Attachment 1

Table 1, "List of Westinghouse's Responses to RAIs Transmitted in DCP/NRC1525"

Docket No. 52-006

DCP/NRC1525

December 2, 2002

Attachment 1

Table 1 "List of Westinghouse's Responses to RAIs Transmitted in DCP/NRC1525"	
100.001	
220.015	471.009
251.011	720.013
251.028	720.018
260.002	720.025
281.001	720.029
440.040	720.030
440.057	720.042
440.067	720.053
440.081	720.056
440.091	720.058
440.092	720.060
440.096	720.063
440.099	720.078
440.119	720.087
440.128	720.088
440.133	720.094
440.162	720.095
440.162P	720.098

DCP/NRC1525

December 2, 2002

Attachment 3

Westinghouse Non-Proprietary Responses
to US Nuclear Regulatory Commission
Requests for Additional Information
dated November 2002

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 100.001

Question:

Westinghouse has not yet requested any exemptions from regulations for the AP1000 design. If exemptions from the regulations are desired to support the design certification, please provide a request and basis for each exemption in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.12.

Westinghouse Response:

For the AP1000 design, Westinghouse will request exemptions from the regulations for the plant safety parameter display console (10 CFR 50.34(f)(2)(iv)), the auxiliary (or emergency) feedwater system (10 CFR 50.62(c)(1)), and offsite power sources (10 CFR Part 50 Appendix A, General Design Criterion (GDC) 17). These exemptions were granted for the AP600, and the staff reviewed the applicability of these exemptions to the AP1000 during the pre-certification review.

Section 50.34(f)(2)(iv) of the NRC's regulations requires a "safety parameter display console that will display to operators a minimum set of parameters defining the safety status..., displaying a full range of important plant parameters..., and capable of indicating when process limits are being approached or exceeded." The AP1000 design certification includes a DAC that is based on the conclusion that the safety parameter display functions of advanced control rooms should be integrated into the main control room design. Thus, the exemption criterion of 10 CFR 50.12(a)(2)(ii), that an exemption may be granted if the "application of the regulation ... is not necessary to achieve the underlying purpose of the rule...," is met, and the request for an exemption similar to that granted for the AP600 design should be acceptable for the AP1000 design.

Section 50.62(c)(1) of the NRC's regulations requires that equipment be available to ensure the automatic startup of the auxiliary feedwater (AFW) system under anticipated transient without scram (ATWS) conditions. For current and evolutionary plant designs, the regulation requires an AFW system. The AP600 design met the requirement for emergency core cooling through its passive residual heat removal (PRHR) system, which is initiated automatically under the conditions of an ATWS. The AP1000 design also has a PRHR heat exchanger that is functionally identical to the AP600 PRHR heat exchanger, and its capacity is increased to accommodate the larger core power. This design feature satisfies the underlying purpose of the regulation, and thus meets the exemption criterion of 10 CFR 50.12(a)(2)(ii).

GDC 17 of 10 CFR Part 50, Appendix A, requires two physically independent offsite power sources. The AP1000 design is based on safety-related passive systems for core cooling and containment integrity, which did not rely on offsite power sources. In this regard, the AP1000 design precludes the need to rely on offsite power sources for core cooling and containment integrity. Therefore AP1000 design satisfies the underlying purpose of the regulation, and thus meets the exemption criterion of 10 CFR 50.12(a)(2)(ii).

The staff reviewed Westinghouse's proposals for exemptions to the Commission's regulations during the pre-certification review and concluded in Reference 1 that, "given the current understanding of the similarity between the AP600 and AP1000 designs, the proposed exemptions are applicable and are expected to be justifiable. This conclusion is contingent on the extent to which potential dissimilarities between the AP600 and AP1000 designs affect the safety areas involved."

Westinghouse letter DCP/NRC1534 provides the request of exemptions to regulations and the basis for their request in accordance with 10 CFR 50.12.

Reference:

1. Letter from J. Lyons to W. E. Cummins, "Applicability of AP600 Standard Plant Design Analysis Codes, Test Program and Exemptions to the AP1000 Standard Plant Design" dated March 25, 2002.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 220.015

Question:

AP1000 DCD Subsection 3.8.4.3.1.4, "Abnormal Loads," discusses loads generated by a postulated high-energy line break accident, including subcompartment pressure loads and subcompartment temperatures. It is stated that "Determination of subcompartment pressure loads (temperatures) is discussed in Subsection 6.2.1.2." The staff reviewed Subsection 6.2.1.2, but could not identify any quantitative data on subcompartment pressures and temperatures. This also applies to subcompartments inside containment (AP1000 DCD, Tier 2 Material, Section 3.8.3).

Please provide quantitative pressure and temperature results from the AP1000 subcompartment analyses for both high and medium energy line breaks, as applicable, for all subcompartments inside and outside containment in which a significant line break has been postulated. In addition, demonstrate that quantitative data supports the use of a uniform 5 psi subcompartment design pressure for AP1000, and describe the methodology used to evaluate the effects of temperature transients resulting from the postulated line breaks. Same concerns are extended to Section 3.8.3, "Concrete and Steel Internal Structures of Steel Containment."

Westinghouse Response:

Table 6.2.1.2-1 provides the results of the AP1000 subcompartment pressurization analyses for subcompartments inside containment. The information presented in Table 6.2.1.2-1 is consistent with the level of detail that was provided for the AP600. The reference to section 6.2.1.2 in the discussion of abnormal loads presented in 3.8.4.3.1.4 is referring to the methodology used in the subcompartment pressurization analyses performed to determine the abnormal loads for the MSIV valve compartment.

As discussed, the quantitative results of the analyses of the subcompartments inside containment are presented in DCD Table 6.2.1.2-1. Although the results of the subcompartment analyses for the MSIV valve compartments that are located outside containment were not included in the AP600 DCD Chapter 6, this information will be included in the AP1000 DCD Table 6.2.1.2-1.

AP1000 Room	Possible Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential Pressure	Table for M&E Data
12306	4-inch Steam Generator Blowdown Line	6.0	5.85	6.2.1.3-5
12404	1 ft^2 Break in the Main Steam Line B	6.0	5.33	6.2.1.3-4
12406	1 ft^2 Break in the Main Steam Line A	6.0	5.35	6.2.1.3-4

Note that for the AP600 MSIV rooms, the peak pressure was calculated to be 4.85 psig, and the design differential pressure for the room was 5.0 psig. The design pressure of this room has been increased for AP1000 to accommodate its higher calculated short-term mass and energy release.

The RAI also requests temperature information be included. Similar to the approach for AP600, the design of the subcompartments inside containment use the results of the bounding global temperature analysis provided in DCD Chapter 6. The MSIV subcompartment temperatures are shown in DCD Figure 3D.5.9. Subsequent to the initial blowdown the compartment atmosphere cools and the compartment walls are evaluated for a long-term gradient across the walls.

Design Control Document (DCD) Revision:

Revise 3.8.4.3.1.4 as shown below:

P_a = Pressure load within or across a compartment generated by the postulated break. The main steam isolation valve (MSIV) and steam generator blowdown valve compartments are designed for a pressurization load of ~~5~~ 6 psi. The subcompartment design pressure bounds the pressurization effects due to postulated breaks in high energy pipe. Determination of subcompartment pressure loads is discussed in subsection 6.2.1.2.

Tables 6.2.1.2-1 and 6.2.1.3-4 are modified as shown.

PRA Revision:

None

Table 6.2.1.2-1 (Sheet 5 of 5)

LISTING OF LINES NOT LBB QUALIFIED AND THE CALCULATED MAXIMUM DIFFERENTIAL PRESSURES

AP1000 Room #	Possible(1) Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential(2) Pressure (psi)	Table for M&E Data
12306	4" SG Blowdown	6.0	5.85	6.2.1.3-5
12404	1 ft^2 Main Steam Line A	6.0	5.35	6.2.1.3-4
12406	1 ft^2 Main Steam Line B	6.0	5.35	6.2.1.3-4

Notes:

1. "None" indicates that there are no High Energy Lines >1" in diameter that are not qualified to LBB.
2. Structures are designed to a pressurization load of 5.0 psig except as follows; ~~except~~ the CVS room pipe tunnel ~~which~~ is designed to a pressurization load of 7.5 psig as discussed ~~. See~~in DCD ~~S~~subsection 3.8.3.5~~.~~; the MSIV rooms are designed to a pressurization load of 6 psig as discussed in DCD subsections 3.8.3.5 and 3.8.4.3.1.4.
3. "NA" indicates that no calculation was performed because no rupture was postulated or that the line was postulated to rupture in a region with a large free volume so compartment differential pressures would be negligible.

Table 6.2.1.3-4

MAIN STEAM LINE (1 ft^2) BREAK MASS AND ENERGY

Time (sec)	Mass (lbm/sec)	Energy (Btu/sec)
0	~~2100~~2300	~~2504900~~2734200
~~3.65~~1.79	~~2100~~2300	~~2504900~~2734200
~~4.65~~2.79	~~6610~~6990	~~3980500~~4304400
~~5.65~~3.79	~~6970~~7350	~~4084400~~4410700
~~6.65~~4.79	~~7060~~7440	~~4109600~~44364500
~~7.65~~5.79	~~7060~~7440	~~4109600~~44364500
~~8.65~~6.79	~~7020~~7390	~~4099700~~4420700
~~9.65~~7.79	~~6940~~7320	~~4075900~~4401500
~~10.65~~8.79	~~6820~~7200	~~4040900~~4366100
~~11.65~~9.79	~~6680~~7060	~~4001300~~4325700
~~12.65~~10.79	~~6520~~6910	~~3951800~~4281400
~~13.65~~11.79	~~6340~~6730	~~3896600~~4225100
~~14.65~~12.79	~~6190~~6580	~~3852700~~4180900
~~15.65~~13.79	~~6000~~6390	~~3792600~~4120300
~~16.65~~14.79	~~5830~~6220	~~3732800~~4066000
~~17.65~~15.79	~~5680~~6070	~~3689700~~4017700

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 251.011

Question:

The application does not address the impact of irradiation on the integrity of the reactor vessel internals. In particular, the peak neutron fluence for the reactor vessel internals at the end of the license period should be identified and its impact on irradiation assisted stress corrosion cracking (IASCC) and void swelling should be discussed. In addition, do the reactor vessel internals contain any cast austentic stainless steel (CASS) components? CASS reactor vessel internals components are subject to both thermal and irradiation embrittlement. The application should discuss the impact of these aging effects on the integrity of the reactor vessel internals components. Since the ASME Code inspections may not detect the impact of these aging effects on the reactor vessel internals, augmented inspection may be required. What augmented inspections will be performed by potential AP1000 licensees to detect these aging effects?

The materials reliability program (MRP) has initiated a program to evaluate the impact of these aging effects on reactor vessel internals. How will potential AP1000 licensees use the results from the MRP reactor vessel internals program to ensure the integrity of the reactor vessel internals? (Section 4.5.2)

Westinghouse Response:

The estimated peak neutron fluence for the AP1000 reactor vessel internals is 9E21 n/cm^2. This peak neutron fluence is not expected to result in any new issues of irradiation assisted stress corrosion cracking (IASCC) or void swelling in the AP1000 reactor internals. Issues identified in the current PWR fleet are being addressed in programs such as the EPRI/MRP reactor internals programs on IASCC and void swelling. Westinghouse is a very active participant in these programs. Any findings from the EPRI/MRP reactor internals programs on these issues will be incorporated into the AP1000 reactor internals design as appropriate.

The AP1000 is designed to minimize the use of cast austenitic stainless steel (CASS). If used, the CASS will be evaluated in terms of thermal aging effects. Any CASS used will be limited in carbon (low carbon grade: L grade) and ferrite contents. The Westinghouse Owners Group (WOG) has also initiated a program to evaluate the impact of these aging effects on reactor vessel internals. The WOG program includes testing of CASS materials from the materials reliability program.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 251.028

Question:

It was stated in the last paragraph of Section 10.2.3.2.1 that there is not a separate material toughness (K_{IC}) requirement for AP1000 rotors. Not having a K_{IC} requirement for the deterministic brittle fracture mechanics analysis is not appropriate. In the AP600 review, the staff accepted the use of the Rolfe-Novak-Barsom correlation of upper shelf Charpy values with K_{IC} in the turbine missile probability analysis. That was because for a missile probability analysis involving more than twenty random variables, the impact of the variability of K_{IC} on the final results is small. It was never the staff's intention to accept the Rolfe-Novak-Barsom correlation for a deterministic brittle fracture mechanics analysis on any components without sufficient safety margin (say 30%) to account for the uncertainty in using this empirical formula. Provide a K_{IC} requirement for AP1000 rotors. (Section 10.2.3)

Westinghouse Response:

For low cycle fatigue evaluations, the fracture toughness is assumed to be 120MPa*√m = 110ksi*√in. This is based upon the design curve for fracture toughness of 3.5% Ni-Cr-Mo-V steel as shown in Figure 251.028-1. Figure 251.028-1 is based upon MHI tests and experience and includes a 20% margin. The minimum allowable fracture toughness for the AP1000 LP rotor at temperature will be 220MPa*√m = 200ksi*√in. This minimum allowable is readily achievable based upon MHI tests and experience. The value used for fracture toughness in low cycle fatigue evaluations is conservative and has adequate safety margin.

The fracture toughness of actual rotors will be verified in addition to Charpy's impact value and FATT.

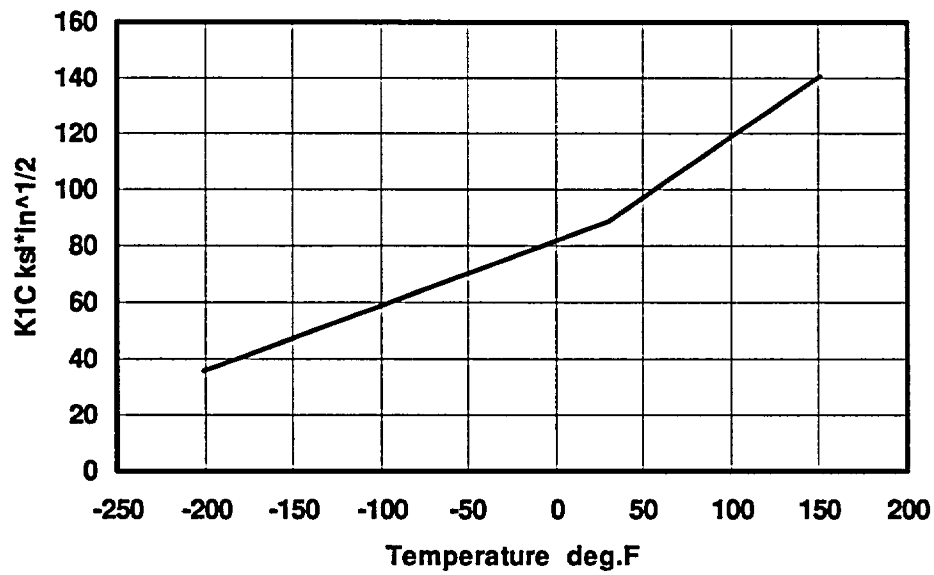
Design Control Document (DCD) Revision:

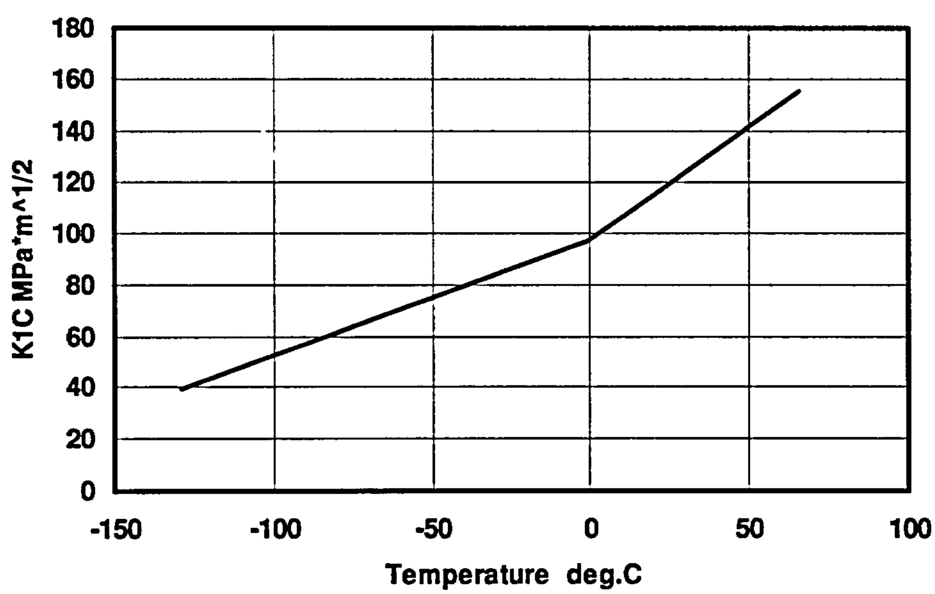
None

PRA Revision:

None

Figure 251.028-1: 3-1/2 Ni-Cr-Mo-V Steel Fracture Toughness





AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 260.002

Question:

Westinghouse should provide information on the differences between the list of safety (risk) significant SSCs under the scope of D-RAP for the AP1000 design versus the AP600 design. Any differences between the risk ranking for the two plant designs (i.e., risk achievement worth and risk reduction worth) should be provided. Any expert panel or engineering judgement information should be included.

Westinghouse Response:

The attached table shows the calculated RAWs and RRWs for CDF and LRF for both the AP600 and AP1000. From inspection of this table you can see the differences between the AP600 and AP1000. Note that #N/A indicate that the RAWs / RRWs were so small they were not calculated. The only difference in expert panel input was for those few cases where a feature was captured by EP for AP600 but was captured by RAW / RRW for AP1000.

Based on our review of the AP1000 RAWs and RRWs, we will make the following changes to the rationale in DCD Table 17.4-1:

	Current DCD (Rev. 2)	Revised DCD (Rev. 3)
PCS, drain isolation valves	RAW/CCF	EP
PXS, IRWST gutter bypass isolation valves	EP	RAW/CCF

Design Control Document (DCD) Revision:

Revise DCD Table 17.4-1 to change the rationale for the PCS drain isolation valves and the PXS gutter bypass isolation valves as indicated above.

PRA Revision:

None

Table 260.002-1 RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP FOR AP600 AND AP1000

System, Structure, or Component (SSC)	AP1000	AP1000, CDF		AP1000, LRF			AP600, CDF		AP600, LRF	
	Rationale	RAW	RRW	RAW	RRW		RAW	RRW	RAW	RRW
Compressed and Instrument Air System										
Air Compressor Transmitter	RRW/CCF	1.73	1.004	1.78	1.004		1.17	1.001	1.87	1.005
Component Cooling Water System										
CCS pumps	EP	1.03	1.000	#N/A	#N/A		1.00	1.000	#N/A	#N/A
Containment System										
Containment Vessel	EP, L2	#N/A	#N/A	1.47	1.055		#N/A	#N/A	#N/A	#N/A
Hydrogen Igniters	EP, L2, Regulation	1.01	1.000	1.24	1.002		1.00	1.000	1.07	1.001
Chemical and Volume Control System										
CVS Makeup Pump Suction & Discharge CVs	RAW	1.87	1.001	1.78	1.001		3.70	1.002	1.83	1.001
CVS Makeup Pumps	RAW/CCF	1.53	1.000	1.03	1.000		3.22	1.000	1.03	1.000
Diverse Actuation System										
Turbine Impulse Pressure Transmitters 1 & 2	RAW	1.09	1.000	#N/A	#N/A		2.43	1.008	1.18	1.001
Containment Isolation Valves DAS Controlled	RAW	2.30	1.001	#N/A	#N/A		1.01	1.000	9.05	1.006
DAS Actuated Hardware	RAW	DAS	1.004	6.44	1.058		2.90	1.020	5.78	1.051
Control Rod MG Set Field	RAW	1.22	1.000	1.47	1.001		3.62	1.005	1.75	1.001
Distribution Panels EDS(1 & 2)-EA-14	RAW	1.04	1.000	1.01	1.000		1.07	1.000	1.01	1.000
Main Power System										
Ancillary Diesel Generators	EP	1.02	1.001	#N/A	#N/A		1.01	1.000	1.03	1.001
Main and Startup Feedwater System										
Startup Feedwater Pumps	EP	1.01	1.000	1.01	1.000		1.00	1.000	1.00	1.000
General Instrumentation and Control										
LP/DP Sensors, IRWST Level Sensors	RAW/CCF	63.02	1.031	55.31	1.027		87.25	1.043	30.68	1.014
HP/DP Sensors:										
Main feedwater flow	RAW/CCF									
Startup feedwater flow	RAW/CCF	1.16	1.000	1.30	1.000		1.06	1.000	1.07	1.000

Table 260.002-1 RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP FOR AP600 AND AP1000

System, Structure, or Component (SSC)	AP1000	AP1000, CDF		AP1000, LRF			AP600, CDF		AP600, LRF	
	Rationale	RAW	RRW	RAW	RRW		RAW	RRW	RAW	RRW
Pressurizer pressure & level	RAW/CCF	36.05	1.017	429.50	1.258		53.18	1.026	458.10	1.280
SG wide & narrow range level	RAW/CCF	1.00	1.000	#N/A	#N/A		1.00	1.000	1.01	1.000
RCS hot leg level & SL pressure	RAW/CCF									
Class 1E dc Power and Uninterruptible Power System										
125 Vdc Distribution Panels	RAW	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
125 Vdc 24-hr Batteries, Inverters, & Chargers	RAW/CCF	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Fused Transfer Switch Box	RAW	5.97	1.001	6.51	1.002		2.00	1.000	3.76	1.001
125 Vdc Motor Control Centers	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
MCR Displays & Systems Level Control Mechanisms to Support Operator Actions	RAW/CCF	32.08	1.000	#N/A	#N/A		53.11	1.000	432.70	1.000
Reactor Coolant Pump Circuit Breakers	RAW/CCF	1.15	1.000	1.59	1.001		1.09	1.000	1.06	1.000
Passive Containment Cooling System										
PCS AOV & Diverse *3rd MOV Drain Isolation	EP, L2	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
PCS Water Storage Tank Recirculation Pumps	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Plant Control System										
PLS Actuation Hardware	RAW/CCF	1.68	1.000	1.50	1.000		1.22	1.000	1.47	1.000
PLS Logic Cabinet Supporting Functions	RAW/CCF	1.00	1.000	1.03	1.000		1.00	1.000	#N/A	#N/A
Protection and Safety Monitoring System										
CMT Level Sensors	RAW/CCF									
PMS Actuation Software	RAW/CCF	800.50	1.009	#N/A	#N/A		1617.00	1.018	14770.00	1.194
Reactor Trip Switch Gear	RAW/CCF	#N/A	#N/A	#N/A	#N/A		1.00	1.000	#N/A	#N/A
PMS Actuation Hardware	RAW/CCF	5.89	1.000	9.26	1.001		362.60	1.029	49.18	1.004
Passive Core Cooling System										
IRWST Check Valves	RAW/CCF	5.14	1.007	1.18	1.000		3.90	1.005	1.33	1.001
IRWST Injection Squib Valves	RAW/CCF	881.20	1.005	110.00	1.001		615.80	1.006	58.82	1.001
IRWST Screens	RAW/CCF	746.80	1.009	9391.00	1.127		1100.00	1.013	10280.00	1.141

Table 260.002-1 RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP FOR AP600 AND AP1000

System, Structure, or Component (SSC)	AP1000	AP1000, CDF		AP1000, LRF			AP600, CDF		AP600, LRF	
	Rationale	RAW	RRW	RAW	RRW		RAW	RRW	RAW	RRW
Containment Recirculation Squib Valves	RAW/CCF	1.25	1.000	10.03	1.001		8482.00	1.283	791.70	1.021
Containment Recirculation Screens	RAW/CCF	6119.00	1.079	166.80	1.002		1100.00	1.013	294.50	1.004
IRWST Gutter Bypass Isolation Valves	RAW/CCF	78.18	1.007	67.22	1.006		#N/A	#N/A	#N/A	#N/A
Accumulator Discharge Check Valves	RAW/CCF	23.94	1.042	1.94	1.002		4.19	1.006	1.05	1.000
CMT Discharge Isolation Valves	RAW/CCF	1.00	1.000	#N/A	#N/A		1.00	1.000	#N/A	#N/A
CMT Discharge Check Valves	RAW/CCF	10.52	1.000	1.03	1.000		6.08	1.000	1.14	1.000
PRHR Heat Exchanger Control Valves	RAW/CCF	78.18	1.007	67.22	1.006		12.66	1.001	7.47	1.001
Reactor Coolant System										
ADS Stages 1/2/3 Motor Operated Valves	RAW	43.85	1.014	63.03	1.021		#N/A	#N/A	#N/A	#N/A
ADS 4th Stage Squib Valves	RAW/CCF	1640.00	1.052	1102.00	1.034		1112.00	1.034	473.30	1.014
Pressurizer Safety Valves	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
RV Insulation Water Inlet/Steam Vent Devices	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Reactor Cavity Doorway Damper	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Normal Residual Heat Removal System										
RNS Pumps	RAW	1.70	1.000	#N/A	#N/A		1.75	1.000	1.77	1.000
RNS Motor-Operated Valves	RAW/CCF	1.77	1.011	2.29	1.019		1.84	1.012	2.40	1.020
Spent Fuel Cooling System										
SFS Pumps	EP	1.01	1.000	1.01	1.000		1.00	1.000	1.00	1.000
Steam Generator System										
Main Steam & Feedwater Isolation Valves	RAW	1.00	1.000	#N/A	#N/A		1.00	1.000	1.01	1.000
Main Steam Safety Valves	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Service Water System										
Service Water Pumps & Cooling Tower Fans	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Nuclear Island Non-Radioactive Ventilation System										
VBS, MCR and I&C Rooms B/C Ancillary Fans	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Chilled Water System										

Table 260.002-1 RISK-SIGNIFICANT SSCs WITHIN THE SCOPE OF D-RAP FOR AP600 AND AP1000

System, Structure, or Component (SSC)	AP1000	AP1000, CDF		AP1000, LRF			AP600, CDF		AP600, LRF	
	Rationale	RAW	RRW	RAW	RRW		RAW	RRW	RAW	RRW
VWS Low Capacity Subsystem	RAW/CCF	1.03	1.000	#N/A	#N/A		1.14	1.000	1.00	1.000
Onsite Standby Power System										
Non-safety-related Standby Diesel Generators	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Standby Diesels Room Cooling Fans	EP	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A
Nuclear Fuel	SMA	#N/A	#N/A	#N/A	#N/A		#N/A	#N/A	#N/A	#N/A

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 281.001

Question:

RG 1.54, Revision 1, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," July 2000, defines the protective coatings-based service levels and the effect of coating failures on equipment during normal and post-accident conditions as delineated in the referenced ASTM standards. The use of the terms "safety-related" and "non-safety-related" are not used in this revision to RG 1.54 to classify coatings. Please clarify which of the coatings listed in Table 6.1-2 meet the definitions of Service Levels I, II, and III. (Section 6.1)

Westinghouse Response:

DCD Section 6.1 will be revised to be consistent with the coatings classifications and associated terminology introduced in Regulatory Guide 1.54 Revision 1 dated July 2000.

Design Control Document (DCD) Revision:

See the attached markup of DCD Section 6.1.

PRA Revision:

None

6.1 Engineered Safety Features Materials

This section provides a description of the materials used in the fabrication of engineered safety features components and of the provisions to avoid material interactions that could potentially impair the operation of the engineered safety features. A list of engineered safety features was given previously in Section 6.0. Reactor coolant system materials, including branch piping connected to the reactor coolant system, are described in subsection 5.2.3.

6.1.1 Metallic Materials

Materials for use in engineered safety features are selected for their compatibility with the reactor coolant system and refueling water.

The edition and addenda of the ASME Code applied in the design and manufacture of each component are the edition and addenda established by the requirements of the Design Certification. The use of editions and addenda issued subsequent to the Design Certification is permitted or required based on the provisions in the Design Certification. The baseline used for the evaluations done to support this safety analysis report and the Design Certification is the 1998 Edition, through the 2000 Addenda. When material is procured to later editions or addenda, the design of the component is reconciled to the new material properties in accordance with the rules of the ASME Code, provided that the later edition and addenda are authorized in 10 CFR 50.55a or in a specific authorization as provided in 50.55a(a)(3).

6.1.1.1 Specifications for Principal Pressure-Retaining Materials

The pressure-retaining materials in engineered safety features system components comply with the corresponding material specification permitted by the ASME Code, Section III, Division 1. The material specifications used for pressure-retaining valves in contact with reactor coolant are the specifications used for reactor coolant pressure boundary valves and piping. See Table 5.2-1 for a listing of these specifications. The material specifications for pressure-retaining materials in each component of an engineered safety features system meet the requirements of Article NC-2000 of the ASME Code, Section III, Class 2, for Quality Group B; Article ND-2000 of the ASME Code, Section III, Class 3, for Quality Group C components; and Article NE-2000 of the ASME Code, Section III for containment pressure boundary components.

Containment penetration materials meet the requirements of Articles NC-2000 or NE-2000 of the ASME Code, Section III, Division 1. The quality groups assigned to each component are given in Section 3.2. The pressure-retaining materials are indicated in Table 6.1-1. Materials for ASME Class 1 equipment are provided in subsection 5.2.3.

The following subsection provides information on the selection and fabrication of the materials in the engineered safety features of the plant.

Components in contact with borated water are fabricated of, or clad with, austenitic stainless steel or equivalent corrosion-resistant material. The use of nickel-chromium-iron alloy in the engineered safety features is limited to Alloy 690. Alloy 600 may be used for welding or buttering. Nickel-chromium-iron alloy is used where the corrosion resistance of the alloy is an important consideration and where the use of nickel-chromium-iron alloy is the choice because of the coefficient of thermal expansion.

The material for the air storage tanks in the main control room emergency habitability system is tested for Charpy V-Notch per supplement S3 of material specification SA-372 and has an average of 20 to 25 mills of lateral expansion at the lowest anticipated service temperature. The material is not permitted to be weld repaired.

6.1.1.2 Fabrication Requirements

The welding materials used for joining the ferritic base materials of the pressure-retaining portions of the engineered safety features conform to, or are equivalent to, ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18, and 5.20. The welding materials used for joining nickel-chromium-iron alloy in similar base material combination, and in dissimilar ferritic or austenitic base material combination, conform to ASME Material Specifications SFA 5.11 and 5.14.

The welding materials used for joining the austenitic stainless steel base materials for the pressure-retaining portions of engineered safety features conform to, or are equivalent to, ASME Material Specifications SFA 5.4 and 5.9. These materials are qualified to the requirements of the ASME Code, Section III and Section IX, and are used in procedures qualified to these same rules. The methods used to control delta ferrite content in austenitic stainless steel weldments in engineered safety features components are the same as those for ASME Code Class 1 components, described in subsection 5.2.3.4.

The integrity of the safety-related components of the engineered safety features is maintained during component manufacture. Austenitic stainless steel is used in the final heat-treated condition as required by the respective ASME Code, Section II, material specification for the particular type or grade of alloy. Also, austenitic stainless steel materials used in the engineered safety features components are handled, protected, stored, and cleaned according to recognized and accepted methods designed to minimize contamination, which could lead to stress corrosion cracking. These controls for engineered safety features components are the same as those for ASME Code Class 1 components, discussed in subsection 5.2.3.4. Sensitization avoidance, intergranular attack prevention, and control of cold work for engineered safety features components are the same as the ASME Code Class 1 components discussed in subsection 5.2.3.4. Cold-worked austenitic stainless steels having a minimum specified yield strength greater than 90,000 psi are not used for components of the engineered safety features.

Information is provided in Section 1.9 concerning the degree of conformance with the following Regulatory Guides:

- Regulatory Guide 1.31, Control of Ferrite Content in Stainless Steel Weld Metal
- Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel

Lead, antimony, cadmium, indium, mercury, zinc, and tin metals and their alloys are not allowed to come in contact with engineered safety features component parts made of stainless steel or high alloy metals during fabrication or operation. Bearing alloys containing greater than 1 percent of lead, antimony, cadmium, or indium are not used in contact with reactor coolant.

6.1.1.3 Specifications for Nonpressure-Retaining Materials

Materials for nonpressure-retaining portions of engineered safety features in contact with borated water or other fluids may be procured under ASTM designation. The principle examples of these items are the in-containment refueling water storage tank liner and the passive containment cooling system storage tank liner.

The walls of the in-containment refueling water storage tank may be fabricated of ASTM A240 Type XM-29. This is a nitrogen-strengthened austenitic stainless steel with higher ultimate tensile and yield strengths than type 304 and 316 stainless steel. This material can be welded using E240 filler metal by either the shielded metal arc welding or gas tungsten arc welding methods. This material is used for applications where the higher strength allows reductions in weight and material costs. The material has a resistance to intergranular stress corrosion cracking similar to or better than type 304 and 304L stainless steel.

6.1.1.4 Material Compatibility with Reactor Coolant System Coolant and Engineered Safety Features Fluids

Engineered safety features components materials are manufactured primarily of stainless steel or other corrosion-resistant material. Protective coatings are applied on carbon steel structures and equipment located inside the containment, as discussed in subsection 6.1.2.

Austenitic stainless steel plate conforms to ASME SA-240. Austenitic stainless steel is confined to those areas or components which are not subject to post-weld heat treatment. Carbon steel forgings conform to ASME SA-350. Austenitic stainless steel forgings conform to ASME SA-182. Nickel-chromium-iron alloy pipe conforms to ASME SB-167. Carbon steel castings conform to ASME SA-352. Austenitic stainless steel castings conform to ASME SA-351.

Hardfacing material in contact with reactor coolant is a qualified low- or zero-cobalt alloy, equivalent to Stellite-6. The use of cobalt-base alloys is minimized. Low- or zero-cobalt alloys used for hardfacing or other applications where cobalt-base alloys have been previously used are qualified by wear and corrosion tests. The corrosion tests qualify the corrosion resistance of the alloy in reactor coolant. Cobalt-free, wear-resistant alloys considered for this application include those developed and qualified in nuclear industry programs.

In post-accident situations where the containment is flooded with water containing boric acid, pH adjustment is provided by the release of trisodium phosphate into the water. The trisodium phosphate is held in baskets located in the floodable volume that includes the steam generator compartments and contains the reactor coolant loop. The addition of trisodium phosphate to the solution is sufficient to raise the pH of the fluid to above 7.0. This pH is consistent with the guidance of NRC Branch Technical Position MTEB-6.1 for the protection of austenitic stainless steel from chloride-induced stress corrosion cracking. Section 6.3 describes the design of the trisodium phosphate baskets.

In the post-accident environment, both aluminum and zinc surfaces in the containment are subject to chemical attack resulting in the production of hydrogen. The non-flooded surfaces would be wetted by condensing steam but they would not be subjected to the boric acid or trisodium phosphate solutions since there is no containment spray. The hydrogen production analysis described in subsection 6.2.5 includes hydrogen generation due to corrosion processes and conservatively assumes that all surfaces are exposed to the solution.

6.1.1.5 Integrity of Safety-Related Components

The pH adjustment baskets provide for long-term pH control. In the case of inadvertent short-term flooding when the pH adjustment baskets remain above the flood level, the condition of the material in contact with the fluid is evaluated prior to return to operation. Based on previous industry testing and experience, the behavior of austenitic stainless steels in the post-design basis accident environment is acceptable. Cracking is not anticipated, provided that the core cooling pH is maintained at an adequate level.

6.1.1.6 Thermal Insulation

The majority of the engineered safety features insulation used in the AP1000 containment is reflective metallic insulation. Fibrous insulation may be used if it is enclosed in stainless steel cans. The selection, procurement, testing, storage, and installation of nonmetallic thermal insulation provides confidence that the leachable concentrations of chloride, fluoride, and silicate are in conformance with Regulatory Guide 1.36. Conformance with Regulatory Guide 1.36 is summarized in Section 1.9.

6.1.1.7 Component and System Cleaning

See subsection 1.9.1 for a discussion on the provisions of Regulatory Guide 1.37 for the cleaning of components and systems.

6.1.2 Organic Materials

6.1.2.1 Protective Coatings

6.1.2.1.1 General

The AP1000 is divided into four areas with respect to the use of protective coatings. These four areas are:

- Inside containment
- Exterior surfaces of the containment vessel
- Radiologically controlled areas outside containment
- Remainder of plant.

The considerations for protective coatings differ for these four areas and the coatings selection process accounts for these differing considerations. The AP1000 design considers the function of the coatings, their potential failure modes, and their requirements for maintenance. Table 6.1-2 lists different areas and surfaces inside containment and on the containment shell that have coatings, their functions and to what extent their coatings are **related to plant** safety~~-related~~.

Coatings used outside containment do not provide ~~safety-related~~ functions **related to plant safety** except for the coating on the outside of the containment shell. The coating on the outside of the containment above elevation 135′ 3″ shell supports passive containment cooling system heat transfer and is classified as ~~safety-related~~a **Service Level III coating.**

The coating used on the inside surface of the containment shell, greater than 7′ above the operating deck, **supports the transfer of thermal energy from the post-accident atmosphere inside containment to the containment shell**~~is not required to support passive containment cooling system heat transfer. However, p~~Passive containment cooling system testing and analysis have been performed with a coating. This coating is classified as a ~~safety-related~~**Service Level I coating.**

Coatings are not used in the vicinity of the containment recirculation screens to minimize the possibility of debris clogging the screens. Subsection 6.3.2.2.7.3 defines the area in the vicinity of the recirculation screens where coatings are not used.

Coatings used inside containment, except for the containment shell, are classified as ~~nonsafety-related~~ **Service Level II coatings** because their failure does not prevent functioning of the engineered safety features. If the ~~nonsafety-related~~ **Service Level II** coatings delaminate, the solid debris they may form will not have a negative impact on the performance of safety-related post-accident cooling systems. See subsection 6.1.2.1.5 for a discussion of the factors including plant design features and low water flows that permit the use of ~~nonsafety-related paint~~ **Service Level II coatings** inside containment. Protective coatings are maintained to provide corrosion protection for the containment pressure boundary and for other system components inside containment.

The corrosion protection **of the containment shell is a safety-related function.** ~~, g~~Good housekeeping and decontamination functions of the coatings are nonsafety-related functions.

For information on coating design features, quality assurance, material and application requirements, and performance monitoring requirements, see subsection 6.1.2.1.6.

6.1.2.1.2 Inside Containment

Carbon Steel

Inorganic zinc primer is the basic coating applied to the containment vessel and structural carbon steel that need coating. Below the operating floor, most of the inorganic zinc primer is top coated with epoxy where enhanced decontamination is desired. The epoxy top coat also extends above the operating floor on structural modules and to a wainscot height of 7 feet above the operating floor on the containment vessel. Where practical, miscellaneous carbon steel items (such as stairs, ceilings, gratings, ladders, railings, conduit, duct, and cable tray) are hot-dip galvanized. Steel surfaces subject to immersion during normal plant operation (such as sumps and gutters) are stainless steel or are coated with epoxy or epoxy phenolic applied directly to the carbon steel without an inorganic zinc primer. Carbon steel structures and equipment are assembled in modules and the modules are coated in the fabrication shop under controlled conditions.

Concrete

Concrete surfaces inside containment are coated primarily to prevent concrete from dusting, to protect it from chemical attack and to enhance decontaminability. In keeping with ALARA goals, the exposed concrete surfaces are made as decontaminable as practical in areas of frequent personnel access and areas subject to liquid spray, splash, spillage or immersion.

Exposed concrete surfaces inside containment are coated with an epoxy sealer to help bind the concrete surface together and reduce dust that can become contaminated and airborne. Concrete floors inside containment are coated with a self-leveling epoxy. Exposed concrete walls inside containment are coated to a minimum height of 7 feet with an epoxy applied over an epoxy surfacer that has been struck flush.

6.1.2.1.3 Exterior of Containment Vessel

The exterior of the containment vessel is coated with the same inorganic zinc as is used inside of the containment. The inorganic zinc coating enhances heat transfer by providing good heat conduction and by enhancing surface wetting of the exterior surface of the containment vessel. The inorganic zinc also provides corrosion protection.

6.1.2.1.4 Radiologically Controlled Areas Outside Containment and Remainder of Plant

The coatings used in the radiologically controlled areas outside containment and in the remainder of the plant are also ~~nonsafety-related~~**classified as Service Level II coatings**. However, these coatings are selected, specified and applied in a manner that optimizes performance and standardization **within the AP1000 design.** ~~W~~**Therefore,** wherever practical, the same coating systems are used in radiologically controlled areas outside containment as are used inside containment. The ALARA concept is carried through in areas subject to radiation exposure and possible radiological contamination. The remainder of the plant coating systems are commercial grade materials that are selected and applied according to the expected conditions in the specific areas where the coatings are applied.

The coatings used in radiologically controlled areas outside of containment are identified in the following.

Carbon Steel Surfaces

Carbon steel is coated with inorganic zinc. An epoxy top coat is used in areas subject to decontamination such as a 7 foot wainscot in high traffic areas or on surfaces subject to radiologically contaminated liquid spray, splash, or spills.

Concrete Floors

Floors subject to heavy traffic or contaminated liquid spills are coated with self-leveling epoxy. An epoxy top coat is applied a minimum of 1 foot up the wall where liquid spills might splash. Floors subject to light traffic and not subject to contaminated liquid spills are coated with an epoxy top coat. The epoxys applied to the concrete surfaces are the same epoxy used as a top coat for the inorganic zinc-coated steel.

Concrete Walls

A 7-foot wainscot on exposed concrete walls in high-traffic areas and any surfaces of walls subject to spray, splash or spills of contaminated liquids are coated with epoxy top coat applied over an epoxy surfacer that has been struck flush. The epoxys used on concrete surfaces are the same as that used as a top coat for the inorganic zinc-coated steel. Remaining concrete walls are coated with an epoxy sealer to reduce or eliminate dusting.

Concrete Ceilings

Exposed concrete ceilings are coated with an epoxy sealer to reduce dusting.

6.1.2.1.5 Safety Evaluation

This subsection describes the basis for classifying coatings as~~-safety related or nonsafety-related~~**Service Level I, II or III.** Table 6.1-2 identifies which coatings are classified as~~-safety-related~~**Service Level I and Service Level III.**

The inorganic zinc coating on the outside of the containment shell above elevation 135′ 3″ supports passive containment cooling system heat transfer and is classified as a ~~safety-related~~**Service Level III coating.**

The inorganic zinc coating used on the inside surface of the containment shell, greater than 7′ above the operating deck, **supports the transfer of thermal energy from the post-accident atmosphere inside containment to the containment shell**~~is not required to support passive containment cooling system heat transfer. However, p~~Passive containment cooling system testing and analysis have been performed with an inorganic zinc coating. This coating is classified as a ~~safety-related~~**Service Level I coating.**

The AP1000 has a number of design features that facilitate the use of ~~nonsafety-related~~ **Service Level II** coatings inside containment. These features include a passive safety injection system that provides a long delay time between a LOCA and the time recirculation starts. This time delay provides time for settling of debris. These passive systems also flood the containment to a high level which allows the use of containment recirculation screens that are located well above the floor and are relatively tall. Significant volume is provided for the accumulation of coating debris without affecting screen plugging. These screens are protected by plates located above the screens that extend out in front and to the side of the screens. Coatings are not used under these plates in the vicinity of the screens. The protective plates, together with low recirculation flow, approach velocity and the screen size preclude postulated coating debris above the plates from reaching the screens. Refer to subsection 6.3.2.2.7.3 for additional discussion of these screens, their protective plates and the areas where coatings are prohibited from being used.

The recirculation inlets are screened enclosures located near the northwest and southwest corners of the east steam generator compartment (refer to the figures in Section 6.3.2.2.7.3). The enclosure bottoms are located above the surrounding floor which prevent ingress of heavy debris (specific gravity greater than 1.05). Additionally, the screens are oriented vertically and are protected by large plates located above the screens, further enhancing the capability of the screens to function with debris in the water. The screen mesh size and the surface area of the containment recirculation screens in the AP1000, in conjunction with the large floor area for debris to settle on, can accommodate failure of coatings inside containment during a design basis accident even though the residue of such a failure is unlikely to be transported to the vicinity of the enclosures.

The AP1000 does not have a safety-related containment spray system. The containment spray system provided in the AP1000 is only used for beyond design basis events. This reduces the chance that coatings will peel off surfaces inside containment because the thermal shock of cold spray water on hot surfaces combined with the rapid depressurization following spray initiation are recognized as contributors to coating failure. Parts of the containment below elevation 110′ are flooded and water is recirculated through the passive core cooling system. However, the volume of water moved in this manner is relatively small and the flow velocity is very low.

The coating systems used inside containment also include epoxy coatings. These are applied to concrete substrates, as top coats over the inorganic zinc primer, and directly to steel, as noted in subsection 6.1.2.1.2. The failure modes of these systems could include delamination or peeling if the epoxy coatings are not properly applied (References 1, 2, 3). The epoxys applied to concrete and carbon steel surfaces are sufficiently heavy (dry film density greater than 100 lb/ft^3) so that transport with the low water velocity in the AP1000 containment is limited.

Inside containment, there are engineered components coated with various manufacturer's standard coating systems which are also classified as ~~nonsafety-related~~ **Service Level II** and may peel or delaminate under design basis accident conditions. The density of these coatings is not limited based on the following considerations:

- The total surface area of low density coatings applied to engineered components is a small percentage of the total area of coatings inside containment.
- The coatings applied to engineered components are less subject to failure during accidents because their dimensions are smaller and their shapes are more complex. Their shapes are complex involving many corners. angles, nuts, bolts, protrusions, holes, etc. For engineered components, temperature changes cause smaller relative expansions and their complex shapes tend to prevent relative movement so that failure of the coating bond is less likely. In addition, even if the coating bond does fail, it is less likely to detach because the complex shapes tend to retain the coating.
- Coatings applied to engineered components are done so in controlled factory conditions so that the quality of application is better than that achieved in the field. Factors contributing to this higher quality include application of coatings in a timely fashion after manufacture, easier control of surface conditions, automated application of coatings and use of personnel that are highly trained.
- Manufacturers have switched to the use of dry powder coatings (polyesters) and water reduced coatings (acrylics). Coatings used on components located inside containment are expected to be dry powder coatings because water reduced coatings are not suitable for use in the harsh containment environment. Dry powder coatings tend to be very tough and defects in application tend to be noticeable. They also have relatively high densities, greater

than epoxys, so that even if they did fail they would settle out before reaching the recirculation screens.

- Engineered components are located throughout the containment so that the majority are located where low density coating debris settle out well away from the recirculation screens.

- Even in the unlikely event that some of these coatings fail, delaminate and do not settle out because of their location and low density, the PXS recirculation screens will prevent blockage of the PXS recirculation **flow path.**

Production of hydrogen as a result of zinc corrosion in design basis accident conditions, including the zinc in paints applied inside containment, is addressed in subsection 6.2.4.3.1.

6.1.2.1.6 Quality Assurance Features

A number of quality assurance features provide confidence that the coating systems inside the containment, on the exterior of the containment vessel and in potentially contaminated areas outside containment will perform as intended. These features enhance the ALARA program and enhance corrosion resistance. The features are discussed in the following paragraphs.

~~Safety-related~~ **Service Level I and Service Level III coatings**

The quality assurance program for ~~safety-related~~ **Service Level I and Service Level III** coatings conforms to the requirements of ASME NQA-1-1983 as endorsed in Regulatory Guide 1.28. Safety related coatings meet the pertinent provisions of 10CFR Part 50 Appendix B to 10CFR Part 50. The **service level classification of** ~~safety-related~~ coatings ~~are~~ is consistent with the positions **given in Revision 1** of Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants". ~~The safety-related~~ **Service Level I and Service Level III** coatings used in the AP1000 are tested for radiation tolerance and for performance under design basis accident conditions. Where decontaminability is desired, the coatings are evaluated for decontaminability. The coating applicator submits and follows acceptable procedures to control surface preparation, application of coatings and inspection of coatings. The painters are qualified and certified, and the inspectors are qualified and certified.

The ~~safety-related~~ inorganic zinc coating used on the inside **surface (Service Level I coatings)** and outside surface **(Service Level III coatings)** of the containment shell is inspected using a non-destructive dry film thickness test and a MEK rub test. These inspections are performed after the initial application and after recoating. Long term surveillance of the coating is provided by visual inspections performed during refueling outages. Other inspections are not required.

The procurement, application, and monitoring of ~~safety-related~~ **Service Level I and Service Level III** coatings are controlled by a program prepared by the Combined License applicant, (refer to subsection 6.1.3.2).

Refer to Table 6.1-2 for identification of ~~safety-related~~ **Service Level I and Service Level III** coating applications in the AP1000.

~~Nonsafety-Related~~ Service Level II Coatings

The use of ~~nonsafety-related~~ **Service Level II** coatings inside containment is based on the use of selected types of coatings and the properties of the coatings. To preclude the use of inappropriate coatings, the procurement of ~~the nonsafety-related~~ **Service Level II** coatings used inside containment is considered a safety-related **activity.**

Appendix B to 10 CFR Part 50 applies to procurement of **Service Level II** coatings used inside containment on internal structures, including walls, floor slabs, structural steel, and the polar crane, except for such surfaces located inside the chemical and volume control system room # 11209. ~~Nonsafety-related~~ **Service Level II** coatings used in the chemical and volume control system room are not subject to procurement under 10 CFR 50, Appendix B, because the room is connected to the containment in a limited way through a drain line. In addition, the drain line is routed to the waste liquid processing system sump which is located well below and separate from the recirculation screens. The specified ~~nonsafety-related~~ **Service Level II** coatings used inside containment are tested for radiation tolerance and for performance under design basis accident conditions. Where decontaminability is desired, the coatings are evaluated for decontaminability.

The ~~application, inspection and monitoring of nonsafety-related~~ **Service Level II** coatings used inside containment are ~~not classified as safety-related~~ as shown in Table 6.1-2. The application, inspection and monitoring of ~~nonsafety-related~~ **Service Level II** coatings are controlled by a program prepared by the Combined License applicant. This program is not subject to 10 CFR 50, Appendix B, quality assurance requirements.

Due to the use of modularized construction, a significant portion of the containment coatings are shop applied to the containment vessel and to piping, structural and equipment modules. This application of coatings under controlled shop conditions provides additional confidence that the coatings will perform as designed and as expected.

The coatings used in radiologically controlled areas outside containment are tested for radiation resistance and evaluated for decontaminability; they are not specified to be design basis accident tested. Where practical, the same coating materials are used in radiologically controlled areas outside containment as are used inside containment. This provides a high level of quality and optimizes maintenance painting over the life of the plant.

6.1.2.2 Other Organic Materials

A listing of other organic materials in the containment is developed based on the specific type of equipment and the supplier selected to provide it. Materials are evaluated for potential interaction with engineered safety features to provide confidence that the performance of the engineered safety features is not unacceptably affected.

6.1.3 Combined License Information Items

6.1.3.1 Procedure Review

The Combined License applicants referencing the AP1000 will address review of vendor fabrication and welding procedures or other quality assurance methods to judge conformance of austenitic stainless steels with Regulatory Guides 1.31 and 1.44.

6.1.3.2 Coating Program

The Combined License applicants referencing the AP1000 will provide a program to control procurement, application, and monitoring of ~~safety-related~~ **Service Level I and Service Level III** coatings. The program for the control of the use of ~~safety-related~~these coatings will be consistent with subsection 6.1.2.1.6.

6.1.4 References

1. NUREG-0797, "Safety Evaluation Report related to the operation of Comanche Peak Steam Electric Station, Units 1 and 2."

2. Bolt, R. O. and J. G. Carroll, "Radiation Effects on Organic Materials", Academic Press, New York, 1963, Chapter 12.

3. Parkinson, W. W. and O. Sisman, "The Use of Plastics and Elastomers in Nuclear Radiation", Nuclear Engineering and Design 17 (1971), pp 247-280, North-Holland Publishing Co., Amsterdam.

Table 6.1-1

ENGINEERED SAFETY FEATURES PRESSURE-RETAINING MATERIALS

Component	Materials
Core makeup tank	Refer to subsection 5.2.3
Passive residual heat removal heat exchanger	Refer to subsection 5.3.4, Table 5.2-1
In-containment refueling water storage tank	ASTM A240 XM-29 or TP304
Passive containment cooling system (safety-related portion)	
Passive containment cooling system water storage tank	ASTM A240 TP304
Valves	SA-182 TP304L
Piping	SA-312 TP304L
Fittings	SA-182 TP304L
PCS Recirculation Subsystem	
Valves	SA-217 Grade WC6
Piping	SA-335 Grade P11
Fittings	SA-234 Grade WP11
Spargers	
Piping	SA-358 TP304 or TP316 or SA-312 TP304 or TP316
Fittings	SA-182 TP304 or SA-403 WP304 or WP316
Containment vessel and penetrations	Refer to subsection 3.8.2.1
Valves in contact with borated water	Refer to subsection 5.2.3, Table 5.2-1
Main control room emergency habitability system	
Valves	SA-182 Grade F11
Pipe	SA-355 Grade P11
Air storage tanks	SA-372

Table 6.1-2 - AP1000 Coated Surfaces, Containment Shell and Surfaces Inside Containment

Surface	Boundary	Surface Material	Coating	Coating Functions/Safety Classifications		Coating Classification (1)
Containment Shell, Outside Surface	Shell surfaces above elevation 135′ 3″	Carbon Steel	Inorganic Zinc	1 Promote wettability 2 Heat conduction 3 Nondetachable 4 Inhibit corrosion	1 Safety 2 Safety 3 Safety 4 Non-safety	Safety - Service Level III
Containment Shell, Inside Surface	Shell surfaces above 7 feet above operating deck	Carbon Steel	Inorganic Zinc	1 Promote wettability 2 Heat conduction 3 Nondetachable 4 Inhibit corrosion	1 Safety (2) 2 Safety 3 Safety 4 ~~Non-s~~Safety	Safety - Service Level I
Inside Containment	Areas surrounding the containment recirculation screens (3)	NA	NA	NA	NA	NA
	Concrete walls, ceilings and floors (4)	Concrete	Epoxy ~~Sealer with Epoxy Topcoat~~ Coating System	1 Ensure settling 2 Prevent dusting 3 Protect from chemical attack 4 Enhance radioactive decontamination	1 Safety (5) 2 Nonsafety 3 Nonsafety 4 Nonsafety	Nonsafety (5) Service Level II
	Steel walls, ceilings, floors, columns, beams, braces, plates (4)	Carbon Steel	Inorganic Zinc	1 Ensure settling 2 Inhibit corrosion	1 Safety (5) 2 Nonsafety	Nonsafety (5) Service Level II
	Steel walls, ceilings, floors, columns, beams, braces, plates (4)	Carbon Steel	~~Inorganic Zinc with~~ Epoxy ~~Topcoat~~ Coating System	1 Ensure settling 2 Inhibit corrosion 3 Enhance radioactive decontamination	1 Safety (5) 2 Nonsafety 3 Nonsafety	Nonsafety (5) Service Level II

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Table 6.1-2 - AP1000 Coated Surfaces, Containment Shell and Surfaces Inside Containment

Notes:

1. The applicability of 10 CFR 50, Appendix B, and other codes and standards to coatings and their application are discussed in DCD subsection 6.1.2.1.6.
2. An inorganic zinc coating on the inside of the containment shell is not required to promote wettability, however it has been included in PCS testing and analysis and as a result is considered safety-related.
3. Areas around PXS recirculation screens do not require coatings as defined in DCD subsection 6.3.2.2.7.3.
4. 10 CFR 50, Appendix B, does not apply to DBA testing and manufacture of coatings in the CVS room inside containment as discussed in DCD subsection 6.1.2.1.6.
5. 10 CFR 50, Appendix B, applies to DBA testing and manufacture of these ~~nonsafety-related~~**Service Level II** coatings as discussed in DCD subsection 6.1.2.1.6.

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.040

Question:

Some of the AP1000 RCP design parameters listed in Table 5.4-1 are different from the values provided in the Westinghouse presentation of May 9, 2002, in the NRC headquarters (see meeting summary dated May 9, 2002). These include unit overall weight, total weight, pump developed head, and motor/pump rotor moment of inertia.

Clarify which are the correct values.

Westinghouse Response:

The current AP1000 RCP parameters are given in the table below:

Parameter	AP1000 Value
Design Flow, gpm	78,750
Developed Head, ft	365
Overall Height, ft-in	21-11.5
Total Weight, lb	184,500
CCS Cooling Water Flow, gpm	360
Maximum Continuous Cooling Water Inlet Temp, F	110
Motor Horsepower/Voltage	~7000/6600
Motor/Pump Moment of Inertia, lb-ft^2	18,150

AP1000 DCD Table 5.4-1 will be revised to reflect changes in the overall height and total weight. The motor/pump moment of inertia given in Table 5.4-1 is the minimum design value to provide the required pump coastdown.

Item 8b of AP1000 Tier 1Table 2.1.2-4 will be revised to reflect the minimum required pump moment of inertia.

The text in AP1000 DCD Section 5.4.1 will be revised to reflect the current flywheel design, which consists of two separate assemblies.

AP1000 DCD Figure 5.4-1 will be revised to reflect the current pump outline drawing.

Design Control Document (DCD) Revision:

From Tier 1 page 2.1.2-23:

Table 2.1.2-4 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
8.b) The RCPs have a rotating inertia to provide RCS flow coastdown on loss of power to the pumps.	Inspection of as-built RCP vendor data will be performed.	The calculated rotating inertia of each RCP is no less than ~~15,750~~16,500 lb-ft^2.

From DCD page 5.4-1, Section 5.4.1.1:

The reactor coolant pump pressure boundary shields the balance of the reactor coolant pressure boundary from theoretical worst-case flywheel failures. The reactor coolant pump pressure boundary is analyzed to demonstrate that a fractured flywheel cannot breach the reactor coolant system boundary (stator shell, flange, and casing) and impair the operation of safety-related systems or components. This meets the requirements of General Design Criteria 4. The reactor coolant pump flywheel ~~assembly~~ is designed, manufactured, and inspected to minimize the potential for the generation of high-energy fragments (missiles) under any anticipated operating or accident condition consistent with the intent of the guidelines set forth in Standard Review Plan Section 5.4.1.1 and Regulatory Guide 1.14. Each flywheel ~~assembly~~ is tested at an overspeed condition to verify the flywheel design and construction.

From DCD page 5.4-2, Section 5.4.1.2.1:

A flywheel, consisting of two separate assemblies,~~y between the motor and pump impeller~~ provides rotating inertia that increases the coastdown time for the pump. ~~The~~ Each flywheel assembly is a composite of an uranium alloy flywheel casting or forging contained within a welded nickel-chromium-iron alloy enclosure. The upper flywheel assembly is located between the motor and pump impeller. The lower assembly is located within the canned motor below the thrust bearing. Surrounding the flywheel assembliesy ~~is~~ are the ~~thick cylindrical~~ heavy walls of the motor end closure, ~~and the heavy wall of the~~ casing, thermal barrier flange, stator shell, ~~and~~ or main flange.

The materials in contact with the reactor coolant and cooling water (with the exception of the bearing material) are austenitic stainless steel, nickel-chromium-iron alloy, or equivalent corrosion-resistant material.

There are two pump journal bearings, one at the bottom of the rotor shaft and the other between the upper flywheel assembly and the motor. The bearings are a hydrodynamic film-riding design. During rotor rotation, a thin film of water forms between the journal and pads, providing lubrication.

From DCD page 5.4-6:

5.4.1.3.6.2 Rotor Seizure

The design of the pump is such as to preclude the instantaneous stopping of any rotating component of the pump or motor for a canned motor of this type. The rotating inertia and power supplied to the motor would overcome interference between the impeller, bearings, flywheel ~~assembly~~**assemblies**, motor rotor, or rotor can and the surrounding components for a period of time. A change in the condition of any of the components sufficient to cause an interference would be indicated by the instrumentation monitoring speed, vibration, temperature, or current.

From DCD page 5.4-6:

5.4.1.3.6.3 Flywheel Integrity

The canned-motor reactor coolant pump in the AP1000 complies with the requirement of General Design Criterion (GDC) Number 4. That Criterion states that components important to safety be protected against the effects of missiles.

The flywheel **assemblies are**~~is~~ located within and surrounded by the **the heavy walls of the motor end closure, casing, thermal barrier flange,** ~~and the heavy wall of the~~ stator shell, **or** ~~and~~ **main** flange. In the event of a postulated worst-case flywheel **assembly** failure, the surrounding structure can, by a large margin, contain the energy of the fragments without causing a rupture of the pressure boundary. The analysis of the capacity of the housing to contain the fragments of the flywheel is done using the energy absorption equations of Hagg and Sankey (Reference 2).

Compliance with the requirement of GDC 4 related to missiles can be demonstrated without reference to flywheel integrity, nevertheless, the intent of the guidelines of Regulatory Guide 1.14 is followed in the design and fabrication of the flywheel. The guidelines in Regulatory Guide 1.14 apply to steel flywheels. Since the uranium alloy of the AP1000 reactor coolant pump flywheel does not respond in the same manner as steel, many of the guidelines in the Regulatory Guide are not directly applicable.

The reactor coolant pump flywheel **assemblies**~~y~~ ~~is~~ **are** fabricated from high-quality, depleted uranium alloy castings or forgings. Castings are poured using a process to minimize the formation of voids, cracks, or other flaws. The forging process is also controlled to minimize the formation of flaws. Subsequent to casting or forging, the flywheel is heat treated by solution annealing in a vacuum furnace and slowly cooled. This heat treatment minimizes the potential for residual stresses. The heat treatment process also removes hydrogen from the material to reduce the potential for hydrogen embrittlement.

The key parameters for the uranium alloy specification are defined in Table 5.4-2. These parameters include the minimum ultimate and yield tensile strength. Nil ductility transition and upper shelf energy are not specified in the requirements for the uranium alloy. These are characteristics of steel not duplicated in the uranium alloys. The material specification has appropriate testing to confirm that the fracture toughness used in the flywheel evaluation is satisfied. A Charpy V-notch test is required. A portion of the uranium is machined off to obtain specimens for tensile and impact tests and to inspect the microstructure.

The uranium is ultrasonically inspected following final machining. The acceptance criteria for the ultrasonic inspection are based on criteria in the ASME Code, Section III, and are done in conformance with the procedures outlined in ASTM-A-609 (Reference 3) with modifications as required for use with uranium alloy. Thermal methods are not used for finishing operations on the uranium. Following finishing operations on the casting the outside surface and the inside bore are subject to liquid penetrant inspections in conformance with the requirements of ASTM-E-165 (Reference 4). In-process controls used during the construction of the flywheel assemblies~~y~~ also provide for the quality of the completed assemblies~~y~~.

The design speed of the flywheel is defined as 125 percent of the normal speed of the motor. The design speed envelopes all expected overspeed conditions. At the normal speed the calculated maximum primary stress in the uranium flywheel is less than one third of minimum yield strength. At the design speed the calculated maximum primary stress in the uranium flywheel is less than two thirds of minimum yield strength.

An analysis of the flywheel failure modes of ductile failure, nonductile failure and excessive deformation of the flywheel is performed to evaluate the flywheel design. The analysis is performed to determine that the critical flywheel failure speeds, based on these failure modes, are greater than the design speed. The critical flywheel failure speeds are not the same as the critical speed identified for the rotor. The critical flywheel failure speeds are greater than the design speed. The overspeed condition for a postulated pipe rupture accident is less than the critical flywheel failure speeds.

The uranium is sealed within a welded nickel-chromium-iron alloy enclosure to prevent contact with the reactor coolant or any other fluid. The enclosure minimizes the potential for corrosion of the flywheel and contamination of the reactor coolant with depleted uranium. The enclosure material specifications are ASTM-B-168 and ASTM-B-564. Even though the welds of the flywheel enclosure are not external pressure boundary welds, these welds are made using procedures and specifications that follow the rules of the ASME Code. A dye penetrant and ~~radiographic~~ **ultrasonic** test of the enclosure welds is performed in conformance with these requirements.

No credit is taken in the analysis of the flywheel missile generation for the retention of the fragments by the enclosure. A leak in the enclosure during operation could result in an out-of-balance flywheel assembly. A postulated small fracture of the flywheel casting inside the enclosure that does not penetrate or significantly deform the enclosure would also be expected to result in an out-of-balance condition. An out-of-balance flywheel exhibits an increase in vibration, which is monitored by vibration instrumentation.

The flywheel enclosure contributes only a small portion of the energy in a rotating flywheel assembly.

The outside ring, inside ring, and ends of the flywheel enclosure are connected together with ~~seal~~ **flexible, full-penetration** welds. ~~These seal welds do not significantly contribute to the strength of the enclosure.~~ The ~~seal~~ **flexible** welds and the local area adjacent to the welds may have stresses greater than the guidelines in Standard Review Plan for normal and design speeds. The stress in the ~~seal~~ **flexible** welds and flywheel enclosure components for normal and design speeds are within the criteria in subsection NG of the ASME Code which is used as a guideline.

Pipe rupture overspeed is based on a break of the largest branch line pipe connected to the reactor coolant system piping that is not qualified for leak-before-break criteria. The exclusion of the reactor coolant loop piping and branch line piping of 6 inches or larger size from the basis of the pump loss of coolant accident overspeed condition is based on the provision in GDC 4 to exclude dynamic effects of pipe rupture when a leak-before-break analysis demonstrates that appropriate criteria are satisfied. See subsection 3.6.3 for a discussion of leak-before-break analyses. The criteria of subsection 3.6.2 are used to determine pipe break size and location for those piping systems that do not satisfy the requirements for mechanistic pipe break criteria.

In addition to material specification and non destructive testing requirement, each flywheel is subject to a spin test at 125 percent overspeed during manufacture. This demonstrates quality of the flywheel. Since the basis for the safety of the flywheel is retention of the fragments within the reactor coolant pump pressure boundary, periodic inservice inspections of the flywheel assembliesy are not required to ensure that the basis for safe operation is maintained.

Because of the configuration of the flywheel assembliesy, inservice inspection of the flywheel assembliesy may not result in significant inspection results. Inspection of the uranium alloy casting would require removal of the assembly from the shaft, removal of the uranium from the enclosures, rewelding of the enclosure, reassembly, and balancing of the pump shaft. Opening of the pump assembly for a periodic inspection of the enclosure would result in an increased occupational radiation exposure and would not be consistent with goals relative to maintaining exposure as low as reasonably achievable. Also, opening the pump may increase the potential for entry of foreign objects into the canned motor area. For these reasons, routine, periodic inspection of the flywheel assembliesy in the AP1000 canned motor reactor coolant pump is not recommended.

From DCD page 5.4-9, Section 5.4.1.4:

The design enables disassembly and removal of the pump internals and canned motor for inspection of the pump casing or pressure boundary welds, as well as the bearings, flywheel assembliesy, and other internal components, if required. As noted earlier, routine inspections of the impeller, flywheel, and motor internals are not required for safe operation of the pump.

From DCD page 5.4-77:

Table 5.4-1

REACTOR COOLANT PUMP DESIGN PARAMETERS

Unit design pressure (psig)	2500
Unit design temperature (°F)	650
Unit overall height (ft-in)	~~19-4~~21-11.5
Component cooling water flow (gpm)	360
Maximum continuous component cooling water inlet temperature (°F)	110
Total weight motor and casing, dry (lb) nominal	~~152,560~~184,500
Pump	
Design flow (gpm)	78,750
Developed head (feet)	365
Pump discharge nozzle, inside diameter (inches)	22
Pump suction nozzle, inside diameter (inches)	26
Speed (synchronous)(rpm)	1800
Motor	
Type	Squirrel Cage Induction
Voltage (V)	6600
Phase	3
Frequency (Hz)	60
Insulation class	Class H or N
Current (amp)	
Starting	Variable
Nominal input, cold reactor coolant	Variable
Motor/pump rotor minimum required moment of inertia (lb-ft^2) ~~nominal~~	16,500

From DCD page 5.4-79:

Table 5.4-3

REACTOR COOLANT PUMP QUALITY ASSURANCE PROGRAM

	RT[a]	UT[a]	PT[a]	MT[a]
Castings				
Flywheel		X	X	
Casing (or pressure boundary)	X		X	
Forgings		X		X
Plate			X	
Weldments				
Circumferential	X	X	X	
Instrument connections			X	
Motor terminals[b]	X		X	

__Notes:__
(a) RT - radiographic, UT - ultrasonic, PT - dye penetrant, MT - magnetic particle
(b) The motor terminals are helium leak tested prior to installation.

From DCD page 5.4-97, Figure 5.4-1:

See attached current and revised figures.

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

Figure From AP1000 DCD Revision 2

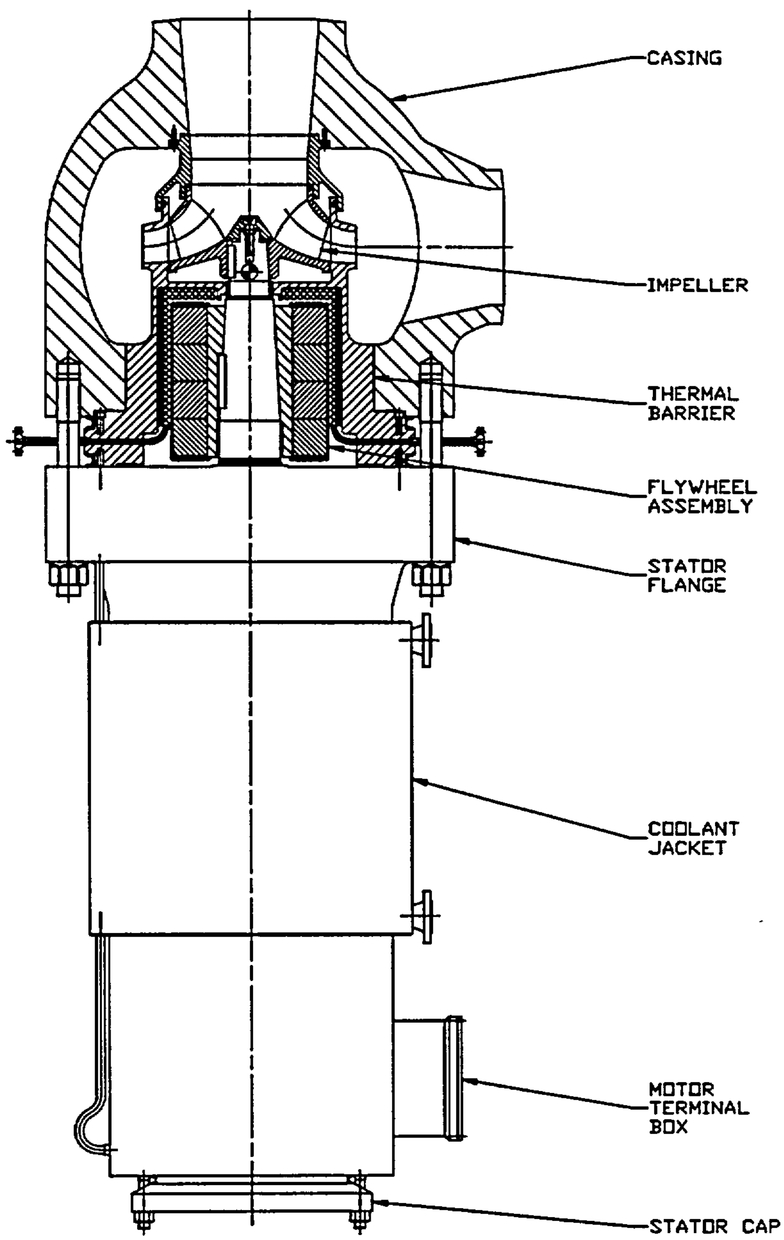


Figure 5.4-1

Reactor Coolant Pump

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

Revised Figure

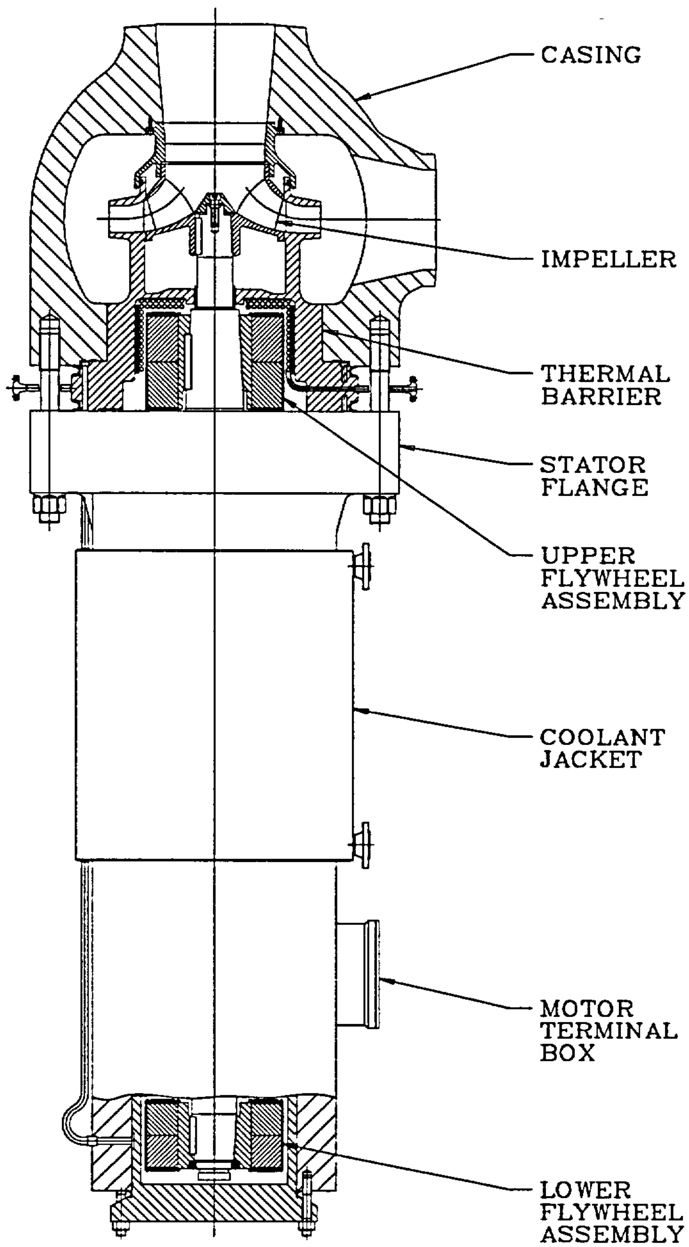


Figure 5.4-1

Reactor Coolant Pump

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.057

Question:

Provide a list of the setpoints with the associated uncertainties for normal operation and the setpoints assumed in the transient analysis for engineered safety feature actuation systems, pressurizer safety valves, SG power-operated relief valves (PORVs) and safety valves. Compare these analytical values with the applicable TS values and address the acceptability of the TS values.

Westinghouse Response:

See the response to RAI 440.103 for a discussion of the approach for identifying the allowable values and the trip setpoints for Technical Specifications Tables 3.3.1-1 and 3.3.2-1, and for calculating instrumentation setpoint uncertainties for engineered safety feature actuation systems. As discussed in the RAI response, the setpoints and associated uncertainties for associated instrumentation are identified in the plant specific setpoint calculation completed by the Combined License applicant once the actual instrumentation has been selected for the plant.

The setpoints, setpoint uncertainty, and accumulation for safety valves are based on ASME Code requirements. These are specified in the ASME Code and described as required in the DCD Sections 5.4.9 and 10.3.2.2.3 and in Technical Specifications and the Bases for the associated Limiting Conditions for Operation (LCO), actions, and surveillance requirements.

Section 5.4.9 and Table 5.4-17 provide a description of the pressurizer safety valve design specifications, including the relief setpoint (2485 psig), tolerance ($\pm$ 1 percent), relief capacity (750,000 lbm/hr), and accumulation (3 percent).

LCO 3.4.7 provides the Technical Specification requirements for the pressurizer safety valves. The LCO identifies the relief setpoint and allowable tolerance band and the Technical Specification Bases reference the appropriate ASME Code sections applicable to the pressurizer safety valves. The Technical Specification surveillance Bases specify a $\pm$ 3 percent setpoint tolerance to satisfy Technical Specifications OPERABILITY requirements (which allows for setpoint drift), assuming that the setpoint tolerance is reset to $\pm$ 1 percent during the In-Service Testing.

Section 10.3.2.2.2 and Table 10.3.2-2 provide a description of the steam generator safety valve design specifications, including the relief setpoints, tolerance ($\pm$ 1 percent), relief capacities (1,390,000 lbm/hr at 110 percent of design pressure), and accumulation (3 percent). The table below provides the nominal lift setpoints and relief capacity for each valve from Table 10.3.2-2.

The valve operational relief capacity in the table below is lower than the design relief capacity since the operational valve relief setpoint (and the associated accumulation pressure) is slightly lower than the design pressure for specifying the valve design relief capacity.

Valve Number	Set Pressure (psig)	Relieving Capacity (lb/hr)
SGS PL V030A(B)	1185	1,248,000
SGS PL V031A(B)	1191	1,254,000
SGS PL V032A(B)	1198	1,262,000
SGS PL V033A(B)	1204	1,268,000
SGS PL V034A(B)	1211	1,275,000
SGS PL V035A(B)	1217	1,282,000

LCO 3.7.1 provides the Technical Specification requirements for the steam generator safety valves. The LCO identifies the relief setpoint and allowable tolerance band and the Technical Specification bases reference the appropriate ASME Code sections applicable to the steam generator safety valves.

The conservative assumptions for operation of the pressurizer safety valve in the safety analyses are identified in the applicable analysis sections of DCD Chapter 15. For example, Section 15.2 describes the analyses for a decrease in secondary system heat removal and describes the assumptions for operation of the pressurizer safety valves to mitigate these events. Section 15.3 describes the analyses for a decrease in RCS flow and Section 15.3.3.2.2. describes assumptions for operation of the pressurizer safety valves to mitigate these events.

The conservative assumptions for operation of the steam generator safety valves in the safety analyses are identified in the applicable analysis sections of Chapter 15. For example, Section 15.2 describes the analyses for a decrease in secondary system heat removal and describes the assumptions for operation of the steam generator safety valves to mitigate these events. The analyses in this section use a simplified steam generator valve model that assumes a lift setpoint corresponding to 1241 psig that conservatively bounds the steam generator safety valve opening setpoint including allowances for setpoint uncertainties.

DCD Section 10.3.2.2.3 and Table 10.3.2-1 provide a description of the steam generator PORV design specifications, including the normal relief setpoint (1150 psig) and relief capacities (70,000 lbm/hr at 100 psia inlet pressure and 1,020,000 lbm/hr at 1200 psia inlet pressure). These valves do not have a setpoint tolerance equivalent to a safety valve since they modulate, with a pressure control setpoint that can be manually adjusted over a range of pressures from the main control room. The normal setpoint of 1150 psig can be varied by the operators based on the desired RCS temperature to be maintained during a plant shutdown condition, when the PORVs are used. The steam generator PORVs do not provide a safety-related heat removal capability, so there are no DCD Technical Specifications for the steam generator PORVs.

Chapter 15 provides a description of the assumptions related to PORV operation for the various safety analyses. While operation of and failure of the valves are considered for some events, the valves may also be ignored for other events if they are not a limiting design condition. For example, Chapter 15.1.4 discusses the inadvertent opening of either a steam generator safety valve or PORV. However, a main steam line break provides a more limiting steam generator depressurization condition, which bounds the relief capacity of the steam generator PORVs and safety valves. For analyses where PORV operation may be a consideration, safety analyses may modify PORV capabilities to make them more limiting for a specific analysis, such as crediting them with the larger flow rate equivalent to a steam generator safety valve for analysis simplification or conservatism. The steam generator PORVs are conservatively modeled to open in the safety analyses, where a specific lifting setpoint is needed in the safety analyses. The relief setpoint for a steam generator tube rupture event is 1150 psig.

Therefore, the steam generator PORV setpoints and the associated uncertainties are not specified in DCD Technical Specifications, but the valve design capabilities are appropriately considered in the safety analyses.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.067

Question:

It is stated on page 15.1-15 that the limiting SLB case is the complete severance of a steam line, with the plant initially at no-load conditions and full reactor coolant flow with offsite power. However, no quantitative analysis is presented to support the limiting SLB case identified. The guidance for the SLB analysis is provided in SRP 15.1.5. Specifically, item b of the acceptance criteria states that "Assumptions as to the loss of the offsite power (LOOP) and the time of loss should be made to study their effects on the consequences of the accident. A LOOP may occur simultaneously with the pipe break, or during the accident, or offsite power may not be lost."

Provide analyses of (1) the SLB cases at full power with and without an LOOP and (2) the SLB at no-load conditions with and without an LOOP, and address its compliance of the SRP guidance related to the assumption of the LOOP. The analysis should consider effects of time of an LOOP (occurred simultaneously with an SLB, or during the transient) on an SLB event and show the calculated DNBRs for both pre-trip and post-trip core conditions at initial power levels of full power and zero power.

Westinghouse Response:

The AP1000 protection system and the passive emergency safeguards features are independent of the availability of offsite power. The principal impact of a loss of offsite power on AP1000 transient performance is the loss of power to the reactor coolant pumps which causes a subsequent reactor coolant pump coast down. Therefore the timing of a loss of offsite power affects the timing of when the reactor coolant pumps coast down.

The AP1000 cool down protection logic includes functions to automatically borate the plant by actuating the core makeup tanks. Signals that actuate the core makeup tanks also automatically trip the reactor coolant pumps.

Assuming a loss of offsite power simultaneous with the pipe break results in a similar transient response to the steam line break case presented in the Section 15.1.5 because the protection system trip the reactor coolant pumps early in the transient. Analysis were performed for the following two cases.

Case 1- Full double ended rupture from hot zero power with offsite power available throughout the event.

Case 2 - Full double ended rupture from hot zero power with offsite power lost simultaneous with the steam line break at the start of the event.

The results of the two cases are summarized and compared in Table 440.067 and Figures 440.067-1 through 440.067-6 compare the results of the two cases. There is no significant change in the results with and without offsite power available. In Case 2 where offsite power is lost, the reactor coolant pumps begin coasting down at Time=0.0. In Case 1 with offsite power available, the protection system automatically trips the reactor coolant pumps 7.363 seconds after the start of the transient. This small difference in the timing of the initiation of the reactor coolant pump coast down has no significant impact on the parameters that affect the return to power. The peak core heat flux obtained for cases with and without offsite power is essentially the same (3%).

A loss of offsite power simultaneous with the break would have less effect if the steam line break is initiated from at power conditions. When initiated from at power conditions, postulating a loss of offsite power simultaneous with the steam line break at the start of the transient would result in a prompt reactor trip (within 1 second) on low reactor coolant pump speed. The early reactor trip on low RCP speed would limit the magnitude of the pre-trip increase in core power. WCAP-9226 Revision 1 "Reactor Core Response to Excessive Secondary Steam Release," dated January 1978 provides detail analysis of steam line breaks from full power and zero power and demonstrates that steam line breaks initiated from no-load conditions bound those that can occur from full load conditions, with respect to core DNBR and post-trip return to criticality.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

Table 440.067 Sequence of Events for Full Double Ended Steam Line Break from HZP Conditions

Event	Time	
	Case 1, with offsite power available	Case 2, offsite power lost simultaneous with the break
Break Initiated	0.0	0.0
Offsite power lost and reactor coolant pumps begin coasting down	-----	0.0
Low steam line pressure setpoint reached	1.363	1.361
Reactor coolant pumps tripped and begin coasting down on a low steam line pressure signal	7.363	-----
Main steam and main feedwater isolation valves closed on a low steam line pressure signal	13.363	13.361
Low cold leg temperature setpoint reached	18.001	17.783
Core makeup tank actuated on low steam line pressure signal	18.363	18.361
Criticality reached	28.8	30.2
Startup feedwater isolated on low cold leg temperature signal	30.001	29.783
Boron begins reaching the core	33.4	33.8
Peak core heat flux occurs	~240 (3.17 % power)	~240 (3.14 % power)

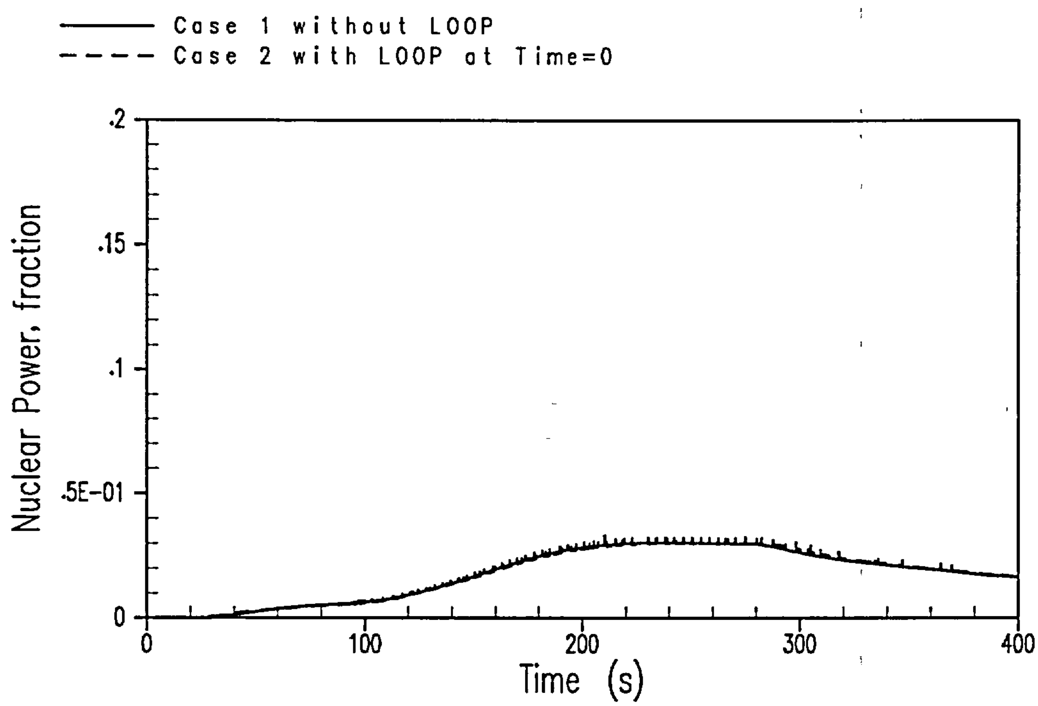


Figure 440.067-1

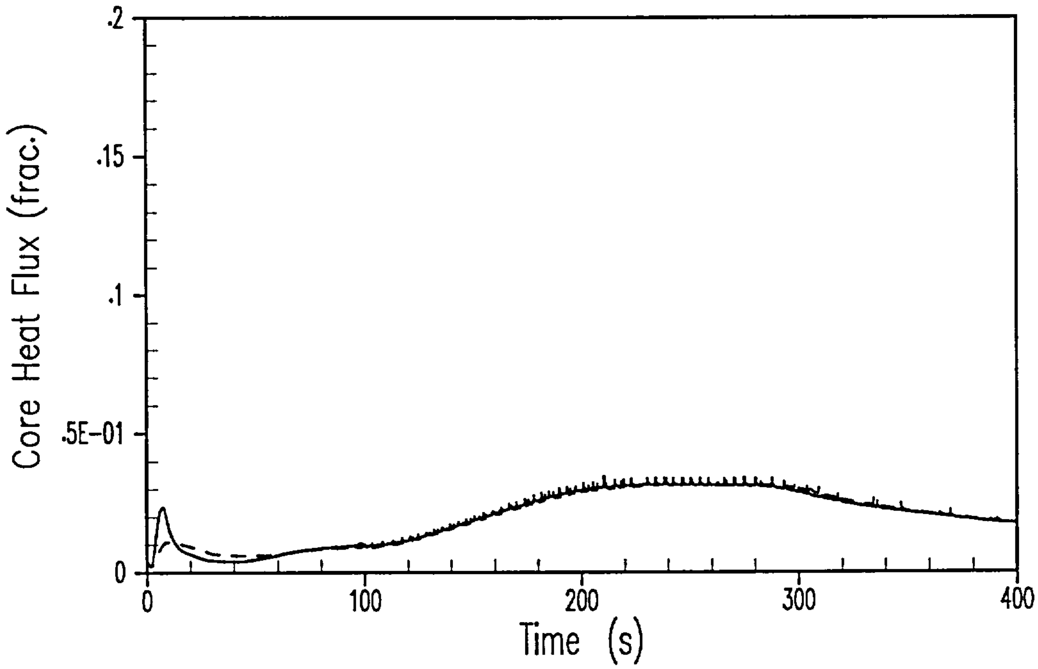


Figure 440.067-2

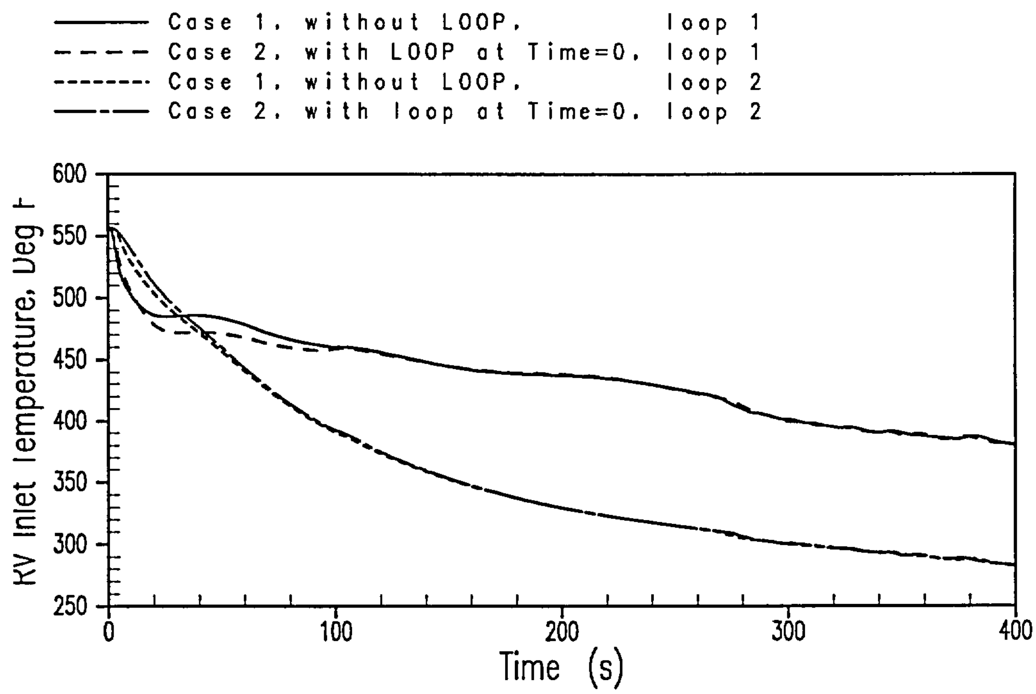


Figure 440.067-3

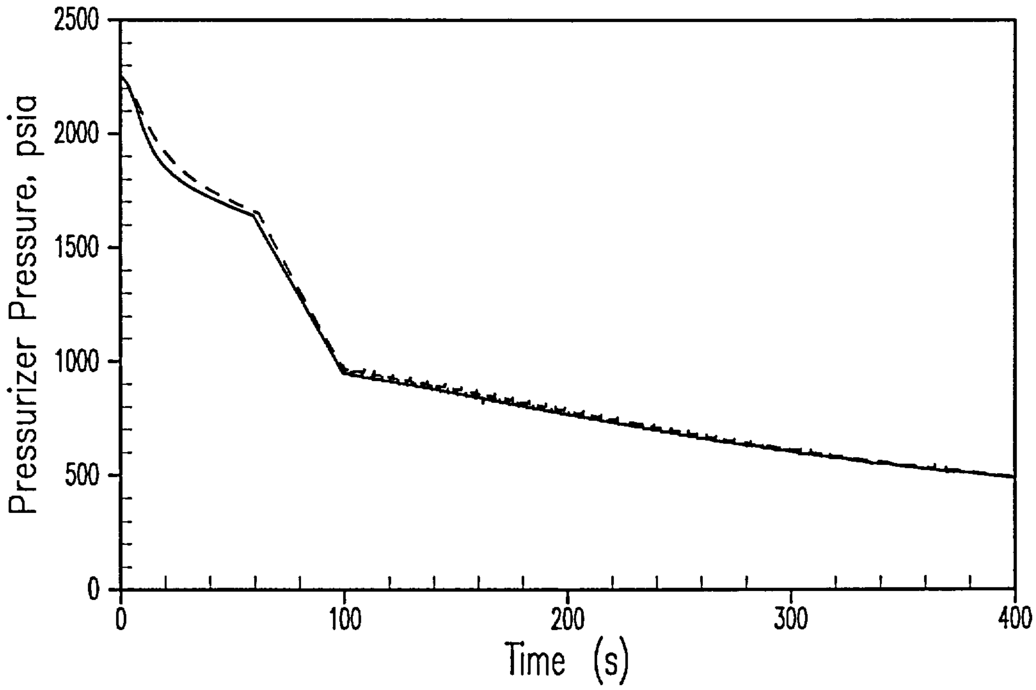


Figure 440.067-4

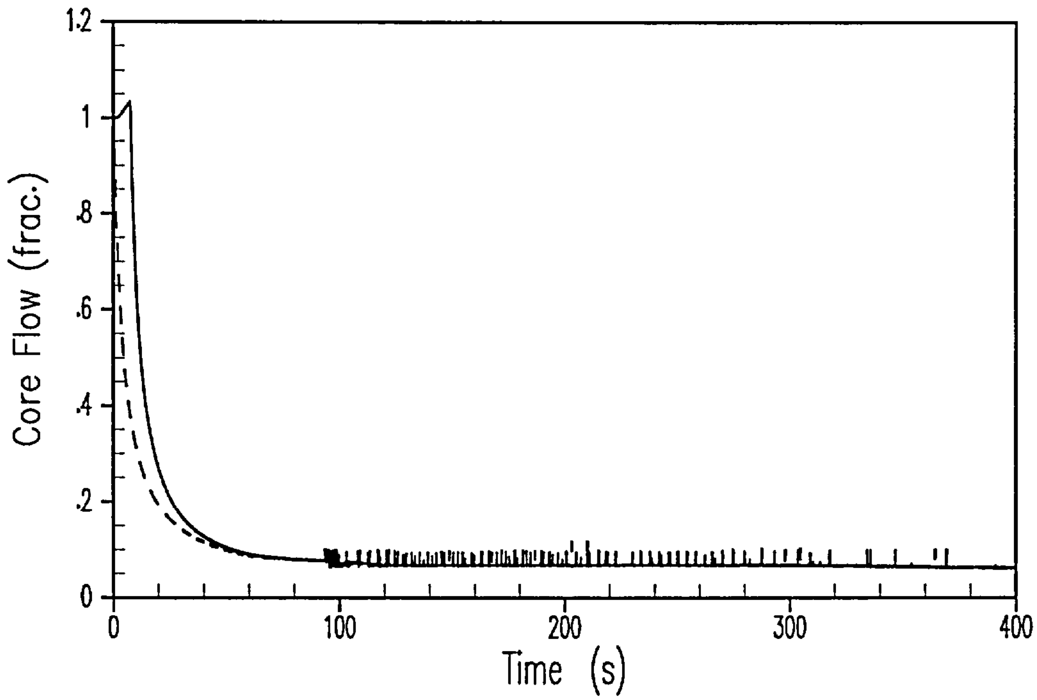


Figure 440.067-5

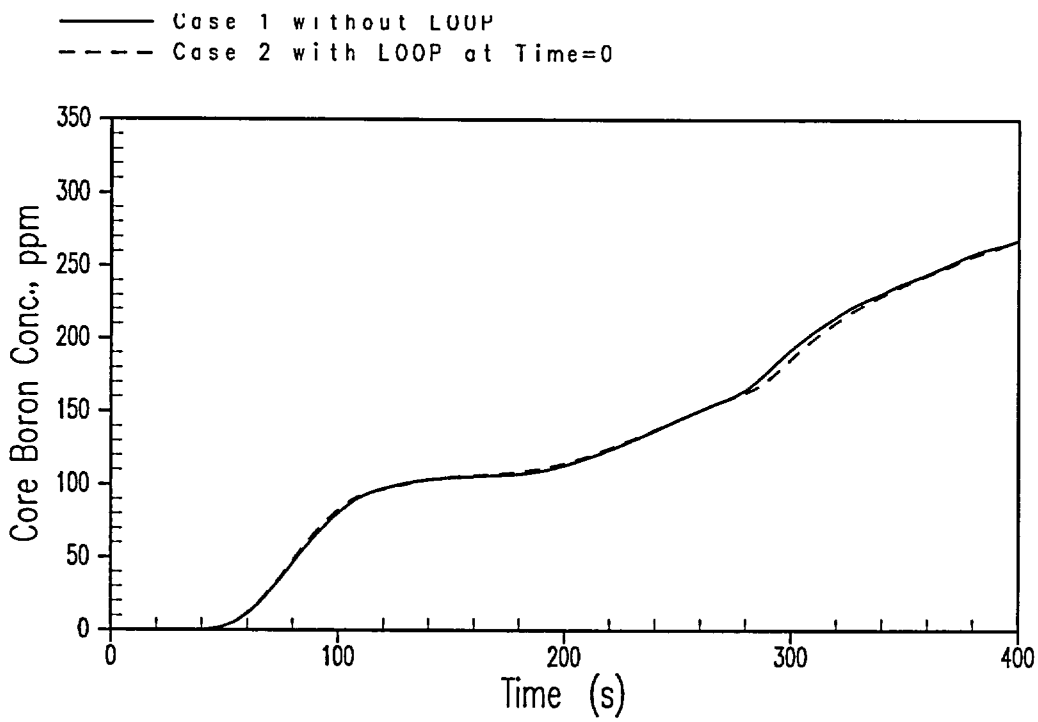


Figure 440.067-6

RAI Number: 440.081

Question:

Section 15.4.3.2.2.2 indicates that the calculated minimum DNBR for the withdrawal of single full-length RCCA event is less than the safety limit. As a result, the fuel rods predicted to fail is less than 5 percent of total fuel rods.

A. Provide a figure showing the calculated DNBRs during the transient.

B. Discuss the analytical methods, input parameters (such as pin census data and peak factors) and assumptions used to determine the number of failed fuel rods, and show that the methods used for the analysis are acceptable and the input parameters and assumptions are conservative with respect to the fuel failure calculations.

Westinghouse Response:

A. For the limiting core configuration, the ANC code provides a census of F-delta-H versus the percentage of rods in the core above that F-delta-H value. From this census, the F-delta-H value corresponding to 5% of total fuel rods is compared to the normal operation F-delta-H limit (it is conservatively assumed that all rods above the normal operation limit will be in DNB during the event). An 8% uncertainty is applied to calculated ANC F-delta-H values, consistent with core design methodology. The AP1000 analysis shows that less than 4% of total fuel rods will be in DNB during the single rod withdrawal event. See Part B for further explanation.

B. The ANC code is used to confirm that peaking factors during single rod withdrawal remain sufficiently low to preclude more than 5% of rods being in DNB during the event. The analysis is performed at full power conditions. The analysis is most limiting for the condition where RCCA rod banks are at the full power rod insertion limits (RILs) except one cluster which is fully withdrawn (clearly, this is the limiting condition for DNBR in the event that an RCCA cluster is withdrawn starting from the RILs). For the AP1000, the RILs are multidimensional, in that the RILs for the non-AO banks depend on how deeply the AO bank is inserted. The limiting configuration is with little or no AO bank insertion, as this allows a "black" (i.e., high-worth) non-AO bank to be as deep as possible in the core; withdrawal of a cluster from this black non-AO bank gives the limiting number of rods in DNB. (Although the AO bank is black itself, the withdrawal of a single AO cluster, while the AO bank is at its deepest insertion, is not the most onerous configuration, since the AO bank is never inserted sufficiently deep into the core.) The analysis assumes the axial offset is at its most positive during the rod withdrawal event, to assure maximum core peaking factors and hence conservative DNB conditions. For the limiting core configuration, ANC provides a census of F-delta-H versus the percentage of rods in the core above that F-delta-H value. From this census, the F-delta-H value corresponding to 5% of total fuel rods is compared to the normal operation F-delta-H limit (it is conservatively assumed that all rods above the normal operation limit will be in DNB during the event). An 8% uncertainty is applied to calculated ANC F-delta-H values, consistent with core design methodology.

The AP1000 analysis shows that less than 4% of total fuel rods will be in DNB during the single rod withdrawal event.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.091

Question:

In the discussion and analysis of the double-ended direct vessel injection (DEDVI) line break (Section 15.6.5.4C.2), it was assumed that the ADS4A valve failed to open (single failure) and the containment pressure is at the WGOTHIC calculated minimum. These conditions may be conservative for depressurization but not from the point of view of long-term cooling. Consider the case when all ADS4 valves open, with a maximum containment pressure. Steam velocity in the ADS4s will be minimum.

Will that steam velocity be able to entrain and remove liquid from the core? (Note, it is not feasible to draw this conclusion from the information in the code applicability report without extensive calculations).

Westinghouse Response:

The question is concerned with the removal of liquid from the AP1000 core / upper plenum at a minimum steam velocity condition. The concern is whether there exists sufficient liquid carryover out the ADS-4 valves post-LOCA to prevent the potential for boron precipitation in the reactor vessel. As was demonstrated for the AP600, liquid carryover from the ADS-4 valves prevents the reactor vessel boron concentration from approaching the concentration where boron would precipitate. A boron concentration of approximately 35,000 ppm at 240F is necessary to cause boron to precipitate out of solution. Bounding calculations performed for the AP1000 have determined that the maximum post-LOCA boron concentration calculated for the limiting long-term cooling analysis cases presented in the DCD is 5500 ppm. This represents a large margin to the value where boron precipitation could be a concern.

This RAI asks that a less conservative (from a core cooling perspective) long-term cooling analysis be performed, to assess whether reduced ADS-4 liquid carryover will result, and thus a higher potential for post-LOCA boron precipitation. A WCOBRA/TRAC calculation of the DEDVI line break has been performed to investigate this scenario. In order to minimize the ADS-4 steam velocity, all the ADS-4 valves are assumed to open as requested in the RAI. In addition, containment pressure is set equal to the maximum calculated pressure from the containment integrity analysis reported in Chapter 6 of the AP1000 DCD. This containment pressure is calculated for a double-ended RCS loop pipe rupture using assumptions that maximize the calculated pressure result; it identifies an upper bound to the pressure response anticipated for a DEDVI break. The DEDVI break features the early actuation of ADS-4, which results in flow through ADS stages 1-3 being limited to a short time interval, thus minimizing IRWST water heatup prior to the long-term cooling phase. Therefore, there will be maximum subcooling of the injection water entering the downcomer during long-term cooling, so a minimum amount of steam is generated in the core.

A set of figures is provided presenting the results obtained from the WCOBRA/TRAC run for this scenario. Liquid flow through the ADS-4 flow paths is adequate to ensure that boron will not concentrate in the core. As seen on Figure 440.091-15, the average steam velocity through the ADS-4 Stage 4A flow path in the offtake pipe from the hot legs is 95 ft/sec, while in the DCD case the average steam velocity at the same location is almost 300 ft/sec (Figure 440.091-16). Overall, the figures show that amount of liquid carryover is increased for this scenario. As seen in comparison to the DEDVI long-term cooling analysis results presented in the DCD, the vessel injection is greater, and reactor vessel level is higher throughout the transient. This is primarily due to the faster RCS depressurization resulting from all four ADS-4 valves opening. Even though the vapor velocity in the ADS-4 flow paths is reduced, the core remains covered and cooled, and the liquid carry-over out the ADS-4 is increased (when compared to the cases presented in the DCD). Thus boron precipitation in the reactor vessel will not be a concern for the postulated scenario raised in this RAI.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

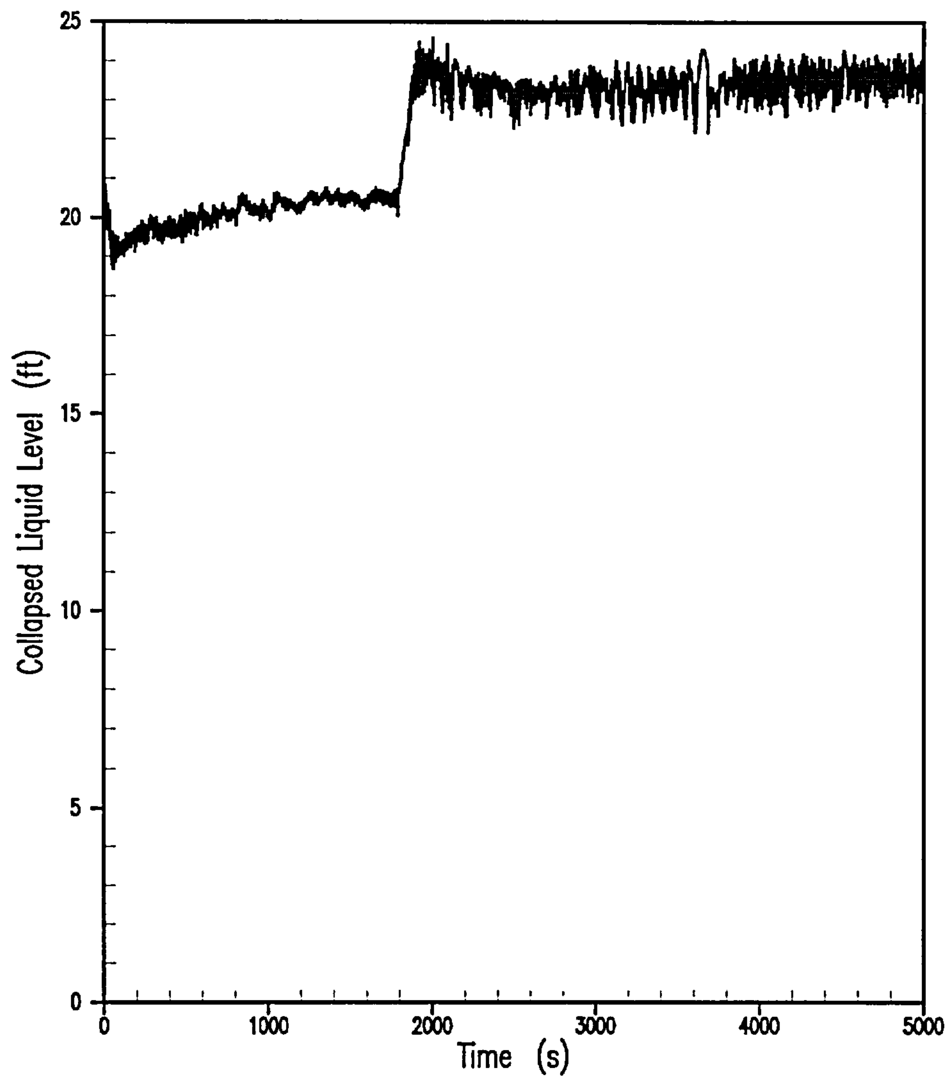


Figure 440.091-1 Collapsed Liquid Level in the Downcomer

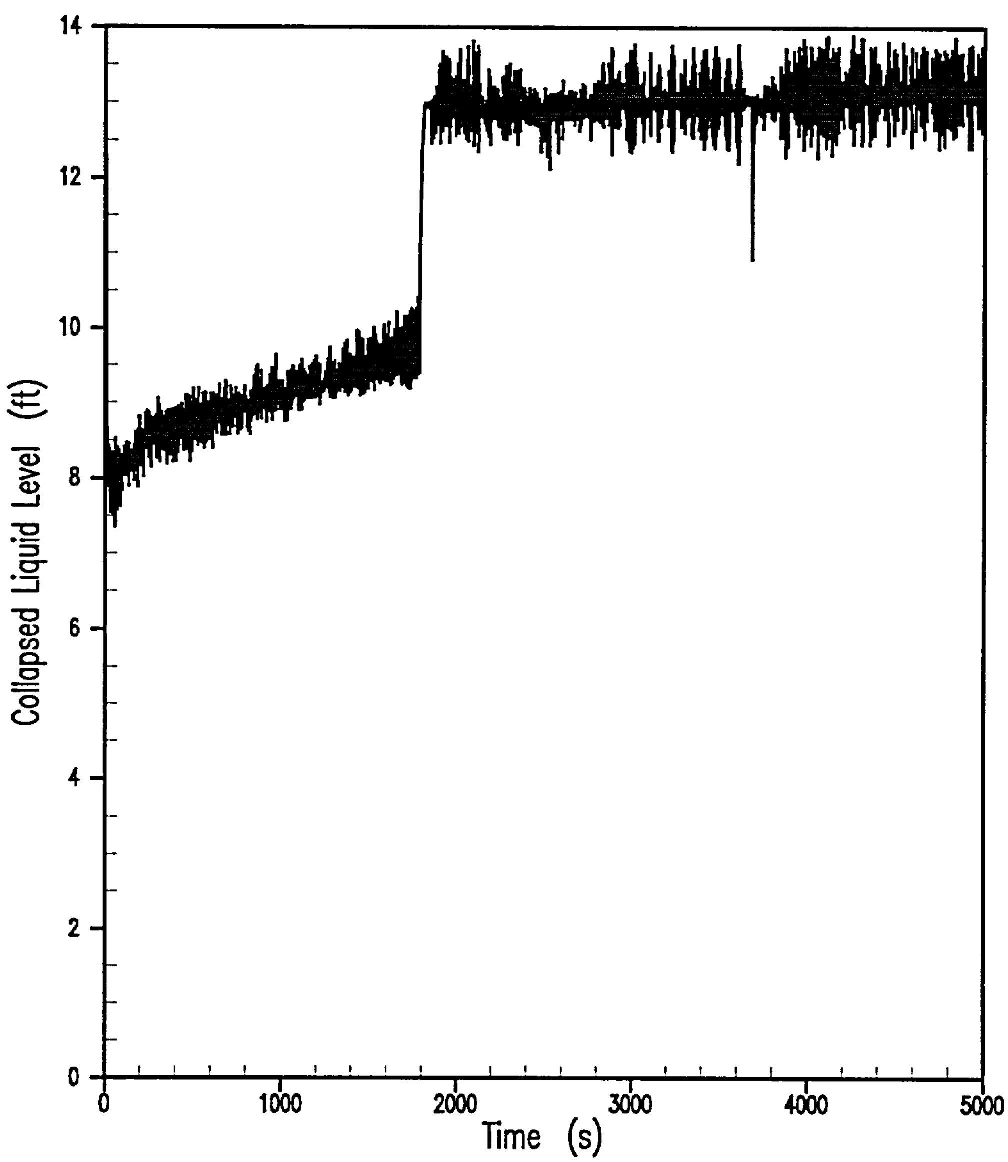


Figure 440.091-2 Collapsed Liquid Level Over the Heated Length of the Fuel

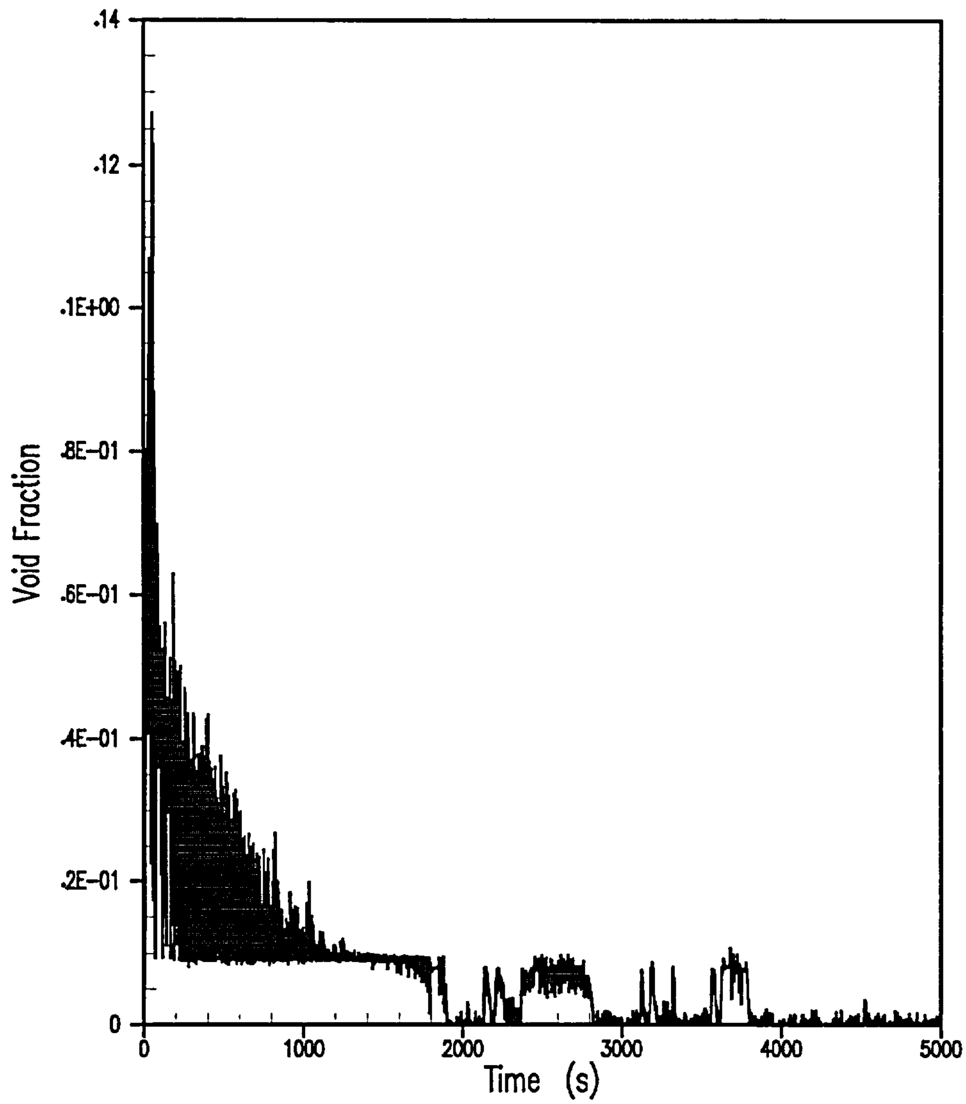


Figure 440.091-3 Void Fraction in Core Cell Level 1 of 2

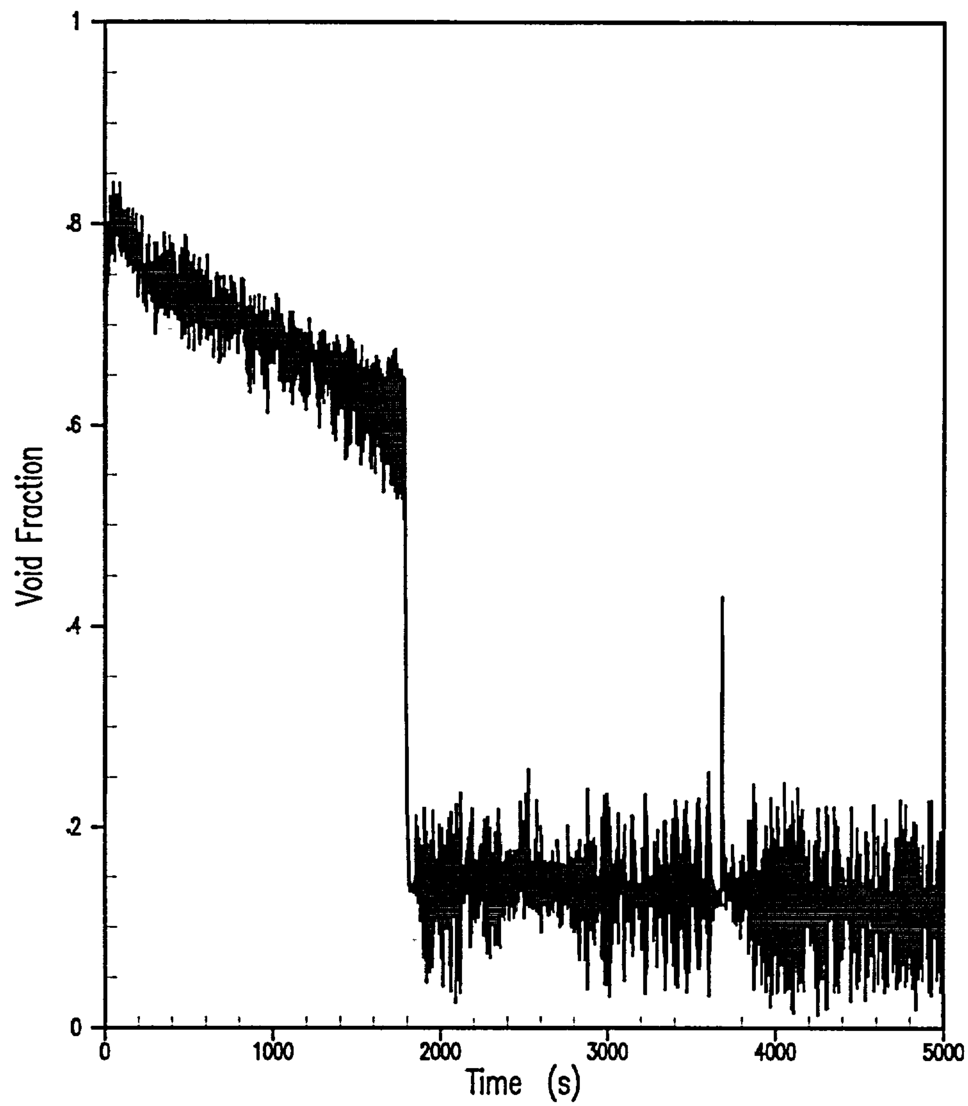


Figure 440.091-4 Void Fraction in Core Cell Level 2 of 2

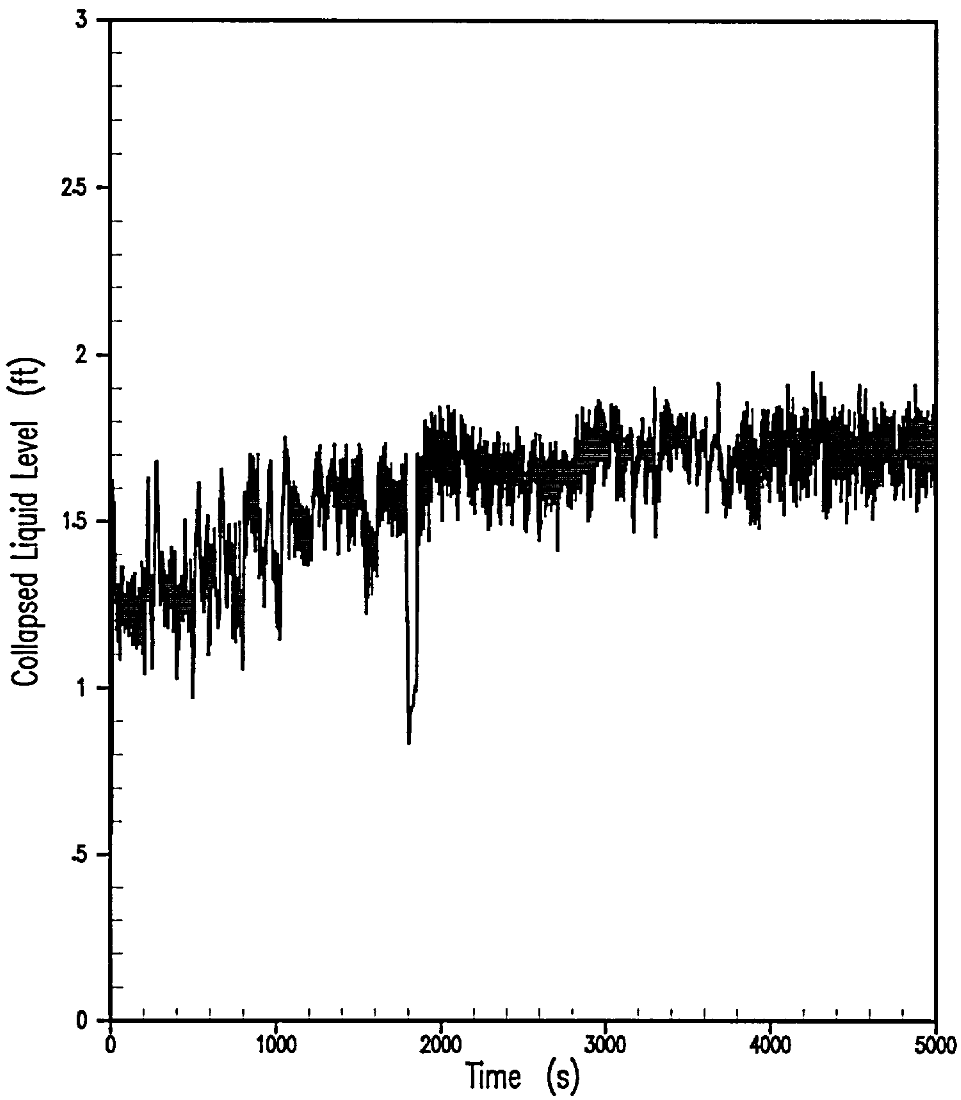


Figure 440.091-5 Collapsed Liquid Level in the Hot Leg of Intact Loop

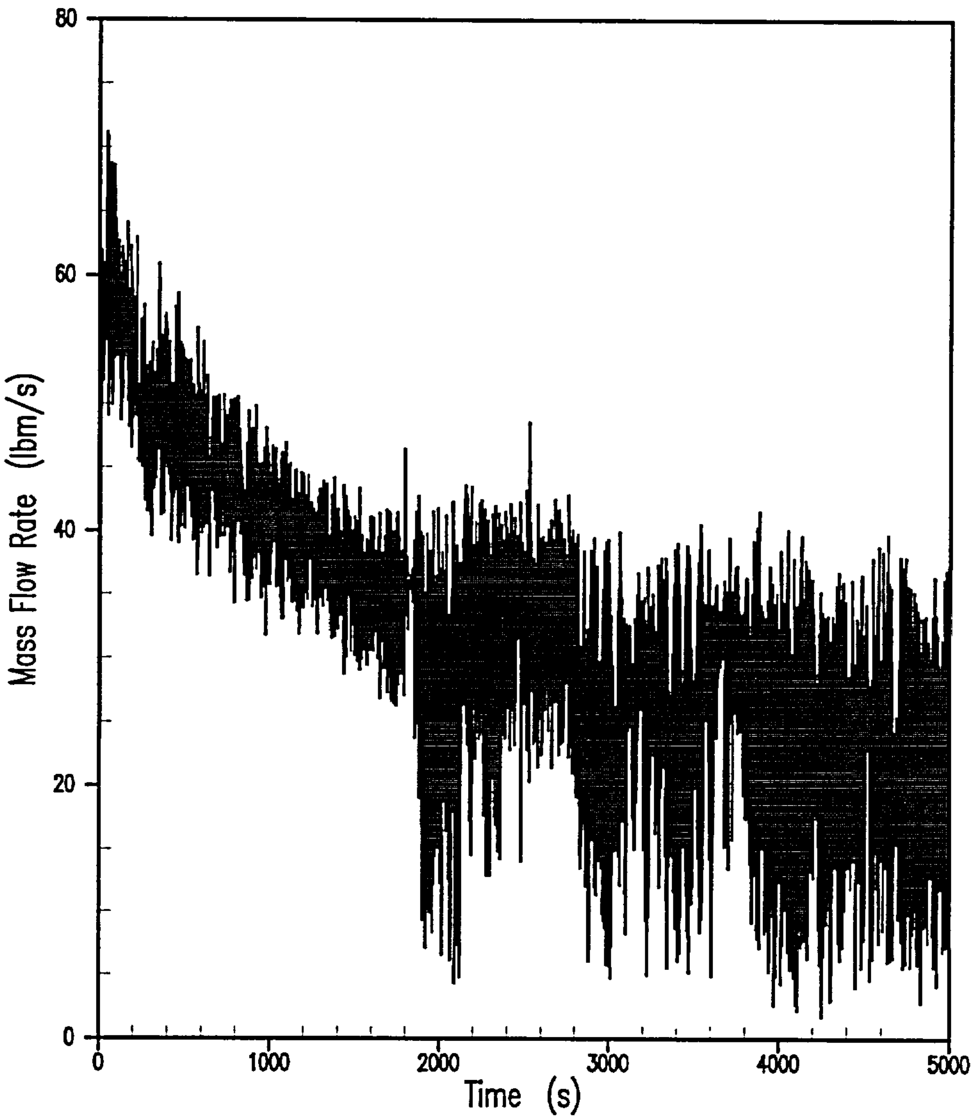


Figure 440.091-6 Vapor Rate out of the Core

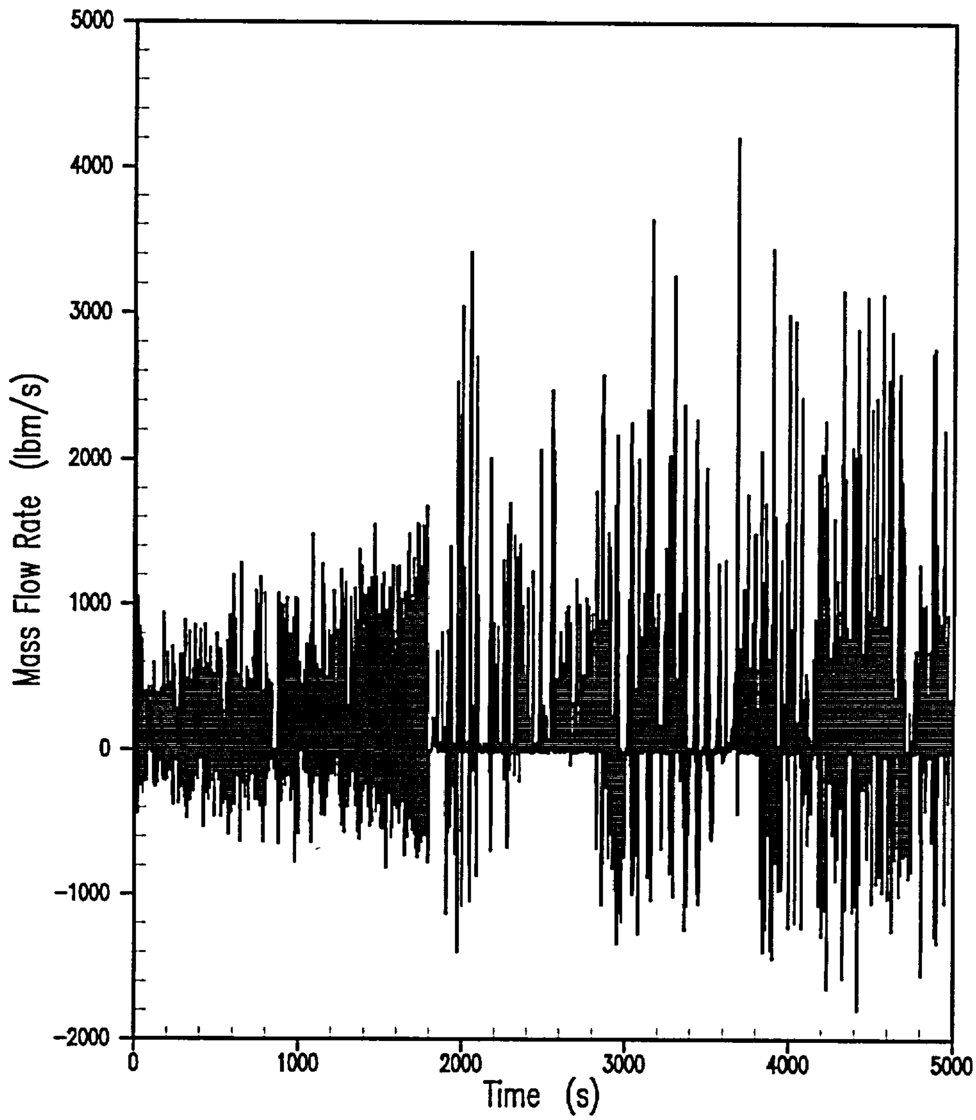


Figure 440.091-7 Liquid Flow Rate out of the Core

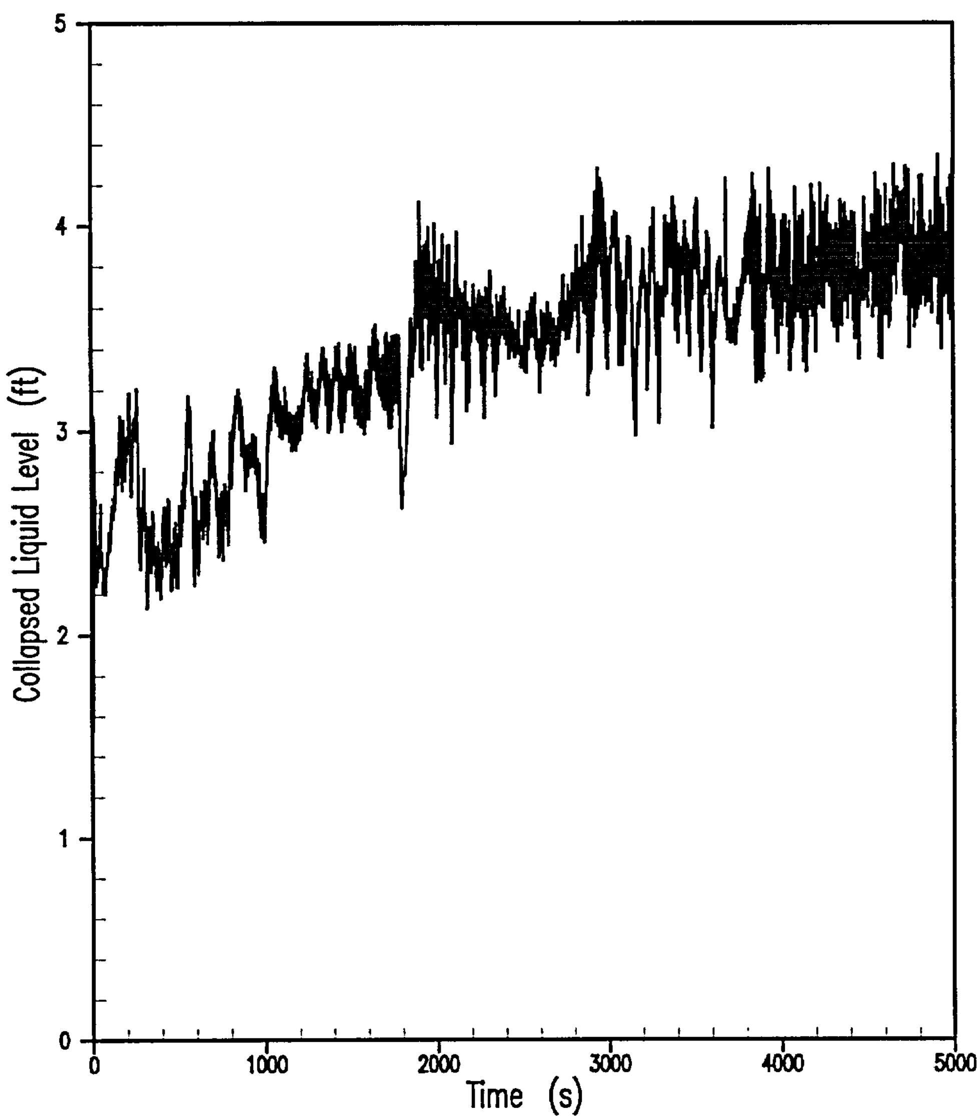


Figure 440.091-8 Collapsed Liquid Level in the Upper Plenum

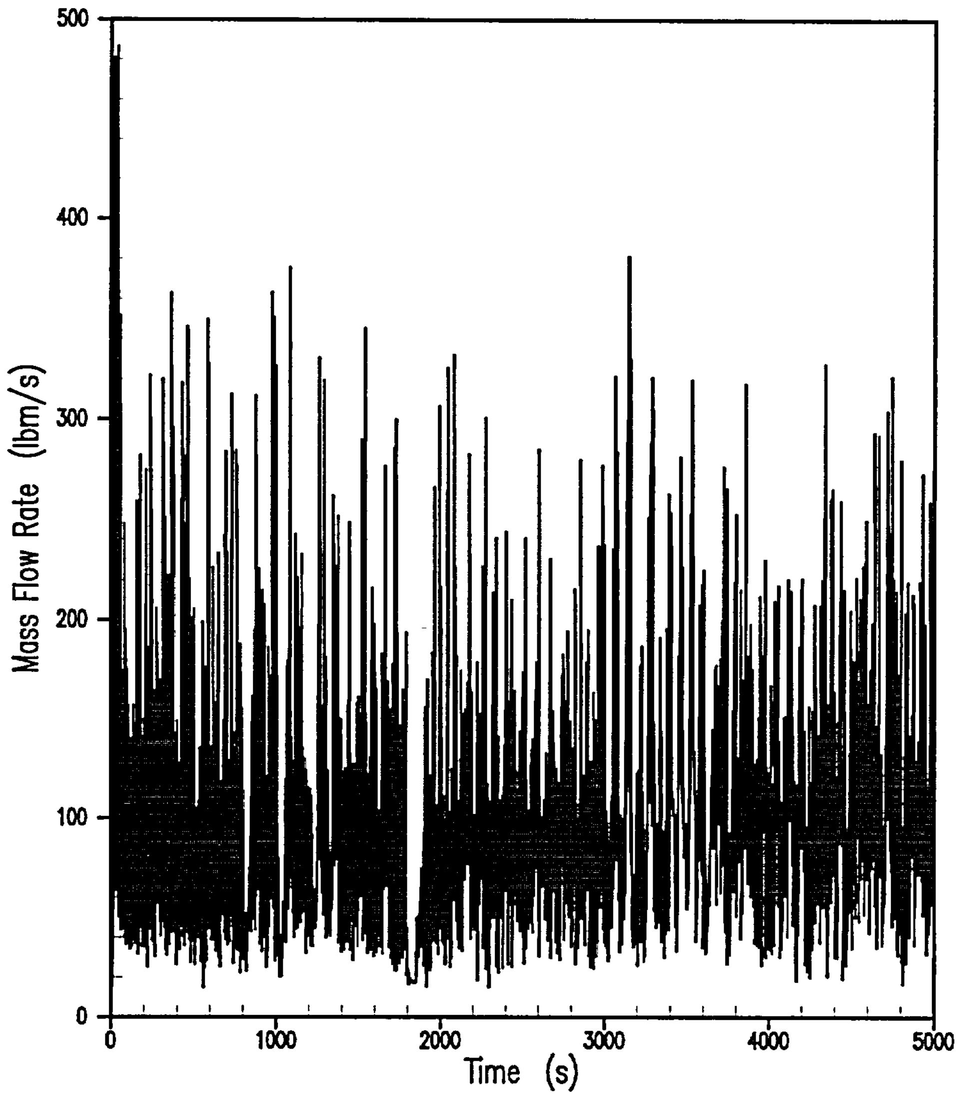


Figure 440.091-9 Mixture Flow Rate Through ADS Stage 4A Valves

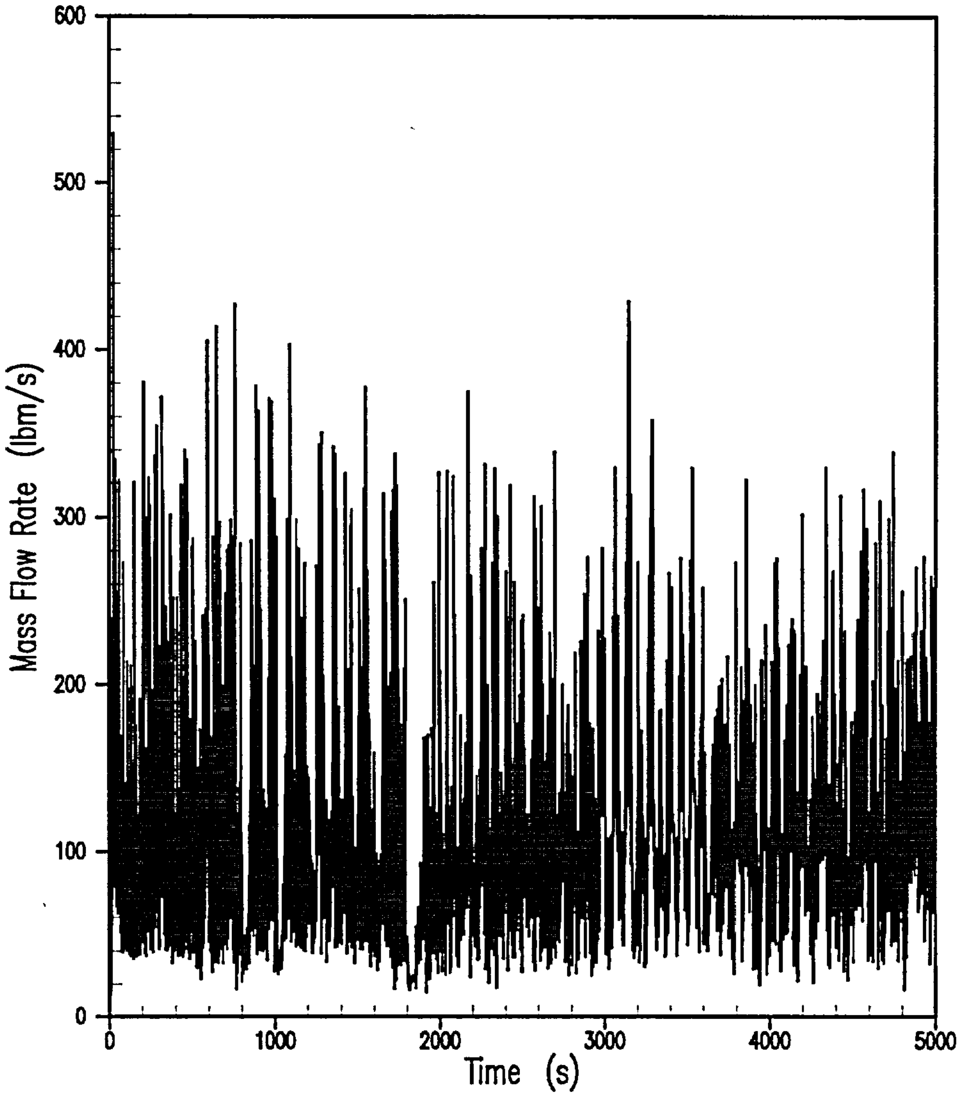


Figure 440.091-10 Mixture Flow Rate Through ADS Stage 4B Valves

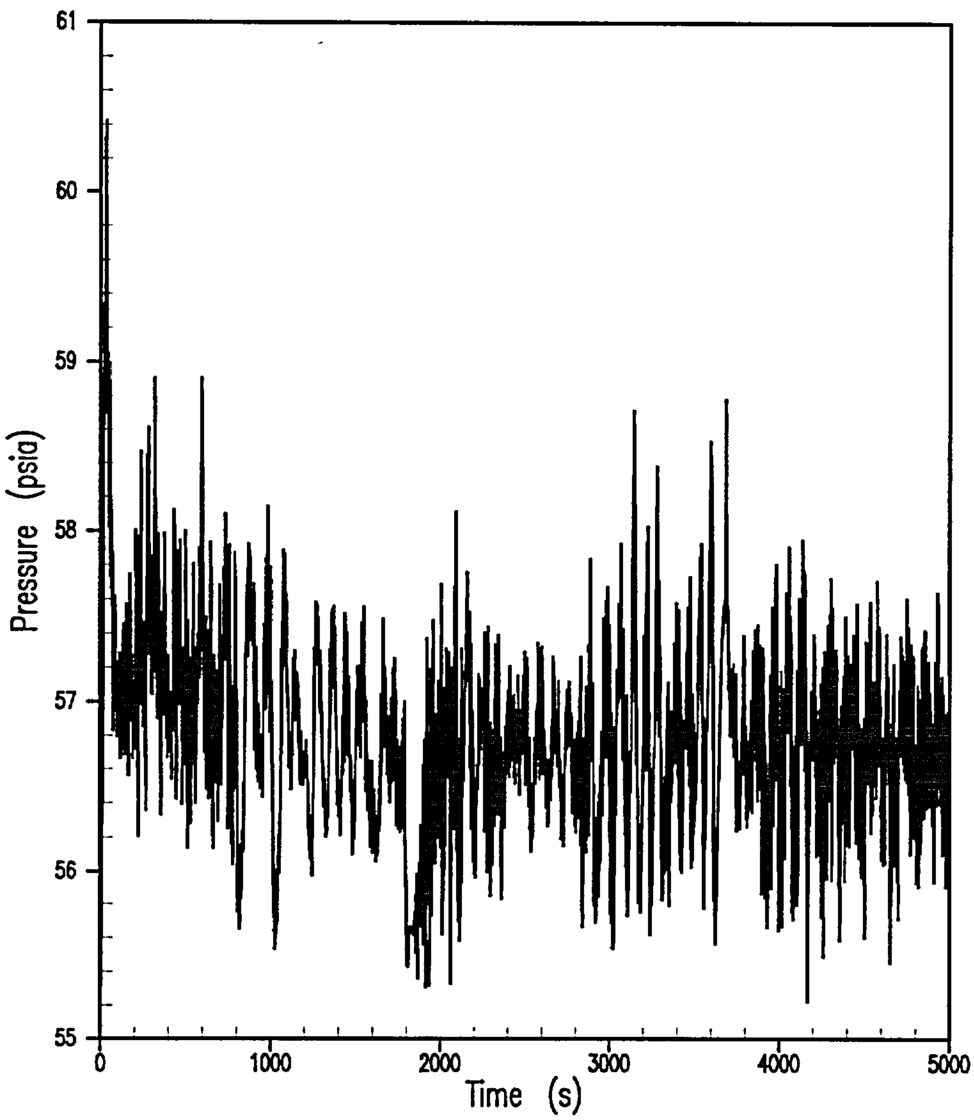


Figure 440.091-11 Upper Plenum Pressure

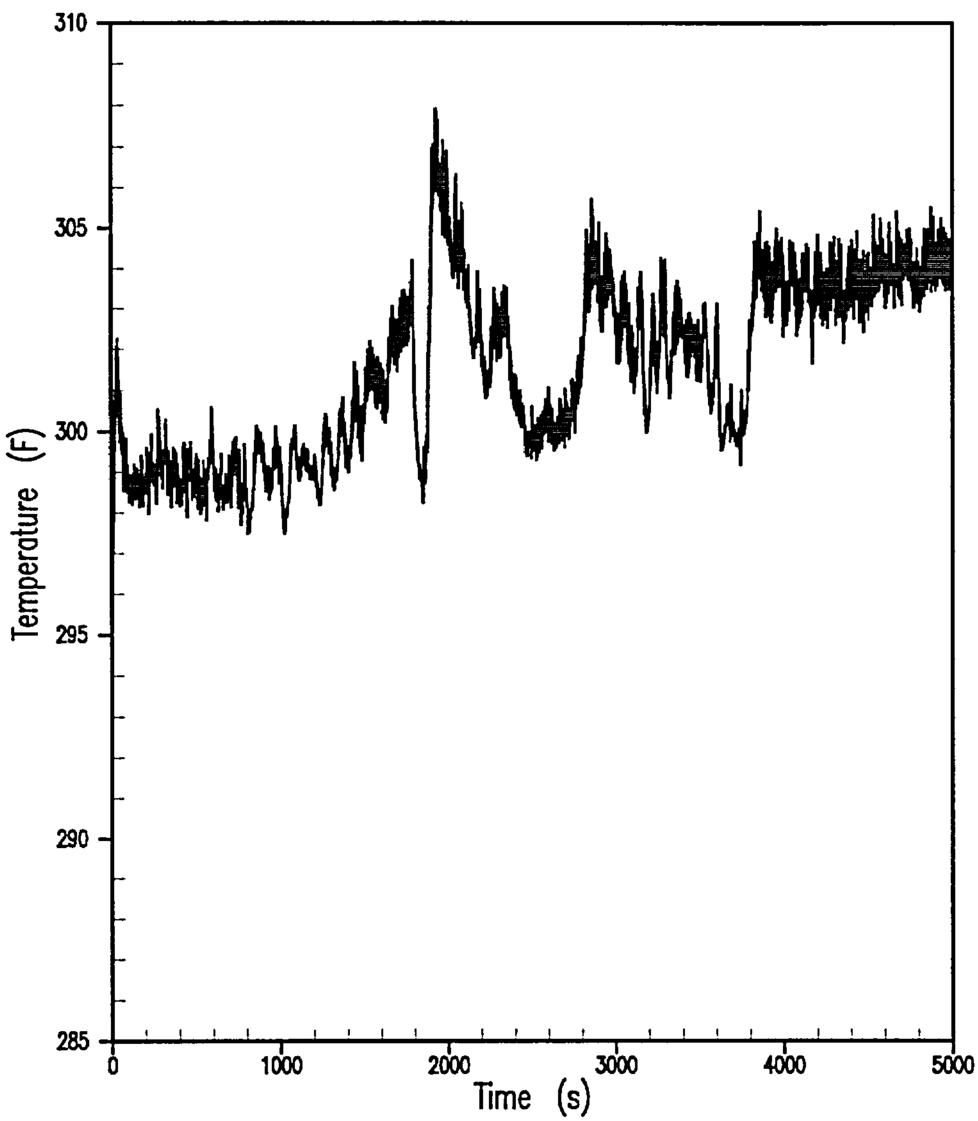


Figure 440.091-12 PCT of the Hot Rod

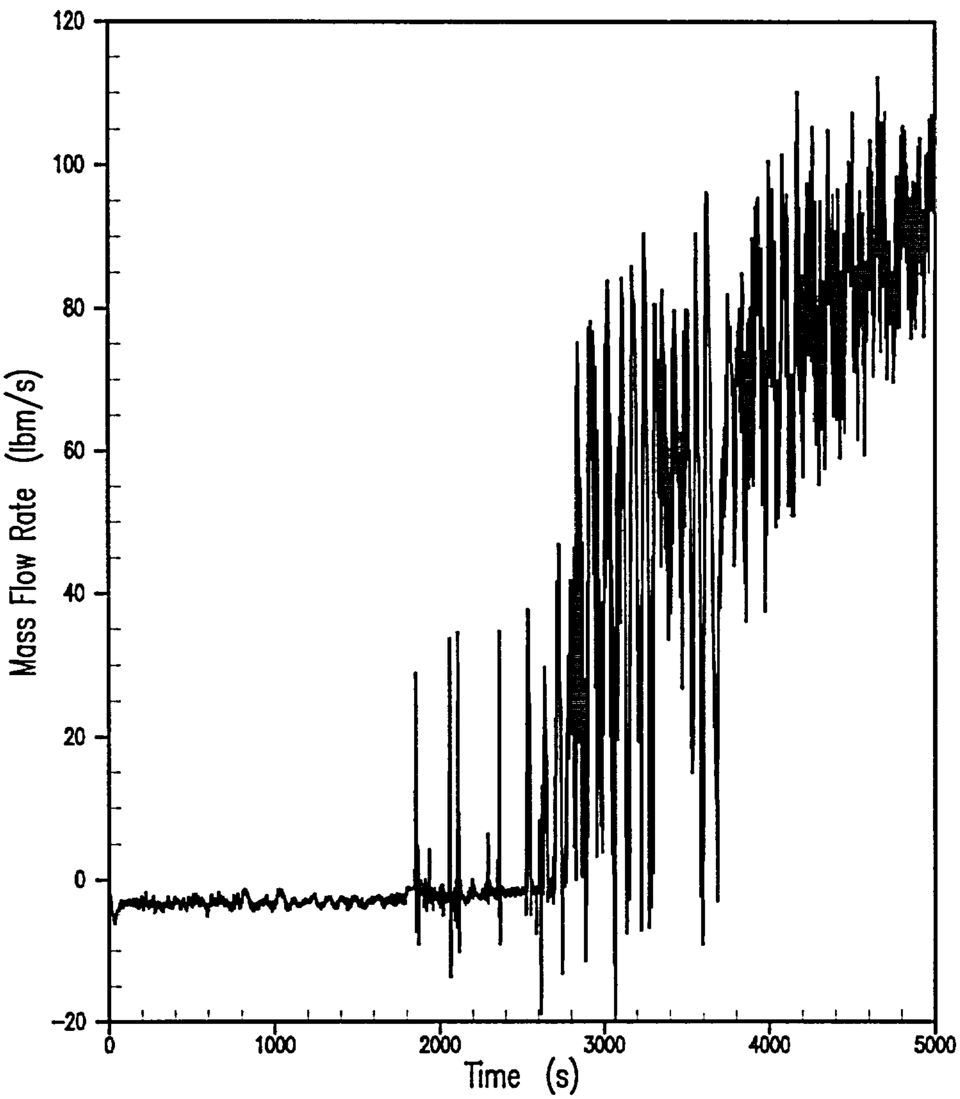


Figure 440.091-13 DVI-A Mixture Flow Rate

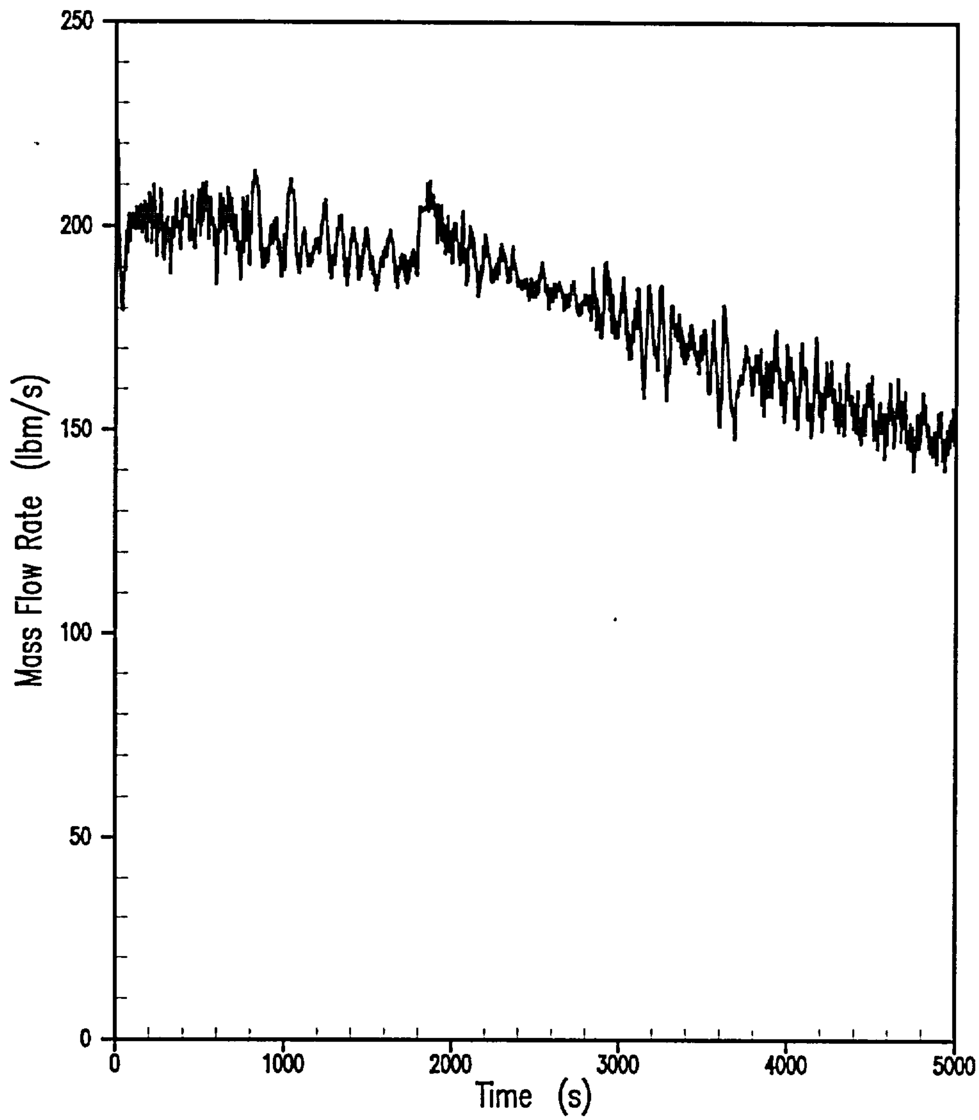


Figure 440-091-14 DVI-B Mixture Flow Rate

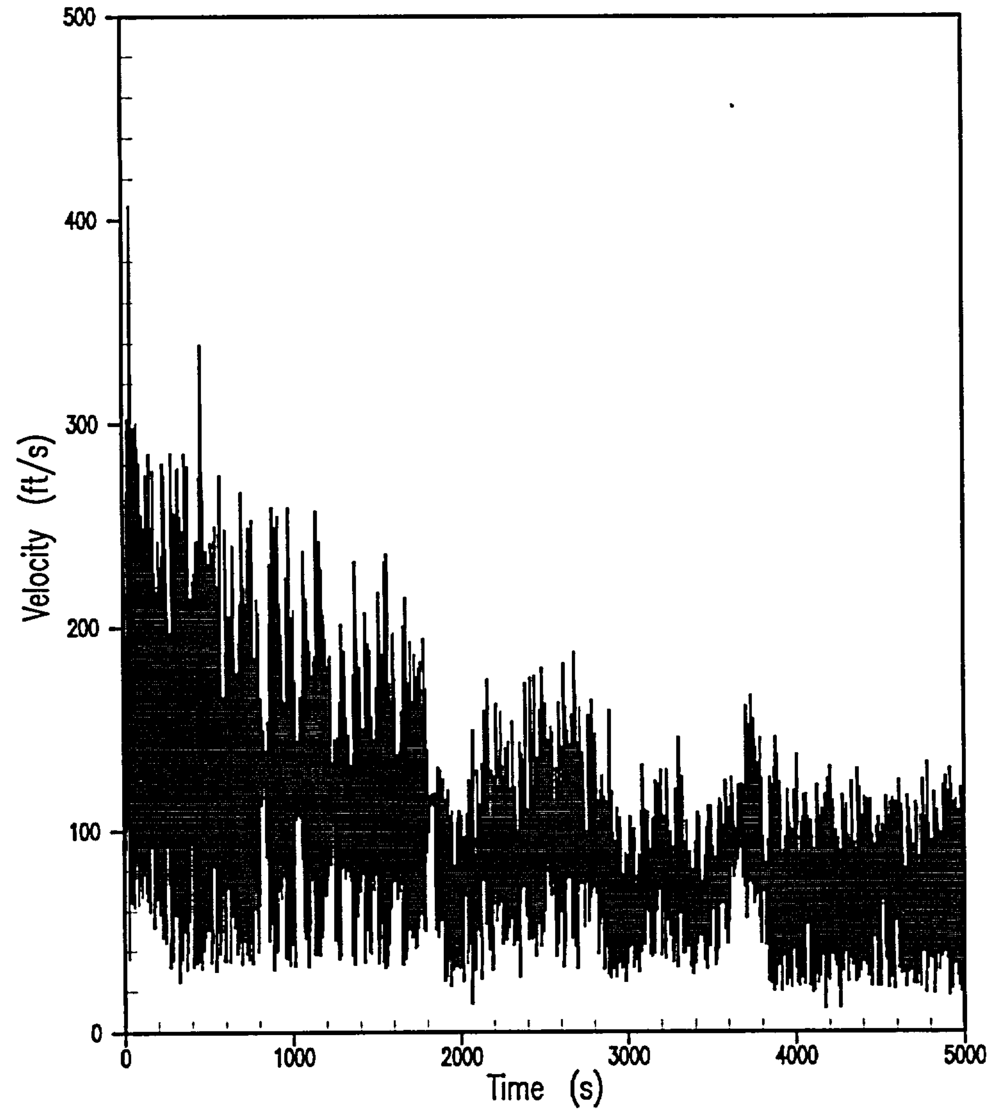


Figure 440.091-15 ADS Stage 4A Vapor Velocity at Offtake Pipe

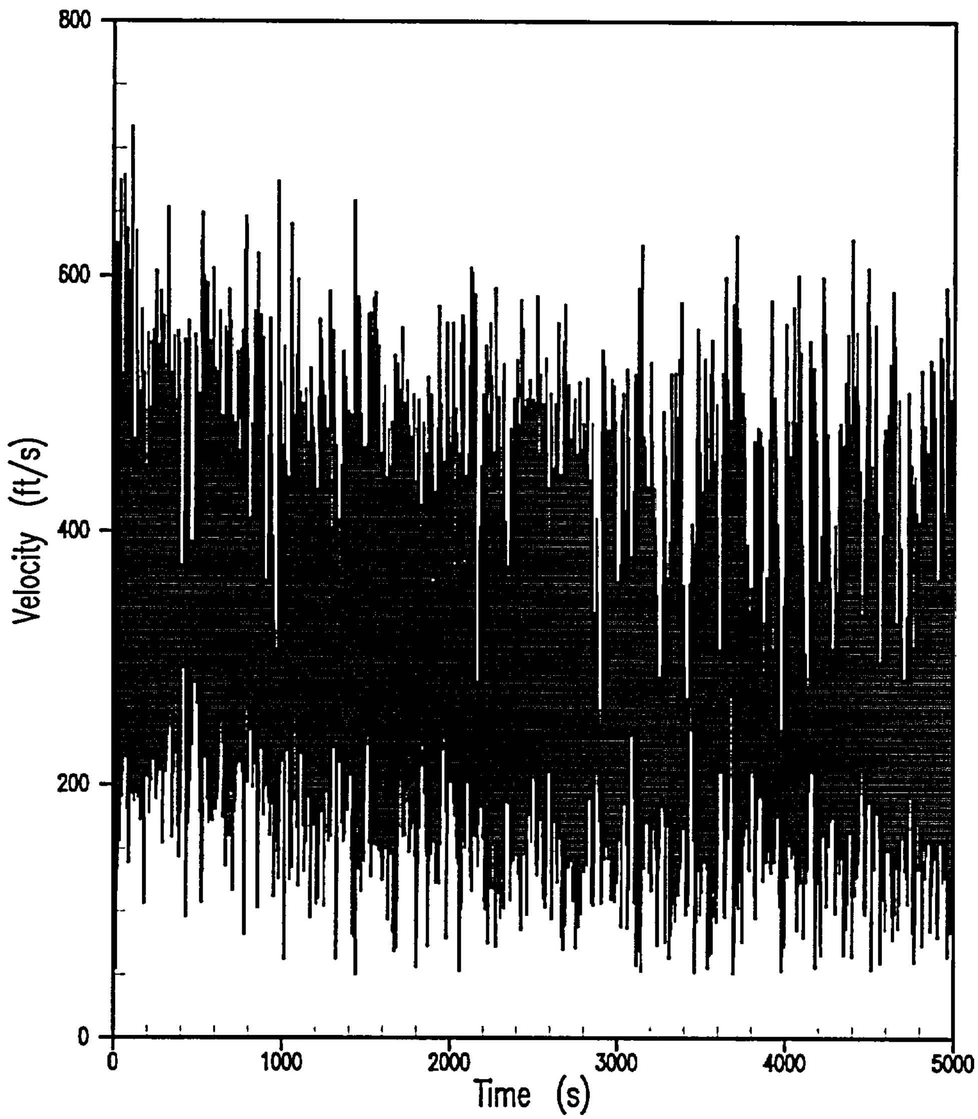


Figure 440.091-16 ADS Stage 4A Vapor Velocity at Offtake Pipe (DCD Long-term Cooling Case)

RAI Number: 440.092

Question:

In the case of the DEDVI break and wall-to-wall floodup (Section 15.6.5.4C.3), it was estimated that 28.5 days will be required to attain this condition.

How was this time estimated? How was the inleak rate derived? Would the long-term cooling be sustainable if the floodup was assumed to occur at the end of the IRWST injection?

Westinghouse Response:

The following assumptions have been included in determining the time to reach wall-to-wall floodup following a DEDVI break in the AP1000.

- The break occurs in the PXS B room. This is more limiting than a break in the RCS loop compartment or in the PXS A room because it results in lowest initial post-LOCA containment flood level.
- All volumes inside containment, below the recirculation flood level, are assumed to flood in the long term.
- Both CMTs, both accumulators, and the IRWST either inject or spill.
- The RCS is water filled water solid up to 80% of the RCS hot leg.
- The containment is pressurized to the resultant pressure following a DEDVI break and a water film exists on surfaces in containment.
- The CMTs are not assumed to refill after injection since they are located above the floodup elevation.
- The accumulators are not assumed to refill after injection. Although they are located below the floodup elevation, enough N2 will remain in the tanks to balance the flood pressure. In addition, series check valves are located in their discharge lines.

All volumes below the recirculation flood level are assumed to flood based on one or a combination of the following reasons:

- Back leakage occurs through the check valves in each room drain line. Note, this is conservative since each drain line has two check valves in series such that failure of both check valves is required to open the drain line.

- Leakage occurs through the concrete walls separating the normally flooded areas from the normally unflooded areas. Again, this is conservative.

Based on the above assumptions, an initial in-leakage rate of 9.0 gpm was assumed at the time of the DVI break. A resistance was assumed between the flooded and normally unflooded areas allowing determination of the time to reach wall to wall flooding considering the initial in-leakage rate of 9.0 gpm. The time to reach wall to wall flooding with an initial leakage rate of 9.0 gpm is about 29 days. A time of 28.5 days was used in the Chapter 15 safety analysis calculations for conservatism.

Note that at 28.5 days, the DCD long-term core cooling analysis shows significant margin. This margin would allow adequate core cooling assuming that wall-to-wall flooding occurred earlier than 28.5 days. However adequate core cooling would most likely not be demonstrated for the hypothetical case where wall-to-wall flooding was assumed immediately after the IRWST injection phase using the conservative methodology used in the DCD analyses.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.096

Question:

Throughout the discussion of long-term cooling, there are water levels indicated but no mention is made of a reference point. For example, section 15.6.5.4C.3, a level of 103.5 ft is given with no reference point. Likewise, in the Figures (from 15.6.1-1 to 15.6.5.4C-28) there are water levels but no reference points are identified, making it difficult or impossible to conclude if the core is covered in the time segment indicated.

Please correct this deficiency.

Westinghouse Response:

Figure 15.0.3-2 shows the AP1000 loop layout and key plant elevations (e.g., top of active fuel, DVI nozzle, HL and CL centerlines, etc...) relative to the bottom inside surface of the reactor vessel. Figures 15.6.5.4B-16, 30, 41, 58, 86, which provide the reactor vessel water level show level in relation to the top of the active fuel, which is indicated on each figure. Figures 15.6.5.4B-9, 21, 42, 66, 77, which provide the downcomer level show level in relation to the DVI nozzle, which is indicated on each figure.

Figure 15.6.5.4B-87 provides composite core mixture level relative to the bottom of the active fuel. This figure will be modified, as indicated below, to show the active fuel location.

The long-term cooling figures 15.6.5.4C-1, 2, 5, 8, 15, 16, 19 and 22, will be modified as indicated below, to show a reference point (e.g., active fuel location, hot leg, RV bottom inside surface).

The text in DCD Section 15.6.5.4.C.3 has been modified, as indicated below, to be consistent with the reference points provided in Figure 15.0.3-2.

Design Control Document (DCD) Revision:

From DCD Section 15.6.5.4C.3:

This subsection presents a DEDVI line break analysis with wall-to-wall flooding due to leakage between compartments, using the window mode methodology. All containment free volume beneath the level of the liquid is assumed filled in this calculation to generate the minimum water level condition during containment recirculation. The time identified for this calculation is 28.5 days into the event, and the core power is calculated accordingly. The initial conditions at the start of the window are consistent with the analysis described in subsection 15.6.5.4C.2. Containment recirculation is simulated during the time window. The calculation is then carried out over 3000 seconds, which is a time period long enough to establish a quasi-steady-state solution; after 1000 seconds, the flow dynamics are quasi-steady-state and the predicted results are independent of the assumed initial conditions.

The liquid level is simulated constant at 28'-9" above the bottom inside surface of the reactor vessel~~103.5 feet~~ (refer to Figure 15 0 3-2 for AP1000 reference plant elevations) during the time window while the liquid temperature in containment is set at the saturation condition at the identified containment pressure of 32.7 psia. The single failure of an ADS Stage 4 flow path is assumed as in the subsection 15.6.5.4C.2 case.

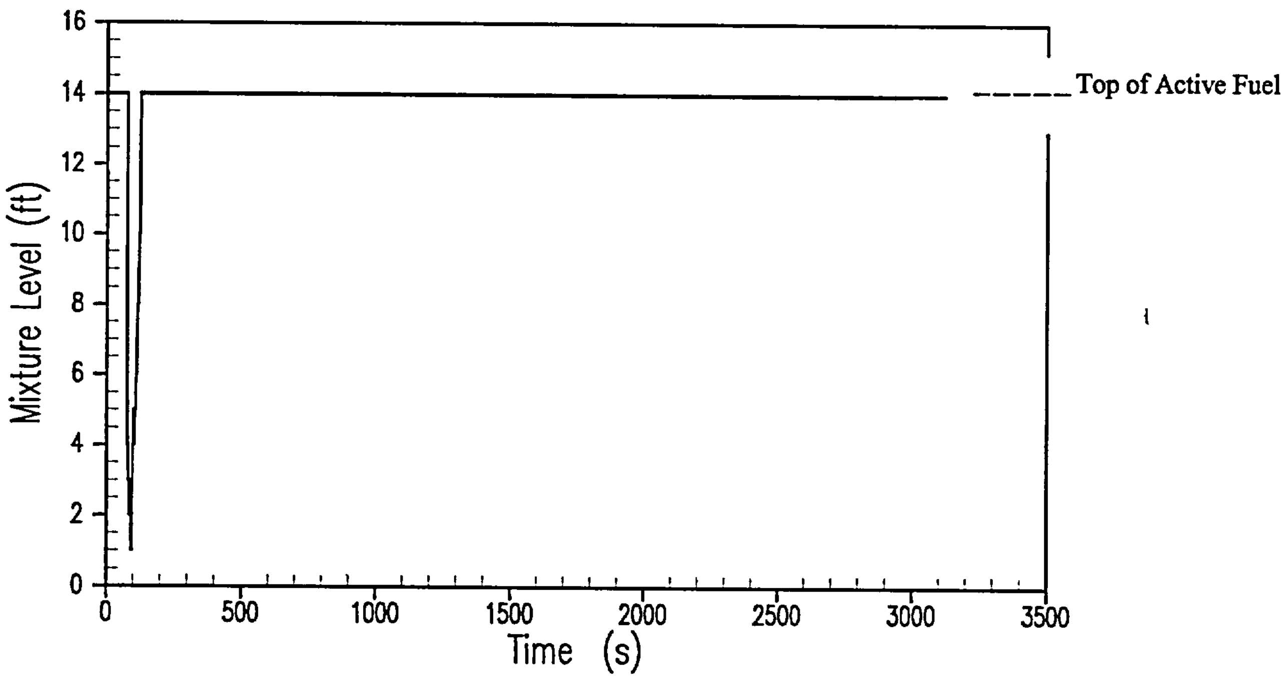


Figure 15.6.5.4B-87

10-Inch Cold Leg Break – Composite Core Mixture Level

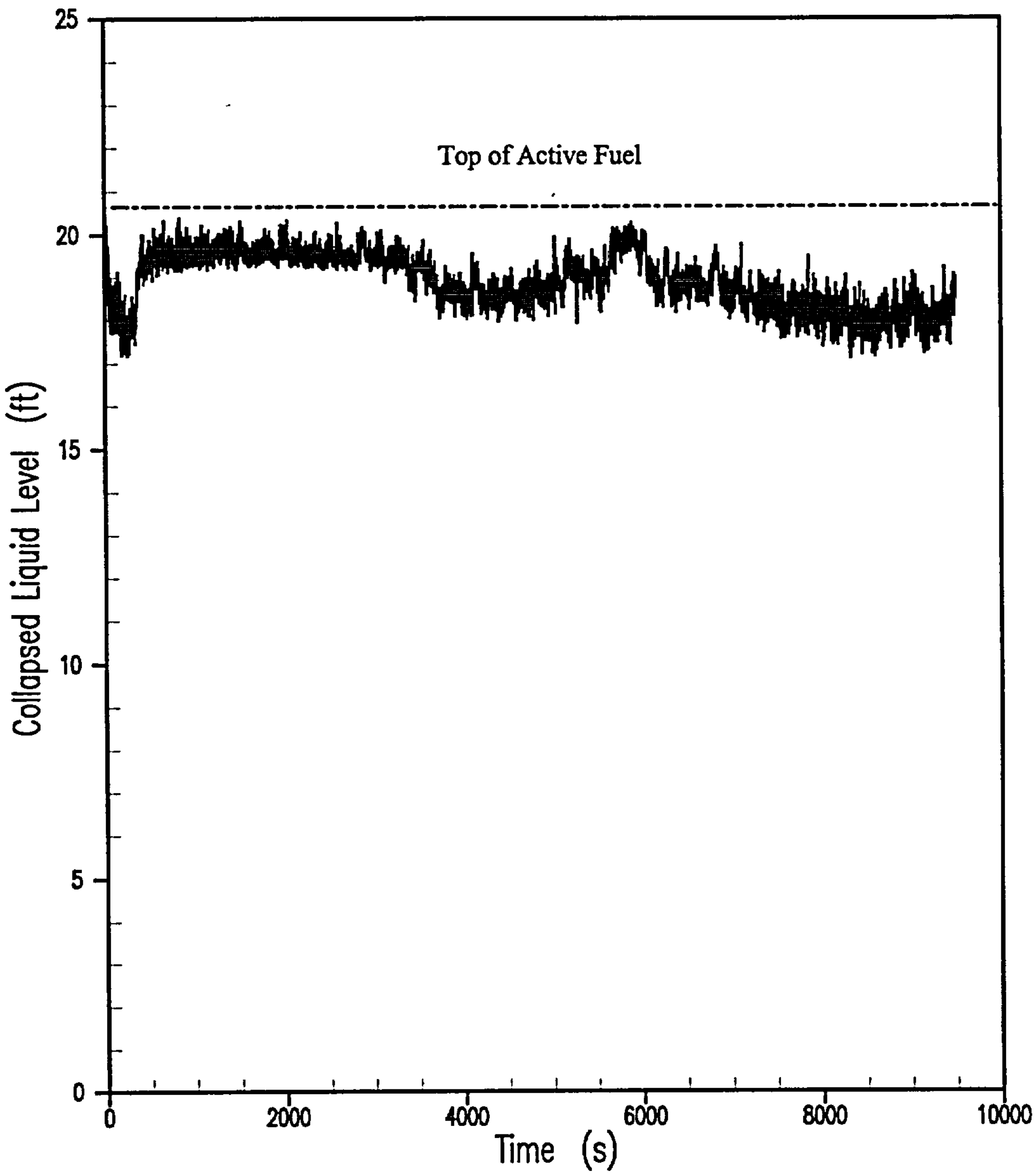


Figure 15.6.5.4C-1

Collapsed Level of Liquid in the Downcomer
(DEDVI Case)

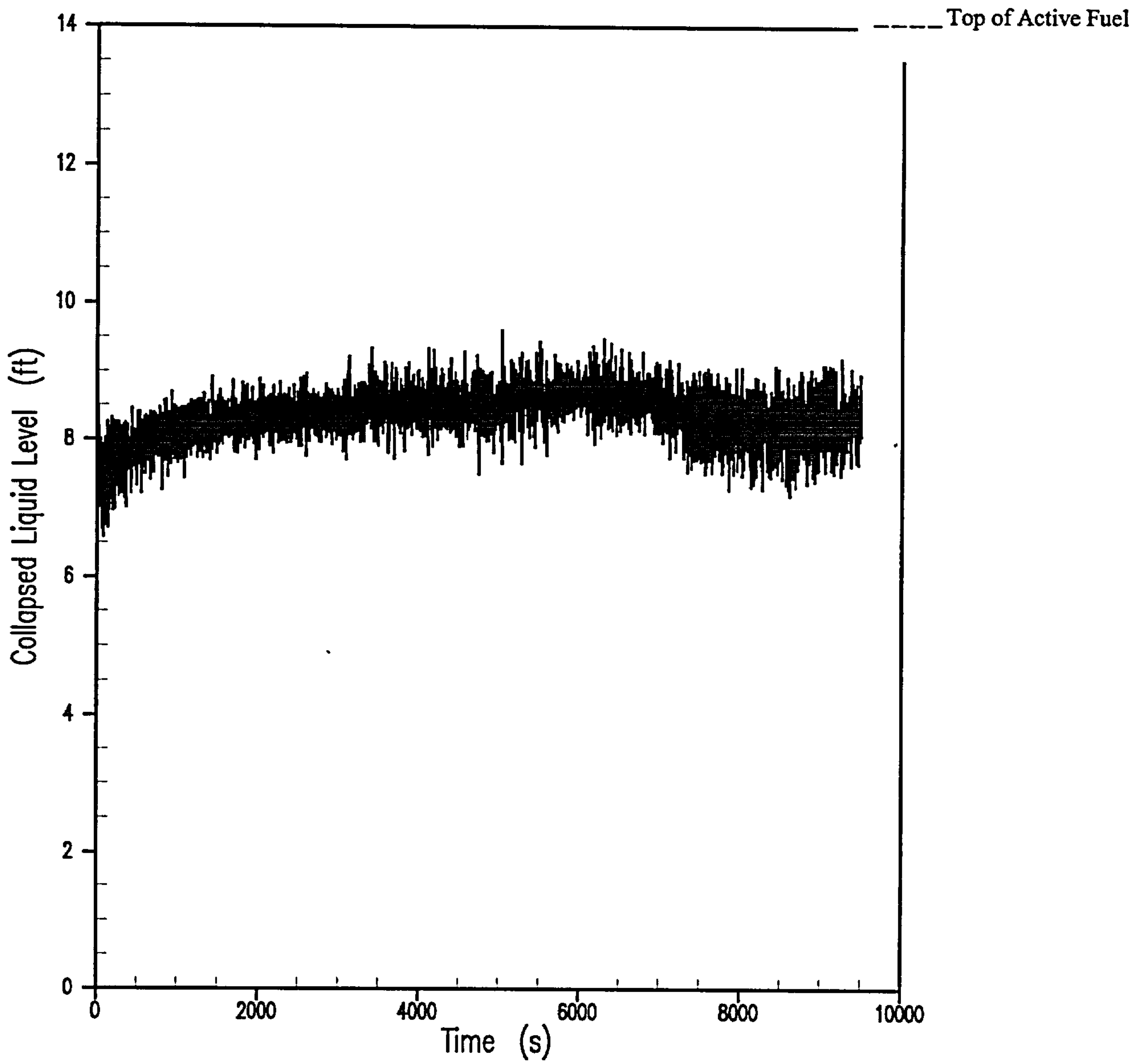


Figure 15.6.5.4C-2

Collapsed Level of Liquid over the Heated Length of the Fuel (DEDVI Case)

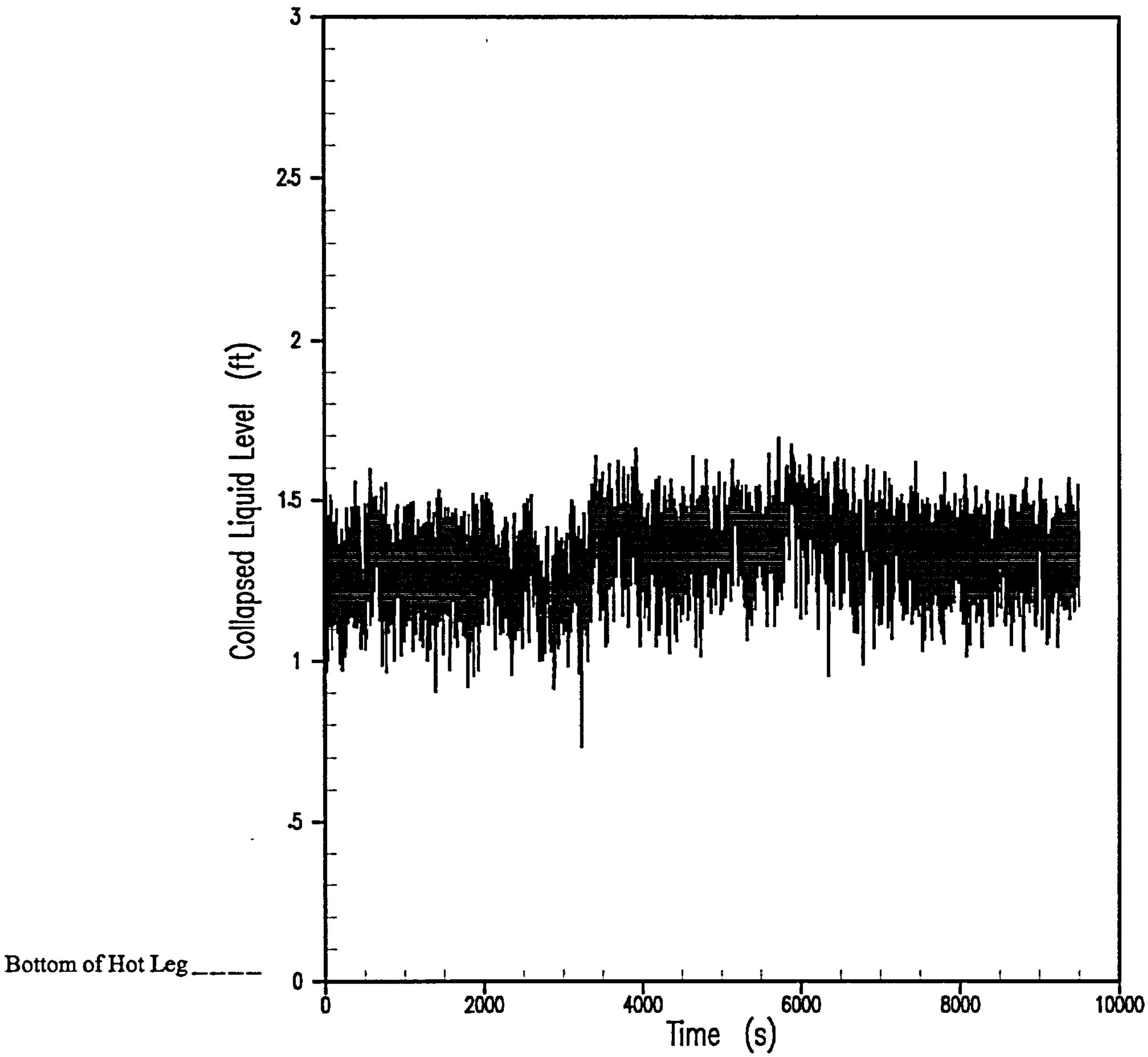


Figure 15.6.5.4C-5

Collapsed Liquid Level in the Hot Leg of Pressurizer Loop (DEDVI Case)

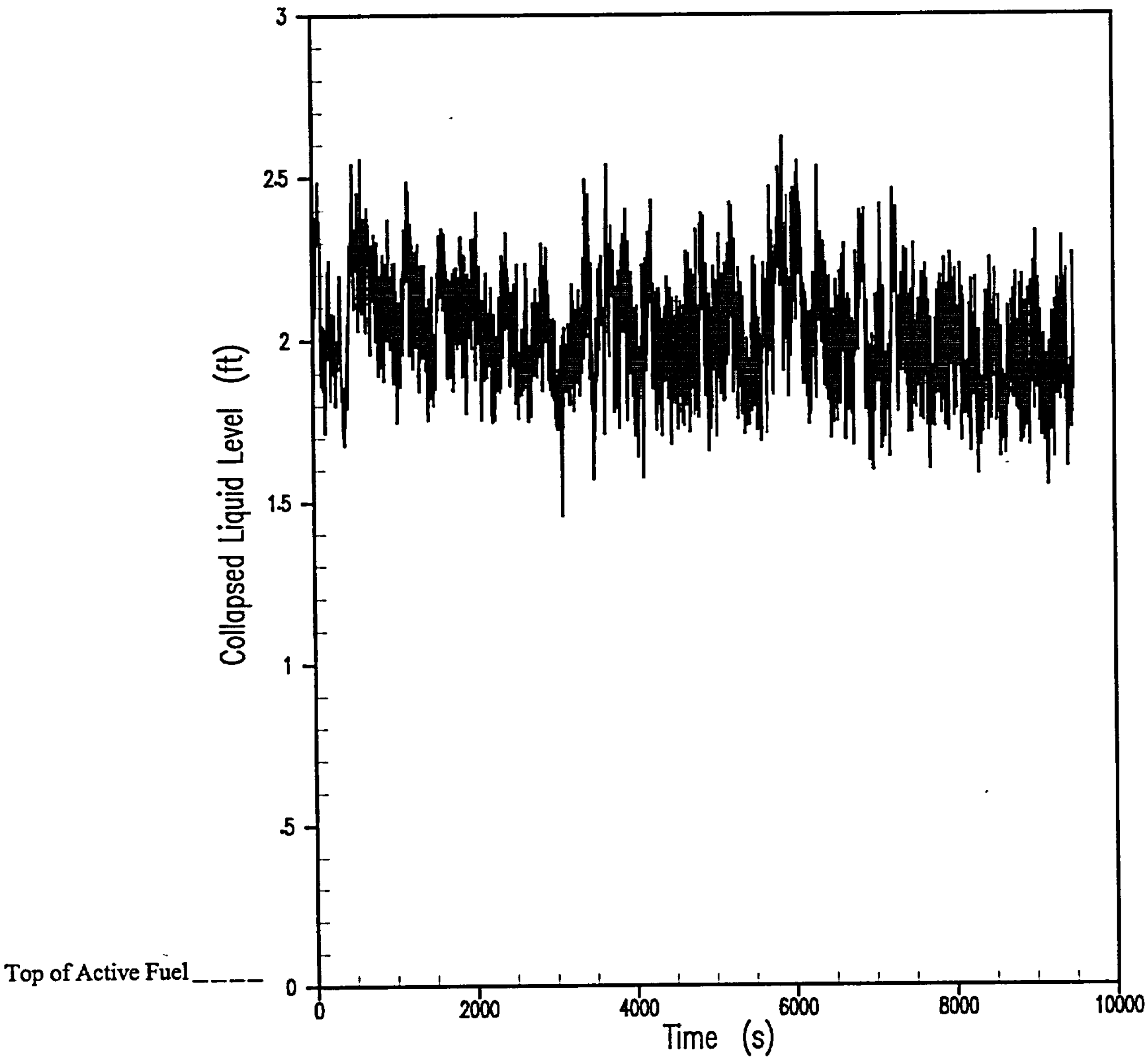


Figure 15.6.5.4C-8

Collapsed Liquid Level in the Upper Plenum
(DEDVI Case)

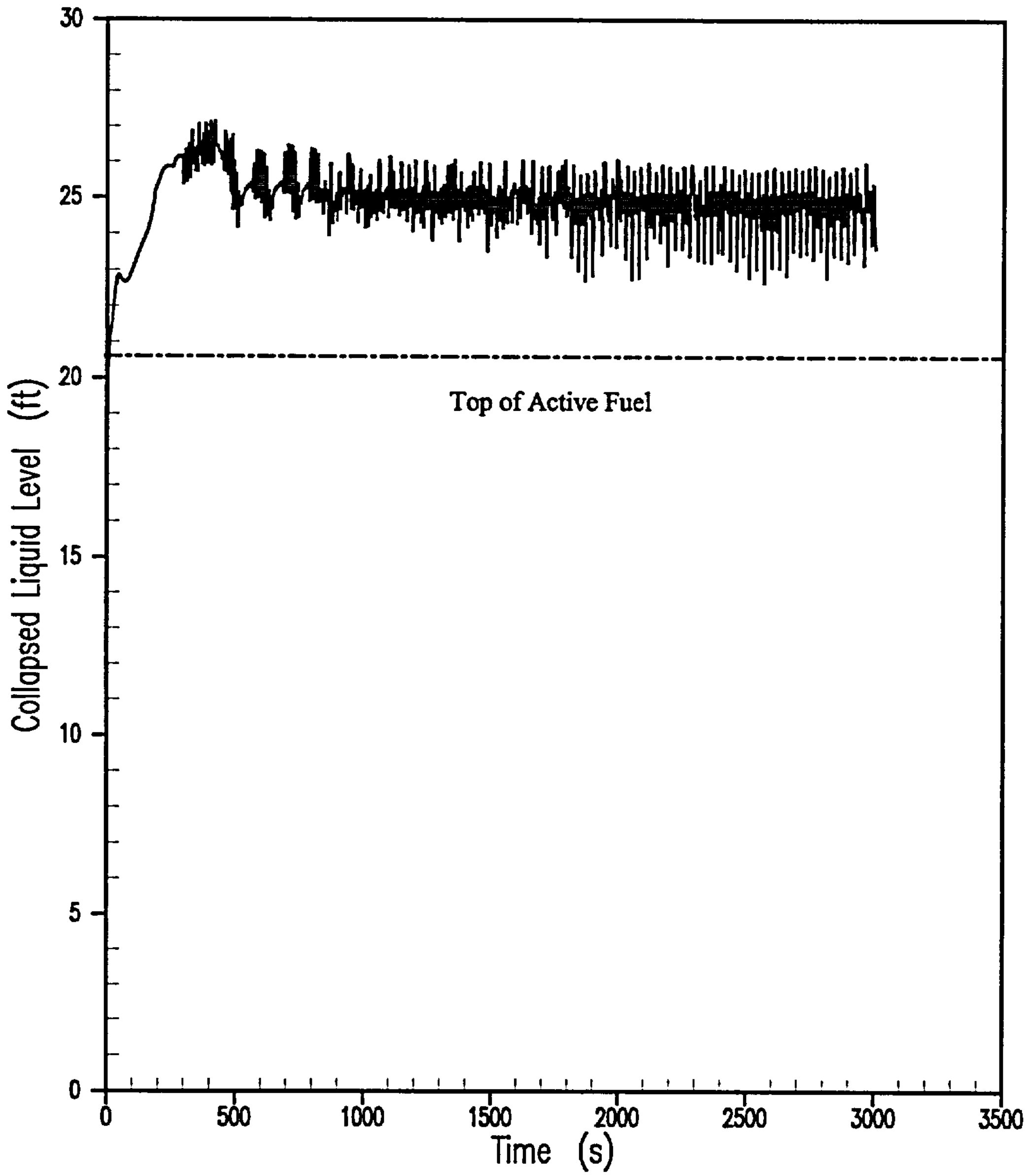


Figure 15.6.5.4C-15

Collapsed Level of Liquid in the Downcomer (Wall-to-Wall Floodup Case)

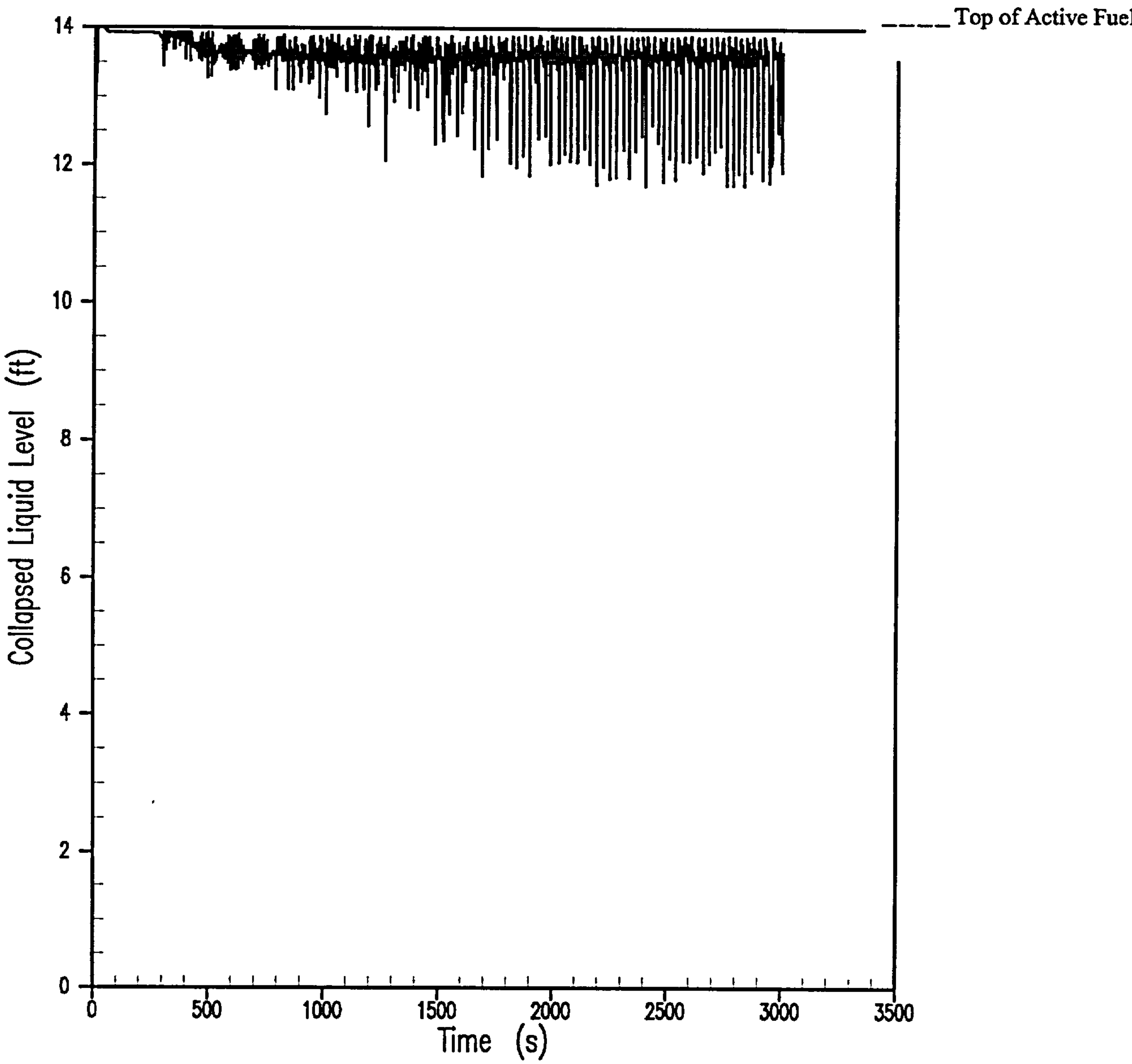


Figure 15.6.5.4C-16

Collapsed Level of Liquid Over the Heated Length of the Fuel
(Wall-to-Wall Floodup Case)

Bottom of Hot Leg

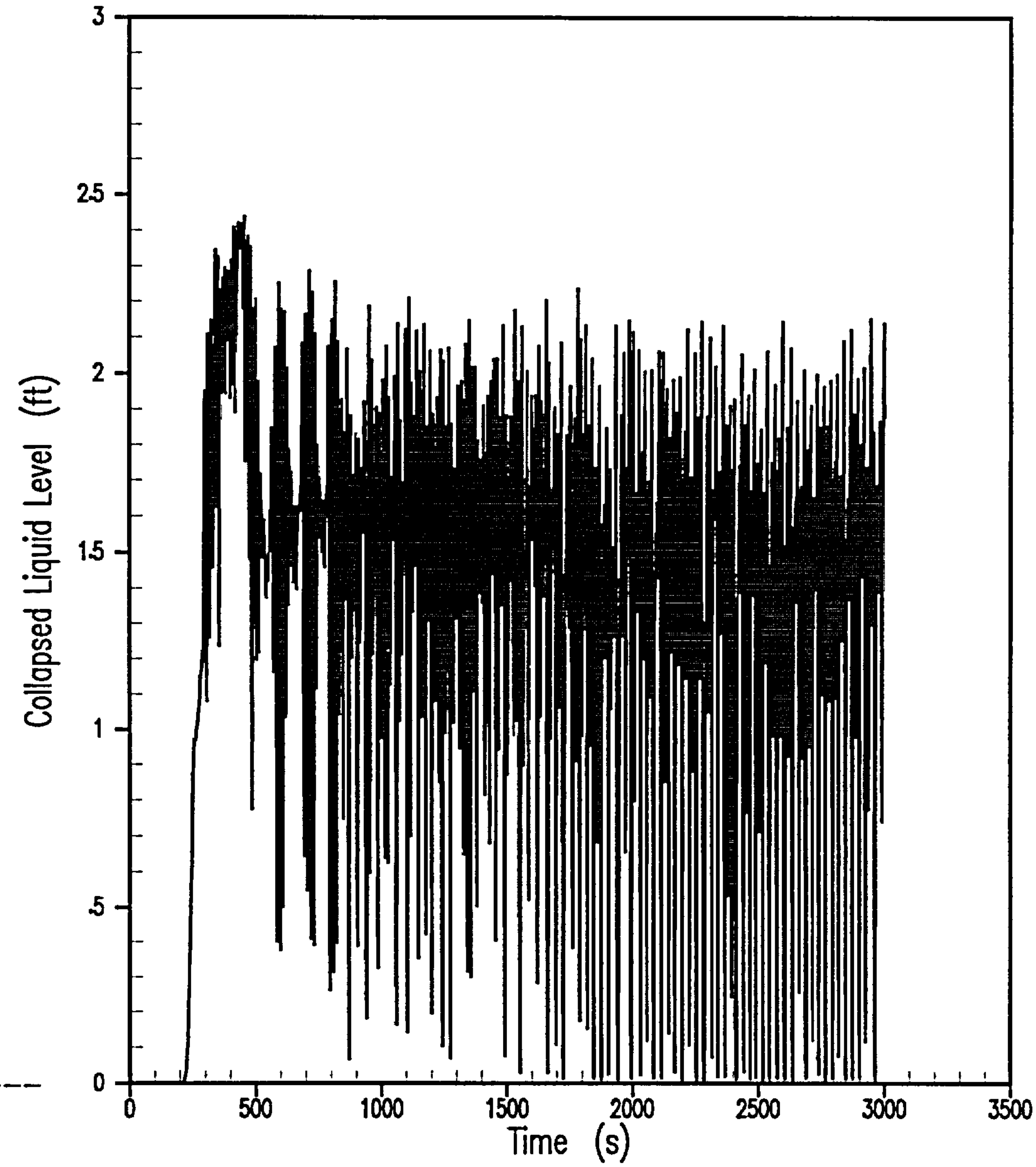


Figure 15.6.5.4C-19

Collapsed Liquid Level in the Hot Leg of Pressurizer Loop
(Wall-to-Wall Floodup Case)

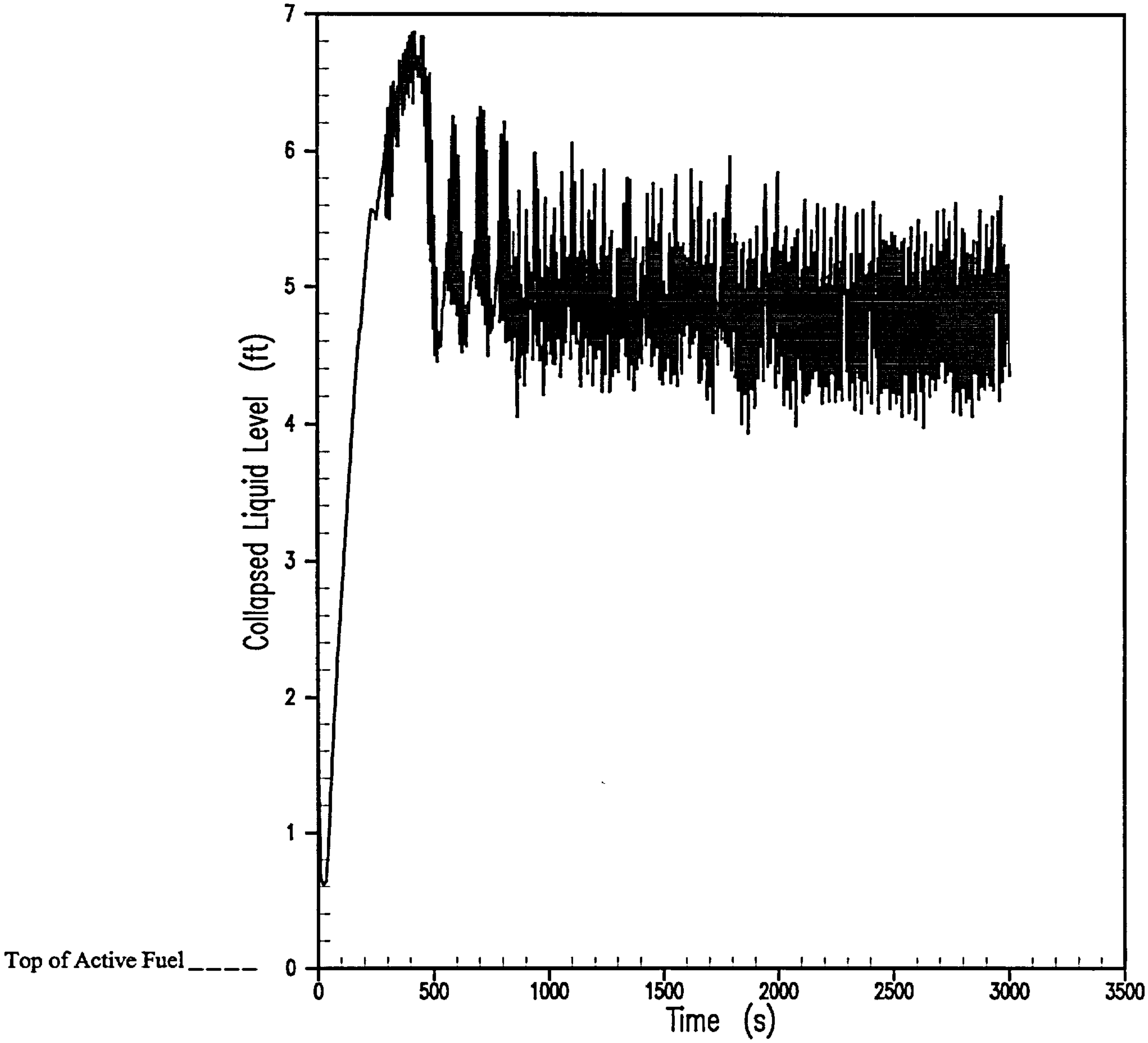


Figure 15.6.5.4C-22

Collapsed Liquid Level in the Upper Plenum
(Wall-to-Wall Floodup Case)

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.099

Question:

During the review of the Westinghouse AP600, the NRC staff raised the issue of boron dilution associated with the SBLOCA reflux condensation, the so called "Finnish Scenario." The staff requested Westinghouse to address the issue in a letter to Westinghouse entitled "AP600 Boron Dilution Transient Analyses, " dated September 2, 1996 (AP600 request for additional information (RAI) No. 440.120). The staff is again requesting Westinghouse to address the same issue as it applies to the AP1000. Westinghouse should also address subsequent concerns that were raised by the staff as a consequence of the incomplete response to the September 2, 1996, letter. The subsequent letters referred to here were dated May 14, 1997, "Revised Response to RAI 440.120 for Rapid Boron Dilution Scenarios"; October 1, 1997, "Response to Request for Additional Information on Mixing in Downcomer and Lower Plenum" (RAI 440.724); and January 16, 1998," AP600 Response to FSER [final safety evaluation report] Open Items."

Westinghouse Response:

As was the case for the AP600, the Finnish Center scenario is not significant to the AP1000 reactor design because the steam generators are not relied on to cool the RCS during a LOCA event. Consequently, the steam generators should not generate any significant amount of boron-free condensate via reflux condensation over an extended period of time during a LOCA event. In the AP1000 design, the steam generator functions as a "heat source" as the RCS depressurizes, rather than a "heat sink" as it does in conventional PWR designs. Therefore, the differential temperature across the primary and secondary side of the generators is such that steam from the reactor will not condense on the tubes.

For the AP600 and AP1000, the PRHR heat exchanger becomes a dominant RCS heat sink following the generation of an "S" signal during postulated SBLOCA events. During the licensing review of the AP600, it was postulated that the PRHR heat exchanger could become a potential source for generating a volume of unborated coolant during a small break LOCA. The staff was concerned that such a scenario could be postulated, and that a reactivity excursion could occur as a result of a restart of a reactor coolant pump after an unborated water slug had collected in the reactor coolant loop. This additional scenario was also shown not to be a safety concern for the AP600.

This scenario is also not a concern for the AP1000 for the same reasons as was given for the AP600. Specifically, the AP1000 reactor coolant loop piping does not contain a loop seal, and thus there is not a collection point for a large slug of unborated condensate to collect in the reactor coolant loop piping. During the small break LOCA, once subcooling in the RCS is lost, steam will enter the PRHR heat exchanger, and will condense on the inside of the PRHR heat exchanger tubes. Steam condensed in the PRHR is delivered to the Loop 1 steam generator outlet plenum. However, like the AP600, the AP1000 loop layout does not contain an RCP crossover leg, and the PRHR condensate will drain continuously from the steam generator channel head into the Loop 1 cold legs, and flow into the reactor vessel. A deborated water slug cannot accumulate in the RCS loop cold legs. During the SBLOCA transient, the water in the cold legs enter the downcomer, where it mixes with the highly borated safety injection flow from either the accumulators, the core makeup tanks, or both. As was the case for the AP600, the relatively low flow rate of fluid from the downcomer into the core during the post RCP-trip natural circulation phase of the AP1000 SBLOCA events enables mixing to occur in the downcomer, and lower plenum. No unmixed slugs of unborated water from the PRHR can form in the downcomer and enter the core during this scenario.

Bounding calculations performed for the AP600, as reported in the Westinghouse response to NRC AP600 RAI 440.720 quantitatively demonstrated that it was not credible to postulate that the boron concentration in the downcomer and lower plenum would be diluted to a critical boron concentration for postulated LOCA. The conclusions from these studies that boron dilution from the operation of the PRHR heat exchanger would not occur was based on demonstration that the PRHR condensate would adequately mix with the water in the downcomer and lower plenum, so that a critical boron concentration would not be reached.

These conclusions are also applicable to the AP1000, even when considering pertinent design differences between the AP600 and the AP1000. The AP1000 uses a lower boron core design. The BOL boron concentration for the AP1000 is approximately 1000 ppm, as compared to approximately 1400 ppm (BOL, equilibrium core cycle, equilibrium xenon) for the AP600. When compared to the AP600 studies, the lower AP1000 core boron concentration significantly reduces the potential of the PRHR to dilute the coolant in the reactor vessel to the point of criticality. Although the AP1000 PRHR flow rate is somewhat larger than for the AP600, the CMT flow rate is also larger, and the reactor vessel downcomer and lower plenum volume is also larger. Taking these differences into account, the AP1000 design changes do not invalidate the conclusions of the earlier AP600 studies, and that post-LOCA boron dilution is not a concern provided that there is good mixing in the vessel.

As was the case for the AP600, mixing in the reactor vessel downcomer and lower plenum are counteract boron dilution in the core due to PRHR operation. For the AP600, Westinghouse identified further technical information to justify that significant mixing occurs in the AP600 downcomer during postulated small break LOCA boron dilution scenarios. Specifically, the Reference 440.099-1 study of the mixing of high pressure safety injection (HPI) water with primary coolant in a simulated PWR downcomer was shown to be relevant to the possible AP600 scenarios. The reference 1 study is also applicable to the AP1000, as discussed below.

Test #106 in Reference 440.099-1 considers a geometry which is representive of the PRHR condensate delivery geometry into the AP1000 downcomer, namely equal flow rates of liquid entering the downcomer through two cold legs which are 90 degrees apart at the connection into the reactor vessel. The downcomer in the Reference 440.748F-1 Loviisa test facility is shorter in length (approximately 10 ft) than the AP1000 dimension (approximately 20 ft from the cold leg bottom to the bottom of the downcomer). The test facility therefore provides less than one-half of the mixing length available in the AP1000 downcomer. The fluid velocity in the test facility cold legs is approximately 0.45 ft/second for the simulated HPI flow injection in Test #106, as indicated by the "C" series of figures in Reference 440.099-1. This is similar to the velocity of the PRHR condensate in the cold legs for small-break LOCA scenarios. Therefore, the parameters of Test #106 are such that the observed results provide meaningful insights into the mixing that occurs in the AP1000 downcomer during the small break LOCA boron dilution scenarios. The results of Test #106 illustrate that the injected plume thoroughly mixes with the resident downcomer liquid during the 10 ft. fall to the bottom elevation.

Further support for AP1000 downcomer mixing is provided by the Test #I 13 results of Reference 440.099-1. Test #113 was run at a simulated HPI injection rate which is 3.6 times greater than that of Test #I06 with a 60 degree angle between the two cold leg injection connections, as depicted in the "D" series of photographs in Reference 440.748F-1. Test #113 results show mixing behavior in the downcomer which closely resembles that of Test #106. Test #113 indicates that the sensitivity of downcomer mixing to initial plume velocity is minor. These two tests from Reference 440.099-I provide compelling evidence that the dilute boron stream in the AP1000 PRHR condensate delivery scenarios is well mixed in the downcomer and that no unmixed slugs enter the lower plenum or core.

The Reference 440.099-1 test results provide additional independent technical justification that the degree of mixing which occurs in the AP1000 downcomer during the PRHR condensate return scenarios is adequate to disperse a plume of dilute boron liquid. The test results support the conclusion that recriticality of the core is not of concern for small break LOCA scenarios.

References:

440.099-1 NUREG/IA-0004, "Thermal Mixing Tests in a Semiannular Downcomer with Interacting Flows from Cold Legs," USNRC. October 1986.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

RAI Number: 440.119

Question:

It indicates on pages 19E-34 and-35 that Reference 10 ("AP600 Shutdown Evaluation Report) of Apendix19E documents analyses of LOCA events and loss of RNR events at lower modes for AP600. It also indicates that Reference 10 for AP600 is applicable to AP1000 because (1) accident analyses presented in Chapter 15 demonstrated that the AP1000 plant response to accidents is similar to the AP600 plant response, and (2) availability of the passive core cooling system components in lower modes is the same for both the AP600 and AP1000.

Discuss a comparison of applicable Chapter 15 analyses to demonstrate that the AP1000 plant response to accidents is similar to the AP600 plant response. In lower modes, the AP1000 plant response to accidents may be different from the AP600 plant response. Explain why the use of Chapter 15 accident analyses (which are performed for Modes 1 and 2 conditions) is acceptable for justifying the applicability of the cited reference to the AP1000 plant at lower modes.

Westinghouse Response:

DCD Appendix 19E.4 provides the assessment of the Chapter 15 accident analyses for shutdown modes for the AP1000. This RAI is related to a discussion in section 19.E.4.8 Loss-of-Coolant Accident Events in Shutdown Modes. Loss of coolant accident (LOCA) analysis results presented in Chapter 15 historically are initiated at full power conditions (Mode 1), when the operating pressure and temperatures are nearest to the design conditions of the reactor coolant system. The LOCA analysis results performed at full power bound those LOCA events initiated in Modes 1, 2 and 3, when the RCS pressure and temperature are elevated. At lower modes, (4, 5 and 6) the RCS pressure and temperatures are reduced, and the margin to the reactor coolant system design pressure and temperature are significantly greater. Therefore, the probability of a pipe break, which is very low even in Mode 1, 2 and 3, is significantly reduced at lower RCS pressure and temperature conditions in Modes 4 and below, and therefore LOCA are not postulated to occur in these lower modes as a Design Basis Accident.

As discussed in the DCD, for the AP600, additional accident analyses were presented in the AP600 Shutdown Evaluation Report (DCD Appendix 19E Reference 10). Since the AP600 relies on passive safety systems, the NRC requested these additional analysis be performed to verify that operation of the passive safety systems would be able to provide adequate protection of the plant during shutdown modes. The results of these analyses confirmed that the passive safety systems are adequate to protect the plant during shutdown modes, and confirmed that the Chapter 15 LOCA analyses initiated from full power conditions bound those initiated in lower modes.

The AP1000 passive safety systems provide a similar level of protection as the AP600 passive systems, as demonstrated by the Chapter 15 accident analyses for at-power events. The availability of the AP1000 passive safety systems in shutdown modes is the same as AP600, and the AP1000 passive safety systems provide a similar level of protection for events that occur at shutdown as provided for AP600. To further demonstrate the robustness of the AP1000 passive safety systems to mitigate the consequences of a LOCA during shutdown modes, a bounding AP1000 analysis of a large-break LOCA initiated in Mode 3 was performed. This analysis is performed assuming the accumulators have been isolated, consistent with expected shutdown operating procedures and timelines. The analysis is performed with the same WCOBRA-TRAC model as used to perform the Chapter 15 DCE large-break LOCA analyses, and is consistent with the shutdown large LOCA analysis performed for AP600. Results of the analysis demonstrate that the passive safety systems provide adequate protection from a LOCA during Mode 3. Attachment 1 provides a proposed markup of DCD Appendix 19E that includes a description of the results of this analysis. This markup will be incorporated in the next revision of the DCD.

Although a LOCA is not postulated to occur in Modes 4 and lower, the AP600 DCD Appendix 19E did provide analysis results for a loss of the normal residual heat removal system (RNS) in mode 4. Two scenarios were evaluated, including a loss of RNS cooling with the RCS intact, and a loss of RNS cooling with the RCS open. The events are analyzed using the same NOTRUMP model as used to perform the Chapter 15 DCD small-break LOCA analyses, and is similar to the shutdown loss of RNS analysis performed for the AP600. Results of the analyses demonstrate that the passive safety systems provide adequate protection from a loss of RNS cooling in shutdown modes. Attachment 2 provides a proposed markup of DCD Appendix 19E that includes a description of the results of this analysis. This markup will be incorporated in the next revision of the DCD.

Design Control Document (DCD) Revision:

See attachment 1 and 2.

PRA Revision:

None

ATTACHMENT 1

19E.4.8 Loss-of-Coolant Accident Events in Shutdown Modes

The AP1000 DCD presents a spectrum of break sizes of the postulated LOCAs at the full-power operating condition. Other things being equal, the reduction in power to decay heat levels associated with shutdown mode operations will make all LOCA events less limiting than those analyzed at full power and reported in DCD subsection 15.6.5. However, as the plant proceeds through shutdown modes of operation, various PXS equipment are removed from service at identified points in time. One particularly significant action in the course of taking the AP1000 to cold shutdown in the elimination of PXS equipment is the isolation of the accumulators at 1000 psig. This procedural action reduces the capability of the PXS to mitigate LOCAs. For assessing the adequacy of the remaining PXS components to mitigate postulated LOCA events, the limiting double-ended cold leg guillotine (DECLG) break that is analyzed in DCD Chapter 15 is analyzed assuming it occurs immediately after the isolation of the accumulators. The analysis is performed using the AP1000 Large-Break LOCA WCOBRA-TRAC model used for the at-power Design Basis Accident analysis. Only safety-related systems are modeled in the analysis of this event.

Depressurization of the AP1000 primary system during shutdown operations will be performed with the same care taken to avoid the flashing of liquid in the core and upper head that is taken by current operating plants. Prudent plant operation dictates that subcooling margin be retained as pressure is reduced. Therefore, since the AP1000 shutdown operations will be conducted in a prudent, controlled manner, it is anticipated that the RCS temperature will be near the 420°F lower limit of Mode 3 when the accumulators are isolated.

For these analyses, the plant was assumed to be shut down in Mode 3 at steady-state conditions of 1000 psig and 425°F with the accumulators isolated. An initial pressure of 1000 psig is assumed because this is the highest pressure with the accumulators isolated and a hot leg temperature of 425°F is the highest expected temperature when the pressure is 1000 psig. The decay heat level is determined at 2.78 hours after reactor shutdown based on the time estimate to cool down the plant from full-power operation to 425°F at a cooldown rate of 50°F per hour. The low pressurizer pressure safeguards signal is also assumed to be disabled because the initial pressure is below the setpoint.

19E.4.8.1 Double-ended Cold Leg Guillotine

The DECLG break is analyzed using the WCOBRA/TRAC computer code and the AP1000-specific noding presented in WCAP-14171, Revision 1 (Reference 14). Table 19E.4.8-1 summarizes the results.

This case models the double-ended rupture of one of the two cold legs in the RCS loop without the PRHR HX at a pressure of 1000 psig just after the accumulators are isolated. Only the core makeup tanks (CMTs) and IRWST are available to deliver PXS flow. This break evaluates the ability of the plant to withstand a large LOCA during shutdown with its conditions and equipment availability. The nominal discharge coefficient (1.0) is modeled. The analysis is performed with 10 CFR 50, Appendix K (Reference 16), required decay heat, and Technical Specification/Core Operating Limits Report maximum peaking factors.

The break is assumed to open instantaneously at 0.0 seconds. The subcooled discharge from the broken cold leg (Figure 19E.4.8-1) causes a rapid RCS depressurization (Figure 19E.4.8-2). In Figure 19E.4.8-1, the positive flow direction is the normal operation direction. The reversal of flow entering the vessel to flow out of the break is shown. Due to high-1 containment pressure, an "S" signal is generated at 2.2 seconds, and following a 2.0-second delay, the isolation valves on the CMT and PRHR HX outlet lines begin to open. The RCPs trip at 8.2 seconds. The nominal discharge coefficient of 1.0 identified in full-power LOCA analyses is assumed.

Within a few seconds, the collapsed liquid level drops within the upper plenum due to voiding (Figure 19E.4.8-3). The downcomer collapsed liquid level (Figure 19E.4.8-4) quickly falls below the elevation of the cold legs; the elevation of the top of the core is 20.47 feet. Because the RCS fluid enthalpy is lower than the full-power value, the RCS depressurization rate is decreased from the Tier 2 Information cases and more of the initial inventory is retained in the reactor vessel.

CMT injection from both tanks replenishes the RCS mass inventory. Injection from the CMTs as the RCS pressure declines terminates the peak cladding temperature (PCT) transient because the stable injection of water from the CMTs exceeds the break flow. The core collapsed level refills are as shown in Figure 19E.4.8-5. The pressure is low enough that the IRWST injection will begin once the CMTs drain to the low-2 level actuation setpoint. The maximum PCT value is approximately 1420F for this bounding break size as shown in Figure 19E.4.8-6, and all the 10 CFR 50.46 (Reference 23) acceptance criteria are met.

Table 19E.4.8-1
Double-ended Cold Leg Guillotine Break
Sequence of Events

Event	Time (seconds)
Break Open	0.0
"S" Signal Receipt	4.2
RCPs Start to Coast Down	8.2
CMT Draindown Begins	5
Lower Plenum Refilled	200

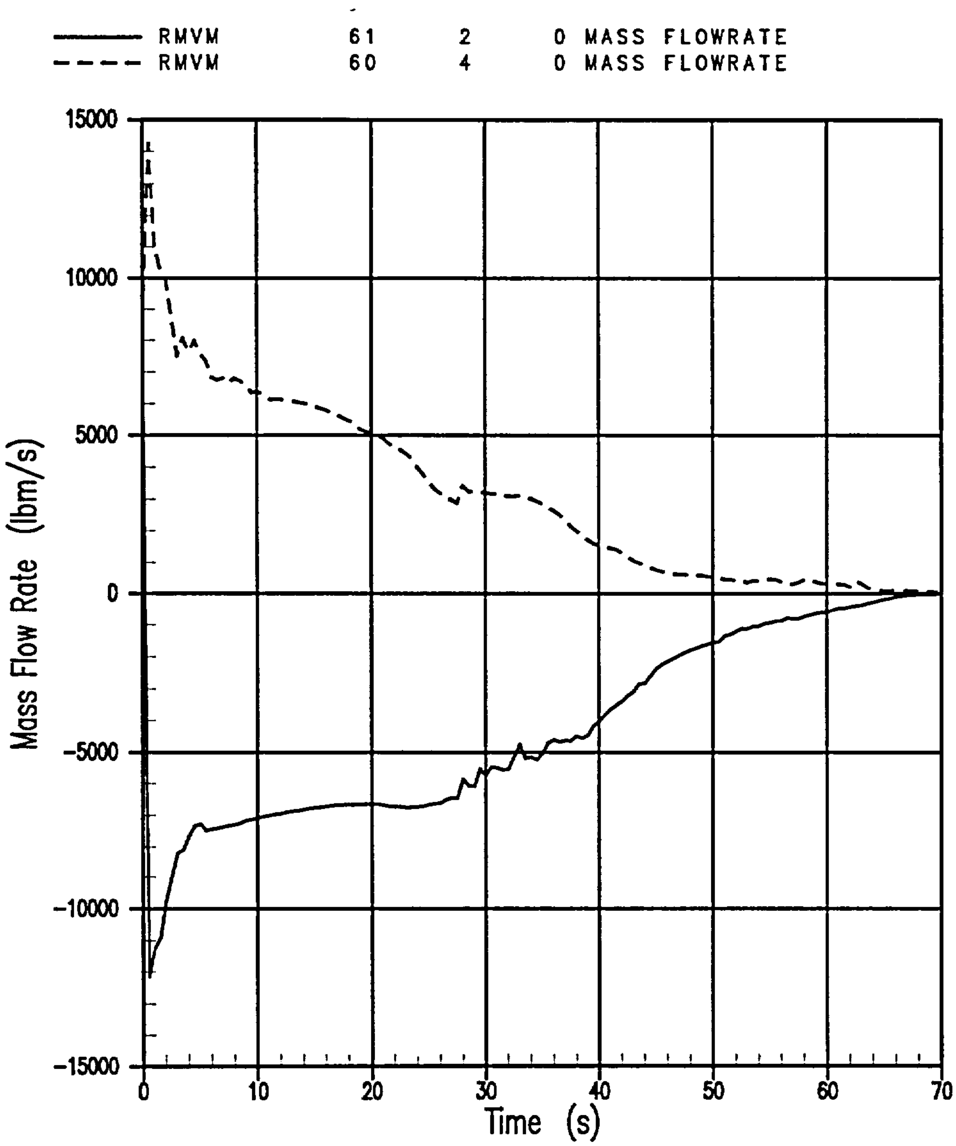


Figure 19E.4.8-1 Mode 3 DECLG Break, Break Flow Rates, Vessel and RCP sides

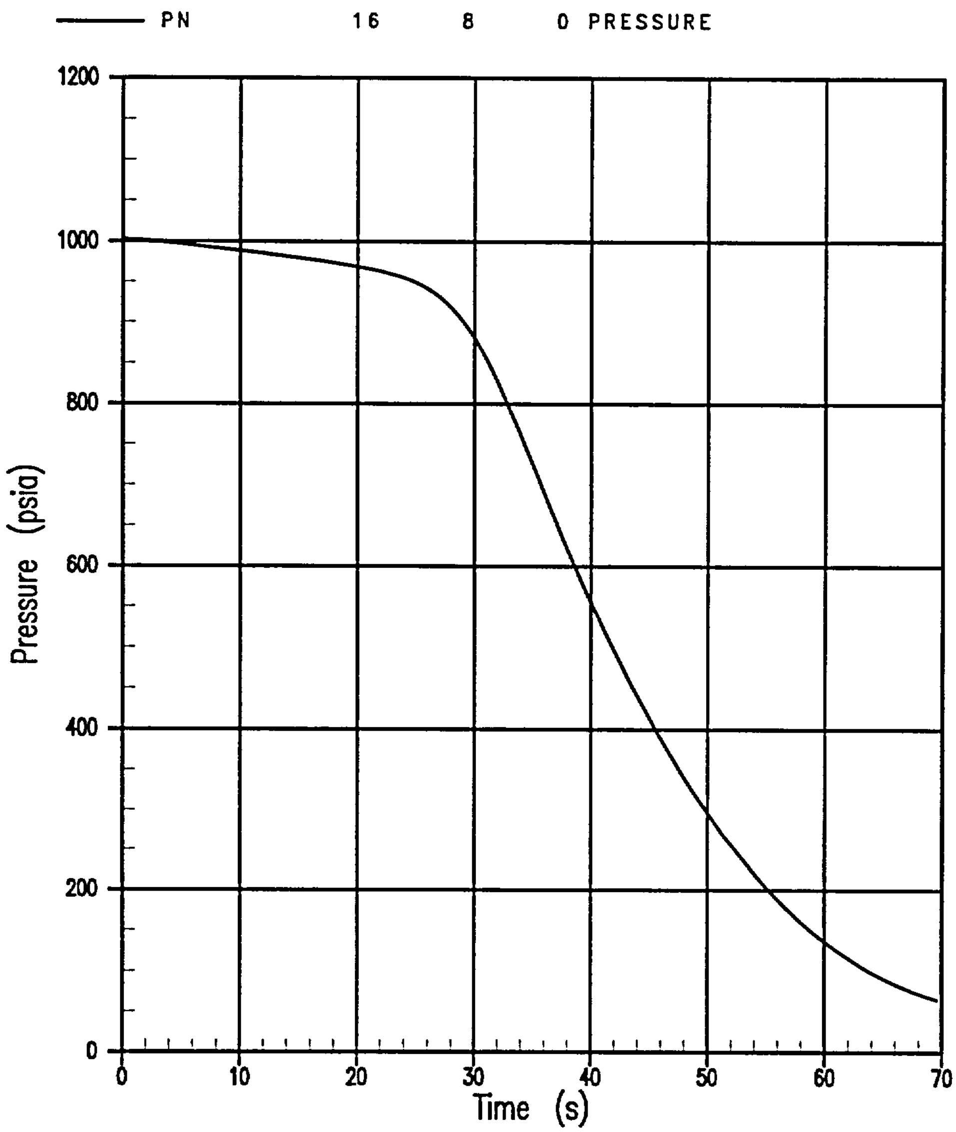


Figure 19E.4.8-2 Mode 3 DECLG Break, Pressurizer Pressure

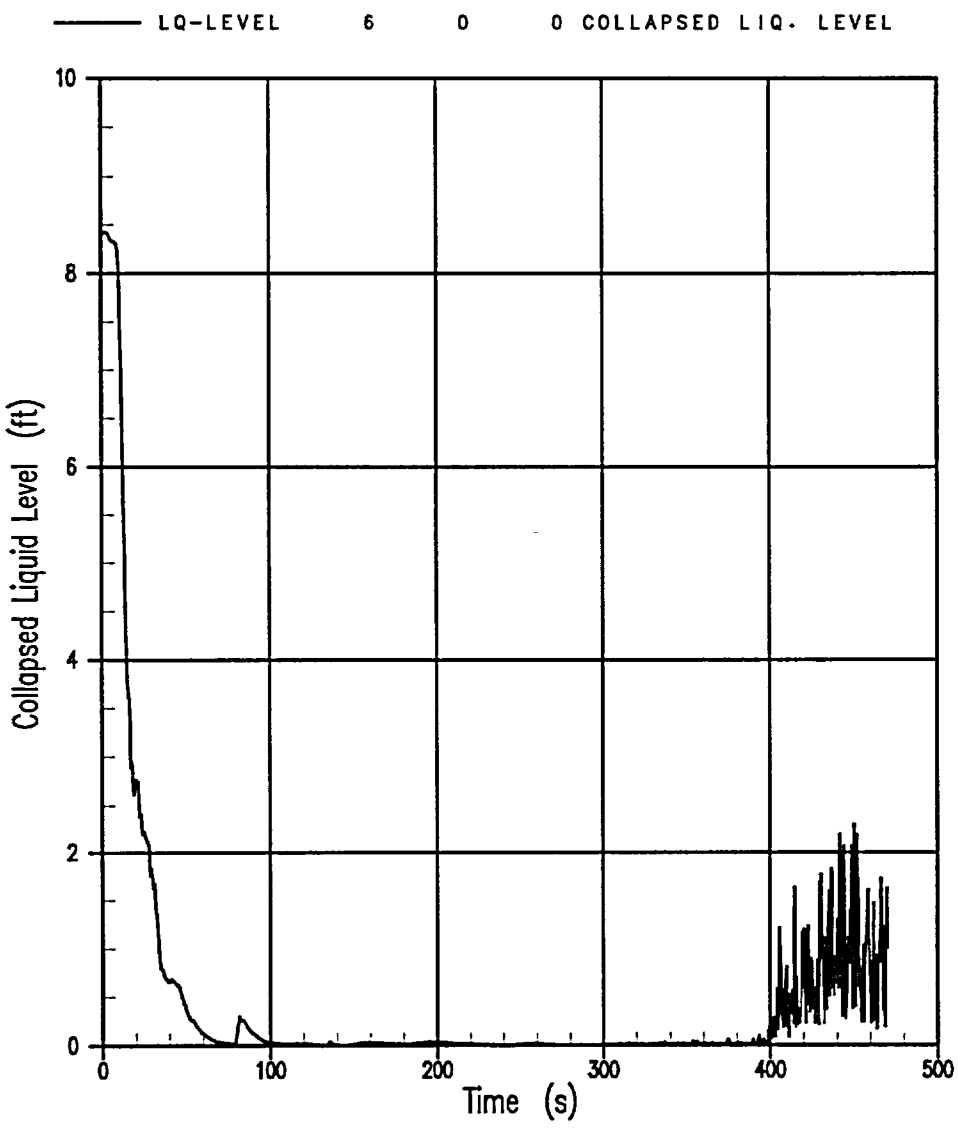


Figure 19E.4.8-3 Mode 3 DECLG Break, Upper Plenum Collapsed Liquid Level

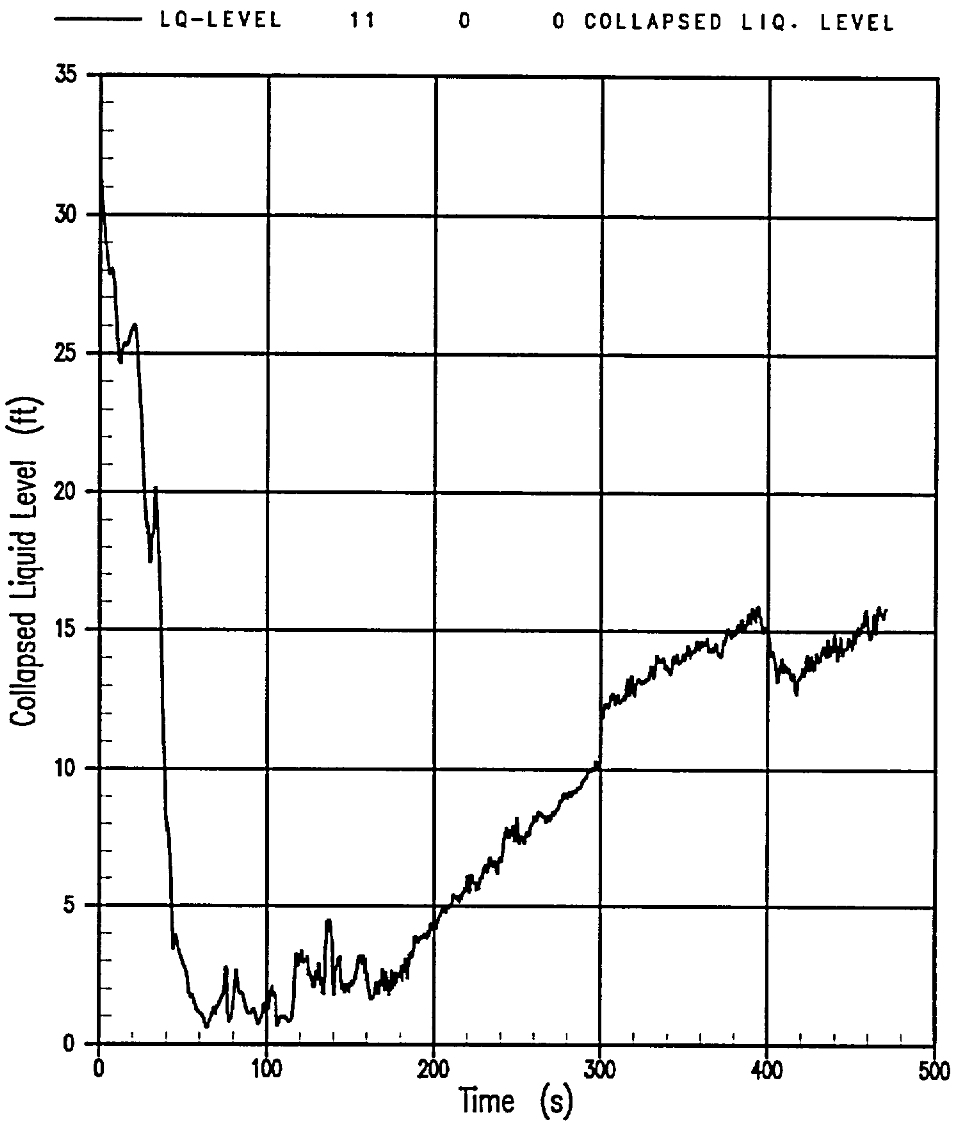


Figure 19E.4.8-4 Mode 3 DECLG Break, Downcomer Collapsed Liquid Level

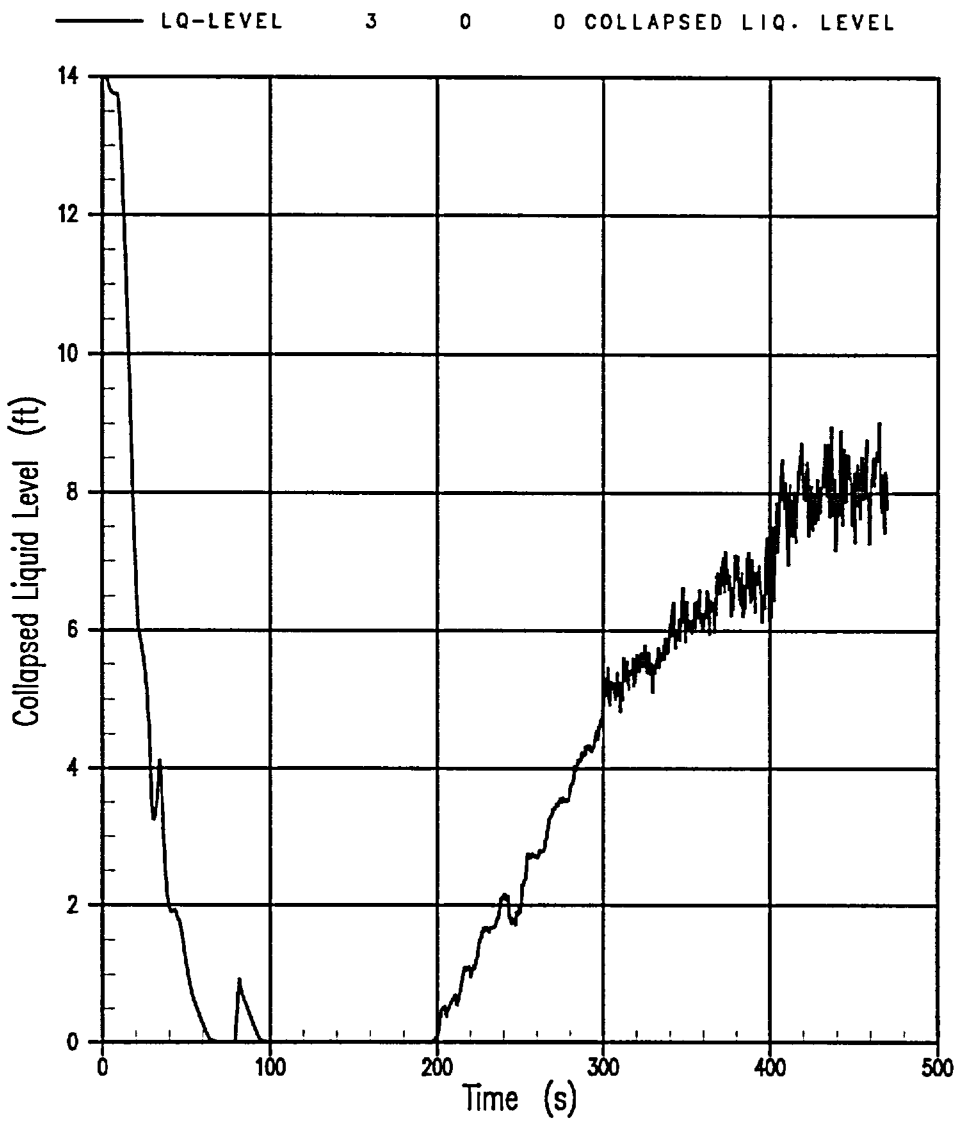


Figure 19E.4.8-5 Mode 3 DECLG Break, Core Collapsed Liquid Level

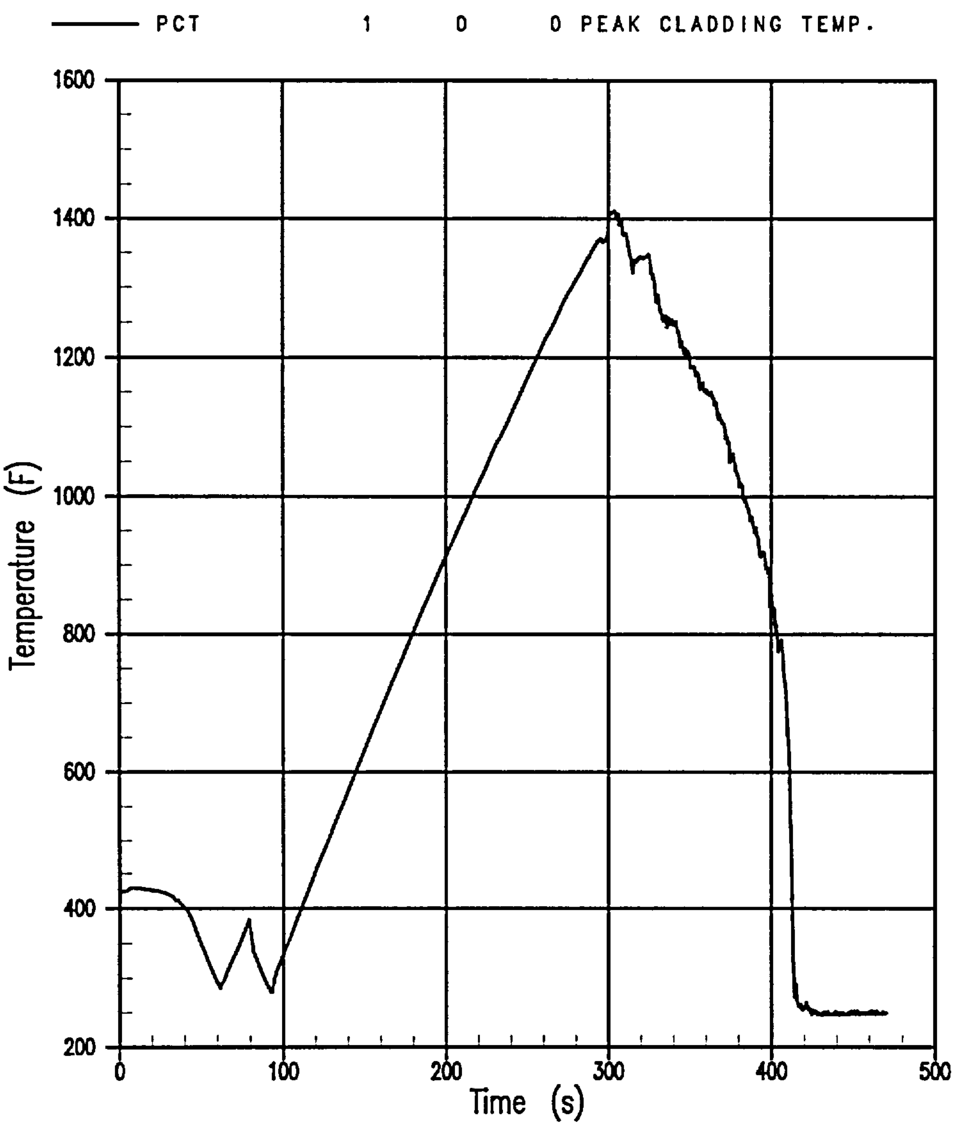


Figure 19E.4.8-6 Mode 3 DECLG Break, Peak Cladding Temperature

ATTACHMENT 2

19E.4.8.5.1 Loss of RNS Cooling in Mode 4 with RCS Intact

For this analysis, it is assumed that the RNS has just been placed in operation at 4 hours after reactor shutdown with the RCS at 350°F and 450 psig (464.7 psia). It is assumed that a loss of offsite power occurs, resulting in a loss of flow through the RNS, and thus in a loss of RNS cooling. The MSS is assumed to be unavailable for heat removal, although the steam generator secondary side is assumed to be at saturated conditions for 350°F with the normal water level. Because the Mode 4 plant conditions assumed for the analysis are more limiting than Mode 5 conditions, this analysis is also applicable for a loss of RNS cooling in Mode 5 when the RCS is intact.

It is assumed that both CMTs are available for injection. Although the Technical Specifications permit one CMT to be taken out of service in Mode 4, there is a high probability that both CMTs will be available, and therefore they were both assumed to operate. If only one CMT is available, the overall results should be similar, although the timing of the event will be affected. Although all of the fourth-stage ADS valves are available in Mode 4, the Technical Specifications permit one of the fourth-stage ADS valves to be out of service in Mode 5 when the RCS is intact. Thus, it was assumed that only three of the fourth-stage ADS valves are available for operation in order to bound the equipment availability in Mode 5. However, one of the three available fourth-stage ADS valves is assumed to fail to open on demand as the single failure, consistent with the single failure assumption used for the small-break LOCA analyses for shutdown conditions.

Two cases were analyzed. The first allowed for automatic safety system actuation on a low pressurizer level signal late in event. During this time, the only mechanism for removing decay heat is boiling off the RCS inventory and venting through the RNS relief valve. The second calculation assumes operator action 1800 seconds after the loss of RNS cooling.

Automatic SI Actuation Case

The accident analyzed is a loss of RNS cooling, which is assumed to result in a complete loss of heat removal for the RCS. The sequence of events for this analysis is presented in Table 19E.4.8-2.

Following the loss of RNS cooling, there is no mechanism for heat removal from the RCS, and the core decay heat generation causes the reactor coolant temperature and pressure to increase. Although the MSS is assumed to be unavailable for heat removal, the steam generators represent a heat sink which slows the rate of heatup of the reactor coolant. The fluid temperature at the core outlet for the transient is shown in Figure 19E.4.8-7. The reactor coolant heatup causes the system pressure to increase as shown in Figure 19E.4.8-8 until the pressure reaches the RNS relief valve setpoint of 818 psig (832.7 psia) at approximately 2750 seconds. The normal relieving capacity of the RNS relief valve is 650 gpm, and the pressure is maintained at the relief valve setpoint as the temperature continues to increase and reactor coolant is discharged from the relief valve. Flow out the relief valve is shown in Figure 19E.4.8-9. The expansion of the water due to the coolant temperature increase also causes the pressurizer level to increase slightly as shown in Figure 19E.4.8-10.

The loss of reactor coolant through the relief valve is not sufficient to remove the core decay heat, and the reactor coolant temperature continues to increase until the core outlet temperature reaches saturation at the relief valve setpoint at approximately 5000 seconds. The generation of steam in the core causes the system pressure to increase above the RNS relief valve setpoint and the pressurizer level to continue to increase. A mixture level begins to form in the upper plenum at approximately 5520 seconds and drops to the top of the hot leg elevation as shown in Figure 19E.4.8-11. At about 5540 seconds, enough mass has been discharged such that a mixture level also forms in the downcomer (Figure 19E.4.8-12), and the downcomer two-phase level begins to decrease. As the boiling front moves lower and lower into the core, more steam generation occurs and the pressure continues to increase. Once the entire core length is boiling, the upper plenum mixture level is within the hot leg perimeter. At approximately 9100 seconds, when steam begins to flow through the relief valve along with liquid, the pressure begins to decrease. The pressurizer level also begins to decrease as water drains from the pressurizer into the reactor coolant system hot leg. However, the voiding in the RCS increases as the pressure decreases, and flashing begins to occur in the pressurizer at approximately 9300 seconds. This additional steam generation causes the pressure to begin to increase, and the relief valve flow becomes solely liquid again. The steam voiding in the pressurizer not only causes the pressure increase, but also facilitates draining, and the pressurizer level continues to decrease.

As the pressurizer level decreases, a CMT actuation signal is generated automatically on low pressurizer level, and following a 1.2-second delay, the isolation valves on the available CMT tank delivery lines open and CMT injection flow is initiated at approximately 10,600 seconds as shown in Figure 19E.4.8-13. The opening of the PRHR HX isolation valve on a CMT actuation signal starts the flow through the heat exchanger. The CMT injection causes the reactor coolant pressure to decrease below the RNS relief valve setpoint, and the loss of reactor coolant is terminated at approximately 10,900 seconds. As the CMT level decreases (Figure 19E.4.8-14), the first-stage ADS setpoint at 67.5 percent is reached at 10,847 seconds. The second-stage and third-stage ADS valves also open following the timer delays for the actuation of the second- and third-stage ADS valves. The vapor and liquid flow through the ADS valves (Figures 19E.4.8-15 and 19E.4.8-16) results in a rapid depressurization of the reactor coolant system. The CMT reaches the fourth-stage ADS setpoint of 20 percent, and two of the four fourth-stage paths open at 11,900 seconds. As noted previously, it is assumed that one of the fourth-stage paths is out of service, and one path is assumed to fail as the single active failure. The vapor and liquid flow through the fourth stage ADS paths (Figures 19E.4.8-17 and 19E.4.8-18) further reduces the pressure to the point where IRWST injection begins at approximately 12,200 seconds (Figure 19E.4.8-19).

The CMT and IRWST injection reverses the decrease in the core stack and downcomer mixture levels as shown in Figures 19E.4.8-11 and 19E.4.8-12, respectively. As shown in Figure 19E.4.8-11, the core stack mixture level is maintained well above the elevation of the top of the core active fuel (20.34 feet) throughout the transient. At the end of the transient, the core stack mixture level has been restored to within the hot leg perimeter and the downcomer mixture level has been restored to the DVI nozzle elevation. The fluid temperature at the core outlet has also been reduced and is being maintained at less than 250°F. As shown in Figure 19E.4.8-20, the reactor coolant mass inventory twice reaches a minimum of approximately 130,000 pounds, when the CMT and IRWST injection then increase the inventory. The reactor coolant mass inventory is greater than 200,000 pounds and is slowly increasing at the end of the transient. Thus, it is concluded that the consequences of a loss of RNS in Modes 4 and 5 with the RCS intact are acceptable.

Manual Safety Actuation

If operator action occurs after 1800 seconds, the CMT and PRHR isolation valves are opened. Initially, the decay heat is greater than the PRHR capacity and the RCS pressure increases to the RNS safety valve setpoint (Figure 19E.4.8-21). At this time, a small amount of inventory is vented through the valve (Figure 19E.4.8-22). Eventually, the decay heat matches the PRHR capacity (Figure 19E.4.8-42), and the RCS pressure decreases slowly to the valve setpoint. For this case, no significant loss of inventory occurs and the ADS is not actuated. The sequence of events for this case is also shown in Table 19E.4.8-2

19E.4.8.5.2 Loss of RNS Cooling in Mode 5 with RCS Open

For this analysis, it is assumed that the RNS is in operation in Mode 5 at 24 hours after reactor shutdown with the ADS Stage 1, 2, and 3 valves open and the RCS vented to the IRWST. The reactor coolant temperature is assumed to be at 160°F, and the pressurizer pressure is assumed to be at atmospheric pressure plus the elevation head in the IRWST, or 18.2 psia. The steam generator secondary side is assumed to be drained, and thus, there is no secondary heat sink for this case. It is assumed that the CMTs and the PRHR are not available because the Technical Specifications permit them to be taken out of service when the RCS is open in Mode 5. It is also assumed that only two of the fourth-stage ADS valves are available for potential use by the operators because the Technical Specifications permit two of the fourth-stage ADS valves to be out of service in Mode 5 when the RCS is open. In addition, one of the two available fourth-stage ADS valves is assumed to fail to open on demand as the single failure. The Technical Specifications also permit one of the two IRWST injection paths to be out of service in Mode 5 with the RCS open, and thus, only one of the IRWST injection paths is assumed to be available.

It is assumed that a loss of offsite power occurs, resulting in a loss of RNS flow, and thus a loss of RNS cooling. The sequence of events for this analysis is presented in Table 19E.4.8-3.

Following the loss of RNS cooling, there is no mechanism for heat removal from the RCS and the core decay heat generation results in an increase in the reactor coolant temperature. The fluid temperature at the core outlet for the transient is shown in Figure 19E.4.8-24. The core outlet fluid temperature increases steadily until approximately 3000 seconds when saturation temperature is reached and voiding is initiated in the core. Because the RCS is vented to the IRWST via ADS Stages 1, 2, and 3, the pressure initially remains constant until approximately 3200 seconds as shown in Figure 19E.4.8-25. As the void generation in the system increases, the vapor flow through ADS Stages 1, 2, and 3 is not sufficient to maintain the pressure, and the pressure increases to approximately 44.0 psia and then begins to decrease. As shown in Figure 19E.4.8-26, the pressurizer level also increases as the reactor coolant temperature increases, and the level subsequently reaches the top of the pressurizer as a result of the steam generation in the system. As shown in Figures 19E.4.8-27 and 19E.4.8-28, a mixture of steam and water is discharged via ADS Stages 1, 2, and 3 after the pressurizer fills.

The continued loss of reactor coolant through ADS Stages 1, 2, and 3 causes the pressure to begin to decrease after approximately 4600 seconds. The core outlet temperature is at saturation and also begins to decrease as the pressure decreases. A mixture level begins to form in the upper plenum at approximately 3550 seconds, and the level begins to decrease as shown in Figure 19.4.8-29, as the voiding continues in the system. At about 4050 seconds, enough mass has been discharged that a mixture level forms in the downcomer (Figure 19.4.8-30) and the downcomer level also begins to decrease. The pressurizer level does not decrease significantly due an increasing void fraction in the pressurizer.

As the voiding in the core continues, the core stack mixture level continues to decrease as shown in Figure 19E.4.8-29. The void fraction in the hot legs also increases, and the mixture level in the hot leg begins to decrease after 3250 seconds. The hot leg is empty at approximately 4800 seconds as shown in Figure 19E.4.8-31. This is the normal signal for opening the fourth-stage ADS valves and to initiate IRWST injection when the systems are aligned for automatic actuation. Thus, it is assumed that the operator will initiate manual action at 4800 seconds to open the fourth-stage ADS valves and to open the IRWST flow path to permit IRWST injection when the downcomer pressure is sufficiently low. Thus, discharge through one of the fourth-stage ADS valves is initiated at 4890 seconds as shown in Figures 19E.4.8-32 and 19E.4.8-33. As noted previously, one of the two available fourth-stage ADS paths is assumed to fail to open as the single active failure. The flow through the fourth-stage ADS path results in a further reduction in the pressurizer pressure and a rapid decrease in the pressurizer level. The downcomer pressure is also reduced to the point where IRWST injection is initiated at approximately 5500 seconds (Figure 19E.4.8-34). However, the pressurizer level increases due to subsequent additional void formation at the lower pressure, and the downcomer pressure increases slightly, temporarily terminating the IRWST flow. The downcomer pressure then drops slowly, resulting in sustained IRWST injection.

The IRWST injection reverses the decrease in the core stack and downcomer mixture levels as shown in Figures 19E.4.8-30 and 19E.4.8-31, respectively. As shown in Figure 19E.4.8-30, the core stack mixture level is maintained well above the elevation of the top of the core active fuel (20.43 feet) throughout the transient. At the end of the transient, the core stack mixture level has been restored to above the middle of the hot leg elevation and the downcomer mixture level is above the DVI nozzle elevation. The fluid temperature at the core outlet has also been reduced to approximately 250°F. As shown in Figure 19E.4.8-35, the reactor coolant mass inventory reaches a minimum of approximately 135,000 pounds and then begins to increase as a result of the IRWST injection. Thus, it is concluded that when the appropriate operator action is performed, one ADS Stage 4 valve is effective in reducing system pressure so that the consequences of a loss of RNS in Mode 5 with the RCS vented are acceptable.

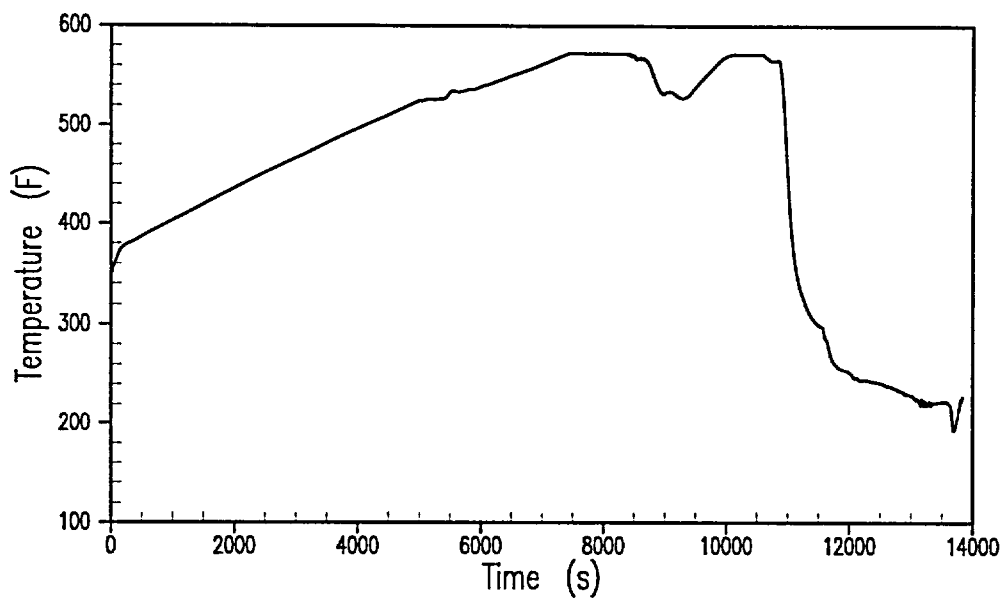
The analysis presented here is a conservative analysis of a loss of RNS cooling during reduced inventory conditions. During Mode 5, prior to draining to mid-loop conditions, the operator manually opens the ADS Stages 1 through 3 paths to the IRWST. With the RCS "open," the operator then proceeds to slowly drain the RCS to "mid-loop" conditions, for the purpose of performing steam generator maintenance or other maintenance that requires a reduced RCS water level. At this moment, it is postulated that a loss of decay heat removal via the nonsafety-related RNS occurs. A loss of RNS cooling at this time is selected because it is the earliest time the RCS could be placed into a reduced inventory (that is, RCS open) condition. In addition, the backpressure on the reactor vessel, due to the presence of water in the pressurizer, is higher at this time. This presents the most challenging condition for the ADS to depressurize the RCS to IRWST cut-in pressure. This transient represents the most limiting "surge line flooding" scenario, a term commonly used for operating plants to refer to the phenomenon associated with water in the pressurizer and surge line causing a high backpressure in the RCS, which potentially challenges the ability of the low head safety injection systems to inject properly. In addition, this scenario can potentially challenge the design pressure of temporary nozzle dams placed in the steam generators to facilitate maintenance of the RCS during refueling.

For a loss of the RNS during mid-loop operations, calculations have been performed to determine the time until core uncovery would occur. The results of these calculations are presented in Table 19E.2-1 of this appendix. The progression of events following a loss of RNS cooling during mid-loop results in a heatup of the RCS to saturation, followed by a boiling off of the coolant to the IRWST via the ADS Stages 1, 2, and 3 valves. Eventually, the operator actuates the IRWST upon a loss of RCS subcooling, followed by the loss of RCS inventory. The conditions in the RCS following IRWST and fourth-stage ADS actuation are similar to those in this evaluation. As shown in Table 19E.2-1, the operator has at least 100 minutes from the loss of RNS cooling until the onset of core uncovery to manually actuate the IRWST and ADS Stage 4. In general, the results of a loss of RNS during mid-loop conditions are similar but slightly less severe to those presented in this evaluation, due to the lower levels of decay heat and to the absence of the initial water inventory in the pressurizer, which serves to reduce the surge line flooding phenomenon that degrades the depressurization capability of the ADS Stages 1 through 3 vent paths.

Table 19E.4.8-2
Loss of RNS Cooling in Mode 4 with RCS Intact
Sequence of Events

Event	Automatic Actuation Time (sec)	Manual Actuation Time (sec)
Loss of RNS Cooling	0	0
RNS Relief Valve Flow Starts	1400	4950
CMT and PRHR Actuated	9500	1800
RNS Relief Valve Flow Terminated	9700	<1 lbm/s @ 25,000
ADS Stage 1 Flow Starts	10,075	-
ADS Stage 2 Flow Starts	10,145	-
ADS Stage 3 Flow Starts	10,265	-
ADS Stage 4 Flow Starts	10,895	-
IRWST Injection Starts	11,845	-

Table 19E.4.8-3 Loss of RNS Cooling in Mode 5 with RCS Open Sequence of Events	
Event	**Time (seconds)**
Loss of RNS Cooling	0
Hot Leg Empty	4800
ADS Stage 4 Flow Initiated	4890
IRWST Injection Starts	5500



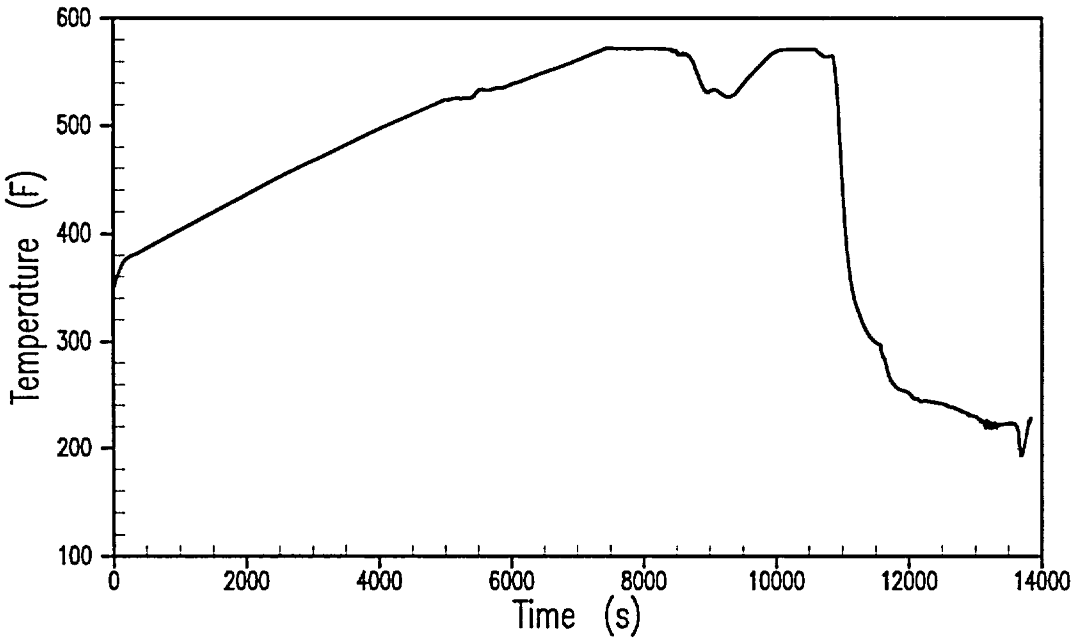


Figure 19E.4.8-7 Core Outlet Temperature, Loss of RNS in Mode 4 with RCS Intact

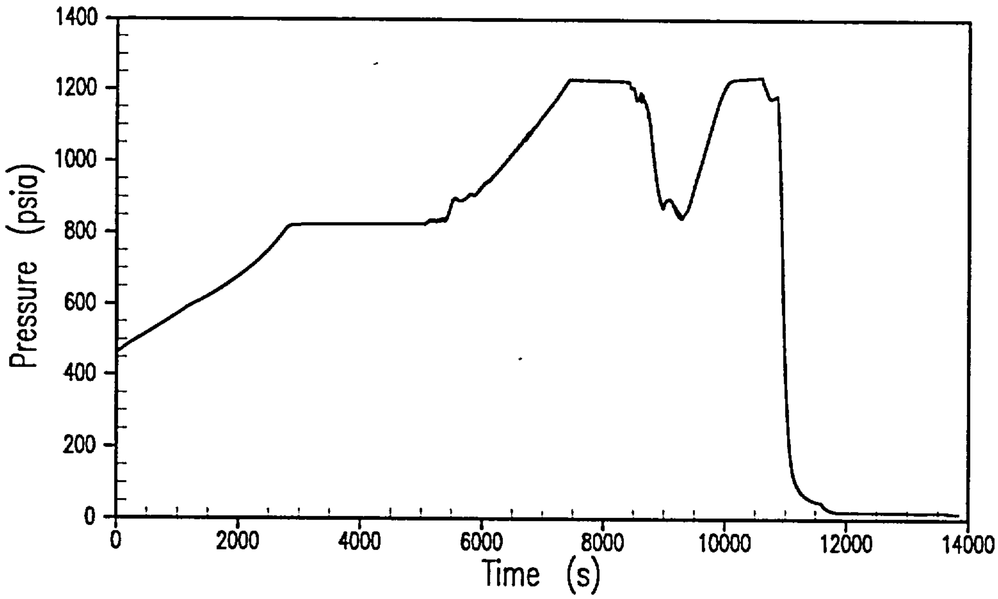


Figure 19E.4.8-8 Pressurizer Pressure, Loss of RNS in Mode 4 with RCS Intact

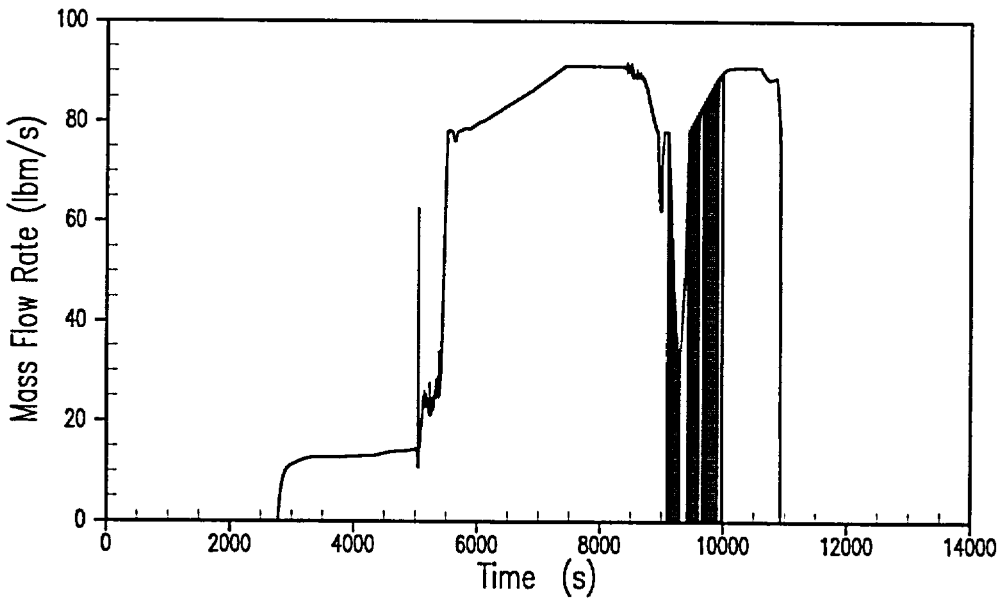


Figure 19E.4.8-9 RNS Relief Valve Flow, Loss of RNS in Mode 4 with RCS Intact

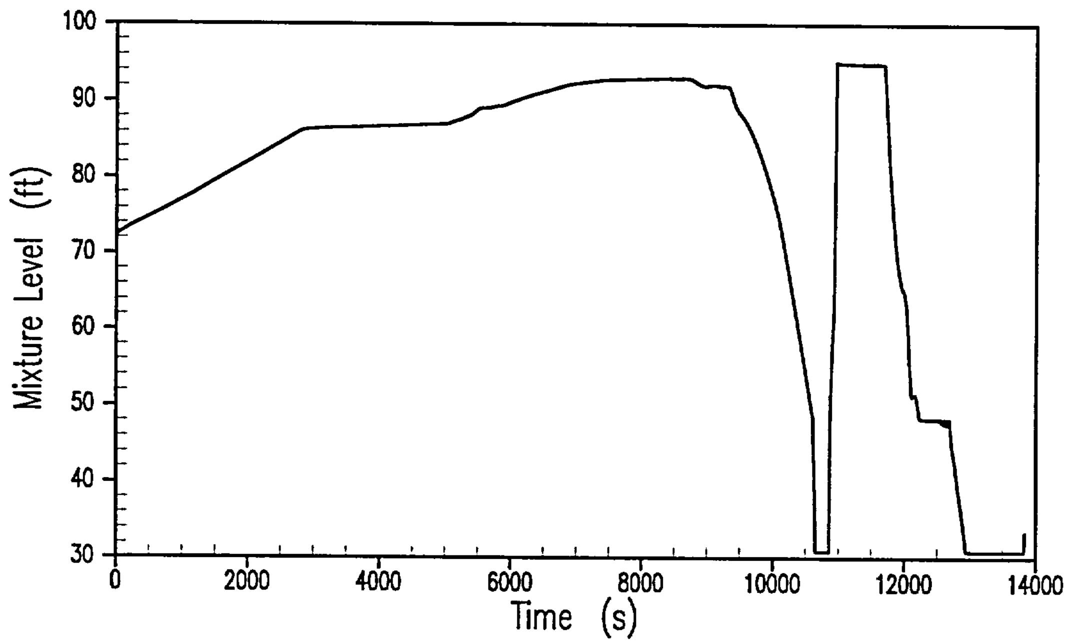


Figure 19E.4.8-10 Pressurizer Mixture Level, Loss of RNS in Mode 4 with RCS Intact

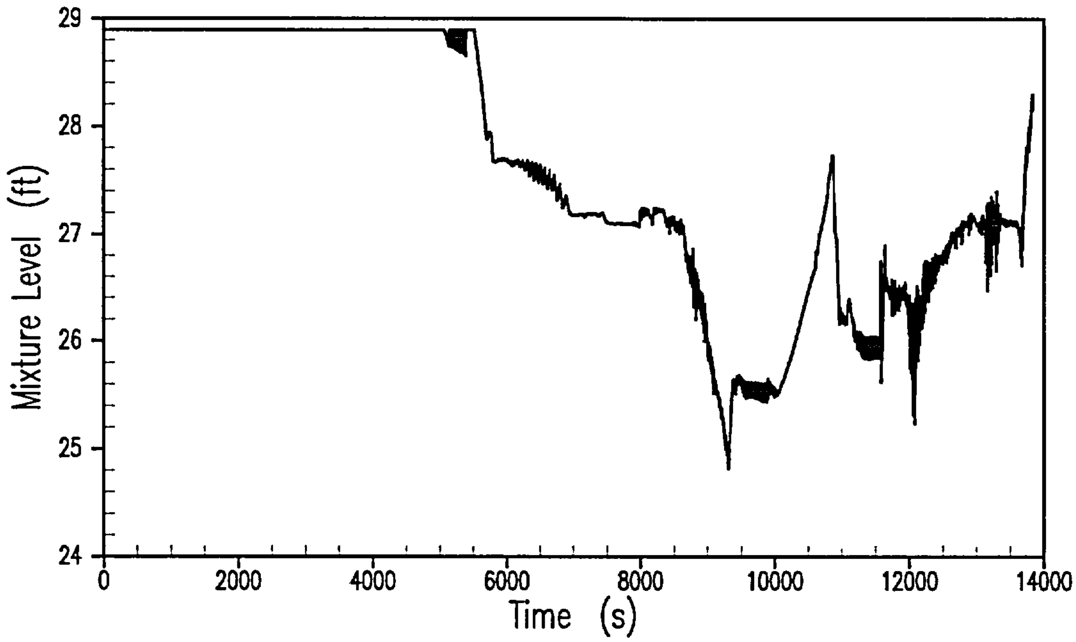


Figure 19E.4.8-11 Core Stack Mixture Level, Loss of RNS in Mode 4 with RCS Intact

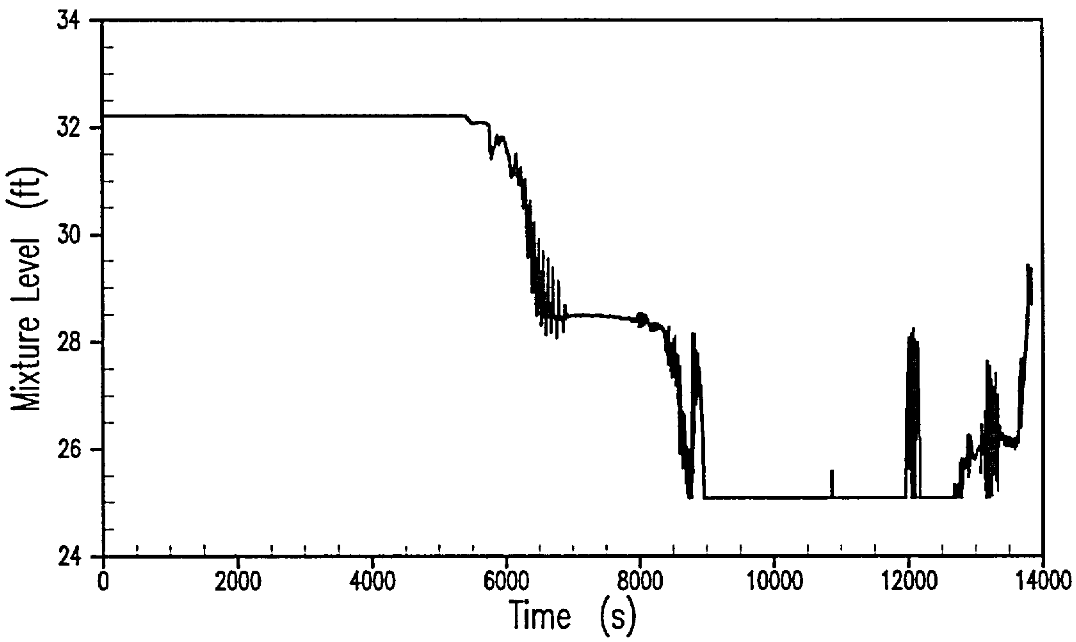


Figure 19E.4.8-12 Downcomer Mixture Level, Loss of RNS in Mode 4 with RCS Intact

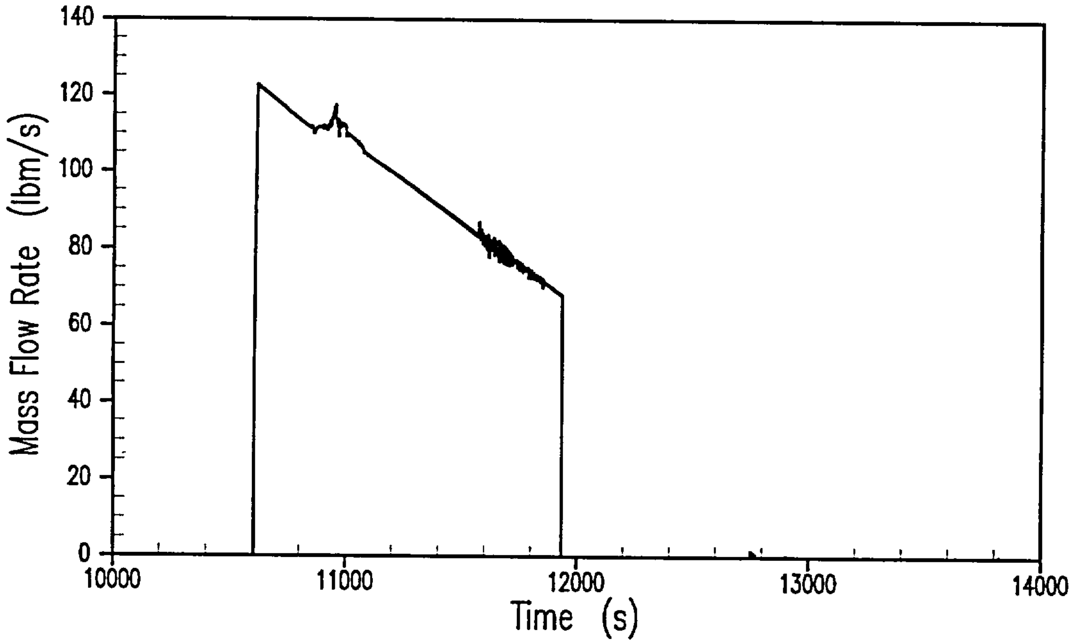


Figure 19E.4.8-13 CMT to DVI Flow, Loss of RNS in Mode 4 with RCS Intact

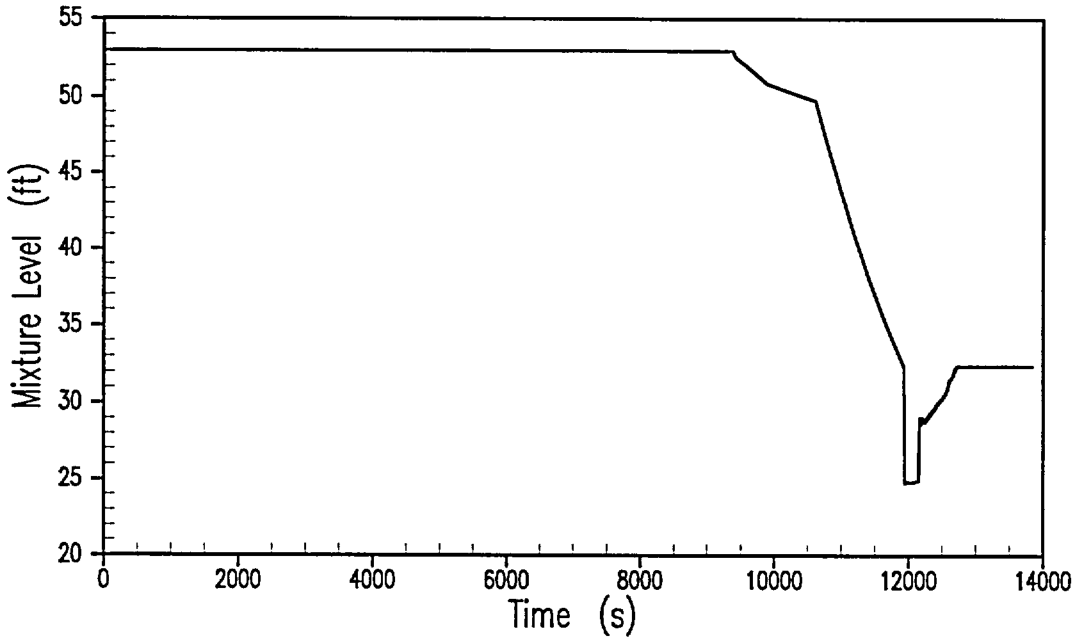


Figure 19E.4.8-14 CMT Mixture Level, Loss of RNS in Mode 4 with RCS Intact

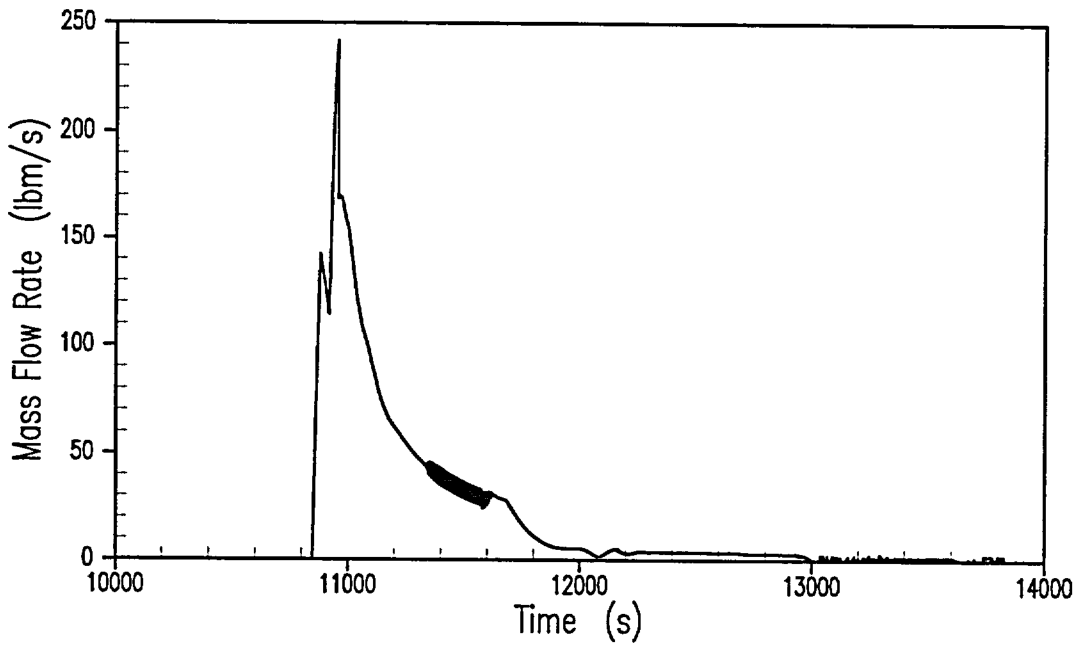


Figure 19E.4.8-15 ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 4 with RCS Intact

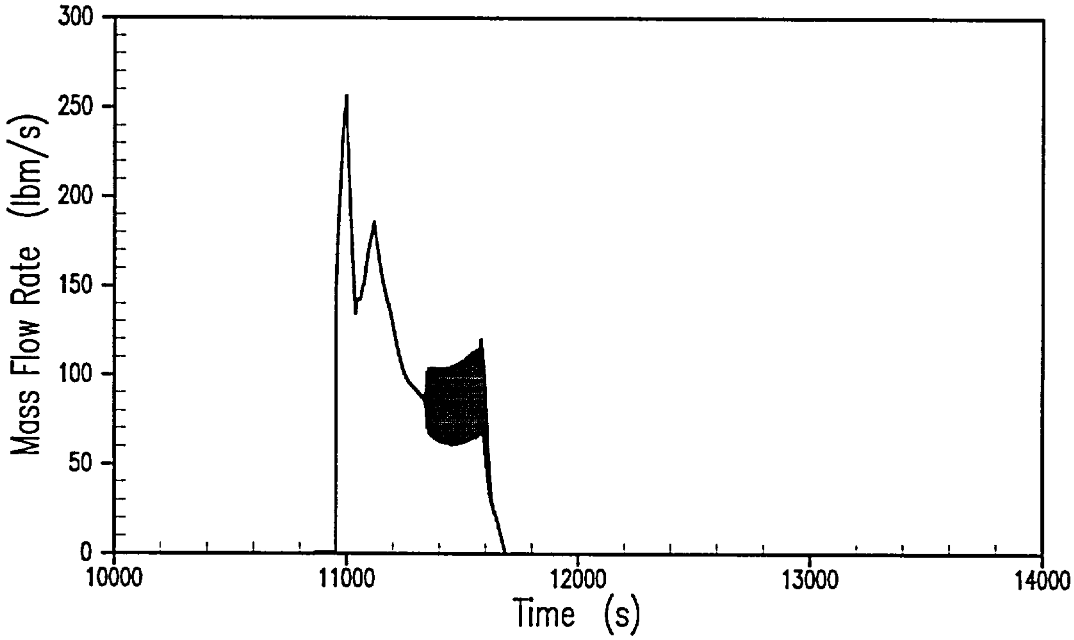


Figure 19E.4.8-16 ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 4 with RCS Intact

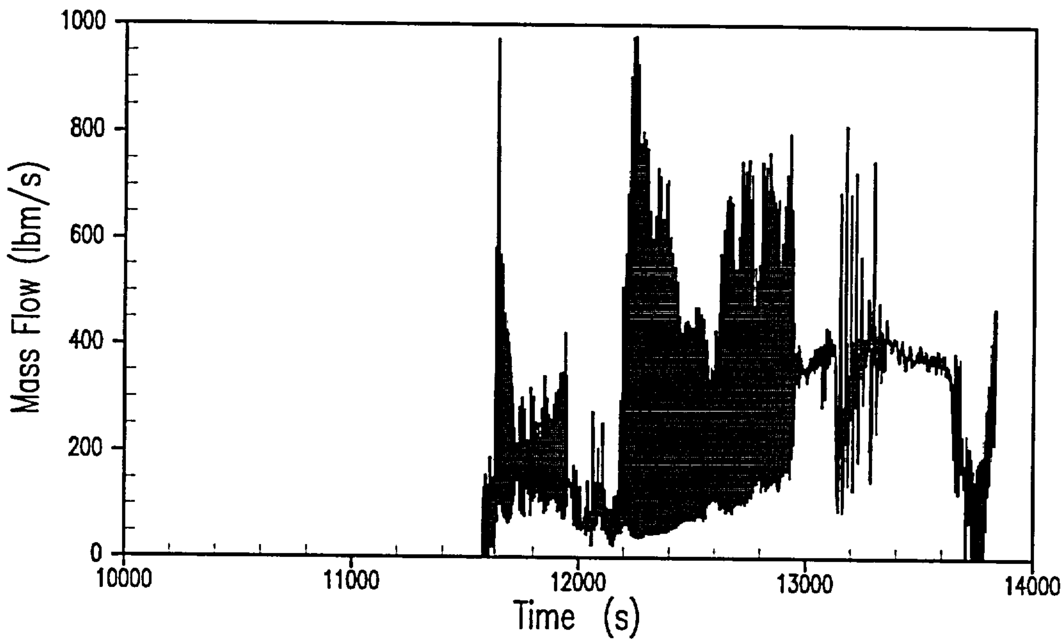


Figure 19E.4.8-18 ADS Stage 4 Liquid Flow, Loss of RNS in Mode 4 with RCS Intact

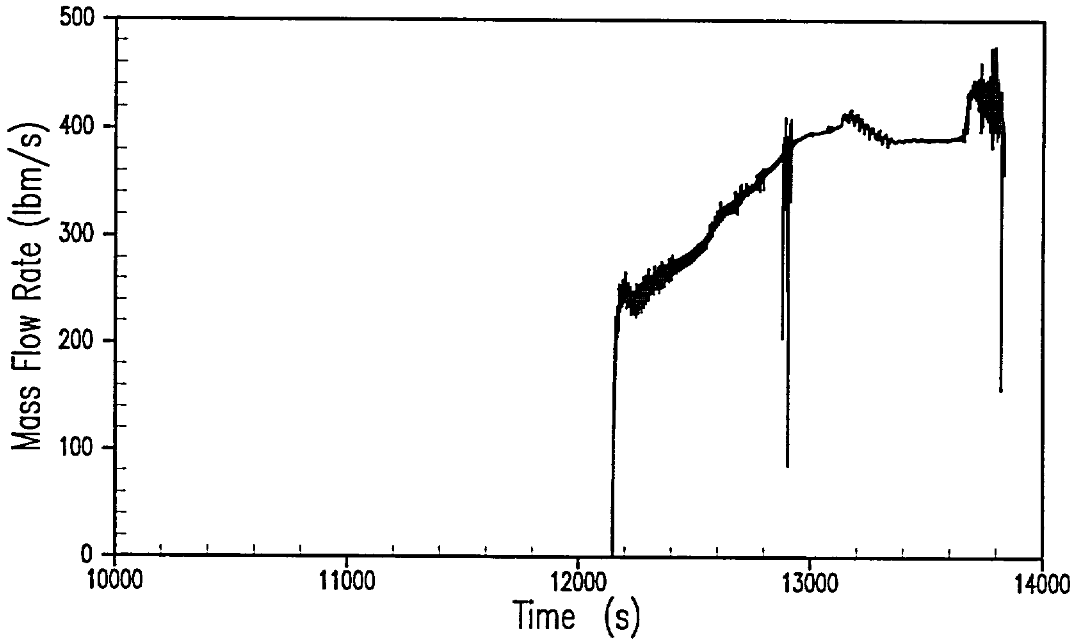


Figure 19E.4.8-19 Loop 1 IRWST Injection Flow, Loss of RNS in Mode 4 with RCS Intact

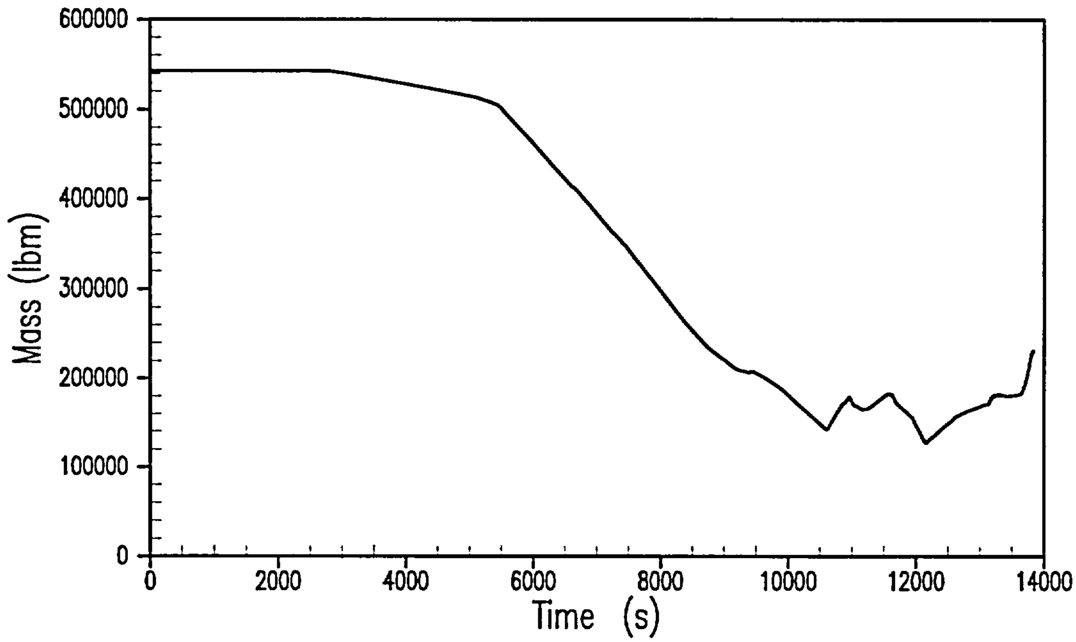


Figure 19E.4.8-20 Primary Mass Inventory, Loss of RNS in Mode 4 with RCS Intact

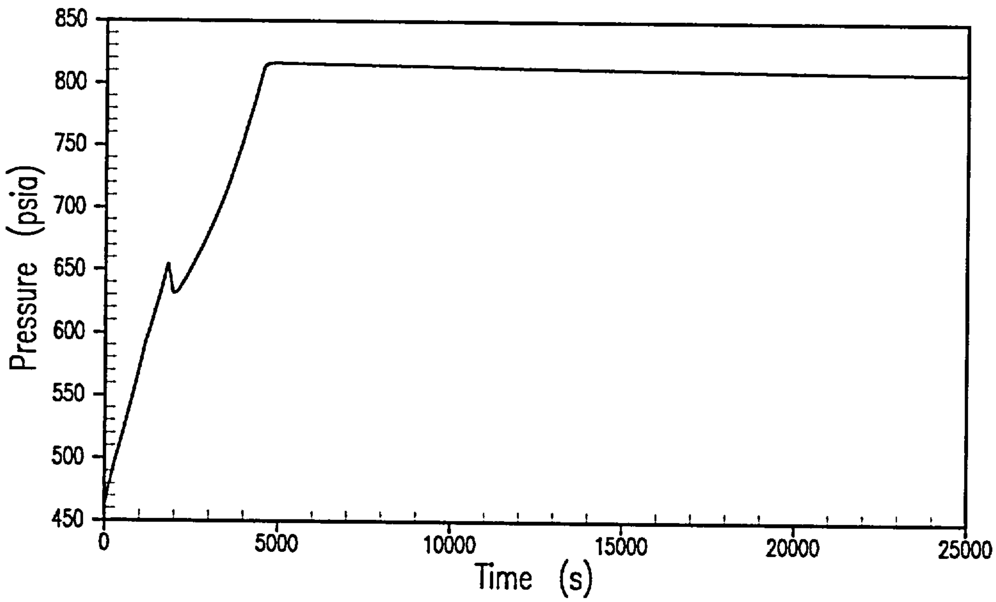


Figure 19E.4.8-21 **Pressurizer Pressure, Loss of RNS in Mode 4 with RCS Intact, Manual Safety System Actuation at 1800 sec.**

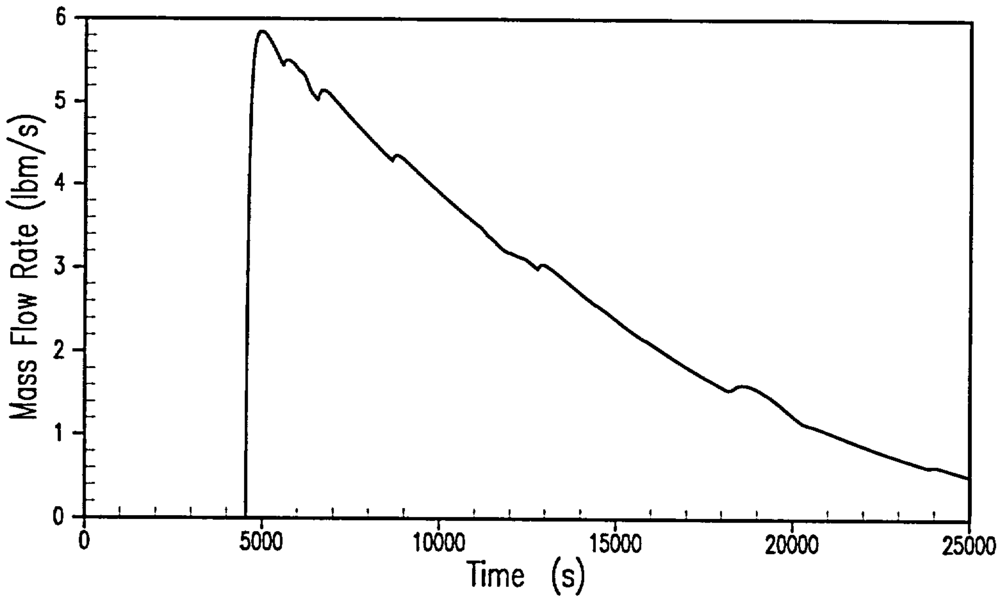


Figure 19E.4.8-22 RNS Safety Valve Flow, Loss of RNS in Mode 4 RCS Intact, Manual Safety System Actuation at 1800 sec.

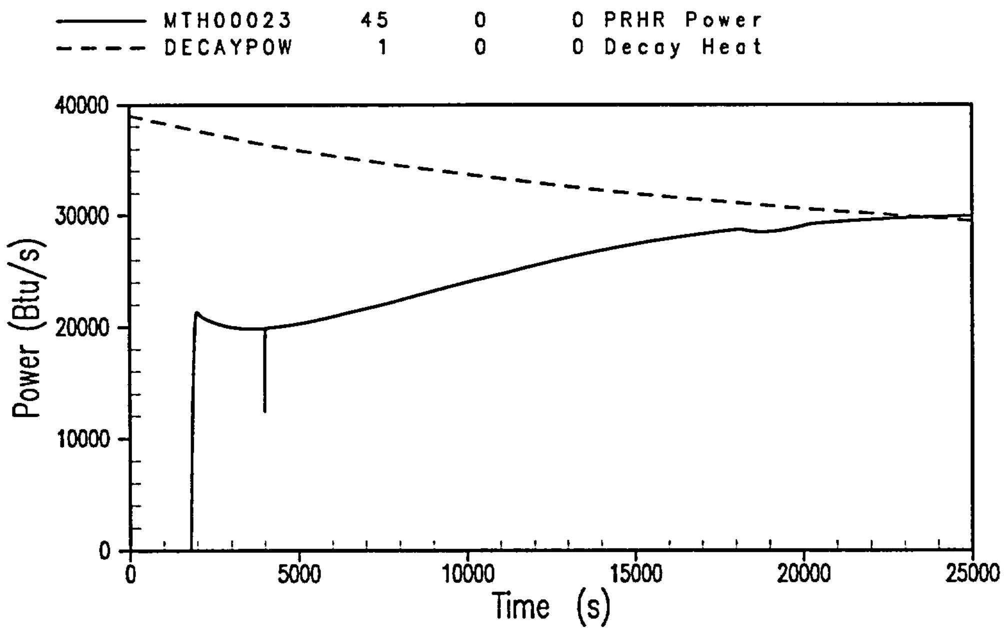


Figure 19E.4.8-23 Decay Heat and PRHR Heat Removal, Loss of RNS in Mode 4 with RCS Intact, Manual Safety System Actuation at 1800 sec.

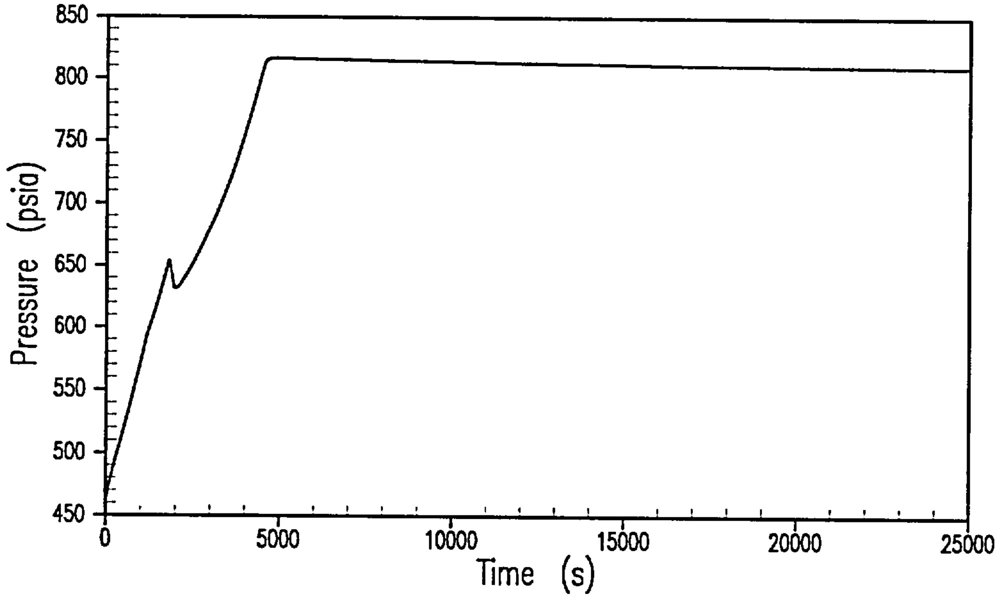


Figure 19E.4.8-24 Core Outlet Fluid Temperature, Loss of RNS in Mode 5 with RCS Open

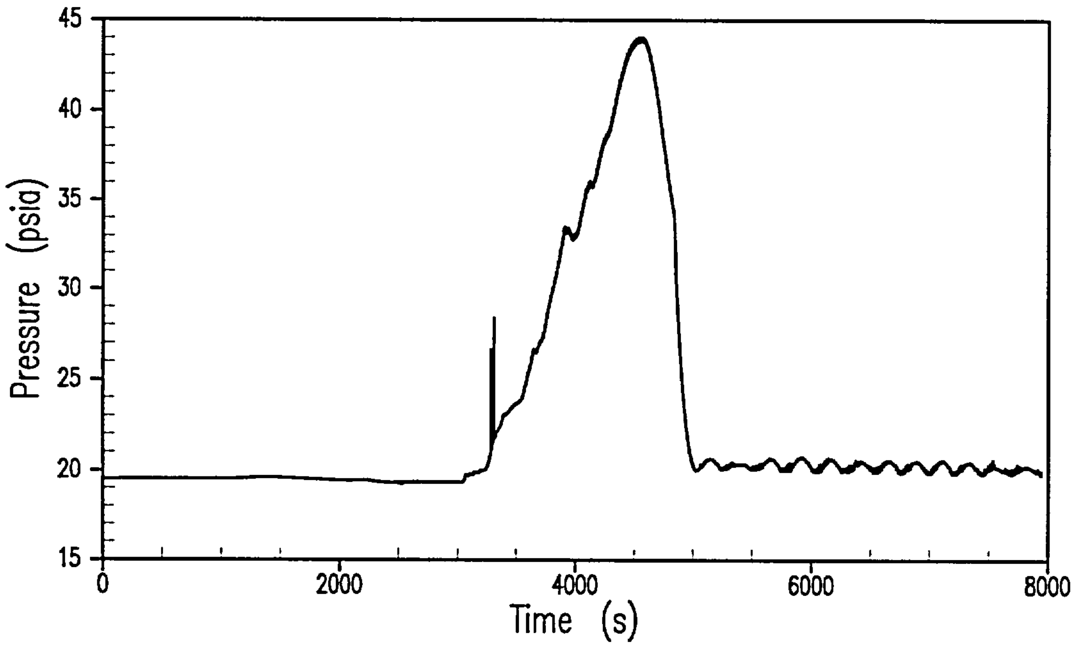


Figure 19E.4.8-25 Pressurizer Pressure, Loss of RNS in Mode 5 with RCS Open

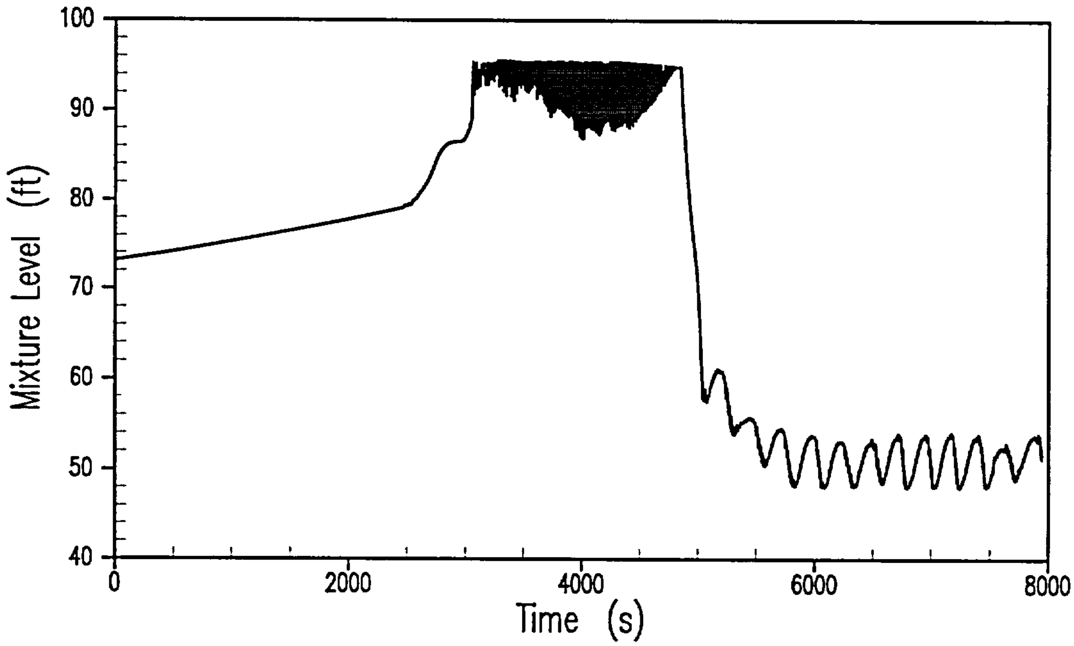


Figure 19E.4.8-26 Pressurizer Mixture Level, Loss of RNS in Mode 5 with RCS Open

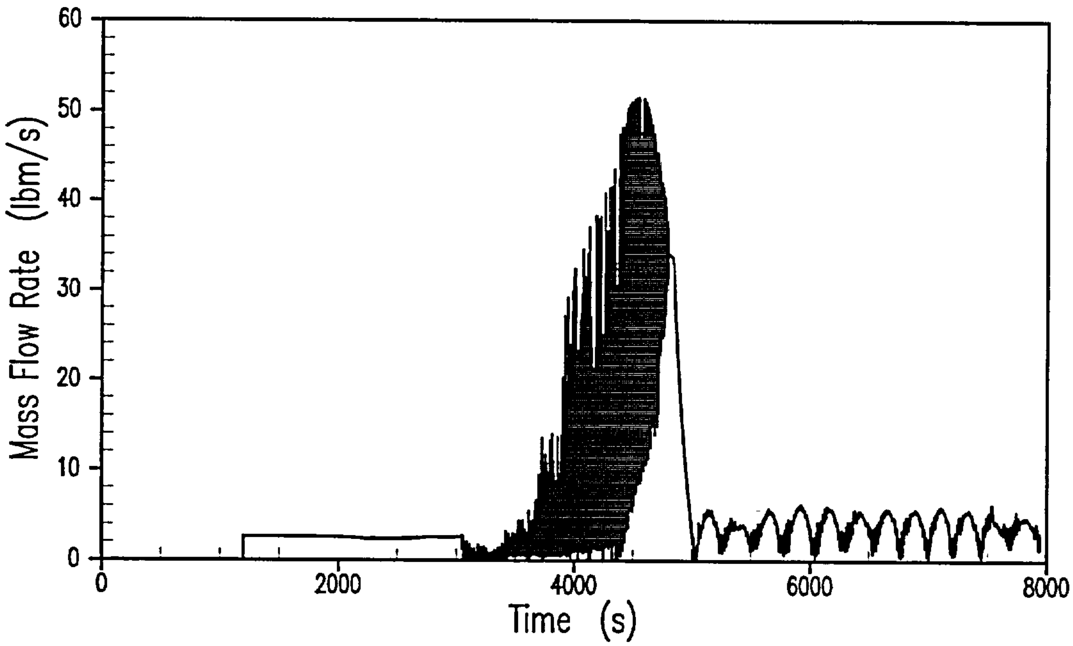


Figure 19E.4.8-27 ADS Stages 1-3 Vapor Flow, Loss of RNS in Mode 5 with RCS Open

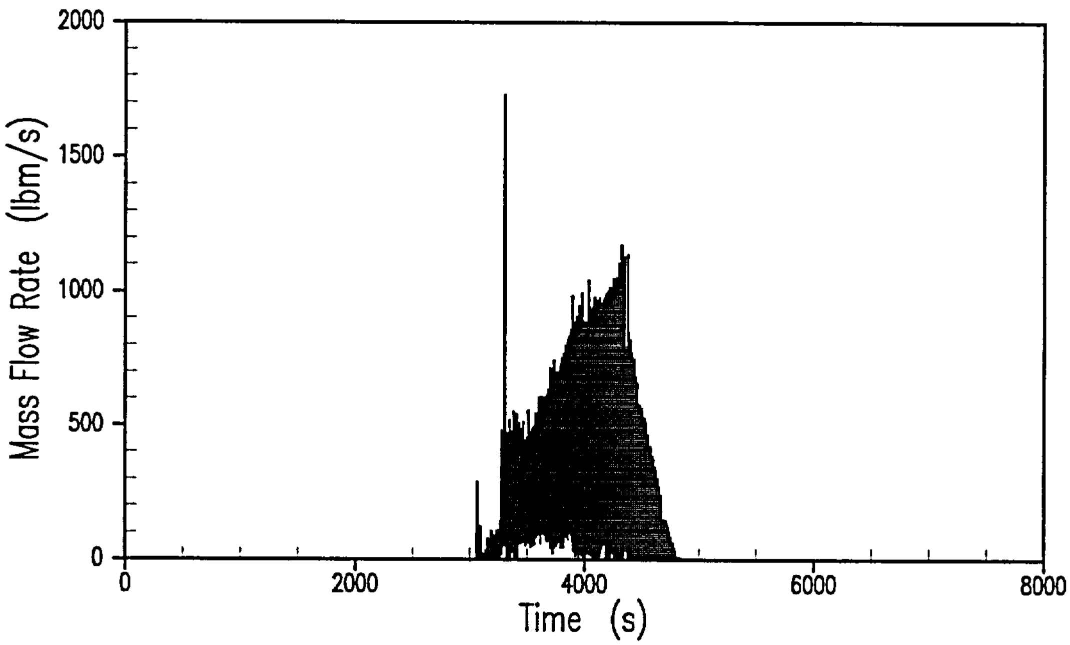


Figure 19E.4.8-28 ADS Stages 1-3 Liquid Flow, Loss of RNS in Mode 5 with RCS Open

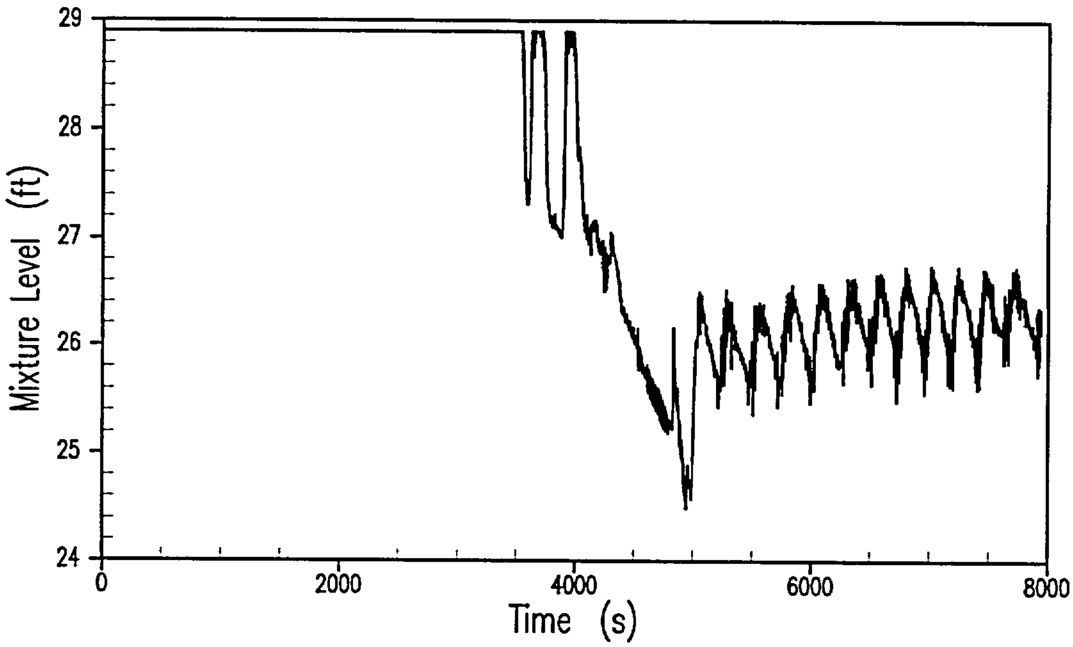


Figure 19E.4.8-29 Core Stack Mixture Level, Loss of RNS in Mode 5 with RCS Open

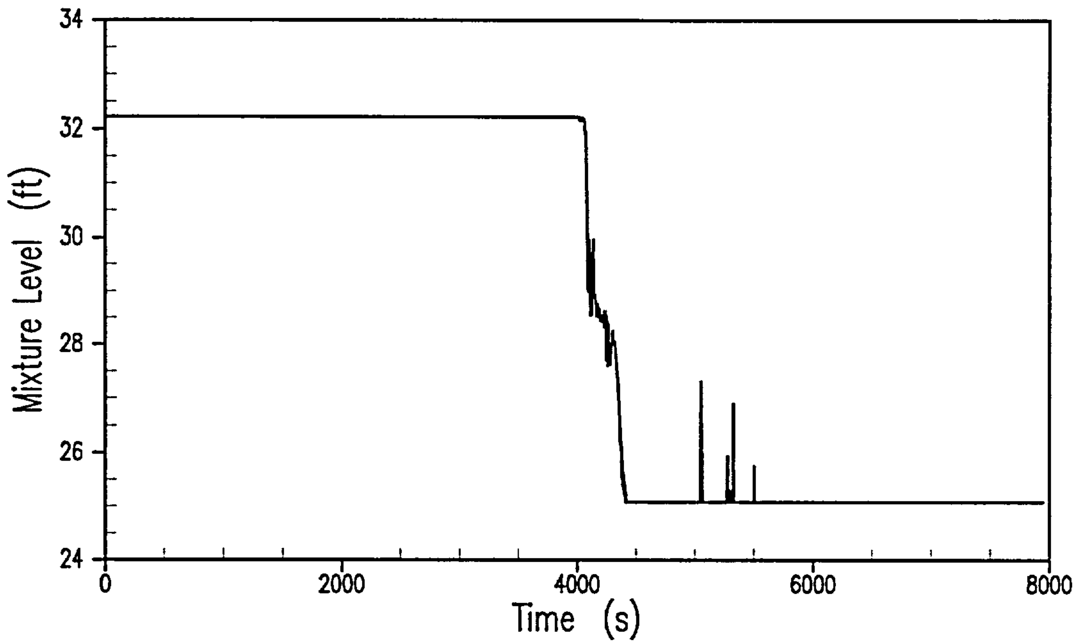


Figure 19E.4.8-30 Downcomer Mixture Level, Loss of RNS in Mode 5 with RCS Open

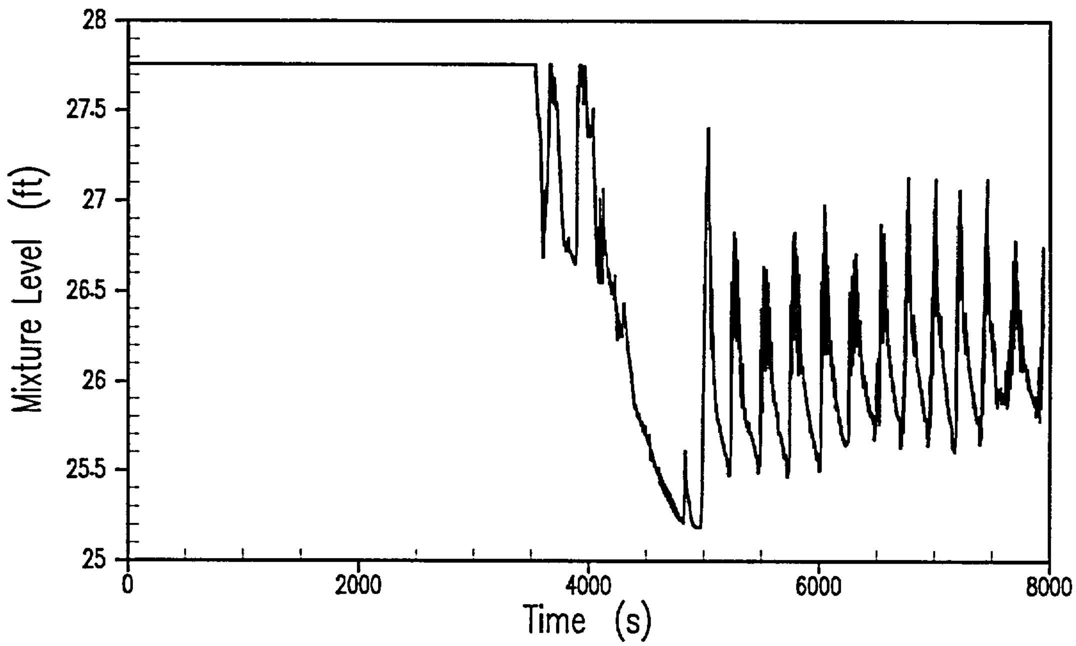


Figure 19E.4.8-31 Loop 1 Hot Leg Mixture Level, Loss of RNS in Mode 5 with RCS Open

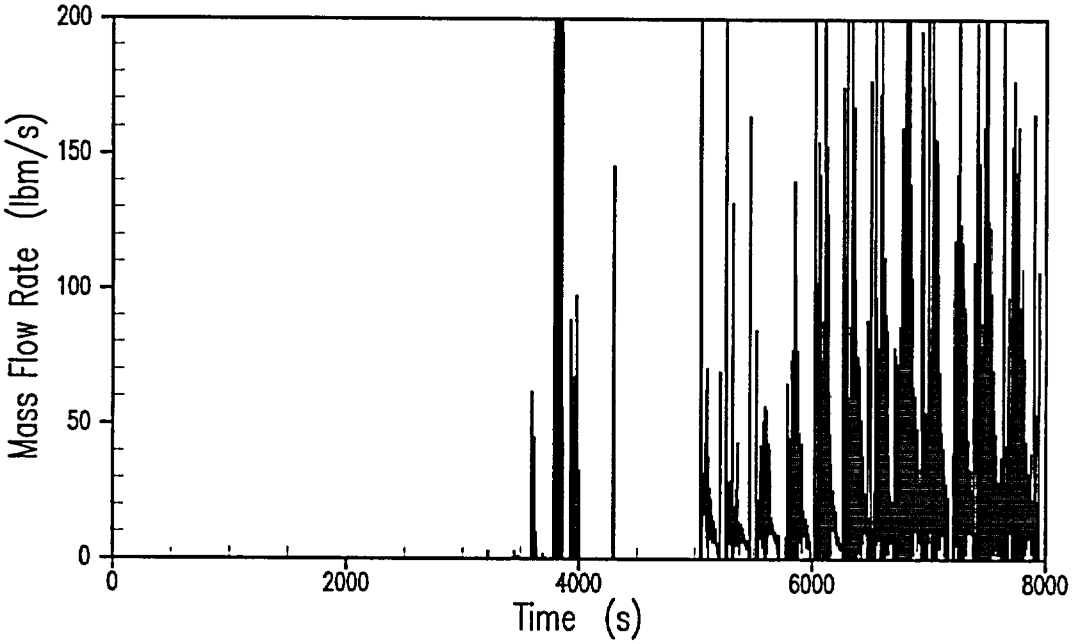


Figure 19E.4.8-32 ADS Stage 4 Vapor Flow, Loss of RNS in Mode 5 with RCS Open

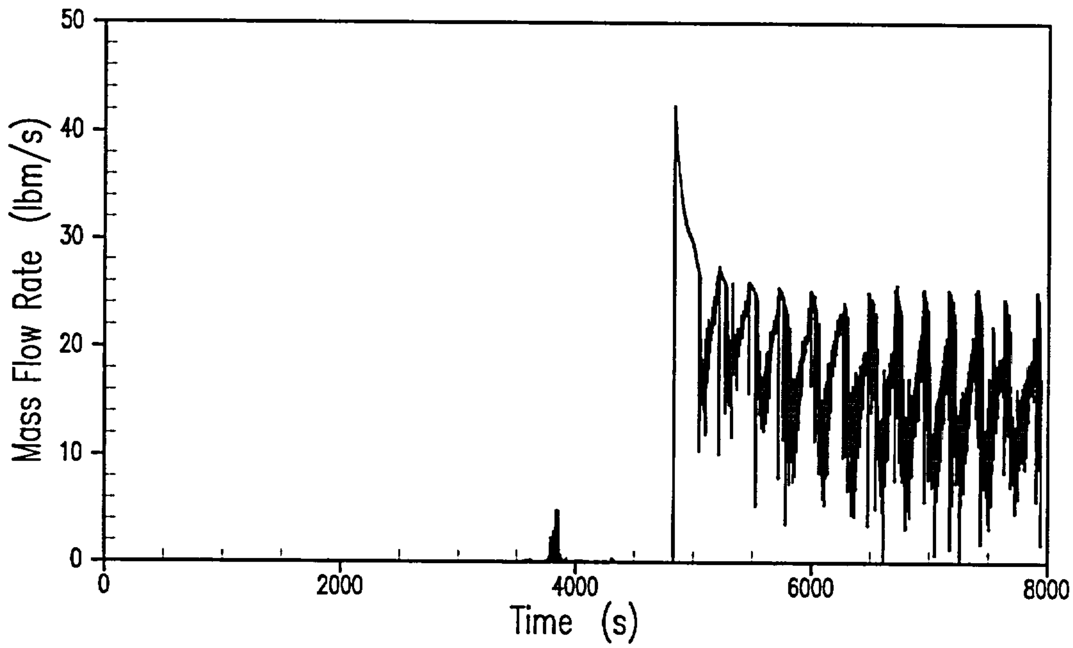


Figure 19E.4.8-33 ADS Stage 4 Liquid Flow, Loss of RNS in Mode 5 with RCS Open

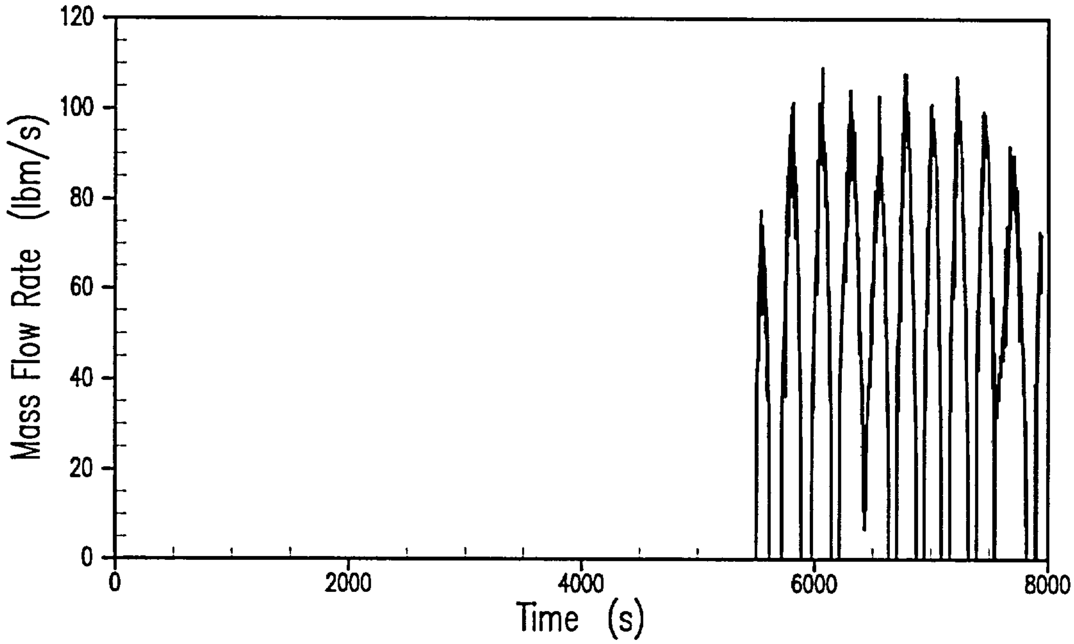


Figure 19E.4.8-34 IRWST Injection Flow, Loss of RNS in Mode 5 with RCS Open

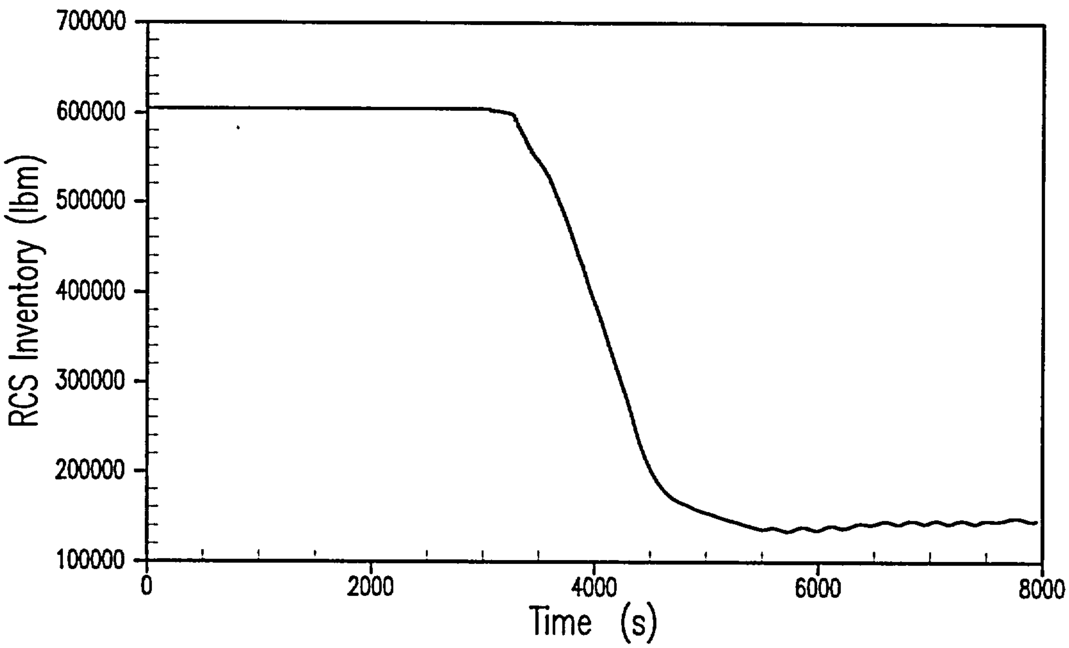


Figure 19E.4.8-35 Primary Mass Inventory, Loss of RNS in Mode 5 with RCS Open

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.128

Question:

NUREG-0933, A Prioritization of Generic Safety Issues," Task Action Plan Item USI A-17 addresses the concerns of adverse systems interactions (ASI) among various structures, systems, and components (SSC) in a plant, and identifies the need to investigate the possibility that unrecognized subtle dependencies among the SSCs have remained hidden and could lead to safety significant events. The staff concluded that occurrence of an actual ASI or the existence of a potential ASI, as well as the potential overall safety impact, are very much a function of an individual plant's design and operational features. Therefore, for new plant designs with new or different configured passive and active systems, such as AP600 and AP1000 designs, the staff believes the designer should perform a systematic search for ASIs, and propose resolutions for any that are discovered. For the AP600 design, Westinghouse submitted topical report WCAP-14477, Revision 1, "The AP600 Adverse System Interaction Evaluation Report," to identify possible adverse interactions among safety-related systems and between safety-related and non-safety-related systems, and to evaluate the potential consequences of such interactions.

Provide a systematic evaluation of the ASI for the AP1000 design, similar to WCAP-14477, Revision 1, or provide detailed justifications, considering the differences between AP600 and AP1000, on why the ASI evaluation performed for the AP600 design and conclusion are applicable to AP1000.

Westinghouse Response:

Systematic evaluation of the ASI for the AP1000 design is provided in WCAP-15992, Rev. 0, "AP1000 Adverse System Interactions Evaluation Report".

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.133

Question:

Section 3.1.13 states that for AP1000 analysis, CMT and accumulator injection to the reactor vessel are input to WCOBRA/TRAC using a FILL component. Please describe how these values are obtained. Include all equations and experimental justification for any standalone calculations.

Westinghouse Response:

The accumulator injection flow rate provided as a FILL component function for the DEDVI break simulation is calculated in a standalone manner by the WCOBRA/TRAC ACCUM component model. The ACCUM component is described in the User's Manual and in the large break LOCA Code Qualification Document, WCAP-12945-P-A, and was approved as part of the approval of the large break LOCA methodology.

The AP1000 accumulator tank parameters and delivery line flow resistance are known from the DCD large break LOCA analysis WCOBRA/TRAC input deck (Ref. 1). Using this information, the accumulator flow rate for the ADS-4 IRWST initiation phase simulation is calculated by initializing to the gas pressure and water mass values taken from the NOTRUMP simulation accumulator parameters at the time of ADS-4 initiation. The downstream pressure for this standalone ACCUM calculation was established in a p Application for Withholding, and Affidavit reliminary WCOBRA/TRAC run simulating the AP1000 ADS-4 IRWST initiation phase.

For the CMT flow, a steady-state momentum balance was performed between the hydrostatic head of the water in the CMT injection line and the pressure drop. The pressure drop is given by

$$\Delta P_{loss} = FLDPFL * m^2 / (2\rho g_c A^2) \qquad (1)$$

where	m	is the mass flow rate of water in the from the CMT
	ρ	is the density of the water in the CMT = 61.7 lb_m/ft^3
	A	is the flow area of the injection line = 0.2541 ft^2
	g_c	is the gravitational constant = 32.2 $lb_m/lb_f\ ft/s^2$
and	FLDPFL	is the loss coefficient from the NOTRUMP model = 23.466

The hydrostatic head is given by

$$\Delta P_{head} = \rho\ g\ z / g_c \qquad (2)$$

where g is the acceleration due to gravity = 32.2 ft/s^2
and z is the elevation of the CMT outlet relative to the DVI line = 26.2 ft

Setting the hydrostatic head equal to the pressure drop and solving for the mass flow,

$$m = 132.44\ lb_m/.s = 60.2\ kg/s$$

This is the value used in the calculation.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 440.162

Question:

Section 2.3.2 provides an assessment of WCOBRA/TRAC-AP using APEX Test SB18. This is a small cold leg break with a simulated failure of one of the ADS-4 lines. Please provide information for the following:

(a) For the comparison of predicted and measured pressurizer levels shown in Figure 2-29, justify the claim that the WC/T level agrees "extremely well" with the data through 1150 seconds, although WC/T clearly underpredicts the level for most of this period and does not capture the oscillations in level that are seen in the data.

(b) The predicted collapsed liquid levels in the downcomer, core, and upper plenum for Test SB18 are shown in Figures 2-31, 2-32, and 2-33, respectively. On page 2-52 the claim is made that the relatively constant code predicted levels are "consistent with the test data." However, no test data are presented in these three Figures. Please provide a meaningful comparison of predicted and measured results to validate this claim.

(c) Page 2-52 describes a "detailed comparison of vessel mass inventory with the test inventory" to show that the WCOBRA/TRAC prediction is in "excellent" agreement with the measured mass reduction during the ADS-4/IRWST initiation phase. There are no Figures comparing the predicted and measured inventories for Test SB18. Please provide this comparison.

(d) Section 2.3.2 concludes that the WCOBRA/TRAC prediction is in reasonable agreement with Test SB18 data and the code can be used in AP1000 calculations. This conclusion is reached with only three comparisons between the predicted and measured results; pressurizer level in Figure 2-29, integrated liquid flow in Figure 2-30, and downcomer pressure in Figure 2-34. Since the system pressure is primarily set by input to the BREAK Components in the model, Figure 2-34 may not be a true indication of code performance. Section 2.2.2 in WCAP-15833 showed that condensation heat transfer is underpredicted and steam flow rates in the hot leg are overpredicted. An overprediction of steam velocities in the hot legs for Test SB18 would result in an overprediction of ADS-4 flows. Thus, the apparently reasonable agreement in Figure 2-30 ADS-4 flow may be right for the wrong reasons. It remains to be shown therefore, that the simulation of Test SB18 is reasonable in comparison to experimental data and free of compensating errors. Please provide sufficient comparisons between predicted and measured results to demonstrate adequate simulation of Test SB18. Included in the comparisons and evaluation of code performance should be ADS-4 steam and liquid flows (not just the total integral), ADS-4 quality, hot leg levels, upper plenum two-phase level, and fluid temperatures throughout the system. Provide information sufficient to characterize how WCOBRA/TRAC predicted entrainment in the upper plenum and hot legs during the simulation of Test SB18.

Westinghouse Response:

a) The WCOBRA/TRAC result is within the fluctuations in the test data through the 1150 second time. Therefore, the agreement is characterized as "reasonable" according to the WCAP-15833 Revision 1 Section 2.3.2 assessment criteria.

b) Figures 440.162-1, 2 and 3 provide the requested comparisons with test data. The code agreement with the upper plenum collapsed liquid level shows that the margin to core uncovery is predicted in a "reasonable" manner by the code. The code predicts less liquid in the downcomer than the data. In Figure 440.162-3, the WCOBRA/TRAC collapsed level shown encompasses a greater span than the length present between the APEX core region pressure taps over which the data was measured. When this is taken into account, the collapsed levels agree even better than the figure indicates. Overall, the level comparisons indicate that the vessel mass prediction is in adequate agreement with the Test SB18 data; the section (c) response provides further information.

c) A plot of the change in reactor vessel mass inventory during the Test SB18 ADS-4 IRWST initiation phase (Figure 440.162-4) is provided for comparison with the WCOBRA/TRAC prediction of this mass inventory change (Figure 440.162-5). Both the test data and the code indicate that a small decrease in the vessel mass inventory occurs by the time of IRWST initiation during Test SB18.

d) Many of the requested comparisons cannot be provided because the necessary test data does not exist for the APEX Facility. Specifically, the ADS-4 steam flow rate was not accurately measured because the flow meters were out of range during the tests. Only the integral liquid flow rates through the ADS-4 flow paths are available. In the absence of the instantaneous steam and liquid flow rate data, the ADS-4 flow quality cannot be calculated. Refer to RAI 440.165 for an estimate of the ADS-4 flow quality for Test SB18.

As regards the requested level comparisons, hot leg levels in the horizontal pipe section are not available for comparison with WCOBRA/TRAC to characterize the entrainment prediction through the ADS-4 offtake. Also, two-phase level in the upper plenum cannot be determined from the available data. The upper plenum collapsed liquid level prediction agrees well with the data as shown in Figure 440.162-1. In the WCOBRA/TRAC test simulation, temperatures are initialized to the NOTRUMP-predicted values to correspond to the method used for the AP1000 calculations. The lower plenum temperature from the test data is presented in Figure 440.162-6 for the ADS-4 IRWST initiation phase of Test SB18. The WCOBRA/TRAC lower plenum temperature is shown in Figure 440.162-7; it exceeds the test value, due to the higher initial value specified at the time that ADS-4 actuates.

Design Control Document (DCD) Revision: None

PRA Revision: None

WCAP Revision: None

(a,b,c)

OSU Test Sb18 2 Inch Cold Leg Break

Upper Plenum Collapsed Levels (Relative to Bottom of Lower Plenum)

Figure 440.162-1

Rev 0

(a b c)

OSU Test Sb18 2 Inch Cold Leg Break

Collapsed Downcomer Levels (Relative to Bottom of Lower Plenum)

Figure 440.162-2

Rev 0

(a,b,c)

OSU Test Sb18 2 Inch Cold Leg Break

Core Collapsed Liquid Levels (Relative to Bottom of Lower Plenum)

Figure 440.162-3

Rev 0

(a,b,c)

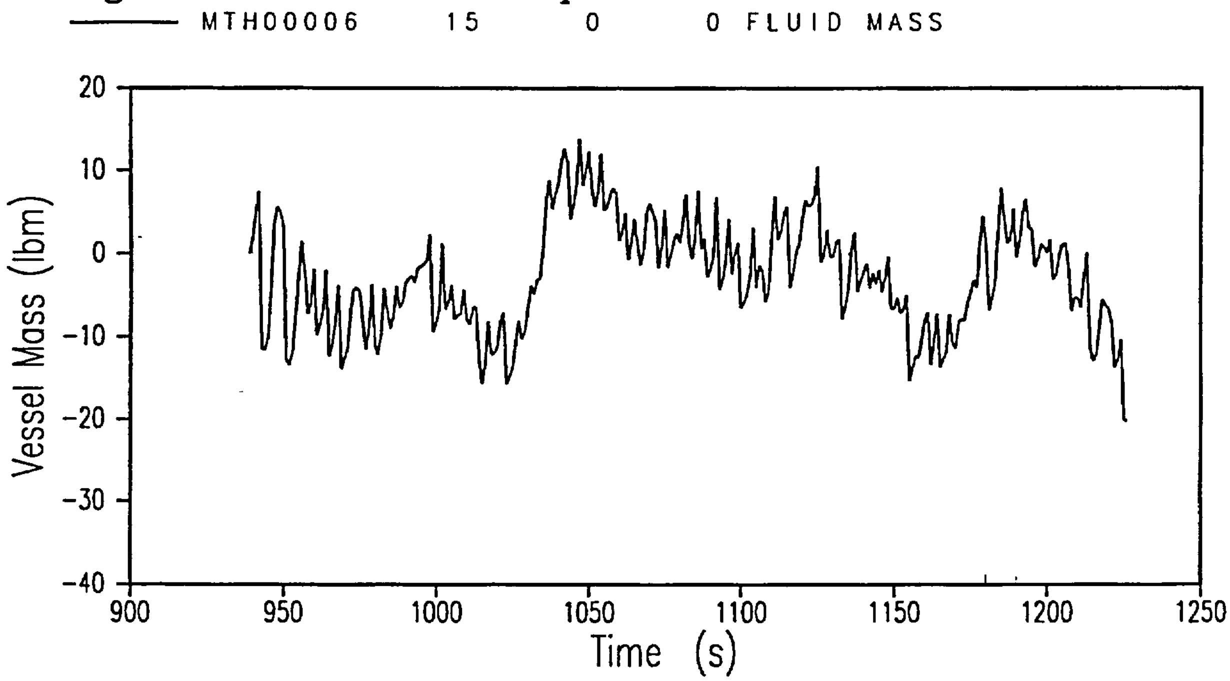
OSU Test Sb18 2 Inch Cold Leg Break

Change In Reactor Vessel Liquid Mass From ADS-4 Actuation

Figure 440.162-4

Rev 0

Figure 440.162-5 WCOBRA/TRAC Simulation of OSU Test SB18 Change in Reactor Vessel Liquid Mass from ADS-4 Actuation



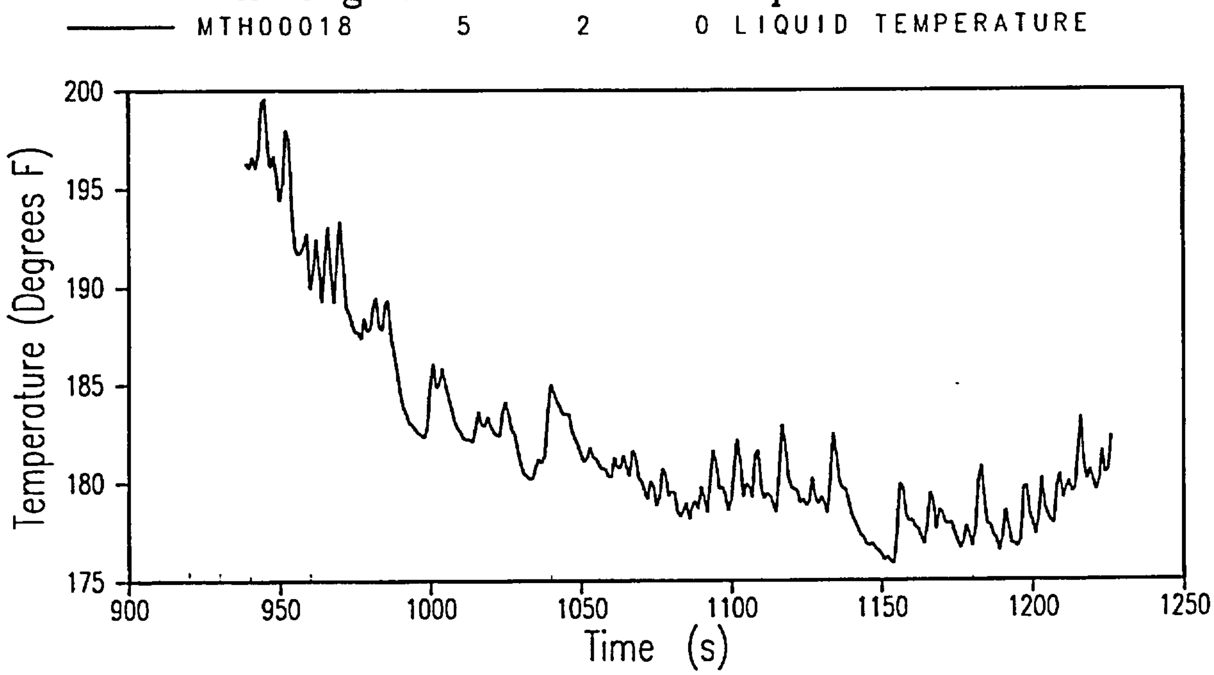
(a b c)

OSU Test Sb18 2 Inch Cold Leg Break
Core Inlet Temperature

Figure 440.162-6

Rev 0

Figure 440.162-7 WCOBRA/TRAC Simulation of OSU Test SB18
Average Lower Plenum Temperature



AP1000 DESIGN CERTIFICATION REVIEW

Response to Request For Additional Information

RAI Number: 471.009

Question:

In response to Question 471.22 for the AP600 (concerning post-accident radiation levels and vital areas), you added Section 12.4.1.8 to the DCD which included a listing of the areas that require post-accident accessibility for the AP600.

A. Verify that the list of vital areas which appears in Section 12.4.1.8 is still an all inclusive list of vital areas for the AP1000.

B. For each of the vital areas listed in Section 12.4.1.8, provide the time period (in hours) following the accident after which it would be necessary to access this area, the time period required for performance of actions at the vital area location (including ingress and egress times), and the integrated whole body dose per individual for each of the vital areas for performance of the vital area duties.

Westinghouse Response:

A. The list of vital areas provided in Section 12.4.1.8 is the appropriate list of areas requiring post-accident access for AP1000.

B. The summary of doses per activity is provided in Table 471.009-1, attached.

Design Control Document (DCD) Revision:

None

PRA Revision:

None

Table 471.009-1

AP1000
Summary of Personnel Exposure for Post-Accident Actions

Area	Time Access is Assumed (Accident is 0 hours)	Duration of Action (Note 1)	Whole Body Dose Received Per Individual REM (Note 1)
Main Control Room - Occupancy	Immediate	30 days (50% occupancy)	0.27
Main Control Room - Ingress and Egress (Note 2)	12 hours	5.4 minutes per ingress or egress	0.34
Spent Fuel Pool Makeup Valve Alignment	64 hours	27.0 minutes	1.11
Passive Containment Cooling System - Long Term Makeup Valve Alignment	64 hours	25.8 minutes	0.065
Ventilation Control for Temporary HVAC to Main Control Room and I&C Equipment Room	64 hours	78.7 minutes	0.063
Electrical Power: Class 1E Regulating Transformer and Ancillary Diesel	64 hours	59.6 minutes	0.57
		Total:	**2.42**

Notes:

1) Duration and dose calculations include ingress and egress except for main control room, where ingress and egress are shown separately.

2) It is assumed that a 12-hour shift begins at the time of the accident. A shift change occurs every 12 hours afterwards for 30 days. The whole body dose for main control room ingress and egress is for one person, entering and exiting once per day for 30 days following the accident.