by the high pressure safety injection pump (HPSIP) prior to the actuation of the SITs. For the intermediate break sizes (approximately 0.2 ft^2 to 0.05 ft^2) both the SITs and HPSIP play an important part in terminating the transient, with the HPSIP becoming more important as the break size decreases.

As shown in Figure 6.3.3.3-7, PCT as a function of break size remains fairly constant until the 0.2 ft^2 break. Then the PCT rises for the 0.05 ft^2 and then falls for the 0.02 ft^2 break. This rise and fall in PCT can be adequately predicted by observing the transient behavior for breaks less than or equal to 0.2 ft^2.

The peak clad temperature is predictably affected by:

1) Time of initial core uncovery,

2) Depth of core uncovery, and

3) Duration of core uncovery.

As the break size becomes progressively smaller than 0.2 ft^2, the inner vessel two phase level follows a definite pattern:

1) The time of initial core uncovery is later,

2) The depth of core uncovery is less,

3) The time of core uncovery becomes longer, and,

4) The actuation of the SITs is later during the period of core uncovery and eventually does not occur.

This trend continues until the core does not uncover at all. For System 80 this occurs for a break size between 0.05 ft^2 and 0.02 ft^2 (and for all smaller breaks).

As the break size decreases, both the later time of initial core uncovery and its shallower depth tend to mitigate the temperature transient. However, the increased duration of uncovery acts in the opposite direction. In progressing from the 0.2 ft^2 break to 0.05 ft^2 break the increased duration dominates and therefore the peak clad temperatures rise. This trend continues until a break size is reached, typified by the 0.05 ft^2 break, where the three parameters are balanced. For breaks smaller than this, the increase in time to initial core uncovery and the shallower depth dominate causing less severe temperature transients. This trend continues until the core does not uncover as typified by the 0.02 ft^2 break. Thus, by analyzing several break sizes over this range, the behavior of PCT versus break size can be adequately determined.

To demonstrate the conservatism associated with the small break ECCS performance results provided herein, the 0.05 ft^2 break was reanalyzed using a more realistic measure of the decay heat generation rate. As required by Appendix K to 10CFR50, the spectrum analysis employed a decay heat generation rate equal to 120% of the standard ANS curve. The reanalysis of the 0.05 ft^2 break used a decay heat generation rate equal to 100% of the ANS curve. This one change reduced the peak clad temperature from 1557°F to 1020°F.

6.3.3.3.7 Instrument Tube Rupture

In addition to the six small breaks discussed above, the rupture of an in-core instrument tube was considered. A break, equal in size to a completely severed instrument tube (0.003 ft^2) was postulated to occur in the reactor vessel bottom head.

Following rupture, the primary system depressurizes until a reactor scram signal and safety injection actuation signal (SIAS) are generated due to low pressurizer pressure at 1600 psia. The assumed loss of offsite power causes the primary coolant pump and the feedwater pumps to coast down. After the 29 second delay required to start the emergency diesel and the high pressure safety injection pump following SIAS, safety injection flow is 10
initiated to the RCS. At this time an emergency feedwater pump is also started, providing a source of cooling to the steam generators. Due to the assumed failure of one diesel, only one high pressure safety injection pump and one emergency feedwater pump are available. (Four SITs and one low pressure safety injection pump are also available but do not inject due to the high RCS pressure.) The steam generator secondary sides also become isolated at this time.

The primary side depressurization continues accompanied by a rise in secondary side pressure until the secondary side pressure reaches the lowest set point of the steam generator safety relief valves. The primary system pressure continues to fall until it is just slightly greater than the secondary side pressure. At this point, the flow from the one operating HPSIP (66.3 lbm/sec) exceeds the leak flow (26.4 lbm/sec). Therefore the

TABLE 6.3.2-1
(Sheet 1 of 2)

SAFETY INJECTION SYSTEM
COMPONENTS PARAMETERS

Low-Pressure Safety Injection Pumps

Quantity	2
Type	Single Stage, Vertical, Centrifugal
Safety Classification	2
Code	ASME III, Class 2
Design Pressure	650 psig
Maximum Operating Suction Pressure	435 psig
Design Temperature	400°F
Design Flow Rate	4200 gpm*
Design Head	335 ft
Maximum Flow Rate	5000 gpm*
Head at Maximum Flow Rate	290 ft
Materials	Stainless Steel Type 304 316 or approved alternate
Seals	Mechanical
Brake Horsepower	470

*Does not include 100 gpm by-pass flow

High-Pressure Safety Injection Pumps

Quantity	2
Type	Multistage, Horizontal Centrifugal
Safety Classification	2
Code	ASME III, Class 2
Design Pressure	2050 psig
Maximum Operating Suction Pressure	100 psig
Design Temperature	350°F
Design Flow Rate	815 gpm*
Design Head	2850 ft
Maximum Flow Rate	1130 gpm*
Head at Maximum Flow Rate	1580 ft
Materials	Stainless Steel, type 304, 316 or approved alternate
Shaft Seal	Mechanical
Brake Horsepower	910

*Does not include 35 gpm by-pass flow

TABLE 6.3.2-1 (Cont'd.)(Sheet 2 of 2)

SAFETY INJECTION SYSTEM
COMPONENTS PARAMETERS

Safety Injection Tanks

Quantity	4	
Safety Classification	2	
Code	ASME III, Class 2	
Design Pressure, Internal/External	700 psig/100 psig	
Design Temperature	200°F	
Operating Temperature	140°F	
Normal Operating Pressure	610 psig	
Minimum Operating Pressure	600 psig	
Volume, Total	2400 ft^3	
Liquid		
Minimum	1790	
Nominal	1858	
Maximum	1927	10
Fluid	Borated Water, 4200 ppm Boron Nominal, 6200 ppm max.	
Material	Clad - Stainless Steel, type 304, 316, or approved alternate Body - Carbon Steel, type SA-516 Gr.7 or approved alternate	

TABLE 6.3.3.3-5

FUEL ROD PERFORMANCE SUMMARY
SMALL BREAK SPECTRUM 4

Break Size (ft^2)	Maximum Clad Surface Temperature [(a)] (°F)	Peak Local Zirconium Oxid. [(b)] (%)	Hot Rod Zirconium Oxid. [(c)] (%)
0.50 ft^2/PD	954	<.0020	<.0003 4
0.35 ft^2/PD	932	<.0015	<.0002
0.20 ft^2/PD	1030	<.0041	.0007
0.05 ft^2/PD	1557	<.8825	<.1430
0.02 ft^2/PD	995	<.0011	<.0003
0.03 ft^2/HL	1012	<.0011	<.00004

(a) Acceptance Criteria is 2200°F.

(b) Acceptance Criteria is 17%.

(c) Acceptance Criteria is 1.0%. Hot rod oxidation values are given as a conservative indication of core-wide oxidation.

TABLE 6.3.3.3-6

TIMES OF INTEREST FOR SMALL BREAKS
(Seconds)

Break Size (ft^2)	HPSI Pump Flow Delivered To RCS (c)	LPSI Pump Flow Delivered To RCS (c)	SI Tanks Flow Delivered To RCS	Hot Spot Peak Clad Temp. Occurs	10
0.50 ft^2/PD	46.5	158.0	142.0	160.0	
0.35 ft^2/PD	50.0	244	204.0	235.0	
0.20 ft^2/PD	62.0	445	400.0	442.0	4
0.05 ft^2/PD	208.0	a.	b.	2010.0	
0.02 ft^2/PD	486.0	a.	b.	437.0	10
0.03 ft^2/PD	585.0	a.	b.	540.0	

(a) Calculation terminated before time of LPSI pump activation.

(b) Calculation terminated before initiation of SI tank discharge.

(c) This time includes a 30 second delay from the time that the pressurizer pressure reaches the low pressurizer pressure SIAS analysis setpoint until the time when the SI pump flow is delivered to RCS at design capacity. 10

TABLE 6.3.3.5-1
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR REPRESENTATIVE LARGE AND SMALL BREAK LOCAs

	Large Break (0.8 DEG/PD)		Small Break (0.02 ft^2)			
Event	Setpoint Or Value	Time, Seconds	Setpoint Or Value	Time, Seconds	Success Path	
Break occurs		0.0		0.0		
Core peak power	117%	0.15	105%	96.0		
Pressurizer Pressure Reaches Reactor Trip and SIAS Analysis Setpoint	1600 psia	9.43	1600 psia	456.0	Reactivity Control	10
Reactor Trip and Safety Injection Actuation Signals generated		10.43		457.0	Reactivity Control	
SIT discharge begins	607.7 psia	16.2	607.7 psia	7500	Reactivity Control	
Reflood begins	607.7 psia	37.7		NA		
Main steam safety valves begin to open		NA	1295 psia	456.0	Sec. Sys. Integrity	
Maximum secondary pressure	1239 psia		1340 psia	184.0		
HPSI pump flow delivered to RCS		68.2		486.0	Reactivity Control	10
SITs empty		68.2		NA		
LPSI pump flow delivered to RCS		68.2		NA	Reactivity Control	10

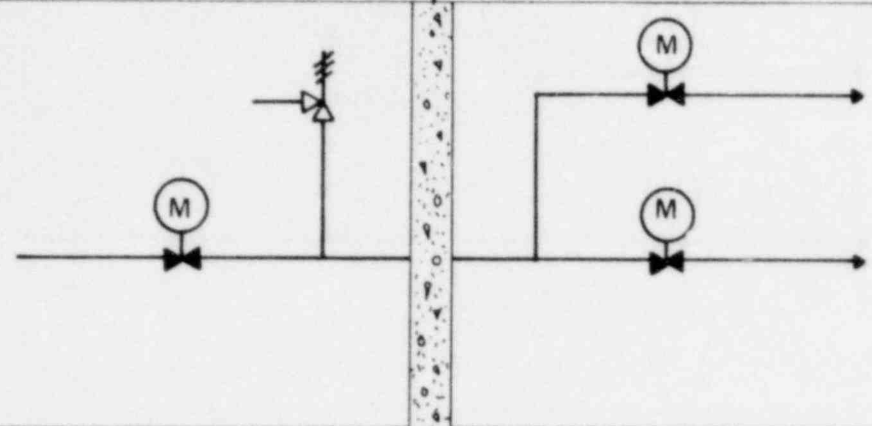
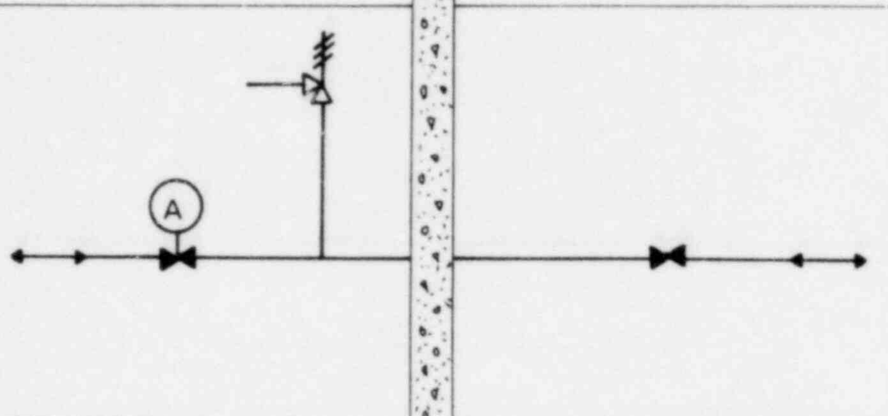
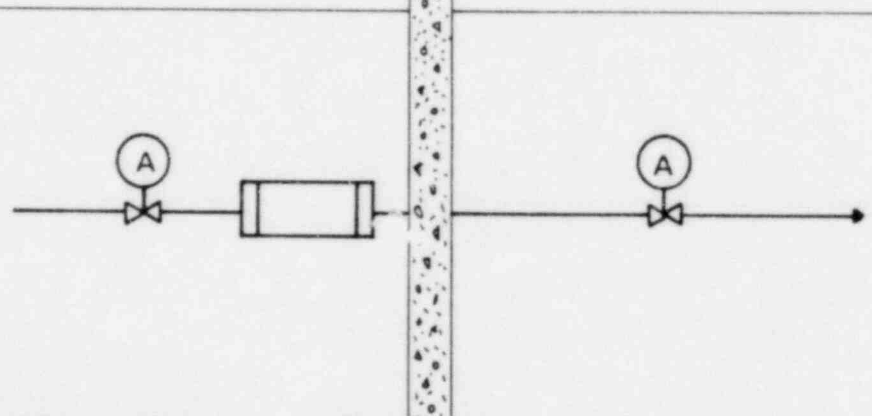
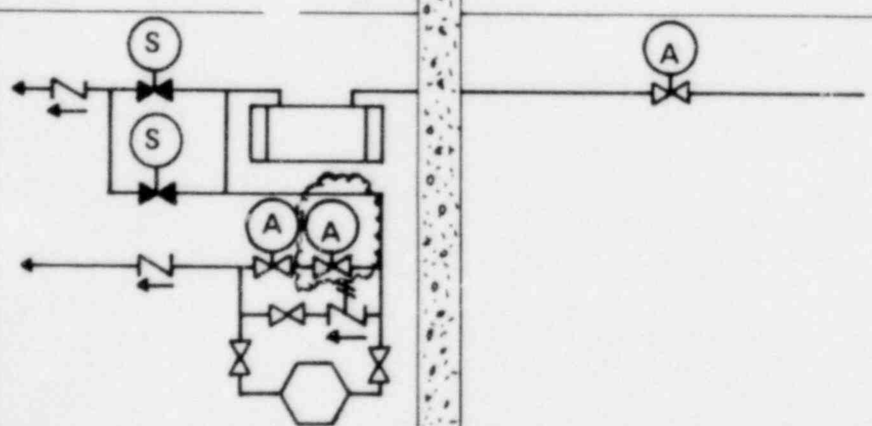
TABLE 6.3.3.5-1 (Cont'd.) (Sheet 2 of 2)

SEQUENCE OF EVENTS FOR REPRESENTATIVE LARGE AND SMALL BREAK LOCAs

	Large Break (0.8 DEG/PD)		Small Break (0.02 ft^2)		
Event	Setpoint Or Value	Time, Seconds	Setpoint Or Value	Time, Seconds	Success Path
Main steam safety valves closed			1295 psia	2600	
Recirculation actuation signal	15% range	120 - 7200	15% range	1200 - 7200	Reactivity Control
Initiate cooldown		3600		3600	Sec. Sys. Integrity
Enter hot & cold leg injection mode		7200		7200	Reactor Heat Removal
Decision point for entry into shutdown cooling or continuation of hot and cold leg injection mode		28800		28800	Reactor Heat Removal

NOTES:

1. For the large break, loss of AC power and start of the diesel generators occurs at initiation of event (t = 0.0). For the small break, loss of AC power and start of the diesel generator occurs at time of P_pL trip (t = 456.0).

Valve Arrangement No.	Inside Containment / Outside Containment	Penetration No.
5		27, 28
6		29
7		40
8		41

Amendment No. 10
June 28, 1985

C-E SYSTEM 80

CONTAINMENT ISOLATION VALVE ARRANGEMENT

Figure 6.2.4-1B

EFFECTIVE PAGE LISTING

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APPENDIX 6B

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CHAPTER 6
APPENDIX 6B

7.14.2 The SCST should be drained using the nitrogen overpressure as the motive force in order to minimize the possibility of drawing air into the SCST.

7.14.3 The drain area should be provided with the safety precautions discussed in Section 7.11 to control hydrazine spillage.

7.15 OVERPRESSURE PROTECTION

Relief valves are provided for overpressure protection of IRS components and isolated piping sections. Relief valve discharges shall be collected in conformance with Sections 7.11, 7.13, and 7.14.

7.16 RELATED SERVICES

7.16.1 PLANT VENTILATION SYSTEM

7.16.1.1 Venting of hydrazine storage areas shall be through vent headers to assure that personnel are protected from hydrazine vapors. Applicable ventilation supply systems shall be designed such that they cannot serve to distribute hydrazine vapors to other plant areas in the event of accidental spills.

7.16.1.2 The SCST relief valve (IR250) and vent valve (IR-152) shall be directed to vent headers to assure that personnel are protected from hydrazine vapors or solution and to assure immediate dilution of hydrazine vapors or solution.

7.16.2 CONTAINMENT SUMP

Long term post-LOCA containment sump solution pH control shall be provided. The solution pH shall be regulated between 7.0 and 8.5 within four hours post-LOCA and maintained between those valves throughout the long term post-LOCA period. Storage of baskets containing di-or tri-sodium phosphate within the containment is the recommended method of pH control.

7.16.3 COMPRESSED NITROGEN SYSTEM

7.16.3.1 The compressed nitrogen system shall have the capability to supply a blanket of nitrogen at 5 psig to the Spray Chemical Storage Tank (SCST).

7.16.3.2 The compressed nitrogen system shall be designed such that the maximum flow to the SCST shall not exceed the SCST relief valve gas flow capacity of 90SCFM given a failure of the upstream pressure regulator.

7.16.4 HYDRAZINE FILL SYSTEM

7.16.4.1 The maximum fill rate shall not exceed the SCST relief valve liquid flow capacity.

7.16.4.2 Provisions shall be made to preclude the introduction of air into the SCST during fill operations. 10

7.16.4.3 All transfer lines and pump components in contact with the hydrazine solution should be clean and hydrazine compatible as recommended by the chemical manufacturers. 10

7.16.5 FIRE PROTECTION

A fire protection system shall be provided to protect the Iodine Removal System and shall include, as a minimum, the following features:

a. Facilities for fire detection and alarming.

b. Facilities or methods to minimize the probability of fire and its associated effects.

c. Facilities for fire extinguishment.

d. Methods of fire prevention such as use of fire resistant and non-combustible materials whenever practical, and minimizing exposure of combustible materials to fire hazards.

e. Assurance that fire protection systems do not adversely affect the functional and structural integrity of safety related structures, systems, and components.

f. Care should be exercised to ensure fire protection systems are designed to assure that their rupture or inadvertent operation does not significantly impair the capability of safety related structures, systems, and components.

7.17 ENVIRONMENTAL

See Section 7.7 and CESSAR Section 3.11 for environmental interfaces.

7.18 MECHANICAL INTERACTION

7.18.1 IRS components shall be properly supported such that pipe stresses and support reactions are within allowable limits, as defined in CESSAR Section 3.9.2. CE provides the Applicant the loads at the supports/structures interface locations for components that CE supplies, under normal, upset, emergency, faulted, and test conditions, as described in CESSAR Section 3.8.5.

7.18.2 IRS piping and fittings shall be Seismic Category I.

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integrated response time of each protection system after installation. Testing criteria are specified in Sections 7.2.2.3.3 and 7.3.2.3.3. Minimum testing frequency requirements are provided in the Technical Specifications (Chapter 16).

Since operation of the ESF Systems is not expected, the systems are periodically tested to verify operability. Complete channels, in the NSSS ESFAS systems, can be individually tested without initiating protective action and without inhibiting the operation of the system.

The system can be checked from the sensor signal through the actuation devices. The functional modules in the sensors system can be tested during reactor operation. The sensors can be checked by comparison with similar channels.

Those actuated devices, which are not tested during the reactor operation will be tested during scheduled reactor shutdown to show that they are capable of performing the necessary functions.

7.1.2.8 Conformance to IEEE 344-1971

The CESSAR Licensing scope compliance with IEEE 344-1971, "IEEE Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations" is discussed in Combustion Engineering Topical Report CENPD-182, "Seismic Qualification of Instrumentation Equipment" (Reference 3). The basic seismic qualification requirements of CESSAR Licensing scope equipment are discussed in Section 3.10.

Equipment outside the CESSAR Licensing scope will be discussed in the Applicant's Safety Analysis Report.

7.1.2.9 Conformance to IEEE 379-1972 as Augmented by Regulatory Guide 1.53 (Rev. 0, 6/73)

Instrumentation for the PPS and ESFAS Auxiliary Relay Cabinets, and the RTSS conform to the requirements of IEEE 379-1972, "IEEE Trial-Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems", as augmented by Regulatory Guide 1.53, "Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems". A discussion of the application of the single failure criterion is provided in Sections 7.2.2.3.2 and 7.3.2.3.2 for these systems.

Additional electrical components, equipment and systems which are outside the CESSAR Licensing scope, and vital to safe operation, are described in the appropriate sections of the Applicant's Safety Analysis Report.

7.1.2.10 Conformance to IEEE 384-1974 as Augmented by Regulatory Guide 1.75 (Rev. 0, 2/74)

The instrumentation for the safety-related electric systems conforms to the requirements of IEEE 384-1974, "IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits", as augmented by Regulatory Guide

1.75, "Physical Independence of Electric Systems". A discussion of the physical independence is provided below which describes the compliance with Section 4.6 of IEEE 279-1971 and General Design Criteria 3 and 21. General Design Criterion 17 is discussed in the Applicant's Safety Analysis Report.

The PPS cabinet is divided into four bays which are separated by mechanical and thermal barriers. Each bay contains one of the four redundant channels of the RPS and ESFAS. This provides the separation and independence necessary to meet the requirements of Section 4.6 of IEEE 279-1971.

Separation of redundant Class 1E circuits within the PPS cabinet is accomplished through 6 inch separation or barriers or conduit. However, in the formation of the logic matrices (AB, AC, BC, AD, BD, CD), initiation circuits, and actuation circuits, 6 inch separation is not maintained, nor can 10
barriers or conduit be utilized. An analysis has been performed to show that the separation achieved is acceptable. Tests and analyses have also been completed to demonstrate that no single credible event in one PPS bay can prevent the circuitry in any other bay from performing its safety function.

The ESFAS Auxiliary Relay Cabinets provide separation and independence for the selective two-out-of-four actuation logics and actuation relays of the two redundant ESF Systems' Trains. Each train's logic and relays are contained in a separate cabinet with all of the train A actuation circuits in one cabinet and all of the train B actuation circuits in the other cabinet. There are mechanical and thermal barriers within the cabinets to protect different portions of the selective two-out-of-four logic from spurious actuation. The two cabinets are physically separated from each other.

The RTSS consists of four RTSG. Each RTSG and its associated switches, contacts, relays, etc. is contained in a separate cabinet. Each cabinet is physically separated from the other cabinets. This method of construction ensures that a single credible failure in one RTSG cannot cause malfunction or failure in another cabinet.

The separation and independence of the power supplies for each of the above systems is discussed in Chapter 8.0. The interface requirements appear in Section 7.1.3 while the implementation will appear in the Applicant's Safety Analysis Report. Protection system analog signals, sent to the Plant Monitoring System (PMS), are isolated from the protection system. Digital signals are also isolated for the associated signals coming from the protection system.

All of these isolation techniques ensure that no credible failures on the output side of the isolation device will effect the PPS side and that the independence of the PPS is not jeopardized. The test results reports on the isolation devices (within CESSAR Licensing scope) will be submitted for review prior to installation of the devices in the first Applicant's facility.

7.1.2.11 Conformance to IEEE 387-1972

Conformance to IEEE 387-1972 , "IEEE Trial-Use Standard: Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations", as criteria in the design of these systems is discussed in the Applicant's Safety Analysis Report.

f. The system is designed to determine the following generating station conditions in order to provide protective action assistance to the ESF during Limiting Faults:

   1. Core power;

   2. RCS pressure;

   3. Steam generator pressure; and

   4. Containment pressure.

g. The system is designed to monitor all generating station variables that are needed to assure adequate determination of the conditions given in listings e. and f. above, over the entire range of normal operation and transient conditions. The full power nominal values and the maximum and minimum values that can be sensed for each monitored plant variable are given in Table 7.2-2. The type, number, and location of the sensors provided to monitor these variables are given in Table 7.2-3.

h. The system is designed to alert the operator when any monitored plant condition is approaching a condition that would initiate protective action.

i. The system is designed so that protective action will not be initiated due to normal operation of the generating station.

   Nominal full power values of monitored conditions and their corresponding protective action (trip) setpoints are given in Table 7.2-4.

   The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays and inaccuracies are taken into account. Reactor trip delay times and analysis setpoints used in the Chapter 15 safety analyses are given in Table 15.0-4.

   The reactor protective system sensor response times, reactor trip delay times, and analysis setpoints used in Chapter 15.0 are representative of the manner in which the RPS and associated instrumentation will operate. 10 These quantities are used in the transient analysis documented in Chapter 15.0. Note that the reactor trip delay times shown in Table 15.0-4 do not include the sensor response times. Actual RPS equipment uncertainties, response times and reactor trip delay times will be obtained from calculations and tests performed on the RPS and associated instrumentation. The verified system uncertainties are factored into all RPS settings and/or setpoints to assure that the system adequately performs its intended function when the errors and uncertainties combine in an adverse manner.

j. All system components are qualified for environmental and seismic conditions in accordance with IEEE Standard 323-1974, and IEEE Standard 344-1971. Compliance is addressed in Section 3.11 and in CENPD-255, "Qualification of Combustior Engineering Class 1E Instrumentation", (Reference 3); and in Section 3.10 and CENPD-182, "Seismic Qualification

of Instrumentation and Electrical Equipment", (Reference 4). In addition, the system is capable of performing its intended function under the most degraded conditions of the energy supply, as addressed in Section 8.3.

7.2.1.3 Final System Drawings

The signal logics, block diagrams, and test circuit block diagrams are shown in Figures 7.2-1 through 7.2-16.

The following discussion compares the logics to be found in the preliminary CESSAR with those contained herein. The figure numbers refer to the numbers used here and are not necessarily those of the preliminary CESSAR.

Figure 7.2-8a shows a simplified block diagram for the SPS.

The simplified functional diagram of Figure 7.2-9 has several changes incorporated. On the table of trip inputs the High Linear Power Level has been replaced with the Variable Overpower Trip. The undervoltage and shunt trip circuits have had contacts from the SPS circuit added. The Reactor Trip Switchgear consisting of nine breakers has been replaced with a four breaker Reactor Trip Switchgear System. These changes create a more reliable means of providing a reactor trip when it is required.

Figure 7.2-13 shows some changes in the interface logic from the PSAR. The first change is that the high-high containment pressure is now provided with a separate transmitter. Secondly, MSIS has added steam generator level signals and containment pressure. Third, the EFAS logic has been added. Finally, the turbine trip has been removed from the RPS.

MCBD's related to the RPS are provided in Section 7.1.

7.2.2 ANALYSIS

7.2.2.1 Introduction

The RPS is designed to provide the following protective functions:

a. Initiate automatic protective action to assure that acceptable RCS and fuel design limits are not exceeded during specified Incidents of Moderate Frequency and Infrequent Incidents.

b. Initiate automatic protective action during Limiting Faults to aid the ESF Systems in limiting the consequences of the limiting faults.

A description of the reactor trips provided in the RPS is given in Section 7.2.1.1.1. Section 7.2.2.2 provides the bases for all the RPS trips and Table 7.2-4 gives the applicable nominal trip setpoints.

Most of the trips in the RPS are single parameter trips (i.e., a trip signal is generated by comparing a single measured variable with a fixed setpoint). The RPS trips that do not fall into this category are as follows:

TABLE 7.2-1

REACTOR PROTECTIVE SYSTEM BYPASSES

Title	Function	Initiated By	Removed By	Notes
DNBR and local power density bypass	Disable low DNBR and high local power density trips	Key-operated switch (1 per channel)	Automatic if power is $\geq$ 1%	Allows low power testing 10
Pressurizer pressure bypass	Disables low pressurizer pressure trip, SIAS, and CIAS	Manual switch (1 per channel) if pressure is <400 psia	Automatic if pressure is >500 psia	
High log power level bypass	Disables high logarithmic power level trip	Manual switch (1 per channel) if power is $>10^{-4}$%	Automatic if power is $<10^{-4}$%	Bypassed during reactor startup
Trip channel bypass	Disables any given trip channel	Manually by controlled access switch	Same switch	Interlocks allow only one channel for any one type trip to be bypassed at one time

TABLE 7.2-2

REACTOR PROTECTIVE SYSTEM MONITORED PLANT VARIABLE RANGES

Monitored Variable	Minimum	Nominal (full power)	Maximum
Neutron flux power, %	$2x10^{-8}$ of full power	100 power	200 of full power
Cold leg temperature, °F	465	565	615
Hot leg temperature, °F	375	621	675
Pressurizer Pressure (narrow range), psia	1,500	2,250	2,500
Pressurizer pressure (wide range), psia	0	2,250	3,000
CEA positions	full in	NA	full out
Reactor coolant pump speed, rpm	100	1,188	1,200
Steam generator water level, %[a]	0	82	100
Steam generator water level, %[b]	0	55	100
Steam generator pressure, psia	0	1,070	1,400
Containment pressure, psig	-4	0	20
Steam generator primary pressure differential,psid	0	43	47

5

a. % of the distance between the wide range level instrument nozzles (above the lower nozzle).

b. % of the distance between the narrow range instrument nozzles (above the lower nozzle).

TABLE 7.3-3

MONITORED VARIABLES REQUIRED FOR ESFAS PROTECTIVE SIGNALS

	CIAS	CSAS	RAS	MSIS	SIAS	EFAS	
Pressurizer Pressure	3				3		
Containment Pressure	1	2		1	1		
Steam Generator Pressure				3		4	10
Refueling Water Tank Level			3				
Steam Generator Water Level				1		3	

1 - High

2 - High-High

3 - Low

4 - High-Differential 10

TABLE 7.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM SENSORS

Monitored Variable	Sensor Type	Number of Sensors	Location
Pressurizer Pressure	Pressure Transducer	4* (wide range)	Pressurizer
Containment Pressure	Pressure Transducer (Wide and Narrow range)	8*	Enclosure Complex
Steam Generator Pressure	Pressure Transducer	4/Steam Generator*	Steam Generator
Refueling Water Tank Level	Differential Pressure Transducer	4	Refueling Water Tank
Steam Generator Level	Differential Pressure Transducer (Wide and Narrow Range)	8/Steam Generator*	Steam Generator

*Shared with the Reactor Protective System

TABLE 7.5-2 (Cont'd.) (Sheet 3 of 3)

ENGINEERED SAFETY FEATURE SYSTEM MONITORING

Parameter	Type of Readout	Number of Channels	Number of IE Channels	Range	Indicator Accuracy	Location
Chemical Volume Control System(3)						
Refueling Water Tank Isolation Valve Position	Indicating Lights	1 pair/ valve	1	N/A	N/A	Control Room
Refueling Water Tank Level	Indicator	4	4	0-100%	± 2%	Control Room
Refueling Water Tank Level	Indicator	2	2	0-100%	± 2%	Control Room

NOTES:

1. All indication on electrically actuated valves in the Safety Injection/Shutdown Cooling System, with exception of SI-661, receive IE power.

2. Valves which are required to bring the plant to cold shutdown have open/close position indicated outside the Control Room also.

3. All CVCS containment isolation valves are open/close type valves.

TABLE 7.5-3

POST-ACCIDENT MONITORING INSTRUMENTATION

Parameter(3)	Type of Readout	Number of 1E Channels	Range(4)	Location	
Pressurizer Pressure	Indicator	2	15-3000 psia	Control Room	
	Recorder	1	15-3000 psia	Control Room	
Reactor Coolant System Pressure	Indicator	2	0-4000 psig	Control Room	10
	Recorder	1	0-4000 psig	Control Room	
Pressurizer Level	Indicator	2	0-100%	Control Room	
	Recorder	1	0-100%	Control Room	
Steam Generator Pressure	Indicator	2/SG	15-1524 psia	Control Room	8
	Recorder	1/SG	15-1524 psia	Control Room	
Steam Generator Level	Indicator	2/SG	0-100%	Control Room	
	Recorder	1/SG	0-100%	Control Room	
Containment Pressure (2)	Indicator	2	-4 to 85 psig	Control Room	
	Recorder	1	-5 to 180 psig	Control Room	
Reactor Coolant Temperature-Hot Leg	Indicator	4	50-750°F	Control Room	8
	Recorder	2	50-750°F	Control Room	
Reactor Coolant Temperature-Cold Leg	Indicator	4	50-750°F	Control Room	
	Recorder	2	50-750°F	Control Room	

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Notes:

1. Post-accident monitoring instrumentation is qualified for the appropriate environmental conditions (refer to Section 3.11).

2. The containment pressure instrumentation may be supplied by the Applicant, the specified range and accuracy values above are typical.

3. MCBD's are provided in Section 7.1. 10

4. Post-accident channel accuracy is a time dependent function of post-accident environmental conditions. 8

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POWER REQUIREMENTS FOR CESSAR DESIGN SCOPE SAFETY-RELATED

ELECTRICAL EQUIPMENT DURING EMERGENCY OPERATION

SYSTEM	POWER REQUIRED PER STANDBY GENERATOR	KW REQUIRED (1)
SIS	HPSI Pump	721
SIS	LPSI Pump	376
CVCS	Charging Pumps (2)	160
SIS/SCS	Valves	50
	120 V Vital AC Instrument Buses (2, inverters)	30.7
	Total Kilowatts for on Standby Generator	1337.7
	POWER REQUIRED PER BATTERY	
SIS/CVCS	Electro-Pneumatic Valves	1.0
SIS	Motor Operated Valves	3.3
	Solenoid Operated Valves	0.5
	Vital Instrument Bus Inverter	
	(If all AC power is lost)	15.34 (average)
	Total Kilowatts for one battery	19.65

NOTES:

(1) KW required to be supplied by the Applicant, specified values are only typical.

(2) These are not required to be automatically sequenced onto the standby generator but must be capable of being manually switched at the operator's discretion.

TABLE 8.3.1-4

REQUIRED STANDBY GENERATOR LOADS

e loads designated below for a particular ESFAS signal are those that shall e started to establish the stated conditions within the times specified. If offsite power is unavailable, then the loads designated below for a particular ESFAS signal shall be supplied from the standby generator, and sequenced on to meet the stated conditions. CSAS will also start the Standby Generator and sequencing shall be determined by the Applicant.

	Loss of Offsite Power Concurrent with the below listed ESFAS:	
Equipment	SIAS	EFAS
LPSI Pumps	(1)	N/A
HPSI Pumps	(1)	N/A
Motor Operated Valves (as appropriate for each signal)	(1)	(2)
Emergency Feedwater Pumps	N/A	(2)

NOTES

N/A: Not Actuated

(1) Sequence on such that flow is delivered to the RCS within a maximum of 29 seconds after SIAS. 10

(2) Sequence on such that flow to the steam generator is attained within a maximum of 45 seconds after EFAS. See Section 5.1.4.

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9.0 AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

9.1.1 NEW FUEL STORAGE

See Applicant's SAR. See Sections 4.2.5 and 9.1.4.6 for interface requirements.

9.1.2 SPENT FUEL STORAGE RACKS

See Applicant's SAR. See Sections 4.2.5 and 9.1.4.6 for interface requirements.

9.1.3 SPENT FUEL POOL COOLING AND CLEANUP SYSTEM

See Applicant's SAR. See Section 9.1.4.6 for interface requirements.

9.1.4 FUEL HANDLING SYSTEM

9.1.4.1 Design Bases

9.1.4.1.1 System

The fuel handling system is designed for the handling and storage of fuel assemblies and control element assemblies (CEAs). Associated with the fuel handling system is the equipment used for assembly, disassembly and storage of the reactor closure head and internals. As appropriate, the fuel handling equipment included interlocks, travel limiting features, and other protective devices to minimize the possibility of mishandling or equipment malfunction that could result in inadvertent damage to a fuel assembly and potential fission product release.

The refueling water provides the coolant medium during spent fuel transfer. The spent fuel pool is provided with a pool cooling and purifications system.

All spent fuel transfer and storage operations are designed to be conducted underwater to insure adequate shielding during refueling and to permit visual control of the operation at all times. The arrangement of the fuel handling system is shown in Figure 9.1-1.

9.1.4.1.2 Fuel Handling Equipment

The principle design criteria for the fuel and CEA handling equipment (refueling machine, fuel transfer equipment, spent fuel handling machine, CEA change platform and new fuel and CEA elevators) are as follows:

a. For non-seismic operating conditions, the bridges, trolleys, hoist units, hoisting cable, grapples and hooks conform to the requirements of Crane Manufacturing Association of America Specification #70. 10

b. For seismic design, the combined dead loads, live loads and seismic loads do not cause any portion of the equipment to disengage from its supports and fall into the pool.

c. Grapples and mechanical latches which carry fuel assemblies or CEAs are mechanically interlocked against inadvertent opening.

d. Equipment is provided with locking devices or restraints to prevent parts, fasteners, or limit switch actuators from becoming loose. In those cases where loosened parts or fasteners can drop into, or are not separated by a barrier from, or whose rotary motion will propel it into the water of the refueling pool or spent fuel pool, these parts and fasteners are lockwired or otherwise positively captured.

e. A positive mechanical stop is provided to prevent the fuel from being lifted above the minimum safe water cover depth and shall not cause damage or distortion to the fuel or the refueling machine when engaged at full operating hoist speed.

f. The fuel hoists are provided with load measuring devices and interlocks to interrupt hoisting if the load increases above the overload set point and interrupt lowering if the load decreases below the underload set point.

g. In the event of loss of power, the equipment, and its load remain in a safe condition.

h. Equipment remaining within the containment is capable of withstanding, without damage, the internal building test pressure.

i. Electrical interlocks are provided to ensure the reliability of system components, to simplify the performance of sequential operations, and to limit travel and loads such that design conditions will not be exceeded. In no case will they be utilized to prevent inadvertent criticality or the reduction of the minimum water coverage for personnel protection. No single interlock failure will result in a condition which will allow equipment malfunction, damage to the fuel, or the reduction of shielding water coverage. Where these results are considered possible, redundant switches, mechanical restraints and physical barriers are employed as well as limiting the hoist stall torque and loading capability to values below those which would result in damage to the fuel.

9.1.4.1.3 Cask Handling Crane and Containment Polar Crane

See Applicant's SAR

the reactor for the operator; electronic and visual indication of the refueling machine position over the core; a protective shroud into which the fuel assembly is drawn by the refueling machine; transfer system upenders manual operation by a special tool in the event that the hydraulic system becomes inoperative; and removal of the transfer system components from the refueling pool for servicing without draining the water from the pool.

c. The fuel transfer tube is sufficiently large to provide natural circulation cooling of a fuel assembly in the unlikely event that the transfer carriage should be stopped in the tube. The manual operator for the fuel transfer tube valve extends from the valve to the operating deck. Also, the valve operator has enough flexibility to allow for operation of the valve even with thermal expansion of the fuel transfer tube.

d. Travel stops in both the refueling and spent fuel handling machines restrict withdrawal of the spent fuel assemblies. This results in the maintenance of a minimum water cover of 9 feet over the active portion of the fuel assembly. The resulting radiation level from the spent fuel is 2.5 mr/hr or less at the surface of the water in the refueling pool (30 mr/hr or less from the spent fuel in the spent fuel pool) when the shielding of the appropriate fuel handling machine is taken into account. 10

9.1.4.3.5 Reactor Vessel Closure Head Handling

The maximum load-carrying capability of the reactor vessel support system was evaluated by an elastic-plastic static analysis of the support columns using the MARC finite element computer program. Each column was modeled with 13 rectangular section beam finite elements. The material properties used were for SA 633 Gr B steel at room temperature (Figures 9.1-18 and 9.1-19). From the stress-strain curves the initial yield point was determined to be 65,000 psi.

The axial load vs. deflection curve (Figure 9.1-20) was obtained by applying a gradually increasing axial load up to the point of static instability. The stiffness of each reactor vessel support column is seen to be about 40 x 10^6 lb per inch, up to a limit load of about 22 x 10^6 lbs.

A nonlinear dynamic elastic-plastic analysis of the reactor vessel support system was performed using the MARC program to evaluate the time-dependent behavior of the columns. The results of a straight drop of the head assembly from 18 feet indicate that the load in the columns will reach the maximum load-carrying capability of the columns and some plastic deformation will occur. The peak axial deflection for a drop from this height was determined to be .66 inches. The results show that the reactor vessel supports would remain intact and continue to support the weight of the vessel following such an event.

Possible drop configurations other than the straight drop of the head assembly were considered to insure that the core will remain coolable for the most severe drop which can occur. An off-angle drop was demonstrated to produce bending about the wider dimension of the support columns, thus producing a more rigid system in response to this type of head drop.

It is concluded that the reactor vessel support system and the shutdown cooling supply flow paths will remain functional in the unlikely event of a free fall of the reactor head assembly from 18 feet above the reactor vessel flange.

In addition, the effect of the postulated dropping of the reactor vessel closure head on the reactor internals and core was assessed by performing a nonlinear elastic-plastic dynamic response analysis. Two basic cases were considered: a flat concentric head drop and an offset head drop. In the flat concentric head drop, the head is assumed to drop in place from a height of 18 feet and contact the internals and vessel flanges uniformly. In the offset head drop, the head is assumed to fall from the same height but from a laterally offset position. In that case, the head would contact the extension shafts and the top of the CEA shroud package.

The flat head drop analysis utilized a spring-mass model of the System 80 internals, core, vessel and vessel supports shown in Figure 9.1-2 as input to the CESHOCK code. The analysis was performed by prescribing an initial velocity to the head mass at contact corresponding to an 18 foot free fall in air. Since the upper guide structure flange is at a slightly higher elevation than the vessel flange, the head first contacts the UGS flange, imparting a downward motion to the upper guide structure assembly. The head then contacts the reactor vessel flange, forcing the vessel downward, compressing the R.V. supports and finally rebounding. The dynamic response and peak forces resulting from the impact were calculated by CESHOCK. Maximum stresses based on the peak loads were then calculated. The results showed that the stresses in the fuel rod cladding would remain well below the yield strength. Peak stresses in the other major components would exceed yeild strength in some local areas but would still remain well below the ultimate strength. Therefore, some local deformation may occur, but total failure or gross deformation of the major components is not expected. This demonstrates that for a flat concentric head drop accident, the core would be maintained in a coolable configuration and fuel rod damage would not occur.

In the event of an offset head drop where the head falls from a 18 foot height but laterally displaced from the centerline of the vessel, the head would first contact the CEA extension shafts and CEA shroud package. Since the CEA extension shafts are long flexible members, the energy required to buckle them is relatively negligible so these components are conservatively omitted from the dynamic model. The analysis performed was similar to the flat head drop analysis. The CESHOCK code spring-mass model is shown in Figure 9.1-2. This model contains an additional loading path going from the head to the CEA shroud package. Since the degree of lateral offset can vary, several cases were considered by varying the stiffness of the CEA shroud package elements. For a small degree of offset, it was assumed that

TABLE 9.2-1

MAKEUP WATER SYSTEM DEMINERALIZER EFFLUENT LIMITS 10

pH*	6.0 to 8.0
Conductivity	Less than 0.2 μmhos
Chloride	Less than 0.005 ppm Cl
Fluoride	Less than 0.005 ppm F 10
Silica (Si O_2)	Less than 0.01 ppm
Sodium	Less than 0.003 ppm

* If water contains CO_2, the pH specification may be lowered to 5.8 to compensate for CO_2 absorption.

10

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time when exposed to normal reactor coolant chemistry conditions, approaching low steady state values within approximately 200 days. The high pH condition produced by high ammonia concentration (to 50 ppm) minimizes corrosion product release and assists in the rapid development of the passive oxide film. Most of the film is established within 7 days at hot, high pH conditions.

To aid in maintaining the pH during this passivation period, lithium in the form of lithium hydroxide, is added to the coolant and maintained within a 1-2 ppm lithium-7 range.

At power, oxygen concentration is limited by maintaining excess dissolved hydrogen gas in the coolant. The excess hydrogen forces the water decomposition/synthesis reaction in the reactor core to water rather than hydrogen and oxygen. Oxygen in the makeup water is removed in the same way.

In order to minimize the effect of crud deposition on the reactor core heat transfer surfaces, lithium-7 hydroxide additions to the reactor coolant are made. The lithium-7 hydroxide produces pH conditions within the reactor coolant at operating temperature which reduces the corrosion product solubility and, hence, the dissolved crud inventory in the circulating reactor coolant. The elevated pH promotes conditions within the coolant for selective deposition of corrosion products on cooler surfaces (SG) rather than hotter surfaces (core). An additional advantage is the formation of a more stable and tenacious passive oxide layer on out-of-core system surfaces. The lithium concentration is maintained within a 1.0-2.0 ppm lithium-7 range during operation. 10

9.3.4.1.3.3 <u>Reactivity Control</u>. Boron concentration is normally controlled by feed and bleed. To change concentration, the makeup system supplies either reactor makeup water or boric acid to the Volume Control Tank, and the letdown stream is diverted to the holdup tanks via the preholdup ion exchanger and the gas stripper. Toward the end of a fuel cycle, with low boric acid concentration in the coolant, feed and bleed becomes inefficient, and the deborating ion exchanger is used to reduce the RCS boron concentration. The ion exchanger contains an anion resin initially in the hydroxyl form, which is converted to a borate form as boron is removed from the reactor coolant.

9.3.4.2 <u>System Description</u>

9.3.4.2.1 System

The normal reactor coolant flow path through the CVCS is indicated by the heavy lines on the Piping and Instrumentation Diagrams, Figures 9.3-1 through 9.3-4.

Parameters for the CVCS are listed in Table 9.3-5. Equipment design parameters for the major components are shown in Table 9.3-6 with locations corresponding to those noted in the ellipses on Figures 9.3-1 through 9.3-4. Equipment seismic and safety classifications are given in Table 3.2-1. See Table 9.3-8 for a listing of active valves in the CVCS.

Letdown flow from one cold leg passes through the tube side of the Regenerative Heat Exchanger for an initial temperature reduction. The pressure is then reduced by a letdown control valve to the letdown heat exchanger operating pressure. The final reduction to the purification subsystem operating temperature and pressure is made by the letdown heat exchanger and letdown backpressure valve. The flow then passes through a filter, an ion exchanger, a strainer, and is sprayed into the Volume Control Tank. A portion of the flow also passes through the Boronometer and Process Radiation Monitor after flowing through the filter.

A Chemical Addition Tank and Chemical Addition Metering Pump are used to transfer chemical additives to the charging line downstream of the seal injection takeoff connection. An excess hydrogen inventory is provided by keeping a hydrogen overpressure in the volume control tank or by adding hydrogen directly to the RCS via the charging line.

The boron recovery portion of the CVCS accepts the letdown flow diverted from the Volume Control Tank as a result of feed and bleed operations for shutdowns, startups, and boron dilution over core life. Reactor coolant quality water from valve and equipment leakoffs, drains, and reliefs within the containment are collected in the Reactor Drain Tank and scheduled for batch processing. Recoverable reactor coolant quality water outside the containment from various equipment and valve leakoffs, reliefs, and drains is collected in the Equipment Drain Tank and scheduled for batch processing.

Reactor coolant collected in the Reactor Drain and Equipment Drain Tanks is periodically discharged by the Reactor Drain Pumps through the reactor drain filter and preholdup ion exchanger. The diverted letdown flow, which has been previously passed through a purification filter and ion exchanger, also passes through the preholdup ion exchanger. The preholdup ion exchanger contains mixed bed resin in the form, thereby removing cesium, lithium, and other ionic radionuclides with high efficiency. The process flow then passes through the gas stripper where hydrogen and fission gases are removed with high efficiency, thus precluding the buildup of explosive gas mixtures in the holdup tank and minimizing the release of radioactive fission product gases via aerated vents and in any liquid discharge. The degassed liquid is automatically pumped from the gas stripper to the holdup tank. When a sufficient volume accumulates in the holdup tank it is pumped by the holdup pump to the boric acid concentrator where the bottoms are concentrated to within the range of 4000 of 4400 ppm boron.

The Boric Acid Concentrator bottoms are continuously monitored for proper boron concentration. Normally, the concentrator bottoms are pumped directly to the Refueling Water Tank. In the event that abnormal quantities of radionuclides are present, the bottoms are concentrated to 12 wt percent boric acid and are discharged to the SWMS.

The resin sluice supply header to the Reactor Drain Tank has an isolation valve located outside the containment that automatically closes on a CIAS.

The charging and seal injection lines carry flow into the containment. Within the containment the charging line branches into two lines, with direct charging flow to the reactor coolant loop and/or flow to the auxiliary spray line to the pressurizer. All of these lines are provided with check valves that preclude back flow from the reactor coolant loop. The line to the reactor coolant loop has a spring loaded bypass valve in parallel with normally open, fail closed, pneumatically operated isolation valves. Each of 10
the four flow control valves in the seal injection distribution header is a normally open, fail open valve. The isolation valves for auxiliary spray are normally closed and fail closed. Fail as-is motor operated containment isolation valves with handwheels are provided on the charging and seal injection lines just outside the containment. These valves remain open upon actuation of CIAS and SIAS to allow for makeup, boron injection and seal injection if necessary.

9.3.4.3.6 Leakage Detection and Control

The components in the CVCS are provided with welded connections wherever possible to minimize leakage to the atmosphere. However, flanged connections are provided on all pump suction and discharge lines, on relief valve inlet and outlet connections on the boric acid batching educator and on some flow meters to permit removal for maintenance. All valves larger than 2 inches and all actuator-operated valves are provided with double-packing, lantern rings, and leakoff connections, unless the valves are diaphragm (packless) valves. Diaphragm valves are utilized around the Volume Control Tank gas space. Thus, activity release due to valve leakage is minimized.

The CVCS can also monitor the total RCS water inventory. If there is no leakage throughout the plant, the level in the Volume Control Tank should remain constant during steady state operation. Therefore, a decreasing level in the Volume Control Tank alerts the operator to a possible leak somewhere in the system.

During refueling shutdown, the reactor makeup water piping is monitored to detect leakage past isolation valve CH-195 (locked shut during refueling shutdown). If leakage occurs, an alarm is annunciated in the control room.

9.3.4.3.7 Failure Mode and Effects Analysis

Table 9.3-7 shows a Failure Mode and Effects Analysis (FMEA) fr the CVCS. At least one failure is postulated for each major component of the CVCS. Additionally, various line breaks throughout the system are also considered. In each case the possible cause of such a failure is presented as well as the local effects, detection methods and compensating provisions.

9.3.4.3.8 Radiological Evaluation

Frequently used manually operated valves located in high radiation or inaccessible areas are provided with extension stem handwheels terminating in low radiation and accessible control areas. Manually operated valves

are provided with locking provisions if unauthorized operation of the valve is considered a potential hazard to plant operation or personnel safety. A radiological evaluation of the CVCS is presented in Section 12.2

9.3.4.4 Testing and Inspection Requirements

Each component is inspected and cleaned prior to installation into the CVCS. A high velocity flush using demineralized water will be used to flush particulate material and other potential contamination from all lines in this system.

Instruments will be calibrated during preoperational testing. Automatic controls will be tested for actuation at the proper set points and alarm functions will be checked for operability and proper set points. The relief valve settings will be checked and adjusted as required. All sections of the CVCS will be operated and tested initially with regard to flow paths, flow capacity and mechanical operability. Pumps will be tested to demonstrate head and capacity.

The CVCS is tested for integrated operation with the RCS during hot functional testing. Heat exchanger performance and proper control of letdown flow and charging pumps by the pressurizer level control program will be tested during hot functional testing. The charging line will be checked to assure that the piping is free of excessive vibration. Response of the makeup portion of the CVCS in the automatic, dilute, and borate modes will be verified. Any defects in operation that could affect plant safety are corrected before fuel loading.

As part of normal plant operation, tests, inspections, data tabulation and instrument calibrations are made to evaluate the condition and performance of the CVCS equipment and instrumentation. Data will be taken periodically during normal plant operation to confirm heat transfer capabilities and purification efficiency. Pump and valve leakage will be monitored.

Appropriate vents, drains, and test connections are provided to permit the Applicant to perform inservice testing of valves.

Provisions are made which will permit the inservice testing of Safety Class 2 and 3 pumps in accordance with ASME Section XI.

9.3.4.5 Instrumentation

9.3.4.5.1 Temperature Instrumentation

a. Holdup Tanks and Reactor Makeup Water Tank Temperature: The temperature of the contents of these tanks is indicated in the main control room. A low temperature alarm annunciates in the main control room to warn the operator of low temperature of the tank contents.

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

d. CH-239, 240 shall be fail-close valves powered from separate power sources. If powered from non-1E qualified sources, class 1E protective devices (isolators) are required in conjunction with a Failure Modes and Effects Analysis for these valves. 10

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	7
CH-536	A	A	

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

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

Amendment No. 7
March 31, 1982

TABLE NO. 9.3-1

(Sheet 1 of 2)

OPERATING LIMITS

1.0 REACTOR COOLANT MAKEUP WATER

Analysis	Normal	
Chloride (Cl)	< 0.15 ppm	
pH	6.0 - 8.0 (1)	10
Fluoride (F)	< 0.1 ppm	
Suspended Solids	< 0.5 ppm	

2.0 PRIMARY WATER

Analysis	Pre Core Hot Functionals (2)	Initial Core Load and Criticality	Operation	
pH (77°)	9.0 - 10.4	4.5 - 10.2	4.5 - 10.2	
Conductivity	(3)	(3)	(3)	10
Hydrazine	30 - 50 ppm (4)	30 - 50 ppm (4)	1.5 x Oxygen ppm (5) (max. 20 ppm)	
Ammonia	<50 ppm	<50 ppm	<0.5 ppm	
Dissolved Gas	---	---	(6)	
Lithium	1-2 ppm	1.0-2.0 ppm	1.0-2.0 ppm	
Hydrogen	---	--- (7)	25 - 50 cc (STP)/kg (H_2O) (8)	10
Oxygen	≤0.1 ppm	≤0.1 ppm (10)	≤0.1 ppm (10)	
Suspended Solids	<0.5 ppm, 2 ppm max. (9)	<0.5 ppm, 2 ppm max. (9)	<0.5 ppm, 2 ppm max. (9)	10
Chloride	≤0.15 ppm	≤0.15 ppm	≤0.15 ppm	
Fluoride	≤0.1 ppm	≤0.1 ppm	≤0.1 ppm	10
Boron	---	<Refueling Concentration	≤Refueling Concentration	

TABLE 9.3-1 (Cont'd) (Sheet 2 of 2)

Notes for Table No. 9.3-1

(1) May be as low as 5.8 if proven due to CO_2 absorption.

(2) Special hot conditioning limits:

Temperature >350°F for 7-10 days

(3) Consistent with additive concentration. 10

(4) Hydrazine is maintained at 30-50 ppm any time the RCS is less than 150°F.

(5) Prior to exceeding 150°F during heatup or below 400°F during cooldown.

(6) Prior to a depressurization shutdown, reduce total gas to <10cc(STP)/kg (H_2O) to limit the possibility for explosive mixtures.

(7) During the transition from post-core to operating, hydrogen should be maintained in the 15 to 25cc(STP)/kg (H_2O) range to minimize degassing requirements in case the reactor plant must be shutdown and depressurized.

(8) Hydrogen should be <5cc(STP)/kg (H_2O) before securing the reactor coolant pumps. 10

(9) The abnormal condition of 0.5 to 2.0 ppm is permitted for up to 14 hours to allow for crud burst conditions.

(10) Not applicable during core load.

TABLE 9.3-6

(Sheet 1 of 4)

CHEMICAL AND VOLUME CONTROL SYSTEM

PROCESS FLOW DATA(5)

CVCS Minimum Purification Operation (One Charging Pump in Operation)

CVCS Location:	1	2	3	4	5	6	7	8	8a	8b	8c	9
Flow, gpm	30	30	30	30	30	30	20	10	2	8	10	30
Press., psig	2235	2235	460	60	60	60	60	60	60	60	60	60
Temp., F	565	300	300	120	120	120	120	120	120	120	120	120

CVCS Minimum Purification Operation (One Charging Pump in Operation)

CVCS Location:	10	10a	10b	10c	11	12	13m	13b	13	13c	13n	13d, e,f,g	13h, j,k,l	14a, b,c,d	14e	14f	14g	
Flow, gpm	30	30	30	44	44	44	44	44	44	0	0	0	0	3.9	0	15.6	15.6	10
Press., psig	60	60	20	20	20	2485	2485	2455	2485	2400	2400	2400	2400	100	100	100	70	
Temp., F	120	120	120	120	120	120	120	385	385	120	120	120	120	180	180	180	180	

CVCS Normal Purification Operation (Two Charging Pumps in Operation)

CVCS Location:	1	2	3	4	5	6	7	8	8a	8b	8c	9
Flow, gpm	72	72	72	72	72	72	62	10	2	8	10	72
Press., psig	2235	2235	460	60	60	60	60	60	60	60	60	60
Temp., F	565	310	310	120	120	120	120	120	120	120	120	120

CVCS Normal Purification Operation (Two Charging Pumps in Operation)

CVCS Location:	10	10a	10b	10c	11	12	13m	13b	13	13c	13n	13d, e,f,g	13h, j,k,l	14a, b,c,d	14e	14f	14g
Flow, gpm	72	72	72	86	88	88	61.6	61.6	61.6	26.4	26.4	6.6	6.6	3.9	0	15.6	15.6
Press., psig	60	60	20	20	20	2485	2455	2485	2400	2400	2400	2400	2400	100	100	100	70
Temp., F	120	120	120	120	120	120	120	445	445	120	120	120	120	180	180	180	180

TABLE 9.3-6 (Cont'd.) (Sheet 2 of 4)

CVCS Maximum Purification Operation (Three Charging Pumps in Operation)

CVCS Location:	1	2	3	4	5	6	7	8	8a	8b	8c	9
Flow, gpm	135	135	135	135	135	135	125	10	2	8	10	135
Press., psig	2235	2235	460	460	60	60	60	60	60	60	60	60
Temp., F	565	405	405	120	120	120	120	120	120	120	120	120

CVCS Maximum Purification Operation (Three Charging Pumps in Operation)

CVCS Location:	10	10a	10b	10c	11	12	13m	13b	13	13c	13n	13d, e,f,g	13h, j,k,l	14a, b,c,d	14e	14f	14g
Flow, gpm	135	135	135	132	132	132	105.6	105.6	105.6	26.4	26.4	6.6	6.6	3.9	0	15.6	15.6
Press., psig	60	60	20	20	20	2485	2485	2455	2485	2400	2400	2400	2400	100	100	100	70
Temp. , F	120	120	120	120	120	120	120	272	272	120	120	120	120	180	180	180	180

CVCS Makeup System Operation - Automatic Mode (Blended Boric Acid Concentration = 900 ppm)

CVCS Location:	15	16	17	18	18a	18d	19	20	21	22	23	23a	24	25
Flow, gpm	54	34	34	34	34	20	34	165	0	131	131	20	131	131
Press., psig	41	130	130	130	130	0	130	130	18	130	130	0	130	130
Temp., F	120	120	120	120	120	120	120	120	120	120	120	120	120	120

CVCS Makeup Operation - Dilute Mode

CVCS Location:	15	16	17	18	18a	18d	19	20	21	22	23	23a	24	25
Flow, gpm	0	0	0	0	0	0	0	165	0	165	165	20	165	165
Press., psig	41	41	41	41	41	0	130	130	18	130	130	0	130	130
Temp., F	120	120	120	120	120	120	120	120	120	120	120	120	120	120

CVCS Makeup System Operation - Shutdown Boration

CVCS Location:	15	16	17	18	18a	18b	18d
Flow, gpm	152	132	132	132	132	132	20
Press., psig	41	130	130	130	130	130	0
Temp., F	120	120	120	120	120	120	120

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 Valves, CH-240 CH-239	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	10
		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.	

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-306	D8	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]	7
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				
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				
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-239	G7	G	2.50	D	A-1, A-2, B	10
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	7
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

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* 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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10.0 STEAM POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

See Applicant's SAR.

10.2 TURBINE GENERATOR

See Applicant's SAR.

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 DESIGN BASES

The Main Steam Supply System is discussed in the Applicant's SAR. See Section 5.1.4 for interface criteria.

10.3.1.1 Environmental Design Bases

The environmental design requirements are contained in the Applicant's SAR.

10.3.1.2 Inservice Inspection Requirements

Inservice inspection requirements are contained in the Applicant's SAR.

10.3.2 EVALUATION

See Applicant's SAR.

10.3.3 INSPECTION AND TESTING REQUIREMENTS

See Applicant's SAR.

10.3.4 SECONDARY WATER CHEMISTRY

10.3.4.1 Chemistry Control Basis

Steam generator secondary side water chemistry control is accomplished by:

a. Close control of the feedwater to limit the amount of impurities which can be introduced into the steam generator.

b. Continuous blowdown of the steam generator to reduce the concentrating effects of the steam generator.

c. Chemical addition to establish and maintain an environment which minimizes system corrosion.

d. Preoperational cleaning of the feedwater system.

e. Minimizing feedwater oxygen content prior to entry into the steam generator.

Secondary water chemistry is based on the zero solids treatment method. This method employs the use of volatile additives to maintain system pH and to scavenge dissolved oxygen present in the feedwater.

A neutralizing amine is added to establish and maintain alkaline conditions in the feedtrain. Neutralizing amines which can be used for pH control are ammoniz, morpholine, and cyclohexylamine. Ammonia should be used in plants employing condensate polishing to avoid resin fouling. Although the amines are volatile and will not concentrate in the steam generator, they will reach an equilibrium level which will establish an alkaline condition in the steam generator.

Hydrazine is added to scavenge dissolved oxygen present in the feedwater. Hydrazine also tends to promote the formation of a protective oxide layer on metal surfaces by keeping these layers in a reduced chemical state.

Both the pH agent and hydrazine can be injected continuously at the discharge headers of the condensate pumps or condensate demineralizer, if installed. These chemicals are added as necessary for chemistry control, and can also be added to the upper steam generator feed line when necessary.

Operating chemistry limits for secondary steam generator water and feedwater
and condensate are give in Tables 10.3.4-1 and 10.3.4-2. 10

The limits stated are divided into two groups; normal and abnormal. The limits provide high quality chemistry control and yet permit operating flexibility. The normal chemistry conditions can be maintained by any plant operating with little or no condenser leakage. The abnormal steam generator limits are suggested to permit operations with minor system fault conditions until the affected component can be isolated and/or repaired.

The following procedures are recommended to the applicant:

When the normal range is exceeded, immediate investigation of the problem should be initiated, sampling frequency increased to the abnormal level (at least twice per 8 hour shift) and blowdown increased to one (1) percent of the main steaming rate. The problem should be corrected and the parameter(s)
returned to the normal range within one week. If this cannot be done, and 10
the parameter has a listed abnormal range, power should be reduced to 25% as if the abnormal range had been exceeded.

When the abnormal range is exceeded, power should be reduced to the lowest value (maximum of 25%) consistent with automatic operation of the feed system. Continued plant operation is then possible while corrective action is taken. Power reduction should be initiated within four hours of exceeding the abnormal range. The problem should be corrected and the parameter(s) returned to the normal range within one hundred (100) hours. If this cannot be done, the unit should be shutdown.

10

Draining or flushing of the steam generators will be necessary to reduce the impurity concentration. 5

10.3.4.2 Corrosion Control Effectiveness

Alkaline conditions in the feedtrain and the steam generator reduce general corrosion at elevated temperatures and tend to decrease the release of soluble corrosion products from metal surfaces. These conditions promote the formation of a protective metal oxide film and thus reduce the corrosion products released into the steam generator.

Hydrazine also promotes the formation of a metal oxide film by the reduction of ferric oxide to magnetite. Ferric oxide may be loosened from the metal surfaces and be transported by the feedwater. Magnetite, however, provides an adherent protective layer on carbon steel surfaces. Hydrazine also promotes the formation of protective metal oxide layers on copper surfaces.

The removal of oxygen from the secondary waters is also essential in reducing corrosion. Oxygen dissolved in water causes general corrosion that can result in pitting of ferrous metals, particularly carbon steel. Oxygen is removed from the steam cycle condensate in the main condenser deaerating section. Additional oxygen protection is obtained by chemical injection of hydrazine into the condensate stream. Maintaining a residual level of hydrazine in the feedwater ensures that any dissolved oxygen not removed by the main condenser is scavenged before it can enter the steam generator.

The presence of free hydroxide (OH^-) can cause rapid corrosion (caustic stress corrosion) if it is allowed to concentrate in a local area. Free hydroxide is avoided by maintaining proper pH control, and by minimizing impurity ingress in the steam generator.

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TABLE 10.3.4-1

OPERATING CHEMISTRY LIMITS FOR SECONDARY STEAM GENERATOR WATER

Variable	Normal Specifications (1)	Abnormal Limits	
pH (mixed system)(2)	8.5 - 9.2		
(copper free)	9.0 - 9.6		
Cation Conductivity(3)	< 0.8 μmhos/cm	0.8-2.0 μmhos/cm	10
Silica	< 300 ppb		
Chloride	< 20 ppb	20-100 ppb	
Sodium(4)	< 20 ppb	20-100 ppb	
Sulfate	< 15 ppb	15-100 ppb	

NOTES:

(1) Normal specifications are those which should be maintained by continuous steam generator blowdown during proper operation of secondary systems.

(2) Mixed system is any secondary system containing copper alloy components.

(3) If the immediate shutdown limit of 7.0 μmhos/cm is exceeded the unit should be shutdown within four hours. 10

(4) If the immediate shutdown limit of 500 ppb is exceeded the unit should be shutdown within four hours.

TABLE 10.3.4-2

OPERATING CHEMISTRY LIMITS FOR FEEDWATER AND CONDENSATE

Variable	Normal[1] Specifications	
pH		
a. Mixed system	8.8 - 9.2	
b. Copper-free system	9.3 - 9.6	
Conductivity (Intensified cation)(Feedwater)	< 0.2 µmhos/cm	
Hydrazine (Feedwater)	10 - 50 ppb	10
Dissolved Oxygen		
(Feed)	< 3 ppb	
(Condensate)	< 10 ppb[2]	
Sodium[3]	< 3 ppb	
Copper (Feedwater)	< 2 ppb[4]	
Iron (Feedwater)	< 20 ppb	
pH Control Additive	(5)	

NOTES:

(1) Normal specifications are those which should be maintained during proper operation of secondary systems.

(2) The condensate abnormal limit is 10-30 ppb but the requirement for immediate shutdown does not apply even if the problem is not corrected within 100 hrs.

(3) For the condensate, sodium is monitored at each condenser hot well. 10

(4) Analysis not required for copper free systems.

(5) Limit is dependent upon pH.

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10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSERS

See Applicant's SAR.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

See Applicant's SAR.

10.4.3 TURBINE GLAND SEALING SYSTEM

See Applicant's SAR.

10.4.4 TURBINE BYPASS SYSTEM

10.4.4.1 Design Bases

The turbine bypass system has no safety functions. The turbine bypass system, operating in conjunction with the reactor power cutback system (Section 7.7.1.1.6), is designed to accomplish the following functions:

a. Accommodate load rejections of any magnitude without tripping the reactor or lifting primary or secondary safety valves.

b. Control NSSS thermal conditions to prevent the opening of safety valves following a unit trip.

c. Maintain the NSSS at hot zero power conditions.

d. Control NSSS thermal conditions when it is desirable to have reactor power greater than turbine power, e.g., during turbine synchronization.

e. Provide pressure limiting control during the loss of one out of two feedwater pumps.

f. Provide a CEA Automatic Motion Inhibit (AMI) signal when turbine power and reactor power fall below selected thresh-holds; provide AMI signal below 15 percent reactor power to block automatic control of the reactor below this power level.

g. Provide a means for manual control of Reactor Coolant System (RCS) temperature during NSSS heatup or cooldown.

h. Provide for operation of the turbine bypass valves in a manner that minimizes valve wear and maintains controllability.

i. Provide for operation of the turbine bypass valves in a sequence which, by proper applicant arrangement of valving to the condenser, limits the flow imbalance between condenser shells to the flow capacity of 1 valve when all turbine bypass valves and condenser shells are available.

j. Include redundancy in the design so that neither a single component failure nor a single operator error result in excess steam releases.

k. Provide a condenser interlock which will block turbine bypass flow when unit condenser pressure exceeds a preset limit.

The environmental design criteria are listed in the Applicant's SAR.

10.4.4.2 System Description and Operation

10.4.4.2.1 General Description

The turbine bypass system consists of the steam bypass control system, the turbine bypass valves and associated piping and instrumentation. The steam bypass control system is described in Section 7.7.1.1.5.

10.4.4.2.2 Piping and Instrumentation

A typical turbine bypass system consisting of eight turbine bypass valves located in lines branching from each main steam line, down stream of the main steam isolation valves and connecting to the main condenser is shown in Figure 10.3.4-1.

10.4.4.2.3 Turbine Bypass Valves

The turbine bypass valves are air operated valves with a combined capacity of 55% of the total full power steam flow at normal full power steam generator pressure (1070 psia). The valves are normally controlled by the steam bypass control system but are capable of remote or local manual operation.
When operating automatically the valves modulate full open or full close in | 10
a minimum of 15 seconds and a maximum of 20 seconds. In response to a quick opening signal from the steam bypass control system they are designed to open in 1 second. In response to a closing signal from the steam bypass control system they are designed to close in 5 seconds. The system is capable of controlling at flows as low as 63,000 lb/hr in order to permit operation at hot standby during precore hot functional testing.

10.4.4.2.4 System Operation

The turbine bypass system takes steam from the main steam lines upstream of the turbine stop valves and discharges it directly to the main condenser, bypassing the turbine-generator. During normal operation, the bypass valves are under the control of the steam bypass control system, as discussed in Section 7.7.1.1.5. During cooldown or hot shutdown, the turbine bypass valves may be actuated individually from the main control room to regulate steam generator pressure and reactor coolant temperature change.

10.4.4.3 Safety Evaluation

The valves in the turbine bypass system are designed to fail closed to prevent uncontrolled bypass of steam to the condenser. Should the bypass valves fail to open on command, the secondary safety valves provide main

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e.) Personnel qualified in accordance with ANSI N45.2.6 - 1978 that do not meet the requirements of education and experience for the Level for which certification is desired shall have documented objective evidence demonstrating comparable competence to that which would be gained from having the required education and experience.

ANSI N45.2.6 - 1978, Paragraph 3, Qualification, is interpreted such that: experience in the operation and testing of nuclear power reactors is acceptable 6
in lieu of the stated experience in quality assurance on a one-for-one basis.

Site personnel may call on the services of technically qualified individuals to assist them in the performance of duties necessary to certify them to a specific Level of ANSI N45.2.6 - 1978.

14.2.3 TEST PROCEDURES

Detailed procedures for the testing of the facility will be prepared by the Applicant or his representative. Appropriate guidelines prepared by CE and others will be utilized in preparing the detailed procedures.

14.2.4 CONDUCT OF INITIAL TEST PROGRAM

Ultimate responsibility for the execution of the testing program rests with the Applicant. Administrative controls will be developed by the Applicant to govern each phase of the program. The entire test program will be conducted by the Applicant or his designated representative with advice and consultation from Combustion Engineering as requested. Combustion Engineering shall participate in the approval process of the NSSS related procedures and shall review any proposed changes to appproved NSSS test procedure.

14.2.5 REVIEW, EVALUATION, AND APPROVAL OF TEST RESULTS

The development of administrative procedures for review, evaluation and approval of test results is the responsibility of the Applicant. Advice and consultation will be provided by Combustion Engineering as appropriate.

Test results shall be recorded as permanent plant records.

14.2.6 TEST RECORDS

An official copy of each completed test procedure, including all required supplemental data, exceptions, conclusions and approval signatures shall be maintained in accordance with the Applicant's administrative controls.

14.2.7 CONFORMANCE OF INITIAL TEST PROGRAMS WITH REGULATORY GUIDES AND INDUSTRY STANDARDS

The intent of the following Regulatory Guides will be followed with the noted differences.

14.2.7.1 Reg. Guide 1.68 Initial Test Programs for Water-Cooled Reactor Power Plants (Revision 0, 11/73).

The following exceptions and/or clarifications address only significant
differences between the System 80 test program and the applicable regulatory 6
position. Minor terminology differences, testing not applicable to the plant design, and testing that is part of required surveillance tests will not be addressed. Reference is made to the applicable portion of Regulatory Guide 1.68 (Revision 0, 11/73).

14.2.7.1.1 Reference Appendix A, Section B.1.c. 9

This section suggests that rod drop times be measured for all control element assemblies (CEAs) at hot and cold full-flow and no-flow conditions.

The CESSAR CEA drop-time testing is consistent with the recommendations of 6
the regulatory guide; however, tests which do not provide meaningful data will be deleted. As outlined in test summary 14.2.12.3.4, the CEA drop-time testing will consist of:

a.) One drop of each CEA at hot, full-flow conditions. 10

b.) Those CEAs falling outside the two-sigma limit for similar CEAs will 6
be dropped three additional times.

c.) Hot no flow scram insertion rod drops will not be performed for System 80
reactors. C-E has demonstrated that rod drop times under full-flow 9
conditions are more limiting than the drop times under conditions of no-flow.

d.) The CEA drop time test at 260°F plateau was eliminated since the hot, fullflow conditions are more bounding and since criticality is not allowed below 500°F except for a short period of time during low power physics testing.

14.2.10 INITIAL FUEL LOADING AND INITIAL CRITICALITY

14.2.10.1 Initial Fuel Loading

Overall direction, coordination, and control of the initial fuel loading evolution will be the responsibility of the Plant Manager-Nuclear. The Unit Coordinator-Startup Operational Test will direct and coordinate the preparation of, and assist in the performance of, the initial fuel loading procedures as part of Phase III of the test program. However, it is intended that qualified plant personnel will actually execute the procedures. Combustion Engineering will provide technical assistance during the initial fuel loading evolution.

The fuel loading evolution will be controlled by use of approved plant procedures which will be used to establish plant conditions, control access, establish security, control maintenance activities, and provide instructions pertaining to the use of fuel handling equipment. The overall process of initial fuel loading will be directed from the main control room. The evolution itself will be supervised by a licensed Senior Reactor Operator.

In the unlikely event that mechanical damage to a fuel assembly is sustained during fuel loading operations, an alternate core loading scheme, whose characteristics closely approximate those of the initially prescribed core configuration, will be determined and approved by plant operations review committee prior to implementation. 6

The fuel assemblies will be installed in the reactor vessel in water containing dissolved boric acid in a quantity calculated to maintain a core effective multiplication constant at 0.95, which is a boron concentration of approximately 2150 ppm. It is not anticipated that the refueling cavity will be completely filled; however, the water level in the reactor vessel will be maintained above the installed fuel assemblies at all times.

The Shutdown Cooling System will be in service to provide coolant circulation to ensure adequate mixing and a means of controlling water temperature. The refueling water storage pool will be in service and will contain borated water at a volume and concentration conforming to the Technical Specifications. Applicable administrative controls will be used to prevent unauthorized alteration of system lineups or change to the boron concentration in the Reactor Coolant System.

Minimum instrumentation for fuel loading will consist of two temporary source range channels installed in the reactor vessel or one temporary channel and one permanently installed excore nuclear channel in the event that one of the temporary channels becomes inoperative. Both temporary and permanent channels will be response checked with a neutron source. The temporary channels will display neutron count rate on a count rate meter installed in the containment and will be monitored by personnel conducting the fuel loading operation. The permanent channel will display neutron count rate on a meter and strip chart recorder located in the main control room and will be monitored by licensed operators. In addition, at least

one temporary channel and one permanent channel will be equipped with audible count rate indicators in two locations, temporary in the containment and permanent in the main control room. 6 10

Continuous area radiation monitoring will be provided during fuel handling and fuel loading operations. Permanently installed radiation monitors display radiation levels in the main control room and will be monitored by licensed operators.

Fuel assemblies, together with inserted components, will be placed in the reactor vessel one at a time according to a previously established and approved sequence which was developed to provide reliable core monitoring with minimum possibility of core mechanical damage. The initial fuel loading procedure will include detailed instructions which will prescribe successive movements of each fuel assembly from its initial position in the storage racks to its final position in the core. The procedures will establish a system and a requirement for verification of each fuel assembly movement prior to proceeding with the next assembly. Multiple checks will be made for fuel assembly and inserted component serial numbers at successive transfer points to guard against possible inadvertent exchanges or substitutions.

At least two fuel assemblies containing neutron sources will be placed into the core at appropriate specified points in the initial fuel loading procedure to ensure a neutron population large enough for adequate monitoring of the core. As each fuel assembly is loaded, at least two separate inverse count rate plots will be maintained to ensure that the extrapolated inverse count rate ratio behaves as would be expected. In addition, nuclear instrumentation 6
will be monitored to ensure that the "just loaded" fuel assembly does not excessively increase the count rate. The results of each loading step will be reviewed and evaluated before the next prescribed step is started.

14.2.10.1.1 Safe Loading Criteria

Criteria for the safe loading of fuel require that loading operations stop immediately if:

a.) The neutron count rate from either temporary nuclear channel unexpectedly doubles during any single loading step, excluding anticipated change due to detector and/or source movement or spatial effects (i.e., fuel) assembly coupling source with a detector), or

b.) The neutron count rate on any individual nuclear channel increases by a factor of five during any single loading step, excluding anticipated changes due to detector and/or source movement or spatial effects (i.e., fuel assembly coupling source with a detector).

2.0 PREREQUISITES

2.1 Pressurizer pressure and level control system instrumentation has been calibrated.

2.2 Support systems required for the operation of the pressurizer pressure and level control systems are operational.

2.3 Test equipment is available and calibrated.

3.0 TEST METHOD

3.1 Simulate a decreasing pressurizer pressure and observe heater response and alarm and interlock setpoints. 6

3.2 Simulate an increasing pressurizer pressure and observe heater and spray valve response and alarm and interlock setpoints. 6

3.3 Simulate a low level error in the pressurizer and observe proper charging pump response and alarm and interlock setpoints. 6

3.4 Simulate a high level error in the pressurizer and observe proper charging pump response and alarm and interlock setpoints. 6

3.5 Simulate a low pressurizer level and observe operation of the letdown control valves. 6 10

3.6 Simulate a low-low pressurizer level and observe heater response and alarm and interlock setpoints.

4.0 DATA REQUIRED

4.1 Response of pressurizer heaters to simulated pressure and level signals. 6

4.2 Response of spray valves to simulated pressurizer pressure. 6

4.3 Response of charging pumps to simulated pressurizer level. 6

4.4 Response of letdown control valves to simulated pressurizer level. 10

4.5 Response of letdown control valves to simulated low pressurizer level. 10

4.6 Values of parameters at which alarms and interlocks occur. 6

5.0 ACCEPTANCE CRITERIA

5.1 The pressurizer performs as described in Sections 7.7.1 and 5.4.10. 6

14.2.12.2.6 Precore Control Element Drive Mechanism Performance

1.0 OBJECTIVE

1.1 To determine the effectiveness of the CEDM cooling system by measurement of coil resistance at several temperature plateaus during RCS heatup.

1.2 To determine the operating temperature of the upper gripper coils.

1.3 To verify proper operation and sequencing of the CEDM armatures.

2.0 PREREQUISITES

2.1 CEDM coil stacks are assembled and associated cabling is connected.

2.2 Cabling between the reactor bulkhead and the CEDM Control System is disconnected.

2.3 CEDM "cold" coil resistance has been measured and recorded.

2.4 Individual CEDM cable resistance has been measured and recorded.

2.5 CEDM cooling system is operational.

2.6 Test equipment is available and calibrated.

2.7 Support systems required for operation of the CEDM are operational.

14.2.12.3 Postcore Hot Functional Tests

14.2.12.3.1 Postcore Hot Functional Test Controlling Document

1.0 OBJECTIVE

To demonstrate the proper integrated operation of plant primary, secondary, and auxiliary systems with fuel loaded in the core.

2.0 PREREQUISITES

2.1 All precore hot functional testing has been completed as required. 10

2.2 Fuel loading has been completed.

2.3 All permanently installed instrumentation on systems to be tested is available and calibrated in accordance with technical specifications 10
and test procedures.

2.4 All necessary test instrumentation is available and calibrated in 10
accordance with technical specifications and test procedures.

2.5 All cabling between the CEDM's and the CEDM control system is connected.

2.6 Steam generators are in wet layup in accordance with the NSSS chemistry manual.

2.7 RCS has been borated to the proper concentration.

3.0 TEST METHOD

3.1 Specify plant conditions and coordinate the execution of the related postcore hot functional test appendices.

4.0 DATA REQUIRED

4.1 As specified by the individual postcore hot functional test appendices.

5.0 ACCEPTANCE CRITERIA

5.1 Integrated operation of the primary, secondary, and related auxiliary systems is in accordance with the CESSAR descriptions. 6

5.2 As specified by the individual postcore hot functional test appendices.

14.2.12.3.2 Postcore Instrument Correlation

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the PPS, CPC and Plant Monitoring System. 6

2.0 PREREQUISITES

2.1 Core Protection Calculators (CPCs) are in operation.

2.2 Plant monitoring system and COLSS program are in operation.

2.3 Permanently installed control room instrumentation for the CPCS, COLSS, PPS and PMS systems have been calibrated and is in operation. 6

3.0 TEST METHOD

3.1 When specified, obtain PPS, CPC, and Plant Monitoring System readouts.

3.2 Obtain control room instrument readings.

4.0 DATA REQUIRED

4.1 Plant Monitoring System readout.

4.2 PPS and CPC data.

4.3 Control room instrument readings.

5.0 ACCEPTANCE CRITERIA

5.1 The PMS, PPS and CPC systems perform as described in Section 7.7.1.3. 6

14.2.12.3.3 Postcore Reactor Coolant System Flow Measurements

1.0 OBJECTIVE

1.1 To determine the postcore RCS flow rate and flow coastdown characteristics.

1.2 To establish reference postcore RCS pressure drops.

1.3 To make adjustments to the flow related constants of the CPCs as required.

1.4 To collect data on the operation of the flow related portions of the COLSS and the CPCs for steady state and transient conditions.

2.0 PREREQUISITES

2.1 Construction activities completed.

2.2 All permanently installed instrumentation is properly calibrated and operational.

2.3 All test instrumentation is available and properly calibrated.

2.4 RCS operating at nominal hot, zero power conditions.

2.5 Required reactor coolant pumps are operational. 6

2.6 COLSS and CPCs are in operation.

3.0 TEST METHOD

3.1 RCS flow is measured for all operationally allowed reactor coolant pump combinations and the necessary data to calculate RCS flow is collected. 6

3.2 RCS flow coastdown measurements are performed by tripping the allowable reactor coolant pump(s) for collection of coastdown data. 6

3.3 CPCs and COLSS flow related data is verified by comparison with measured flows.

4.0 DATA REQUIRED

4.1 COLSS and CPCs flow related data.

4.2 Peactor coolant pump differential pressure and speed.

4.3 Reactor vessel differential pressure.

4.4 RCS temperature and pressure.

4.5 Pump configuration.

4.6 Coastdown time.

5.0 ACCEPTANCE CRITERIA

5.1 Measured RCS flow exceeds the flowrates used in the safety analysis in Chapter 15.

5.2 Measured RCS flow coastdown is conservative with respect to the coastdown used in the safety analysis. 6

5.3 CPC and COLSS flow algorithms are adjusted to be conservative with respect to the measured flows and for those portions of the coastdowns which occur prior to CPC initiation of a trip.

14.2.12.3.4 Postcore Control Element Drive Mechanism Performance

1.0 OBJECTIVE

1.1 To demonstrate the proper operation of the CEDM's and CEA's under HOT SHUTDOWN and Hot, Zero Power conditions.

1.2 To verify proper operation of the CEA position indicating system and alarms.

1.3 To measure CEA drop times.

2.0 PREREQUISITES

2.1 The CEDMCS precore performance test has been completed.

2.2 All test instrumentation is available and calibrated.

2.3 Plant Monitoring System is operational.

2.4 The CEDM cooling system is operational.

2.5 CEDM coil resistances have been measured.

3.0 TEST METHOD

3.1 Perform the following at HOT SHUTDOWN conditions:

3.1.1 Withdraw and insert each CEA to verify proper operation of CEDM. 10

3.2 Perform the following at hot, zero power conditions:

3.2.1 Withdraw and insert each CEA to verify proper operation of CEDM. 10

3.2.2 Measure and record drop time for each CEA.

3.2.3 Perform three measurements of drop time for each of those CEA's falling outside the two-sigma limit for similar CEA's. 6

3.3 Perform the following at any time:

3.3.1 Withdraw and insert each CEA while recording position indications and alarms. 10

4.0 DATA REQUIRED

4.1 CEA drop time.

4.2 RCS temperature and pressure to be taken during measurement and recording of drop time for each CEA. 10

4.3 CEA position and alarm indications.

5.2 The movable incore detector system is demonstrated capable of accessing the various core locations.

5.3 Accessible core path lengths have been measured.

14.2.12.4 <u>Low Power Physics Tests</u>

14.2.12.4.1 Low Power Biological Shield Survey Test* 6

1.0 <u>OBJECTIVE</u>

1.1 To measure radiation in accessible locations of the plant outside of the biological shield.

1.2 To obtain base line levels for comparison with future measurements of level buildup with operation.

2.0 <u>PREREQUISITES</u>

2.1 Radiation survey instruments calibrated.

2.2 Background radiation levels measured in designation locations prior to initial criticality.

3.0 <u>TEST METHOD</u>

3.1 Measure gamma and neutron dose rates during low power physics tests.

4.0 <u>DATA REQUIRED</u>

4.1 Power level.

4.2 Gamma and neutron dose rates at each specified location.

5.0 <u>ACCEPTANCE CRITERIA</u>

5.1 Radiation levels have been demonstrated to be comparable to those measured in previous C-E plants. 6

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*The Low Power Biological Shielding Survey Test for "First-of-a-Kind" plants will be performed at both 320°F and 565°F plateaus. The 320°F measurement will not be performed for "Follow-in-Plants", since they will not be critical. 6

Amendment No. 6

November 20, 1981

14.2.12.4.2 CEA Symmetry Test 10

1.0 OBJECTIVE

1.1 To demonstrate that no loading or fabrication errors that result in measurable CEA worth asymmetries have occurred.

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Amendment No. 10
June 28, 1985

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2.0 PREREQUISITES

2.1 The reactivity computer is in operation.

2.2 The reactor is critical at the desired conditions with the controlling CEA group partially inserted and in manual control.

3.0 TEST METHOD

3.1 CEA Symmetry Test (hot, zero power conditions - 565°F, 2250 psia) 10

3.1.1 The first CEA of a symmetric group is fully inserted with all remaining CEAs withdrawn except the controlling group, which is positioned for zero reactivity. 10

3.1.2 The inserted CEA is withdrawn while another CEA in the symmetric group is inserted and the differences in worth (net reactivity) of the CEAs is determined from the reactivity computer. 10

3.1.3 The remainder of the CEAs in the symmetric group are sequentially 10
swapped until the relative worths of each CEA in the symmetric group has been determined. 6

3.1.4 Repeat steps 3.1.1 - 3.1.3 for the remainder of the groups. 10

4.0 DATA REQUIRED

4.1 Conditions of the measurement.

4.1.1 RCS temperature.

4.1.2 Pressurizer pressure.

4.1.3 Boron concentration.

4.2 Time dependent data.

4.2.1 CEA position.

4.2.2 Reactivity computer traces.

5.0 ACCEPTANCE CRITERIA

5.1 The relative worth of symmetric CEAs are within the acceptance criteria specified in Table 14.2-7. 6

10

14.2.12.4.3 Isothermal Temperature Coefficient Test

1.0 OBJECTIVE

1.1 To measure the isothermal temperature coefficients (ITCs) for various RCS temperatures, pressures, and CEA configurations.*

1.2 To determine the moderator temperature coefficient (MTC) from the measured ITC.

2.0 PREREQUISITES

2.1 The reactor is critical with a stable boron concentration and the desired CEA configuration and RCS temperature and pressure.

2.2 The reactivity computer is operable.

3.0 TEST METHOD

3.1 Changes in RCS temperature are introduced and the resultant changes in reactivity measured.

3.2 Reactivity and power swings are limited by compensation with CEA motion when necessary.

4.0 DATA REQUIRED

4.1 Conditions of the measurement.

4.1.1 Pressurizer pressure.

4.1.2 CEA configuration.

4.1.3 Boron concentration.

4.2 Time dependent information.

4.2.1 Reactivity variation (strip chart).

4.2.2 CEA position.

4.2.3 Temperature variations.

5.0 ACCEPTANCE CRITERIA

5.1 The measured ITCs agree with the predicted values within the acceptance criteria specified in Table 14.2-7.

5.2 The moderator temperature coefficients (MTC) derived from the measured ITC are in compliance with the Technical Specifications. 6

*For "follow-on" units, this test will be performed only at 565°F, 2250 psia.

14.2.12.4.4 Shutdown and Regulating CEA Group Worth Test 6

1.0 OBJECTIVE

1.1 To determine regulating and shutdown CEA group worths necessary to 10
demonstrate shutdown margin (i.e., worth of all CEA's less the 6
highest worth CEA).

1.2 To demonstrate that the shutdown margin is adequate.

2.0 PREREQUISITES

2.1 The reactor is critical.

2.2 The reactivity computer is operating.

3.0 TEST METHOD

3.1 A 320°F measurement of regulating and shutdown CEA groups down to the net shutdown configuration (for "first-of-a-kind" plant only). 10

3.1.1 The CEA group worths will be measured by dilution/boration of the RCS.

3.2 Hot, zero power measurement of regulating CEA groups.* 10

3.2.1 The CEA group worths will be measured by dilution/boration of the RCS.

3.2.2 Where dilution/boration is not feasible, worths may be determined by CEA drop and/or by use of alternate CEA configurations.

4.0 DATA REQUIRED

4.1 Conditions of the measurement.

4.1.1 RCS temperature.

4.1.2 Pressurizer pressure.

4.1.3 CEA configuration.

4.1.4 Boron concentration.

4.2 Time dependant information.

4.2.1 Reactivity variation (strip chart).

4.2.2 CEA positions.

* On "follow-on" units the net shutdown measurement is made at 565°F. 10

6

14.2.12.4.7 Pseudo Dropped and Ejected CEA Worth Test*

1.0 OBJECTIVE

1.1 To measure the worth of the "dropped" CEA.

1.2 To measure the worth of the "ejected" CEA from the zero power dependent insertion limit (ZPDIL).

2.0 PREREQUISITES

2.1 Reactor critical at hot, zero power conditions with appropriate CEA configurations.

2.2 The reactivity computer is in operation.

3.0 TEST METHOD

3.1 Pseudo worst "dropped" CEA measurement

3.1.1 The pseudo worst and next worst "dropped" CEA worths are established on the basis of predictions and verified during the symmetry check.

3.1.2 The worths of the worst and next worst dropped CEAs are then measured by dilution/boration and/or CEA compensation. 10

3.2 Pseudo worst "dropped" PLCEA and worst "dropped" PLCEA subgroup measurement.

3.2.1 The pseudo worst "dropped" PLCEA and worst "dropped" PLCEA subgroups are established by prediction. 6

3.2.2 The worths of the worst single PLCEA and PLCEA subgroup are measured by boron dilution/boration and/or CEA compensation.

3.3 Pseudo worst "ejected" CEA measurement

3.3.1 The worth of the pseudo worst "ejected" CEA is established by means of a prediction.

3.3.2 The worths of the worst and next worst "ejected" CEAs are measured by boration/dilution and/or CEA compensation from the ZPIL CEA configuration. 10

4.0 DATA REQUIRED

4.1 Conditions of the measurement

4.1.1 RCS temperature

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

4.1.2 Pressurizer pressure.

4.1.3 CEA configuration.

4.1.4 Boron concentration.

4.2 Time dependent information.

4.2.1 Reactivity variation (strip chart).

4.2.2 CEA position.

5.0 ACCEPTANCE CRITERIA

5.1 The measured worths agree with the predicted worths within the acceptance criteria specified in Table 14.2-7. 6

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November 20, 1981

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 6
the C-E Fuel Pre-conditioning Guidelines and as allowed by the RRS
will be performed at power levels in the 75 to 95% range and in the 10
25 to 50% power range.

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.

4.1.7 Feedwater temperature. 9

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 6
data has been taken that will demonstrate the plant's ability to
meet unit load swing design transients.

5.2 That no audible noise or significant vibration is observed in the 9
economizer or in the rest of the Feedwater and Emergency Feedwater
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 steady state and 10
transient conditions 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.

4.1.7 Feedwater temperature. 10

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 steady state operation and are capable of returning these parameters to within their control bands in response to transient operation. 10

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.

4.0 DATA REQUIRED

4.1 Conditions of the measurement.

4.1.1 Power.

4.1.2 RCS temperature.

4.1.3 Boron concentration.

4.1.4 Core average burnup.

4.2 Samples for measurement of gross activities and/or isotopic activities.

5.0 ACCEPTANCE CRITERIA

5.1 Measured activity levels are within their limits.

5.2 The process radiation monitors agree with the laboratory analyses within measurement uncertainties. 6

5.3 Procedures for sample collection and analysis are verified.

14.2.12.5.6 Turbine Trip Test

1.0 OBJECTIVE

1.1 To demonstrate that the plant responds and is controlled as designed following a 100% turbine trip without RPCS in service.

2.0 PREREQUISITES

2.1 The reactor is operating above 95% power. 6

2.2 The SBCS, FWCS, RRS, and pressurizer pressure and level control systems are in automatic operation. 10

2.3 The RPCS is in Auto Actuate Out of Service. 10

3.0 TEST METHOD

3.1 The turbine is tripped.

3.2 The plant behavior is monitored to assure that the RRS, SBCS, FWCS, and pressurizer pressure and level control systems maintain the NSSS within operating limits. 10

4.0 DATA REQUIRED

4.1 Power level prior to trip.

4.2 The following acceptance criteria parameters are monitored prior to and throughout the transient. 10

4.2.1 Pressurizer pressure, and level.

4.2.2 RCS Hot Leg temperatures.

4.2.3 SG pressures. 10

4.3 Additional key plant parameters will be monitored for base line data.

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5.0 ACCEPTANCE CRITERIA

5.1 The test will be evaluated against single valued acceptance limits 6
for those safety parameters which approach a safety limit. 10

14.2.12.5.7 Unit Load Rejection Test

1.0 OBJECTIVE

1.1 To demonstrate that the plant responds and is controlled as designed following a 100% load rejection with RPCS in service. 10

2.0 PREREQUISITES

2.1 The reactor is operating above 95% power. 6

2.2 The SBCS, FWCS, RRS, CEDMCS, RPCS, and pressurizer pressure and level 10
control are in automatic operation.

3.0 TEST METHOD

3.1 A breaker(s) is tripped so as to subject the turbine to the 6
maximum credible overspeed condition.

3.2 The plant behavior is monitored to assure that the RRS, CEDMCS, SBCS,
RPCS, FWCS, and pressurizer pressure and level control systems 10
maintain the monitored parameters. 6

4.0 DATA REQUIRED

4.1 Plant condition prior to trip. 6

4.2 The following acceptance criteria parameters are monitored prior to and throughout the transient.

4.2.1 Pressurizer pressure, and level.

4.2.2 RCS Hot Leg temperatures. 10

4.2.3 SG pressures.

4.3 Additional key plant parameters will be monitored for baseline data.

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5.0 ACCEPTANCE CRITERIA

5.1 The test will be evaluated against single valued acceptance limits for those safety parameters which approach a safety limit. 6 10

14.2.12.5.8 Shutdown from Outside the Control Room Test

1.0 OBJECTIVE

1.1 To demonstrate that the plant can be maintained in HOT STANDBY from outside the control room following a reactor trip.

2.0 PREREQUISITES

2.1 The reactor is operating at $\geq$ 10% of rated power.

2.2 The capability to cooldown on the shutdown cooling systems has been demonstrated during pre and post core hot functional tests.

2.3 The remote shutdown panel instrumentation is operating properly.

2.4 The communication systems between the control room and remote shutdown location has been demonstrated to be operational. 6

2.5 The remote shutdown instrumentation controls and systems have been preoperationally tested.

3.0 TEST METHOD

3.1 The operating crew evacuates the control room (standby crew remains in the control room).

3.2 The reactor is tripped from outside the control room. 6

3.3 The reactor is brought to HOT STANDBY by the operating crew from outside the control room and is maintained in this condition for at least 30 minutes.

4.0 DATA REQUIRED

4.1 Time dependent data.

4.1.1 Pressurizer level and pressure.

4.1.2 RCS temperatures.

4.1.3 Steam generator pressure and level.

5.0 ACCEPTANCE CRITERIA

5.1 The ability to achieve and control the reactor at HOT STANDBY from outside the control room is demonstrated.

2.2 Results of the radiation surveys performed at zero power conditions are available.

3.0 TEST METHOD

3.1 Measure gamma and neutron dose rates at 20, 50, 80 and 100% power levels. 6

4.0 DATA REQUIRED

4.1 Power level.

4.2 Gamma dose rates in the accessible locations.

4.3 Neutron dose rates in the accessible locations. 6

5.0 ACCEPTANCE CRITERIA

5.1 Accessible areas and occupancy times during power operation have been defined. 6

14.2.12.5.11 Xenon Oscillation Control (PLCEA) Test*

1.0 OBJECTIVE

1.1 To demonstrate a technique for damping xenon oscillations. 6

2.0 PREREQUISITES

2.1 The reactor is greater than or equal to 50% power.

2.2 The COLSS and the incore detector system are in operation. 10

3.0 TEST METHOD

3.1 A free oscillation is established.

3.2 The PLCEA's/or CEA's are used to dampen the oscillation. 6

4.0 DATA REQUIRED

4.1 Reactor conditions.

4.1.1 Power level.

4.1.2 Boron concentration.

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

4.1.3 RCS temperatures.

4.1.4 Burnup.

4.1.5 CEA position.

4.2 Time dependent data.

4.2.1 Incore detector maps.

4.2.2 Excore detector information.

4.2.3 PLCEA's and CEA position. 6

5.0 <u>ACCEPTANCE CRITERIA</u>

5.1 The technique necessary to damp xenon oscillations using the PLCEAs and/or CEA's has been demonstrated. 10

14.2.12.5.12 "Ejected" CEA Test*

1.0 <u>OBJECTIVE</u>

1.1 To determine the power distribution associated with the pseudo CEA ejection from the full power dependent insertion limit (FPDIL) CEA configuration. 6

2.0 <u>PREREQUISITES</u>

2.1 Testing at 80% power has been completed.

2.2 The reactor is at approximately 50% power with equilibrium conditions and with the CEAs at the FPDIL.

2.3 The incore detector system is in operation.

3.0 <u>TEST METHOD</u>

3.1 The "worst" case CEA (selected by calculation) is fully withdrawn.

3.2 Incore detector maps are taken before and after withdrawal of the static "ejected" CEA.

3.3 The next worst "ejected" CEA is withdrawn while inserting the previous CEA.

3.4 An incore detector map is taken.

3.5 The CEAs are returned to normal configuration.

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

4.0 DATA REQUIRED

4.1 Conditions of the measurement.

4.1.1 Boron concentration.

4.1.2 Burnup.

4.2 Time dependent data.

4.2.1 Power.

4.2.2 Incore and excore detector readings.

4.2.3 RCS temperature.

4.2.4 CEA position.

5.0 ACCEPTANCE CRITERIA

5.1 The difference between the measured and predicted ratios of the post-ejected CEA to pre-ejected CEA power distributions are within the acceptance band specified in Table 14.2-7. 10

14.2.12.5.13 Dropped CEA Test*

1.0 OBJECTIVE

1.1 To determine the power distribution resulting from a "dropped" CEA.

2.0 PREREQUISITES

2.1 Testing at 80% power has been completed.

2.2 The reactor is at approximately 50% power with equilibrium conditions for the desired CEA configuration.

2.3 The incore detector system is in operation.

3.0 TEST METHOD

3.1 A full length CEA is selected, based on calculations, which will best verify the dropped rod assumptions used in the safety analyses. 6

3.1.1 The selected CEA is rapidly inserted to the full-in position. 10

3.1.2 The CEA remains inserted for a preselected time.

3.1.3 Excore and incore instrument signals are recorded before and after the CEA insertion.

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

3.2 PLCEA

3.2.1 The PLCEA, selected as prescribed in 3.1.1, is rapidly inserted to the full-in position. 6

3.2.2 The PLCEA remains inserted for a preselected time.

3.2.3 Excore and incore instrument signals are recored before and after the CEA insertion.

4.0 <u>DATA REQUIRED</u>

4.1 Conditions of the measurement.

4.1.1 Boron concentration.

4.1.2 Burnup.

4.2 Time dependent data.

4.2.1 Power.

4.2.2 Incore and excore detector readings.

4.2.3 RCS temperatures.

4.2.4 CEA position.

5.0 <u>ACCEPTANCE CRITERIA</u>

5.1 The difference between the measured and predicted ratios of the post-dropped CEA to pre-dropped CEA power distributions are within the acceptance band specified in Table 14.2-7. 10

14.2.12.5.14 Steady State Core Performance Test

1.0 <u>OBJECTIVE</u>

1.1 To determine core power distributions using incore instrumentation. 10

2.0 <u>PREREQUISITES</u>

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

2.2 The incore instrumentation system is in operation.

3.0 TEST METHOD

3.1 Selected plant computer outputs and CPC outputs are recorded. 10

3.2 Reactor power is determined by performing a heat balance.

3.3 The core power distribution is obtained using the incore detectors.

4.0 DATA REQUIRED

4.1 Conditions of the test.

4.1.1 Reactor power.

4.1.2 CEA positions.

4.1.3 Boron concentration.

4.1.4 Core average burnup.

4.1.5 Selected plant computer outputs and CPC outputs.

4.1.6 Incore detector maps. 10

5.0 ACCEPTANCE CRITERIA

5.1 Agreement between the predicted and measured power distributions and core peaking factors are within the acceptance criteria specified in Table 14.2-7. 10

14.2.12.5.15 Intercomparison of PPS, Core Protection Calculator (CPC), and PMS Inputs

1.0 OBJECTIVE

1.1 To verify that process variable inputs/outputs of the PPS, the CPCs, the PMS, and the console instruments are consistent. 6

2.0 PREREQUISITES

2.1 The plant is operating at the desired conditions.

2.2 All CPCs and CEACs, and the PMS are operable.

3.0 TEST METHOD

3.1 Process variable inputs/outputs of the PPS, the CPCs, the PMS, and console instruments are read as near simultaneously as practical. | 6

4.0 DATA REQUIRED

4.1 Conditions of the measurement.

4.1.1 Power.

4.1.2 Boron concentration.

4.1.3 RCS temperatures.

4.1.4 Pressurizer pressure and level.

4.1.5 Steam generator pressures and levels.

4.1.6 RCP speeds and differential pressures.

5.0 ACCEPTANCE CRITERIA

5.1 The process variable inputs/outputs from the PPS, the CPCs, the PMS, and the console instruments are within the uncertainties assumed for them in the CPC, PPS and the PMS. | 6

14.2.12.5.16 Verification of CPC Power Distribution Related Constants Test

1.0 OBJECTIVE

1.1 To verify the planar radial peaking, temperature annealing, and CEA shadowing factors, and the shape annealing matrix and boundary point power correlation constants, and to verify the algorithms used in the CPCs to relate excore signals to incore power distribution.

2.0 PREREQUISITES

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

2.2 The incore detector system is in operation.

2.3 The safety channels have been properly calibrated.

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 shadowing factors are verified by comparing core power and excore detector responses for various RCS temperatures. 10

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 shadowing factors used in the CPCs agree within the acceptance criteria specified in the CPC test requirements.** 10 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

**As specified in the appropriate revisions or supplements of CEN-235(V). 10

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

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. Specifically, the downcomer to economizer transfer will be monitored for noise or vibration due to Water Hammer. 9

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

4.1.6 Feedwater temperature 9

4.1.7 CEA Position

5.0 ACCEPTANCE CRITERIA

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

5.2 No effects due to water hammer are detected. Check for water hammer noise utilizing appropriately placed personnel or check for water hammer vibration utilizing suitable instrumentation. 10

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 equilibrium 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.

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4.0 DATA REQUIRED

4.1 Reactor power.

4.2 CEA positions.

4.3 Boron concentration.

4.4 Specified CPC inputs, outputs, and constants. 10

5.0 ACCEPTANCE CRITERIA

5.1 The values of DNBR and LPD calculated by the CPCs are consistent with the values calculated by the CPC Fortran code. 10

14.2.12.5.19 Steam Bypass Valve Capacity Test

1.0 OBJECTIVE

1.1 To demonstrate that the maximum steam flow capacity of each atmospheric steam dump valve upstream of the main steam isolation valves is less than that assumed for the safety analysis. 10

1.2 To measure the capacity of each steam bypass valve individually to determine that the capacity of each steam bypass valve is less than the value used in the safety analysis. 10

2.0 PREREQUISITES

2.1 The reactor power is > 15% full power. 10

2.2 Control systems are in automatic where applicable.

2.3 The operation of the atmospheric steam dump, turbine by-pass and shutdown cooling system have been demonstrated as part of the HOT FUNCTIONAL testing. 10 6

3.0 TEST METHOD

3.1 The individual steam flows through each of the atmospheric dump valves upstream of the MSIVs are measured.

3.2 The capacity of each steam bypass valve is measured. 10

4.0 DATA REQUIRED

4.1 Reactor power.

4.2 RCS temperatures.

4.3 Pressurizer pressure.

4.4 Steam generator levels and pressure.

4.5 Steam dump and bypass valve positions.

5.0 ACCEPTANCE CRITERIA

5.1 The capacities of the individual steam dump valves are less than the values used in the safety analysis but greater than the values required for a safe cooldown. 10

5.2 The capacity of each steam bypass valve has been measured, and the capacity of each steam bypass valve is less than the value used in the safety analysis. 10

14.2.12.5.20 Incore Detector Test

1.0 OBJECTIVE

1.1 To verify conversion of the fixed incore detector signals to voltages for input to the plant computer. 6

1.2 To collect baseline performance data for the movable incore detector system.

2.0 PREREQUISITES

2.1 The reactor is at the specified power level and conditions.

2.2 The plant computer is operable.

2.3 The incore detector system is operable.

3.0 TEST METHOD

3.1 Fixed incore detector signal verification.

3.1.1 Amplifier output signals are measured based on test input signals. 6

3.1.2 Group symmetric instrument signals are measured.

3.2 Data is recorded from the movable incore detectors during core traverses.

4.0 DATA REQUIRED

4.1 Reactor power.

4.2 CEA position.

TABLE 14.2-1

LOW POWER PHYSICS TESTS

Test Title	First-of-a-kind*	Follow-On Units**	
			10
Low Power Biological Shield Survey Test	320°F/565°F	565°F	6
CEA Symmetry Test	565°F	565°F	10
Isothermal Temperature Coefficient Test	320°F-565°F	565°F	6
Regulating CEA Group Worth Test	320°F & 565°F	565°F	
Shutdown CEA Group Worth Test	320°F	565°F	10
Differential Boron Worth Test	320°F & 565°F	565°F	
Critical Boron Concentration Test	320°F-565°	565°F	
Pseudo Dropped and Ejected CEA Worth Test	565°F	N/A	6

* An expanded test program is conducted for the "first-of-a-kind" in order to validate the design, the design methods, and the safety analysis assumptions.

** Reduced testing is contingent upon the demonstration that "Follow-On" plants behave in an identical manner as the First-Of-A-Kind plant through conformance with the Acceptance Criteria given in Table 14.2-7. 10 6

TABLE 14.2-2
(Sheet 1 of 2)
POWER ASCENSION TEST

Test Title	First-of-a-Kind*	Follow-On Units**	10
Natural Circulation Test	*** ≥ 80%	N/A	
Variable Tavg (Isothermal Temperature**** Coefficient & Power Coefficient) Test	20, 50, 80, 100%	50 & 100%	10
Unit Load Transient Test	50, 100%	50, 100%	10
Control Systems Checkout Test	20, 50, 80, 100%	50, 80%	10
RCS and Secondary Chemistry and Radiochemistry Test	20, 50, 80, 100%	20, 50, 80, 100%	
Turbine Trip Test	100%	100%	
Unit Load Rejection Test	100%	100%	10
Shutdown from Outside the Control Room Test	≥ 10%	≥ 10%	
Loss of Offsite Power Test	≥ 10%	≥ 10%	
Biological Shield Survey Test	20, 50, 80, 100%	20, 50, 80, 100%	
Xenon Oscillation Control Test	≥ 50%	N/A	10
Dropped CEA TEST	Post 80%	N/A	10
"Ejected" CEA Test	Post 80%	N/A	10
Steady-State Core Performance Test	20, 50, 80, 100%	20, 50, 80, 100%	
Intercomparison of PPS, CPC and Process Computer Inputs	20, 50, 80, 100%	20, 50, 80, 100%	
Verification of CPC Power Distribution Related Constants	20, 50%	20, 50%	10

* An Expanded test program is conducted for the "first-of-a-kind" in order to validate the design, the design methods, and the safety analysis assumptions.

** Reduced testing is contingent upon the demonstration that "Follow-On" plants behave in an identical manner as the "First-of-a-Kind" plant through conformance with the acceptance criteria given in Table 14.2-7. 6

*** Initial Power Level

**** The temperature and power coefficient: measurements are done as close as possible to 100% power at a level where CEA motion is practical accounting for margin considerations. 10

TABLE 14.2-6

POWER ASCENSION TESTS

Paragraph	Title
14.2.12.5.1	Nautural Circulation Test
14.2.12.5.2	Variable T_{avg} (Isothermal Temperature Coefficient & Power Coefficient) Test
14.2.12.5.3	Unit Load Transient Test
14.2.12.5.4	Control Systems Checkout Test
14.2.12.5.5	RCS and Secondary Chemistry and Radio-Chemistry Test
14.2.12.5.6	Turbine Trip Test
14.2.12.5.7	Unit Load Rejection Test
14.2.12.5.8	Shutdown from Outside the Control Room Test
14.2.12.5.9	Loss of Offsite Power Test
14.2.12.5.10	Biological Shield Survey Test
14.2.12.5.11	Xenon Oscillation Control Test (PLCEA)
14.2.12.5.12	"EJECTED" CEA Test
14.2.12.5.13	Dropped CEA Test
14.2.12.5.14	Steady-State Core Performance Test
14.2.12.5.15	Intercomparison of PPS, CPCs and Process Computer Inputs
14.2.12.5.16	Verification of CPC Power Distribution Related Constants
14.2.12.5.17	Main and Emergency Feedwater System Test
14.2.12.5.18	CPC Verification
14.2.12.5.19	Steam Bypass Valve Test
14.2.12.5.20	Incore Detector Test
14.2.12.5.21	COLSS Verification

6

6

 6

Table 14.2-7

PHYSICS (STEADY STATE) TEST ACCEPTANCE CRITERIA TOLERANCES 10

Parameter	First-of-a-kind	Follow-on Plant	
LPTT			
Symmetry Test	± 1 1/2 ¢	± 1 1/2 ¢	6
CEA Group Worths	± 15% or .1% Δρ whichever is greater	± 10% or .05% Δρ whichever is greater	
Total Worth (Net Shutdown)	±10%	±10%	10
Temperature Coefficient	± .5 x 10^{-4} Δρ/°F	± .3 x 10^{-4} Δρ/°F	
Critical Boron Concentration	± 100 ppm	± 50 ppm	
Boron Worth	± 15 ppm/% Δρ		6
Dropped and Ejected CEA Worths	± 25% or .1% Δρ whichever is greater	N/A	
PAPT			
Power Distribution (Radial and Axial)	**RMS $\leq$ 5%	**RMS $\leq$ 3%*	10
Peaking Factors (Fxy,FR,Fzl,Fq)	± 10%	± 7.5%	
Temperature Coefficient	± .5 x 10^{-4} Δρ/°F	± .3 x 10^{-4} Δρ/°F	6
Power Coefficient	± .2 x 10^{-4} Δρ/% power	± .2 x 10^{-4} Δρ/% power	
Pseudo Ejected CEA (2D Power Density Ratio Comparison)	± 20%	N/A	
Dropped CEA (2D Power Density Ratio Comparison)	± .2	N/A	10

* at 50% power and above 6

** $$RMS = \frac{\sum_{1}^{N} (RPD^{PRED} - RPD^{MEAS})^2}{N}$$

where N = 1, 2, 3 ---- N (Total number of fuel assemblies in core or number of axial planes, as appropriate). 10

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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 value of the monitored parameter at the sensor equals or exceeds the trip setpoint.

The reactor protective system response time is the sum of the sensor response time and the reactor trip delay time. The sensor response time is defined as the time from when the value of the monitored parameter at the sensor equals or exceeds the reactor protective system trip setpoint until the sensor output 10
equals or exceeds the trip setpoint. The sensor response is modeled by using a transfer function for the particular sensor used. The reactor trip delay time (Table 15.0-4) is defined as the elapsed time from the time the sensor output equals or exceeds the trip setpoint to the time the reactor trip breakers are fully open.

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.

TABLE 15.0-3

(This table intentionally blank)

TABLE 15.0-4

REACTOR PROTECTION SYSTEM TRIPS USED IN THE SAFETY ANALYSIS

Event	RPS	Analysis Setpoint [f]	Reactor Trip Delay Time [c]	
				10
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	Steam Generator ΔP Low Flow	90%[g]	(h)	10
	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 reactor trip delay times are also discussed in Section 7.2. 10

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.

f. Some Chapter 15 analyses assumed more conservative setpoints for specific events.

g. Percent of hot leg flow. 10

h. 1.0 second from time of occurrence of low flow trip condition until the reactor trip breakers open.

Amendment No. 10
June 28, 1985

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	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 above 90% power equals 560°F; and Section 15.1.5, 10
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

---

* Control Element Drive Mechanism does not respond to control signal. Release of CEA(s) on trip is not inhibited.

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 1850.4 seconds when the | 10
operator manually trips the reactor. At 1850.55 seconds the trip breakers
open. At this point, both the local and core average power decrease rapidly | 10
and DNBR increases. From 1858 seconds to 1886 seconds the MSSV's release steam.

At 2149.4 seconds the steam generator pressure drops below the MSIS setpoint of 820 psia. The MSIS initiates closure of the MSIV's and MFIV's at 2150.4 seconds. | 10
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 turbine trip 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 exist for 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 10
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. At 52 seconds the MSSV's open and release steam until 81 seconds. 10
Voids begin to form in the upper head of the reactor vessel at 74 seconds.

At 312.4 seconds the steam generator pressure drops below the MSIS setpoint of 10
820 psia. The MSIS initiates closure of the MSIV's and MFIV's at 313.4 seconds.
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.

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	
1850.4	Operator initiates manual trip	--	10
1850.55	Trip breakers open	--	10
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	--	
2149.4	Steam generator pressure reaches main steam isolation signal (MSIS) analysis setpoint, psia	820	10
2150.4	Main steam isolation signal generated	--	
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 signal generated	--	10
45.75	Trip breakers open	--	10
46.1	Minimum transient DNBR	1.05	
48	Hot channel DNBR increases above 1.195	--	
52	Main steam safety valves open, psia	1282	10
81	Main steam safety valves close, psia	1218	
74	Void begins to form in RV upper head	--	
312.4	Steam generator pressure reaches main steam isolation signal (MSIS) analysis setpoint, psia	820	10
313.4	Main steam isolation signal generated	--	
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	--	

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 9
case 5 (SLBFPD) there is no single failure which increases the potential for
degradation in fuel cladding performance or which increases the offsite dose.
However the failure of a MSIV was used in the analysis to be consistent with 9
case 2 (SLBFP).

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 <u>Analysis of Effects and Consequences</u>

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 15.1.6-1 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. At 7.7 seconds the steam generator pressure drops below the
MSIS setpoint of 810 psia. At 8.0 seconds voids begin to form in the upper
head of the reactor vessel. The MSIS initiates closure of the MSIVs and MFIVs
at 8.7 seconds. The MFIVs and MSIVs close by 13.3 seconds. EFW is automatically
initiated to the intact steam generator, assuming no delay after the EFAS 10
signal on low level in the intact steam generator, at 13.3 seconds. At 120
seconds the Pressurizer empties. At 177.4 seconds the pressurizer pressure has
dropped below 1600 psia and initiates a SIAS at 178.4 seconds. Within 29.6
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. At 11.9 seconds voids begin to
form in the upper head of the reactor vessel. At 12.9 seconds the steam 10
generator pressure drops below the MSIS setpoint of 810 psia. The MSIS
initiates closure of the MSIVs and MFIVs at 13.9 seconds. The MFIVs and the 10
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 89.4 seconds the pressurizer pressure drops below 1600 psia and 10
initiates a SIAS at 90.4 seconds. Within 29.6 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. At 5.0 seconds the steam generator pressure drops below the 10
MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and MFIVs
at 6.0 seconds. The MFIVs and MSIVs close by 10.6 seconds. EFW is auto-
matically initiated to the intact steam generator, assuming no delay after 10
the EFAS signal on low level in the intact steam generator, at 10.6 seconds.

At 44.6 seconds the pressurizer pressure drops below 1600 psia and initiates a SIAS at 45.6 seconds. Within 29.6 seconds of SIAS the operable HPSI pump is 10
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°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 5.64 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. The MSIS initiates closure of the MSIVs and MFIVs at 11.2 seconds. The MFIVs and MSIVs close by 10
11.2 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 11.2 seconds. At 40.6 seconds the pressurizer pressure drops below 1600 psia and initiates a SIAS at 41.6 seconds. Within 29.6 seconds of 10
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°F and 400 psia.

Case 5: Small Steam Line Break Outside Containment During Full Power Operation with Offsite Power available (SLBFPD) 9

The dynamic behavior of the salient NSSS parameters following a typical limiting SLBFPD is presented in Figures 15.1.5-5.1 through 15.1.5-5.8. Table 9
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 SLBFPDs for a spectrum of break sizes, due to the protective action of the core protection calculators (CPCs). See the discussion in Section 15C.3.2 and Figure 15C-1 of Appendix 15C. The largest break size yields the minimum DNBR. Therefore the transient presented 9
here is that which results from the double ended break of a main steam line.

Not later than 5.85 seconds after initiation of the steam line break, a trip signal is initiated by the CPCs on a projected DNBR of 1.19. At 6.00 seconds

the reactor trip breakers open. At 7.49 seconds a minimum transient DNBR of 1.11 is calculated to occur, after which DNBR rapidly increases, as shown in Figure 15.1.5-5.9, At 8.94 seconds voids begin to form in the upper head of the reactor vessel, At 12.2 seconds the steam generator pressure drops below 10
the MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and 9
MFIVs at 13.2 seconds. The MFIVs and the operable MSIVs close by 17.8 seconds. 10

Subsequently, the events of this transient follow a sequence similar to those of the SLBFP (Case 2). Since the cooldown is less severe the potential for post-trip degradation in fuel cladding performance is less for this case (SLBFBD) 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 9
coolant activity of 618 μCi/gm. Assuming one gpm steam generator tube leakage, during a period of two hours after initiation of the SLBFBD, 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 153,000 lbm. 9
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 9
calculated inhalation thyroid dose is not more than 9.8 rem for the blowdown originating from the secondary system fluid discharge from the affected steam generator.

Less than 86,000 lbm of steam from the unaffected steam generator will be released trough the steam line break. During the SLBFPD the MSIVs will isolate 9
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 condenser vacuum be lost during this transient,up to an additional 860,000 lbm of steam from the unaffected steam 10
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 0.5 rem. 10

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 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 15.0 rem for the blowdown steam originating from the initial steam generator mass inventory. 10

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) 57 rem, assuming an event-induced iodine spike. 10

The maximum potential for radiological releases due to fuel failure occurs
for full power steam line breaks outside containment in combination with 9
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.

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 Signal Generated, Projected DNBR	1.19	10
0.75	Trip Breakers Open	--	
7.7	Steam Generator Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint, psia	810	10
8.0	Voids Begin to Form in RV Upper Head	--	
8.7	Main Steam Isolation Signal, Generated	--	10
13.3	MFIVs Close Completely	--	
13.3	MSIVs Close Completely	--	
13.3	Steam Generator Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, % of wide range	25	10
13.3	EFW Initiated to Intact Steam Generator	--	
120	Pressurizer Empties	--	
177.4	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia	1600	10
178.4	Safety Injection Actuation Signal Generated	--	
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	--	

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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 Signal Generated, Projected DNBR	1.19	10
7.10	Trip Breakers Open	--	10
11.9	Voids Begin to Form in RV Upper Head	--	
12.9	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810	10
13.9	Main Steam Isolation Signal Generated	--	
18.5	MFIVs Close Completely	--	
18.5	MSIVs Close Completely	--	
18.5	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, percent of wide range	25	10
18.5	EFW Initiated to Intact Steam Generator	--	
67	Pressurizer Empties	--	
89.4	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1600	10
90.4	Safety Injection Actuation Signal Generated	--	
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	--	

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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 Signal Generated, Projected DNBR	1.19	10
0.75	Trip Breakers Open	--	
5.0	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810	
6.0	Main Steam Isolation Signal Generated	--	
10.6	MFIVs Close Completely	--	
10.6	MSIVs Close Completely	--	
10.6	Steam Generator Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, % wide range	25	10
10.6	EFW Initiated to Intact Steam Generator	--	
44.6	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1600	
45.6	Safety Injection Actuation Signal Generated	--	
55	Voids Begin to Form in RV Upper Head	--	
59	Pressurizer Empties		
75.2	Safety Injection Flow Begins	--	10
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	--	

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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	--	
5.64	Steam Generator Pressure Reaches Reactor Trip Analysis Setpoint, psia	810	
5.64	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810	10
6.64	Low Steam Generator Pressure Reactor Trip and Main Steam Isolation Signal Generated	--	
6.79	Trip Breakers Open	--	
11.2	MFIVs Close Completely	--	
11.2	MSIVs Close Completely	--	
11.2	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis (Setpoint) % wide range	25	10
11.2	EFW Initiated to Intact Steam Generator	--	
40.6	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1600	
41.6	Safety Injection Actuation Signal Generated	--	
48	Voids Begin to Form in RV Upper Head	--	
52	Pressurizer Empties	--	
71.2	Safety Injection Flow Begins	--	10
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 (SLBFPD)

Time (Sec)	Event	Setpoint or Value	
0.0	Steam Line Break Occurs	--	
5.85	Low DNBR Trip Signal Generated Projected DNBR	1.19	10 9
6.00	Trip Breakers Open	--	10
7.49	Minimum Transient DNBR	1.11	
8.94	Voids Begin to Form in RV Upper Head	--	9
12.2	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810	
13.2	Main Steam Isolation Signal Generated	--	10
17.8	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, percent of wide range	25	
17.8	EFW Initiated to Intact Steam Generator		
17.8	MFIVs Close Completely	--	9
17.8	MSIVs Close Completely	--	
64.6	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia	1600	10
65.6	Safety Injection Actuation Signal Generated		
75	Maximum Post-trip Transient Reactivity, 10^{-2} $\Delta\rho$	1.92	9
95.2	Safety Injection Flow Begins	--	10
100	Affected Steam Generator Empties	--	
200	Safety Injection Boron Begins to reach Reactor Core	--	9
430	Secondary Post-trip Transient Reactivity Peak, 10^{-2} $\Delta\rho$	-2.06	
1800	Operator Initiates Cooldown	--	

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TABLE 15.1.5-6

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	182000
intact	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

15.2.3.3 Analysis of Effects and Consequences

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°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 5.84 seconds. The reactor trip breakers open at 6.99 seconds and limit the maximum core power to 102% of full power. 10

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 6.7 seconds and the maximum secondary pressure of 1353 psia is reached at 14.0 seconds. 10

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 44.1 seconds and continues to | 10
fill the steam generators until a normal level is reached at 1408 seconds. At 964.1 seconds a safety injection actuation signal is generated when the | 10
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 <u>Conclusions</u>

For both the loss of condenser vacuum event, and LOCV with a single failure, the maximum RCS pressure remains below 2760 psia, thus ensuring primary system integrity. The minimum DNBR remains above 1.19, thus ensuring fuel cladding integrity.

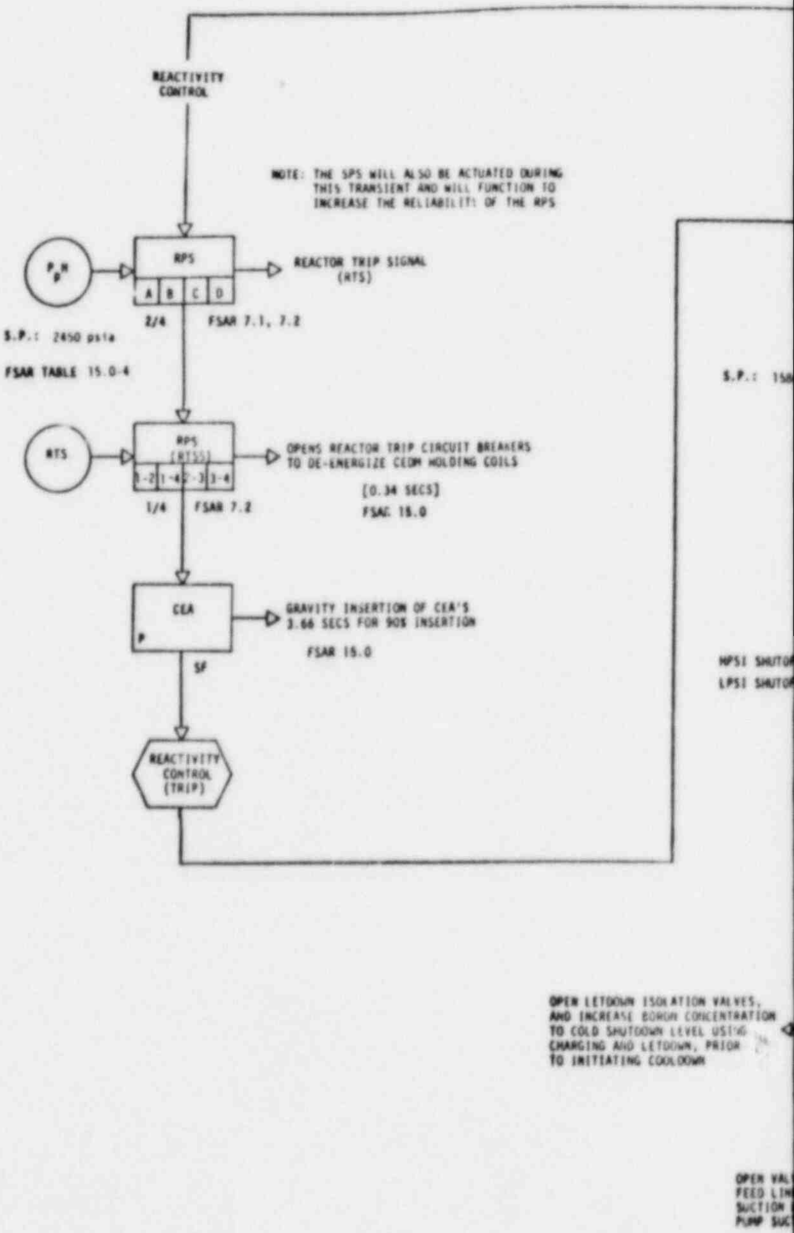
TABLE 15.2.3-1 (Sheet 1 of 2)

SEQUENCE OF EVENTS FOR THE LOCV

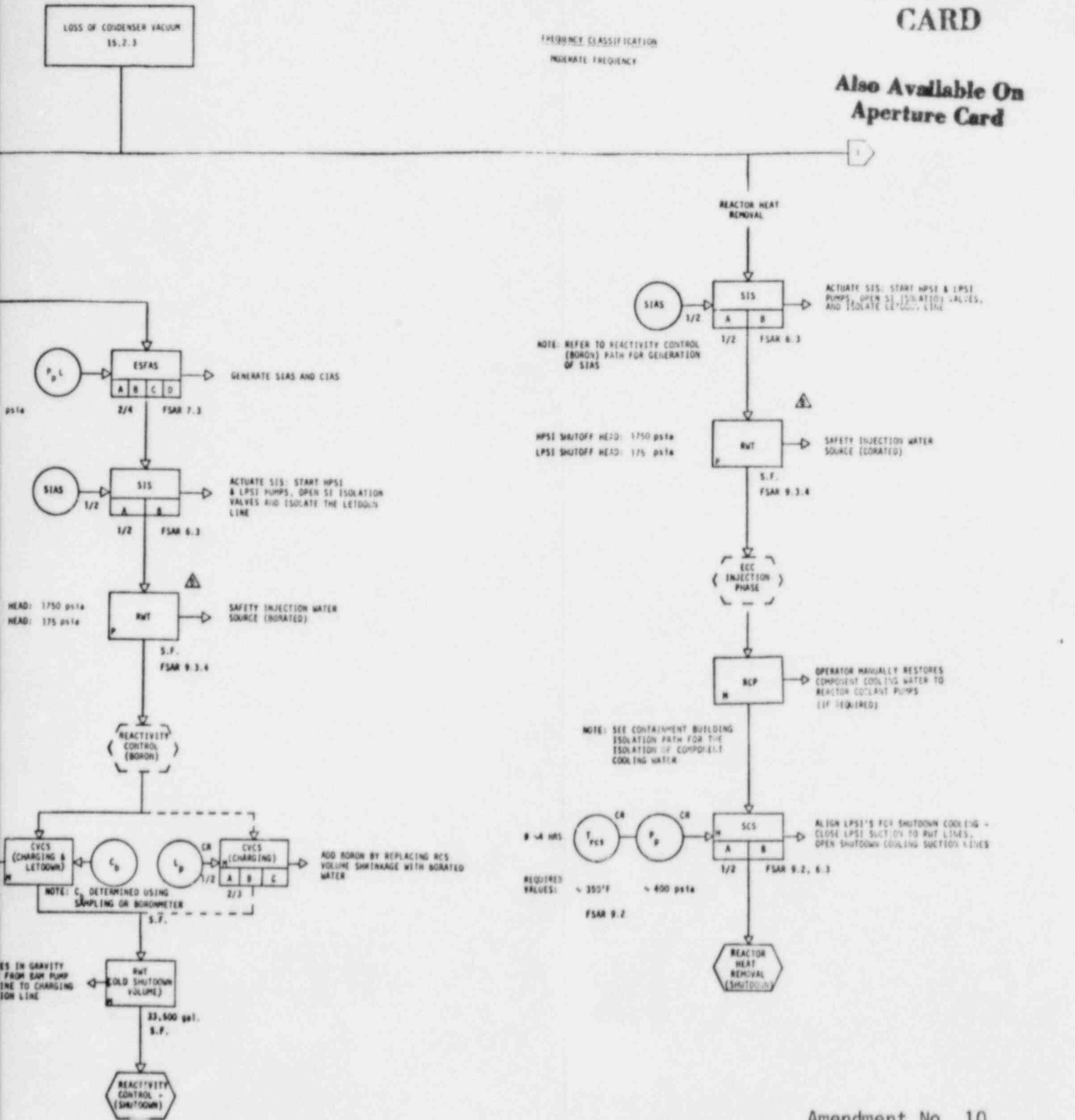
Time (Sec)	Event	Setpoint or Value	Success Path	
0.0	Loss of Condenser Vacuum			
5.84	Pressurizer Pressure Reaches Reactor Trip Analysis Setpoint, psia	2450	Reactivity Control	10
6.7	Main Steam Safety Valves Open psia	1282	Secondary System Integrity	
6.7	Steam Generator Water Level Reaches Reactor Trip Analysis Setpoint; percent of wide range	40		10
6.8	Maximum Core Power, % of Design Power	102	Reactivity Control	
6.84	High Pressurizer Pressure Trip Signal Generated		Reactivity Control	10
6.9	Pressurizer Safety Valves, Open psia	2525	Primary Integrity System	
6.99	Trip Breakers Open		Reactivity Control	10
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		
33.1	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, percent of wide range	15		
34.1	Emergency Feedwater Actuation Signal Generated			10
44.1	Emergency Feedwater Flow Initiated, gpm	875	Secondary System Integrity	

TABLE 15.2.3-1 (Cont.)(Sheet 2 of 2)

Time (Sec)	Event	Setpoint or Value	Success Path	
346.0	Main Safety Valves Close, psia	1218	Secondary System Integrity	
963.1	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1580	Reactor Heat Removal	
964.1	Safety Injection Actuation Signal Generated		Reactor Heat Removal	10
993.7	Safety Injection Flow Initiated		Primary System Integrity	
1150.0	Borated HPSI Flow Enters the Core		Reactivity Control	
1408.0	Steam Generator Water Level Reaches EFAS Reset Analysis Setpoint, percent of wide range	80	Secondary System Integrity	10
1800.0	Operator Initiates Plant Cooldown		Reactor Heat Removal	



REACTIVITY CONTROL
NOTE: THE SPS WILL ALSO BE ACTUATED DURING THIS TRANSIENT AND WILL FUNCTION TO INCREASE THE RELIABILIT: 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]
FSAC 15.0
1/4
FSAR 7.2
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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June 28, 1935

C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR LOCV	Figure 15.2.3 1A

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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 - Loss of Main Feedwater			
0.6	Low DNBR Trip Signal Generated, Projected DNBR	1.19	Reactivity Control	10
0.75	Trip Breakers Open		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	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity	10
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			

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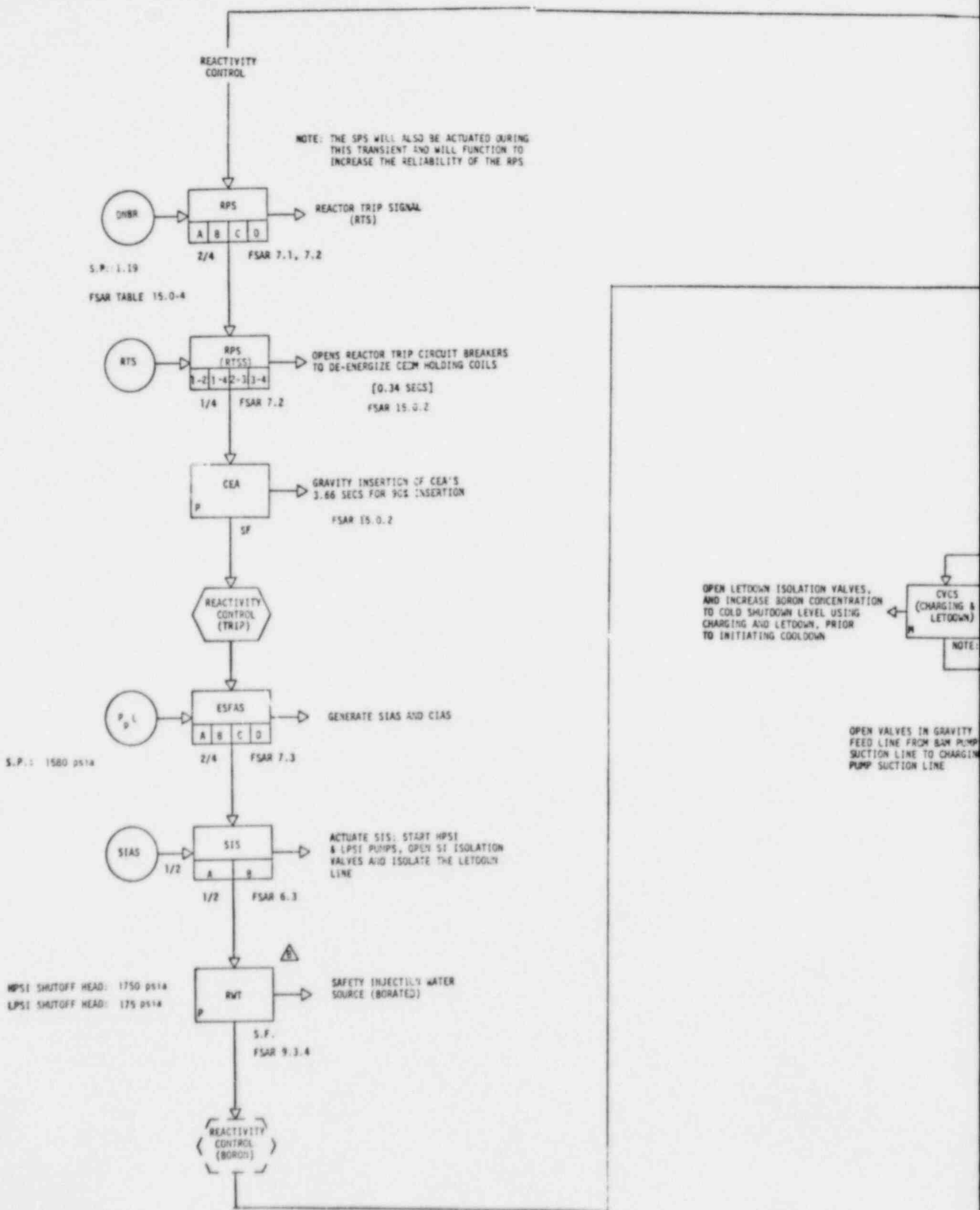
TABLE 15.3.1-2 (Sheet 1 of 2)

DISPOSITION OF NORMALLY OPERATING SYSTEMS

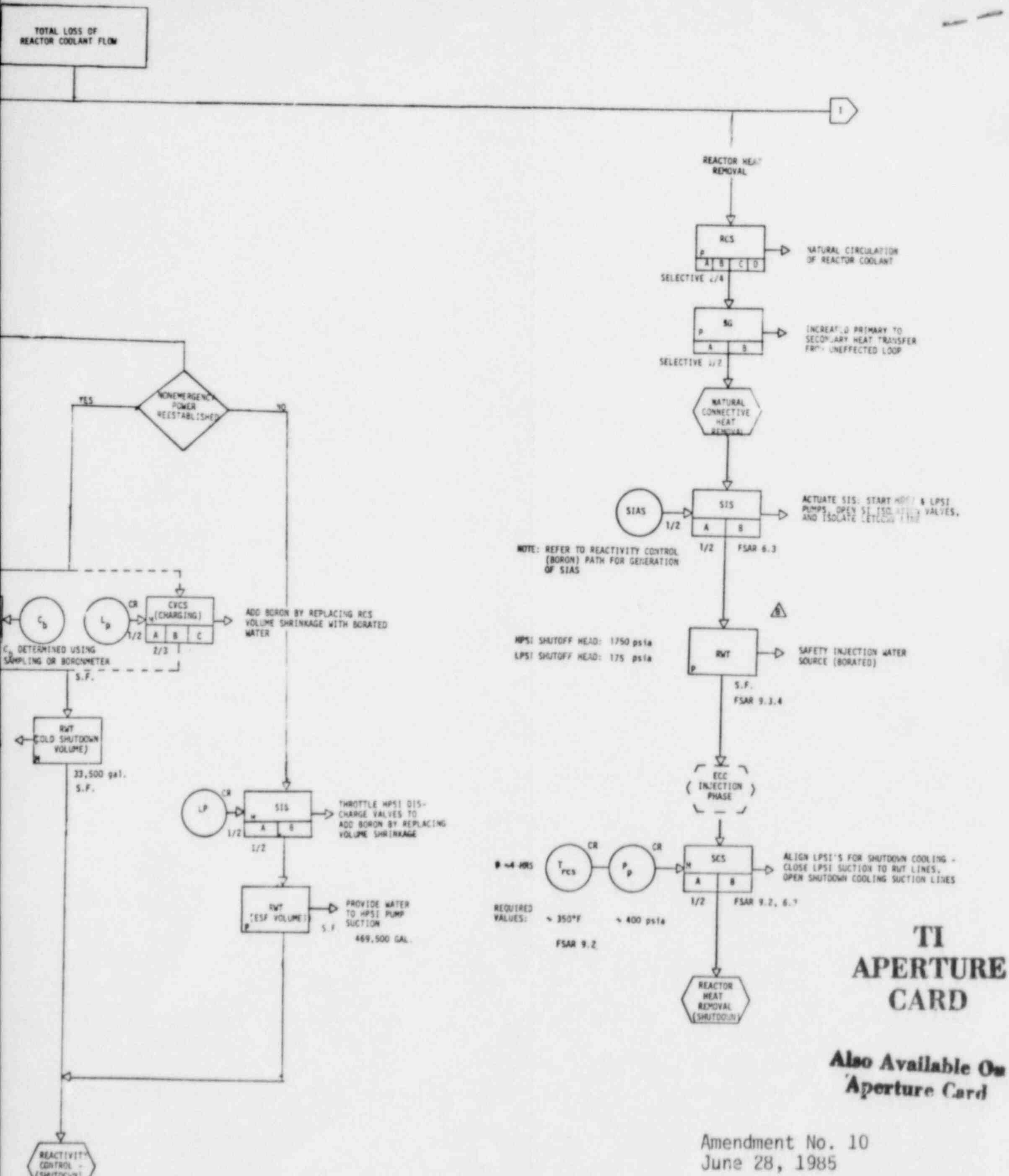
FOR THE TOTAL LOSS OF REACTOR COOLANT FLOW

SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	NORMAL 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 -



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
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)
OPEN LETDOWN ISOLATION VALVES, AND INCREASE BORON CONCENTRATION TO COLD SHUTDOWN LEVEL USING CHARGING AND LETDOWN, PRIOR TO INITIATING COOLDOWN
CVCS (CHARGING & LETDOWN)
M
NOTE:
ESFAS
A B C D
GENERATE SIAS AND CIAS
OPEN VALVES IN GRAVITY FEED LINE FROM BAM PUMP SUCTION LINE TO CHARGING PUMP SUCTION LINE
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
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)



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C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR TOTAL LOSS OF REACTOR COOLANT FLOW	Figure 15.3.1-1A

TABLE 15.3.3-1

(Sheet 1 of 3) 10

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 Valve Flow (lbm)	Success Path	
0.0	Seizure of a Single Reactor Coolant Pump	---	---	---	
0.76	Low DNBR Trip Signal Generated, projected	1.19	---	Reactivity Control	8
0.91	Reactor Trip Breakers Open	---	---	Reactivity Control	10
1.25	CEAs Begin to Drop into the Core	---	---	Reactivity Control	8
1.25	Turbine Trip/Generator Trip	---	---	---	
1.4	Minimum Transient DNBR	0.967	---	---	
4.1	Main Steam Safety Valves Open, Unaffected Loop, psia	1280	---	Secondary System Integrity	
4.2	Maximum RCS Pressure, psia	2387	---	---	
4.25	Loss of Offsite Power Occurs	---	---	---	8
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	---	

TABLE 15.3.3-1 (Continued)

(Sheet 2 of 3) | 10

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 Valve Flow (lbm)	Success Path
217	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Unaffected Loop, percent of wide range	20		Secondary System Integrity
218	Emergency Feedwater Actuation Signal Generated		85,679	Secondary System Integrity
263	Emergency Feedwater Begins Entering Steam Generator, Unaffected Loop, lbm/sec	119	91,407	Secondary System Integrity
696	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Affected Loop, percent of wide range	20		Secondary System Integrity
697	Emergency Feedwater Actuation Signal Generated		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

10

10

 10

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 Valve Flow (lbm)	Success Path
1800	Atmospheric Dump Valves Opened to Initiate Plant Cooldown, °F/hour. One Atmospheric Dump Valve Sticks Open	-100.0	120,398	Secondary System Integrity
7200	Total Steam Release to Atmosphere, lbm	---	1,128,293	---

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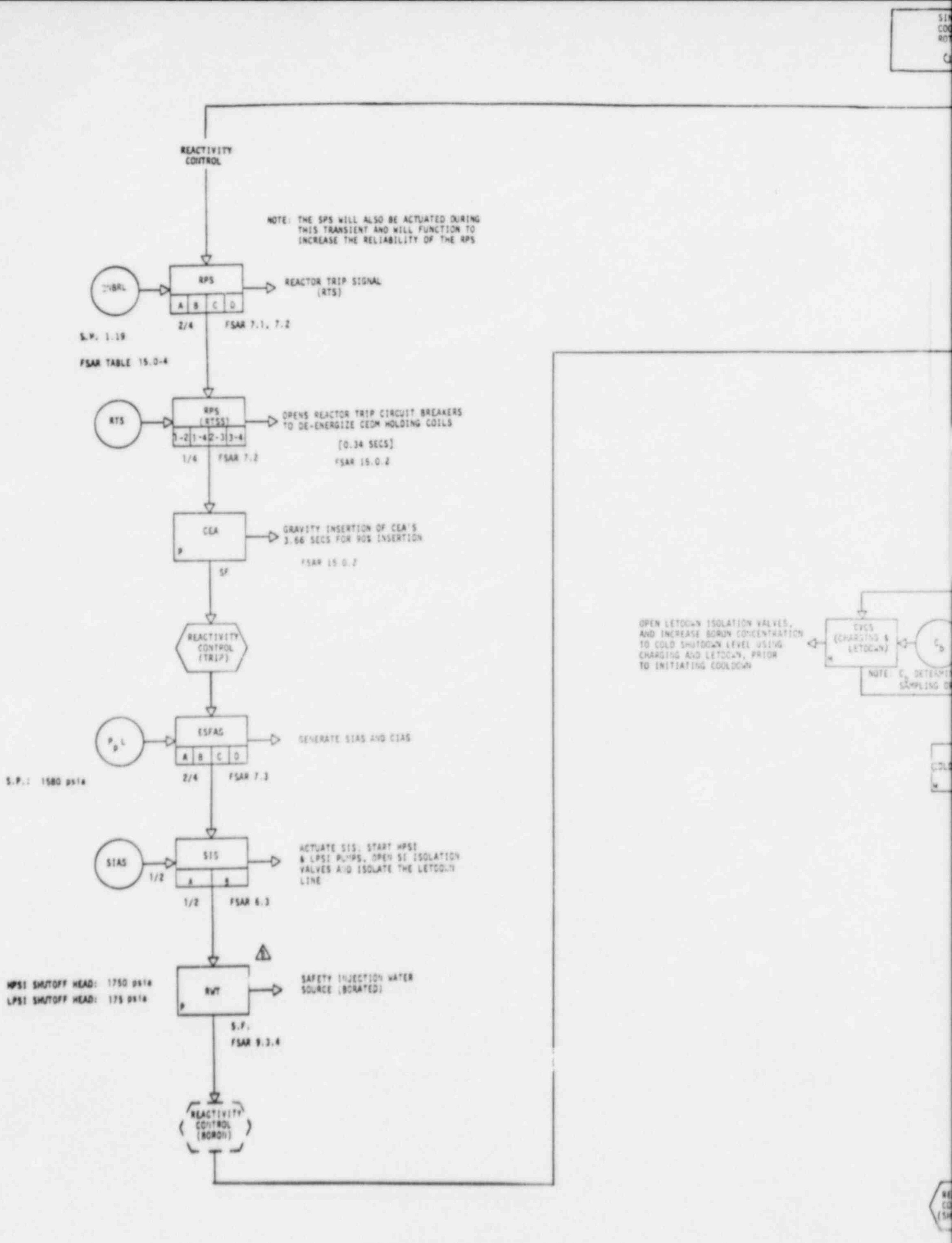
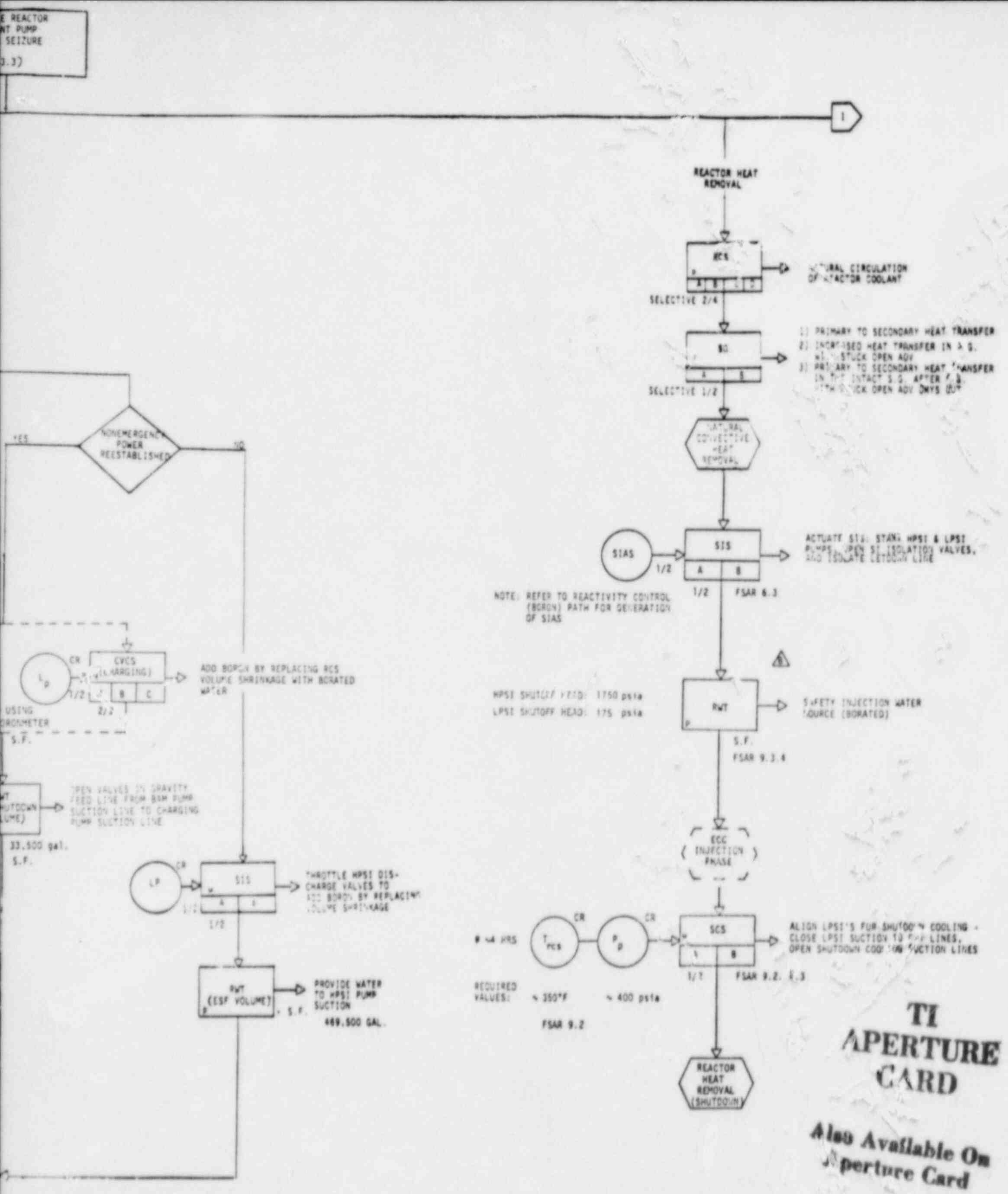


REACTIVITY CONTROL
NOTE: THE SPS WILL ALSO BE ACTUATED DURING THIS TRANSIENT AND WILL FUNCTION TO INCREASE THE RELIABILITY OF THE RPS
DNBRL
RPS
A B C D
REACTOR TRIP SIGNAL (RTS)
2/4
FSAR 7.1, 7.2
S.P.: 1.19
FSAR TABLE 15.0-4
RTS
RPS (RTSS)
1-2 1-4 2-3 3-4
OPENS REACTOR TRIP CIRCUIT BREAKERS TO DE-ENERGIZE CEDM HOLDING COILS
[0.34 SECS]
FSAR 15.0.2
1/4
FSAR 7.2
CEA
GRAVITY INSERTION OF CEA'S 3.66 SECS FOR 90% INSERTION
FSAR 15.0.2
SF
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
ACTUATE SIS: START HPSI & LPSI PUMPS, OPEN SI ISOLATION VALVES AND ISOLATE THE LETDOWN LINE
1/2
1/2
FSAR 6.3
HPSI SHUTOFF HEAD: 1750 psia
LPSI SHUTOFF HEAD: 175 psia
RWT
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)



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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

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 23.75 seconds into the transient, a variable overpower trip is actuated. The CEA's begin dropping into the core and terminates the transient. The hot channel minimum DNBR reached during the transient is 4.84 at 27.00 seconds. 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 13.8 KW/ft. 10 10

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	
0.00	Withdrawal of CEA's - Initiating Event	---	Reactivity Control	
23.35	Core Power Reaches Variable Overpower Reactor Trip Analysis Setpoint, percent of design power	17.0	Reactivity Control	
23.75	Variable Overpower Trip, Signal Generated	---	Reactivity Control	
23.90	Trip Breakers Open	---	Reactivity Control	10
25.40	Maximum Core Power, % of Design Power	45.8		
26.65	Maximum Core Average Heat Flux, % of Full Power Heat Flux	17.53		
27.0	Minimum DNBR	4.84		
35.20	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 15.4.1-4

ASSUMPTIONS AND INITIAL CONDITION FOR THE LOW POWER CEA WITHDRAWAL ANALYSIS

Parameter	Value	
Initial core power level, MWt	1	
Core inlet coolant temperature, °F	564.5	
Core mass flowrate, 10^6 lb_m/h	148.4	10
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} $\Delta\rho/°F$	+0.5	
Doppler coefficient multiplier	.85	
CEA reactivity addition rate, 10^{-4} $\Delta\rho/°sec$	2.5	
CEA Worth on trip, 10^{-2} $\Delta\rho$	-6.4[a]	10
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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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 15.4.2-2 to 15.4.2-12. 10

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 9.51 seconds after 10
initiation of the transient, a reactor trip on low DNBR is actuated. At 9.66 seconds the trip breakers are opened. The CEA's begin dropping into the core and terminates the transient. The minimum DNBR reached during the transient 10
is 1.19 at 11.00 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	
9.51	Low DNBR Trip Signal Generated, projected DNBR	1.19	Reactivity Control	10
9.66	Trip Breakers Open	--	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		

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

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
4.9 seconds. The pressurizer pressure increases to a maximum of 2525 psia at | 10
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.

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	Core Power Reaches Variable Overpower Reactor Trip Analysis Setpoint, percent of design power	117	Reactivity Control	10
0.05	CEA Fully Ejected	--		
0.08	Maximum Core power, % of design power	138.3		
0.43	Variable Overpower Trip Signal Generated		Reactivity Control	
0.58	Trip Breakers Open	--	Reactivity Control	10
0.92	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	

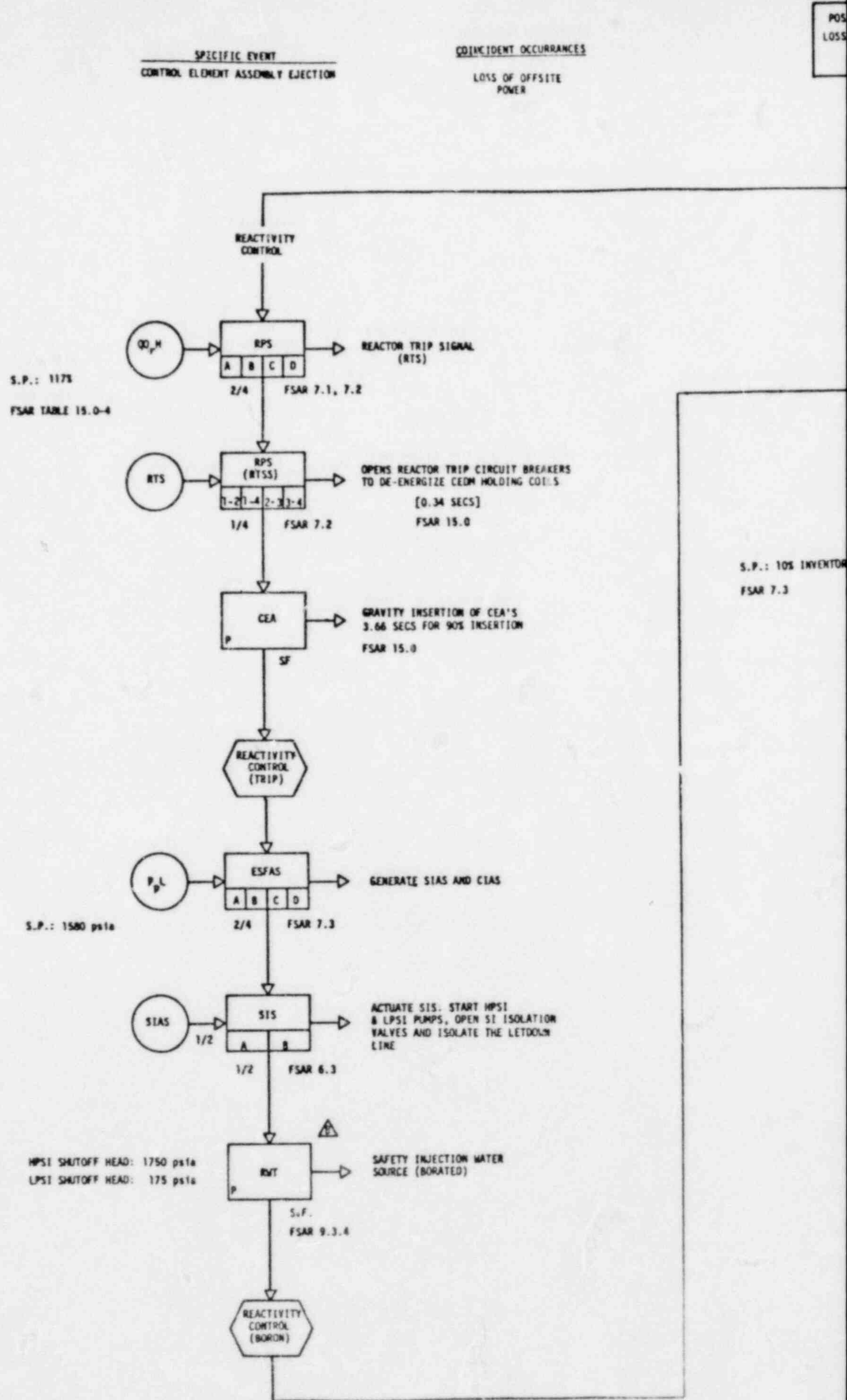
TABLE 15.4.8-1 (Cont'd) (Sheet 2 of 2)

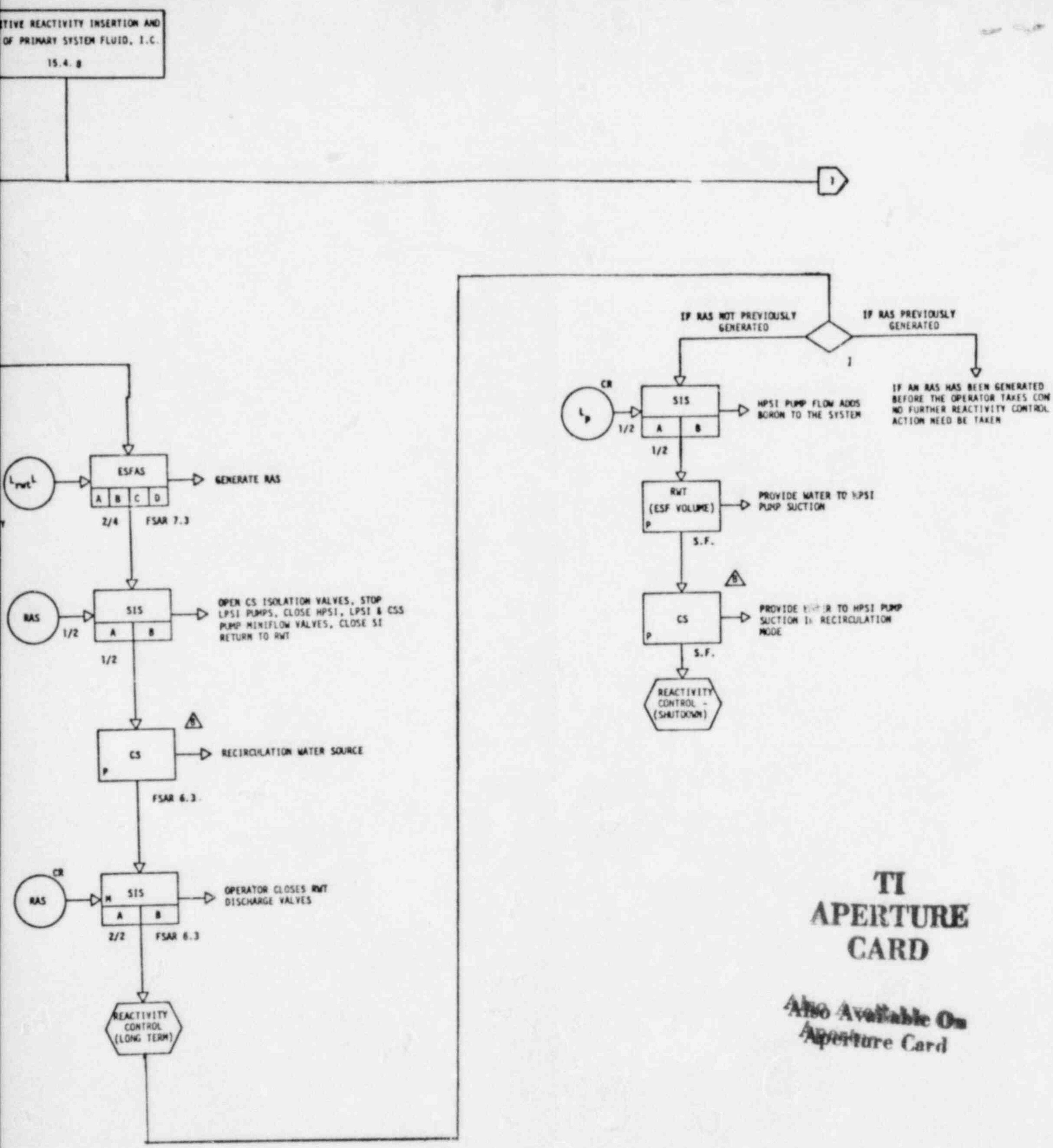
SEQUENCE OF EVENTS FOR THE CEA EJECTION EVENT

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	
4.9	Maximum Steam Generator Pressure, psia	1348		
39.5	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1580	Reactor Heat Removal	10
40.5	Safety Injection Actuation Signal Generated	--	Reactor Heat Removal	
70.1	Safety Injection Flow Initiated	--	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, °F	400/350	Reactor Heat Removal	

SPECIFIC EVENT
CONTROL ELEMENT ASSEMBLY EJECTION

COINCIDENT OCCURRANCES
LOSS OF OFFSITE POWER





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C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8 -1A

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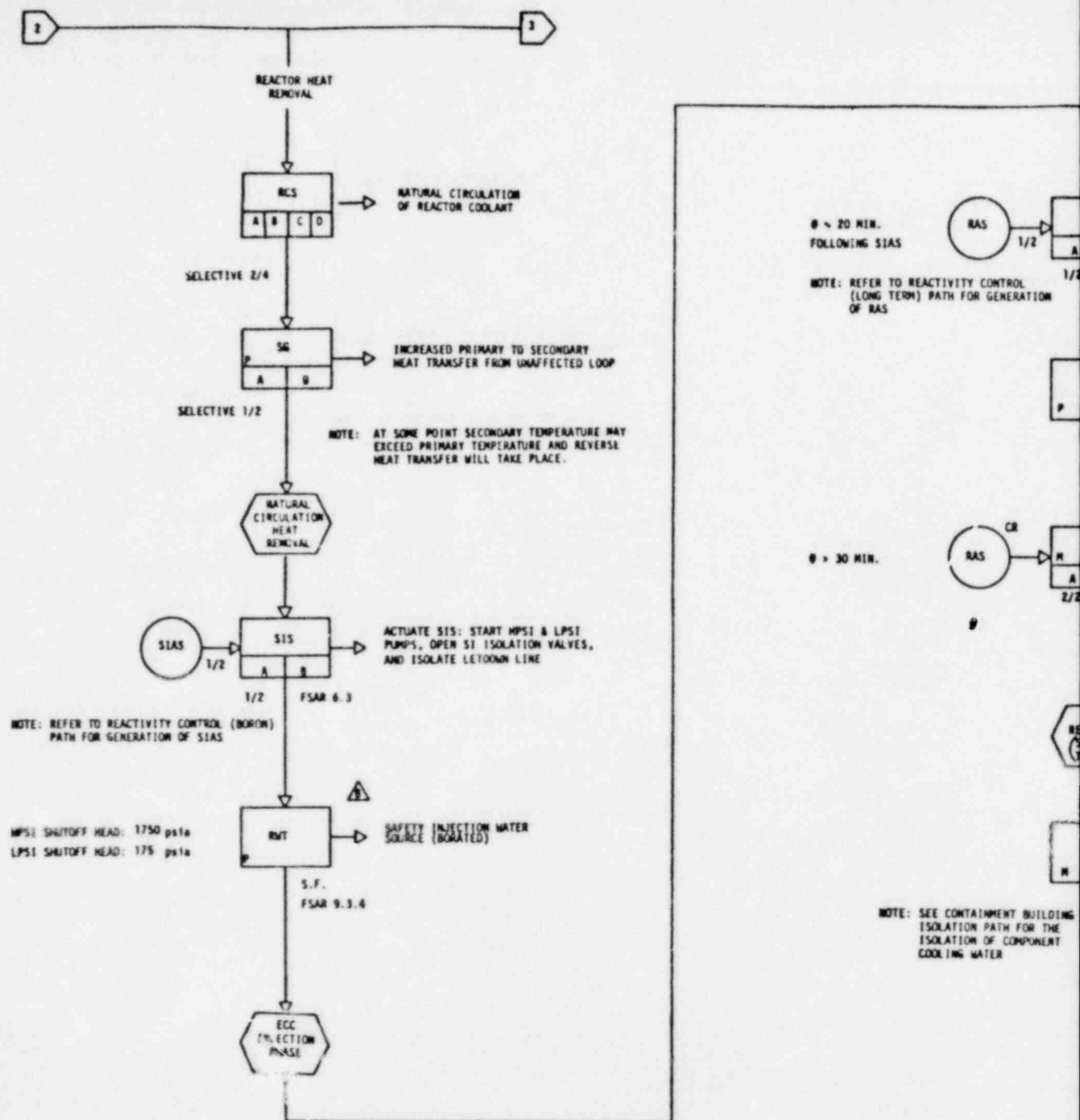
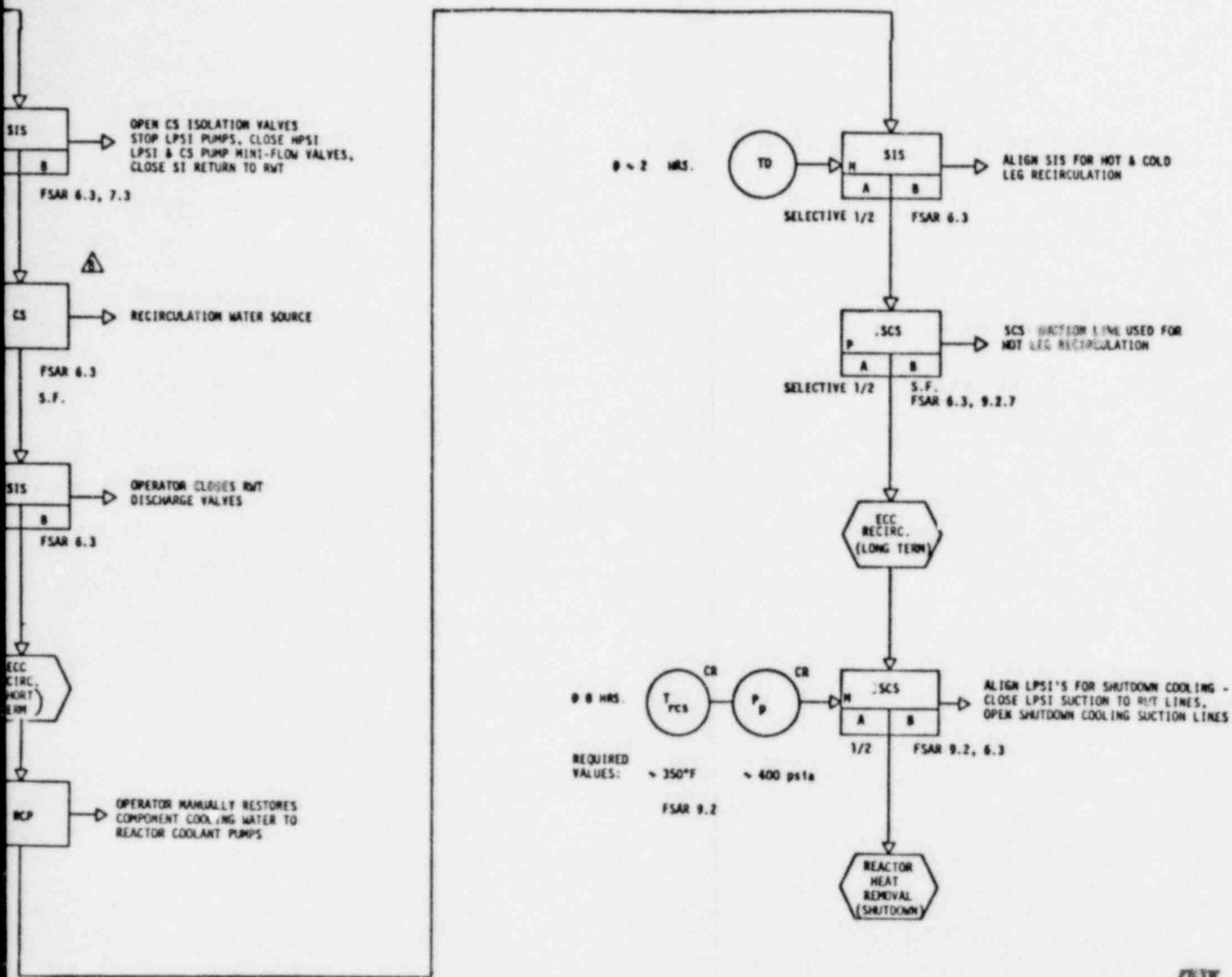


2
3
REACTOR HEAT REMOVAL
RCS
A B C D
NATURAL CIRCULATION OF REACTOR COOLANT
SELECTIVE 2/4
SG
P
A B
INCREASED PRIMARY TO SECONDARY HEAT TRANSFER FROM UNAFFECTED LOOP
SELECTIVE 1/2
NOTE: AT SOME POINT SECONDARY TEMPERATURE MAY EXCEED PRIMARY TEMPERATURE AND REVERSE HEAT TRANSFER WILL TAKE PLACE.
NATURAL 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
NOTE: REFER TO REACTIVITY CONTROL (BORON) PATH FOR GENERATION OF SIAS
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
RAS
1/2
NOTE: REFER TO REACTIVITY CONTROL (LONG TERM) PATH FOR GENERATION OF RAS
RAS
CR
2/2
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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June 28, 1985

C-E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR CEA EJECTION WITH LOSS OF OFFSITE POWER	Figure 15.4.8 -1C

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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 Figures 15.5.2-2 to 15.5.2-11.

Failure of the Pressurizer Level Control System (PLCS) causes an increase in reactor coolant system 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 reactor trip
analysis setpoint of 2450 psia at 1250.1 seconds. The trip breakers open at 10
1251.25 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 Conclusion

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	--		
1250.1	Pressurizer Pressure Reaches Reactor Trip Analysis Setpoint, psia	2450	Reactivity Control	
1251.1	High Pressurizer Pressure Trip Signal Generated	--		
1251.25	Trip Breakers Open	--	Reactivity Control	10
1251.6	Turbine Trip, Loss of Offsite Power	--		
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	

TABLE 15.5.2-2 (Sheet 1 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
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-						

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 model used for evaluation of core and system performance 10
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 1186.75
seconds after the initiation of the tube rupture a reactor trip signal 10
is generated due to exceeding the CPC low pressure boundary.

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 1563.2 seconds and the initiation of the 10

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.

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 1148.3 seconds a 10
reactor trip signal is generated due to exceeding the CPC low pressure
boundary. The pressurizer empties at approximately 1151 seconds. At 1181.8 10
seconds a safety injection actuation signal is generated, and 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

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

safety injection flow. As a result, the upper head voids begin to 10
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 1714.6 seconds. Subsequently, at 1759.6 seconds, emergency 10
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

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		
1148.3	CPC Low Pressure Boundary Trip Signal Generated	--	Reactivity Control	10
	Feedwater Flow Starts Ramp Down to 5% of Initial Full power Flow			
1148.45	Trip Breakers Open	--	Reactivity Control	10
1149	Turbine Trip: Stop Valves Start to Close	-- --	Control Secondary System Integrity	
1151	Pressurizer Empties	--	--	
1152	Turbine Stop Valves Closed	--	Secondary System Integrity	
1180.8	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia	1578	Reactor Heat Removal	10

TABLE 15.6.3-1 (Cont'd.) (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	
1181.8	Safety Injection Actuation Signal Generated		Reactivity Control and Reactor Heat Removal	
1181.8	Safety Injection Flow Initiated	--		10
1181.8	Letdown Isolation Valves Closed on SIAS	--	Primary System Integrity	
1209	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity	
1210	Maximum Steam Generator Pressure, psia	1283		10
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	

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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		
1186.75	CPC Low Pressure Boundary Trip Signal, Generated	--	Reactivity Control	
1186.90	Trip Breakers Open	--	Reactivity Control	10
1188	Turbine/Generator Trip	--	Secondary System Integrity	
1191	Loss of Offsite Power	--		
1197	LH Main Steam Safety Valves open, psia	1282	Secondary System Integrity	
1197	RH Main Steam Safety Valves open, psia	1282	Secondary System Integrity	
1201	Pressurizer Empties	--		
1205	Maximum Steam Generator Pressures Both Steam Generator, psia	1310		

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	
1562.2	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1578	Reactivity Control	
1563.2	Safety Injection Actuation Signal Generated		Reactivity Control	
1563.2	Safety Injection Flow Initiates	--	Reactivity Control	
1563.2	Letdown Isolation Valves Closed on SIAS	--	Primary System Integrity	10
1713.6	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, percent of wide range	25	Secondary System Integrity	
1714.6	Emergency Feedwater Actuation Signal Generated		Secondary System Integrity	
1721	Main Steam Safety Values Closed, psia	1218	Secondary System Integrity	
1759.6	Emergency Feedwater Flow Begins	--	Secondary System Integrity	10
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

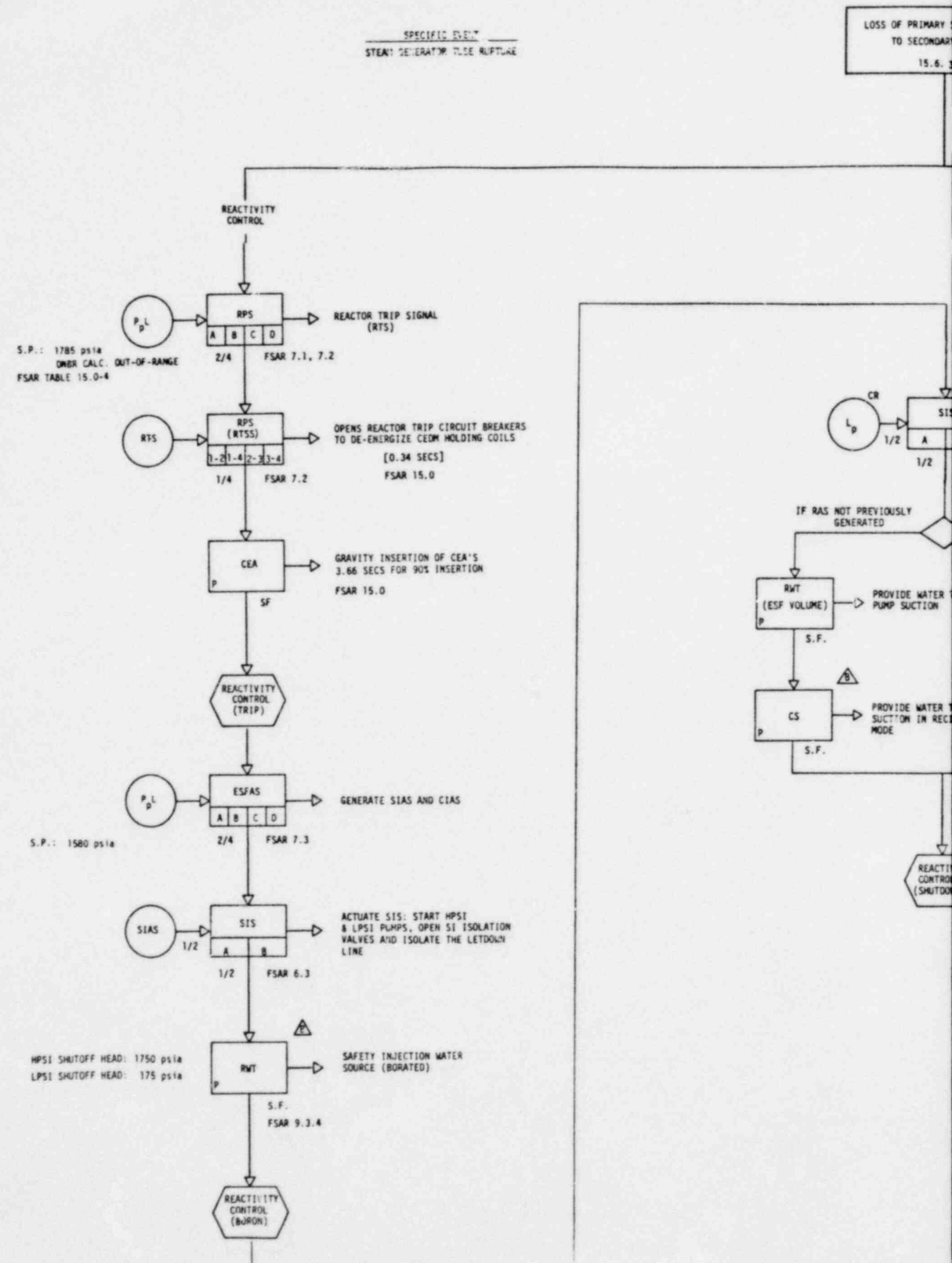
WITH A LOSS OF OFFSITE POWER

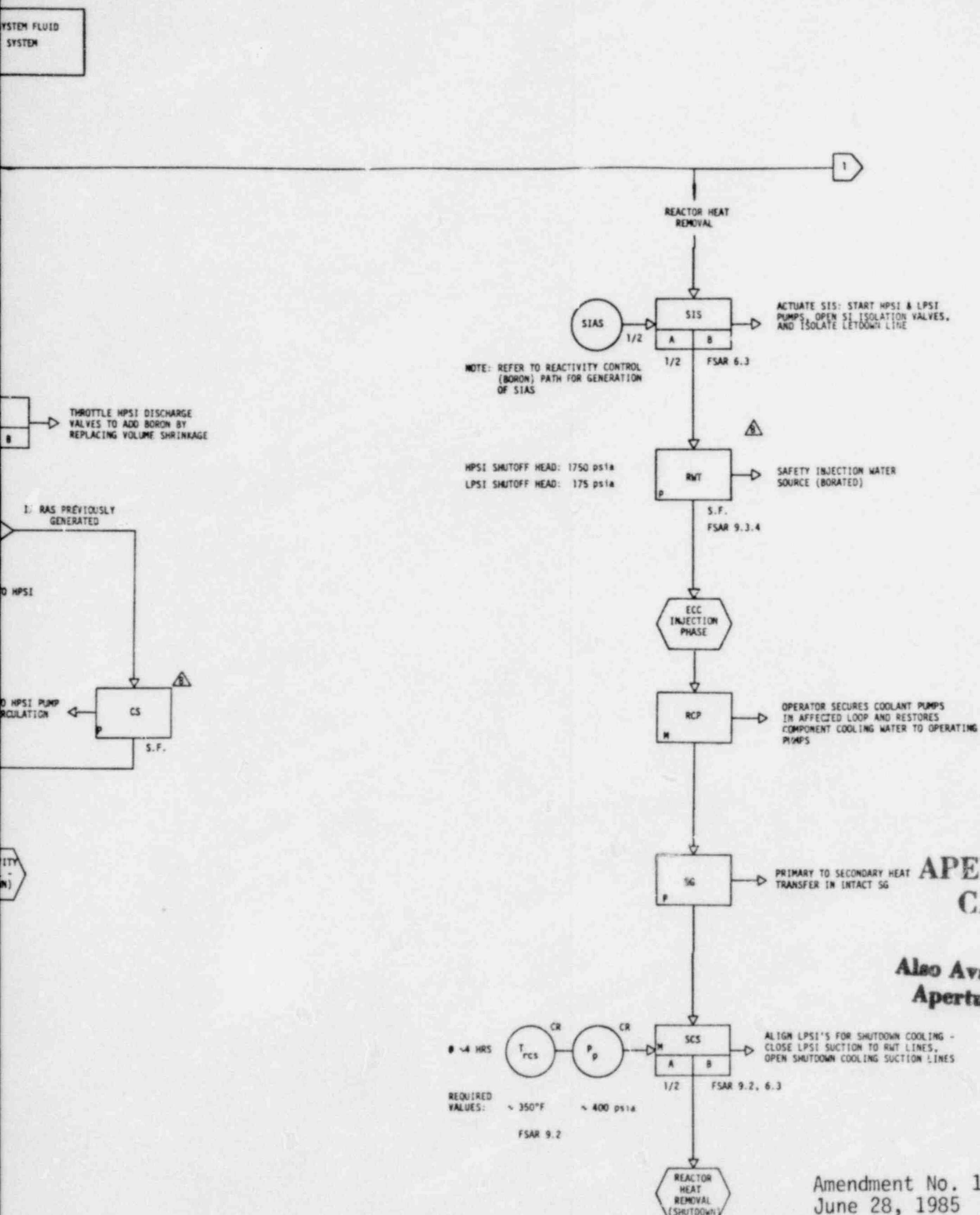
SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	NORMAL MANUAL MODE THROUGH-OUT TRANSIENT	NORMAL AUTOMATIC MODE INOPERATIVE ON LOSS OF A.C.	MANUAL MODE INOPERATIVE ON LOSS OF A.C.	SINGLE-FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater Control System			✓			
2. Main Feedwater Pump Turbine 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 -

SPECIFIC EVENT

STEAM GENERATOR TUBE RUPTURE





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C - E SYSTEM 80	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE	Figure 15.6.3 -1A

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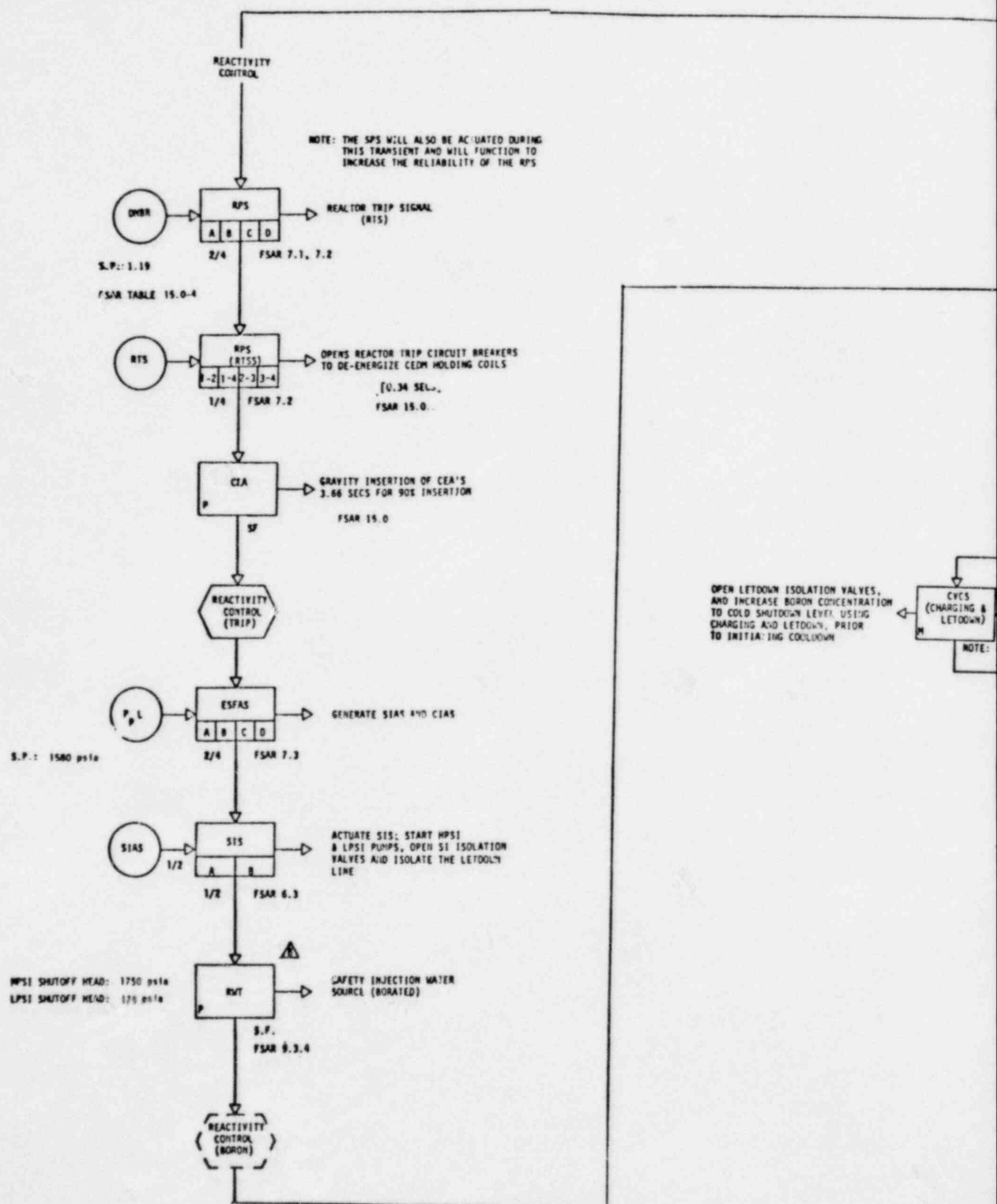
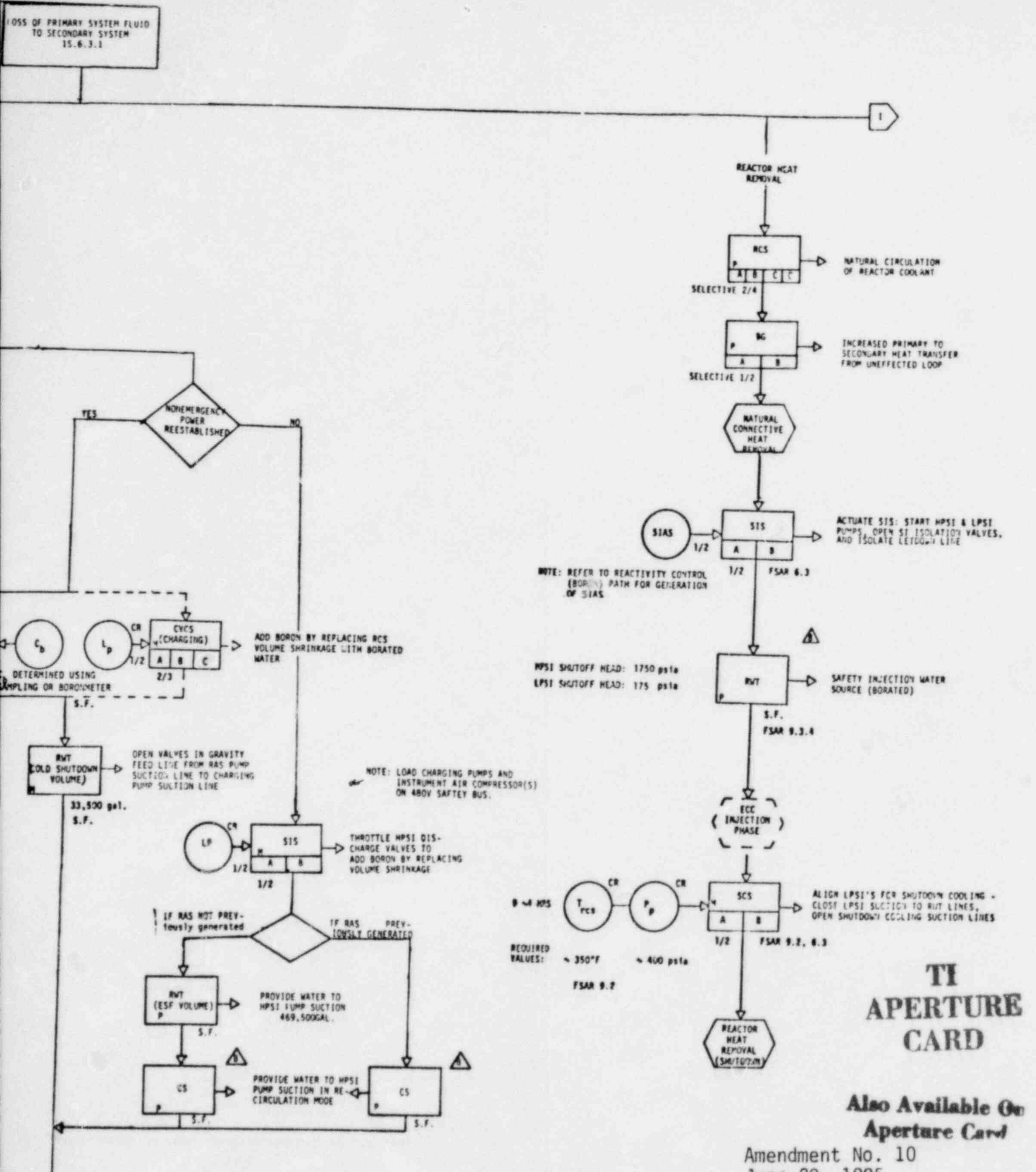
SPECIFIC EVENT
STEAM GENERATOR TUBE RUPTURE

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

EFFECTIVE PAGE LISTING

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CHAPTER 15

APPENDIX 15B

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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 water and pressurization of the steam generators during
the first 33.82 seconds which reduces the primary-to-secondary heat transfer 10
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 33.82 seconds the ruptured steam generator is assumed to instantaneously 10
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 34.82 seconds simultaneous with a high pressurizer pressure trip 10
signal. The rate of reactor coolant system pressurization is further
aggravated at 35.8 seconds. Closure of the turbine leaves the pipe break as 10
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 2206 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 166.0 seconds on low steam 10
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 imbalance 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 90.0 seconds maintaining an adequate 10
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.

A 0.20 ft^2 rupture in the main feedwater line is assumed to instantaneously
terminate feedwater flow to both steam generators and establish critical flow
from the generator nearest the break an initial rate of 1979 lbm/sec. This
causes a decrease in steam generator liquid mass as shown by Figure 15B-39. 8

The break discharge enthalpy is assumed to remain that of saturated liquid until the ruptured steam generator empties, at which time saturated vapor enthalpy is assumed.

The absence of subcooled feedwater flow causes a constant heatup and
pressurization of the steam generators during the first 25.98 seconds which 10
reduces the primary-to-secondary heat transfer rate. Rising primary coolant
temperatures and pressures result. Due to the temperature reactivity feedback 8
during this period core power is reduced from an initial value of 102% to
99.0% at 25.98 seconds. 10

At 26.98 seconds the ruptured steam generator produces a low water level 10
reactor trip signal. This reactor trip signal is coincident with a high 8
pressurizer pressure trip signal. At 25.98 seconds heat transfer in the 10
ruptured steam generator begins to degrade due to insufficient inventory. 8
This degradation initiates a rapid heat up and pressurization of the reactor
coolant system. At 27.13 seconds the reactor trip breakers open followed by 10
an assumed instantaneous turbine trip at 27.97 seconds. Immediately following
turbine trip, the failure to fast transfer to offsite power occurs, resulting
in the coastdown of two reactor coolant pumps. These occurrences further
aggravate the primary pressurization.

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 to two pumps decreases the heat transfer coefficient of the coolant in
the steam generator tubes. A significant heat transfer reduction occurs. 8

Compression of the pressurizer steam volume due to the high insurge flow raises the pressure to the safety valve setpoint at 28.3 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. At 30.2 seconds, the surge line flow reaches its maximum value of 1458 lbm/sec.

At this point in time, the reactor coolant system pressure is at a maximum of 2712 psia. Also, the increased pressure establishes a surge line pressure gradient which provides sufficient flow to allow the reactor coolant to expand

the reactor coolant to expand under the existing heatup with no further pressurization. The rate of heatup decreases subsequent to core heat flux decay, causing primary pressures to drop.

At 30.0 seconds the main steam safety valves opened stablizing 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 1342 psia at 33.8 seconds before the heat transfer begins to decrease. The core-to-steam generator heat mismatch is reduced sufficiently by 37.4 seconds to allow closure of the pressurizer safety valves, and 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.

Subsequently, a main steam isolation signal is generated on low steam generator pressure which closes the mains team 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. With the main steam safety valves re-opening, the primary-to-secondary heat imbalance is eliminated shortly 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 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.

15B.6.4 CONCLUSION

This evaluation shows that the plant response to the limiting small feedwater line break event with the most adverse single failure with offsite power available produces a maximum RCS pressure which is within 110% of design (2750 psia).

TABLE 15B-1

ASSUMPTIONS FOR THE LIMITING CASE
LOSS OF FEEDWATER INVENTORY EVENT

Parameter	Nominal Value	Assumed Value
Initial Core Power, MWt	3800	3876
Initial Core Inlet Temperature, F	565	560
Initial Reactor Vessel Flow, GPM	446000	446000
Initial Pressurizer Pressure, psia	2250	1920
Fuel Gas Gap Heat Transfer Coefficient BTU/HR-ft^2-F	>540	540
Doppler Coefficient Multiplier	1.0	1.0
Pressurizer Safety Valves Rated Flow, lbm/hr	>460000	460000
Initial Pressurizer Liquid Volume, feet^3	930	1120
Initial Steam Generator Inventory, lbm	173000	173000
Initial Feedwater Enthalpy, BTU/lbm	430	376
Steam Bypass Control System	Automatic	Manual
Normal On-Site or Off-Site Electrical Power After Turbine Trip	Available	Unavailable
Feedwater Pipe Break Area, feet^2	--	0.2
CEA Worth at Trip, 10^{-2} $\Delta\rho$	-14.8	-10.0

TABLE 15B-2 8

(Sheet 1 of 3) 10

SEQUENCE OF EVENTS FOR THE LIMITING CASE LOSS OF FEEDWATER INVENTORY EVENT

8

Time (Sec)	Event	Setpoint or Value	
0.0	Break in the Main Feedwater Line, ft^2	0.2	10
0.0	Instantaneous Loss of All Feedwater Flow to Both Steam Generators		
0.0	Instantaneous Development of Critical Flow from the Ruptured Steam Generator to the Break	--	8
33.82	Instantaneous Loss of All Heat Transfer to the Ruptured Steam Generator	--	
33.82	Steam Generator Water Level Reaches Reactor Trip Analysis Setpoint in the Ruptured Generator	Empty	
33.82	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Ruptured Generator	Empty	10
33.82	Pressurizer Pressure Reaches Reactor Trip Analysis Setpoint, psia	2475	
34.6	Pressurizer Safety Valves Open, psia	2525	
34.82	Low Water Level Trip Signal Generated	--	
34.82	Emergency Feedwater Actuation Signal Generated	--	
34.82	High Pressurizer Pressure Trip Signal Generated	--	
34.97	Trip Breakers Open	--	
35.8	Instantaneous Closure of the Turbine Stop Valves	--	8

TABLE 15B-2 (Cont'd.) (Sheet 2 of 3) 10

SEQUENCE OF EVENTS FOR THE LIMITING CASE LOSS OF FEEDWATER INVENTORY EVENT

Time (Sec)	Event	Setpoint or Value	
			8
35.8	Loss of Normal On-Site and Off-Site Electrical Power	--	
36.4	Steam Generator Water Level Reaches Reactor Trip Analysis Setpoint in the Intact Generator, percent of wide range	35	
38.2	Maximum Reactor Coolant Pressure, psia	2843	
	Maximum Pressurizer Pressure, psia	2587	
	Maximum Pressurizer Surge Line Flow, lbm/sec	2206	
40.5	Main Steam Safety Valves Open	1282	
44.0	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Intact Generator, percent of wide range	10	10
45.0	Emergency Feedwater Actuation Signal Generated		
44.8	Maximum Steam Generator Pressure, psia	1318	
45.4	Pressurizer Safety Valves Close, psia	2525	
45.8	Minimum Pressurizer Steam Volume, ft^3	138	
73.8	Main Steam Safety Valves Close, psia	1218	
90.0	Emergency Feedwater Flow Initiated to the Intact Steam Generator, gpm	875	
165.0	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810	

TABLE 15B-2 (Cont'd.) (Sheet 3 of 3) 10

SEQUENCE OF EVENTS FOR THE LIMITING CASE LOSS OF FEEDWATER INVENTORY EVENT 8

Time (Sec)	Event	Setpoint or Value	
166.0	Main Steam Isolation Signal Generated		
170.6	Minimum Intact Steam Generator Liquid Mass, lbm	8100	10
170.[illegible]	Main Steam Isolation Valves Closed		
314.2	Main Steam Safety Valves Open, psia	1282	
1800.0	Operator Opens the Atmospheric Steam Dump Valves to Begin Plant Cooldown to Shutdown Cooling		

TABLE 15B-3

ASSUMPTIONS FOR THE REANALYSIS OF THE LIMITING SMALL BREAK

LOSS OF FEEDWATER INVENTORY EVENT

Parameter	Assumed Value
Initial Core Power, MWt	3893
Core Inlet Temperature, °F	560
Core Mass Flowrate, 10^6 lbm/hr	164.9
Reactor Coolant System Pressure, psia	2115
Steam Generator Pressure, psia	1026
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-10.0
Pressurizer Safety Valves Rated Flow, lbm/hr	460,000
Initial Pressurizer Liquid Volume, ft^3	1120
Initial Steam Generator Inventory, lbm	173,000
Feedwater Pipe Break Area, ft^2	0.20
Steam Bypass Control System	Manual
Pressurizer Pressure Control System	Manual
Pressurizer Level Control System	Manual

TABLE 15B-4

SEQUENCE OF EVENTS FOR THE REANALYSIS OF THE LIMITING SMALL BREAK

LOSS OF FEEDWATER INVENTORY EVENT

Time (sec)	Event	Setpoint or Value	
			8
0.0	Rupture in the Main Feedwater Line, ft^2	0.20	
0.0	Complete Loss of Feedwater to Both Steam Generators	----	
0.0	Initial Steam Generator Break Flow, lbm/sec	1979	
25.98	Pressurizer Pressure Reaches Reactor Trip Analysis Setpoint, psia	2475	
25.98	Steam Generator Water Level Reaches Reactor Trip Analysis Setpoint in the Ruptured Generator, lb_m liquid remaining	35000	
25.98	Heat Transfer Degradation in Ruptured SG Begins	----	
26.98	High Pressurizer Pressure Trip Signal Generated	----	1
26.98	Low Water Level Trip Signal Generated	----	
27.13	Reactor Trip Breakers Open	----	
27.97	Turbine Trip on Reactor Trip	----	
27.97	Failure to Fast Transfer - Two Reactor Coolant Pumps Coast Down	----	
28.3	Pressurizer Safety Valves, psia	2525	
30.0	Main Steam Safety Valves Open	1282	
30.2	Maximum Surge Line Flow, lbm/sec	1458	
30.2	Maximum RCS Pressure, psia	2712	8
33.8	Maximum Steam Generator Pressure, psia	1342	
36.8	Ruptured SG Dries Out	----	
37.4	Primary Safety Valves Close, psia	2523	

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Tables

Due to the assumed failure of one ADV to reclose, the operator will need to close the ADV block valve to isolate the affected steam generator. The decreasing SG level in the affected steam generator, continued indication of steam flow from the affected steam generator, and continued alarming from the stack radiation monitors will alert the operator to the stuck open ADV. Once the affected steam generator is isolated the operator will steam from the intact steam generator in order to bring the RCS to shutdown cooling entry conditions. The operator will steam from the affected SG in order to prevent overfilling.

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.

15D.3 ANALYSIS OF EFFECTS AND CONSEQUENCES

15D.3.1 CORE AND SYSTEM PERFORMANCE

A. Mathematical Model

The thermal hydraulic response of the Nuclear Steam Supply System (NSSS) to the steam generator tube rupture with a loss of offsite power and stuck open ADV was simulated using the CESEC-III computer program up to the time the operator takes control of the plant and a CESEC-III based cooldown algorithm thereafter. The CESEC-III computer program is described in Reference 3. The thermal margin on DNBR in the reactor core was evaluated using the TORC computer program (Reference 4) as described in Section 15.0.3 with the CE-1 critical heat flux correlation described in CENPD-162 (Reference 5).

B. Input Parameters and Initial Conditions

The initial conditions and input parameters employed in the analyses of the system response to a steam generator tube rupture with a concurrent loss of offsite power and stuck open ADV are listed in Table 15D-4. Additional discussion on the input parameters and the initial conditions are provided in Section 15.0. Conditions were chosen to maximize the 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 with a loss of offsite power and stuck open ADV. Various combinations of initial operating conditions were considered in order to determine the reactor trip time which would result in the most adverse radiological releases. The parametric studies indicated that the maximum offsite mass release is obtained when the transient is initiated with the minimum allowed RCS pressure, minimum initial pressurizer liquid volume, maximum initial steam generator liquid volume, maximum core power, minimum

core coolant flow, and maximum core coolant inlet temperature. This combination of initial conditions results in an early generation of a reactor trip signal due to exceeding the CPC hot leg saturation temperature range limit.

C. Results

The dynamic behavior of important NSSS parameters following a steam generator tube rupture is presented in Figures 15D-1 to 15D-15. 9

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 2100 psia. The primary to secondary leak rate and drop in pressurizer water level causes the second and third CVCS charging pumps to turn on. Even with all three CVCS charging pumps on line the pressurizer pressure and level continue to drop. At 47 seconds a reactor trip signal is generated due to exceeding the CPC hot leg saturation temperature range limit. The pressurizer empties at approximately 546 seconds (Figure 15D-5). At 570 seconds a safety injection actuation signal is generated, and the safety 10
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 4020 seconds. Due to flashing caused by the depressurization, and the boil off due to the metal structure to coolant heat transfer, the reactor vessel upper head begins to void at about 77 seconds (Figure 15D-6). Consequently, the RCS pressure (Figure 15D-2) begins to decrease at a lower rate at this time.

Following reactor trip and with turbine bypass unavailable, the main steam system pressure increases until the MSSVs open at 52 seconds to control the main steam system pressure. A maximum main steam system pressure of 1330 psia occurs at 56 seconds. Subsequent to this peak in the pressure, the main steam system pressure decreases, resulting in the closure of the main steam safety valves at 95 seconds. The MSSVs cycle twice more in this manner until the operator takes control of the plant. 9

Prior to reactor trip, the main 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 main feedwater flow is terminated due to the loss of offsite power. As the level in the steam generators decrease an Emergency Feedwater Actuation Signal (EFAS) is generated resulting in, auxiliary feedwater flow which acts to restore the SG level.

At 460 seconds the operator takes control of the plant and opens one ADV on each SG to cool down the plant. This is consistent with the EPGs. At 2100 seconds the RCS has been cooled to 550°F. The operator isolates the auxiliary feedwater to the affected generator, closes the main steam isolation valves of both steam generators, and attempts to close the ADV of the affected generator. The operator recognizes that the ADV did not close and has the appropriate block valve closed within 30 minutes. The operator then initiates an orderly cooldown by means of the atmospheric

TABLE 15D-1 (Page 1 of 2)

SEQUENCE OF EVENTS FOR A STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND STUCK OPEN ADV

Time (Sec)	Event	Setpoint or Value	Success Path	
				9
0.0	Tube Rupture Occurs	---		
40	Third Charging Pump Started, feet below program level	-0.75	Primary System Integrity	
40	Letdown Control Valve Throttled Back to Minimum Flow, feet below program level	-0.75	Primary System Integrity	
47	CPC Hot Leg Saturation Trip Signal	---	Reactivity Control	
47.15	Trip Breakers Open	---	Reactivity Control	
48	Turbine/Generator Trip	--- ---	Secondary System Integrity Reactivity Control	10
51	Loss of Offsite Power	---		
52	LH Main Steam Safety Valves open, psia	1265	Secondary System Integrity	
52	RH Main Steam Safety Valves open, psia	1265	Secondary System Integrity	9
56	Maximum Steam Generator Pressures Both Steam Generator, psia	1330		
95	Main Steam Safety Valves Closed, psia	1218	Secondary System Integrity	
121.0	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal (EFAS) Analysis Setpoint in the Unaffected Generator, percent wide range	25	Secondary System Integrity	
122.0	EFAS Generated	---		10
131.0	Steam Generator Water Level Reaches EFAS Analysis Setpoint in the Affected Generator, percent wide range	25	Secondary System Integrity	

TABLE 15D-1 (Page 2 of 2)

Time (Sec)	Event	Setpoint or Value	Success Path	
132.0	EFAS Generated	---		
167.0	Emergency Feedwater Initiated to Unaffected Steam Generator	---	Secondary System Integrity	10
177.0	Emergency Feedwater Initiated to affected Steam Generator	---	Secondary System Integrity	
460	Operator Initiates Plant Cooldown by Opening One ADV on each SG	---	Reactor Heat Removal	9
546	Pressurizer Empties	---		
570	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia	1578	Reactivity Control	10
570	Safety Injection Actuation Signal Generated		Reactivity Control	
570	Safety Injection Flow Initiated	---	Reactivity Control	
2100	Operator Attempts to Isolate the Damaged Generator, RCS Tem., °F	550	Secondary System Integrity	
3900	Operator Closes the ADV Block Valve	---	Secondary System Integrity	9
4020	Operator Initiates Auxiliary Spray Flow		Primary System Inventory	
4500	Operator Controls Auxiliary Spray Flow, Backup Pressurizer Heater Output, and HPSI Flow to Reduce RCS Pressure and Control Subcooling, °F	20	Primary System Integrity	
28,800	Shutdown Cooling Entry Conditions Reached, RCS Pressure, psia/ Temperature, °F	400/350	Reactor Heat Removal	

TABLE 15 D-3

UTILIZATION OF SAFETY SYSTEMS

FOR

THE STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND STUCK OPEN ADV

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.

Ammendment No. 9
February 27, 1984

*Balance-of-Plant Systems -

TABLE 15D-4

ASSUMPTIONS AND INITIAL CONDITIONS FOR THE STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND STUCK OPEN ADV

Parameter	Assumed Value	
Core Power Level, MWt	3876	
Core Inlet Coolant Temperature, °F	570	9
Reactor Coolant System Pressure, psia	2100	
Core Mass Flow Rate, 10^6 lbm/hr	155	
One Pin Integrated Radial Peaking Factor, with Uncertainty	1.53	
Steam Generator Pressure, psia	1126	
Moderator Temperature Coefficient, 10^{-4} $\Delta\rho$/°F	-1.1	10
Doppler Coefficient Multiplier	1.0	
CEA Worth at Trip, % $\Delta\rho$ (most reactive CEA fully withdrawn)	-10.0	9

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ASB 9.5.1 GUIDELINES FOR FIRE PROTECTION FOR NUCLEAR POWER PLANTS UNDER REVIEW AND CONSTRUCTION

SUMMARY

This Branch Technical Position provides the Staff's considerations in the implementation of General Design Criterion 3. Appendix A provides acceptable alternatives for Applicant's with CP applications docketed prior to July 1, 1976. The BTP is virtually identical to R.G. 1.120, Rev. 1.

POSITION

C-E's position on ASB 9.5-1, and its Appendix A, is identical to the position statement on R.G. 1.120, Rev. 1.

Regulatory Guide 1.68.2, Revision 1
INITIAL STARTUP TEST PROGRAM TO DEMONSTRATE REMOTE
SHUTDOWN CAPABILITY FOR WATER-COOLED NUCLEAR POWER PLANTS

SUMMARY

Regulatory Guide 1.68.2, Rev. 1 describes an initial startup test program acceptable to the NRC staff for demonstrating hot standby capability and the potential for cold shutdown from outside the control room.

POSITION

The CESSAR initial startup test program fully meets the intent of Regulatory Guide 1.68.2.

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APPENDIX B

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TABLE 3-1
EVALUATION OF ICC DETECTION INSTRUMENTATION TO DOCUMENTATION REQUIREMENTS OF NUREG-0737 ITEM II.F.2

ITEM	RESPONSE
1.a.	Description of the ICC Detection Instrumentation is provided in Section 2.0.
1.b.	The instrumentation described in Section 2.0 will be the ICC detection instrumentation design for the System 80 plant. 6
1.c.	Any modification would be plant specific.
2.	The design analysis and evaluation of the ICC detection instrumentation is presented in Section 1.0 and Appendix A. The HJTC-based reactor vessel level monitoring system has been tested in three phases: Phase 1 - Proof of Principle Tests, Phase 2 - Design Development Tests, and Phase 3 - Prototype Tests. The results of these tests are available in the Phase 1, Phase 2, and Phase 3 Test Reports.
3.	The Phase 3 test program consisted of high temperature and pressure testing of a manufactured production prototype system HJTC probe assembly and processing electronics. The Phase 3 test program was executed at the C-E test facility used for the Phase 2 test. 7
	No special verification or experimental tests are planned for the hot leg and cold leg RTD sensors, the pressurizer pressure sensors, or the Type K (chromel-alumel) core exit thermocouples since they are standard high quality nuclear instruments with well known responses. 6
	For qualification testing, all out-of-vessel sensors and equipment, including the QSPDS up to and including the CFMS isolation, is environmentally qualified according to the methodology presented in Section 3.11, and seismically qualified according to the methodology presented in Section 3.10. 7

4. This table evaluates the ICC Detection Instrumentation's conformance to the NUREG-0737, Item II.F.2 documentation requirements. Table 3-2 evaluates conformance to Attachment 1 of Item II.F.2. Table 3-3 evaluates conformance to Appendix B 6
of NUREG-0737.

5. The ICC detection instrumentation processing and display consists of two computer systems; the 2 redundant channel safety grade microcomputer based QSPDS, and the single large scale non safety grade minicomputer based CFMS. The ICC inputs are acquired and processed by the safety grade QSPDS 9
and isolated and transmitted to the primary display in the non-safety-grade CFMS. The QSPDS also has the seismically qualified displays for the ICC detection instruments. The software functions for processing are listed in Section 2.2; 6
the functions for display are listed in Section 2.3.

The software for the QSPDS has been designed using the 9
recommendations of the draft standard, IEEE Std. P742/ANS 4.3.2, "Criteria for the Application of Programmable Digital 6
Computer Systems in the Safety Systems of Nuclear Power 9
Generating Stations" as a design guideline. This design procedure verifies and validates that the QSPDS software is properly implemented and integrated with the system hardware 6
to meet the system's functional requirements. This procedure is quality assured by means of the C-E QADP. Although the 9
CFMS is designed as a non-safety class system, a similar procedure is being applied to the CFMS design to assure 6
compatibility with the QSPDS.

The QSPDS hardware is designed as a redundant safety grade qualified computer system which is designed to the avail- 9
ability goal of 0.99 with the appropriate spare parts and maintenance support. The CFMS is a single highly reliable 6
minicomputer system that is designed to the availability goal of (0.99) with the appropriate spare parts and maintenance 9
support.

6. This requirement is plant specific. 6

7. Guidelines and procedures for the use of the ICC instruments will be addressed on a plant-specific basis. The C-E Owner's Group has developed generic emergency procedure guidelines 10
addressing ICC.

8. Key operator actions for ICC contained in emergency procedures 9
will be addressed on a plant specific basis.

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APPENDIX C*

Leak Before Break Evaluation of
the Main Loop Piping of a C-E
Reactor Coolant System

* Appendix C is being added in its entirety in Amendment 10.
Revision lines are not included for this, the intial entry.

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ABSTRACT

The studies conducted by CE over the past decade related to the demonstration of leak-before-break in the main loop piping of a CE PWR are summarized. Recent analyses which address the safety margins available in meeting the leak-before-break criterion are also presented. The results clearly demonstrate that the margin against instability for detectable leaking cracks is substantial in terms of margin on material properties, loadings, and crack size required for instability for both normal operation and seismic conditions.

All the requirements necessary for the demonstration that a leak-before-break condition exists in the main loop piping of a CE PWR are shown to be satisified with considerable margin.

1. INTRODUCTION

Nuclear power plants are designed to withstand very large mechanical loadings that are intended to envelop conservatively a wide range of hypothetical accident conditions. These loadings are typically associated with a hypothetical initiating event that is judged to be more severe than any realistic event. The primary coolant system main loop pipe break is one of these initiating events that forms the design basis for many systems and components of a pressurized water reactor (PWR).

The present criteria, which define the location, type and size of pipe breaks are based on the assumption that a sudden complete circumferential severance (guillotine break) of a pipe can occur Ref. (1). Advances in the field of fracture mechanics and elastic-plastic stress analysis during the past decade have provided the capability to more realistically assess the way that cracks would grow in piping systems. Application of these analytical methods to the main loop piping in the CE PWR has demonstrated that a leak before break condition exists and that a complete circumferential severance of a main loop pipe cannot occur.

The analyses that have been performed in support of the leak-before-break demonstration are described in this report. These analyses form the basis for the position that the existing criteria could be revised to not require the consideration of the guillotine break, and still satisfy the requirement of enveloping conservatively all possible accident conditions. Analyses are also presented which address the leak before break condition of axial slots in piping elbows. These analyses demonstrate that a large margin exists for leak-before-break.

This analysis emphasizes circumferential pipe cracks because the circumferential severance currently hypothesized is the most severe type of pipe break and results in the requirement for pipe whip restraints.

Many CE published reports are reviewed and summarized in order to bring all important CE work on the leak-before-break issue together in one report. Frequently, sections of these reports are restated "verbatim" with permission of the authors of the original studies.

2. LEAK-BEFORE-BREAK CRITERION

In order to demonstrate that a leak-before-break condition exists for a particular piping system, three conditions must be met. The first condition is that any initial flaws must tend to propagate through the pipe wall rather than in the circumferential or axial direction. This characteristic of the flaw growth is dependent on the loading and environmental conditions to which the piping is exposed. The second condition is that through wall cracks must open sufficiently to allow detection by normal leakage monitoring under normal full power loading conditions. The nature of the crack opening is dependent on the piping stiffness, the normal operation loadings and the material properties of the pipe.

The third condition is that cracks of detectable length must remain stable even under severe loading. The most severe loading is considered here to be the Safe-Shutdown Earthquake or SSE seismic loading. Crack stability is dependent on the toughness or crack resistance of the material, and the manner in which the cracked pipe is able to distribute or shed loads as crack extension occurs.

Leak-before-break can be demonstrated if the three conditions identified above are satisfied with sufficient margin to assure that unforeseen variations in loadings or material properties cannot cause one of the conditions to not be satisfied.

Analyses that have been performed by CE over the past decade addressing these three conditions are summarized in sections 3, 4, and 5. In section 6, more recent analyses aimed toward quantifying the safety margins in meeting the three conditions.

3. THROUGH WALL CRACK GROWTH

The first step in the leak-before-break evaluation is the determination of the manner in which a crack could grow through the pipe wall and cause a violation of pressure boundary integrity. Crack growth is caused by cyclic loading on an existing crack. In order to evaluate crack growth, the loading conditions and the initial crack size must be established.

a. Crack Size and Loadings

The anticipated loading conditions for CE PWR primary piping are shown in Table 1. These loading conditions are well understood and contain no severe thermal or dynamic conditions. These anticipated conditions are employed in the ASME code fatigue analysis for the piping. There is the possibility that a more severe loading, e.g. thermal transient, may occur during an emergency or faulted type of event, but the scarcity of such events precludes the need for consideration of such loadings in a fatigue or fatigue crack growth analysis.

The main loop piping has no valves which might open or shut, it experiences no rapid thermal transients during normal operation and it is not subject to significant flow stratification during normal operation. Clearly, since these statements cannot be made about piping in general, the conclusions drawn concerning leak before break apply only to the main loop piping.

The CE main loop pipes are fabricated and inspected in accordance with NB 2532 and NB 5000 of the ASME Section III Code which requires volumetric examination of 100% of the base metal and weld joints and allows indications no longer than three inches nor deeper than 10% of the pipe wall thickness. Therefore, only small cracks could exist in the piping before service. In order to conservatively evaluate crack growth and extension, a variety of crack sizes much larger than those expected to exist are considered in the subsequent analyses.

b. Crack Growth Analysis

Crack Growth analyses have been performed based on the methods of linear elastic fracture mechanics, Ref. (3). Recent analyses have employed the methods of the ASME Code Section XI as those fracture mechanics procedures have developed Ref. (4).

Section XI of the ASME Code, Ref. (5) defines a fatigue crack growth rate law of the form:

$$\frac{da}{dN} = C'(\Delta K_I)^n \qquad (1)$$

where n is the slope of the log (da/dN) vs. log (K_I) curve, and C' is a scaling constant. This material property curve has been determined experimentally, and the material constants for carbon steel for fatigue crack growth in a water environment are as follows: $C' = 3.795 \times 10^{-10}$ and $n = 3.726$. The rate of crack growth (da/dN) is measured in inches per cycle from this relationship. This crack growth law is intended to be a conservative upper bound to the

experimental data, however, recent fatigue crack growth studies have produced data which lie above this curve. Figure 1 shows the da/dN vs. K_I curve which has been proposed as a revision to the Section XI curve and is seen to envelope all of the fatigue crack growth data. The results of this study include the upper bound to the crack growth rate curve as given in Figure 1.

For the purpose of determining the range of defect sizes which could grow to threaten the integrity of the system, semi-elliptical shaped inner surface flaws were hypothesized for various initial crack depths, a_o, and lengths, 2 C_o. A computer methodology was used to evaluate the stress intensity factor for a given flaw size and loading function and then compute the growth rate in both the through thickness and circumferential directions of the flaw under cyclic loading conditions.

The method of analysis is based on the Section XI, Appendix A flaw evaluation procedure. This method is applicable to flaws which have not fully penetrated the wall thickness. From this method for K_I determination, the ΔK_I level is calculated based on the crack size and loading conditions. Using a stepping procedure for the number of cycles of loading in a given time period, depth and length crack growth rates are calculated and the corresponding change in crack size is determined. This permits a determination of the time to produce first leak when an existing flaw would enlarge and subsequently "pop-through" the thickness of the pipe. This "pop-through" phenomenon is what is meant by a suddenly-appearing through-thickness crack. The circumferential length of the through-wall crack is important to the determination of crack stability.

For cracks which are calculated to grow to penetrate the wall thickness, the subsequent calculation of the stress intensity factor, K_I, was evaluated using the finite element method since the Section XI flaw evaluation procedure does not extend to through-wall cracks. The finite element analysis enabled the determination of K_I as a function of the circumferential crack length, 2C, and the applied load. This information was incorporated into the crack growth procedure. In this manner the fatigue crack growth study was continued for circumferential growth of through-wall cracks.

A wide range of initial flaw sizes and shapes were considered, and the resulting crack growth rates were calculated for the design basis loading transients and corresponding frequencies of occurrence given in Table 1. An example of the predicted growth behavior for a defect with an initial depth of 0.5 in. and an initial length of 39.0 in. is shown in Figure 2. Under the influence of the prescribed cyclic loading history such a flaw was calculated to become a leaking crack in 21 years of operation, which is less than the normal (40 year) plant life. The circumferential extension of the crack is only about one inch which is negligible compared to the initial crack length. It should be emphasized that the loading histories used in this analysis are conservative representations of the design transients and are intended to describe the upper limit of possible reactor operating

experience. If, after formation of a through-wall crack, the defect remains undetected and operation of the reactor continues, the calculated fatigue crack growth is also shown in this figure. It can be seen that the through wall crack would remain stable for many more years of service, increasing the likelihood of detection.

Figure 3 shows a similar plot of crack size vs. years of operation for an initial flaw with dimensions a_o = 1.0 in. and 2 C_o = 34.0 in. This initial flaw size also results in the formation of a large circumferential through-wall leaking crack in only 4 years of reactor operation. The circumferential extension of this crack is negligible. Subsequent extension of the leaking crack due to continued operation is also shown on Figure 3.

The results of the fatigue crack growth study for a .35 in. deep and 45.5 long initial flaw are presented in Figure 4. From this figure it is seen that the time required to cause a leaking crack would be 38 years. Again circumferential extension even of such a long (half circumference) crack is negligible.

In earlier CE work, Ref. (3), it was shown that cracks shorter than those considered above would require many more than the design basis number of cycles of loading to grow through the pipe wall. The startup-shutdown transient was found to be the greatest contributor to the usage factor for the main loop piping. A cyclic stress, conservatively enveloping this startup-shutdown stress was applied to hypothetical flaws one inch deep and from 8 to 18 inches long in the circumferential direction in both the 42-inch diameter hot leg and 30-inch diameter cold leg piping. Figure 5 shows that the number of start-up-shutdown cycles necessary to cause a one-inch deep crack to grow through the pipe wall and leak is an order of magnitude greater than the plant life.

In these cases it was observed that the circumferential crack extension was small. The analyses indicate that the transients that the pipe is anticipated to experience produce preferential crack growth in the through-wall direction of the pipe thereby causing a leak prior to significant circumferential extension. In Reference 3 the same conclusions about preferential through thickness crack growth were also demonstrated for cracks in the axial direction.

One other crack extension mechanism, stress corrosion cracking has the potential to cause crack growth more uniformly around the pipe circumference. The CE main loop piping environment, however, is not corrosive and no evidence of stress corrosion in this piping has ever been observed. This crack growth mechanism is not considered to be active in CE main loop piping.

4. CRACK LEAKAGE

The second step in the leak-before-break evaluation is the determination of the amount of leakage which will result from a given crack which has extended through the pipe wall. CE has performed a detailed study of crack opening areas at two locations in the main loop piping: the pump discharge leg terminal end at the reactor vessel inlet nozzle and the hot leg terminal end at the reactor vessel outlet nozzle, Ref. (6). These locations are selected because they are regions of relatively high stress and are locations where guillotine ruptures must be postulated according to the present pipe break criteria, Ref. (1).

The crack opening area was calculated for normal operating conditions since these are the most prevalent conditions during plant operating life, when leakage is to be detected. Since the leak rate is related to the amount of crack opening, a finite element analysis was performed to calculate crack opening areas as a function of crack length for various orientations around the pipe at these locations.

a. Crack Opening Area Analysis

The crack opening area was determined for several circumferential through-crack lengths oriented at the top, bottom, and sides of the discharge leg and hot leg terminal ends at the reactor vessel nozzles under normal operating conditions. Figure 6 shows the locations in the primary coolant system of the regions analyzed. By symmetry of geometry, material, and normal operating loading, the results for these two regions also apply to the other pipe terminal ends at the reactor vessel nozzles. Figures 7 and 8 show the geometry details used for the finite element modeling of the discharge leg and hot leg, respectively, and the coordinate systems in which the forces and moments are specified. Table 2 gives the combined forces and moments due to pressure, weight, and thermal expansion for steady state normal operating conditions. All crack opening area analyses were linear elastic using the material property values which are given in Table 2. Plasticity is conservatively ignored since plastic deformation would cause greater opening areas and more leakage. The MARC finite element program was used to perform all crack opening area analyses.

The extent of the detailed model of both structures was chosen so that nozzle and pipe/elbow end modeling would have a negligible effect on crack opening area. Figure 9 shows the finite element mesh for the 30 inch discharge leg terminal end with a crack. The 42 inch pipe mesh is not shown because it is very similar. Figure 10 shows the mesh refinement in the structure immediately surrounding the crack which was needed for accurate crack opening area determination and simulation of cracks of different length without the need for overall mesh regeneration.

For each terminal end finite element model, the total combined "in-system" loads of Table 2 were applied to produce equivalent beam displacements and rotations at the ends of the models. These calculated displacements and rotations were then applied to the crack

models because the displacement-controlled loading was judged to realistically represent the nature of the actual normal operating loading applied to the cracked structures. The boundary deformations of these structures, even under loadings like axial pressure, are substantially constrained by the resisting stiffness of the rest of the piping-component system.

For determining leakage rates from a narrow through-thickness crack in the pipe, it is necessary to determine the minimum opening area at any location through the wall because that section limits the flow from such a crack. For this reason, the crack opening area was calculated at the outside surface, inside surface, and midplane of the pipe wall. The midplane crack opening area was calculated directly from the shell midplane displacements. For the inside and outside surface areas the relative displacements due to the through thickness rotations were added to the midplane displacements. The opening area computed at the midplane of the pipe wall was compared to the crack opening area at the surfaces. For the hot leg the smallest area was always greater than 92 percent of the midplane value for all crack sizes and orientations evaluated. For the discharge leg the smallest area was always above 73 percent of the midplane value for all crack sizes at all orientations, except the bottom. At the bottom, the area was as little as 23 percent of the midplane value for the shortest cracks. These results illustrate that there are significant variations in the crack opening area at the inner and outer surfaces of the pipe, especially for the minimum crack opening area orientation.

Figure 11 shows the minimum pipe surface crack opening areas vs crack length at the various orientations around the discharge leg terminal end. The bending moment at the terminal end produces a greater opening area on the top of the pipe than on the bottom during normal operating conditions. Cracks at all pipe orientations open significantly indicating that the axial load, caused mostly by system pressure, predominates over the bending moments.

Figure 12 shows the minimum pipe surface crack opening areas vs crack length at the top and side of the hot leg terminal end. Cracks hypothesized in the bottom of this pipe do not grow or open because the region is in compression.

b. Leak Detection

There are two major facets to crack detection based on leakage in addition to the crack opening size. These are the leak detection sensitivity, and the flow rate correlation for leakage through a crack. A more detailed discussion of leakage rates is presented in Ref. (7).

For a PWR in the USA leak detection systems capable of detecting less than 1.0 gallon per minute (gpm) leakage from the primary system, with a Technical Specification upper limit of 10 gpm are employed per the guidance of Regulatory Guide 1.45 utilized, Ref. (8). Diverse measurement means are utilized, including water inventory monitoring, sump level and flow monitoring, and measurement of airborn radioactive particulates or gases.

The other major facet of crack detection based on leak rate, namely the flow rate correlation for leakage through a given crack size, can not be predicted precisely. Variables such as surface roughness of the side walls of the crack, the nonparallel relationship of the side walls due to the elongated crack shape, and possibly zig-zag tearing of the material during crack formation all introduce uncertainties in defining an exact flow rate correlation.

NUREG/CR-1319 Ref. (9), provides a treatment of leakage through small cracks considering various uncertainties in crack definition, including crack wall surface roughness, effective L/Dh ratio of the elongated crack shape, and the possibility that the crack may be longer at the inside of the pipe wall than at the outer surface of the pipe, resulting in a convergent opening. The results of Figure 4-13 of Reference (9) for typical PWR conditions at 2250 psi and 550°F for a high friction factor of .01 are replotted on Figure 13 in units of gpm per square inch of crack opening versus outer surface crack area, Ae. Also plotted in Figure 13 are flow predictions based on similar orifice flow with a discharge coefficient of 0.6, and also a flow prediction using a Henry-Fauske, Ref. (10), critical flow model.

The Henry-Fauske correlation was developed on the basis of subcooled flow through nozzles, and provides an upper bound for flow through an irregular crack opening. The orifice flow does not consider subcooled water effects, and the constant discharge coefficient does not consider the irregular crack shape. Even so, the orifice prediction falls in the range of the NUREG/CR-1319 predictions, providing a measure of comparison.

The NUREG/CR-1319 predictions show a slight increase in flow rate per unit of exit plane area with increasing area, and a large increase for decreasing Ae/Ao ratios. Since, for the purposes of identifying a through wall crack by means of leakage it would be conservative to underpredict the flow rate, the lowest value of all of these various predictions is recommended. The lowest flow rate prediction is about 885 gpm/sq. in. at .001 sq. in. This means that a crack which opens to slightly greater than .001 sq. in. will leak at least 1 gpm, and, therefore, will be within the range of detection by the normal leakage monioring systems for a PWR.

Using the relationship between leakage rate and crack area of 885 gpm per square inch, the leakage rate for all the crack cases of Figures 11 and 12 can be determined. These flow rates are shown in Figure 14.

Considering some margin for conservatism, through wall cracks resulting in leakage of 1 to 2 gpm will be detected during operation. This limit is also shown on Figure 14. It can be seen that relatively small cracks produce detectable leakage. For all locations except the bottom of both terminal ends, a 5-inch long crack would be detectable. For the bottom of the discharge leg terminal end a 10 inch (254 mm) long crack would be detectable. The crack length required for detectable leakage at the bottom of the pipe is greater than the other orientations because the normal operating loading is smaller in this region. This smaller loading is seen later when the stability of cracks of various orientations is considered.

The bottom of the hot leg terminal end is always in compression and is not considered a viable crack location.

5. Crack Stability Analyses

The third condition for leak before break is that cracks which are large enough to leak will remain stable during extreme loading conditions, thereby preventing a complete pipe severance. Sufficient margin on stability must be available to account for variations in actual leak detectability, material properties and loading events between the time of the beginning of leakage and plant shutdown for leak repair.

CE has performed fracture mechanics analysis on a variety of hypothetical crack sizes subject to a variety of loading conditions. Both normal operation loads and seismic loadings have been considered to determine the size of crack which will remain stable under various loading conditions.

a. Crack Stability Criteria

Two crack stability criteria have been used over the years to assess the likelihood of unstable crack extension in the main loop piping. These methods are the traditional linear elastic fracture mechanics which employs a K_{IC} criterion, and the Ductile Tearing or J-integral ductile fracture mechanics which employ a J_{IC} and Tearing Modulus criterion.

.1 Instability Principle

In linear elastic fracture mechanics, the stress intensity factor at the tip of a hypothetical crack, K_I, is computed as a function of loading and geometry. This factor represents essentially the crack opening force applied. This value is compared to the fracture toughness, K_{IC} which is the material resistance to fracture. If

$$K_I < K_{IC}$$

then the crack is stable and if

$$K_I \geq K_{IC}, \text{ then}$$

unstable crack extension occurs.

The ductile fracture mechanics methods have been developed more recently and, therefore have been used in various stages of that development in the analyses described here. The tearing modulus concept is an elastic plastic crack instability theory based on the J integral elastic plastic crack tip parameter and a J-resistance curve material property such as shown in Figure 15 Ref. (11). This figure shows the results of a series of tests indicating the amount of crack extension as a function of the value of J at the crack tip. The J value below which there is essentially no crack extension is called J_{IC}.

The slope of the line beyond J_{IC} giving the rate of increase of J required for subsequent crack extension, $\partial J/\partial a$, is used to assess the stability of the crack. Figure 16 is an idealization of the J-

resistance curve which illustrates the instability criterion. If the loading on the crack is such that the rate of change of J with crack extension $\partial J/\partial a$, applied is greater than the resistance $\partial J/\partial a$ material, then unstable crack extension will occur.

If $\partial J/\partial a$ applied is less than $\partial J/\partial a$ material then unstable crack extension will not occur even though J_{IC} is exceeded. The non-dimensional tearing modulus T, is defined as:

$$T = \frac{\partial J}{\partial a} \frac{E}{\sigma_o^2} \qquad (2)$$

where E is Young's modulus and σ_o is the yield stress of the material. Figure 17 shows how the point of instability can be found as the intersection of the loading curve in terms of J(T) and the J resistance material property curve. This figure illustrates how the structural behavior influences crack instability. If the J applied does not increase with crack extension more than the J-Resistance curve because of load redistribution or load shedding, i.e. $T_{applied}$ is small, then the crack will not become unstable. If however, the crack loading, J applied increases rapidly with crack extension i.e. $T_{applied}$ is large, instability will occur.

.2 Material Properties

The main loop piping for System 80 designs is constructed from SA516 Gr70 plate. The J-resistance curve for this material developed in reference (11), is shown in Figure 15.

The figure indicates that J_{IC} ranges from 600 in lb/in^2 at 300F to 400 in lb/in^2 at 550F. The slope of the J vs a curve, however, is essentially the same at both temperatures. From the figure, the slope, $\partial J/\partial a$, can be measured as a function of J.

Using the relationship for tearing modulus in equation (2), and the temperature dependent yield stress values σ_o = 34 ksi at 300F and σ_o = 30 ksi at 550F, the J vs Tmat instability curves are developed. These curves are shown in Figure 17.

Confirmation of the applicability of the J resistance curve of Figure 15 to the piping material used in actual plants can be attempted by comparison with actual material data. The material data obtained for each pipe section, however, is typically limited to Charpy tests so a Charpy/K_{IC}/J_{IC} correlation must be employed. Figure 18 shows the Charpy energy vs temperature data for Palo Verde Unit 1 SA516 Gr70 pipe material (in plate form). Figure 19 shows the Charpy energy for weld material for a SA516 Gr. 70 to SA533 B1 or 508 Class 2 welds, typical of the pipe to component safe end welds.

Using the Barsom-Rolfe-Novak correlation

$$K_{IC}^2 = 2E\ (CV_N)^{3/2} \qquad (3)$$

where CV_N is the Charpy energy,

and the plane strain relationship

$$J_{IC} = \frac{K_{IC}^2\ (1-\nu^2)}{E} \qquad (4)$$

where ν is Poisson's ratio, the resulting K_{IC} and J_{IC} vs temperature relationships are shown in Figure 20 and 21 for the base metal and weld material.

Figure 21 indicates that the J_{IC} value of 400 to 600 inlb/in.^{2} (of Figure 15) is reasonable for the actual pipe material at operating temperatures. The figure also indicates that the weld material has a significantly higher J_{IC} and use of the pipe material J_{IC} for stability evaluations will be very conservative for welds. For the cases of linear elasticity and small scale yield fracture mechanics the parameter J is related to K_I by

$$K_I = \sqrt{J \cdot E/(1-\nu^2)} \quad \text{for plane strain}$$
$$K = \sqrt{J \cdot E} \quad \text{for plane stress} \qquad (5)$$

This relationship is frequently used with the finite element method for the calculation of K_I. It also permits a comparison of the two crack stability criteria. For example, from Figure 15, J_{IC} is found to be about 600 in-lb/in.^{2} for SA 516 Gr. 70. According to equation (3), assuming plane stress, and $E = 30 \times 10^6$ psi, $K_{IC} = 134$ ksi$\sqrt{in.}$ It is generally accepted that linear elastic fracture mechanics applies until K_{IC} approaches the upper shelf toughness which is in the 200 ksi$\sqrt{in}$ to 250 ksi$\sqrt{in}$ range. Using 225 ksi$\sqrt{in}$ as an average upper shelf toughness, the corresponding J would be 1690 in lb/in.^{2}. Figure 15 indicates that significant crack extension would result from application of a J value of this magnitude. The rate of increase of J, however, is required to assess crack instability.

b. Normal Operating Loads

Both short through wall and long through wall circumferential cracks have been analyzed for crack stability. Static analyses have been employed for small cracks to determine the margin against crack instability for cracks which may be just leaking during normal operation Ref. (6).

The stability of through-wall cracks in primary system piping is evaluated using the J-integral technique. The crack tip parameter, J, can be compared to the experimentally determined elastic-plastic toughness, J_{IC}, to evaluate the stability of a crack. For $J < J_{IC}$, no crack extension will occur, hence, the crack will remain stable.

The J-integral was evaluated in the finite element analysis using Park's method Ref. (12) which has been demonstrated to produce accurate results without the need for special crack tip elements. The J-integral value was calculated at both crack tips for normal operation loadings which include pressure, weight and thermal expansion forces, at various orientations around the circumference of the terminal end models discussed in Section 4a. From the calculated stress values, no significant plastic deformation would be expected at the crack tip under normal operating loads for crack lengths less than 25 inches or so. A plot of J vs crack length is shown in Figure 22 for through-wall cracks centered at the top and side of the hot leg terminal end and the top, outward side and bottom of the discharge leg terminal end. For all orientations, the calculated J-integral value increases as crack length increases. The J value for the hot leg follows the pattern associated with a dominant bending load. It reaches 224 in-lb/in^2 for a 22 inch crack at the top of the pipe. For the discharge leg the J values are much less than the J values for the top of the hot leg. The J value for a 17 1/2 inch crack at the top of the discharge leg is only 26 in-lb/in.^{2} The crack in the bottom of the discharge leg terminal end, which was seen to have the largest crack length for detectable leakage from Figure 14 has, by far, the lowest J value. This indicates that the bottom is not a critical region for crack stability or concern for violation of the leak-before-break criteria.

The computed J values for all cracks are well below the critical value of J_{IC} in Figure 15, thereby assuring that no crack extension due to normal operating loads will occur for these cracks.

A dynamic elastic plastic analysis was performed to evaluate the stability and opening area of long hypothetical circumferential cracks, in the 30-in. ID, cold leg pipe in Ref. (13). The pipe is assumed to be under normal operating pressure of 2250 psi and subject to the axial load caused by that pressure. A circumferential crack is assumed to suddenly appear with a length of half the circumference of the pipe. A schematic view of the pipe containing the circumferential crack is shown in Figure 23. Since two planes of symmetry exist, one quarter of the pipe can be modeled. The finite element model of one-quarter of the pipe is shown flattened out and not to scale in Figure 24. The boundary axially remote from the crack is permitted to move axially and rotate as a plane. The force on the boundary is the axial force caused by the pressure and no depressurization due to the crack opening is assumed.

The pipe material, SA516 Gr 70, was permitted to deform plastically in accordance with the stress strain curve of Figure 25. The crack opening area during the opening is shown in Figure 26. The maximum opening of5.3 in.^{2} occurs at 3.0 milliseconds. This opening would result in over 5000 gpm leakage on the basis of the leak rate relationship discussed in Section 4.b.

The J-integral computed during the opening is shown in Figure 27. These values were computed by MARC and are the average of two near crack contours. The maximum J-integral value is 1250 in-lb/in.^{2} which is above the J_{IC} value of Figure 15. The tearing modulus

criterion is, therefore, required to indicate whether the crack is stable or unstable. From Figure 17, the T mat value at J=1250 in-lb/in is about 280.
The J applied of 1250 in lb/in.^{2} corresponds to a half circumference crack which has a half length, a, of 24 inches. Recent work (see Section 6.b) has indicated that $J_{applied}$ for this geometry can be approximated as a cubic function of crack length, ie,

$$J_{applied} = C_J a^3 \tag{6}$$

and, therefore,

$$\partial J/\partial a_{\ applied} = 3C_J a^2 \tag{7}$$

Substituting equation 6 into equation 7 leads to:

$$\partial J/\partial a_{\ applied} = 3J/a = 156 \text{ in lb/in.}^2\text{/in.}$$

and, therefore,

$$T \text{ applied} = \frac{\partial J}{\partial a} \frac{E}{\sigma_o^2} = \frac{(156)(29 \times 10^6)}{(30 \times 10^3)^2} = 5.0$$

Since $T_{applied} < T_{mat}$ this tearing modulus evaluation indicates that crack instability will not occur. It is concluded, therefore, that the circumferential crack halfway around the pipe will not be unstable if it suddenly appears during normal operating conditions.

c. Analysis of Crack Subject to Seismic Loads

In order to determine the largest crack which would remain stable under seismic loadings, a dynamic elastic plastic finite element analysis of a crack in the discharge leg terminal end was performed (Ref.14).

In the previous section it was demonstrated that a crack must exist more than halfway around the circumference of the pipe before instability (rapid crack growth) can occur due to normal operating loads.

As a first consideration for the seismic analysis, the same crack size will be evaluated for stability. Therefore, a one-half circumference stable crack is postulated to occur in the discharge leg terminal end, a region of particular concern to the integrity of the primary cooling system. The crack is presumed to exist at a point in the Safe Shutdown Earthquake (SSE) loading transient which would produce the most severe loading condition at the crack tip. A detailed elastic-plastic dynamic analysis was performed to determine the overall response of the pipe. The stress intensity factor, K_I, was computed as a function of time using the J-Integral technique. The calculated values for K_I are compared with experimental material toughness data to determine the inherent resistance of the material to further crack propagation. The maximum crack opening area is calculated in order to determine leak rates.

All computations were performed using the MARC general purpose nonlinear finite element program.

c.1 Main Loop Piping System Model

For the seismic analysis a model representing the entire primary system is employed.

A three dimensional shell model of the elbow section of the discharge leg pipe was constructed using doubly-curved thin shell elements to provide a detailed finite element description of this region. The shell element was chosen to model the pipe elbow and nozzle because through-thickness cracks can be modelled with relative ease, localized plasticity effects can be included, and the J-Integral technique can be utilized to calculate K_I at the crack tip.

Because the discharge leg is a single component in a more complex system, it is important to analyze the response of the pipe to seismic loads considering the interrelated effects due to the adjacent structural members. For this purpose, three-dimensional beam elements were used to model the reactor vessel and its vertical support columns, as well as the reactor coolant pump, its horizontal and vertical supports, and the snubber. Beam elements were also used for the remaining portions of the discharge leg pipe which were not modelled as shells. A superimposed view of the finite element model of the pipe and the other system structural components is presented in Figure 28.

Only one leg of the reactor coolant system was evaluated in this analysis. The criteria for analysis of uncoupled subsystems are discussed in Reference 15. The major components and their support structures are modelled so that the substructure model will respond as if it were part of the entire system. Seismic loading is applied as time history motion of the supports.

Boundary conditions were applied to the model at the points of attachment to the foundation. The behavior of the model was checked under static conditions, with and without the presence of a crack, to verify the overall response of the finite element model to externally applied loading.

A static analysis of the system containing a hypothetical one-half circumference crack was performed to determine the effects of internal operating pressure on the cracked structure. The crack was presumed to exist at the outside of the elbow halfway around the circumference of the pipe where crack opening effects are expected to be at a maximum. To be conservative it was assumed that the presence of the crack does not produce a depressurization of the system which would tend to reduce the level of stress in the pipe.

The maximum static value of K_I at the crack tip was calculated to be 92 ksi $\sqrt{in.}$ This value of K_I due to a one-half circumferential crack in the discharge leg pipe under static operating pressure is well below the fracture toughness of carbon steel at 550°F operating

temperature, which has an upper shelf near 250 ksi $\sqrt{in.}$ Thus, the crack would be stable and would not tend to propagate further under pressure loading alone.

The crack opening area for static pressure loading was calculated to be 1.36 in^2. Figure 29 shows a magnified view of the crack opening displacements for a one-half circumferential crack under static operating pressure loading. In the dynamic analysis of Section 5.b, the maximum crack opening area under dynamic loading for a one-half circumference crack was determined to be 5.2 in^2. However, this value was based on the assumption of free (unrestrained) motion at both ends of the pipe. The end restraint provided by the reactor vessel and discharge pump significantly limits the amount of crack opening which can occur.

c.2 Seismic Loading Conditions

In the design of nuclear reactor components for seismic loading, excitations are usually applied in the form of support motion time histories rather than by externally applied forces. The deterministic earthquake response analysis of a structural system must consider these factors which contribute to the input conditions:

a. simple (rigid-body) translation of the base,
b. rigid base rotations,
c. relative motion of different support locations,
d. the effects of soil-structure interaction where the motion of the base does not directly follow the free-field motion.

For this analysis, all support motions were considered to be the same. This assumption is conservative based on the following method used for determining support time histories.

The in-structure response spectrum used to define the SSE loading conditions is shown in Figure 30.

The support acceleration time history was generated from the in-structure response spectra using a procedure for generating a seismic artificial time history with a compatible response spectra based on the Fourier transform method (Ref. 16,17). An advantage to using an artificial time history is that it can be generated with a short overall duration which maintains the identical design spectrum over the frequency range of interest. The only requirement is that the total duration must be significantly greater than the period of the lowest frequency. For this analysis, a total duration of 6 seconds was chosen for the seismic event, with a rise time of 1 second and a decay time of 2 seconds.

The resulting acceleration and velocity time histories for horizontal support motion are shown in Figure 31. In this Figure the maximum acceleration is 1.2 g from the artificially-generated time history, and the corresponding peak in velocity is 54 in/sec. Typical values for peak horizontal ground acceleration used in design basis earthquakes are on the order of 0.2 - 0.3 g (Ref. 15). It follows from this that the corresponding maximum velocity would be

approximately 12 in/sec. The seismic loading used in this analysis, therefore, represents a "very severe" earthquake.

The artificially-generated time history motion was applied to the support locations, in 3 directions, and the dynamic response of the discharge leg pipe was evaluated for these seismic loading conditions. The results of the analysis using the model of Figure 28, without a crack, were compared with the behavior of the coupled model during seismic loading (Ref. 15). The maximum values calculated for the support reaction forces and moments at the reactor vessel upper column support are in excellent agreement with the coupled model. This demonstrates the validity of the approach used in the seismic loading of the structure, and verifies the overall dynamic response of the structural model of Figure 28.

c.3 Elastic-Plastic Dynamic Analysis

The natural frequencies of the reactor coolant system were extracted by a modal analysis. It was determined that the first (lowest) natural frequency of the discharge leg pipe without a crack was 16-17 cycles per second. This is within the range of frequencies which would contribute to normal modes during seismic loading.

The static load state of the system with operating pressure was used as the initial state for the dynamic analysis. The pipe was considered to be uncracked at time t=0 and a circumferential crack was presumed to initiate at a critical point during the seismic event. A criterion for crack initiation would, for example, be maximum tensile strain at the terminal end of the reactor vessel inlet nozzle. Generally it can be argued that maximum strain is produced in a structure during a seismic event shortly after the peak acceleration. On this basis, a large time step of 0.1 seconds was chosen for the early portion of the dynamic analysis during the "buildup" phase of the earthquake.

Direct integration of the dynamic equations was performed using the Newmark-Beta method. Stability problems did not arise since a recycling method was used to ensure that dynamic equilibrium was satisfied at the end of each time step within a set tolerance. In addition, a small amount of stiffness damping was included with a damping factor of 1.0×10^{-5}. This damping factor imposes less than .05 percent damping on modes with frequencies lower than 100 Hz.

From the time history plots in Figure 31, it is apparent that the maximum positive seismic excitation occurs at a time of t=1 second. This corresponds to the most severe externally applied loading for a one-half circumference crack around the outside of the pipe elbow.

Prior to the time of most severe loading, a smaller time step of 0.01 seconds was introduced at time t=0.9 seconds while the pipe remained uncracked. The smaller time step was chosen to delineate the high frequency response of the pipe (16-17 Hz) which would also contribute to the crack opening.

Figure 32 shows a response curve of the velocity time history at the midpoint of the discharge leg pipe. "Smoothing" effects due to the large time steps can be seen for time $t < 0.9$ seconds, whereas, the higher frequency response is apparent for time $t > 0.9$ seconds when the smaller time steps were used.

A determination of the most critical time to release the crack during the seismic analysis was based on energy principles. On that basis, it was determined that the loadings would produce maximum crack opening for a suddenly appearing crack initiated at $t = 0.99$ seconds.

A second analysis was performed which included the introduction of a one-half circumference crack at time $t = 0.99$ seconds. The dynamic behavior of the pipe with the crack was traced with time steps of 0.01 seconds to determine the maximum crack opening. Local plasticity effects were taken into account at the crack tip region for stress levels exceeding the yield strength of the material. Work hardening effects were included for SA-516 Gr-70 carbon steel using the stress-strain curve shown in Figure 21 for this material. K_I values were calculated at each time step using the J-Integral technique for determination of the crack tip stress intensity factor. The analysis was continued for a sufficient number of time steps to determine the total extent of crack opening and the maximum stress intensity at the crack tip due to combined pressure and seismic loading.

For comparison with the generated seismic velocities, a plot of the velocity time history at the base of the reactor vessel support column is shown in Figure 33. The analysis was carried out to a total time of 1.19 seconds, well past the peak in the velocity curve.

A similar velocity time history at the midpoint of the discharge leg pipe is given in Figure 34. A noticeable difference in the velocity profile occurs at the point of crack opening. The change is apparent in both the magnitude and frequency of the natural periodic motion. A comparison with the uncracked velocity time history shown in Figure 28 indicates that the peak velocity is reduced due to the incidence of the crack. This indicates a reduction in the kinetic energy of the pipe resulting from a change in stiffness. In effect, energy in the pipe is reduced due to crack opening, and the response of the pipe with the crack is substantially different due to the change in stiffness of the system.

c.4 Resulting Crack Behavior

Crack opening effects are best described in terms of the stress intensity factor, K_I. A plot of K_I vs. time starting at the point of crack initiation is shown in Figure 35. The rapid release of energy following crack initiation is characterized by the sharp increase in K_I to a value of 107 ksi in. The increase in K_I due to dynamic effects is approximately 16 percent above the static value of pressure loading alone. The response of the pipe following the opening of the crack causes fluctuations in the value of K_I about the average static value of 92 ksi in. The contribution of the seismic loading to the crack opening is small in comparison to the pressure effects. This is due to the fact that the structural stiffness at the reactor vessel and pump ends of the discharge leg

pipe severely restricts the rotations and displacements which are a prerequisite to large crack opening effects. The support provided by the reactor vessel and the pump tends to hold the pipe in place so long as a portion of the pipe remains intact. This end constraint severely limits the effects of seismic loading on a crack in the discharge leg pipe. The calculated values for K_I remain well below the critical value for crack instability.

The maximum crack opening area for a one-half circumference crack under pressure and seismic loadings was calculated to be 1.65 in.^{2}. A 1.65 in.^{2} crack opening can be compared with the maximum crack opening area of 5.42 in.^{2} which would result from a one-half circumference crack in a pipe without the end constraint afforded by the reactor vessel and reactor coolant pump.

From this work it can be concluded that circumferential cracks must be larger than halfway around the circumference before the effects of both pressure and SSE could cause rapid crack extension.

d. Axial Slot in Elbow

In addition to circumferential or guillotine type breaks, axial cracks or slots are included in the list of design basis pipe breaks. Reference 1 shows that slots are to be hypothesized on the inside of two of the pump suction leg elbows.

In order to evaluate the "leak-before-break" concept and compute leakage areas in the pump suction elbow, a finite element model of one half of a 90° elbow was constructed using shell elements available in the MARC program. The shell model is augmented with a beam at the end to facilitate the application of boundary conditions and the moment loads on the elbow end. Appropriate boundary conditions are chosen on the lines of symmetry and ends. Details of a typical mesh in the surface coordinate system are shown in Figure 36. Figure 37 shows the mesh in a cartesian coordinate system.

A number of different crack lengths, 8, 12, 16 and 20 degrees, on the half elbow are chosen for leakage area and J_I calculations. The crack lengths correspond to approximately 8, 12, 16 and 20 inches crack length at the inside radius of the torus on the 90° elbow.

Operating pressure (2250 psi) and the maximum bending moment due to normal plus seismic loadings (1,000,000 in-lb) are applied to the cracked elbow. An elastic static analysis was then performed. The total crack opening area and J integral vs crack length are presented in Figure 38. The leakage area ranges from 0 to 0.7 square inches whereas J varies from 0 to 500 inlb/in.^{2}.

Using the value of 885 gpm/in.^{2} of crack area, the 8 inch long crack would be clearly detectable with a leakage of about 60 gpm. A crack of length much less than 8 inches therefore would be detectable at a 10 gpm rate.

An elastic plastic analysis of the 20 inch long crack in the pump suction leg elbow was performed to assess the conservatism of the elastic analysis. The resulting crack opening area for the same

loading condition was 1.0 in.^{2} and the corresponding J_I was essentially unchanged. This result indicates that the elastic analysis for leak-before-break evaluation is conservative because the elastic analysis produces a lower leakage area but (for these loadings) essentially the same value of J_I.

The maximum value of the Tearing Modulus for the largest crack analyzed is:

$$T = \frac{\partial J}{\partial a} \quad \frac{E}{\sigma^2}$$

$$= 50 \times \frac{29 \times 10^6}{(30 \times 10^3)^2} = 1.6$$

An evaluation of the contributions of the pressure and moment loadings shows that only the pressure loading contributes to the stress concentration and leakage areas. The end moment has negligible effect on these parameters because the moment predominantly produces only axial stress in the elbow which has no effect on crack opening.

6. MARGINS

In order to assess the safety margins for the leak-before-break condition in the main loop piping of System 80 plants, two dynamic analyses have been performed. The first analysis is intended to establish the margin of safety on the seismic load carrying capability of the pipe with a leaking crack. The second analysis is intended to establish the margin of safety on the leaking crack length relative to the critical crack length.

In addition to the dynamic analyses, two static analyses have been performed to verify and bound the margins of safety. The static effect of the maximum seismic moment on various cracks at the discharge leg terminal end is computed, and a tearing instability analysis is performed in order to illustrate the inherent stability of the main loop piping system.

a. Safety Margin on Seismic Load Carrying Capability

To assess the margin and seismic load carrying capability, an analysis was performed to determine the likelihood of extension of a crack which is just large enough to leak at a 10 gpm rate during normal operation. The SSE loading was applied and the ductile fracture J-resistance curve was conservatively considered to be degraded to 25% of nominal properties of J_{IC} and T_{mat}. These properties are shown in Figure 39. In Section 5a, it was shown that the weld toughness properties are significantly better than the base metal properties for the main loop piping. The arbitrary degradation of a factor of four, therefore, is not intended to represent weld material properties or to imply that less ductile properties actually might exist in service. The use of an additional safety factor of four was imposed to more clearly demonstrate the stability of the piping system.

The analysis procedure is essentially the same as that used for the seismic analysis in Section 5c. The finite element mesh in the crack region has been made to be consistent with the mesh used for the static crack opening calculations in Section 4a. The overall system model has been extended to include the steam generators in order to obtain more accurate system response. The finite element mesh is shown in Figure 40.

From the crack opening area calculation described in Section 4a, cracks of the same size in the top and outward side of the discharge leg terminal end are found to open essentially the same when subjected to normal operating loads. For a 10 gpm leakage, Figure 17 indicates that a crack length of 7.5 to 8 inches would be required. For the seismic loading analysis, therefore, the crack length is assumed to extend over a 30° arc since that results in a crack length on the inside diameter of the pipe of 7.85 inches.

The SSE loading was developed from the seismic response spectra by the fourier transform method for generating an artificial time history as described in Section 5c. The response spectra utilized is considered typical for System 80 plants and is shown in Figure 41 and the generated support displacement history is shown in Figure 42. A comparison of the spectrum with the enveloping spectrum of the analysis of section 5c (Figure 30) further shows the severity of the

envelope used previously. The several displacement cycles in Figure 42 have essentially the same form and magnitude. For this analysis, a displacement which envelopes each cycle is applied as a representative loading condition for all cycles during the seismic event. The representative seismic cycle loading is shown in Figure 42. Consideration is given to the number of cycles which the crack tip experiences in assessing crack stability.

The normal full power loadings are statically applied to the finite element model conta'ning the 30° circumferential crack to simulate the initial condition for the dynamic analysis. The J integral value and crack opening area are found to be essentially the same as those given in section 4a, the-eby confirming that modelling changes did not significantly effe:t the static results. The seismic support motions are then applied a d the resulting J and crack opening area histories are shown in Figure 43 and 44.

The J integral value is not greatly affected by the seismic loadings, which is consistent with the results of the analysis of section 5c. Similarily, the crack opening area increase due to the seismic loads is very small. The J integral results when compared to the "degraded" value of J_{IC} (100 to 150 in lb/in.^{2} from Figure 39), show a considerable margin against instability.

b. Safety Margin on Crack Length

To assess the margin on crack length, the smallest length of crack which will be unstable when subjected to the SSE loading and evaluated using only 25% of the ductile crack resistance properties must be determined. For this analysis the loading conditions are applied in the same manner as in the analysis of Section 6a. The assumed crack size, however, is much larger. Previous analyses indicated that a crack must be more than halfway around the circumference in order to be unstable even during seismic loading. Those analyses, however, did not consider the significant property reduction employed in this analysis.

The ductile crack stability criterion states that a crack will be unstable if:

$$J \geq J_{IC} \text{ and}$$

the tearing modulus $T = \dfrac{\partial J}{\partial a} \dfrac{E}{\sigma_0^2} > T_{mat}.$

In order to determine T, more than one crack size must be evaluated so that the derivative term $\partial J/\partial a$ can be evaluated.

It is appropriate, therefore, to consider the cracks for evaluation to be a half circumference crack and a crack somewhat le.s than half circumference long. Evaluation of these cracks will enable a comparison with previous work and enable an interpolation or slight extrapolation to the length which will be unstable for the imposed loads and properties.

The crack opening area results for the normal loadings of section 4a

show that the opening is greater for cracks on the top and outward side of the elbow and less for the bottom and inward side. It is assumed, therefore, that the top and outward side are the crack locations to consider for the most conservative stability evaluation. The two long cracks which are evaluated are a half circumferential crack centered 30° toward the outside from the top and a one third circumferential crack also centered at 30° toward the outside from the top of the elbow. These assumed cracks are shown in Figure 45.

The normal operation loads are statically imposed on the finite element model containing the larger cracks. For the half circumferential crack, the J value is 374 in lb/in.^{2}, at the "a" end crack tip and 227 in lb/in.^{2} at the "b" end crack tip. The average

value is slightly higher than the value found in Section 5c. (The K_I average of 92 ksi $\sqrt{in}$ found in section 5c corresponds to a J value of 282 in lb/in.^{2}). This is reasonable because the skewed crack is expected to be slightly more severe than an outward side crack. The excellent agreement, however, confirms the new modelling and gives confidence in the consistency of the results. The J value for the one third circumference crack is 109 in lb/in.^{2} at the "a" end crack tip and 84 in lb/in.^{2} at the "b" end.

A plot of static normal operation load J vs half crack length is shown in Figure 46. For the larger crack sizes the J values fit a cubic curve in crack length very precisely. This cubic relationship enables a more precise calculation of $T_{applied}$. This cubic form was used in section 5b in order to obtain $T_{applied}$ from only one analysis. Also shown is the degraded J_{IC} which indicates that for cracks greater than 150° in circumference, $J_{applied} > J_{IC}$. The value of $T_{applied}$ however, for the "a" tip of the half circumference crack is only 1.5 which is much lower than the degraded value of Figure 39. An instability diagram using the degraded values of Figure 39 is shown in Figure 47. The applied loadings for the normal operation load for the 180° and 120° circumferential cracks in also shown. The margin between the loading values and the instability line show that instability will not occur for these cracks during normal operation even if the degraded properties are considered.

In order to compute J for normal operation plus seismic loads the seismic support displacements are applied in the same manner as in the previous section and the dynamic analysis procedes in the same way. The resulting J vs time curves for each of the crack tips is shown in Figure 48 for the 120° crack and in Figure 49 for the 180° crack. The increase in crack opening area caused by the seismic loading for both crack sizes is very small compared to the areas determined during normal operating conditions of 0.5 in.^{2} and 1.6 in.^{2} for the 120° circumferential and 180° circumferential cracks respectively.

The $J_{applied}$ and $T_{applied}$ values during the seismic loading are not changed significantly from the normal operation loading results. This is consistent with the results of section 5c where only a small increase in crack tip loading occurred for a much higher seismic loading. The $J_{applied}$ and $T_{applied}$ values, shown on the instability diagram of Figure 47 represent the seismic as well as the normal operating loading case. This analysis shows clearly, that very long cracks in the main loop piping will remain stable when subjected to normal operation and SSE loads even if the ductile crack resistance material properties are considered to be only a fourth of the nominal value.

These results satisfy, with considerable margin, the requirements for the demonstration of leak-before-break in the main loop piping.

c. Margin on Axial Slot in Elbow

The results of the analysis of the 20 inch long axial slot in the 90° pipe elbow described in Section 5d, are plotted on the instability diagram in Figure 50. The stability of this crack is evident from the curve, which reflects the very low value of $T_{applied}$.

d. Seismic Moments

The maximum bending moments computed by the traditional seismic analysis in the uncracked pipe at the discharge leg terminal end at the RV inlet nozzle are shown in Table 3. The maximum component, around the vertical axis, is 2, 140 in kips. The other components, about axes in the horizontal plane are less than half of the maximum moment. From Appendix A, it is seen that the seismic moments are much less than the normal operating moments.

In order to determine the effect of the crack on the magnitude of the applied moment, the finite element of model Figure 28 and 29 was used. A relative displacement between the pump and the reactor vessel which produced a moment mostly about the vertical axis at the crack location was imposed on the model and the crack length was increased. The crack was assumed to be located on the outside of the elbow where it would be opened by the bending moment. The decrease in the moment due to increasing the crack length is shown in Figure 51. From the figure, it can be seen that cracks shorter than 120° circumference cause less than a 10% reduction in bending moment. Longer cracks cause significantly more moment reduction. This moment reduction enhances the stability of the main loop piping system subject to seismic loads.

The J integral values for several crack lengths for the system relative motion which produces a moment of 2, 140 in-kips in the uncracked pipe are shown in Figure 52. These values are very small and are smaller than the occilations found in the dynamic analysis of Section 6a.

e. Tearing Instability Evaluation

In order to obtain a bounding check on the results of the seismic analyses of the main loop with cracked pipes, a stability analysis was performed. The analysis was performed according to the tearing instability procedure of NUREG CR3464 (Ref.18). This procedure conservatively presumes that the cracked section is loaded to be fully plastic.

The main step in the procedure is to determine the "residual elastic stiffness" of the piping system. A finite element model similar to the one in Figure 28 (except that the crack region was replaced by pipe elements) was employed. The pipe elements were disconnected in the rotational degrees of freedom to simulate a "ball and socket" joint. A unit moment of $1x10^6$ in-lb about the vertical axis was applied on each side of the joint, as shown in Figure 53. The resulting rotations are also shown in the figure. Because this moment direction is the maximum during seismic loading, it is felt to be the proper direction for consideration of stability.

From Figure 53, the residual stiffness can be calculated as

$$K_\phi = \frac{M}{\phi} = \frac{1.0 \times 10^6}{2.256 \times 10^{-4}} \text{ IN-lb}$$
$$= 0.443 \times 10^{10} \text{ IN-lb}$$

Using the formula

$$T_{Appl} = \frac{2h^2 t E}{K_\phi}$$

where $h = R(\cos\theta + \sin\theta)$

and 2θ is the extent of the circumferential crack, t is pipe thickness and R is pipe radius,

the values of T appl are computed in Table 4. The maximum value in the Table, 13.5, is confined by the bounding equation

$$T_{Appl} = \frac{1.6\ E I}{2 R K_\phi} = 13.5$$

where I is the pipe moment of inertia.

In Section 6b, it was seen that the T applied in the seismic analysis was on the order of 2. The valve computed above of 13.5 represents the fully plastic condition which is the upper bound of T applied. The T applied value for actual loadings is significantly lower.

Stability is assurred if T appl < T mat. From the figures 47 and 50, it is seen that T mat is much larger than the upper bound T applied, thereby assuring stability for any loading in addition to those explicitly considered in Section 6a and 6b.

7. CONCLUSIONS

In this report, a variety of crack sizes, loadings and material properties have been considered and analyzed in order to demonstrate that a leak-before-break condition exists in the main loop piping of a CE PWR. It was shown that cracks in this piping system would tend to grow through the pipe wall rather than circumferentially due to the fatigue loading conditions.

Conservative crack opening area calculations showed that a circumferential crack about 8 inches long in the top of side of the discharge leg terminal end would leak at a rate of 10 gpm but would have a high margin against instability even when subject to safe shutdown seismic loads. At the bottom of the terminal ends, a greater crack length is required for a leak rate of 10 gpm, but the loading in this region is so small that crack instability is not a concern. The margin against instability for detectably leaking cracks is demonstrated to be substantial in terms of margin on material propertes, on loadings, and on crack size required for instability.

An axial slot less than 8 inches in length was shown to leak more than 10 gpm. This size crack has a very high margin against instability since even

20 inch long cracks are clearly stable. The requirements for the demonstration of leak-before-break therefore are also satisfied for axial slot cracks in the piping elbows.

A tearing instability evaluation was also performed which demonstrated that the piping system is stable even when subject to a moment sufficient to cause a fully plastic pipe section. All these analyses clearly demonstrate that leak-before-break conditions are satisfied with considerable margin in the main loop piping of a CE PWR.

8. REFERENCES

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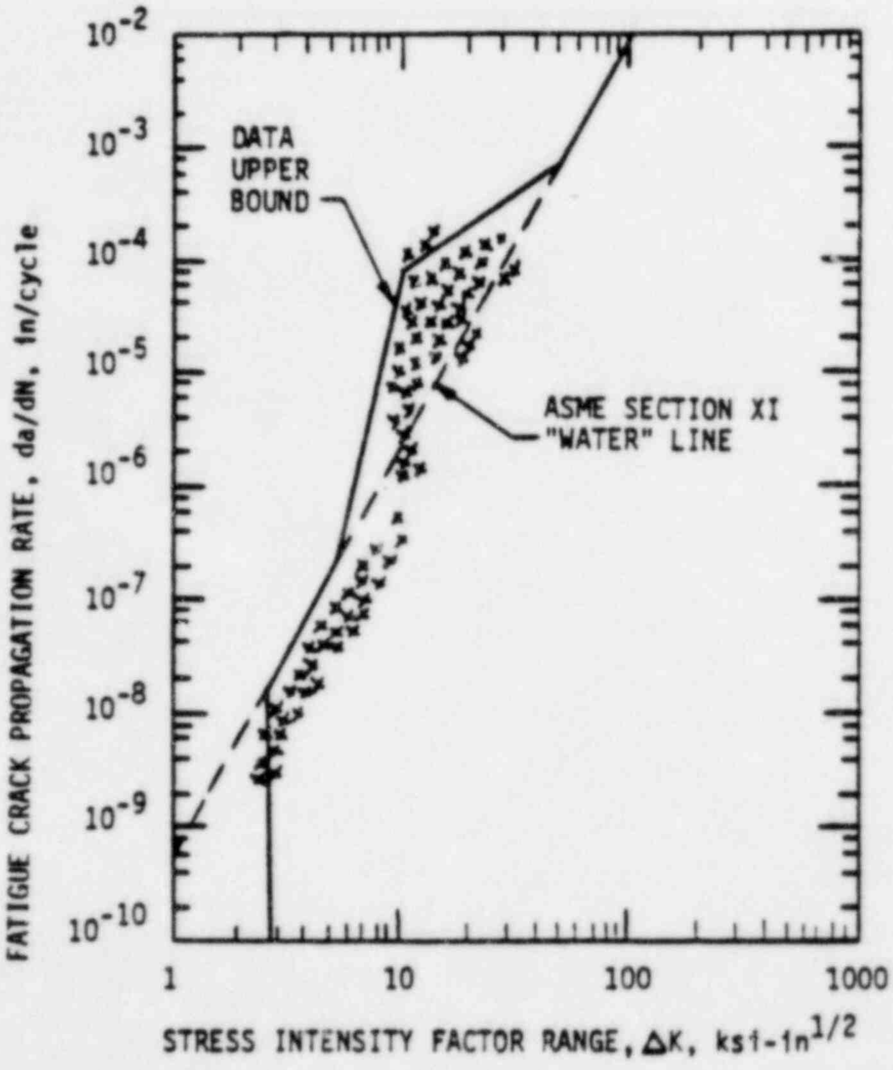


Fig. 1: FATIGUE CRACK GROWTH CURVE, da/dN vs. ΔK

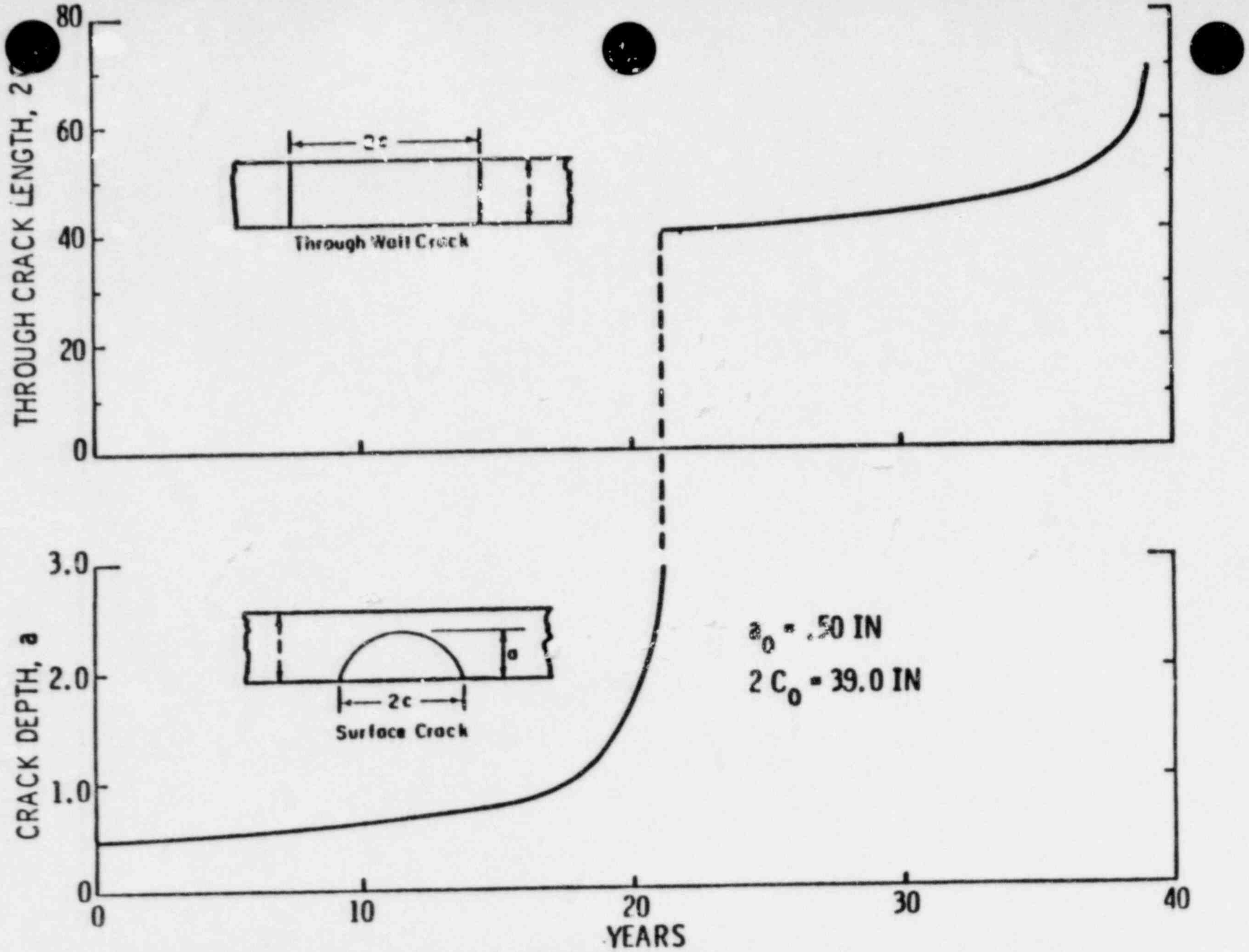


Fig. 2 FATIGUE CRACK GROWTH VS. YEARS OF OPERATION

a_0= .50 in., 2 C_0= 39.0 in.

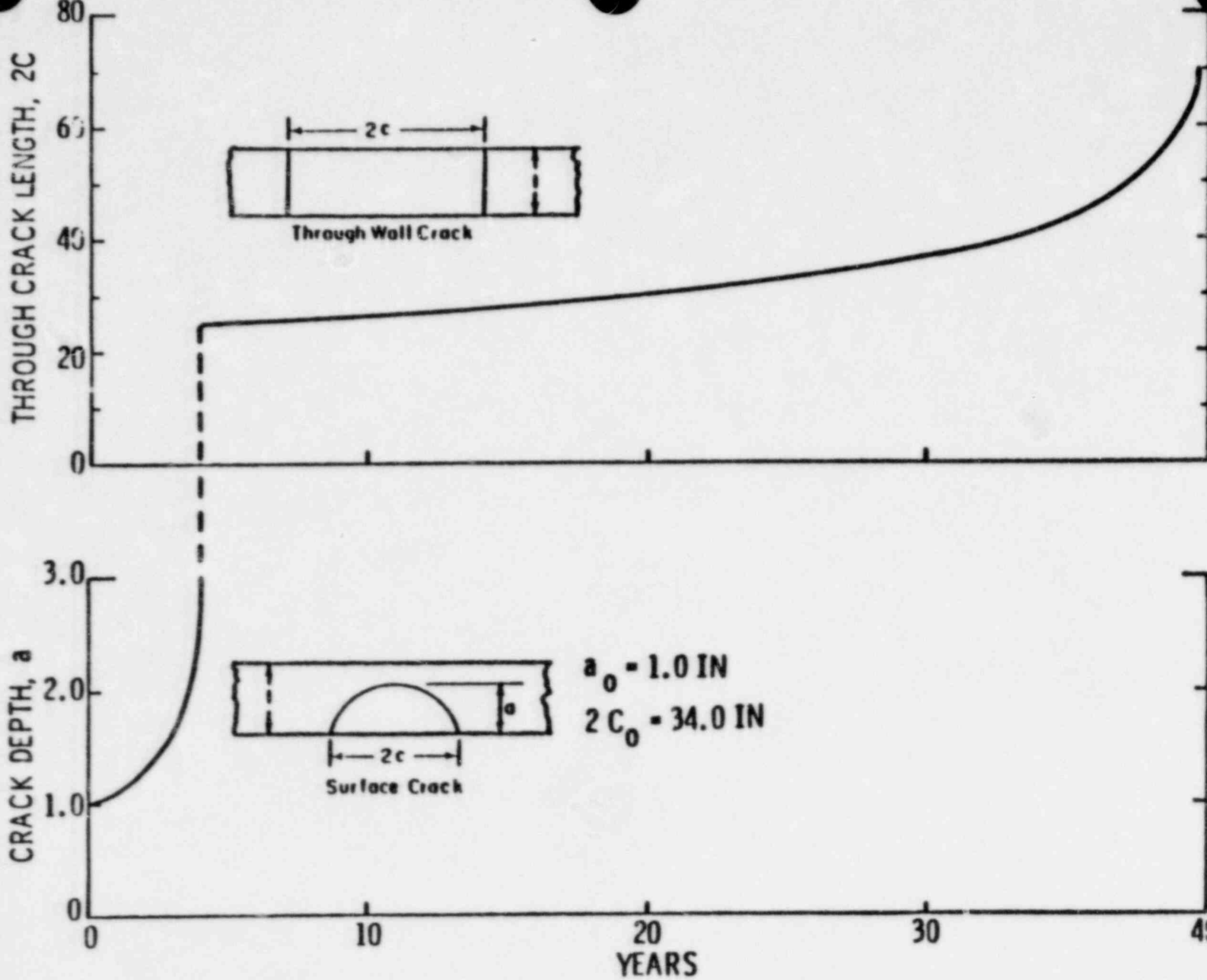


Fig. 3 FATGUE CRACK GROWTH VS. YEARS OF OPERATION
a_o=1.0 in., 2 C_o= 34.0 in.

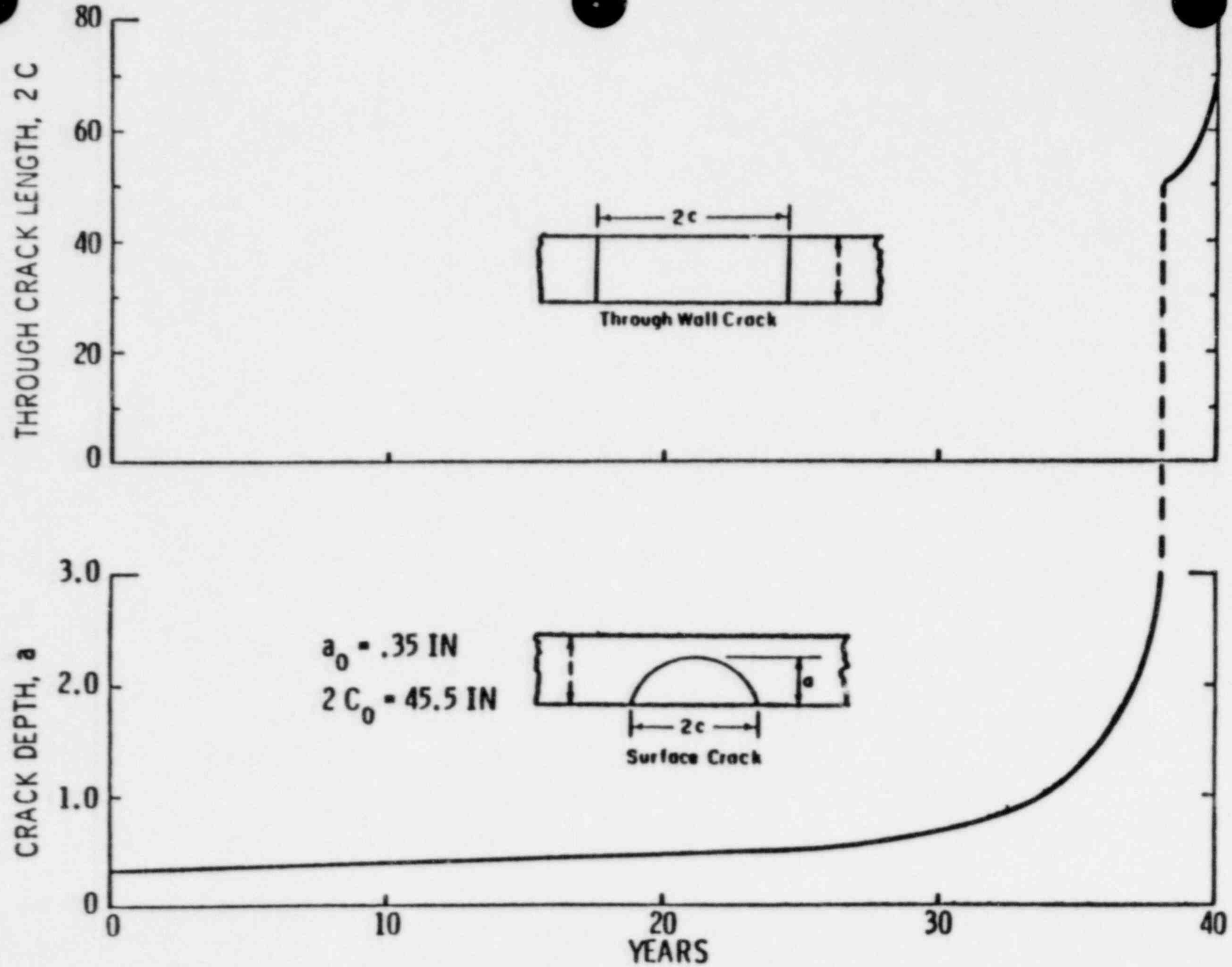


Fig. 4 FATIGUE CRACK GROWTH VS. YEARS OF OPERATION

a_o= .35 in., 2 C_o= 45.5 in.

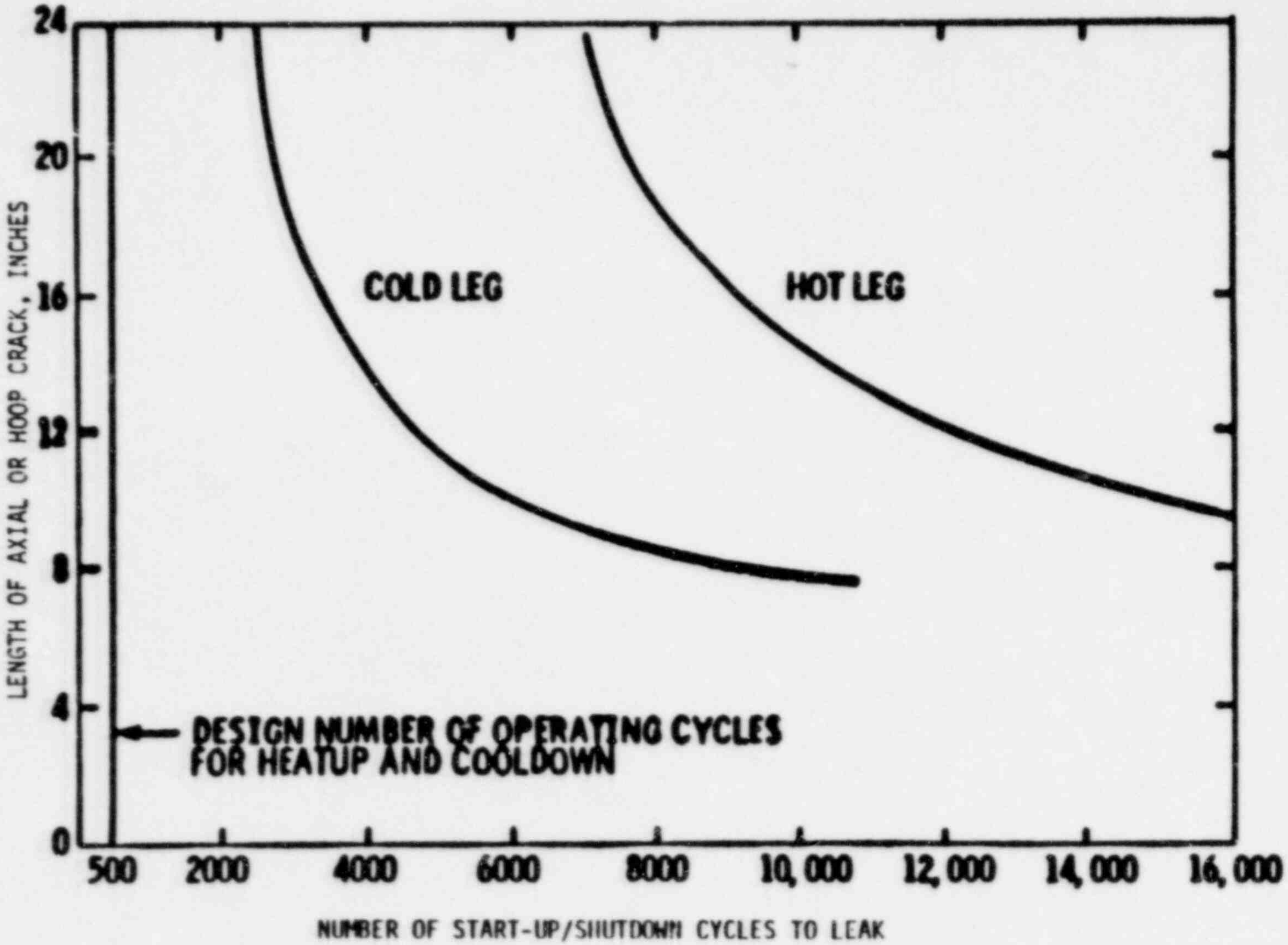


Fig. 5 NUMBER OF CYCLES AT 18 KSI TO CAUSE A CRACK ORIGINALLY ONE INCH DEEP TO LEAK

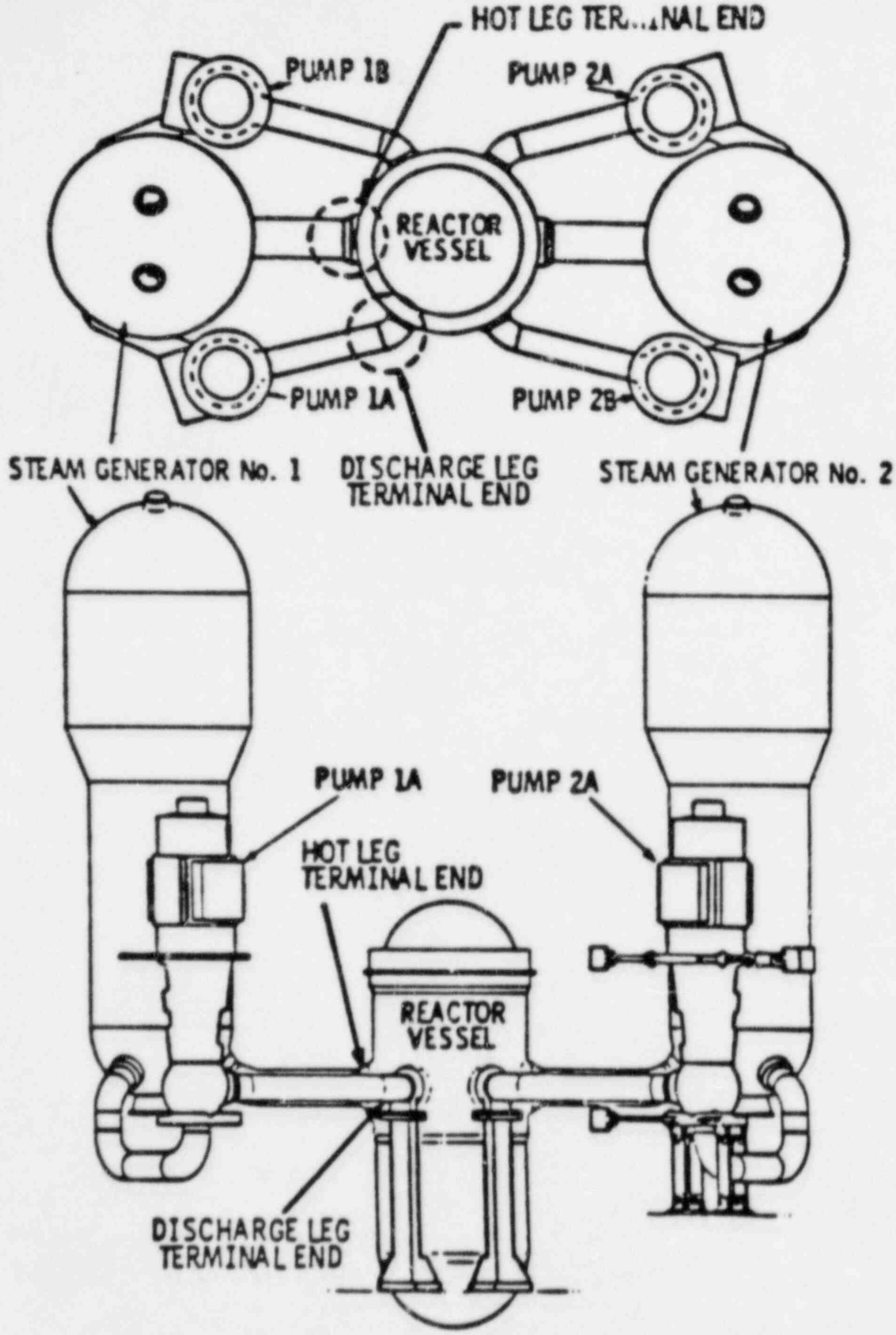
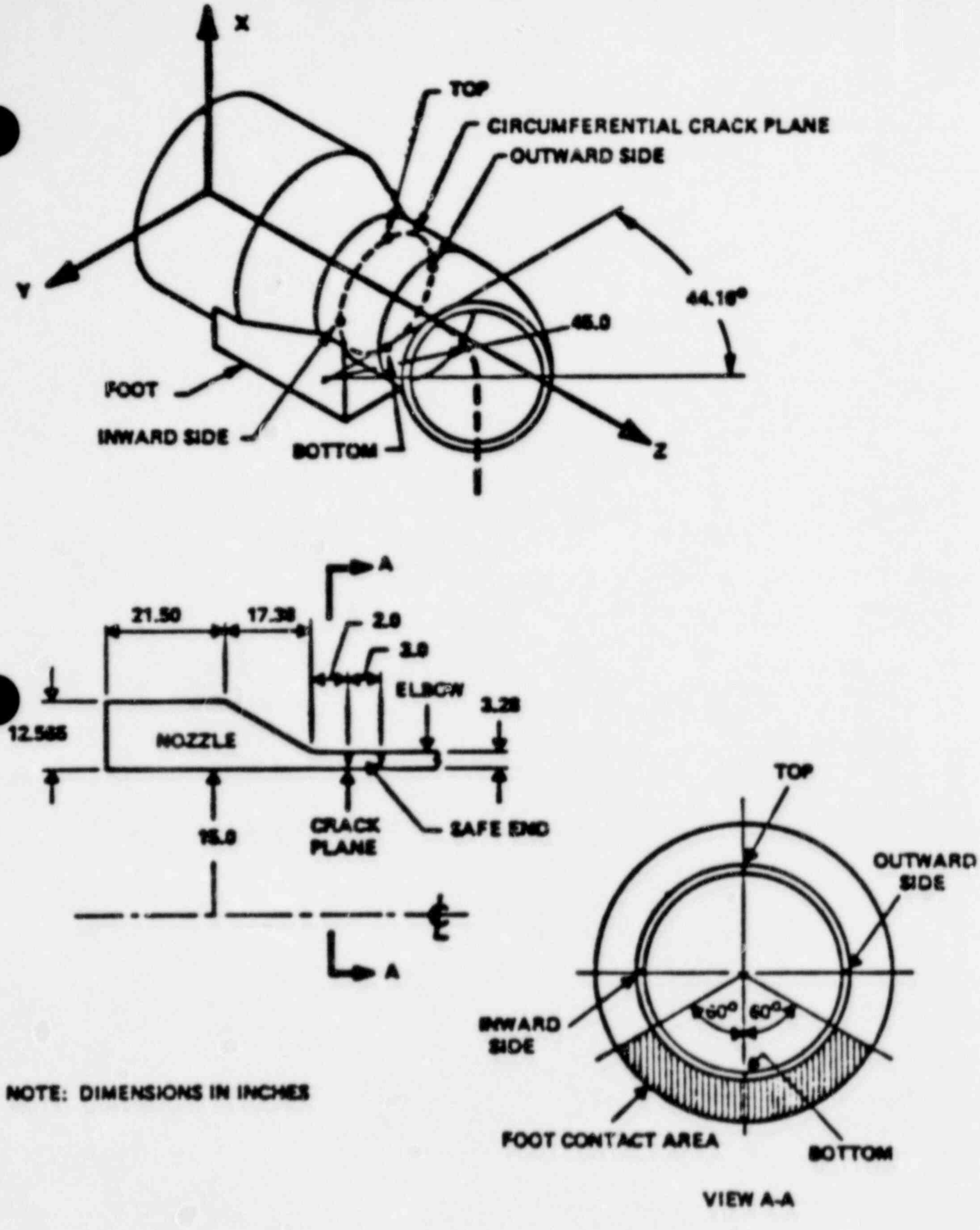
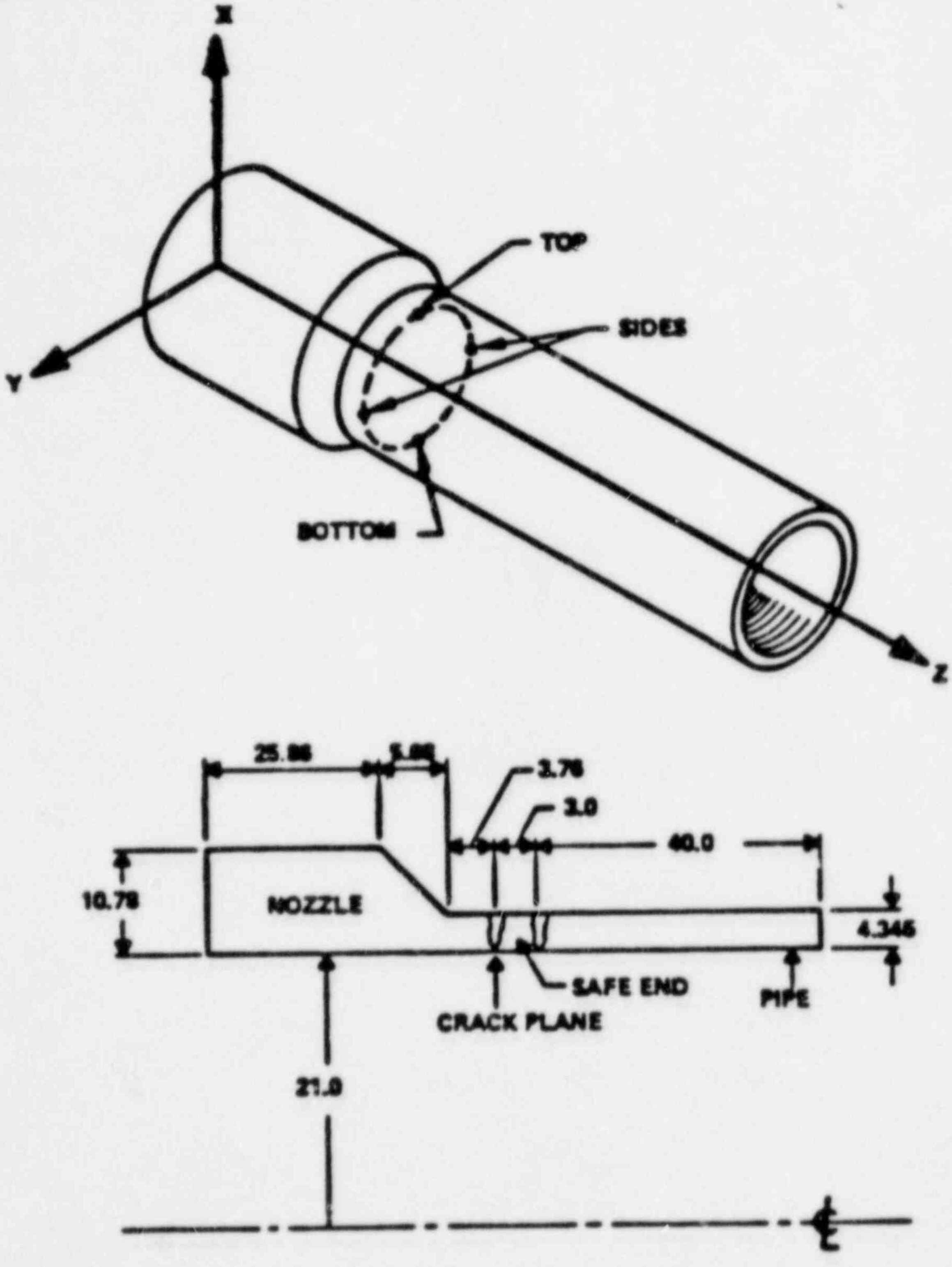


Fig. 6 NUCLEAR STEAM SUPPLY SYSTEM ARRANGEMENT SHOWING LOCATIONS IN THE PRIMARY COOLANT SYSTEM THAT WERE ANALYZED



NOTE: DIMENSIONS IN INCHES

Fig. 7: DISCHARGE LEG TERMINAL END



NOTE: DIMENSIONS IN INCHES

Fig. 8 : HOT LEG TERMINAL END

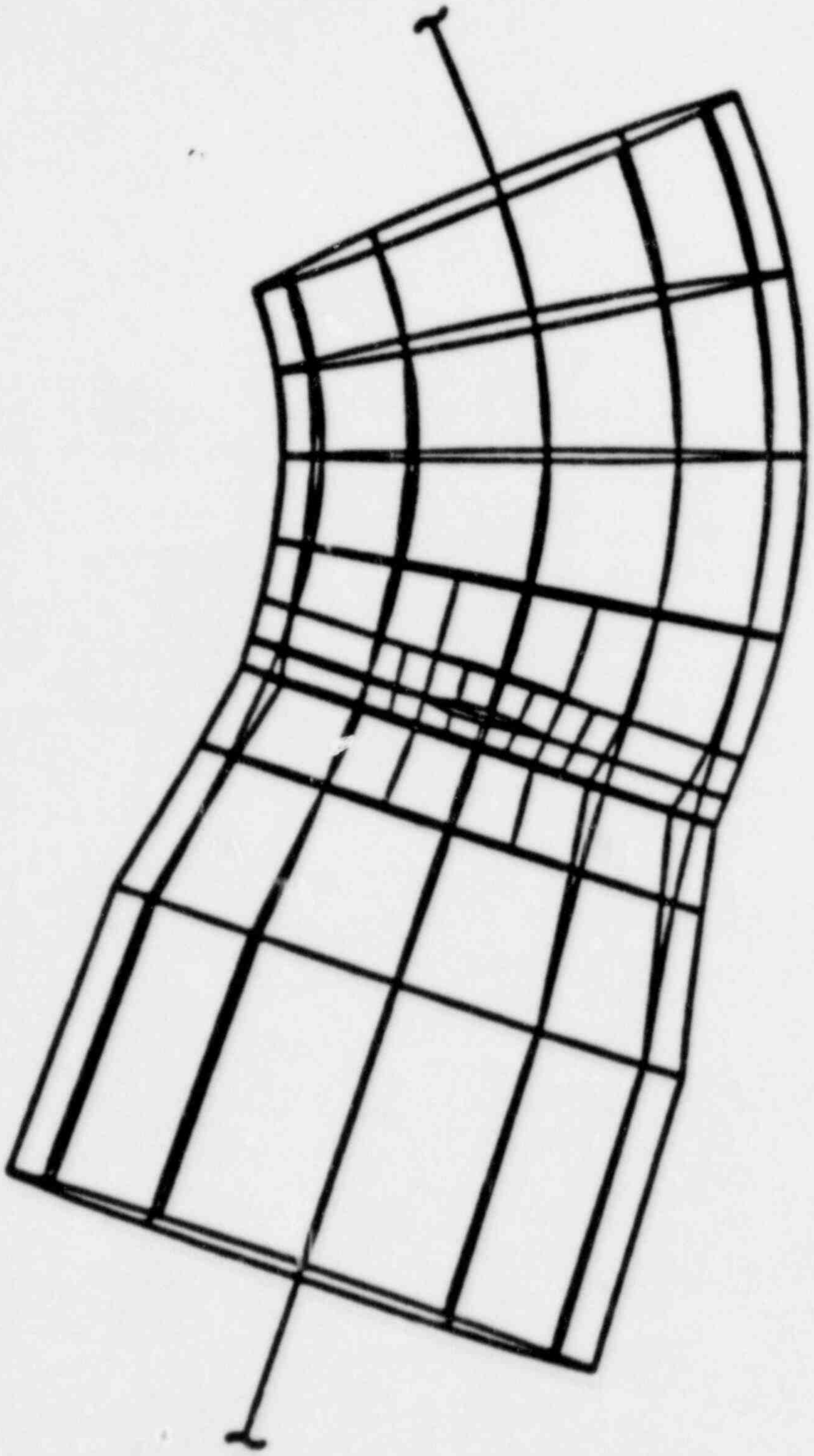
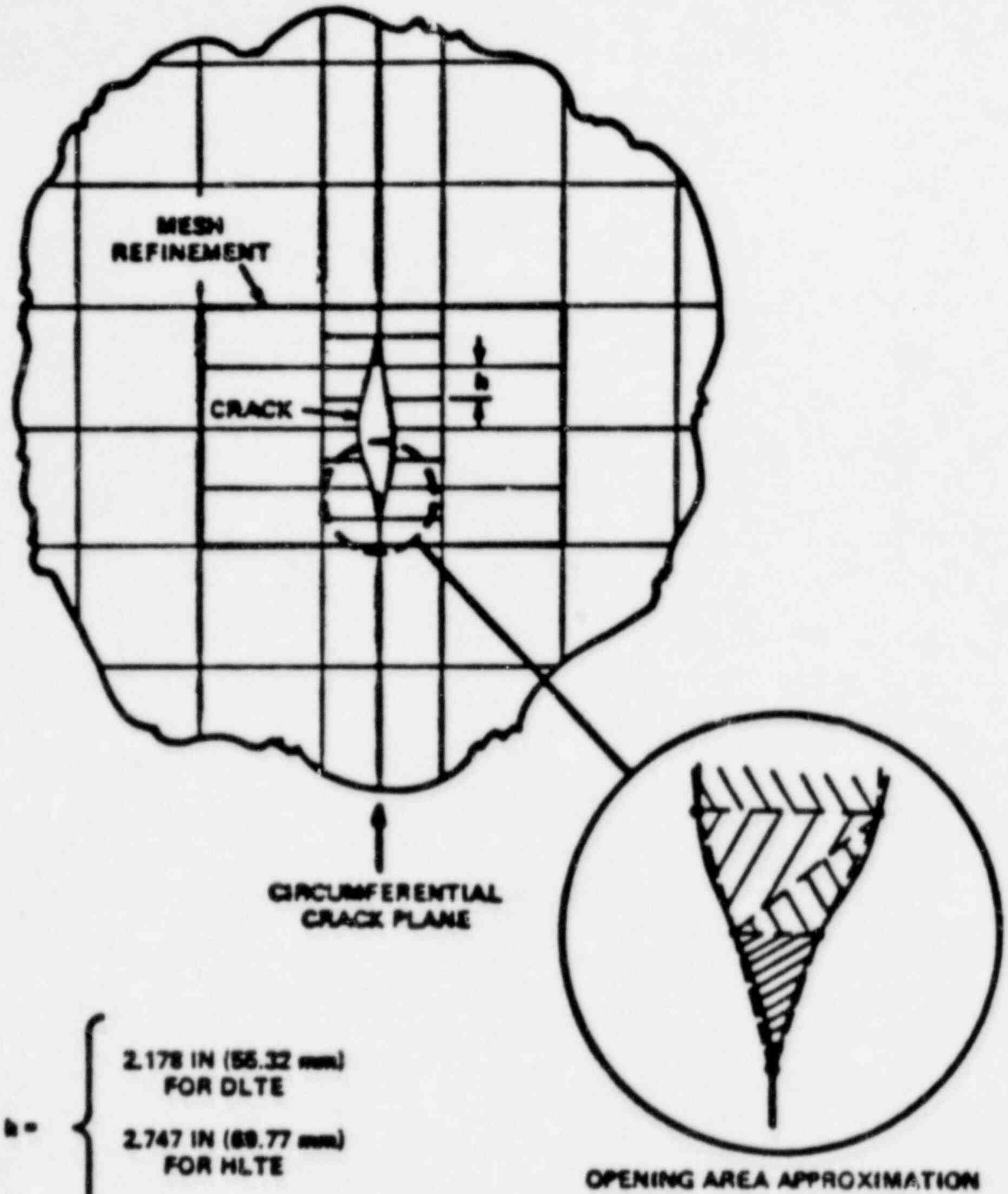


Fig. 9: **FINITE ELEMENT MODEL AFTER DEFORMATION OF DISCHARGE LEG TERMINAL END WITH BOTTOM CRACK**



h = 2.178 IN (55.32 mm) FOR DLTE
2.747 IN (69.77 mm) FOR HLTE

Fig. 10: MESH REFINEMENT FOR CRACK OPENING AREA MODELLING

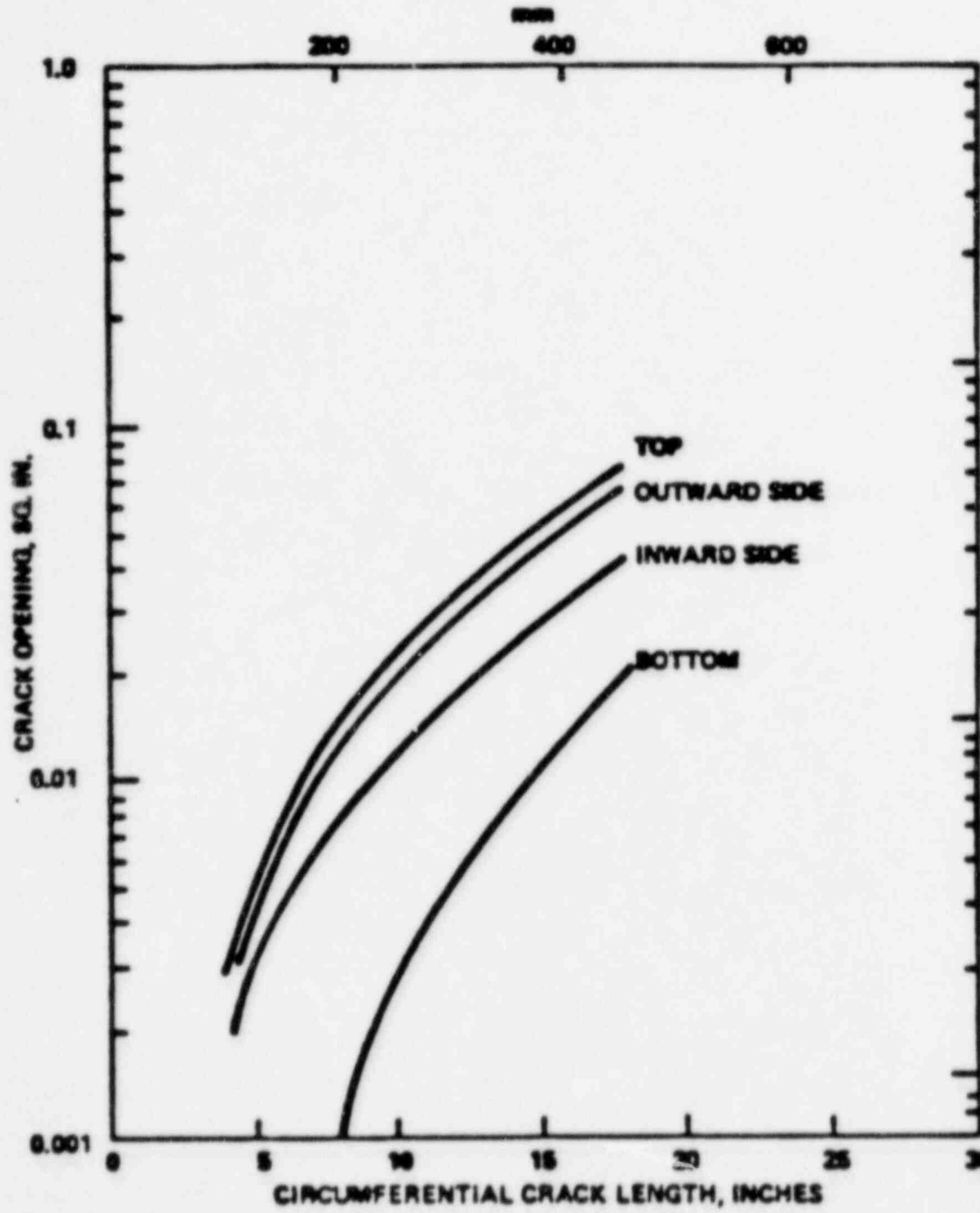


Fig. 11: CRACK OPENING AREA vs CRACK LENGTH FOR 30" DISCHARGE LEG TERMINAL END AT REACTOR VESSEL INLET NOZZLE WITH NORMAL OPERATING SYSTEM LOADS

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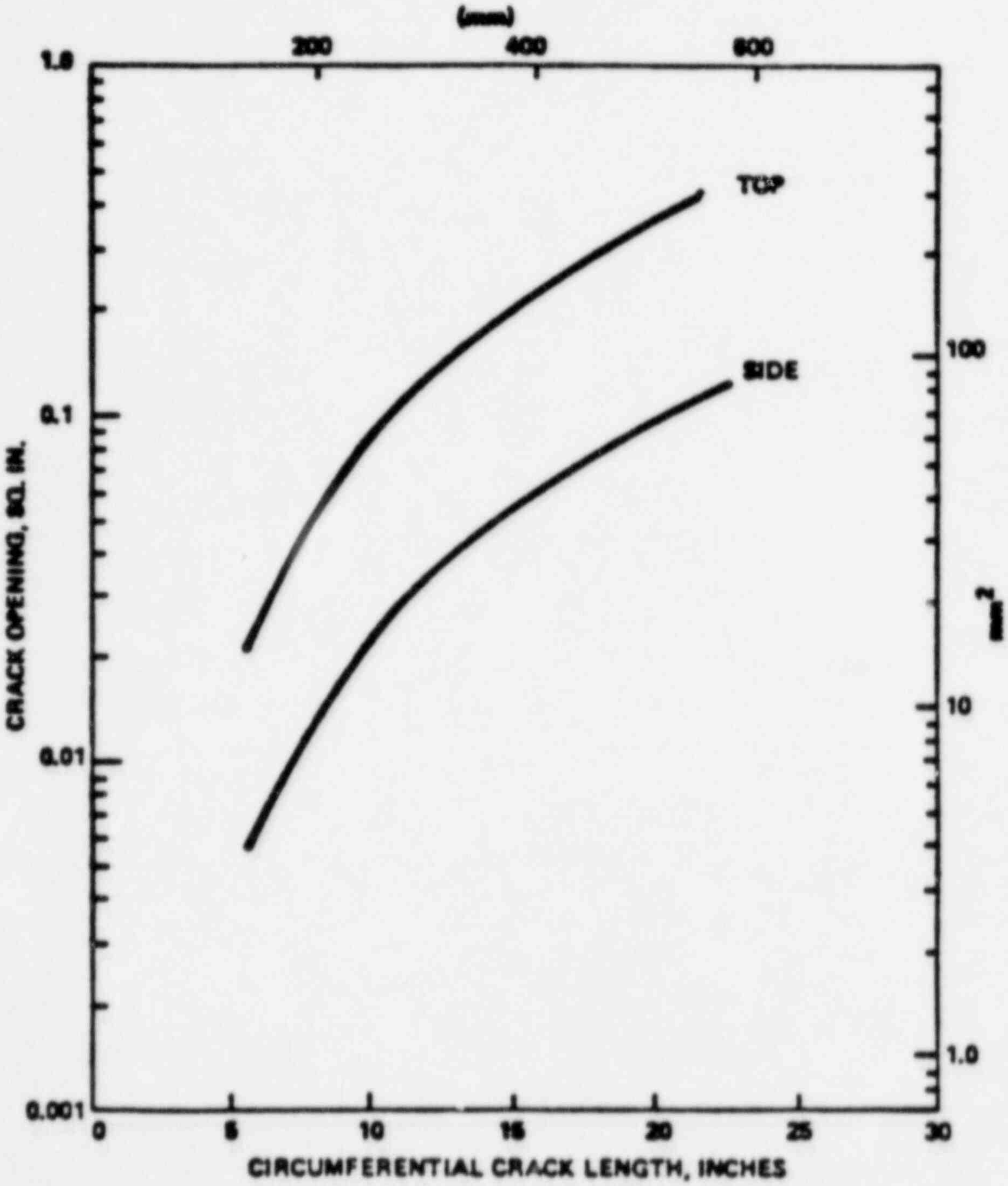

Fig. 12: CRACK OPENING AREA vs CRACK LENGTH FOR 42" HOT LEG TERMINAL END AT REACTOR VESSEL OUTLET NOZZLE WITH NORMAL OPERATING SYSTEM LOADS

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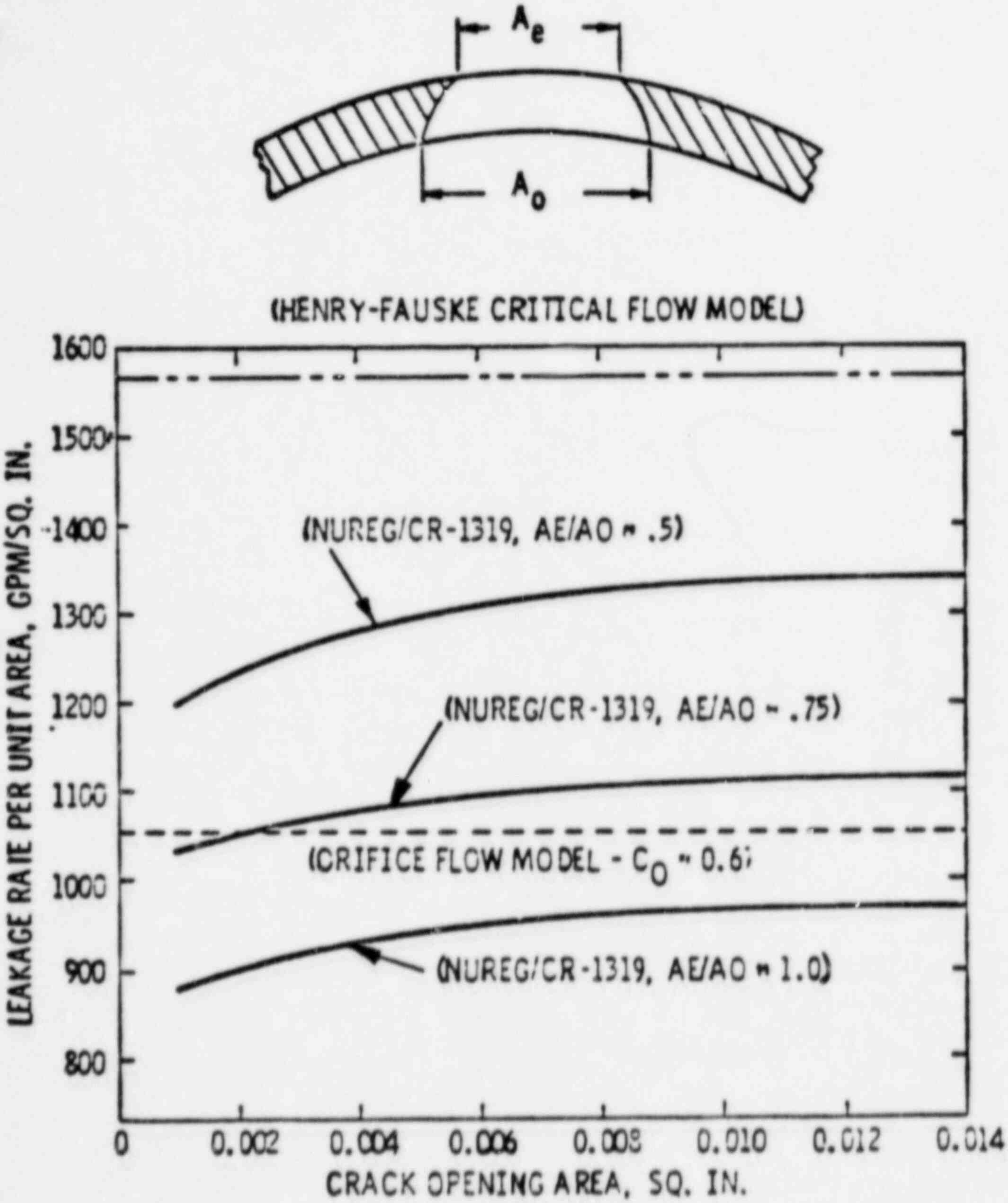

Fig. 13

Flow/Crack Area Correlations

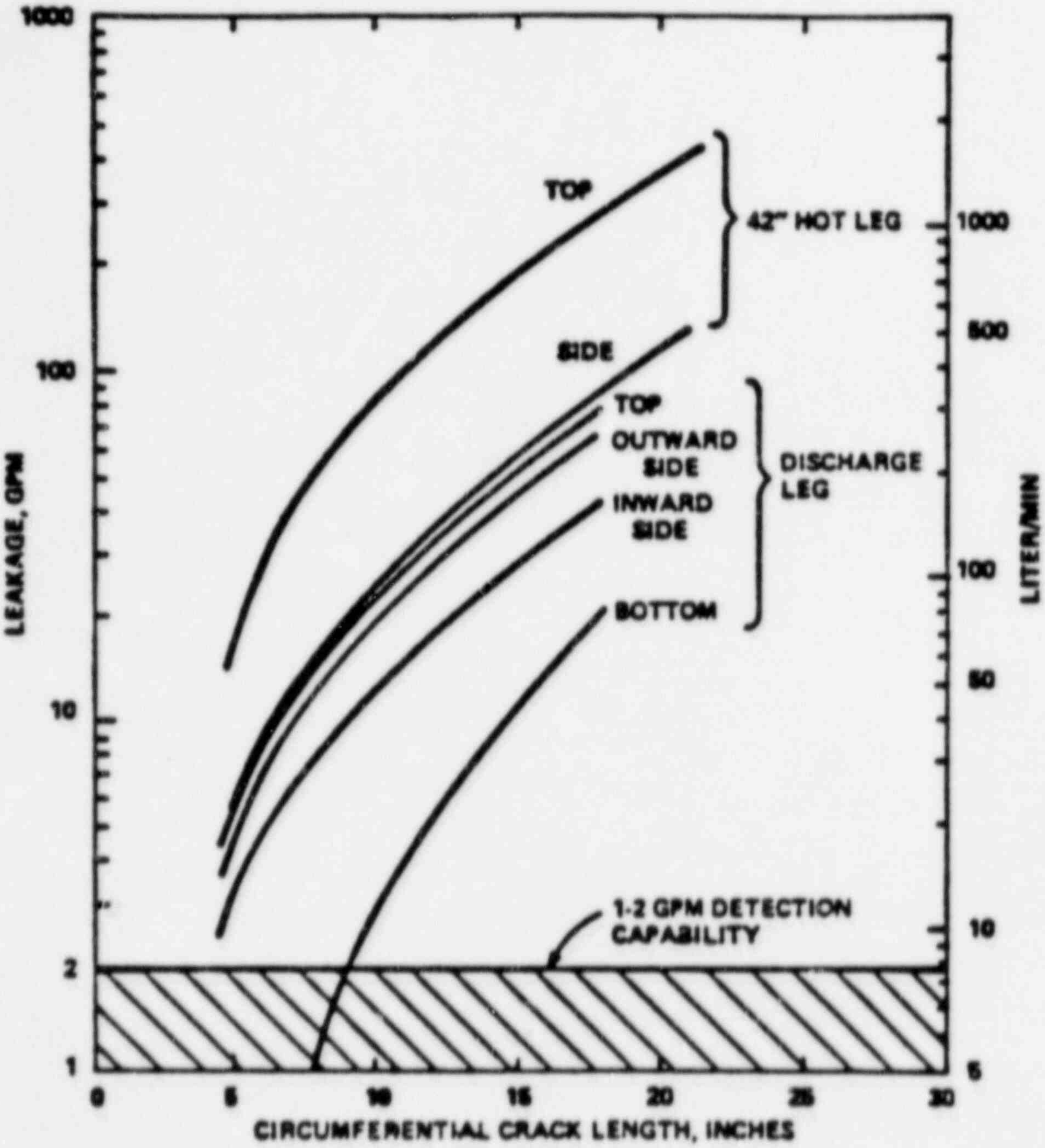

Fig. 14: LEAKAGE RATE vs CRACK LENGTH FOR 30" AND 42" PIPE TERMINAL ENDS AT REACTOR VESSEL NOZZLES WITH NORMAL OPERATING SYSTEM LOADS

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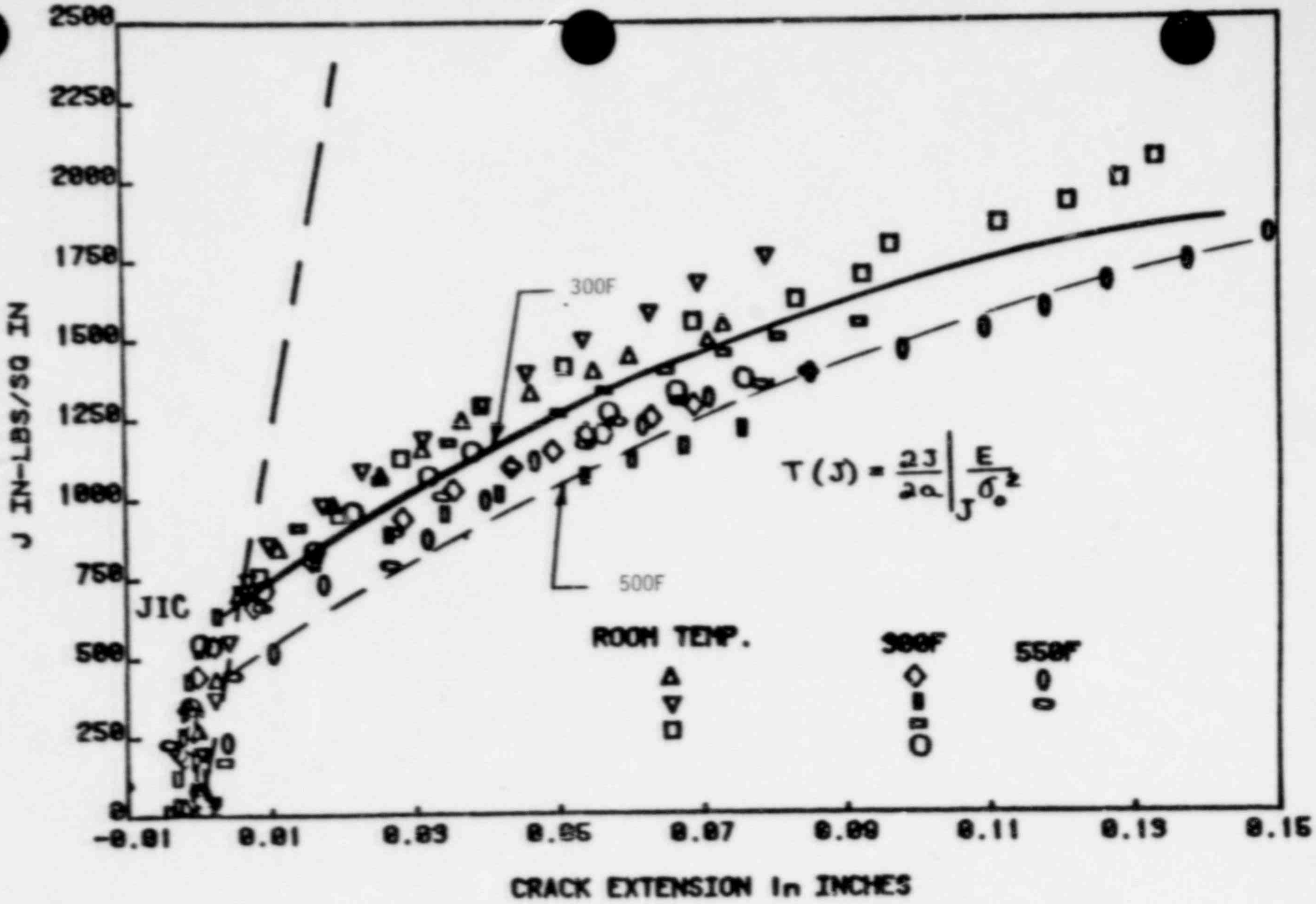

Fig. 15: J vs Crack Extension A516 (20% Side Grooves)

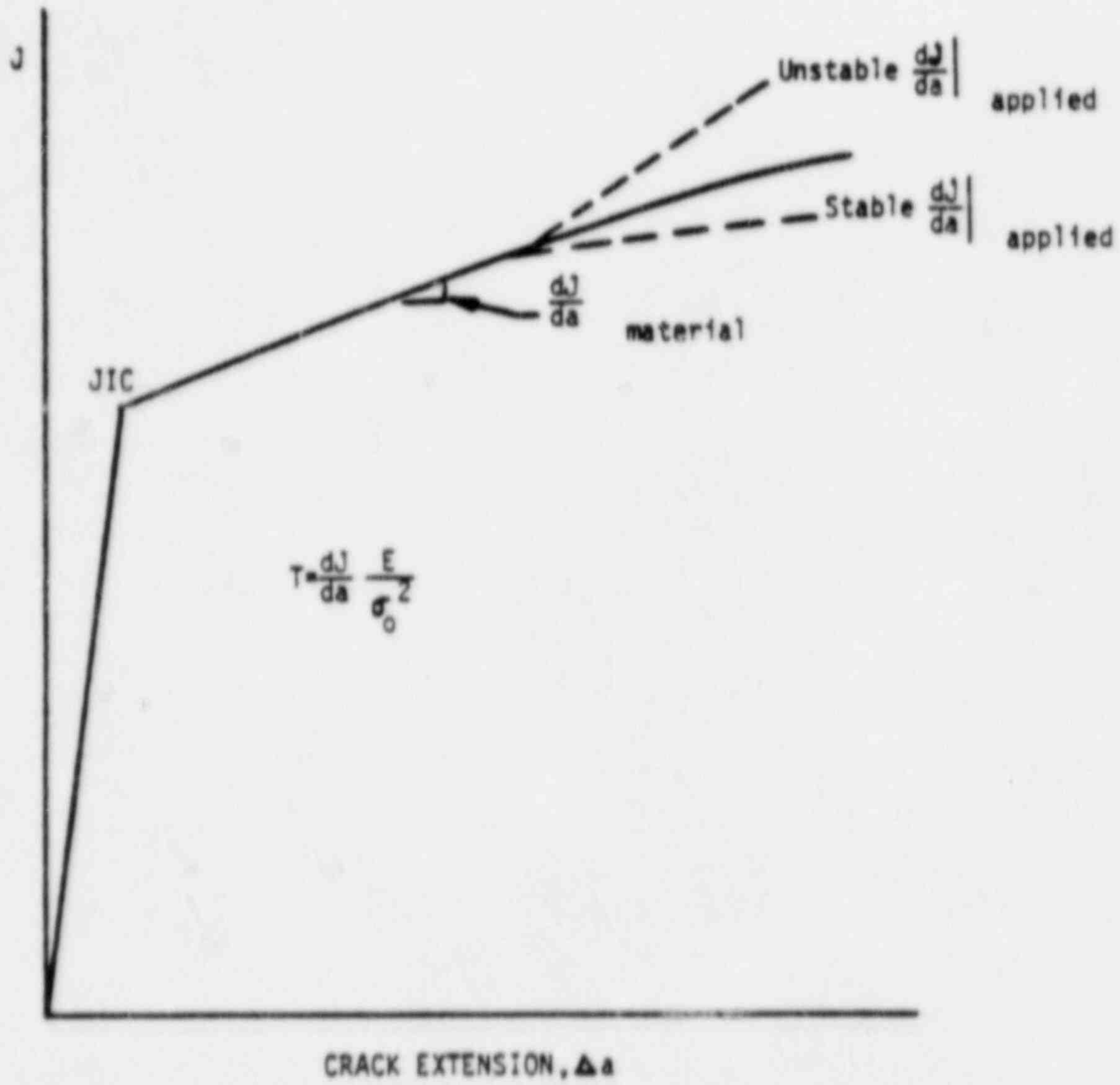

Fig. 16: PLASTIC INSTABILITY CRITERION

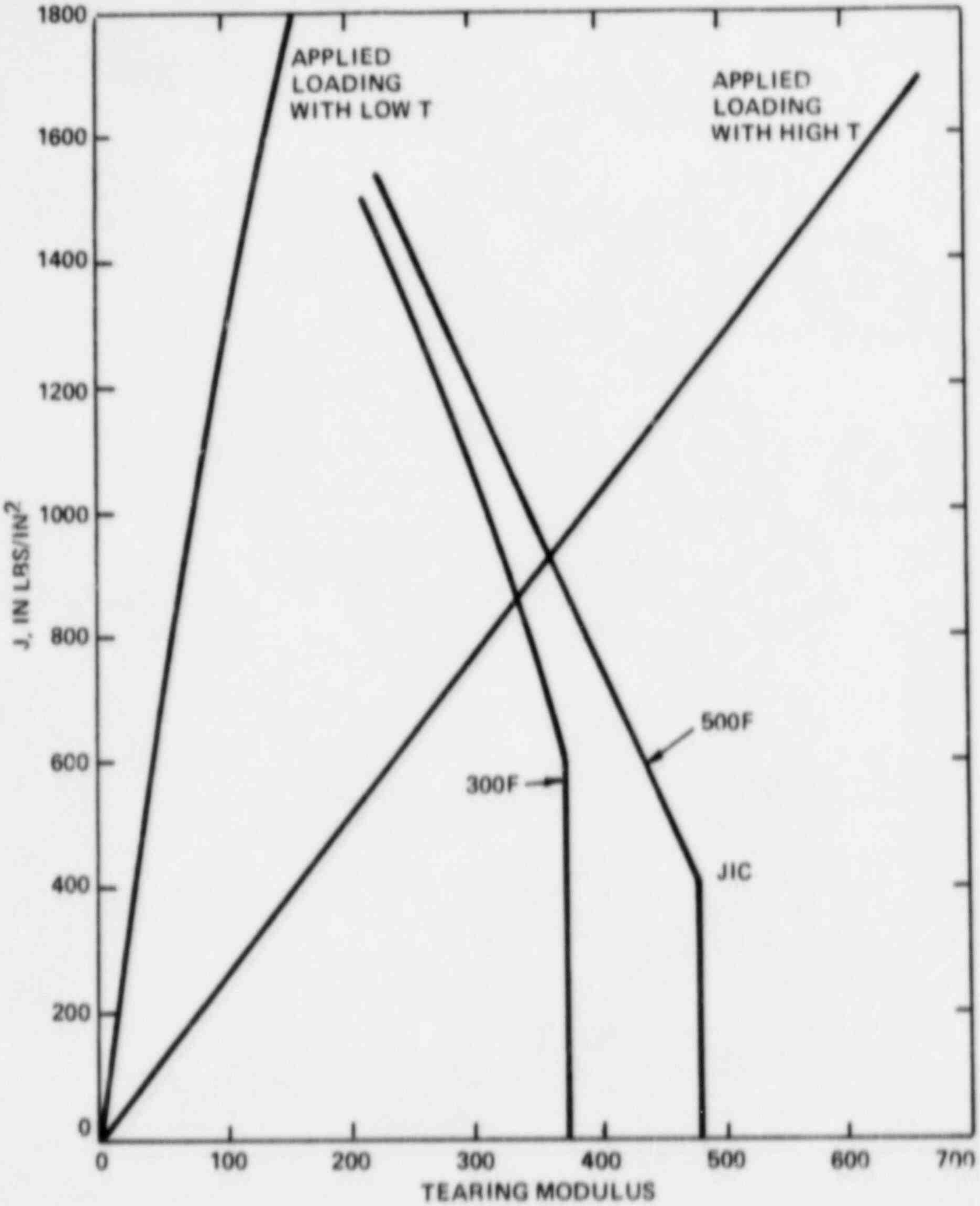

FIGURE 17: INSTABILITY DIAGRAM ILLUSTRATING THE INTERACTIONS OF MATERIAL AND STRUCTURAL PARAMETERS

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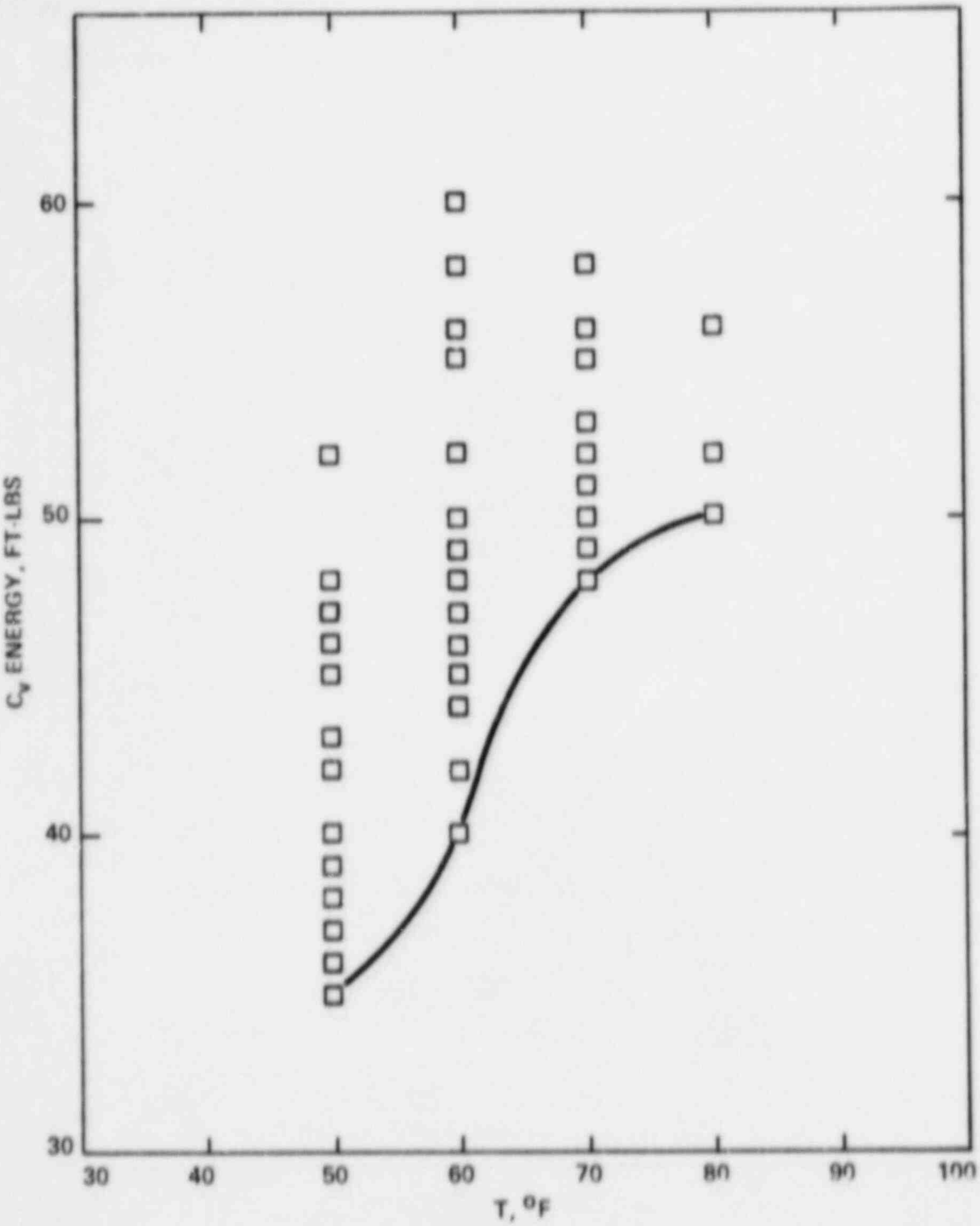

FIGURE 18: SA 516 GR 70 PIPE (PLATE) MATERIAL FOR ARIZONA I

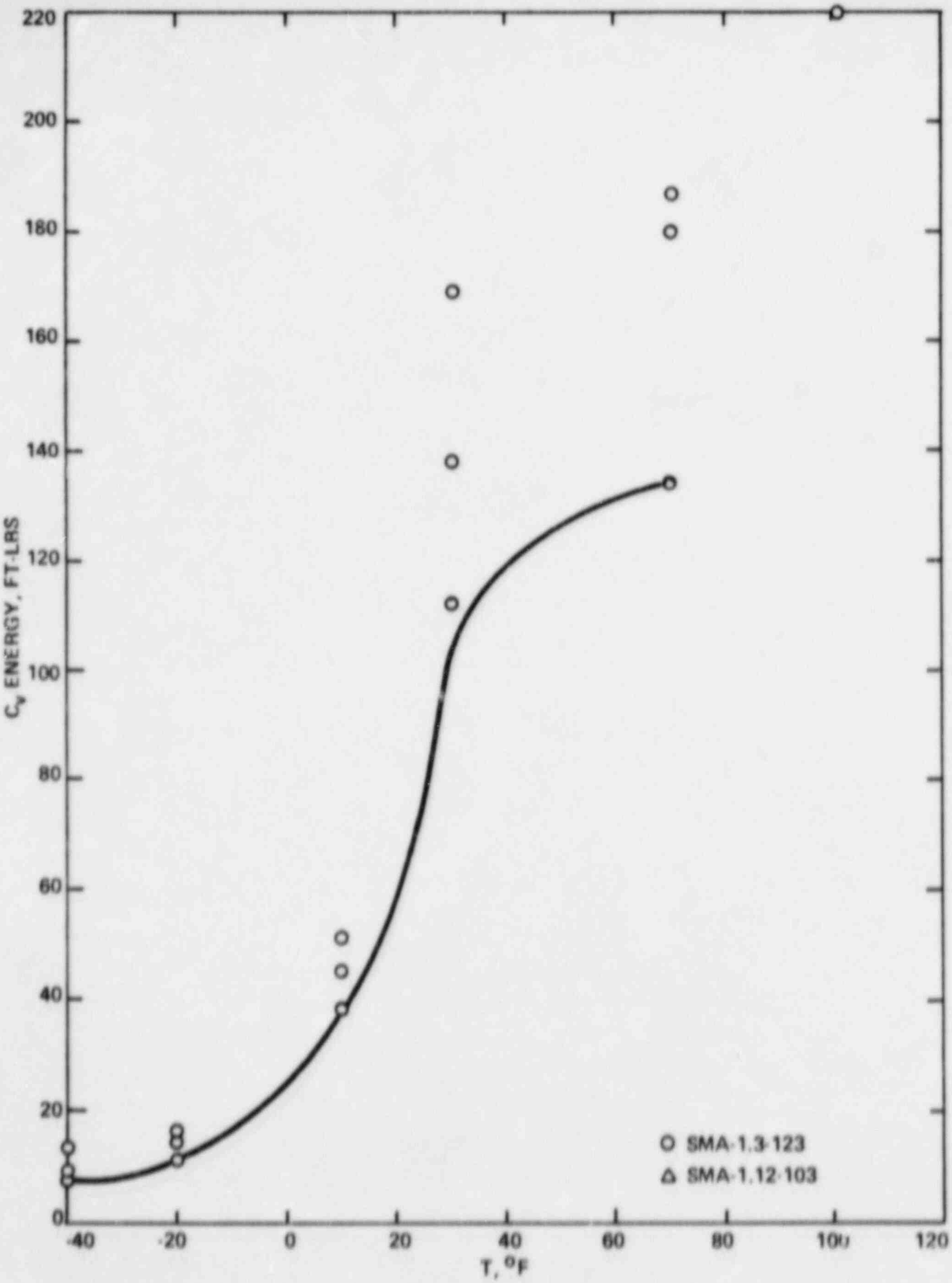

FIGURE 19: WELD BETWEEN SA 516 GR. 70 Q&T AND SA 533 GR. B CL. 1 Q&T

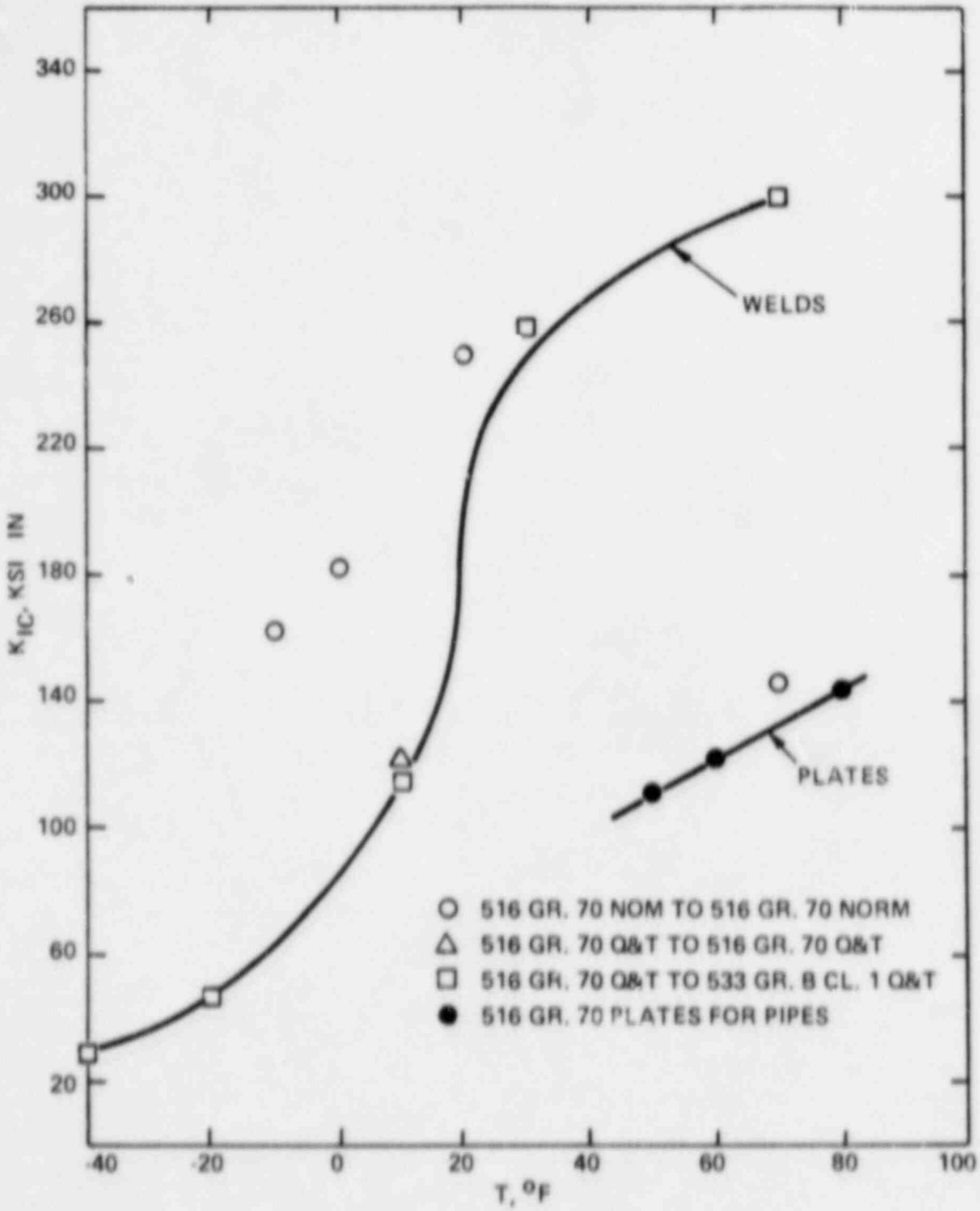

FIGURE 20: K_{IC} MATERIAL

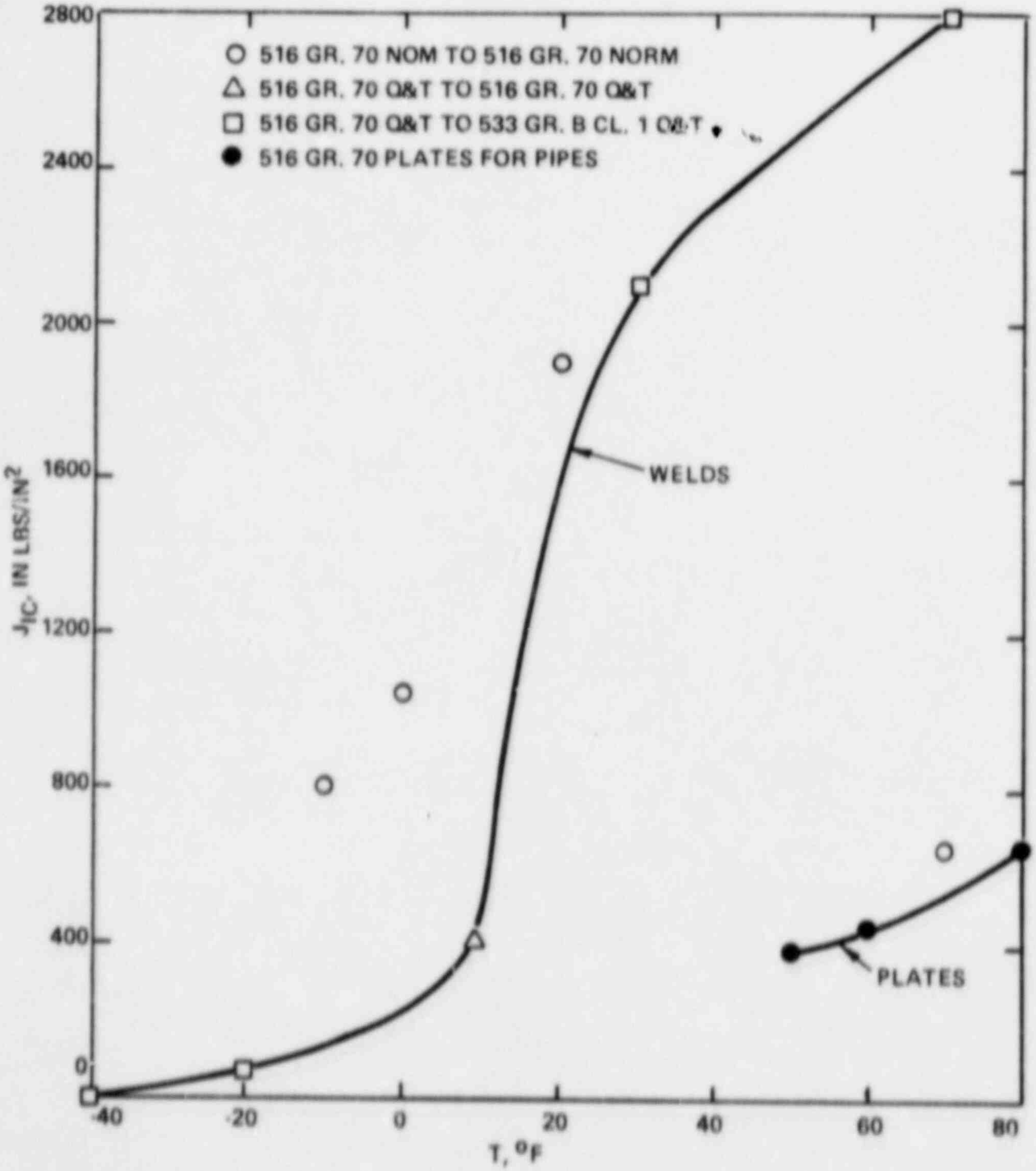

FIGURE 21: J_{IC} MATERIAL

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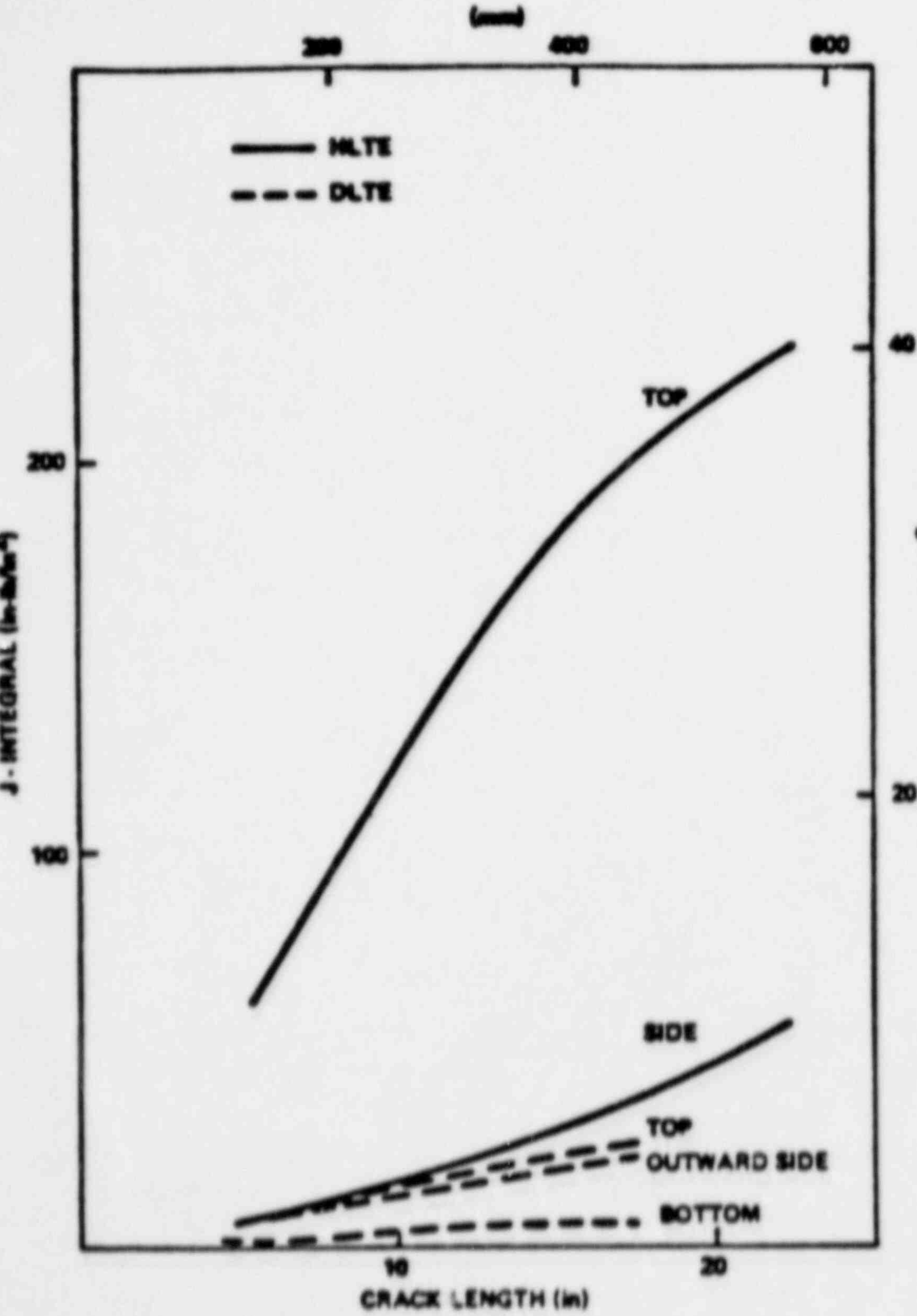

Fig. 22: MAXIMUM J - INTEGRAL VALUE

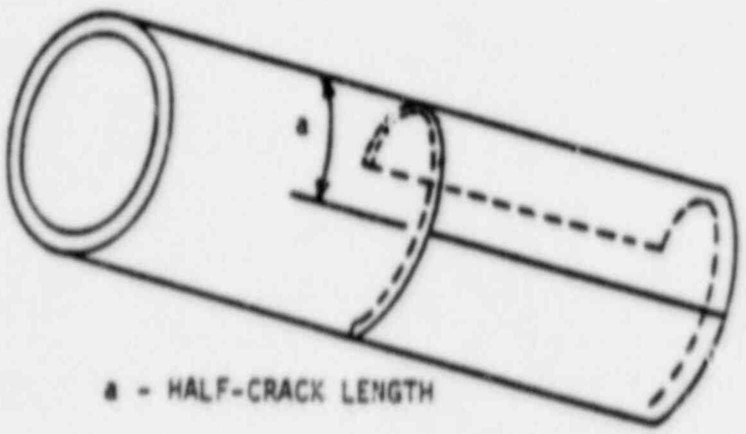

Fig. 23: GEOMETRY OF PIPE WITH HYPOTHETICAL HALF-CIRCUMFERENCE CRACK

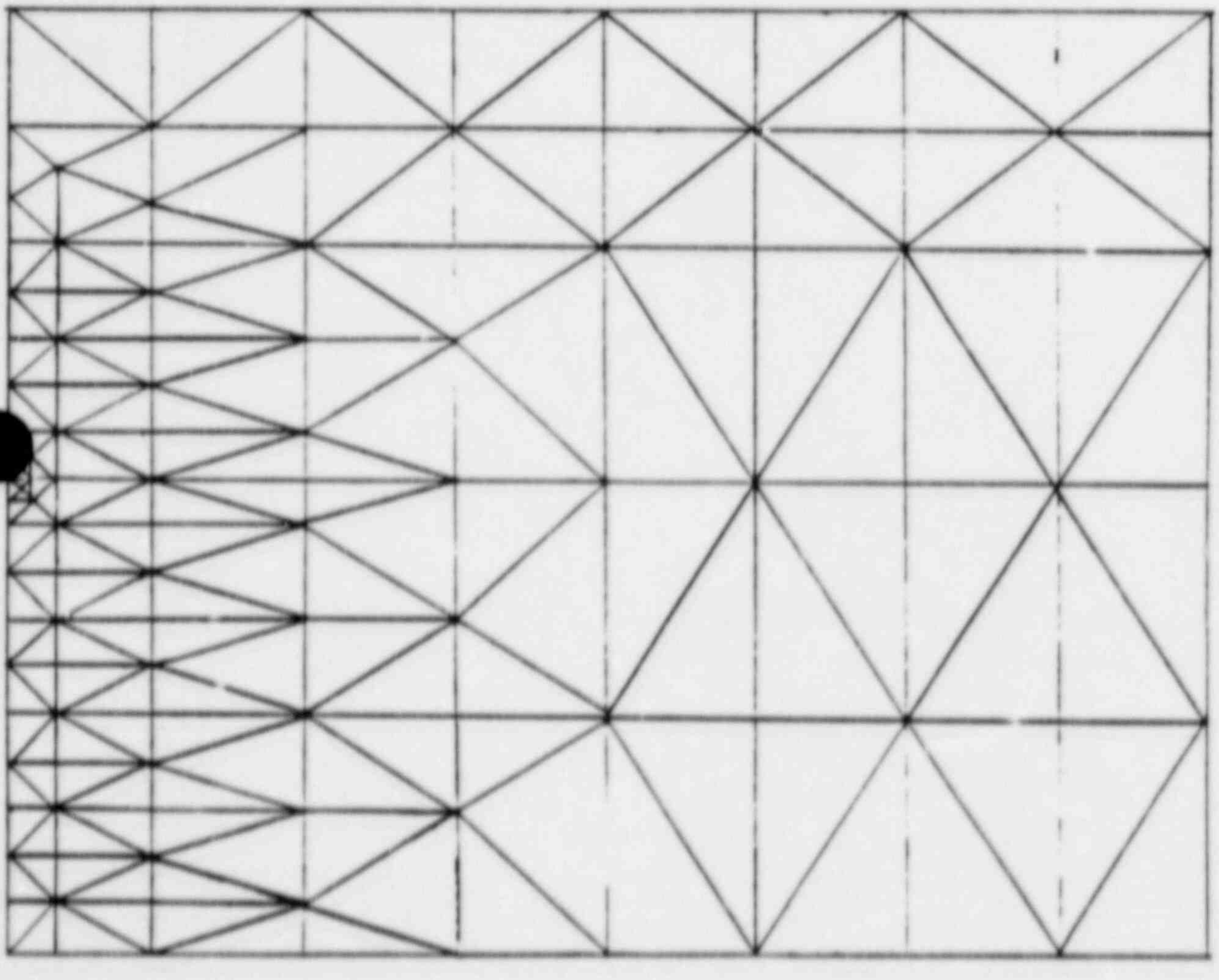

Fig. 24: SHELL MODEL FOR HALF-CIRCUMFERENCE CRACK IN PIPE

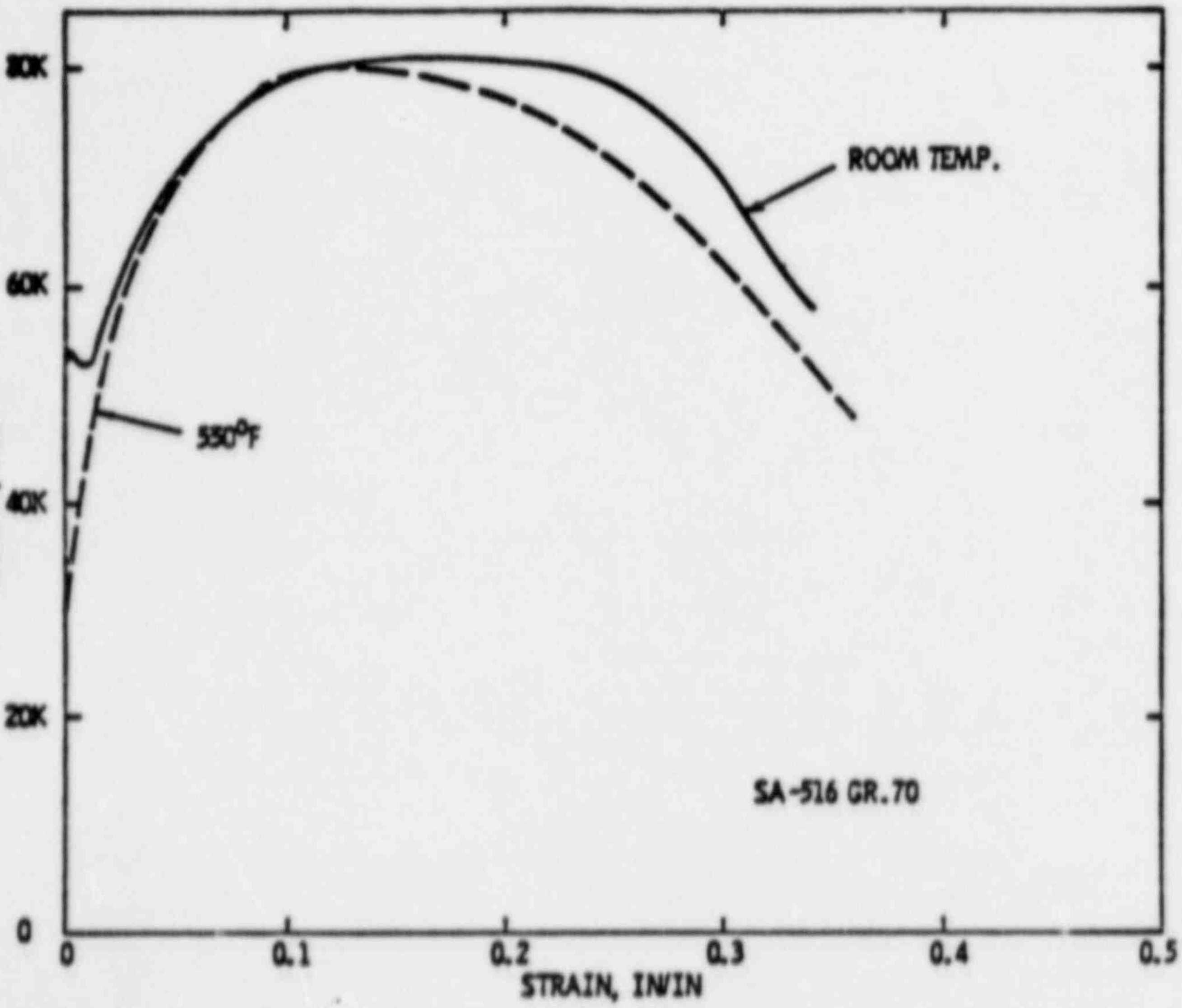

Fig. 25: **STRESS-STRAIN CURVE**

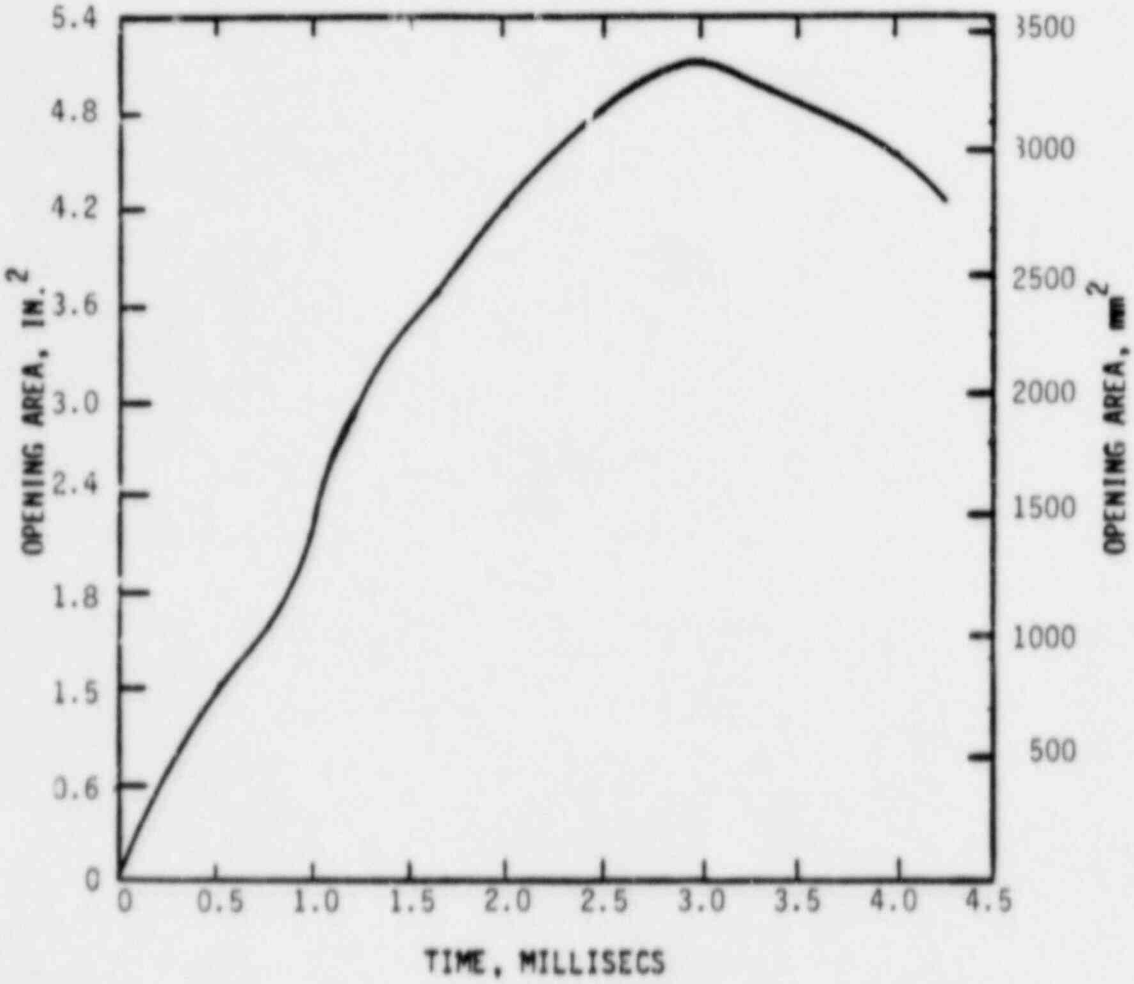

Fig. 26 OPENING AREA OF HALF-CIRCUMFERENCE CRACK VS. TIME

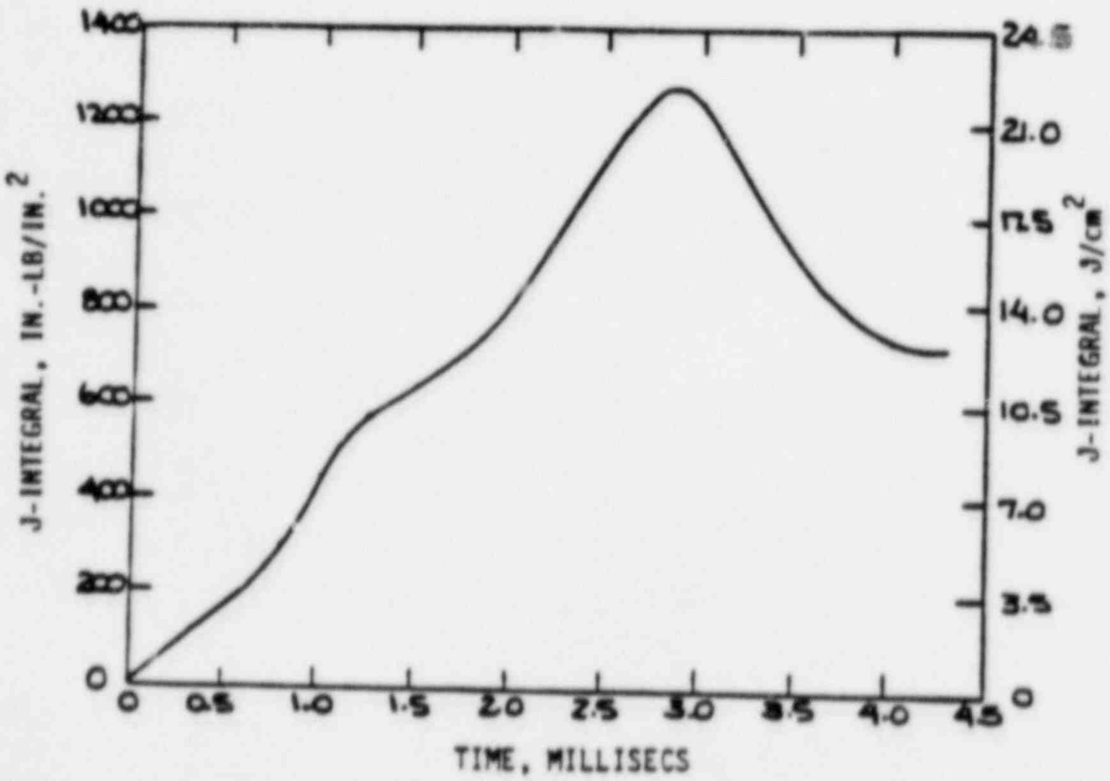

Fig. 27: J-INTEGRAL VS. TIME DURING OPENING OF HALF-CIRCUMFERENCE CRACK

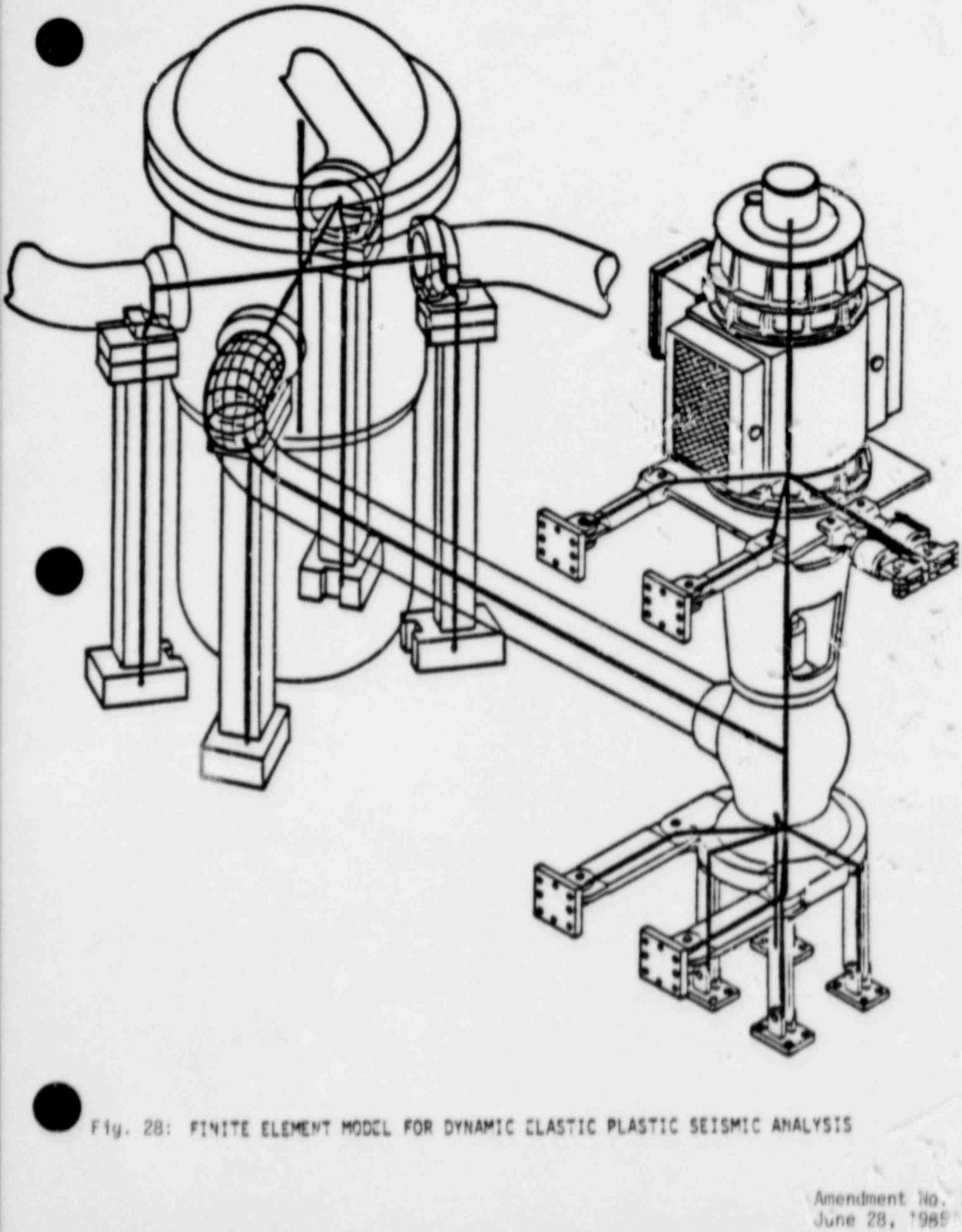

Fig. 28: FINITE ELEMENT MODEL FOR DYNAMIC ELASTIC PLASTIC SEISMIC ANALYSIS

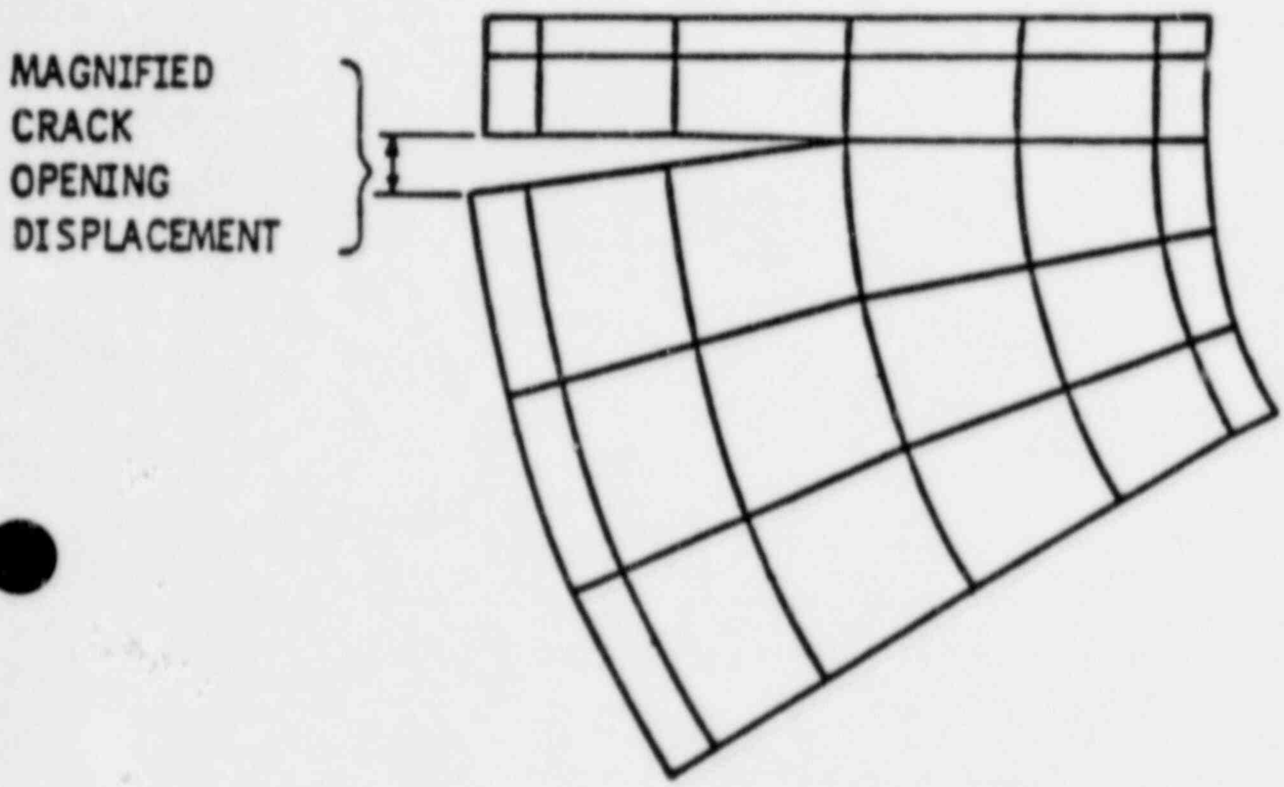

Fig. 29 Top View Of Pipe With Crack

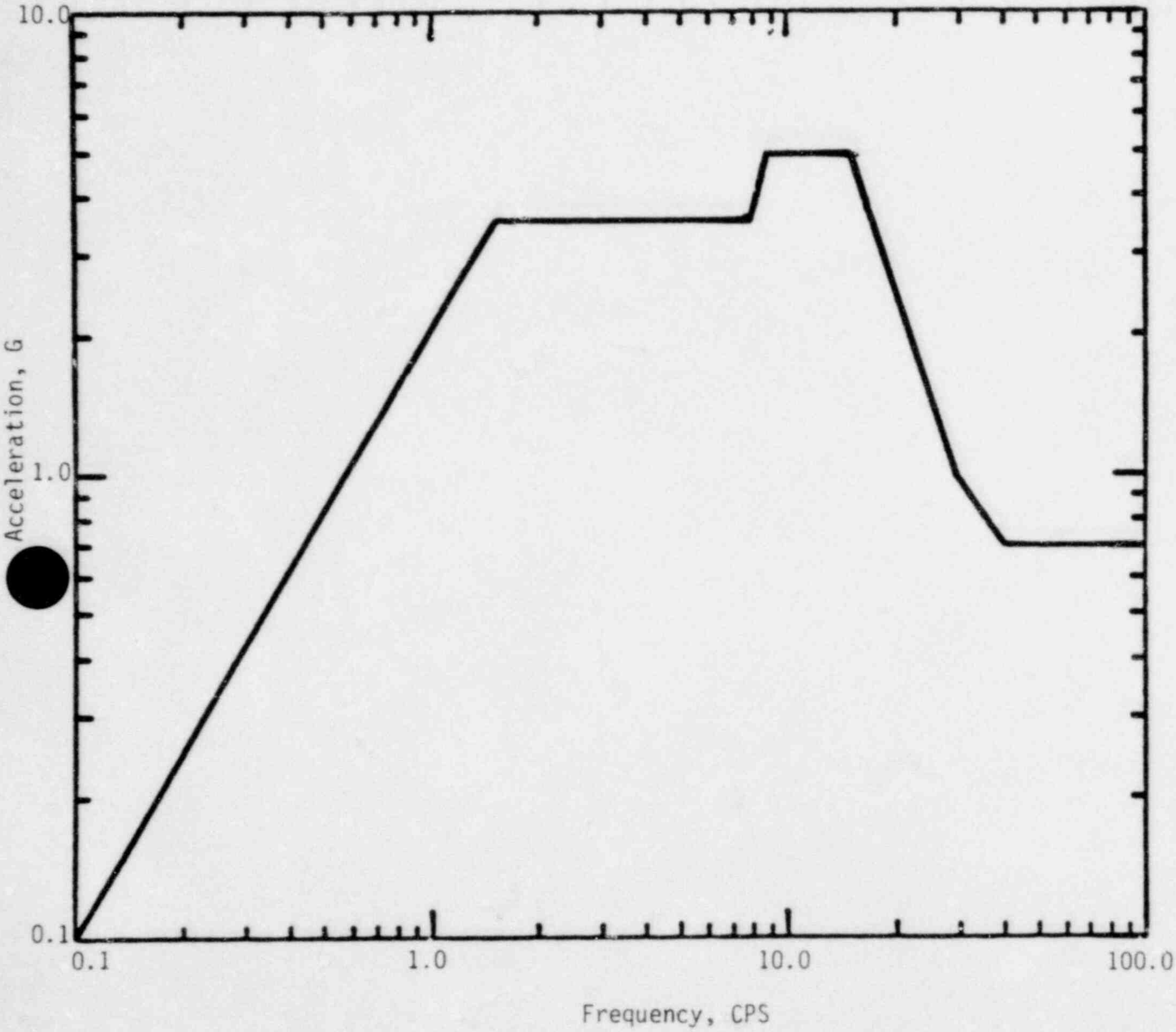

Fig. 30: SSE Frequency Response Spectra

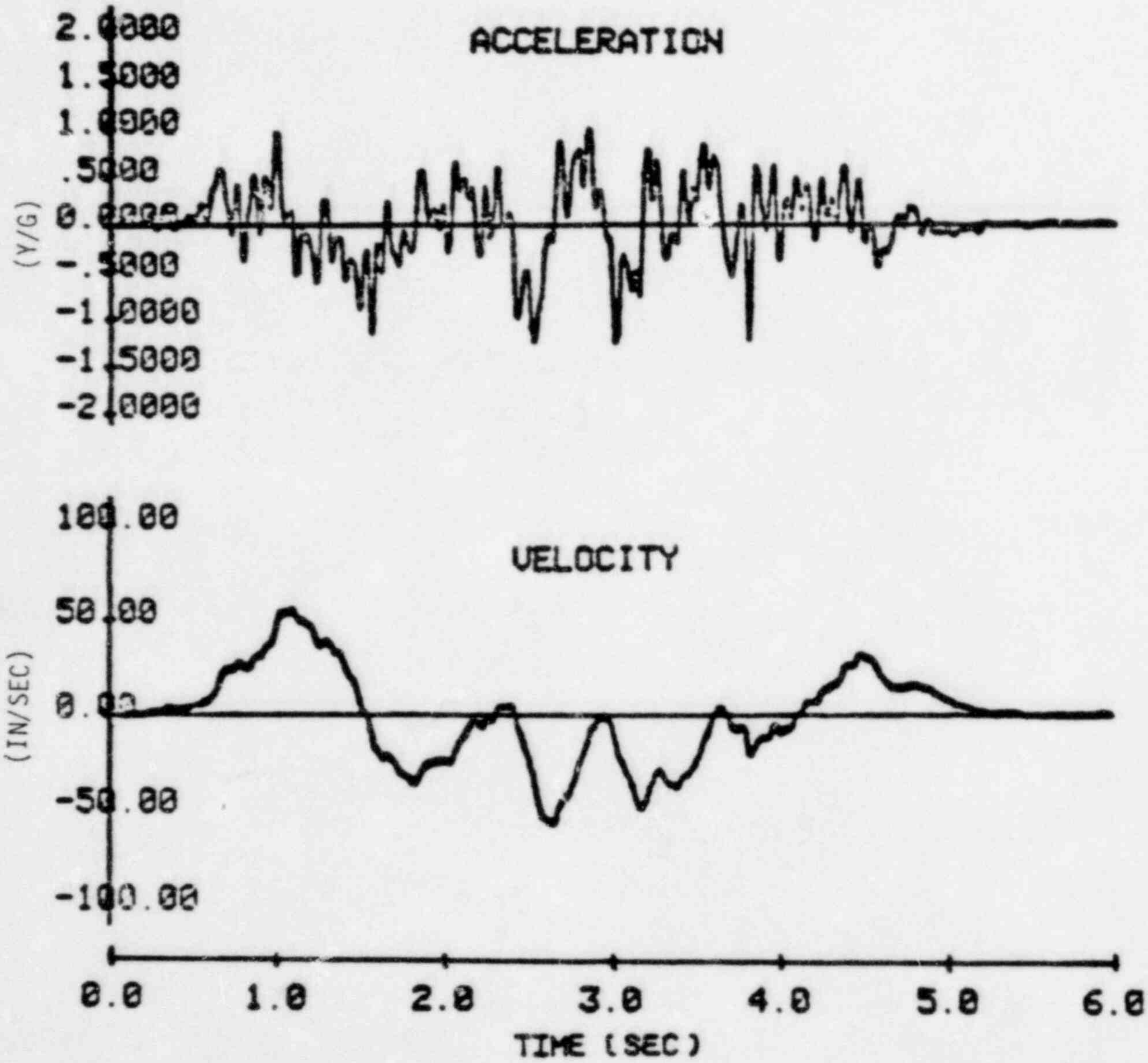

Fig. 31: TIME HISTORIES GENERATED FROM RESPONSE SPECTRA

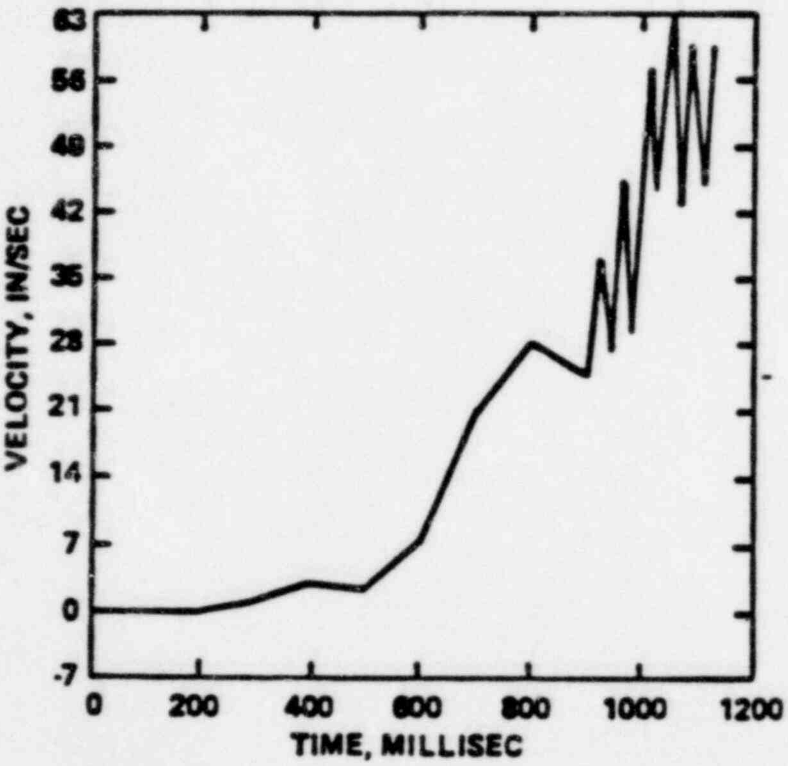

Fig. 32: **VELOCITY IN PIPE vs TIME (WITHOUT CRACK)**

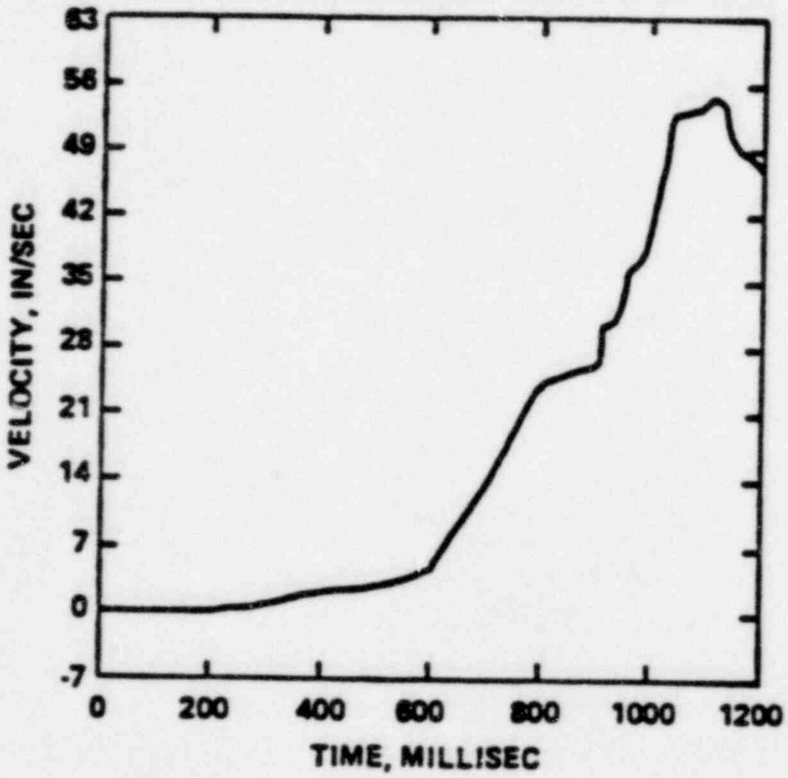

Fig. 33: **VELOCITY AT BASE vs TIME**

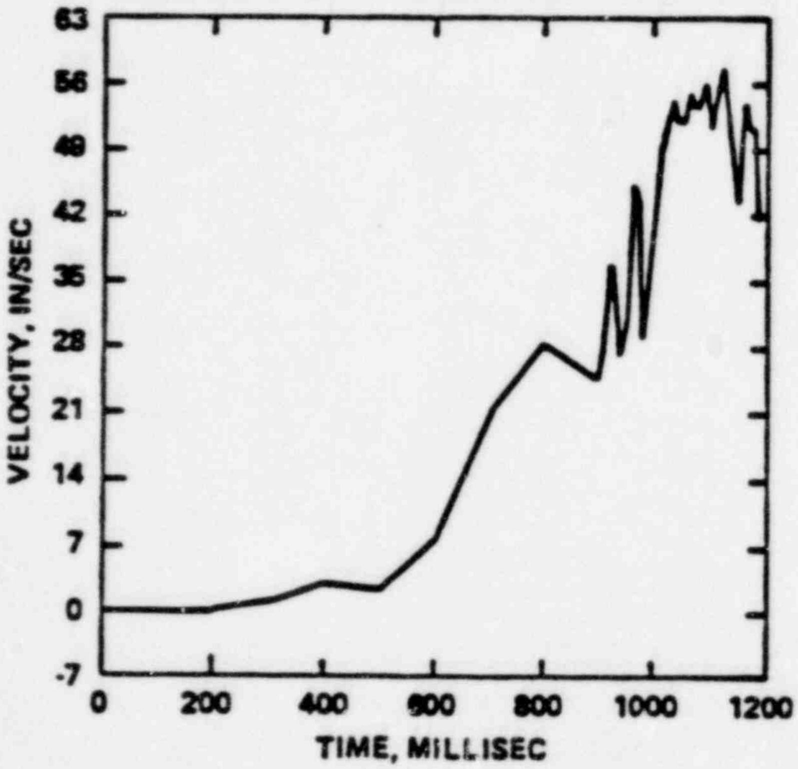

Fig. 34: **VELOCITY IN PIPE vs TIME (1/2 CIRCUMFERENCE CRACK)**

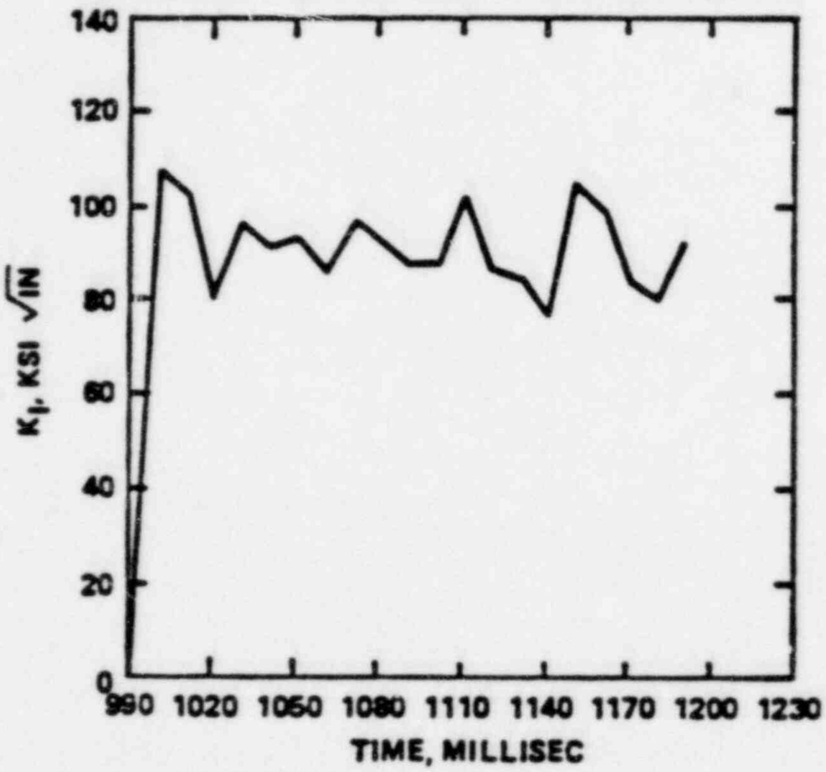

Fig. 35: **STRESS INTENSITY (K_I) vs TIME (1/2 CIRCUMFERENCE CRACK)**

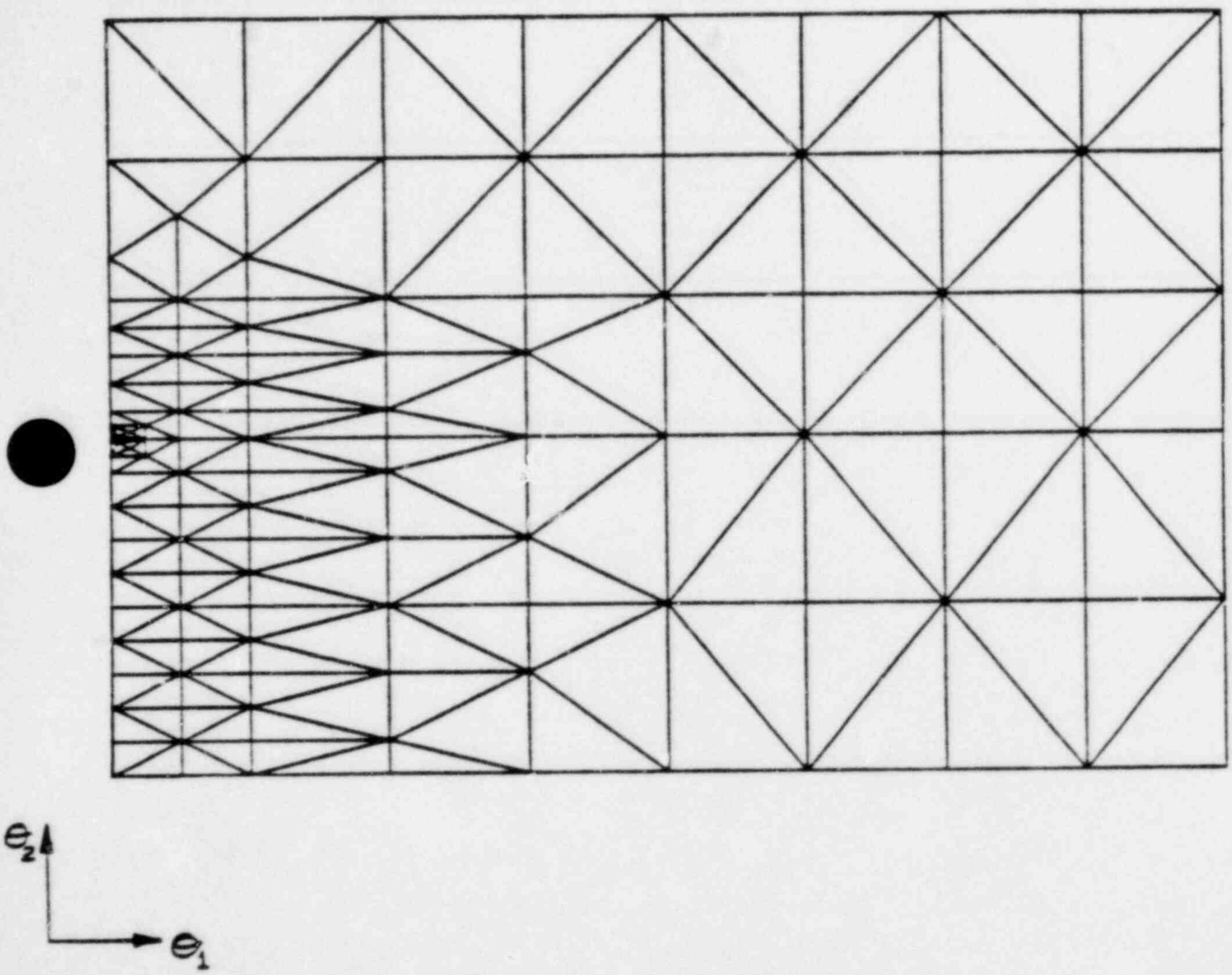

Fig. 36: Finite Element Mesh In Surface
Coordinate System
(20 Crack In 45 Elbow)

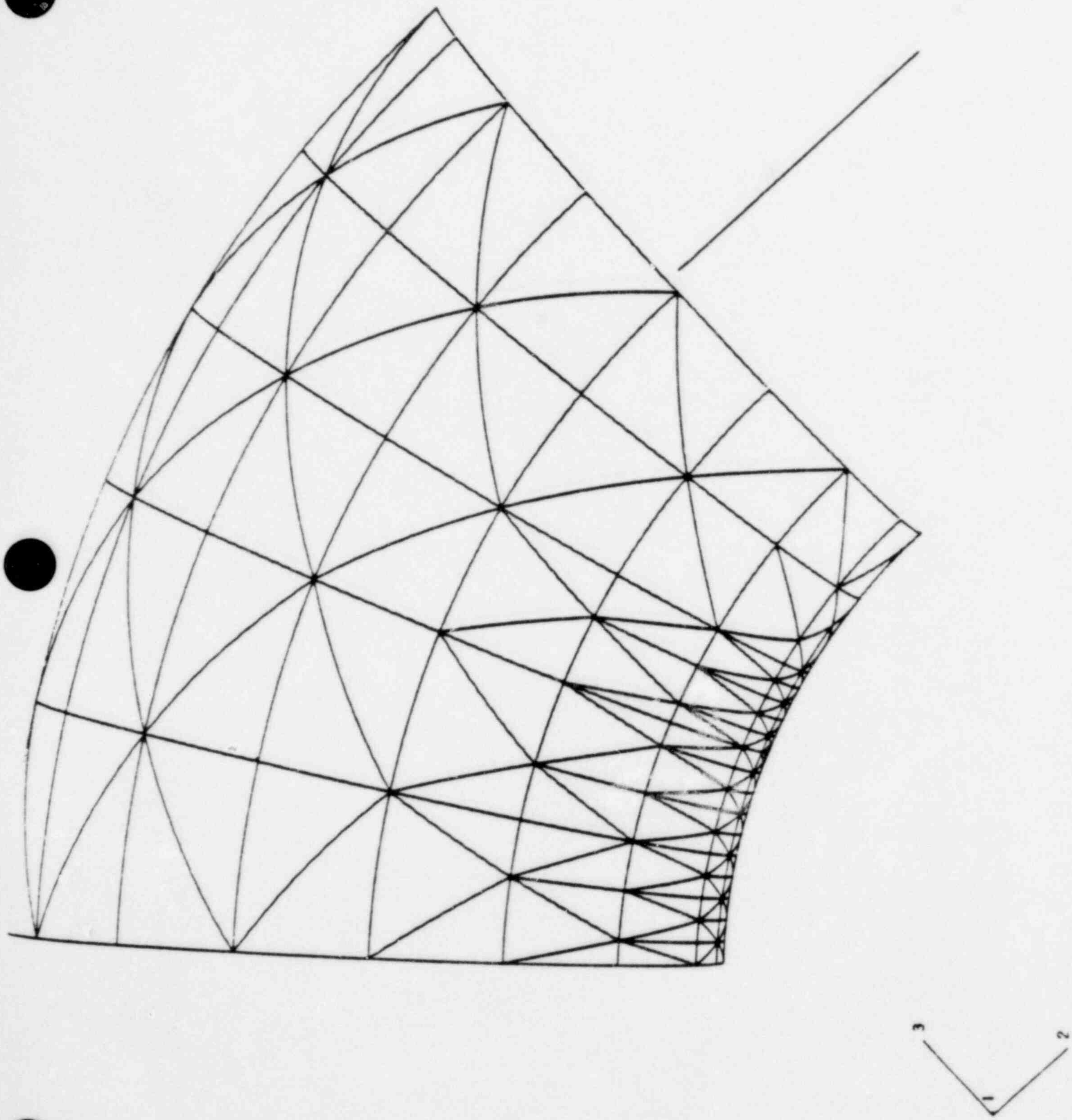

Figure 37: Finite Element Mesh in X-Y-Z Cartesian Coordinates (20 Crack in 45 Elbow)

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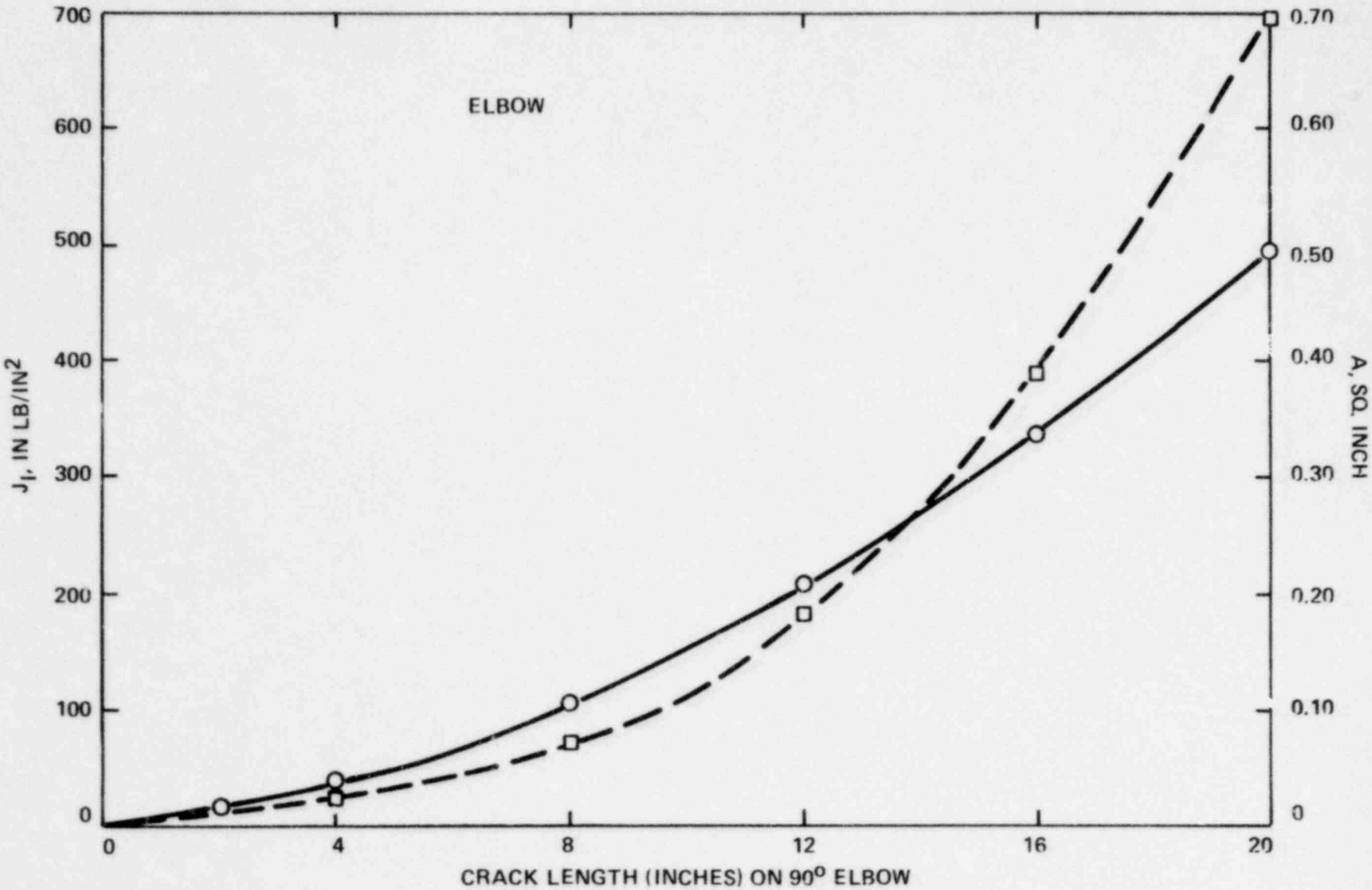

FIGURE 38: J_I AND LEAKAGE AREA vs CRACK LENGTH

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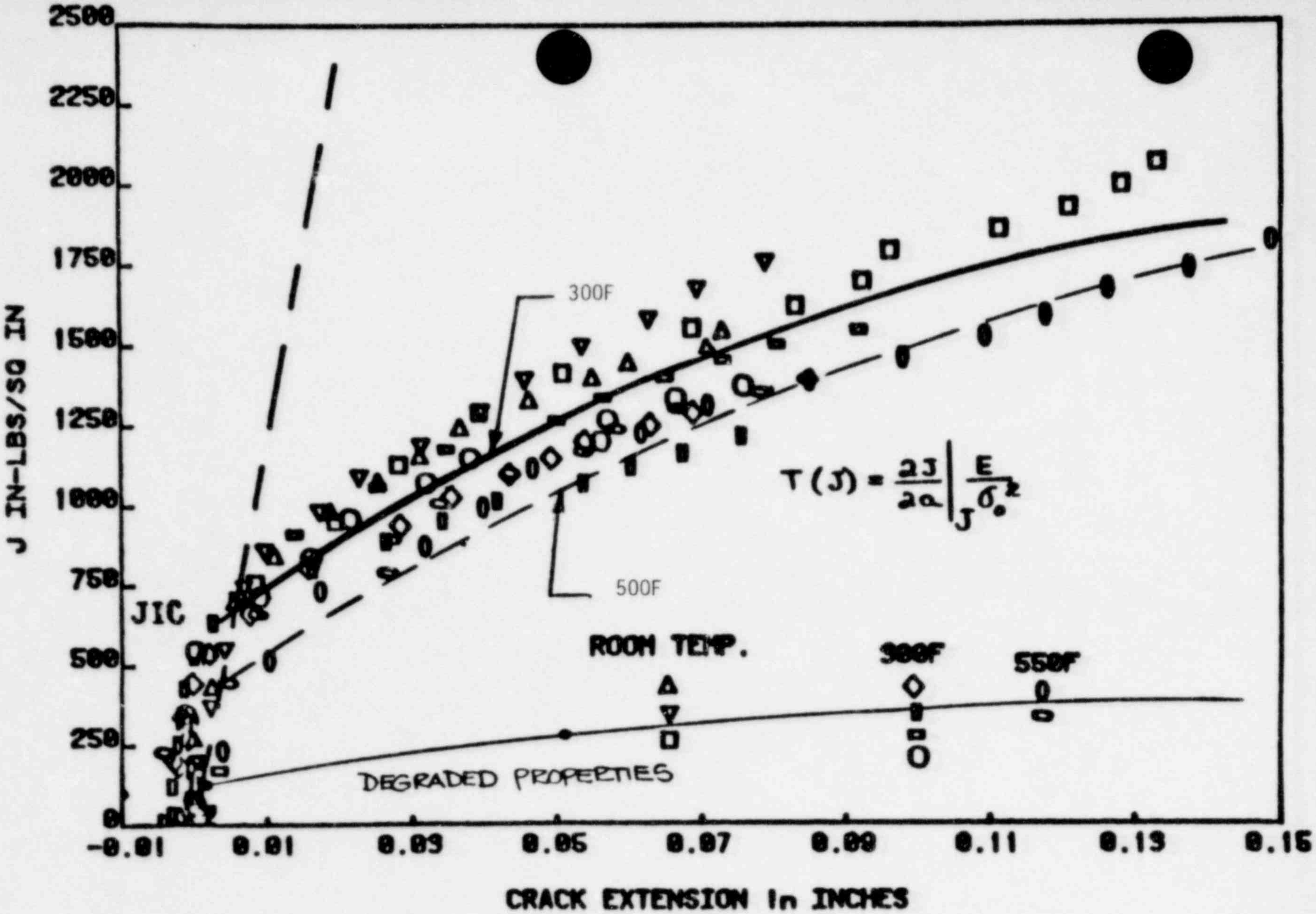

Fig. 39: J vs CRACK EXTENSION, A516 (20 % SIDE GROOVES)

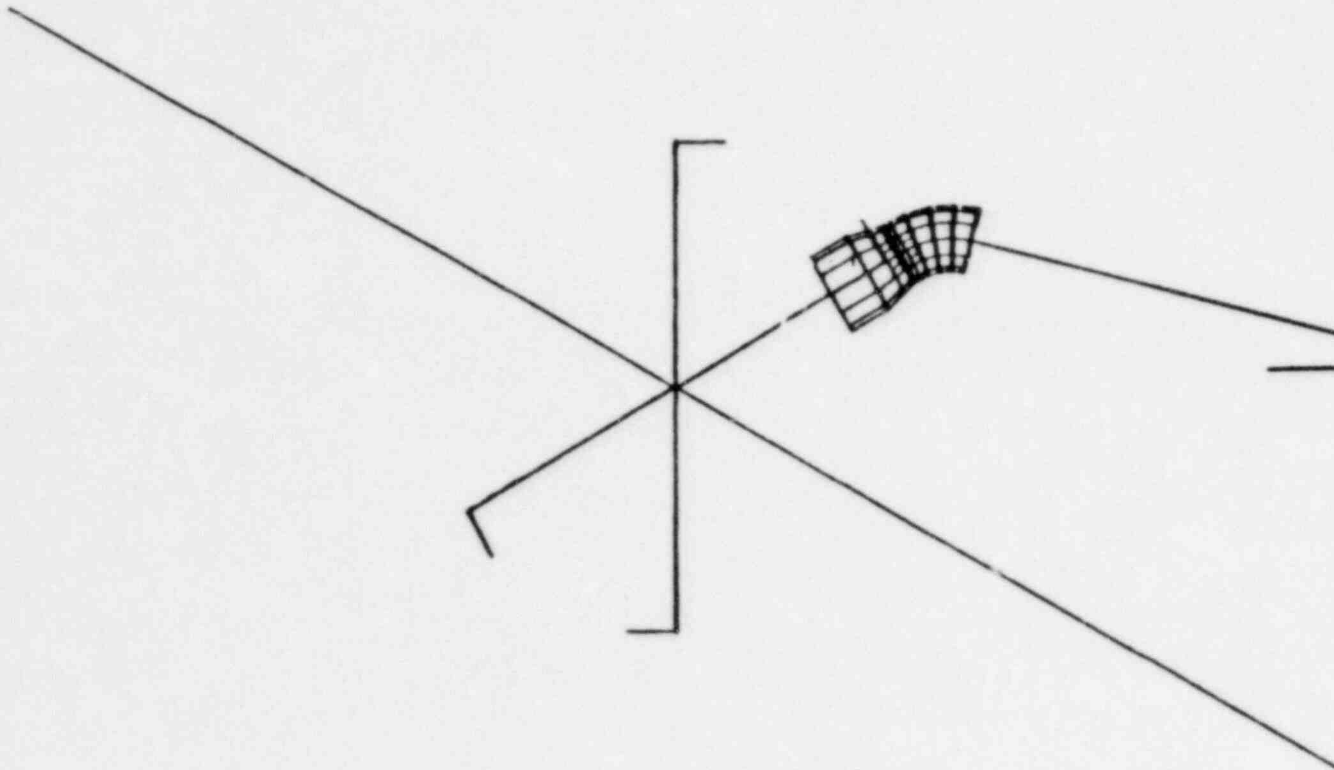

Fig. 40: FINITE ELEMENT MODEL FOR SYSTEM 80 SEISMIC LOADING ANALYSIS

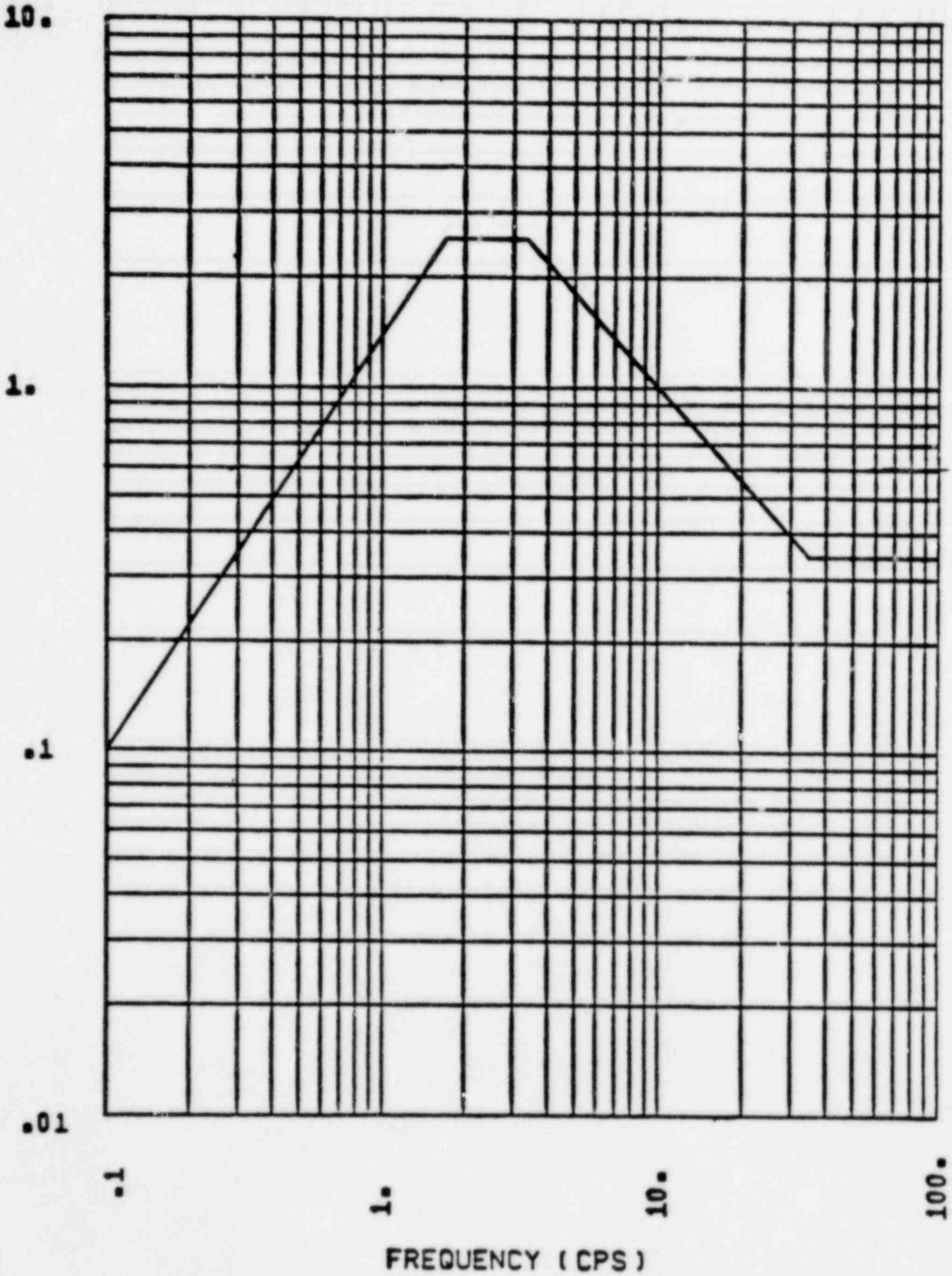

Fig. 41: SEISMIC SPECTRUM

ENVELOPE OF RV AND RCP SUPPORTS: SSE 2% DAMPING

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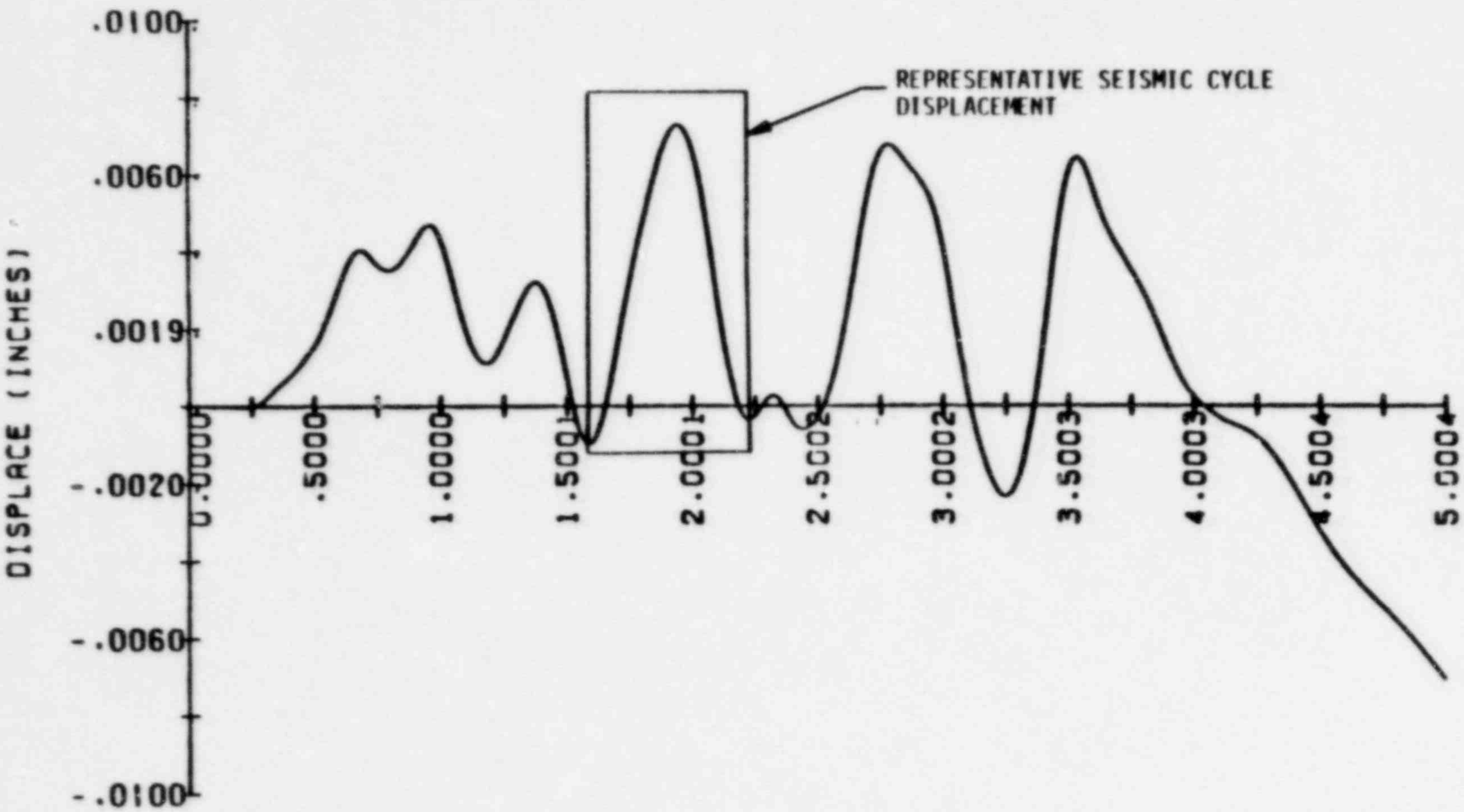

Fig. 42: SYSTEM 80 SSE ANALYSIS - DOUBLE INTEGRATION OF ARTIF ACCEL. TIME HISTORY

SYSTEM 80 SSE SPECTRUM ANALYSIS - ARTIF DISP. TH

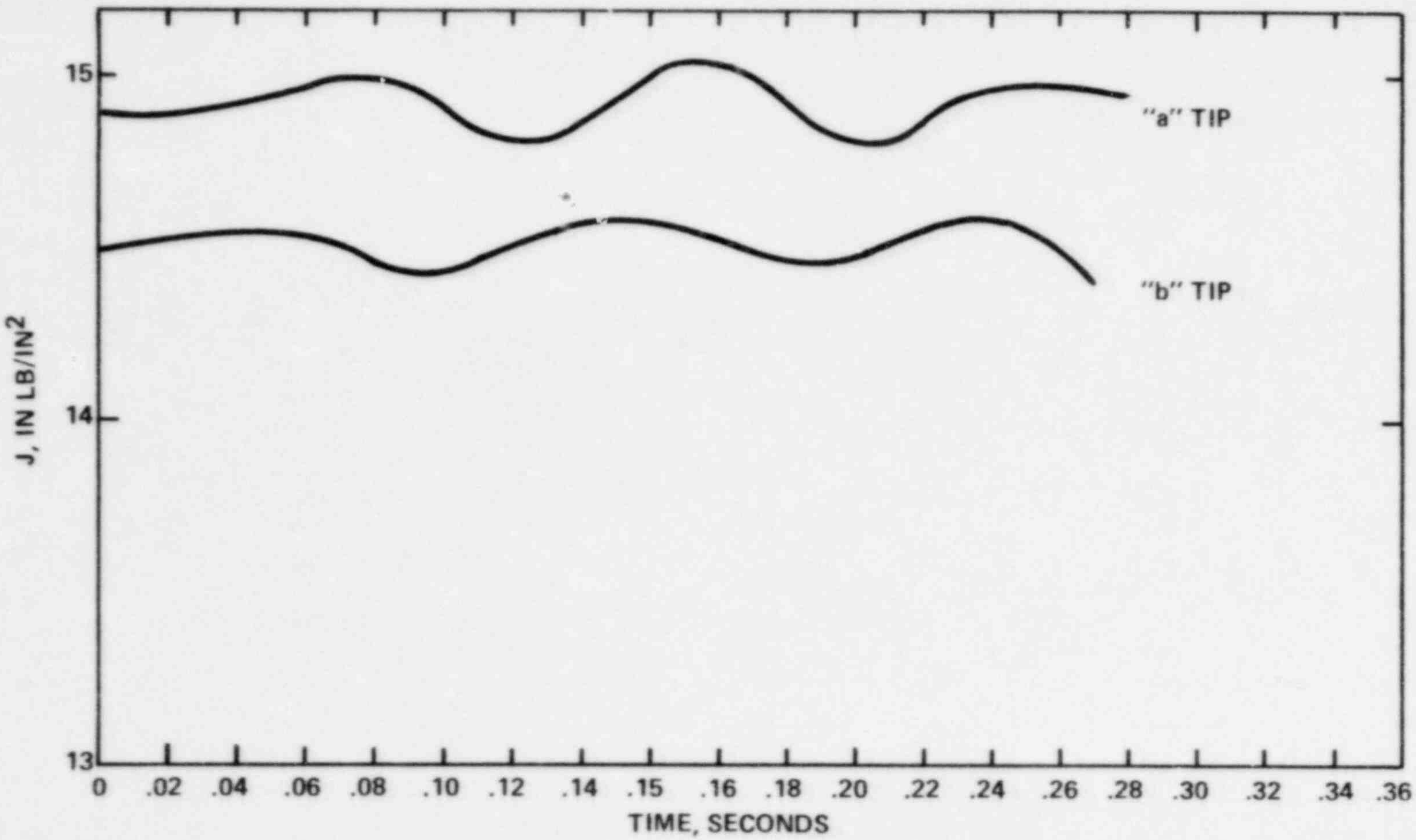

FIGURE 43: J vs TIME FOR REPRESENTATIVE SEISMIC CYCLE
30° CIRCUMFERENTIAL (8 INCH LONG) CRACK

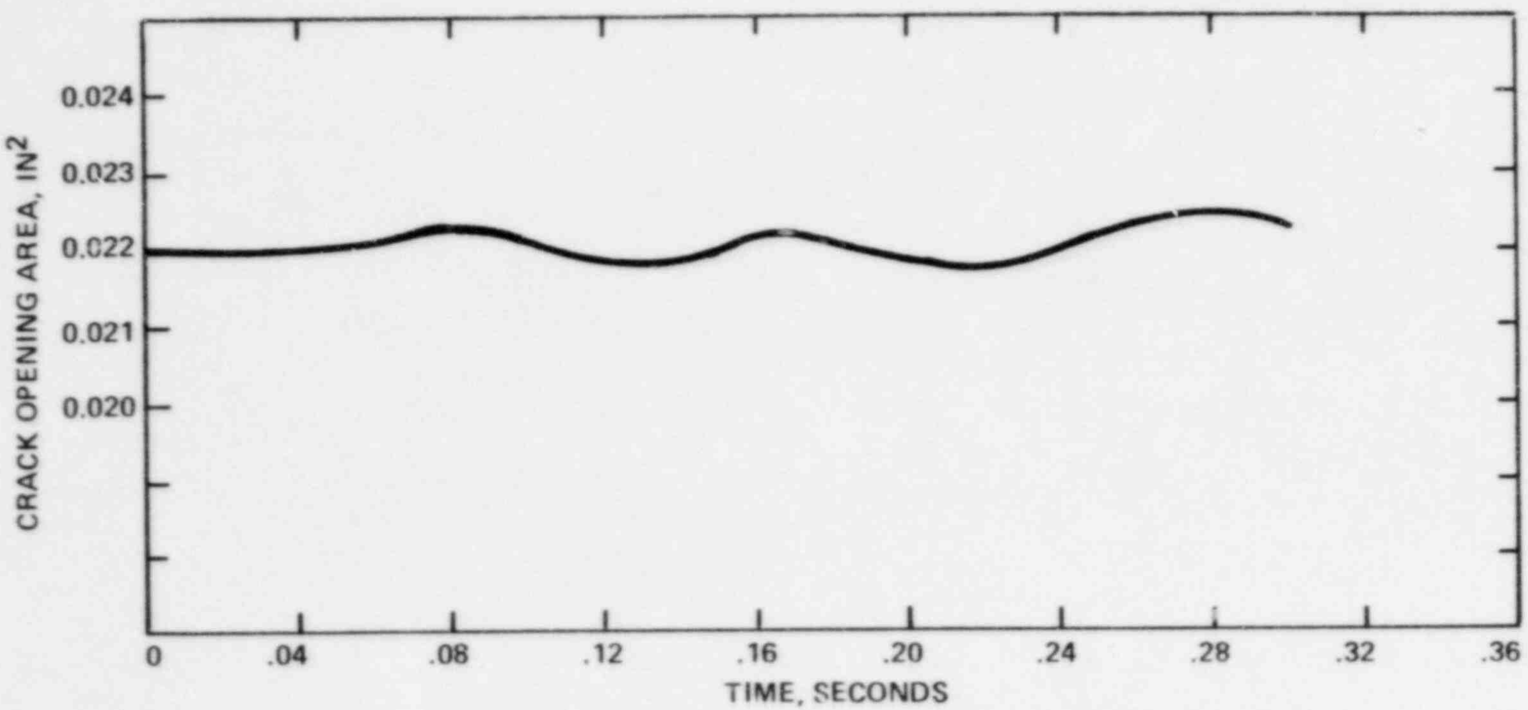

FIGURE 44: CRACK OPENING AREA FOR REPRESENTATIVE SEISMIC CYCLE
30° CIRCUMFERENTIAL (8 INCH LONG) CRACK

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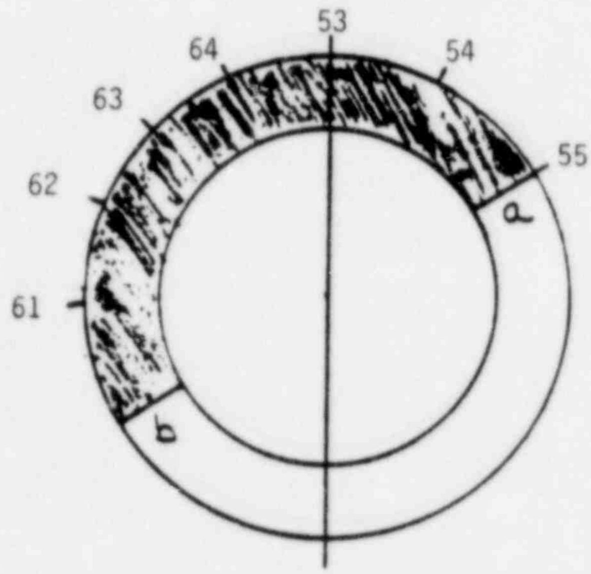
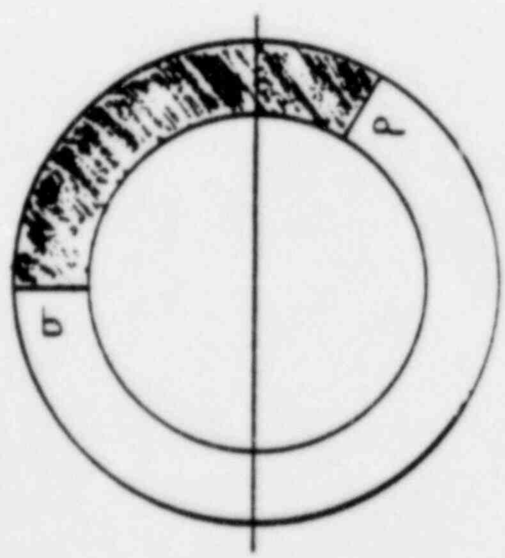


180 Crack Looking Toward RV



120 Crack

Fig. 45: Assumed Crack Size For Determination Of Maximum Stable Crack Size

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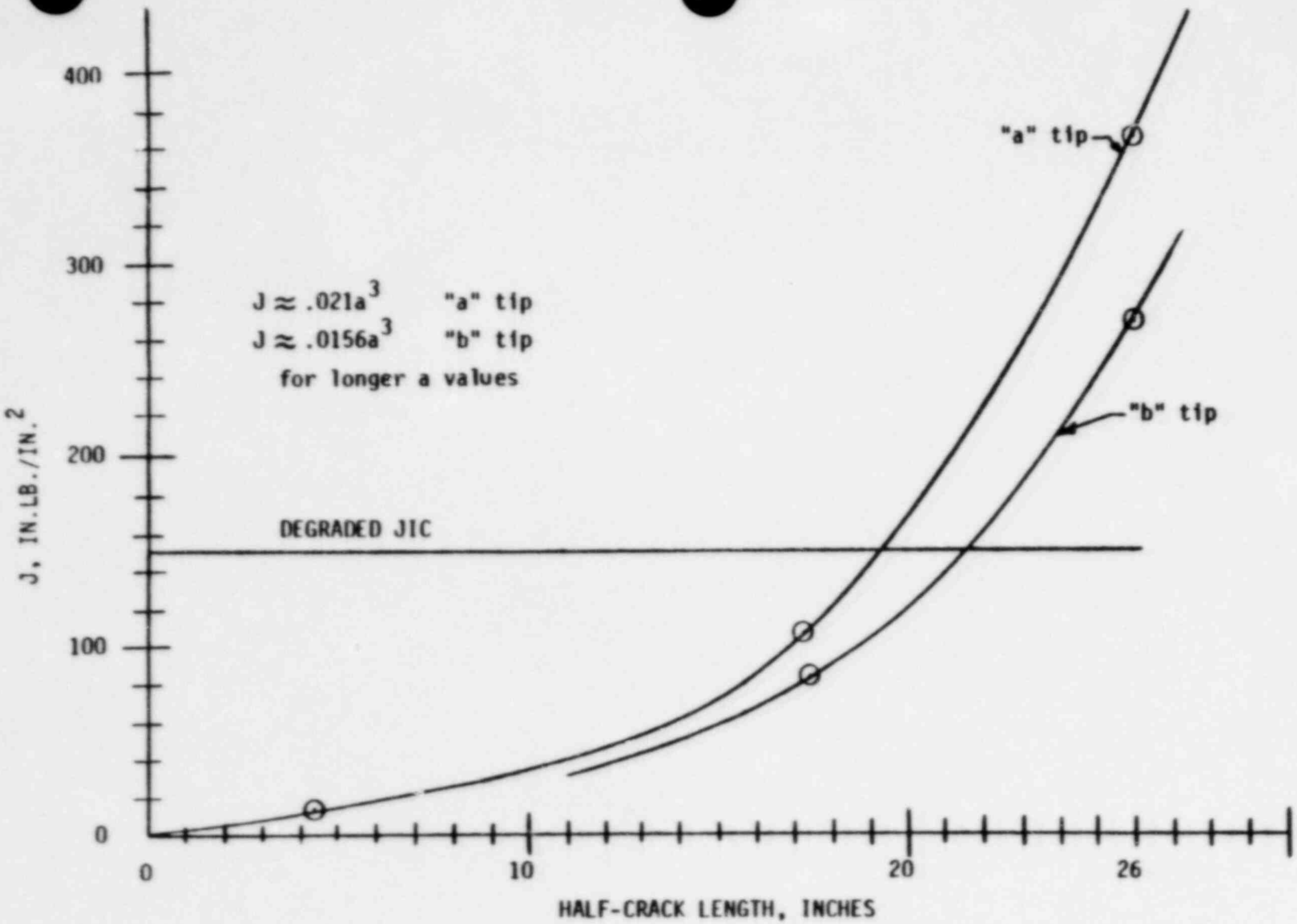

Fig. 46: J VS. CRACK SIZE FOR NORMAL OPERATING LOADS

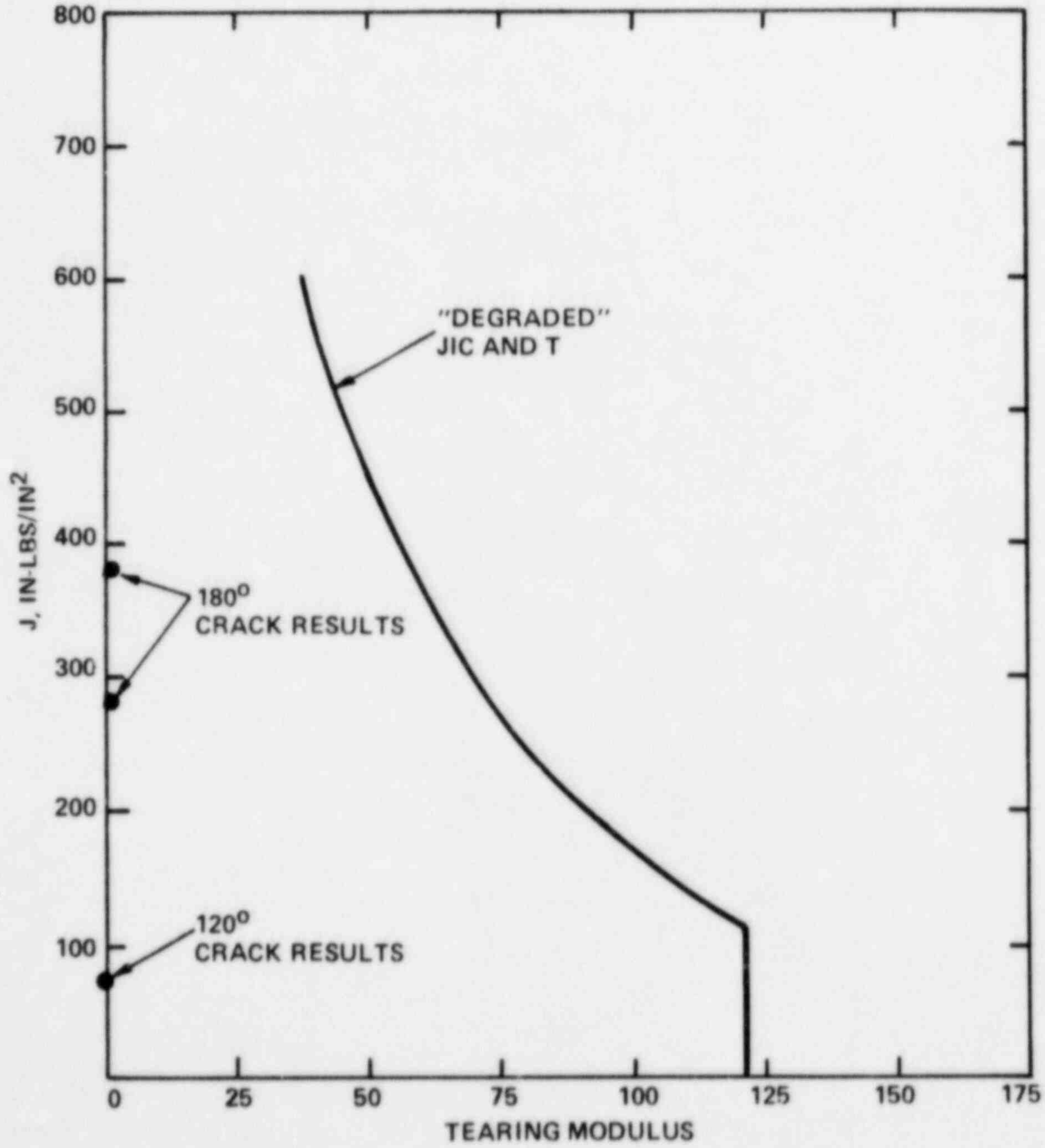

FIGURE 47: INSTABILITY DIAGRAM FOR 180° AND 120° CRACKS

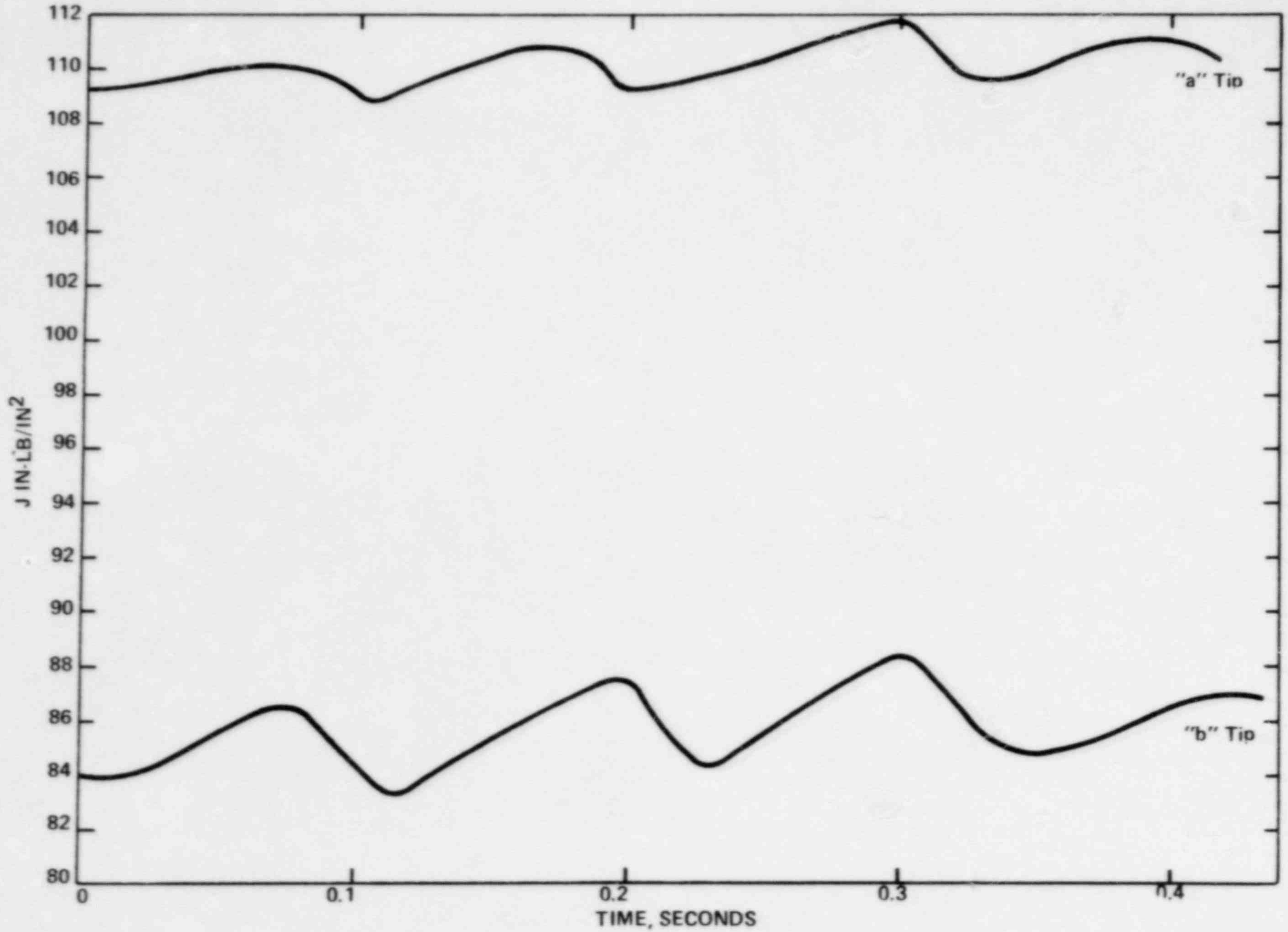

FIGURE 48: J vs TIME FOR REPRESENTATIVE SEISMIC CYCLE 120° CIRCUMFERENTIAL (33 INCH LONG) CRACK

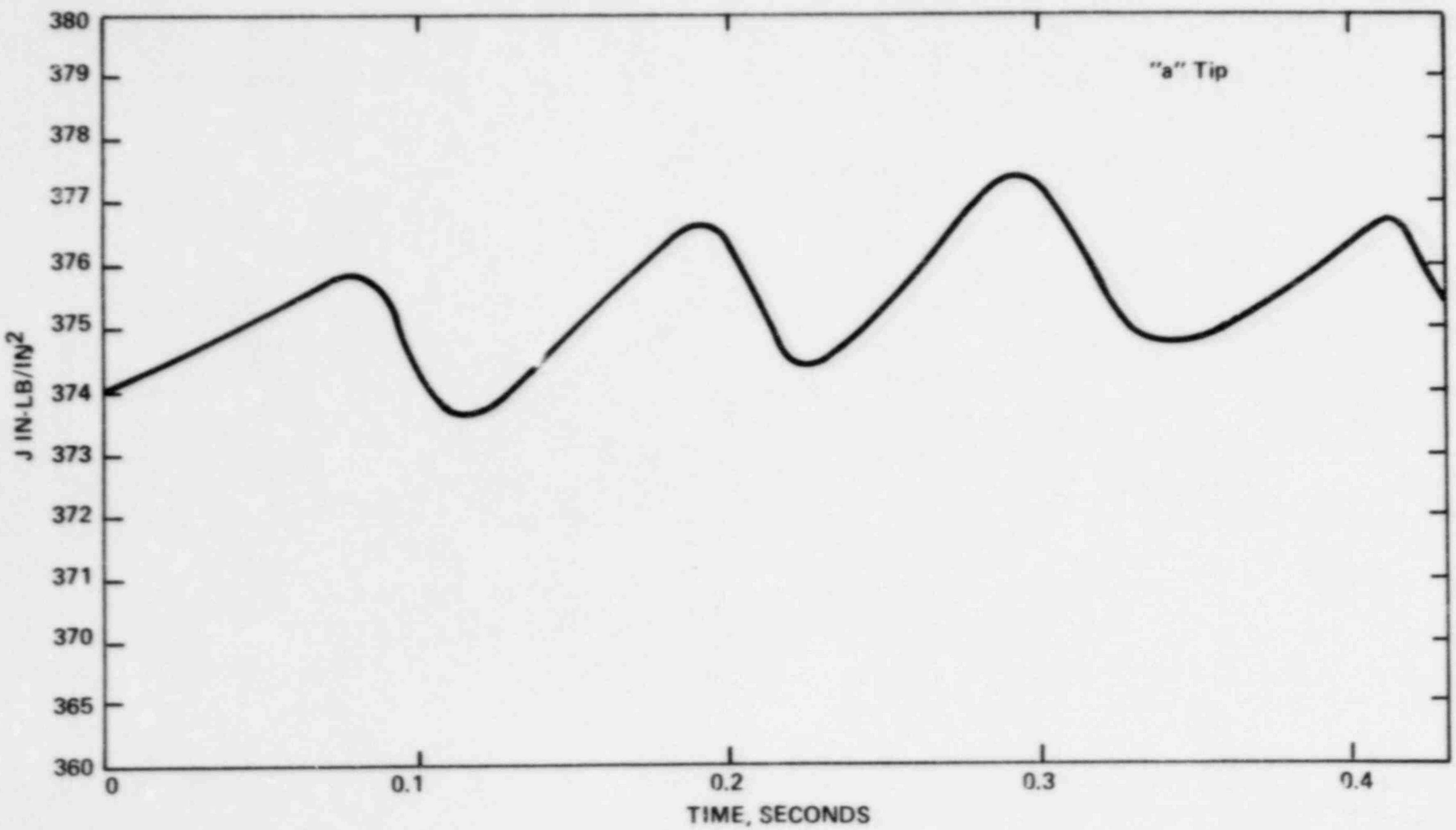

FIGURE 49A: J vs TIME FOR REPRESENTATIVE SEISMIC CYCLE
180° CIRCUMFERENTIAL (52 IN. LONG) CRACK

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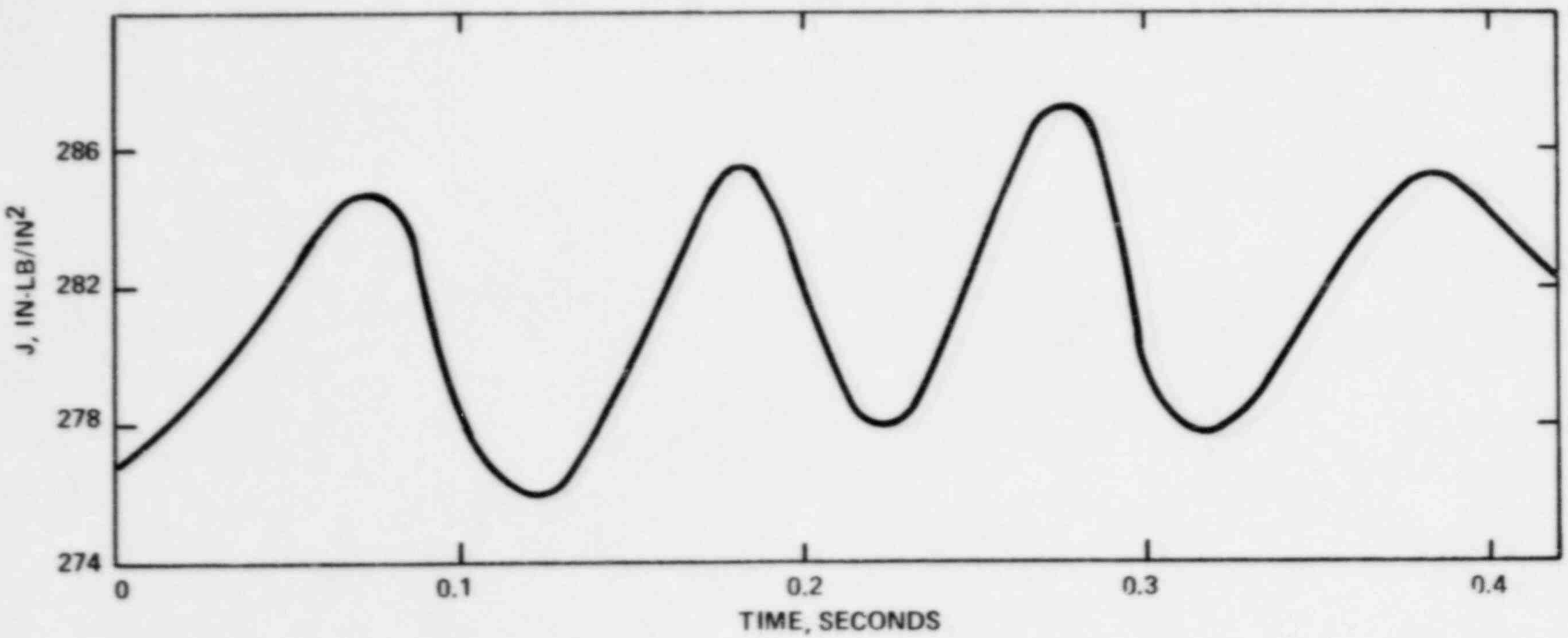


FIGURE 49B: J vs TIME FOR REPRESENTATIVE SEISMIC CYCLE
180° CIRCUMFERENTIAL (52 IN. LONG) CRACK, "b" TIP

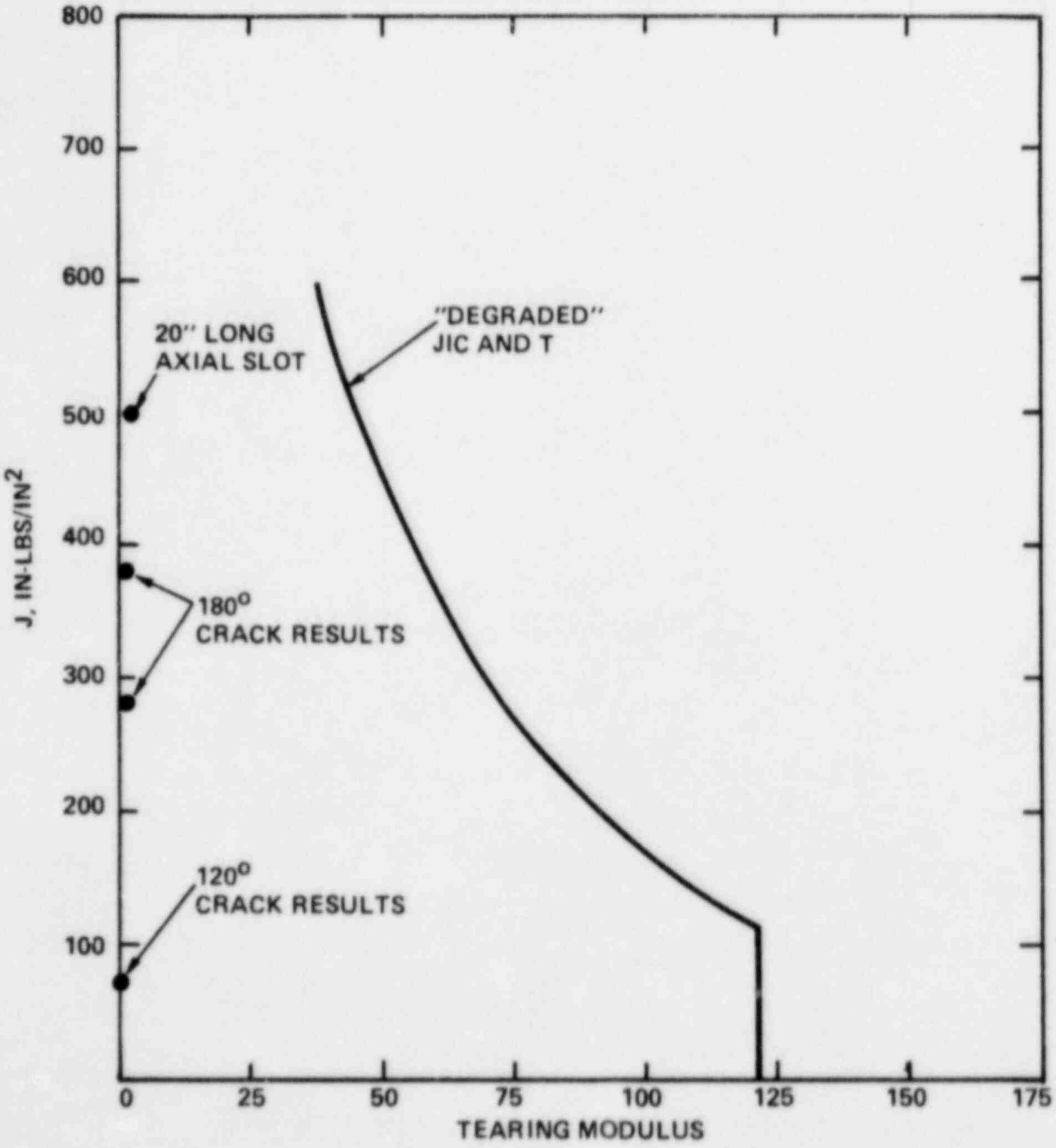


FIGURE 50: INSTABILITY DIAGRAM FOR AXIAL SLOT IN ELBOW

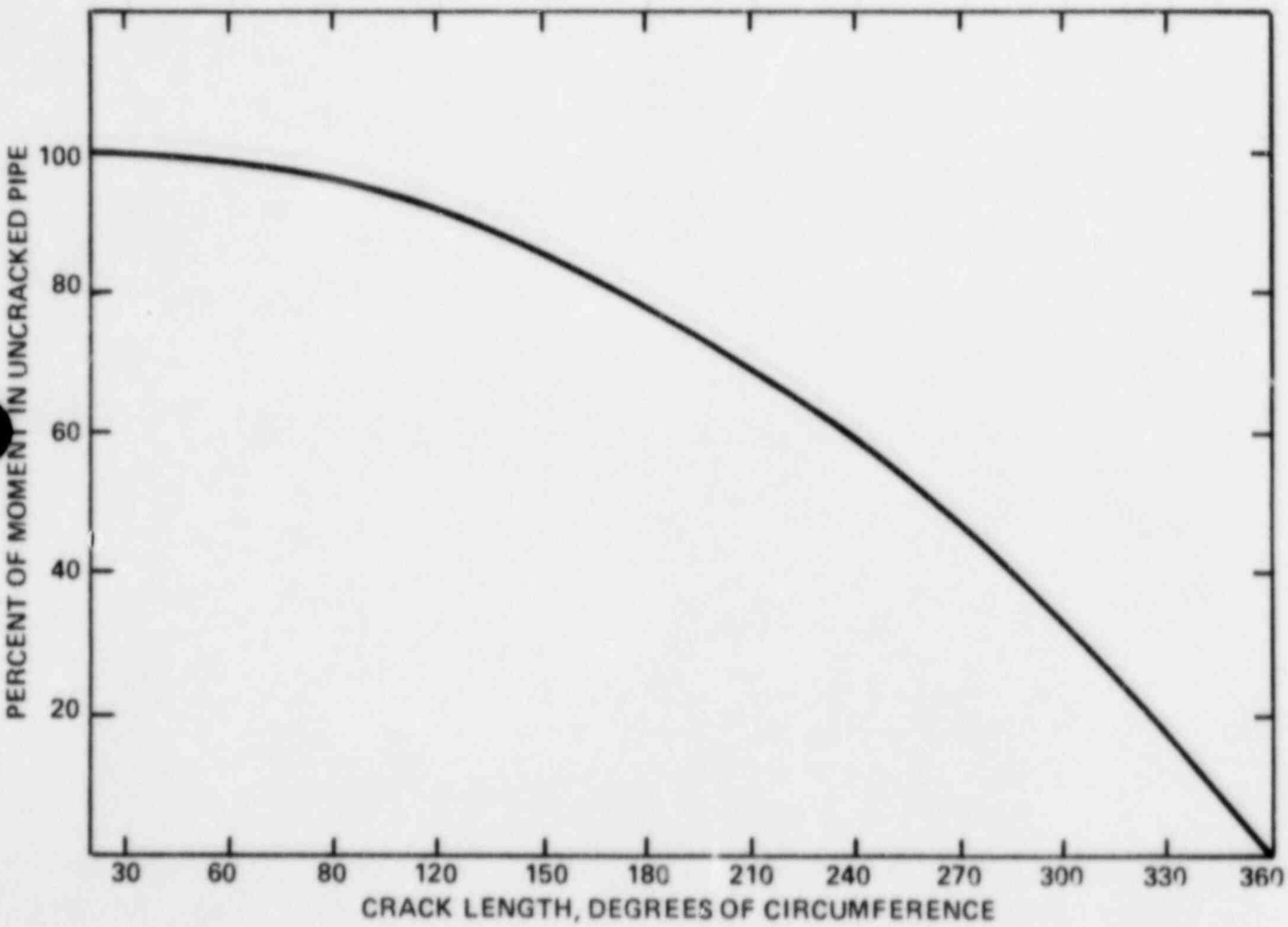


FIGURE 51: MOMENT vs CRACK SIZE FOR SEISMIC TYPE LOADING

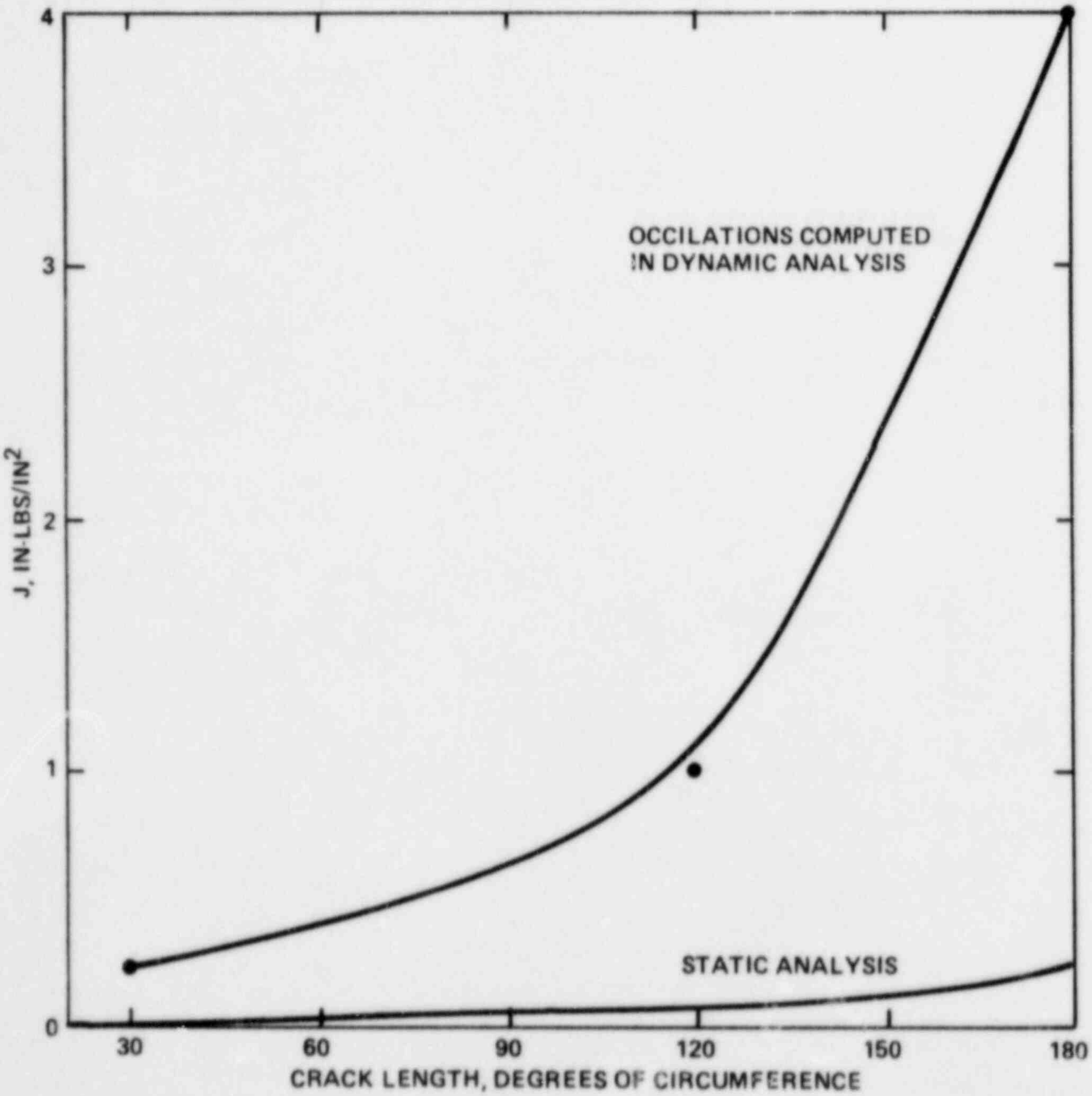
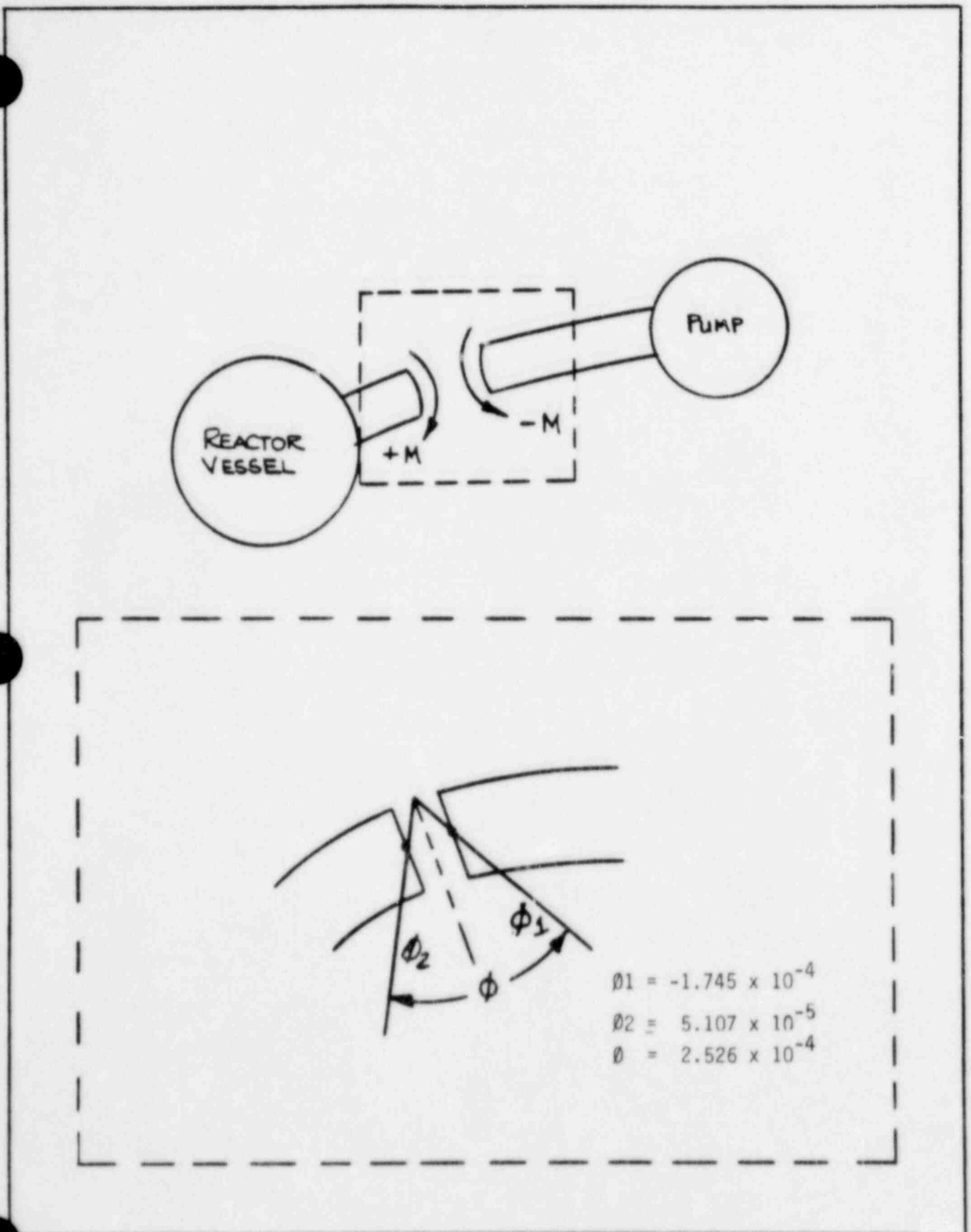


FIGURE 52: J vs CRACK SIZE FOR MAXIMUM SEISMIC LOADING

Amendment No. 10
June 28, 1985



Determination of Residual
Elastic Stiffness

Figure 53

Table 1

LOADING TRANSIENTS ANALYZED AND LIFE OCCURENCES

Loading transients	Life Occurances
a. Plant heatup, 100°F/hr	500
b. Plant cooldown, 100°F/hr	500
c. Plant loading, 5%/min.	15,000
d. Plant unloading, 5%/min.	15,000
e. 10% step load increase	2,000
f. 10% step load decrease	2,000
g. Normal plant variation (± 100 psi, ± 10°F)	10^6
h. Reactor Trip	400
i. Leak test, 2250 psia, 100°F-400°F	200
j. Hydrostatic test, 3125 psia, 100°F-400°F	10
k. Loss of Reactor Coolant Flow (*)	40
l. Loss of Turbine Generator Load (*)	40
m. Loss of Secondary Pressure (*)	5
n. Operating Basis Earthquake (*)	200

* Abnormal Transient Conditions

Table 2

LOADS AND ELASTIC MATERIAL PROPERTIES USED FOR CRACK OPENING AREA STRUCTURAL ANALYSES

		COMBINED NORMAL OPERATING LOADS FOR THERMAL EXPANSION, WEIGHT, AND 2250 PSIA INTERNAL PRESSURE					
		F_X LBS	F_Y LBS	F_Z LBS	M_X FT-LBS	M_Y FT-LBS	M_Z FT-LBS
DLTE	ELBOW	-8.570×10^4	1.204×10^6	1.157×10^6	-2.619×10^5	-1.719×10^5	2.518×10^5
	NOZZLE	-1.202×10^6	-9.167×10^4	-1.533×10^6	9.103×10^5	-1.976×10^6	-3.414×10^5
HLTE	PIPE	-7.509×10^5	0.0	3.071×10^6	0.0	-6.406×10^6	0.0

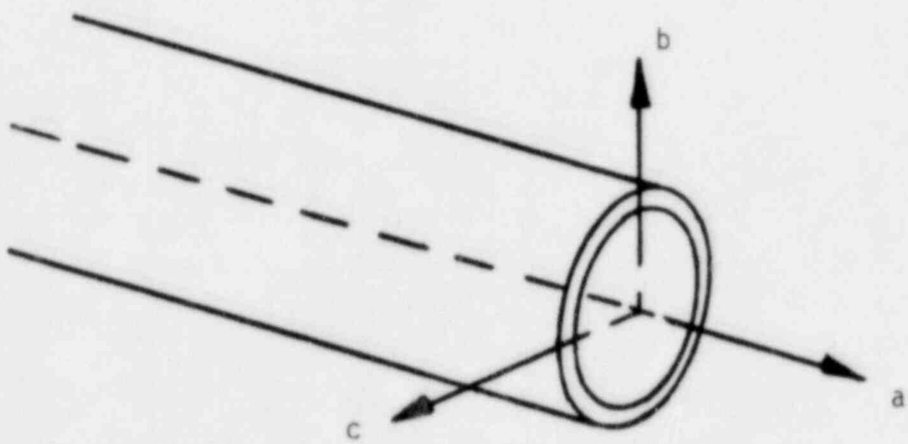
YOUNG'S MODULUS = 2.800 x 10^7 PSI

POISSON'S RATIO = 0.290

Table 3

Seismic Moments For Palo Verde

At The Reactor Vessel Inlet Nozzle



Ma = 840 IN-KIPS

Mb = 2140 IN-KIPS

Mc = 870 IN-KIPS

Table 4

TAPPL For Various Crack Sizes

Assuming Fully Plastic Moment
At Discharge Leg Terminal End

$$\text{TAPPL} = \frac{2h^2\, tE}{K\emptyset}$$

$$\text{Where } h = R\left(\cos\emptyset + \sin\frac{\emptyset}{2}\right)$$

0 = $\frac{\text{Crack Length}}{2}$	h = Inches	TAPPL
30	18.56	13.5
60	16.5	10.7
90	11.7	5.3

APPENDIX CA

Forces and Moments in the System 80 Main Loop Piping Due to Normal and Upset Loadings

Forces and moments computed in the System 80 main loop are presented in Table A. The location of the joints listed and the coordinate system used are given in Figure A-1. The loads and moments given envelope all System 80.

Loadings for a specific plant may be significantly less than the values given in Table A.

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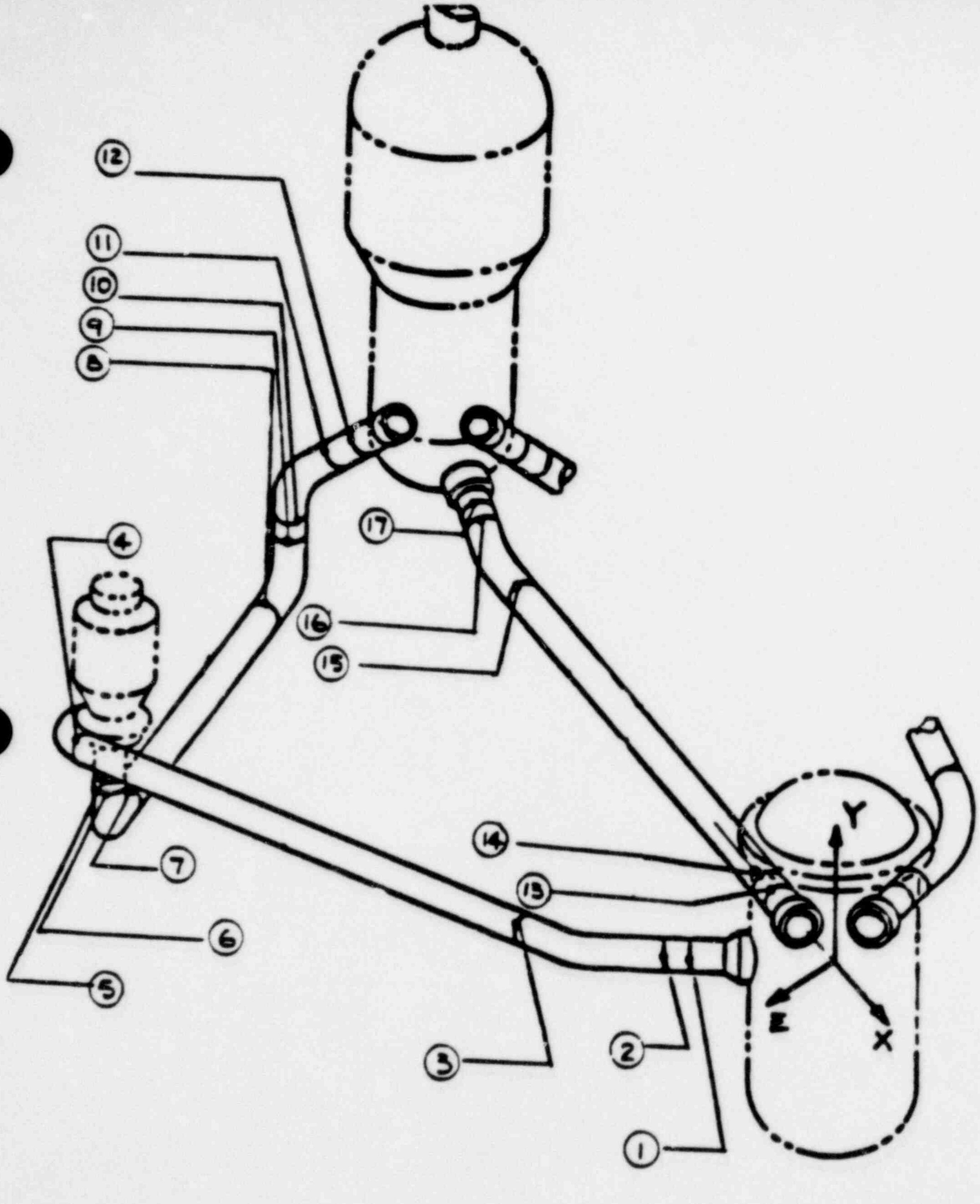

Fig. CA-1 LOCATION OF PIPE JOINTS LISTED IN TABLE CA-1

__Notes to the following listings 1 through 17__

1. MX, MY & MZ denote global coordinates X, Y & Z moments due to thermal expansion.

2. $_{th}S_p$ denotes thermal stress calculated based on EQ (12) of the ASME Code Section III or

$$_{th}S_p = \frac{K_3}{2(1-\nu)} E\alpha|\Delta T1| + K_3 C_3 E_{AB}|\alpha_A TA - \alpha_B TB| + \frac{E\alpha}{1-\nu}|\Delta T2|$$

3. Abbreviations for the transients:

No t	-	Room temperature
N op	-	Normal Operation
PL HU	-	Plant Heatup
PL CD	-	Plant Cooldown
PL L	-	Plant Loading
PL UL	-	Plant Unloading
ST I1	-	Step Load Increase 1
ST I2	-	Step Load Increase 2
ST D1	-	Step Load Decrease 1
ST D2	-	Step Load Decrease 2
RE T1	-	Reactor Trip 1
RE T2	-	Reactor Trip 2
PL TH	-	Plant Leak Test Heatup
PL TC	-	Plant Leak Test Cooldown
HY T	-	Hydro Static Test
D WT	-	Due to Dead Weight Along
I	-	Load Set 1
L	-	Load Set 2
NI	-	Cycles for Load Set 1
NL	-	Cycles for Lead Set 2
NU	-	Cycles for the Smaller of Load Set 1 or Load Set 2
NA	-	ASME Code Section III Allowable Cycles

4. Listing values shown for the plant variations conditions, load set 7 through 10, were calculated based on a pressure variation of ± 50 psi and a temperature variation of ±6°F, which are lower than the currently specified values of ±100 psi and ±10°F. However, the effect of these deviations is neglegible since load set 7 through load set 10 are not the controlling loading case and stresses induced from the total range of pressure and temperature variations contribute only a small portion of the resulting usage factor.

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Table CA-1
(Sheet 1 of 17)

1. Inlet Nozzle at Nozzle End: Joint No. 1

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-628512	620331	-1438727	0	0	0	0	0
3.	PL HU	500	2250	-343248	25670	-519187	8.0	35.0	4.5	0	18514
4.	PL CD	500	0	-568770	368877	-1380816	-9.0	-38.5	-4.5	0	20297
5.	PL L	15000	2290	-628512	620331	-1438727	2.0	3.0	1.0	0	2065
6.	PL UL	15000	2210	-628512	620331	-1438727	-2.0	-3.0	-1.0	0	2065
7.	ST I1	4000	2250	-628512	620331	-1438727	-3.0	-1.0	-3.0	0	1946
8.	ST I2	4000	2280	-628512	620331	-1438727	2.5	1.0	2.0	0	1565
9.	ST D1	4000	2230	-628512	620331	-1438727	3.0	1.0	2.5	0	1816
10.	ST D2	4000	2186	-628512	620331	-1438727	-2.5	-1.0	-1.5	0	1435
11.	RE T1	480	1680	-628512	620331	-1438727	-14.0	-4.5	-11.0	0	8228
12.	RE T2	960	2250	-628512	620331	-1438727	4.0	1.0	7.0	0	3226
13.	PL TH	200	2250	0	0	0	7.5	33.0	4.5	0	17512
14.	PL TC	200	400	0	0	0	-8.0	-36.0	-4.5	0	18954
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	29349	1540	67254	-	-	-	-	-

2. Discharge Side Elbow: Joint No.(2)

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-530339	551837	-1382065	0	0	0	0	0
3.	PL HU	500	2250	-304960	36910	-497089	7.5	0	3.5	0	2084
4.	PL CD	500	0	-476011	346437	-1327276	-8.5	0	-4.0	0	2370
5.	PL L	15000	2290	-530339	551837	-1382065	2.5	0	1.0	0	651
6.	PL UL	15000	2210	-530339	551837	-1382065	-2.0	0	-1.0	0	651
7.	ST I1	4000	2250	-530339	551837	-1382065	-3.5	0	-3.0	0	1327
8.	ST I2	4000	2280	-530339	551837	-1382065	2.5	0	2.0	0	911
9.	ST D1	4000	2230	-530339	551837	-1382065	3.5	0	2.5	0	1197
10.	ST D2	4000	2186	-530339	551837	-1382065	-2.5	0	-1.5	0	781
11.	RE T1	480	1680	-530339	551837	-1382065	-15.0	0	-10.5	0	5075
12.	RE T2	960	2250	-530339	551837	-1382065	4.5	0	7.0	0	2521
13.	PL TH	200	2250	0	0	0	7.0	0	3.5	0	2005
14.	PL TC	200	400	0	0	0	-7.5	0	-3.5	0	2084
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	28768	1201	66928	-	-	-	-	-

Table CA-1
(Sheet 3 of 17)

3. Discharge Side Elbow: Joint No. 3

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-220387	332634	-1047558	0	0	0	0	0
3.	PL HU	500	2250	-184078	48882	-366631	7.5	0	3.5	0	2084
4.	PL CD	500	0	-183150	254080	-1011216	-8.5	0	-4.0	0	2370
5.	PL L	15000	2290	-220387	332684	-1047558	2.5	0	1.0	0	651
6.	PL UL	15000	2210	-220387	332684	-1047558	-2.0	0	-1.0	0	651
7.	ST I1	4000	2250	-220387	332684	-1047558	-3.5	0	-3.0	0	1327
8.	ST I2	4000	2280	-220387	332684	-1047558	2.5	0	2.0	0	911
9.	ST D1	4000	2230	-220387	332684	-1047558	3.5	0	2.5	0	1197
10.	ST D2	4000	2186	-220387	332684	-1047558	-2.5	0	-1.5	0	781
11.	RE T1	480	1680	-220387	332684	-1047558	-15.0	0	-10.5	0	5075
12.	RE T2	960	2250	-220387	332684	-1047558	4.5	0	7.0	0	2521
13.	PL TH	200	2250	0	0	0	7.0	0	3.5	0	2005
14.	PL TC	200	400	0	0	0	-7.5	0	-3.5	0	2084
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	24646	400	61921	-	-	-	-	-

4. Discharge Side Pipe: Joint No. 4

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^S p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	1014769	-563805	1527743	0	0	0	0	0
3.	PL HU	500	2250	297634	-65964	537741	7.5	0	3.5	0	2084
4.	PL CD	500	0	983898	-297510	1422079	-8.5	0	-4.0	0	2370
5.	PL L	15000	2290	1014769	-563805	1527743	2.5	0	1.0	0	651
6.	PL UL	15000	2210	1014769	-563805	1527743	-2.0	0	-1.0	0	651
7.	ST I1	4000	2250	1014769	-563805	1527743	-3.5	0	-3.0	0	1327
8.	ST I2	4000	2280	1014769	-563805	1527743	2.5	0	2.0	0	911
9.	ST D1	4000	2230	1014769	-563805	1527743	3.5	0	2.5	0	1197
10.	ST D2	4000	2186	1014769	-563805	1527743	-2.5	0	-1.5	0	781
11.	RE T1	480	1680	1014769	-563805	1527743	-15.0	0	-10.5	0	5075
12.	RE T2	960	2250	1014769	-563805	1527743	4.5	0	7.0	0	2521
13.	PL TH	200	2250	0	0	0	7.0	0	3.5	0	2005
14.	PL TC	200	400	0	0	0	-7.5	0	-3.5	0	2084
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-65960	-612	-127009	-	-	-	-	-

5. Suction Side Pipe: Joint No. 5

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-532880	-539857	742414	0	0	0	0	0
3.	PL HU	500	2250	217739	-21390	-254994	6.5	-2.0	3.0	0	2237
4.	PL CD	500	0	-124349	-356807	210700	-7.5	2.0	-3.5	0	2523
5.	PL L	15000	2290	-532880	-539857	742414	2.0	-1.0	1.0	0	793
6.	PL UL	15000	2210	-532880	-539857	742414	-2.0	1.0	-1.0	0	793
7.	ST I1	4000	2250	-532880	-539857	742414	-3.5	1.0	-2.5	0	1417
8.	ST I2	4000	2280	-532880	-539857	742414	2.5	-1.0	2.0	0	1130
9.	ST D1	4000	2230	-532880	-539857	742414	3.5	-1.0	2.5	0	1417
10.	ST D2	4000	2186	-532880	-539857	742414	-2.5	1.0	-1.5	0	1001
11.	RE T1	480	1680	-532880	-539857	742414	-15.0	2.0	-10.0	0	5385
12.	RE T2	960	2250	-532880	-539857	742414	5.0	-1.0	7.0	0	2819
13.	PL TH	200	2250	0	0	0	6.0	-2.0	3.0	0	2185
14.	PL TC	200	400	0	0	0	-6.5	2.0	-3.0	0	2237
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	7978	8782	-25408	-	-	-	-	-

6. Suction Side Elbow: Joint No. 6

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-507634	-539867	574591	0	0	0	0	0
3.	PL HU	500	2250	192884	-21390	-223525	6,5	-2.0	3.0	0	2237
4.	PL CD	500	0	-142345	-395807	210051	-7,5	2,0	-3.5	0	2523
5.	PL L	15000	2290	-507634	-539857	674591	2,0	-1.0	1.0	0	793
6.	PL UL	15000	2210	-507634	-539857	674591	-2.0	1.0	-1,0	0	793
7.	ST I1	4000	2250	-507634	-539857	674591	-3.5	1,0	-2,5	0	1417
8.	ST I2	4000	2280	-507634	-539857	674591	2.5	-1,0	2,0	0	1130
9.	ST D1	4000	2230	-507634	-539857	674591	3,5	-1.0	2.5	0	1417
10.	ST D2	4000	2186	-507634	-539857	674591	-2.5	1,0	-1.5	0	1001
11.	RE T1	480	1680	-507634	-539857	674591	-15.0	2.0	-10.0	0	5385
12.	RE T2	960	2250	-507634	-539857	674591	5,0	-1,0	7,0	0	2819
13.	PL TH	200	2250	0	0	0	6.0	-2,0	3,0	0	2185
14.	PL TC	200	400	0	0	0	-6,5	2,0	-3.0	0	2237
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	8538	6782	-25552	-	-	-	-	-

7. Suction Side Elbow: Joint No. 7

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-138875	-351708	-155765	0	0	0	0	0
3.	PL HU	500	2250	-65112	-5010	104972	6.5	-2.0	3.0	0	2237
4.	PL CD	500	0	-252079	-251102	113158	-7.5	2.0	-3.5	0	2523
5.	PL L	15000	2290	-138875	-351708	-155765	2.0	-1.0	1.0	0	793
6.	PL UL	15000	2210	-138875	-351708	-155765	-2.0	1.0	-1.0	0	793
7.	ST I1	4000	2250	-138875	-351708	-155765	-3.5	1.0	-2.5	0	1417
8.	ST I2	4000	2280	-138875	-351708	-155765	2.5	-1.0	2.0	0	1130
9.	ST D1	4000	2230	-138875	-351708	-155765	3.5	-1.0	2.5	0	1417
10.	ST D2	4000	2186	-138875	-351708	-155765	-2.5	1.0	-1.5	0	1001
11.	RE T1	480	1680	-138875	-351708	-155765	-15.0	2.0	-10.0	0	5385
12.	RE T2	960	2250	-138875	-351708	-155765	5.0	-1.0	7.0	0	2819
13.	PL TH	200	2250	0	0	0	6.0	-2.0	3.0	0	2185
14.	PL TC	200	400	0	0	0	-6.5	2.0	-3.0	0	2237
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-7535	5188	2784	-	-	-	-	-

8. Suction Side Elbow: Joint No. 8

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	S_{thp}
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	146610	85927	-549813	0	0	0	0	0
3.	PL HU	500	2250	-102077	32631	155993	6.5	-2.0	3.0	0	2237
4.	PL CD	500	0	-99746	87156	-97099	-7.5	2.0	-3.5	0	2523
5.	PL L	15000	2290	146610	85927	-549813	2.0	-1.0	1.0	0	793
6.	PL UL	15000	2210	146610	85927	-549813	-2.0	1.0	-1.0	0	793
7.	ST I1	4000	2250	146610	85927	-549813	-3.5	1.0	-2.5	0	1417
8.	ST I2	4000	2280	146610	85927	-549813	2.5	-1.0	2.0	0	1130
9.	ST D1	4000	2230	146610	85927	-549813	3.5	-1.0	2.5	0	1417
10.	ST D2	4000	2186	146610	85927	-549813	-2.5	1.0	-1.5	0	1001
11.	RE T1	480	1680	146610	85927	-549813	-15.0	2.0	-10.0	0	5385
12.	RE T2	960	2250	146610	85927	-549813	5.0	-1.0	7.0	0	2819
13.	PL TH	200	2250	0	0	0	6.0	-2.0	3.0	0	2185
14.	PL TC	200	400	0	0	0	-6.5	2.0	-3.0	0	2237
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-13411	-3153	10892	-	-	-	-	-

Table CA-1
(Sheet 9 of 17)

9. Suction Side Elbow: Joint No. 9

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	23634	274318	-98893	0	0	0	0	0
3.	PL HU	500	2250	124096	48878	-128554	6.5	-2.0	3.0	0	2237
4.	PL CD	500	0	141132	232827	-181324	-7.5	2.0	-3.5	0	2523
5.	PL L	15000	2290	23634	274318	-58893	2.0	-1.0	1.0	0	793
6.	PL UL	15000	2210	23634	274318	-58893	-2.0	1.0	-1.0	0	793
7.	ST I1	4000	2250	23634	274318	-58893	-3.5	1.0	-2.5	0	1417
8.	ST I2	4000	2280	23634	274318	-58893	2.5	-1.0	2.0	0	1130
9.	ST D1	4000	2230	23634	274318	-58893	3.5	-1.0	2.5	0	1417
10.	ST D2	4000	2186	23634	274318	-58893	-2.5	1.0	-1.5	0	1001
11.	RE T1	480	1680	23634	274318	-58893	-15.0	2.0	-10.0	0	5385
12.	RE T2	960	2250	23634	274318	-58893	5.0	-1.0	7.0	0	2819
13.	PL TH	200	2250	0	0	0	6.0	-2.0	3.0	0	2185
14.	PL TC	200	400	0	0	0	-6.5	2.0	-3.0	0	2237
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-2385	-5746	-10452	-	-	-	-	-

Table CA-1
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10. Suction Side Elbow: Joint No. 10

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	23570	274318	-58721	0	0	0	0	0
3.	PL HU	500	2250	124160	48878	-128634	6.5	-2.0	3.0	0	2237
4.	PL CD	500	0	141177	232827	-181322	-7.5	2.0	-3.5	0	2523
5.	PL L	15000	2290	23570	274318	-58721	2.0	-1.0	1.0	0	793
6.	PL UL	15000	2210	23570	274318	-58721	-2.0	1.0	-1.0	0	793
7.	ST I1	4000	2250	23570	274318	-58721	-3.5	1.0	-2.5	0	1417
8.	ST I2	4000	2280	23570	274318	-58721	2.5	-1.0	2.0	0	1130
9.	ST D1	4000	2230	23570	274318	-58721	3.5	-1.0	2.5	0	1417
10.	ST D2	4000	2186	23570	274318	-58721	-2.5	1.0	-1.5	0	1001
11.	RE T1	480	1680	23570	274318	-58721	-15.0	2.0	-10.0	0	5385
12.	RE T2	960	2250	23570	274318	-58721	5.0	-1.0	7.0	0	2819
13.	PL TH	200	2250	0	0	0	6.0	-2.0	3.0	0	2185
14.	PL TC	200	400	0	0	0	-6.5	2.0	-3.0	0	2237
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-2387	-6746	-10452	-	-	-	-	-

11. Suction Side Elbow: Joint No. 11

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-106808	461649	451192	0	0	0	0	0
3.	PL HU	500	2250	289557	-64456	-350753	6.5	-2.0	3.0	0	2237
4.	PL CD	500	0	288112	197944	-153773	-7.5	2.0	-3.5	0	2523
5.	PL L	15000	2290	-106608	461649	451182	2.0	-1.0	1.0	0	793
6.	PL UL	15000	2210	-106808	461649	451182	-2.0	1.0	-1.0	0	793
7.	ST I1	4000	2250	-106808	461649	451182	-3.5	1.0	-2.5	0	1417
8.	ST I2	4000	2280	-106808	461649	451182	2.5	-1.0	2.0	0	1130
9.	ST D1	4000	2230	-106808	461649	451182	3.5	-1.0	2.5	0	1417
10.	ST D2	4000	2186	-106808	461649	451182	-2.5	1.0	-1.5	0	1001
11.	RE T1	480	1680	-106808	461649	451182	-15.0	2.0	-10.0	0	5385
12.	RE T2	960	2250	-106808	461649	451182	5.0	-1.0	7.0	0	2819
13.	PL TH	200	2250	0	0	0	6.0	-2.0	3.0	0	2185
14.	PL TC	200	400	0	0	0	-6.5	2.0	-3.0	0	2237
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	6254	-5330	3015	-	-	-	-	-

12. Outlet Nozzle End: Joint No. (12)

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-124465	577699	597508	0	0	0	0	0
3.	PL HU	500	2250	329863	-134723	-409661	9.0	8.0	5.0	0	7000
4.	PL CD	500	0	334116	175279	-138295	-10.0	-9.0	-5.0	0	7683
5.	PL L	15000	2290	-124465	577699	597508	2.5	1.5	1.5	0	1655
6.	PL UL	15000	2210	-124465	577699	597508	-2.5	-1.5	-1.0	0	1526
7.	ST I1	4000	2250	-124465	577699	597508	-3.0	-1.0	-3.0	0	1946
8.	ST I2	4000	2280	-124465	577699	597508	2.5	1.0	2.0	0	1565
9.	ST D1	4000	2230	-124465	577699	597508	3.0	1.0	2.5	0	1816
10.	ST D2	4000	2186	-124465	577699	597508	-2.5	-1.0	-1.5	0	1435
11.	RE T1	480	1680	-124465	577699	597508	-14.0	-3.0	-11.0	0	7568
12.	RE T2	960	2250	-124465	577699	597508	4.0	1.0	7.0	0	3225
13.	PL TH	200	2250	0	0	0	8.5	7.5	5.0	0	6659
14.	PL TC	200	400	0	0	0	-9.0	-8.0	-5.0	0	7000
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	13948	-4452	11967	-	-	-	-	-

13. Hot Leg Outlet Nozzle End: Joint No. 13

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	th^{S}_{F}
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-443	3250	-5707294	0	0	0	0	0
3.	PL HU	500	2250	-227	-3542	-2072053	14.0	44.0	6.5	0	24494
4.	PL CD	500	0	-747	-12743	-5814303	-15.0	-48.0	-7.0	0	26631
5.	PL L	15000	2290	-443	3250	-5707294	22.0	23.0	10.0	0	18076
6.	PL UL	15000	2210	-443	3250	-5707294	-30.5	-18.0	-19.0	0	20265
7.	ST I1	4000	2250	-443	3250	-5707294	0	0	0	0	0
8.	ST I2	4000	2280	-443	3250	-5707294	6.0	3.5	4.0	0	4036
9.	ST D1	4000	2230	-443	3250	-5707294	0	0	0	0	0
10.	ST D2	4000	2186	-443	3250	-5707294	-5.5	-1.0	-3.5	0	2683
11.	RE T1	480	1680	-443	3250	-5707294	-50.0	-17.0	-35.0	0	28702
12.	RE T2	960	2250	-443	3250	-5707294	0	0	0	0	0
13.	PL TH	200	2250	0	0	0	13.0	41.5	6.5	0	23148
14.	PL TC	200	400	0	0	0	-14.0	-44.5	-7.0	0	24844
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-185	-1097	539111	-	-	-	-	-

Table CA-1
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14. Hot Leg Pipe: Joint No. 14

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	th^{S}_{p}
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-443	3320	-5546572	0	0	0	0	0
3.	PL HU	500	2250	-227	-3414	-2008336	14.0	27.0	6.5	0	9811
4.	PL CD	500	0	-747	-12301	-5640955	-15.0	-29.0	-7.0	0	10536
5.	PL L	15000	2290	-443	3320	-5546572	22.0	16.0	10.0	0	9557
6.	PL UL	15000	2210	-443	3320	-5546572	-30.5	-13.5	-19.0	0	12675
7.	ST I1	4000	2250	-443	3320	-5546572	0	0	0	0	0
8.	ST I2	4000	2280	-443	3320	-5546572	6.0	2.0	4.0	0	2417
9.	ST D1	4000	2230	-443	3320	-5546572	0	0	0	0	0
10.	ST D2	4000	2186	-443	3320	-5546572	-5.5	-1.5	-3.5	0	2100
11.	RE T1	480	1680	-443	3320	-5546572	-50.0	-13.0	-35.0	0	19773
12.	RE T2	960	2250	-443	3320	-5546572	0	0	0	0	0
13.	PL TH	200	2250	0	0	0	13.0	25.5	6.5	0	9324
14.	PL TC	200	400	0	0	0	-14.0	-27.5	-7.0	0	10050
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-185	-1035	525621	-	-	-	-	0

15. Hot Leg Elbow: Joint No. 15

Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	S_{thp}
1. No T	500	0	0	0	0	0	0	0	0	0
2. N OP	10^6	2250	-443	5770	62893	0	0	0	0	0
3. PL HU	500	2250	-227	1036	215462	12.5	-1.0	5.5	0	3606
4. PL CD	500	0	-747	3139	409155	-14.5	1.0	-6.0	0	4049
5. PL L	15000	2290	-443	5770	62893	23.5	-3.0	10.0	0	6937
6. PL UL	15000	2210	-443	5770	62893	-32.0	3.0	-18.5	0	10475
7. ST I1	4000	2250	-443	5770	62893	0	0	0	0	0
8. ST I2	4000	2280	-443	5770	62893	6.0	-1.0	4.0	0	2198
9. ST D1	4000	2230	-443	5770	62893	0	0	0	0	0
10. ST D2	4000	2186	-443	5770	62893	-6.0	1.0	-3.5	0	2068
11. RE T1	480	1680	-443	5770	62893	-52.5	3.0	-35.0	0	17969
12. RE T2	960	2250	-443	5770	62893	0	0	0	0	0
13. PL TH	200	2250	0	0	0	12.0	-1.0	5.5	0	3528
14. PL TC	200	400	0	0	0	-13.0	1.0	-5.5	0	3685
15. HY T	10	3125	0	0	0	0	0	0	0	0
16. D WT	-	-	-185	1128	-112515	-	-	-	-	0

16. Hot Leg Elbow: Joint No. 16

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-238	6421	1169507	0	0	0	0	0
3.	PL HU	500	2250	145	2218	490662	12.5	-1.0	5.5	0	3606
4.	PL CD	500	0	545	7240	2415350	-14.5	1.0	-6.0	0	4049
5.	PL L	15000	2290	-238	6421	1169507	23.5	-3.0	10.0	0	6937
6.	PL UL	15000	2210	-238	6421	1169507	-32.0	3.0	-18.5	0	10475
7.	ST I1	4000	2250	-238	6421	1169057	0	0	0	0	0
8.	ST I2	4000	2280	-238	6421	1169507	6.0	-1.0	4.0	0	2198
9.	ST D1	4000	2230	-238	6421	1169507	0	0	0	0	0
10.	ST D2	4000	2186	-238	6421	1169507	-6.0	1.0	-3.5	0	2068
11.	RE T1	480	1680	-238	6421	1169507	-52.5	3.0	-35.0	0	17969
12.	RE T2	960	2250	-238	6421	1169507	0	0	0	0	0
13.	PL TH	200	2250	0	0	0	12.0	-1.0	5.5	0	3528
14.	PL TC	200	400	0	0	0	-13.0	1.0	-5.5	0	3685
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	-3	1703	-326136	-	-	-	-	0

17. Hot Leg Nozzle End; Joint No. 17

	Load Set	Cycles	Pressure Psi	MX FT-LB	MY FT-LB	MZ FT-LB	ΔT1 °F	TA °F	ΔT2 °F	TB °F	$th^{S}p$
1.	No T	500	0	0	0	0	0	0	0	0	0
2.	N OP	10^6	2250	-195	6480	1227509	0	0	0	0	0
3.	PL HU	500	2250	220	2325	480791	16.0	9.5	8.0	0	10120
4.	PL CD	500	0	805	7612	2641255	-18.5	-11.0	-8.5	0	11514
5.	PL L	15000	2290	-196	6480	1227509	26.5	9.0	13.0	0	13744
6.	PL UL	15000	2210	-196	6480	1227509	-32.5	-8.0	-21.5	0	16964
7.	ST I1	4000	2250	-196	6430	1227509	0	0	0	0	0
8.	ST I2	4000	2280	-196	6480	1227509	6.0	1.0	4.5	0	3060
9.	ST D1	4000	2230	-196	6480	1227509	0	0	.0	0	0
10.	ST D2	4000	2186	-196	6480	1227509	-5.5	-1.0	-4.0	0	2810
11.	RE T1	480	1680	-196	6480	1227509	-50.0	-8.5	-30.0	0	23631
12.	RE T2	960	2250	-196	6480	1227509	0	0	0	0	0
13.	PL TH	200	2250	0	0	0	15.0	9.0	8.0	0	9658
14.	PL TC	200	400	0	0	0	-16.5	-10.0	-8.0	0	10461
15.	HY T	10	3125	0	0	0	0	0	0	0	0
16.	D WT	-	-	32	1755	-345277	-	-	-	-	0

Table CA-2

Seismic and Pump Vibration Loads

Location	Fx,(K)	Fy,(K)	Fz,(K)	Mx,(in-K)	My,(in-K)	Mz,(in-K)
Joint No. 2:						
SSE	145	33	157	2499	3693	2679
Pump Vibration	2.14	2.85	3.32	25.72	19.33	25.55
Joint No. 4:						
SSE	198	34	75	2308	977	4937
Pump Vibration	4.53	.39	1.71	26.88	43.98	62.89
Joint No. 5:						
SSE	29	13	23	1373	1834	1353
Pump Vibration	.74	.22	.84	55.41	27.21	47.35
Joint No. 11:						
SSE	56	45	56	3131	2318	3131
Pump Vibration	.84	.35	.84	44	49	44
Joint No. 14:						
SSE	510	125	89	2918	6574	10599
Pump Vibration	.78	.33	.15	.58	31.29	35
Joint No. 16:						
SSE	533	467	82	6752	6576	6247
Pump Vibration	.78	.82	.14	7.49	7.19	25.87

Notes:
1. All loads are in global coordinate system
2. Each of the six load components are maximums over all time. Maximums for all components do not necessarily occur simultaneously.
3. Loads for the remainder joints can be obtained from the given loads of the nearby joint by transposition.