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July 8, 2005
L-05-112

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Subject: **Beaver Valley Power Station, Unit Nos. 1 and 2**
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173

By letter dated May 5, 2005, the U.S. Nuclear Regulatory Commission (NRC) issued a request for additional information (RAI) pertaining to FirstEnergy Nuclear Operating Company (FENOC) License Amendment Request (LAR) Nos. 302 and 173 (Reference 1). These LARs propose an Extended Power Uprate (EPU) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2. The EPU LAR proposes increasing the licensed power level approximately 8 percent above the current licensed power level.

Enclosure 1, and its attachments, contain the Non-Proprietary FENOC responses to the May 5, 2005 RAI. The Proprietary information in Enclosure 1 has been identified with brackets and deleted.

Enclosure 2, and its attachments, contain the complete responses, including the information proprietary to Westinghouse Electric Company LLC, along with an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b) (4) of Section 2.390 of the Commission's regulations.

The regulatory commitments contained in this submittal are listed in Enclosure 3. The responses contained in this transmittal have no impact on the proposed Technical Specification changes, or the no significant hazards consideration, transmitted by Reference 1.

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If you have questions or require additional information, please contact Mr. Henry L. Hegrat, Supervisor - Licensing, at 330-315-6944.

I declare under penalty of perjury that the foregoing is true and correct. Executed on July 8, 2005.

Sincerely,

L. W. Pearce

L. William Pearce

Enclosures:

1. Non-Proprietary responses to RAI dated May 5, 2005

   Enclosure 1 Attachments

   A. Summary Report for Beaver Valley Units 1 and 2 (DLW/DMW) - Small Break LOCA Licensing Basis Analyses

   B. SUT-08, Semi-Scale Validation Simulation Test

   C. FENOC 10 CFR 50.59 Evaluation Number 98-258 - UFSAR Change Package – Pressurizer Code Safety Valve Operability

2. Affidavit and Proprietary responses to RAI dated May 5, 2005

   Enclosure 2 Attachments

   A. Summary Report for Beaver Valley Units 1 and 2 (DLW/DMW) - Small Break LOCA Licensing Basis Analyses

   B. SUT-08, Semi-Scale Validation Simulation Test

   C. FENOC 10 CFR 50.59 Evaluation Number 98-258 - UFSAR Change Package – Pressurizer Code Safety Valve Operability

3. Commitment List

References:

1. FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

c: Mr. T. G. Colburn, NRR Senior Project Manager
Mr. P. C. Cataldo, NRC Sr. Resident Inspector
Mr. S. J. Collins, NRC Region I Administrator
Mr. D. A. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

L-05-112 Enclosure 1 (Non-Proprietary)

Non-Proprietary responses to RAI dated May 5, 2005

On October 4, 2004 FirstEnergy Nuclear Operating Company (FENOC) submitted license amendment request (LAR) 302 and 173 by letter L-04-125. This submittal requested an Extended Power Uprate (EPU) for Beaver Valley Power Station (BVPS) Unit Nos. 1 and 2 and is known as the EPU LAR.

On April 13, 2005 FENOC submitted LAR 320 by letter L-05-069. This LAR is known as the replacement steam generator (RSG) LAR. The RSG LAR contains the technical specification changes proposed in the EPU LAR that are needed to replace the BVPS Unit No. 1 steam generators and to credit the safety analyses at 2900 MWt.

The following Table of Contents identifies the LAR applicability of the May 5, 2005 RAI questions pertaining to the EPU LAR. An entry of (Applicable to EPU) means that the question is applicable to the EPU LAR. An entry of (Applicable to RSG & EPU) means that the question is applicable to both the EPU and RSG LAR.

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REQUEST FOR ADDITIONAL INFORMATION

RELATED TO FIRSTENERGY NUCLEAR OPERATING COMPANY (FENOC)

BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 (BVPS-1 AND 2)

EXTENDED POWER UPRATE (EPU)

DOCKET NOS. 50-334 AND 50-412

By letter, dated October 4, 2004 (Reference 1), Agencywide Documents Access and Management System (ADAMS) Accession No. ML042920300, FENOC (licensee) proposed changes to the BVPS-1 and 2 operating licenses to increase the maximum authorized power level from 2689 to 2900 megawatts thermal (MWt) rated thermal power (RTP) or approximately 8%. The Nuclear Regulatory Commission (NRC) staff has reviewed the licensee's application against the guidelines in the EPU review standard (Reference 2) and determined that it will need the additional information identified below to complete its review.

General Questions

A.1 (Applicable to RSG & EPU)
Please provide a table listing the key assumptions and input parameter values for all accident analyses in the licensing bases of BVPS-1 and 2, both before and following the proposed power uprate.

Response:

The key assumptions and input parameters are provided in Tables A.1-1A through A.1-23. For certain accident analyses, the EPU Licensing Report Section 5 already contains tables showing key parameters for the proposed EPU conditions. The response provides the same table from the EPU Licensing Report and the current power values have been included. For other accidents that do not include the key input parameters in tabular form, separate tables were created as part of this response.

Table A.1-1A
BVPS-1 Major Plant Parameters
Used in the Best-Estimate Large Break LOCA Analysis
(EPU Licensing Report Table 5.2.1-1A)

Parameter	EPU Value	Current Value
Plant Physical Description		
Steam Generator Tube Plugging	≤ 22 %	≤ 30 %
Plant Initial Operating Conditions		
Reactor Power	≤ 100.6% of 2900 MWt including 0.6% Calorimetric Uncertainty	≤ 100.6% of 2689 MWt including 0.6% Calorimetric Uncertainty
Peaking Factor	F_Q=2.52, $F_{\Delta H}$=1.75	F_Q=N/A, $F_{\Delta H}$=1.62

Table A.1-1A (cont.) BVPS-1 Major Plant Parameters Used in the Best-Estimate Large Break LOCA Analysis (EPU Licensing Report Table 5.2.1-1A)		
Parameter	**EPU Value**	**Current Value**
Fluids Conditions		
RCS Average Temperature (T_{avg})	566.2 ± 4.1°F ≤ T_{avg} ≤ 580.0 ± 4.1°F	576.2°F + 4.5°F
Pressurizer Pressure	2200-2300 psia	2210-2290 psia
Reactor Coolant Flow	≥ 87,200 gpm/loop	≥ 87,200 gpm/loop
Accumulator Temperature	70-105°F	93°F
Accumulator Pressure	575-716 psia	600 psia minimum
Accumulator Water Volume (useable tank volume)	893-1022 ft^3	969-990 ft^3
Accident Boundary Conditions		
Single Failure Assumptions	1 Train of ECCS Pumps	1 Train of ECCS Pumps
Safety Injection Flow	Table A.1-2A	Table A.1-2A
Safety Injection Temperature	45-105°F	50°F
Safety Injection Initiation Delay Time	≤ 17 sec Off-Site Power Available ≤ 27 sec Loss of Off-Site Power (LOOP)	Off-Site Power Available - N/A ≤ 27 sec Loss of Off-Site Power (LOOP)

Table A.1-1B BVPS-2 Major Plant Parameters Used in the Best-Estimate Large Break LOCA Analysis (Licensing Report 5.2.1-1B)		
Parameter	**EPU Value**	**Current Value**
Plant Physical Description		
Steam Generator Tube Plugging	≤ 22 %	≤ 30 %
Plant Initial Operating Conditions		
Reactor Power	≤ 100.6% of 2900 MWt including 0.6% Calorimetric Uncertainty	≤ 100.6% of 2689 MWt including 0.6% Calorimetric Uncertainty
Peaking Factor	F_Q=2.52, $F_{\Delta H}$=1.75	F_Q= N/A, $F_{\Delta H}$=1.62
Fluids Conditions		
RCS Average Temperature (T_{avg})	566.2 ± 4°F ≤ T_{avg} ≤ 580.0 ± 4°F	581.0°F
Pressurizer Pressure	2200-2300 psia	2200-2300 psia
Reactor Coolant Flow	≥ 87,200 gpm/loop	≥ 87,200 gpm/loop
Accumulator Temperature	70-105°F	89°F
Accumulator Pressure	575-716 psia	600 psia minimum
Accumulator Water Volume (useable tank volume)	922-1072 ft^3	1006-1043 ft^3
Accident Boundary Conditions		
Single Failure Assumptions	1 Train of ECCS Pumps	1 Train of ECCS Pumps
Safety Injection Flow	Table A.1-2B	Table A.1-2B
Safety Injection Temperature	45-105°F	50°F
Safety Injection Initiation Delay Time	≤ 17 sec Off-Site Power Available ≤ 27 sec Loss of Off-Site Power (LOOP)	Off-Site Power Available- N/A ≤ 27 sec Loss of Off-Site Power (LOOP)

Table A.1-2A BVPS-1 Best-Estimate Large Break LOCA Total Minimum Injected SI Flow (HHSI and LHSI from 2 Intact Loops) (EPU Licensing Report Table 5.2.1-2A)		
RCS Pressure (psig)	EPU Flow Rate (gpm)	Current Flow Rate
0	2433.0	2402
10	2272.1	2279*
20	2106.2	2157
50	1569.1	1625*
100	338.1	360
105	278.4	239
150	270.4	224*
200	261.4	202
400	219.2	77
600	173.4	0
* interpolated data		

Table A.1-2B BVPS-2 Best-Estimate Large Break LOCA Total Minimum Injected SI Flow (HHSI and LHSI from 2 Intact Loops) (EPU Licensing Report Table 5.2.1-2B)		
RCS Pressure (psig)	EPU Flow Rate (gpm)	Current Flow Rate (gpm)
0	2719.5	2553
10	2556.5	2318*
20	2385.5	2203
50	1807.6	1569*
90	441.3	248*
100	251.5	247*
150	245.2	244*
200	239.1	239
400	215.0	219
600	189.1	173
* interpolated data		

Table A.1-3A BVPS-1 Input Parameters Used in the Small Break LOCA Analysis (EPU Licensing Report Table 5.2.2-1A)		
Input Parameter	**EPU Value**	**Current Value**
Core Rated Thermal Power-100%	2900	2689
Calorimetric Uncertainty, %	0.6	0.6
Fuel Type	17 X 17 Robust Fuel Assembly (RFA)	17 X 17 Robust Fuel Assembly (RFA)
Total Core Peaking Factor, F_Q	2.40	2.40
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	1.62	1.62
Hot Assembly Average Power Factor, P_{HA}	1.42	1.46
Maximum Axial Offset, %	+13	+13
Initial RCS Loop Flow, gpm/loop	82,840	82,840
Initial Vessel T_{avg}, °F	Max: 580.0 + 4 Min: 566.2 – 4	580.0 + 4.1
Initial Pressurizer Pressure (plus uncertainties), psia	2300	2300
Reactor Coolant Pump Type	Model 93A with Weir	Model 93A with Weir
Pressurizer Low-Pressure Reactor Trip Setpoint, psia	1935	1935
Reactor Trip Signal Delay Time, seconds	2.0	2.0
Rod Drop Delay Time, seconds	2.7	2.7
Auxiliary Feedwater Temperature (Maximum), °F	120	120
Number of AFW Pumps Available Following a LOOP	1 Motor Driven	1 Motor Driven
AFW Flow (Minimum) to all 3 Steam Generators, gpm	294 (98 gpm/SG * 3) at 1107 psig	(163 gpm/SG * 3) at 1107 psig
AFW Flow Delay Time (Maximum), seconds	60	60
AFW Actuation Signal	Pressurizer Low-Pressure Safety Injection	Pressurizer Low-Pressure Safety Injection
Steam Generator Type	Model 54F	Model 51
Maximum AFW Piping Purge Volume, ft^3	168	168
Steam Generator Tube Plugging (Maximum), %	10 (PCWG parameters are based on 22%)	30
Maximum MFW Isolation Signal Delay Time, seconds	3	3
MFW Control Valve Isolation Ramp Time, seconds	7	7

Table A.1-3A (cont.) BVPS-1 Input Parameters Used in the Small Break LOCA Analysis (EPU Licensing Report Table 5.2.2-1A)		
Input Parameter	**EPU Value**	**Current Value**
MFW Isolation Signal	Pressurizer Low-Pressure Safety Injection	Pressurizer Low-Pressure Safety Injection
Isolation of Steam Line Signal	Pressurizer Low-Pressure Reactor Trip/LOOP	Pressurizer Low-Pressure Reactor Trip/LOOP
RWST Deliverable Volume (Minimum), gallons	317,000	317,000
SI Temp at Cold Leg Recirculation Time (Maximum), °F	190	190
ECCS Configuration	1 HHSI pump, faulted line injects to RCS pressure	1 HHSI pump, faulted line injects to RCS pressure
ECCS Water Temperature (Maximum), °F	65	105
Pressurizer Low-Pressure Safety Injection Setpoint, psia	1745	1745
SI Flow Delay Time, seconds	27	27
ECCS Flow vs. Pressure	See Table A.1-4	See Table A.1-4
Initial Accumulator Water/Gas Temperature, °F	105	105
Initial Nominal Accumulator Water Volume, ft^3	957	957
Minimum Accumulator Pressure, psia	575	575

Table A.1-3B
BVPS-2 Input Parameters Used in the Small Break LOCA Analysis
(EPU Licensing Report Table 5.2.2-1B)

Input Parameter	EPU Value	Current Value
Core Rated Thermal Power-100%	2900	2689
Calorimetric Uncertainty, %	0.6	0.6
Fuel Type	17 X 17 Robust Fuel Assembly (RFA)	17 X 17 Robust Fuel Assembly (RFA)
Total Core Peaking Factor, F_Q	2.40	2.40
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	1.62	1.62
Hot Assembly Average Power Factor, P_{HA}	1.42	1.42
Maximum Axial Offset, %	+13	+13
Initial RCS Loop Flow, gpm/loop	82,840	82,840
Initial Vessel T_{avg}, °F	Max: 580.0 + 4 Min: 566.2 – 4	576.2 + 2.8
Initial Pressurizer Pressure (plus uncertainties), psia	2300	2292
Reactor Coolant Pump Type	Model 93A with Weir	Model 93A with Weir
Pressurizer Low-Pressure Reactor Trip Setpoint, psia	1935	1935
Reactor Trip Signal Delay Time, seconds	2.0	2.0
Rod Drop Delay Time, seconds	2.7	2.7
Auxiliary Feedwater Temperature (Maximum), °F	120	120
Number of AFW Pumps Available Following a LOOP	1 Motor Driven	1 Motor Driven
AFW Flow (Minimum) to all 3 Steam Generators, gpm	294 (98 gpm/SG *3) at 1107 psig	294 (98 gpm/SG *3) at 1107 psig
AFW Flow Delay Time (Maximum), seconds	60	60
AFW Actuation Signal	Pressurizer Low-Pressure Safety Injection	Pressurizer Low-Pressure Safety Injection
Steam Generator Type	Model 51M	Model 51M
Maximum AFW Piping Purge Volume, ft^3	125.7	125.7
Steam Generator Tube Plugging (Maximum), %	22	25
Maximum MFW Isolation Signal Delay Time, seconds	2	2
MFW Control Valve Isolation Ramp Time, seconds	5	5
MFW Isolation Signal	Pressurizer Low-Pressure Safety Injection	Pressurizer Low-Pressure Safety Injection

Table A.1-3B (cont.) BVPS-2 Input Parameters Used in the Small Break LOCA Analysis (EPU Licensing Report Table 5.2.2-1B)		
Input Parameter	**EPU Value**	**Current Value**
Isolation of Steam Line Signal	Pressurizer Low-Pressure Reactor Trip/LOOP	Pressurizer Low-Pressure Reactor Trip/LOOP
RWST Deliverable Volume (Minimum), gallons	403,000	403,000
SI Temp at Cold Leg Recirculation Time (Maximum), °F	212	212
ECCS Configuration	1 HHSI pump, faulted line injects to RCS pressure	1 HHSI pump, faulted line injects to RCS pressure
ECCS Water Temperature (Maximum), °F	65	65
Pressurizer Low-Pressure Safety Injection Setpoint, psia	1760	1760
SI Flow Delay Time, seconds	27	27
ECCS Flow vs. Pressure	See Table A.1-4	See Table A.1-4
Initial Accumulator Water/Gas Temperature, °F	105	105
Initial Nominal Accumulator Water Volume, ft^3	997	1025
Minimum Accumulator Pressure, psia	575	575

Table A.1-4
Safety Injection Flows Used in the Small Break LOCA Analysis
(1 HHSI pump, faulted loop injects to RCS pressure)
(EPU Licensing Report Table 5.2.2-2)

RCS Pressure (psia)	EPU Value		BVPS-1 Current Value		BVPS-2 Current Value	
	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)
314.7	37.59	20.28	36.1	19.7	33.3*	17.4*
414.7	36.63	19.79	35.1	19.2	32.4	17
514.7	35.56	19.17	34.1	18.7	31.6*	16.5*
614.7	34.45	18.61	33.0	18.0	30.6	16
714.7	33.42	18.06	32	17.5	29.8*	15.6*
814.7	32.34	17.50	31	16.9	28.8	15
914.7	31.25	16.88	29.8	16.3	27.8*	14.6*
1014.7	30.14	16.25	28.7	15.7	26.8	14
1114.7	29.03	15.70	27.5	15.0	25.8*	13.5*
1214.7	27.92	15.07	26.3	14.4	24.7	12.9
1314.7	26.67	14.45	25.0	13.7	23.6*	12.3*
1414.7	25.28	13.61	23.7	13	22.5	11.8
1514.7	23.85	12.92	22.4	12.3	21.8*	11.1*
1614.7	22.43	12.08	20.9	11.4	20.1	10.5
1714.7	20.97	11.39	19.4	10.6	18.8*	9.8*
1814.7	19.50	10.56	17.8	9.7	17.4	9.1

* interpolated values

Table A.1-5 Hot Leg Switchover (EPU Licensing Report Section 5.2.3)					
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**	**Notes**
Accumulator Boron Concentration, ppm B, maximum	2600	2600	2600	2600	
Accumulator Water Deliverable Volume, cubic feet, each, maximum	1022	1072	1022	1072	
RCS Boron Concentration, ppm B maximum	2400	2400	2400	2400	
RCS Mass, lb, maximum	386,000	388,000	382,000	388,000	
Reactor Power, MWt, nominal	2900	2900	2689	2689	
Calorimetric Uncertainty, %	0.6	0.6	0.6	0.6	
RWST Boron Concentration, ppm B, maximum	2600	2600	2600	2600	
RWST Useable Volume, gal, maximum	441,100	910,000	436,500	910,000	
SI Flow Rate Used in Switchover Analysis, gpm	289	289	279.5	279.5	
Decay Heat Model	ANS 1971 finite	ANS 1971 finite	ANS 1971 finite	ANS 1971 finite	RAI responses are based on 1971 ANS, Infinite, 20% margin

Table A.1-6 Post LOCA Subcriticality and Long Term Cooling (EPU Licensing Report Section 5.2.4)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
Accumulator Boron Concentration, ppm B, minimum	2300	2300	2300	2300
Accumulator Water Deliverable Volume, cubic feet, each, minimum	893	922	893	922
RCS Boron Concentration, ppm B, minimum	0	0	0	0
RCS Mass, lb, maximum	502,000	497,000	508,700	500,000
RWST Boron Concentration, ppm B, minimum	2400	2400	2400	2400
RWST Useable Volume Before Switchover, gal, minimum	317,000	368,000	275000	328,000

Table A.1-7 Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition (EPU Licensing Report Section 5.3.2)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
Delayed Neutron Fraction, maximum	0.0075	0.0075	0.0075	0.0075
Reactivity Insertion Rate, pcm/s, maximum	75	75	75	75
Doppler Power Defect, pcm, minimum	962	962	962	962
Moderator Temperature Coefficient, pcm/°F, maximum	+5	+5	+2	+2
Initial NSSS Power, MWt, nominal	2910	2910	2697	2697
Initial Power Level, fraction, minimum	10^{-9}	10^{-9}	10^{-9}	10^{-9}
Initial RCS Flow, 2 RCPs operating, gpm, minimum	162,192	162,192	162,192	162,192
Initial RCS Vessel Average (T_{avg}) Temp – Zero (No) Load, °F, nominal	547.0	547.0	547.0	547.0
Initial RCS Pressure, psia, minimum	2205	2205	2210	2205

Table A.1-8
Uncontrolled RCCA Bank Withdrawal at Power
(EPU Licensing Report Section 5.3.3)

Parameter Name	BVPS-1 EPU Value	BVPS-2 EPU Value	BVPS-1 Current Value	BVPS-2 Current Value
Delayed Neutron Fraction for Minimum Feedback Case, minimum	0.0047	0.0047	0.0047	0.0047
Delayed Neutron Fraction for Maximum Feedback Case, maximum	0.0075	0.0075	0.0075	0.0075
Reactivity Insertion Rate, pcm/sec	Up to 110	Up to 110	Up to 110	Up to 110
Moderator Feedback for Minimum Feedback Case (MTC), pcm/°F, maximum	+5	+5	+2	+2
Moderator Feedback for Maximum Feedback Case (MDC), Δk/gm/cc, maximum	0.43	0.43	0.43	0.43
Initial NSSS Power, MWt, nominal	2910	2910	2697	2697
Initial Power Level, fraction of nominal	1.0, 0.6, & 0.1	1.0, 0.6, & 0.1	1.0, 0.6, & 0.1	1.0, 0.6, & 0.1
Initial Pzr Pressure, psia, nominal with bias	2250	2242.5	2250	2242.5
Initial RCS Minimum Measured Flow, gpm, nominal	266,800	266,800	266,800	266,800
RCS Vessel Average (T_{avg}) Temp, °F, nominal with bias	581 (100% RTP), 567.8 (60% RTP), & 551.3 (10% RTP)	581 (100% RTP), 567.8 (60% RTP), & 551.3 (10% RTP)	580.9 (100% RTP), 569.2 (60% RTP), & 554.6 (10% RTP)	580.9 (100% RTP), 569.2 (60% RTP), & 554.6 (10% RTP)

Table A.1-9 Uncontrolled Boron Dilution (EPU Licensing Report Section 5.3.5)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
Charging Pump Capacity for Boron Dilution Event – Mode 1, Mode 2 & Mode 3, gpm, maximum	231	231	231	231
Mode 1/2 Critical Boron Concentration, ppm B, maximum	1500	1500	1500	1500
Mode 3 Critical Boron Concentration, ppm B, maximum	1900	1900	N/A	1475
RCS Active Water Volume (Mode 1 & Mode 2), cubic feet, nominal	7593	7520	7506	7522
RCS Active Water Volume (Mode 3), cubic feet, nominal	6964	6893	N/A	6,895
RCS Pressure, psia, nominal	2250	2250	2250	2250
RCS Average (T_{avg}) Temp – Mode 1, °F, maximum	588.5	588.5	583.8	583.7
RCS Average (T_{avg}) Temp – Mode 2, °F. maximum	557.2	557.2	556.0	556.0
RCS Average (T_{avg}) Temp – Mode 3, °F, maximum	547.0	547.0	547.0	547.0

Table A.1-10 Loss of External Load and/or Turbine Trip (EPU Licensing Report Section 5.3.6)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
Loss of load/turbine trip (DNB Case)				
Moderator Temperature Coefficient, pcm/°F, maximum	0	+5	+2	+2
Initial NSSS Power, MWt, nominal	2910	2910	2697	2697
Initial Pzr Pressure, psia, nominal with bias	2250	2242.5	2250	2242.5
RCS Vessel Average (T_{avg}) Temp, °F, nominal with bias	584.5	584.5	580.9	580.9
Initial RCS Minimum Measured Flow, gpm, nominal	266,800	266,800	266,800	266,800
Loss of load/turbine trip (Pressure Case)				
Moderator Temperature Coefficient, pcm/°F, maximum	0	+5	+2	+2
Initial NSSS Power, MWt, maximum	2927.5	2927.5	2713.2	2713.2
Initial Pzr Pressure, psia, minimum	2210	2205	2210	2205
RCS Vessel Average (T_{avg}) Temp, °F, maximum	588.5	588.5	583.8	583.7
Initial RCS Thermal Design Flow, gpm, nominal	261,600	261,600	261,600	261,600

Table A.1-11 Loss of Normal Feedwater and Loss of AC Power to the Station Auxiliaries (EPU Licensing Report Sections 5.3.7 & 5.3.8)					
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**	**Notes**
AFW Flow Delay (from SG low-low level to AFW pumps at full speed), seconds, maximum	60	60	60	60	
AFW Flow, gpm, minimum	489 evenly split	400 evenly split	315 evenly split	345 evenly split	
AFW Purge Volume, per loop, cubic feet, maximum	168	125.7	139.46	125.7	
Moderator Temperature Coefficient, pcm/°F, maximum	0	0	0	0	
Initial NSSS Power, MWt, maximum	2927.5	2927.5	2713.2	2713.2	
Pzr Pressure, psia, range, minimum and maximum	2210 & 2290	2205 & 2295	2220 & 2280	2205 & 2295	
Initial RCS Vessel Average (T_{avg}) Temp, High T_{avg} Case, °F, range, maximum	588.5 & 570.5	588.5 & 570.5	581.72 & 573.72	583.7 & 566.7	Both biases are evaluated.
Initial RCS Vessel Average (T_{avg}) Temp, Low T_{avg} Case, °F, range, minimum	574.7 & 556.7	574.7 & 556.7	N/A	N/A	Both biases are evaluated.
Initial RCS Thermal Design Flow, gpm, nominal	261,600	261,600	265,500	261,600	

Table A.1-12
Excessive Heat Removal Due to Feedwater Malfunctions
(EPU Licensing Report Section 5.3.9)

Parameter Name	BVPS-1 EPU Value	BVPS-2 EPU Value	BVPS-1 Current Value	BVPS-2 Current Value	Notes
Feedwater Malfunction – Feedwater Flow Increase					
Feedwater Flow to SG with Open FCV – Full Power Case, fraction of nominal, maximum	1.64	1.56	1.37	1.60	
Feedwater Flow to SG with Open FCV – Zero Power Case, fraction of nominal, maximum	1.87	1.75	1.65	1.70	
Initial NSSS Power, MWt, nominal	2910	2910	2697	2697	
Initial Power Level, fraction of nominal	1.0 & 0.0	1.0 & 0.0	1.0 & 0.0	1.0 & 0.0	
Initial Pzr Pressure, psia, nominal with bias	2250	2242.5	2250	2242.5	
Initial RCS Minimum Measured Flow/Thermal Design Flow, gpm, RTDP/STDP	266,800 (100% Power Case) & 261,600 (0%) Power Case	266,800 (100% Power Case) & 261,600 (0%) Power Case	266,800 (100% Power Case) & 261,600 (0%) Power Case	266,800 (100% Power Case) & 261,600 (0%) Power Case	
Initial RCS Vessel Average (T_{avg}) Temp, °F, nominal with bias	584.5 (100% Power Case) & 547 (0% Power Case)	584.5 (100% Power Case) & 547 (0% Power Case)	580.9 (100% Power Case) & 547 (0% Power Case)	580.9 (100% Power Case) & 547 (0% Power Case)	
Initial Feedwater Temperature, °F, minimum	400 (100% Power Case) & 32 (0% Power Case)	400 (100% Power Case) & 32 (0% Power Case)	439.3 (100% Power Case) & 32 (0% Power Case)	439.3 (100% Power Case) & 32 (0% Power Case)	Westinghouse methodology runs multiple cases to determine the worst case.
Feedwater Malfunction – Feedwater Temperature Decrease					
Initial NSSS Power, MWt, nominal	2910	2910	N/A	N/A	
Initial Power Level, fraction of nominal	1.0	1.0	N/A	N/A	
Initial Pzr Pressure, psia, nominal with bias	2250	2242.5	N/A	N/A	

Table A.1-12 (cont.) Excessive Heat Removal Due to Feedwater Malfunctions (EPU Licensing Report Section 5.3.9)					
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**	**Notes**
Initial RCS Minimum Measured Flow, gpm, nominal	266,800	266,800	N/A	N/A	
Initial RCS Vessel Average (T_{avg}) Temp, °F, nominal with bias	584.5	584.5	N/A	N/A	
Initial Feedwater Temperature, °F, maximum	455	455	N/A	N/A	Westinghouse methodology runs multiple cases to determine the worst case.
Feedwater Temperature Reduction to all SGs, Delta F, maximum	155	155	N/A	N/A	

Table A.1-13 Excessive Load Increase Incident (EPU Licensing Report Section 5.3.10)					
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**	**Notes**
Initial Reactor Power, MWt, nominal	2900	2900	2689	2689	
Initial Pzr Pressure, psia, nominal with bias	2242.5	2242.5	2242	2242	
Initial RCS Minimum Measured Flow, gpm, nominal	266,800	266,800	266,800	266,800	RTDP methodology
Initial RCS Vessel Average (T_{avg}) Temp, HFP, High T_{avg} Case, °F, nominal	580.0	580.0	580.9	580.9	

Table A.1-14 Accidental Depressurization of the RCS (EPU Licensing Report Section 5.3.11)					
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**	**Notes**
Initial NSSS Power, MWt, nominal	2910	2910	2697	2697	
Moderator Temperature Coefficient, pcm/°F, maximum	+5	+5	+2	+2	
Initial Pzr Pressure, psia, nominal with bias	2250	2242.5	2250	2242.5	
Initial RCS Flow, total gpm, nominal	266,800	266,800	266,800	266,800	RTDP methodology
Initial RCS Vessel Average (T_{avg}) Temp, °F, nominal with bias	584.5	584.5	580.9	580.9	

Table A.1-15 Major Rupture of a Main Steam Pipe (EPU Licensing Report Section 5.3.12)					
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**	**Notes**
Break Area, square feet, maximum	1.4 (U1 RSG)	1.069	1.4 & 4.6	1.4	
Accumulator Boron Concentration, ppm B, minimum	2300	2300	1900	1900	
Accumulator Actuation Pressure, psia, minimum	575	575	600	600	
AFW Flow, gpm, maximum	930	930	1400	1400	Flow limited by cavitating venturis in EPU analysis.
Safety Injection Mass Flow Rate, lb/sec, minimum	See Table A.1-15B	See Table A.1-15B	See Table A.1-15A	See Table A.1-15A	
RWST Boron Concentration, ppm B, minimum	2400	2400	2000	2000	
Pzr Pressure, psia, nominal	2250	2250	2250	2250	
Initial RCS Thermal Design Flow, gpm, minimum	261,600	261,600	265,500	265,500	STDP methodology
RCS Vessel Average (T_{avg}) Temp, no load, °F, nominal	547	547	547	547	
Shutdown Margin, delta K/K, minimum	1.77	1.77	1.77	1.77	

Table A.1-15A Current Safety Injection Flow vs. Pressure For HZP Main Steamline Break (EPU Licensing Report Section 5.3.12)	
RCS Pressure (psia)	Mass Flow (lbm/sec) BVPS-1 and BVPS-2 Value
215	63.13
415	60.49
815	57.65
1015	51.34
1215	47.88
1415	44.21
1815	40.26
2015	30.9
2215	24.46
2412	10.06

Table A.1-15B EPU Safety Injection Flow vs. Pressure For HZP Main Steamline Break (EPU Licensing Report Section 5.3.12)		
RCS pressure (psia)	Mass Flow (lbm/sec)	
	BVPS-1 Value	BVPS-2 Value
214.7	59.7	53.2
614.7	53.3	47.4
814.7	49.8	43.3
1014.7	46.2	39.3
1214.7	42.4	35.6
1414.7	38.2	31.6
1614.7	33.7	27.2
1814.7	28.7	22.3
2014.7	22.7	16.0

Table A.1-16 Loss of Reactor Coolant Flow/Single Reactor Coolant Pump Locked Rotor (EPU Licensing Report Sections 5.3.13, 5.3.14 & 5.3.15)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
Loss of Flow/Locked Rotor (DNB Case)				
NSSS Power, MWt, nominal	2910	2910	2697	2697
Initial RCS Vessel Average (T_{avg}) Temp, °F, nominal with bias	584.5	584.5	580.7	580.9
Initial Pzr Pressure, psia, nominal with bias	2250	2242.5	2250	2242.5
Initial RCS Minimum Measured Flow, gpm, nominal	266,800	266,800	266,800	266,800
$F_{\Delta H}$ – Full Power, maximum	1.68	1.68	1.68	1.68
Locked Rotor (Pressure Case)				
NSSS Power, MWt, maximum	2927.5	2927.5	2713.2	2713.2
Initial RCS Vessel Average (T_{avg}) Temp, °F, maximum	588.5	588.5	583.8	583.8
Initial Pzr Pressure, psia, maximum	2290	2295	2290	2295
Initial RCS Thermal Design Flow, gpm, minimum	261,600	261,600	261,600	261,600
$F_{\Delta H}$ – Full Power, maximum	1.75	1.75	1.75	1.75
Moderator Temperature Coefficient, pcm/°F, maximum	0	0	0	0

Table A.1-17 Rupture of a Control Rod Drive Mechanism Housing Rod Cluster Control Assembly Ejection (EPU Licensing Report Section 5.3.16)					
Parameter Name	BVPS-1 EPU Value	BVPS-2 EPU Value	BVPS-1 Current Value	BVPS-2 Current Value	Notes
Core Power Level, %, nominal	(0)/100	(0)/100	(0)/100	(0)/100	(zero power)/ 100% power
Ejected Rod Worth (end of cycle), % Delta K, maximum	(.98)/.21	(.98)/.21	(1.0)/.21	(1.0)/.21	(zero power)/ 100% power
Ejected Rod Worth (beginning of cycle), % Delta K, maximum	(0.7)/0.2	(0.7)/0.2	(0.7)/0.2	(0.7)/0.2	(zero power)/ 100% power
Delayed Neutron Fraction (end of cycle), %	.47	.47	.44	.44	
Delayed Neutron Fraction (beginning of cycle), %	.55	.55	.55	.55	
Feedback Reactivity Weighting (beginning of cycle)	(1.866)/1.5	(1.866)/1.5	(1.866)/1.5	(1.744)/1.3	(zero power)/ 100% power
Feedback Reactivity Weighting (end of cycle)	(3.62)/1.567	(3.62)/1.567	(3.62)/1.587	(3.55)/1.6	(zero power)/ 100% power
Trip Reactivity (beginning and end of cycle), % Delta K	(2.0)/4.0	(2.0)/4.0	(2.0)/4.0	(2.0)/4.0	(zero power)/ 100% power
Operational Loops	(2)/3	(2)/3	(2)/3	(2)/3	(zero power)/ 100% power

Table A.1-18 Rupture of a Main Feedwater Pipe (EPU Licensing Report Section 5.3.17)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
AFW Flow Delay (from SG low-low level to AFW pumps at full speed), seconds, maximum	60	60	60	60
AFW Flow, Total gpm, minimum	See Table A.1-18A	See Table A.1-18A	none prior to isolation, 300 after isolation (10 minutes).	250 gpm prior to isolation, 400 after isolation (15 minutes)
AFW Purge Volume, per loop, ft^3/loop, maximum	168	125.7	168	125.7
Feedwater Temperature, °F, maximum	455	455	439.3	439.3
Moderator Coefficient, pcm/°F (MTC) or Δk/g/cc (MDC), maximum	+5 MTC or 0.43 MDC	+5 MTC or 0.43 MDC	+2 MTC or 0.43 MDC	+2 MTC or 0.43 MDC
Initial NSSS Power, MWt, maximum	2927.5	2927.5	2713	2713
Pzr Pressure, psia, minimum	2210	2205	2210	2205
RCS Vessel Average (T_{avg}) Temp, °F, maximum	588.5	588.5	583.8	583.7
SG Level Uncertainty, %, maximum	+10% for faulted SGs and -10% for intact SGs	+7% for faulted SGs and -10.3% for intact SGs	+6 % for faulted SGs and -6 % for intact SGs	+6 % for faulted SGs and -6 % for intact SGs
Break Size, square feet	0.922	0.717 & 1.36	0.717 & 1.36	0.717 & 1.36
Initial RCS Thermal Design Flow, gpm, minimum	261,600	261,600	261,600	261,600

Table A.1-18A EPU Feedline Break AFW Flows (EPU Licensing Report Section 5.3.17)	
250 gpm pre-isolation	split equally to 2 intact SGs
400 gpm post-isolation	split equally to 2 intact SGs
Isolation is assumed 15 minutes after rod motion	

Table A.1-19 Spurious Operation of the Safety Injection System at Power (EPU Licensing Report Section 5.3.18)				
Parameter Name	BVPS-1 EPU Value	BVPS-2 EPU Value	BVPS-1 Current Value	BVPS-2 Current Value
Initial NSSS Power, MWt, maximum	2927.5	2927.5	2660	2713.2
Initial RCS Thermal Design Flow, gpm, minimum	261,600	261,600	265,500	261,600
Initial Pzr Pressure, psia, minimum	2210	2205	2220	2200
Initial Pressurizer level, % span, maximum	50	50	53	59
RCS Vessel Average (T_{avg}) Temp, °F, minimum	556.7	556.7	572.2	569.2
SI Flow Rate vs. Pressure, lbm/sec vs. psia, maximum	See Table A.1-19C	See Table A.1-19C	See Table A.1-19A	See Table A.1-19B

Table A.1-19A BVPS-1 Current Maximum SI Flow Rates For Spurious Safety Injection (EPU Licensing Report Section 5.3.18)	
RCS Pressure (psia)	SI Mass Flow (lbm/sec)
1415	44.2
1815	40.3
2015	30.9
2215	24.5
2415	10.1

Table A.1-19B BVPS-2 Current Maximum SI Flow Rates For Spurious Safety Injection (EPU Licensing Report Section 5.3.18)	
RCS Pressure (psia)	SI Mass Flow (lbm/sec)
1614.7	67.4
1814.7	60.7
2014.7	53.6
2214.7	45.4
2314.7	40.8
2414.7	35.9
2514.7	25.8
2614.7	10.7
2700	10.7
2800	10.7

Table A.1-19C EPU Maximum SI Flow Rates For Spurious Safety Injection (EPU Licensing Report Section 5.3.18)	
RCS Pressure (psia)	SI Mass Flow (lbm/sec)
1014.7	96.4
1214.7	90.6
1414.7	84.7
1614.7	77.7
1814.7	70.4
2014.7	63.0
2214.7	54.3
2414.7	33.5
2614.7	7.6
2634.7	0.0

Table A.1-20 Steam System Piping Failure at Full Power (EPU Licensing Report Section 5.3.19)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
Break Size, square feet	Range from 0.1 to 1.4	Range from 0.1 to 1.4	*	*
Feedwater Temperature, °F, minimum	400	400	*	*
Moderator Feedback, $\Delta k/g/cc$, maximum	0.43	0.43	*	*
Initial NSSS Power, MWt, nominal	2910	2910	*	*
Initial Pressurizer Pressure, psia, nominal with bias	2250	2242.5	*	*
Initial RCS Minimum Measured Flow, gpm, nominal	266,800	266,800	*	*
Initial RCS Vessel Average (T_{avg}) Temp, °F, nominal with bias	584.5	581.0	*	*

* As described in Section 5.3.1, the limiting steamline break for current conditions is a break initiated from Hot Zero Power (based on the conclusions of WCAP-9226). Thus, an analysis for steamline break initiated from Hot Full Power is not required for current conditions.

Table A.1-21 Steam Generator Tube Rupture Releases for Offsite Dose Analysis (EPU Licensing Report Section 5.4.1 and 5.4.3)				
Parameter Name	**BVPS-1 EPU Value**	**BVPS-2 EPU Value**	**BVPS-1 Current Value**	**BVPS-2 Current Value**
Reactor Power, MWt, nominal	2900	2900	2689	2689
Reactor Power Uncertainty, %, maximum	0.6	0.6	0.6	0.6
Decay Heat Model	ANS 1971 + 20%	ANS 1971 + 20%	ANS 1971 + 20%	ANS 1971 + 20%
Main Feedwater Temperature HFP, F, maximum	455	455	437.5	437.5
Main Feedwater Temperature HFP, F, minimum	400	400	437.5	437.5
RCS Vessel Average (T_{avg}) Temp, HFP, High T_{avg} Case, °F, nominal	580	580	576.2	576.2
SG Tube Plugging, %, minimum	0	0	0	0

Table A.1-22
Steam Generator Tube Rupture Overfill Analysis
(EPU Licensing Report Section 5.4.2)

Parameter Name	BVPS-1* EPU Value	BVPS-2 EPU Value	BVPS-2 Current Value	Notes
AFW Flow, Total gpm, maximum	930	930	930	Split evenly
Identify and isolate MSIV for ruptured SG, after Rx trip, minutes	16.7	15	10.75 from the beginning of the event	
Initiate RCS cooldown by local operation of Residual Heat Removal Valve (RHRV) and/or ASDV, after MSIV closure, minutes	10	7	Not used	Single failure case, different failure combinations analyzed
Initiate RCS cooldown by operation of two ASDVs from MCR, after MSIV closure, minutes	2.4	2	Operation of ASDVs in 9 minutes	No failure case, different failure combinations analyzed
Initiate RCS depressurization, after cooldown, minutes	4.9	4	2.5	
Initiate SI Termination, after depressurization, minutes	3	3	1.25	
Isolate/control AFW to ruptured SG, after Rx trip, minutes	6.8	5.5	10.75 from the beginning of the event	
Main Feedwater Temperature HFP, °F, minimum	400	400	437.5	
Pzr PORV Capacity, per valve, lb/hr, nominal	210,000 @ 2500 psia	232,000 @ 2350 psia	210,000	
Pzr Pressure Uncertainty, psi, maximum	+/- 40	+/- 45	30	
RCS Pressure, psia, nominal	2250	2250	2250	
RCS Vessel Average (T_{avg}) Temp, HFP, Low T_{avg} Case, °F, nominal	566.2	566.2	576.2	
SG Tube Plugging,%, maximum	22	22	30	
SG Water Level, Greater than 20% Power, % narrow range, nominal	65 (U1 RSG)	44	44	
SI Act – Pressurizer Pressure, psig, nominal	1845	1856	1856	
SI Flow Rate vs. Pressure (Max Safeguards), gpm vs. psig, maximum	See Table A.1-22B	See Table A.1-22B	See Table A.1-22A	
SI Full Flow Delay (without offsite power), seconds, nominal	10	10	0	

* Unit 1 EPU information presented is the LOFTTR2 operational response analysis. There is no current Unit 1 LOFTTR2 operational response analysis.

Table A.1-22A BVPS-2 Current Total Injected Flow into Core vs. RCS Backpressure For SGTR Overfill (EPU Licensing Report Section 5.4.2)		
RCS Pressure (psig)	Injected Flow (lb/sec)	Injected Flow (gpm)
1000	85.56	611.5
1200	81.06	579.3
1400	76.29	545.2
1600	71.16	508.6
1800	65.58	468.7
2000	59.38	424.4
2200	52.27	373.6
2400	43.70	312.3
2600	32.16	229.8

Table A.1-22B EPU Total Injected Flow into Core vs. RCS Backpressure For SGTR Overfill (EPU Licensing Report Section 5.4.2)	
RCS Pressure (psig)	Injected Flow (gpm)
0	788
100	775.3
200	762
400	731
600	699.4
800	664.3
1000	627.3
1200	589
1400	547.6
1600	504
1800	456
2000	402.7
2200	342
2400	253
2600	153.2

As indicated in the EPU Licensing Report, the impact of EPU on the site boundary and control room doses are discussed for the following accidents applicable to the BVPS licensing basis:

1. Loss of Coolant Accident (LOCA)
2. Control Rod Ejection Accident (CREA)
3. Main Steam Line Break (MSLB) Outside Containment
4. Steam Generator Tube Rupture (SGTR)
5. Locked Rotor Accident (LRA)
6. Loss of AC Power (LACP)
7. Fuel Handling Accident (FHA) in the Fuel Pool or in Containment
8. Small Line Break (SLB) Outside Containment
9. Waste Gas System Rupture (WGSR)

As part of the EPU, BVPS proposed: a) the full implementation of Alternative Source Terms (AST), as outlined in Regulatory Guide 1.183 for purposes of assessing dose consequences at the site boundary and in the control room, and b) use of ARCON96 methodology to determine on-site atmospheric dispersion factors.

The key assumptions and input parameter values used in the radiological dose consequence analyses for the EPU are provided in the text and associated tables presented in Section 5.11.9 of the EPU Licensing Report. Source terms and computer codes used for the assessment are discussed in Sections 5.11.4 and 5.11.3, respectively. Regulatory acceptance criteria used for the assessment are summarized in Section 5.11.2.

The methodology and acceptance criteria used for the EPU are different from that listed in the current licensing basis, which, except as noted, are based on: a) meeting the dose acceptance criteria of 10 CFR 100.11 (as modified by NUREG 0800) and General Design Criteria (GDC) 19 and, b) using on-site atmospheric dispersion factors based on Ramsdell methodology. A selective implementation of AST has been previously approved for the BVPS: a) FHA via the NRC Safety Evaluation Report (SER) associated with issuance of operating license (OL) Amendments 241/121, and b) LOCA and CREA via the NRC SER associated with issuance of OL Amendments 257/139. On-site atmospheric dispersion factors based on ARCON96 were used for the LOCA and CREA evaluations.

The key assumptions and input parameters used in the radiological dose consequence analyses supporting the current licensing basis (CLB) are provided in the BVPS-1 and 2 UFSARs as updated by the NRC Safety Evaluation Report associated with issuance of Amendments 257/139. See Table A.1-23 for details.

Table A.1-23 Radiological Dose Consequence Analysis Key Assumptions /Input Parameter Values			
Accident	**BVPS-1 CLB**	**BVPS-1 CLB**	**EPU Licensing Basis**
LOCA	NRC SER for Amendment 257	NRC SER for Amendment 139	EPU LR Section 5.11.9.5
CREA	NRC SER for Amendment 257	NRC SER for Amendment 139	EPU LR Section 5.11.9.6
MSLB	UFSAR Section 14.2.5 as updated by NRC SER for Amendment 257 (UFSAR Table 14.2-10)	UFSAR Section 15.1.5 as updated by NRC SER for Amendment 139 (UFSAR Table 15.1-3)	EPU LR Section 5.11.9.7 (Table 5.11.9-4A/B)
SGTR	UFSAR Section 14.2.4 (UFSAR Table 14.2-9)	UFSAR Section 15.6.3 (UFSAR Table 15.6-5A/B)	EPU LR Section 5.11.9.8 (Table 5.11.9-5A/B)
LRA	UFSAR Section 14.2.7 as updated by NRC SER for Amendment 257 (UFSAR Table 14.2-4B)	UFSAR Section 15.3.3 (UFSAR Table 15.3-3)	EPU LR Section 5.11.9.9 (Table 5.11.9-6)
LACP	UFSAR Section 14.1.11 (UFSAR Table 14.1.3)	UFSAR Section 15.2.6 (UFSAR Table 15.2-2)	EPU LR Section 5.11.9.9 (Table 5.11.9-7)
FHA	UFSAR Section 14.2.1 (UFSAR Table 14.2-6)	UFSAR Section 15.7.4 (UFSAR Table 15.7-6)	EPU LR Section 5.11.9.10 (Table 5.11.9-8)
SLB	UFSAR Section 11.3.5 (UFSAR Table 14.3-10)	UFSAR Section 15.6.2 (UFSAR Table 15.6-2)	EPU LR Section 5.11.9.11 (Table 5.11.9)
WGSR	UFSAR Section 14.2.3 (UFSAR Table 14.2-8)	UFSAR Section 15.7.1 (UFSAR Table 15.7-1)	EPU LR Section 5.11.9.12 (Table 5.11.9-10)

A.2 (Applicable to RSG & EPU)

Please provide a summary table listing all accident analyses in the licensing bases of BVPS-1 and 2 and how they're shown to meet applicable acceptance criteria under the conditions of the proposed license amendment (e.g., by re-analysis, by evaluation, by being bounded by current licensing basis analyses, or by not being affected by the requested license amendment).

Response:

Tables A.2-1A and A.2-1B define how the acceptance criteria for each accident are confirmed and documented.

Table A.2-1A
BVPS-1 Summary of Event Discussions

UFSAR Section	Report Section	UFSAR Event	Acceptance Criteria Demonstrated
14.1.1	5.3.2	Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition	Specific analysis for EPU
14.1.2	5.3.3	Uncontrolled RCCA Bank Withdrawal at Power	Specific analysis for EPU
14.1.3	5.3.4	RCCA Misalignment	Specific analysis for EPU demonstrating applicability of the generic analysis
14.1.4	5.3.5	Uncontrolled Boron Dilution	Specific analysis for EPU
14.1.5	5.3.13	Partial Loss of Forced Reactor Coolant Flow	Specific analysis for EPU
14.1.6	5.3.1	Startup of an Inactive Reactor Coolant Loop	(Note 1)
14.1.7	5.3.6	Loss of External Electrical Load and/or Turbine Trip	Specific analysis for EPU
14.1.8	5.3.7	Loss of Normal Feedwater	Specific analysis for EPU
14.1.9	5.3.9	Excessive Heat Removal Due to Feedwater System Malfunctions	Specific analysis for EPU
14.1.10	5.3.10	Excessive Load Increase Incident	Specification evaluation for EPU
14.1.11	5.3.8	Loss of Offsite Power to the Station Auxiliaries (Station Blackout)	Specific analysis for EPU
14.1.12	N/A	Turbine Missiles	Not affected by EPU
14.1.13	5.3.1	Accidental Depressurization of Main Steam System	(Note 1)
14.1.14	N/A	Accidents Due to External Environmental Causes	Not affected by EPU
14.1.15	5.3.11	Accidental Depressurization of the Reactor Coolant System	Specific analysis for EPU
14.1.16	5.3.18	Spurious Operation of the Safety Injection System at Power	Specific analysis for EPU

Table A.2-1A (cont.)
BVPS-1 Summary of Event Discussions

UFSAR Section	Report Section	UFSAR Event	Acceptance Criteria Demonstrated
14.2.1	5.11.9.10	Fuel Handling Accident	Specific analysis for EPU
14.2.2	N/A	Accident Release of Waste Liquid	UFSAR conclusions not affected by EPU
14.2.3	5.11.9.12	Accident Release of Waste Gases	Specific analysis for EPU
14.2.4	5.4.1	Steam Generator Tube Rupture	Specific analysis for EPU
14.2.5.1	5.3.12	Major Rupture of a Main Steam Pipe	Specific analysis for EPU
14.2.5.2	5.3.17	Major Rupture of a Main Feedwater Pipe	Specific analysis for EPU
14.2.6	5.3.16	Rupture of a Control Rod Drive Mechanism Housing RCCA Ejection	Specific analysis for EPU
14.2.7	5.3.15	Single Reactor Coolant Pump Locked Rotor	Specific analysis for EPU
14.2.8	N/A	Inadvertent Loading of a Fuel Assembly into an Improper Position	UFSAR conclusions not affected by EPU
14.2.9	5.3.14	Complete Loss of Forced Reactor Coolant Flow	Specific analysis for EPU
14.2.10	N/A	Single RCCA Withdrawal at Full Power	UFSAR conclusions not affected by EPU
14.2.11	N/A	Minor Secondary System Pipe Breaks	UFSAR conclusions (that this accident is bounded by the large break) not affected by EPU
14.3.1	5.2.2	Loss of Reactor Coolant from Small Ruptured Pipes or From Cracks in Large Pipes Which Actuates Emergency Core Cooling System	Specific analysis for EPU
14.3.2	5.2.1	Major Reactor Coolant System Pipe Ruptures (LOCA)	Specific analysis for EPU

Notes:
(1) This event is no longer analyzed. Refer to discussion in Section 5.3.1 for more details.

Table A.2-1B
BVPS-2 Summary of Event Discussions

UFSAR Section	Report Section	UFSAR Event	Acceptance Criteria Demonstrated
15.1.1 & 15.1.2	5.3.9	Excessive Heat Removal Due to Feedwater System Malfunctions	Specific analysis for EPU
15.1.3	5.3.10	Excessive Load Increase Incident	Specification evaluation of EPU
15.1.4	5.3.1	Accidental Depressurizatrio of Main Steam System	(Note 1)
15.1.5	5.3.12	Major Rupture of a Main Steam Pipe	Specific analysis for EPU
15.2.2 & 15.2.3	5.3.6	Loss of External Electrical Load and/or Turbine Trip	Specific analysis for EPU
15.2.6	5.3.8	Loss of Offsite Power to the Station Auxiliaries (Station Blackout)	Specific analysis for EPU
15.2.7	5.3.7	Loss of Normal Feedwater	Specific analysis for EPU
15.2.8	5.3.17	Major Rupture of a Main Feedwater Pipe	Specific analysis for EPU
15.3.1	5.3.13	Partial Loss of Forced Reactor Coolant Flow	Specific analysis for EPU
15.3.2	5.3.14	Complete Loss of Forced Reactor Coolant Flow	Specific analysis for EPU
15.3.3	5.3.15	Single Reactor Coolant Pump Locked Rotor	Specific analysis for EPU
15.4.1	5.3.2	Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition	Specific analysis for EPU
15.4.2	5.3.3	Uncontrolled RCCA Bank Withdrawal at Power	Specific analysis for EPU
15.4.3	5.3.4	RCCA Misalignment	Specific analysis for EPU demonstrating applicability of the generic analysis
15.4.4	5.3.1	Startup of an Inactive Reactor Coolant Loop	(Note 1)
15.4.6	5.3.5	Uncontrolled Boron Dilution	Specific analysis for EPU
15.4.8	5.3.16	Rupture of a Control Rod Drive Mechanism Housing RCCA Ejection	Specific analysis for EPU
15.5.1	5.3.18	Spurious Operation of the Safety Injection System at Power	Specific analysis for EPU
15.6.1	5.3.11	Accidental Depressurization of the Reactor Coolant System	Specific analysis for EPU
15.6.3	5.4.2 & 5.4.3	Steam Generator Tube Rupture	Specific analysis for EPU
15.6.5	5.2.1	Major Reactor Coolant System Pipe Ruptures (LOCA)	Specific analysis for EPU
15.6.5	5.2.2	Loss of Reactor Coolant from Small Ruptured Pipes or From Cracks in Large Pipes Which Actuates Emergency Core Cooling System	Specific analysis for EPU
15.7	5.11	Radiological Consequences	See Table A.1-23

Note:
(1) This event is no longer analyzed. Refer to discussion in Section 5.3.1 for more details.

A.3 (Applicable to EPU)

Provide summary, quantitative information to show how the proposed EPU would be accomplished (the heat balance discussion in Section 8.2 deals only with the balance-of-plant (BOP) equipment).

Response:

The EPU represents a core power increase of approximately 8% above the current core power of 2689 MWt. No changes are being made to the minimum RCS total Thermal Design Flow of 261,600 gpm. The increase in core power will be accomplished by increasing the core temperature rise. The EPU Power Capability Working Group (PCWG) parameters are shown in Tables 2.1.1-2 and 2.1.1-3 of the EPU Licensing Report for BVPS-1 and 2, respectively. Table A.3-1 summarizes the changes that account for the 8% increase in core power. The EPU best estimate Nuclear Steam Supply System (NSSS) parameters are shown in Table 2.1.2-1 of the EPU Licensing Report.

Table A.3-1
EPU Parameters

EPU Licensing Report	Reactor Mass Flow 10^6 Lb/hr	Vessel Outlet Temp °F	Vessel Outlet Enthalpy BTU/Lb	Vessel/ Core Inlet Temp °F	Vessel/ Core Inlet Enthalpy BTU/Lb	Core Power BTU/hr	Ratio of EPU Power to Current Operation
Current Operation Table 2.1.1-1	99.5	610.8	628.97	541.60	536.83	9.168E+09	N/A
EPU Low T_{avg} Table 2.1.1-2/3	101.1	603.9	618.84	528.50	520.98	9.894E+09	1.08
EPU High T_{avg} Table 2.1.1-2/3	99.3	617.0	638.35	543.10	538.67	9.898E+09	1.08

A.4 (Applicable to EPU)

In the BVPS-1 and 2 EPU submittal, it is stated that the thermal design flow is reduced relative to the original power capability working group parameters, and that this reduction is evaluated and implemented as part of a previous project, not as an EPU project change. Please provide more detailed background information to support this statement.

Response:

The current BVPS-1 and 2 design/licening basis Thermal Design Flow (TDF) is 87,200 gpm/loop. The EPU Project analyses and evaluations are based on the EPU Power Capability Working Group (PCWG) parameters that include this same value of TDF.

The reduction in TDF occurred in 1993 as part of a BVPS-1 and 2 analysis project to accommodate future increased steam generator tube plugging (SGTP) levels for the original steam generators in both units. As part of this project, TDF was reduced from 88,500 gpm/loop to 87,200 gpm/loop and the PCWG parameters were recalculated for use in project analysis. FENOC subsequently submitted License Amendment Request No. 208/74 to the NRC by FENOC letter dated February 19, 1993, as supplemented by FENOC letters dated March 31 and April 19, 1993. The NRC approved the requested changes and issued BVPS-1 Amendment No. 172 and BVPS-2 Amendment No. 51 to FENOC by NRC letter dated June 1, 1993. The subject NRC letter included the NRC Safety Evaluation Report (SER) for the amendments, including the NRC evaluation of the TDF reduction from 88,500 gpm/loop to 87,200 gpm/loop.

A.5 (Applicable to RSG & EPU)

Table 9.1-1 shows that the reactor coolant system (RCS) temperature-related EPU power capability working group values are specified as ranges of values. Provide a more detailed rationale for your selection of initial plant conditions for each transient analyzed to achieve the most conservative results.

Response:

In general, Westinghouse safety analysis standards define guidance for the selection of initial plant conditions for each transient analyzed in order to achieve conservative results with respect to the transient acceptance criteria. The guidance defines which initial plant conditions are to be selected or biased in a conservative direction and which initial plant conditions are to be treated as nominal values. The definition of initial plant conditions is different for different transients depending on the transient acceptance criteria.

The EPU Licensing Report sections for each transient analyzed include an Input Parameters and Assumptions section that provides information on the selection of initial plant conditions. In response to RAI A.1, Tables A.1-1A through A.1-23 provide listings of key assumptions and input parameters for each accident analyzed. To supplement this information, Table A.5-1 provides more detailed information on the selection of initial conditions for PCWG parameters and the rationale for their selection.

Table A.5-1 Licensing Basis Safety Analyses	
Accident	**Rationale for Biasing of Initial Conditions**
Best Estimate Large Break LOCA (EPU LR Section 5.2.1)	Key acceptance criteria are calculated maximum fuel peak clad temperature (PCT) and clad oxidation. The BE LOCA methodology requires that ranges of initial plant conditions be addressed for select plant parameters. Initial plant conditions are selected to maximize calculated PCT and clad oxidation. Specific initial condition selection and biasing for this accident include: 1. Reactor power is selected as the maximum value (+) and includes maximum power measurement uncertainty, which increases power level and decay heat level. 2. RCS flow is selected as Thermal Design Flow (TDF), which is a minimum value (-) that increases reactor coolant loop resistance and conservatively reduces steam venting. 3. RCS temperature is selected as the maximum (+) and the minimum (-) end of the T_{avg} range and includes maximum temperature measurement uncertainties on both the maximum and minimum end. 4. RCS pressure is selected as the maximum (+) and the minimum (-) values and includes maximum pressure measurement uncertainties on both the maximum and minimum end. 5. Core peaking factors are selected as maximum values (+) to maximize the calculation of PCT. 6. The ranges and/or values of other key input parameters are selected and/or biased maximum (+) or minimum (-) to maximize the calculation of PCT.
Small Break LOCA (EPU LR Section 5.2.2)	Key acceptance criteria are calculated maximum fuel PCT and clad oxidation. Initial plant conditions are selected to maximize calculated PCT and clad oxidation. Specific initial condition selection and biasing for this accident include: 1. Reactor power is selected as the maximum value (+) and includes maximum power measurement uncertainty, which increases power level and decay heat level. 2. RCS flow is selected as a minimum value (-) that increases reactor coolant loop resistance and conservatively reduces steam venting. 3. RCS temperature is selected as the maximum (+) and the minimum (-) end of the T_{avg} range and includes maximum temperature measurement uncertainties on both the maximum and minimum end. 4. RCS pressure is selected as the maximum value (+) and includes maximum pressure measurement uncertainty, which increases break flow. 5. Core peaking factors are selected as maximum values (+) to maximize the calculation of PCT. 6. Steam generator tube plugging (SGTP) is selected as a maximum value (+) to increase reactor coolant loop resistance and conservatively reduce steam venting. 7. The ranges and/or values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to maximize the calculation of PCT.

Table A.5-1 (cont.)
Licensing Basis Safety Analyses

Accident	Rationale for Biasing of Initial Conditions
Hot Leg Switchover (EPU LR Section 5.2.3)	Post-LOCA Hot Leg Switchover evaluates the acceptability of the available emergency core cooling system hot leg recirculation flow to meet hot leg flow requirements that are sufficient to provide core cooling at the time established for hot leg switchover. Initial plant conditions are selected to maximize the hot leg flow requirements. Specific initial condition selection and biasing for this accident include: 1. Reactor power is selected as the maximum value (+) and includes maximum power measurement uncertainty, which increases power level and decay heat level. 2. Sources of boron (volumes and boron concentration) are selected at maximum values (+) to maximize boron buildup in the sump and reactor vessel, which decreases the time of hot leg switchover. 3. Available emergency core cooling system hot leg flows are selected as minimum values (-), so that the comparison with the hot leg flow requirement is conservative.
Post-LOCA Subcriticality and Long-Term Core Cooling (EPU LR Section 5.2.4)	Post-LOCA Subcriticality and Long-Term Core Cooling develops the post-LOCA sump boron concentration curve that is included in the Reload Safety Evaluation process and is used to confirm that adequate boron exists to maintain sub-criticality in the long-term post-LOCA. Initial plant conditions are selected to minimize the boron in the sump and reactor vessel. Sources of boron (volumes and boron concentration) are selected at minimum values (-) to minimize boron in the long-term post-LOCA. Since this analysis begins after the LOCA has occurred, initial plant conditions for PCWG parameters (e.g., power, temperature, pressure, and flow) are not significant.
Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition (EPU LR Section 5.3.2)	The key acceptance criterion is minimum DNBR. Initial plant conditions are selected to minimize DNBR. Analysis methodology employs the Standard Thermal Design Procedure (STDP), which applies the total initial condition uncertainties on reactor power, RCS pressure, and RCS temperature to these parameters in the conservative direction to obtain initial plant conditions. Specific initial condition selection and biasing for this accident include: 1. NSSS power is selected as the maximum nominal value (+), which increases power level. 2. RCS temperature is selected as the nominal no-load value. 3. RCS pressure is selected as the minimum value (-) and includes maximum pressure measurement uncertainty, which decreases DNBR. 4. RCS flow is selected as the minimum flow from 2 RCPs operating, which is a minimum value (-) that decreases DNBR. 5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR.

Table A.5-1 (cont.) Licensing Basis Safety Analyses	
Accident	**Rationale for Biasing of Initial Conditions**
Uncontrolled RCCA Bank Withdrawal at Power (EPU LR Section 5.3.3)	The key acceptance criterion is minimum DNBR. Initial plant conditions are selected to minimize DNBR. DNBR analysis methodology employs the Revised Thermal Design Procedure (RTDP), which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition selection and biasing for this accident include: 1. NSSS power is selected as the maximum nominal value (+), which maximizes power level and decreases DNBR. 2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which decreases DNBR. 3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which decreases DNBR. 4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology. 5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR.
RCCA Misalignment (EPU LR Section 5.3.4)	The key acceptance criterion is minimum DNBR. The RCCA Misalignment events are analyzed generically. Changes in key PCWG parameters were evaluated to confirm the continued applicability of the generic statepoints for EPU conditions.
Uncontrolled Boron Dilution (EPU LR Section 5.3.5)	Key acceptance criterion is the time from the start of the transient to the loss of shutdown margin. Initial plant conditions are selected to minimize the time to loss of shutdown margin. Specific initial condition selection and biasing for this accident include: 1. RCS temperatures for Modes 1 and 2 are selected as the maximum values (+) including total measurement uncertainty. RCS temperature for Mode 3 is selected as the nominal no-load value. 2. RCS pressure is selected as the nominal value. 3. RCS volumes (dilution volumes) are selected as nominal values. 4. Charging pump capacity (dilution flow) is selected at the maximum value (+), which minimizes the time to loss of shutdown margin. 5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize the time to loss of shutdown margin.

Table A.5-1 (cont.)
Licensing Basis Safety Analyses

Accident	Rationale for Biasing of Initial Conditions
Loss of External Electrical Load and/or Turbine Trip (EPU LR Section 5.3.6)	The key acceptance criteria are minimum DNBR, peak primary pressure, and peak secondary pressure. Two cases are analyzed. One case (DNB Case) is used to analyze for minimum DNBR and one case is used to analyze for peak primary and secondary pressure. Initial plant conditions for the DNB Case are selected to minimize DNBR. This case employs the RTDP methodology which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition selection and biasing for the DNB Case includes: 1. NSSS power is selected as the maximum nominal value (+), which maximizes power level and decreases DNBR. 2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which decreases DNBR. 3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which decreases DNBR. 4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology. 5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR. Initial plant conditions for the Pressure Case are selected to maximize peak primary and secondary pressure. This case employs the STDP methodology, which applies the total initial condition uncertainties on reactor power, RCS pressure, and RCS temperature to these parameters in the conservative direction to obtain initial plant conditions. Specific initial condition selection and biasing for the Pressure Case includes: 1. NSSS power is selected as a maximum value (+) and includes maximum power measurement uncertainty, which increases power level and peak pressures. 2. RCS temperature is selected as the maximum (top of range) value (+) and includes maximum temperature measurement uncertainty, which increases peak pressures. 3. RCS pressure is selected as the minimum value (-) and includes maximum pressure measurement uncertainty, which increases peak pressures. 4. RCS flow is selected as the TDF, which is a minimum value (-) consistent with STDP methodology. 5. The values of other key input parameters are selected and/or biased maximum (+) or minimum (-) values to maximize peak pressures.

Table A.5-1 (cont.)
Licensing Basis Safety Analyses

Accident	Rationale for Biasing of Initial Conditions
Loss of Normal Feedwater and Loss of Non-Emergency AC Power to the Plant Auxiliaries (LOOP) (EPU LR Sections 5.3.7 and 5.3.8)	Key acceptance criterion is peak pressurizer volume. Initial plant conditions are selected to maximize peak pressurizer volume. Specific initial condition selection and biasing for this accident include: 1. NSSS power is selected as a maximum value (+) and includes maximum power measurement uncertainty, which increases power level and peak volume. 2. RCS temperature is selected as the maximum (+) and the minimum (-) end of the T_{avg} range and includes maximum temperature measurement uncertainty, which increases peak volume. 3. RCS pressure is selected as the maximum (+) and minimum (-) values and includes maximum pressure measurement uncertainty, which increases peak volume. 4. RCS flow is selected as the TDF, which is a minimum value (-) that increases peak volume. 5. The values of other key input parameters are selected and/or biased maximum (+) or minimum (-) values to maximize peak volume.
Excessive Heat Removal Due to Feedwater System Malfunctions (EPU LR Section 5.3.9)	The key acceptance criteria are minimum DNBR, peak primary pressure, and peak secondary pressure. Two feedwater system malfunction cases are analyzed. One is for excessive feedwater flow and one is for feedwater temperature reduction. Both cases are evaluated relative to all three acceptance criteria Initial plant conditions for both cases are selected to minimize DNBR. These cases employ the RTDP methodology which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition biasing for these cases include: 1. NSSS power is selected as the maximum nominal value (+), which maximizes power level and decreases DNBR. 2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which decreases DNBR. 3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which decreases DNBR. 4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology. 5. Feedwater temperature is selected as the maximum (+) and the minimum (-) end of the feedwater temperature range, which decreases DNBR. 6. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR.

Table A.5-1 (cont.) Licensing Basis Safety Analyses	
Accident	**Rationale for Biasing of Initial Conditions**
Excessive Load Increase Incident (EPU LR Section 5.3.10)	The key acceptance criteria are minimum DNBR, peak primary pressure, and peak secondary pressure. Initial plant conditions are selected to minimize DNBR. These cases employ the RTDP methodology which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition selection and biasing for these events include: 1. Reactor power is selected as the maximum nominal value (+), which maximizes power level and decreases DNBR. 2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which decreases DNBR. 3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which decreases DNBR. 4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology. 5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR.
Accidental Depressurization of the RCS (EPU LR Section 5.3.11)	The key acceptance criterion is minimum DNBR. Initial plant conditions are selected to minimize DNBR. These cases employ the RTDP methodology which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition selection and biasing for these events include: 1. NSSS power is selected as the maximum nominal value (+), which maximizes power level and decreases DNBR. 2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which decreases DNBR. 3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which decreases DNBR. 4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology. 5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR.

Table A.5-1 (cont.) Licensing Basis Safety Analyses	
Accident	**Rationale for Biasing of Initial Conditions**
Major Rupture of a Main Steam Pipe (EPU LR Section 5.3.12)	The key acceptance criterion is minimum DNBR. Initial plant conditions are selected and/or biased to minimize DNBR. This case employs the STDP methodology, which applies the total initial condition uncertainties on reactor power, RCS pressure, and RCS temperature to these parameters in the conservative direction to obtain initial plant conditions. Specific initial condition selection and biasing for these events include: 1. NSSS power is selected as the minimum nominal value (-). 2. RCS temperature is selected as the nominal no-load value. 3. RCS pressure is selected as the nominal value. 4. RCS flow is selected as the TDF, which is a minimum value (-) consistent with STDP methodology. 5. The values of other key fuel input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR.
Partial and Complete Loss of Forced Reactor Coolant Flow (EPU LR Sections 5.3.13 and 5.3.14)	The key acceptance criteria are minimum DNBR, peak primary pressure, and peak secondary pressure. Initial plant conditions are selected to minimize DNBR. These cases employ the RTDP methodology which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition selection and biasing for these events include: 1. NSSS power is selected as the maximum nominal value (+), which maximizes power level and decreases DNBR. 2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which decreases DNBR. 3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which decreases DNBR. 4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology. 5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to minimize DNBR.

<table>
<tr><th colspan="2">Table A.5-1 (cont.)
Licensing Basis Safety Analyses</th></tr>
<tr><th>Accident</th><th>Rationale for Biasing of Initial Conditions</th></tr>
<tr><td>Single Reactor Coolant Pump Locked Rotor
(EPU LR Section 5.3.15)</td><td>The key acceptance criteria are minimum DNBR and peak primary pressure. Two cases are analyzed. One case (DNB Case) is used to analyze for percentage of Rods-In-DNB and one case is used to analyze for peak primary pressure.

Initial plant conditions for the Rods-In-DNB Case are selected to maximize the number of Rods-In-DNB. This case employs the RTDP methodology which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition selection and biasing for the DNB Case includes:
1. NSSS power is selected as the maximum nominal value (+), which maximizes power level and Rods-In-DNB.
2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which increases the Rods-In-DNB.
3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which increases the Rods-In-DNB.
4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology.
5. The values of other key input parameters are selected and/or biased as maximum (+) or minimum (-) values to maximize the Rods-In-DNB.

Initial plant conditions for the Pressure Case are selected to maximize peak primary pressure. This case employs the STDP methodology, which applies the total initial condition uncertainties on reactor power, RCS pressure, and RCS temperature to these parameters in the conservative direction to obtain initial plant conditions. Specific initial condition selection and biasing for the Pressure Case includes:
1. NSSS power is selected as a maximum value (+) and includes maximum power measurement uncertainty, which increases power level and peak pressure.
2. RCS temperature is selected as the maximum (top of range) value (+) and includes maximum temperature measurement uncertainty, which increases peak pressure.
3. RCS pressure is selected as the maximum value (+) and includes maximum pressure measurement uncertainty, which increases peak pressure.
4. RCS flow is selected as the TDF, which is a minimum value (-) consistent with STDP methodology.
5. The values of other key input parameters are selected and/or biased maximum (+) or minimum (-) values to maximize peak pressure.</td></tr>
</table>

Table A.5-1 (cont.) Licensing Basis Safety Analyses	
Accident	**Rationale for Biasing of Initial Conditions**
Rupture of a Control Rod Drive Mechanism Housing RCCA Ejection (EPU LR Section 5.3.16)	The key acceptance criterion is maximum fuel stored energy. Initial plant conditions are selected to maximize fuel stored energy. Cases are run for 0% and 100% power and beginning of life (BOL) and end of life (EOL). Specific initial conditions for these events consist principally of fuel input parameters that are selected as maximum (+) or minimum (-) values to maximize fuel stored energy. Since the RCCA ejection transient is a rapid transient, initial plant conditions for PCWG parameters (e.g., power, pressure, flow, and temperature) are not significant.
Rupture of a Main Feedwater Pipe (EPU LR 5.3.17)	The key acceptance criterion is margin to hot leg boiling, which is used to conservatively satisfy the specific criteria for peak primary and secondary pressure, fuel damage, and radioactivity release. Initial plant conditions are selected to maximize hot leg boiling. Specific initial condition selection and biasing for this accident include: 1. NSSS power is selected as a maximum value (+) and includes maximum power measurement uncertainty, which increases power level and RCS temperatures. 2. RCS temperature is selected as the maximum (top of range) value (+) and includes maximum temperature measurement uncertainty, which increases RCS temperatures. 3. RCS pressure is selected as the minimum value (-) and includes maximum pressure measurement uncertainty, which minimizes the margin to hot leg boiling. 4. RCS flow is selected as the TDF, which is a minimum value (-) that maximizes RCS temperatures. 5. The values of other key input parameters are selected and/or biased maximum (+) or minimum (-) values to minimize the margin to hot leg boiling.
Spurious Operation of the Safety Injection System at Power (EPU LR Section 5.3.18)	The key acceptance criterion is peak pressurizer volume, which is used to conservatively satisfy the specific criteria that this event of moderate frequency does not generate into a more serious plant condition without other faults occurring independently. Initial plant conditions are selected to maximize pressurizer filling. Specific initial condition selection and biasing for this accident: 1. NSSS power is selected as a maximum value (+) and includes maximum power measurement uncertainty, which increases power level and peak volume. 2. RCS temperature is selected as the minimum (bottom of range) value (-) and includes maximum temperature measurement uncertainty, which increases peak volume. 3. RCS pressure is selected as the minimum (bottom of range) value (-) and includes maximum pressure measurement uncertainty, which increases peak volume. 4. RCS flow is selected as the TDF, which is a minimum value (-) that increases peak volume. 5. The values of other key input parameters are selected and/or biased maximum (+) or minimum (-) values to maximize peak volume.

Table A.5-1 (cont.)
Licensing Basis Safety Analyses

Accident	Rationale for Biasing of Initial Conditions
Steam System Piping Failure at Full Power (EPU LR Section 5.3.19)	The key acceptance criterion is minimum DNBR. Initial plant conditions are selected and/or biased to minimize DNBR. This case employs the RTDP methodology which assumes that reactor power, RCS pressure, and RCS temperature are at their nominal values adjusted to account for any applicable measurement biases. Uncertainties in initial conditions are included in the DNBR limit. Specific initial condition selection and biasing for these events include: 1. NSSS power is selected as the maximum nominal value (-), which maximizes power level. 2. RCS temperature is selected as the maximum (top of range) nominal value (+) and includes temperature measurement bias, which decreases DNBR. 3. RCS pressure is selected as the nominal value (-) and includes pressure measurement bias, which decreases DNBR. 4. RCS flow is selected as Minimum Measured Flow (MMF), which is a minimum nominal value (-) consistent with RTDP methodology. 5. The values of other key input parameters are selected as maximum (+) or minimum (-) values to minimize DNBR.

Table A.5-1 (cont.) Licensing Basis Safety Analyses	
Accident	**Rationale for Biasing of Initial Conditions**
Steam Generator Tube Rupture (EPU LR Section 5.4)	The key acceptance criteria are mass releases for use in dose consequence analysis and peak steam generator secondary volume (overfill). Two cases are analyzed, one for development of steam generator tube rupture (SGTR) mass release data for use in dose consequence analysis and one for evaluation of ruptured steam generator overfill. Initial plant conditions for the SGTR mass release data case are selected and/or biased to maximize the mass releases from the primary side to the secondary side of the ruptured steam generator. Initial plant conditions for this case are selected to maximize mass releases. Specific initial condition selection and biasing for this case includes: 1. Reactor power is selected as a maximum value (+) and includes maximum power measurement uncertainty, which increases power level. 2. RCS temperature is selected as the maximum (top of range) nominal value (+). 3. RCS pressure is selected as the nominal value. 4. RCS flow is selected as the TDF, which is a minimum value (-). 5. Feedwater temperature is selected as the maximum (top of range) nominal value (+), which maximizes dose release data. 6. The values of other key input parameters are selected and/or biased maximum (+) or minimum (-) values to maximize dose release data. Initial plant conditions for the overfill case are selected to maximize the peak secondary side volume of the ruptured steam generator. Initial plant conditions for this case are selected to maximize ruptured steam generator secondary side volume. Specific initial condition selection and biasing for this case includes: 1. NSSS power is selected as a maximum value (+) and includes maximum power measurement uncertainty, which increases power level. 2. RCS temperature is selected as the minimum (bottom of range) nominal value (+). 3. RCS pressure is selected as the nominal value. 4. RCS flow is selected as the TDF, which is a minimum value (-). 5. Feedwater temperature is selected as the minimum (bottom of range) nominal value (+), which maximizes peak secondary volume. 6. The values of other key input parameters are selected and/or biased maximum (+) or minimum (-) values to maximize peak secondary volume.

Table A.5-1 (cont.) Licensing Basis Safety Analyses	
Accident	**Rationale for Biasing of Initial Conditions**
Anticipated Transients Without Scram (EPU LR Section 5.8)	The key acceptance criterion is peak primary pressure. The ATWS events are analyzed generically. Changes in key nominal PCWG parameters were evaluated to confirm the continued applicability of the generic ATWS analysis for EPU conditions, including maximum nominal reactor power, maximum nominal feedwater temperature, and minimum nominal steam generator tube plugging to maximize initial steam generator steam pressure.

A.6 (Applicable to RSG & EPU)

BVPS-1 and 2 are provided with loop isolation valves in each of the three RCS loops. Please indicate whether they are credited in the analysis of any transients or design-basis events. If so, please explain.

Response:

Loop isolation valve operation is not credited in any transients or design basis events for BVPS-1 and 2.

A.7 (Applicable to RSG & EPU)

Discuss the design basis of the pressurizer safety valve (PSV) sizing at BVPS-1 and 2. Are they sized according to the method described in NUREG-0800, "Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants." Section 5.2.2, which is based upon the assumption of a reactor trip, on the second reactor trip signal? Verify the adequacy of the PSVs at BVPS-1 and 2 for the EPU conditions using methods that are consistent with the current licensing basis for BVPS-1 and 2.

Response:

The current BVPS-1 and 2 overpressure protection is based on the safety analysis methodology described in WCAP-7769, which remains applicable for Extended Power Uprate (EPU) analyses. The current overpressurization analyses are discussed in Chapter 14 (BVPS-1) and 15 (BVPS-2) of the Updated Final Safety Analysis Report (UFSAR).

The guidelines of SRP 5.2.2 were utilized by Westinghouse during the initial stages of BVPS plant design, as well as other Westinghouse-designed units. The use of this approach for design allowed for a very conservative calculation of the required safety valve relief capacity to be installed at these units. An example of such conservatism is the assumption of relying on the second safety-grade reactor trip signal in the safety valve sizing calculations. However, following installation of these safety valves, overpressure protection of the Reactor Coolant System (RCS) and main steam system has been demonstrated via the analysis of the most limiting pressurization transients, as described in the UFSAR.

These analyses have been performed following the methodology detailed in WCAP-7769 which is the same as that used in the sizing of the safety valves except that credit is taken for Doppler feedback and appropriate reactor trip, other than direct reactor trip on turbine trip. These analyses do not include the additional conservative design assumption of a common mode failure of the first safety grade reactor trip signal.

The analyses performed in support of the BVPS EPU Project are not safety valve sizing calculations – no changes are being made to the safety valves as a result of this project. The Loss of External Electrical Load/Turbine Trip analysis performed for the EPU Project, presented in Section 5.3.6, demonstrates that the installed safety valve capacities are sufficient to maintain peak primary pressure below 110% of design, which satisfies the requirements of GDC-15. GDC-15 applies to "any condition of normal operation, including anticipated operational occurrences" which does not include a common mode failure of the first safety grade reactor trip signal.

A.8 (Applicable to EPU)

Provide a quantitative tabulation of the time needed for plant cooldown to cold shutdown conditions (natural circulation cooldown using only safety grade equipment), and for plant cooldown per the requirements of Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Appendix R (regarding fire protection), for each of the Beaver Valley units both at the EPU power level and at the current power level.

Response:

The capability to achieve cold shutdown (200°F) using safety-grade equipment is explained below for both the current and EPU power levels. The BVPS-2 final safety analysis report includes an appendix, 5A, that defines how the plant approached compliance to achieving full safety-grade cold shutdown capability. Analyses were performed for the Beaver Valley units that demonstrate compliance with 10 CFR 50, Appendix R, cold shutdown capability.

<u>BVPS-2</u>

<u>Natural Circulation and Cold Shutdown</u>

The BVPS-2 systems and equipment to maintain natural circulation and achieve cold shutdown are safety-grade. The initial phase of the cooldown is via the safety-grade atmospheric steam dump valves (one per steam generator). Redundant to these valves is a larger valve, the residual heat removal valve, shared by all steam lines that is powered from a separate safety-grade bus. Water is provided to the steam generators from the safety-grade auxiliary feedwater system. Section 3.1.4.1.2 of the EPU Licensing Report evaluates the capacity of the main steam system atmospheric relieving valves for their capability to cool the plant to Residual Heat Removal System (RHRS) initiating temperature at a rate of 50°F per hour at uprated power. This cool down rate is permissible when there is forced reactor coolant flow. Since BVPS-2 is limited to a 25°F per hour natural circulation cool down rate due to its upper head T_{hot} temperature, the unit can be cooled to 350°F from no load 547°F in approximately 8 hours. Sufficient steam relieving capacity is available for the maximum allowable natural circulation cool down from 547°F to 350°F at uprated power.

UFSAR Appendix 5A, UFSAR Section 5.4.7.1, and UFSAR Table 1.9-1 (for compliance with Regulatory Guide 1.139) describe the scenario of a unit cool down with only a safety-grade bus available for steam relief. For the safety-grade cold shutdown scenario with a single failure in the main steam relieving system, the licensing basis commits to a 36 hour cool down to RHRS initiating temperature of 350°F (an average cool down rate of about 5°F per hour). The failure of the bus powering the 3 atmospheric dump valves (one per steam generator) would be the limiting single failure for plant cool down. The residual heat removal valve has a capacity that is about 68% of the three atmospheric steam dump valves.

A specific analysis was not performed using just the Residual Heat Removal Valve at the uprated power to show that the plant can be cooled down at a rate of 5°F per hour or how fast it can be cooled down. However, from the above rationale that correlates to the 25°F/hr cooldown rate to the atmospheric dump valve capacity, the Residual Heat Removal Valve is capable of cooling the plant to RHRS conditions in 36 hours.

As part of the EPU natural circulation evaluation, a specific analysis using the TREAT code (ANS 51.1-1979 decay heat model) was made to model thermal/hydraulic conditions and operator actions. Using the Residual Heat Removal Valve and crediting one atmospheric dump valve (locally if necessary), this analysis showed that the plant was cooled down to 350°F in 16.8 hours after shutdown. The nine hour soak period would be in addition to this time.

The second phase of the cool down to 200°F and beyond is via the Residual Heat Removal System (RHRS). The current BVPS-2 UFSAR describes the cool down time with full and single-train RHRS capacities. These cool down times (from the time of zero reactor power) from the current UFSAR for full operation of the RHRS and component cooling water systems are:

1. 8 hours to reach 212°F.
2. 9 hours to reach 140°F.

The UFSAR states that for a single train of RHRS in service, the cool down times are as follows:

1. 29 hours to reach 212°F.
2. 31 hours to reach 200°F.

The UFSAR cases are based on full operation of auxiliary plant equipment that adds heat loads to the component cooling water system. For a natural circulation cool down without offsite power, this auxiliary equipment will not be operating, and the RHRS will cool down the plant faster.

The EPU Licensing Report presents RHRS cool down times (from zero reactor power) for three scenarios:

1. full RHRS operating that begins in 4 hours and achieves 140°F in 51 hours.
2. one train of RHRS operating that begins in 4 hours and achieves 200°F in 57.9 hours.
3. one train of RHRS operating with loss of offsite power (limited auxiliary heat loads on the component cooling water system) that begins in 36 hours and achieves 200°F in 43 hours.

Appendix R Timetable to Cold Shutdown

For BVPS-2, the safe shutdown evaluation described in Section 5.12 was performed and concluded that there are no plant modifications proposed for implementation of EPU that will impact the shutdown scenarios. The decay heat increases with EPU conditions; however, the total time required to reach cold shutdown remains within the 72 hour acceptance criteria for cold shutdown identified in Standard Review Plan (SRP) 9.5.1 and applicable to BVPS-2. The assessments and analyses performed for the 36 hour natural circulation cool down to RHRS initiating conditions and the performance of a single train of RHRS bound the cool down performance for the 10 CFR 50, Appendix R fire scenario at EPU conditions. The BVPS-2 systems and components credited in the 36 hour natural circulation cool down and subsequent RHRS operation are based on operation of critical systems that have redundant components, power supplies, fire separation, and single train performance.

BVPS-1

Natural Circulation and Cold Shutdown

Similar systems and components are used at BVPS-1 (compared to BVPS-2) to maintain natural circulation and achieve cold shutdown. For the natural circulation scenario, the primary difference between BVPS-1 and 2 is in the valve operators for the atmospheric steam dump valves and the pressurizer PORVs used to depressurize the RCS to the RHRS initiating pressure (360 psig). These BVPS-1 valves are air-operated. The atmospheric steam dump valves must be locally operated if instrument air is lost. In section 3.1.4.1.2 of the Licensing Report, of the the relieving capacity is evaluated with respect to the ability to cool the plant at 50°F per hour at uprated power. The pressurizer PORVs have nitrogen bottles inside containment to allow operation with loss of instrument air. The BVPS-1 instrument air system has an automatically-actuated, diesel powered backup compressor in the event of a loss of offsite power.

Another difference between BVPS-1 and 2 is the capacities of the atmospheric steam dump valves. The total atmospheric relieving capacities (three atmospheric steam dump valves and one common residual heat removal valve) are larger for BVPS-1 compared to BVPS-2, however the common residual heat removal valve is smaller. Refer to the response to RAI E.18 for valve capacities.

Auxiliary feedwater system capacities and system configuration are comparable between BVPS-1 and 2.

The BVPS-1 natural circulation cool down rate is similarly limited to 25°F per hour because of the reactor vessel upper head temperature. Even though no pre-uprate or EPU specific BVPS-1 natural circulation cool down time analyses were performed, the equipment capacities indicate that the cool down results prior to RHRS initiation described for BVPS-2 are conservative for BVPS-1.

For the response describing the second phase of cool down, RHRS operation, a comparison is made to show that the cooldown results from BVPS-2, noted above, bound BVPS-1. EPU Licensing Report Table 9.3-1 shows that design parameters for the BVPS-1 cool down to 140°F result in a faster cool down than for BVPS-2. Therefore the times required to go from 350°F to cold shutdown, defined above for BVPS-2, are conservative for BVPS-1. The design analysis performed for the BVPS-1 EPU RHRS is that presented in Table 9.3-1 of the EPU Licensing Report.

Appendix R Timetable to Cold Shutdown

For BVPS-1, the safe shutdown evaluation described in Section 5.12 concluded that the impact of the EPU on fire protection safe shutdown is acceptable. An analysis for cold shutdown capability was performed for a scenario that includes a limiting "worst case" fire that envelops the auxiliary feedwater pump (AFW) pump room fire that credits only the minimum set of equipment expected to be available for recovery. The analytical simulation showed that for EPU conditions, the reactor coolant system can be safely shut down and cooled down to cold shutdown conditions within the NRC-approved cold shutdown time requirement of 127 hours (Reference NRC Safety Evaluation Report (SER) for BVPS-1 dated March 14, 1983).

For the EPU, separate, more detailed LOFTRAN and TREAT analyses were performed using the ORIGEN decay heat model. The limiting scenario for operation of the dedicated auxiliary feedwater pump and atmospheric steam dump valves was applied as the method to cool down the unit. The objective of the analyses is to confirm that the plant could be brought to 200°F within 127 hours using the same methodology. This approach is described in Section 5.12 of the EPU Licensing Report and confirms that the plant is still capable of achieving 200°F within the required 127 hours.

A.9 (Applicable to RSG & EPU)

Please provide a tabulation of all computer codes and methodologies used in the re-analyses to support the EPU; and, for each, indicate the NRC approval status, any conditions or limitations on their use, and how the limitations, if any, are applied in the EPU analyses for BVPS-1 and 2.

Response:

Table A.9-1 provides a tabulation of the principal computer codes (See Table 1.0-2 of the EPU Licensing Report) used to support the BVPS-1 and 2 EPU LAR. WCOBRA/TRAC is not addressed since it is part of a separate BELOCA LAR submittal.

Table A.9-1
Computer Code Description

ANC

ANC is an advanced nodal code capable of two-dimensional and three-dimensional neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, and so forth. In addition, three-dimensional ANC validates one-dimensional and two-dimensional results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.

Reference:
1. WCAP-10965-P-A, "ANC: A Westinghouse Advanced Nodal Computer Code," September 1986.

Date of NRC Acceptance: June 23, 1986, Carl Berlinger to E. P. Rahe

SER Conditions: There are no SER restrictions applicable to this application.

DORT/BUGLE-96

The DORT discrete ordinates transport module of the DOORS 3.1 code package, in conjunction with the BUGLE-96 cross-section library, is used to determine the neutron flux and gamma-ray heating rate environment. This code and the associated cross-section library have been used by Westinghouse to calculate vessel fluences and reactor internals heating rates for other projects that have been submitted to, and approved by, the NRC. Furthermore, these calculation tools are specified in Regulatory Guide 1.190 for this type of work.

References:
1. RSICC Computer Code Collection CCC-650, "DOORS 3.1, One-, Two-, and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System," August 1996.
2. RSICC Data Library Collection DLC-185, "BUGLE-96, Coupled 47 Neutron, 20 Gamma-Ray Group Cross-Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications," March 1996.
3. Regulatory Guide RG-1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U. S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001.

Date of NRC Acceptance: There is no formal NRC acceptance.

SER Conditions: N/A

Table A.9-1 (cont.) Computer Code Description
FACTRAN FACTRAN calculates the transient temperature distribution in a cross section of a metal clad, uranium dioxide fuel rod and the transient heat flux at the surface of the cladding using the time-dependent input of nuclear power and reactor coolant parameters of pressure, flow, temperature and density. The code uses a fuel model containing a sufficiently large number of radial-spatial nodes to adequately model very fast transients. FACTRAN uses material properties, which are a function of temperature, and has the capability to perform a detailed fuel-to-cladding gap heat transfer calculation. Two sets of transient equations, representing an energy balance and the heat conduction for each radial node, are solved simultaneously. The solutions to these equations consist of the heat flux at the surface of the fuel rod and the fuel rod temperatures at the end of each time step. Reference: 1. WCAP-7908-A, "FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," December 1989. Date of NRC Acceptance: September 30, 1986 (SER from C. E. Rossi (NRC) to E. P. Rahe (Westinghouse))
SER Conditions and Justification
1. *"The fuel volume-averaged temperature or surface temperature can be chosen at a desired value which includes conservatisms reviewed and approved by the NRC."* **Justification** The bounding initial fuel temperatures for transients were calculated using the PAD 4.0 computer code (see WCAP-15063-P-A). As indicated in WCAP-15063-P-A, the method of determining uncertainties for PAD 4.0 fuel temperatures has been approved by the NRC. 2. *"Table 2 presents the guidelines used to select initial temperatures."* **Justification** In summary, Table 2 of the SER specifies that the initial fuel temperatures assumed in the FACTRAN analyses of the following transients should be "High" and include uncertainties: Loss of Flow, Locked Rotor, and Rod Ejection. The assumed fuel temperatures, which were based on bounding temperatures calculated using the PAD 4.0 computer code (see WCAP-15063-P-A), include uncertainties and are conservatively high.

Table A.9-1 (cont.) Computer Code Description
3. *"The gap heat transfer coefficient may be held at the initial constant value or can be varied as a function of time as specified in the input."* **Justification** The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2. For the RCCA Withdrawal from a Subcritical Condition transient, the gap heat transfer coefficient is kept at a conservative constant value throughout the transient; a high constant value is assumed to maximize the peak heat flux (for DNB concerns) and a low constant value is assumed to maximize transient fuel temperatures. For the RCCA Ejection transients, the initial gap heat transfer coefficient is based on the predicted initial fuel surface temperature, and is ramped rapidly to a very high value at the beginning of the transient to simulate clad collapse onto the fuel pellet.
4. *"...the Bishop-Sandberg-Tong correlation is sufficiently conservative and can be used in the FACTRAN code. It should be cautioned that since these correlations are applicable for local conditions only, it is necessary to use input to the FACTRAN code which reflects the local conditions. If the input values reflecting average conditions are used, there must be sufficient conservatism in the input values to make the overall method conservative."* **Justification** Local conditions related to temperature, heat flux, peaking factors and channel information were input to FACTRAN for each transient analyzed.
5. *"The fuel rod is divided into a number of concentric rings. The maximum number of rings used to represent the fuel is 10. Based on our audit calculations we require that the minimum of 6 should be used in the analyses."* **Justification** At least 6 concentric rings were assumed in FACTRAN for each transient analyzed.
6. *"Although time-<u>independent</u> mechanical behavior (e.g., thermal expansion, elastic deformation) of the cladding are considered in FACTRAN, time-<u>dependent</u> mechanical behavior (e.g., plastic deformation) is not considered in the code. ...for those events in which the FACTRAN code is applied (see Table 1), significant time-dependent deformation of the cladding is not expected to occur due to the short duration of these events or low cladding temperatures involved (where DNBR Limits apply), or the gap heat transfer coefficient is adjusted to a high value to simulate clad collapse onto the fuel pellet."* **Justification** The two transients that were analyzed with FACTRAN (RCCA Withdrawal from a Subcritical Condition (UFSAR 15.4.1) and RCCA Ejection (UFSAR 15.4.8)) are included in the list of transients provided in Table 1 of the SER; each of these transients is of short duration. For the RCCA Withdrawal from a Subcritical Condition transient, relatively low cladding temperatures are involved, and the gap heat transfer coefficient is kept constant throughout the transient. For the RCCA Ejection transient, a high gap heat transfer coefficient is applied to simulate clad collapse onto the fuel pellet. The gap heat transfer coefficients applied in the FACTRAN analyses are consistent with SER Table 2.

Table A.9-1 (cont.) Computer Code Description
7. *"The one group diffusion theory model in the FACTRAN code slightly overestimates at beginning of life (BOL) and underestimates at end of life (EOL) the magnitude of flux depression in the fuel when compared to the LASER code predictions for the same fuel enrichment. The LASER code uses transport theory. There is a difference of about 3 percent in the flux depression calculated using these two codes. When (T(centerline) – T(Surface)) is on the order of 3000°F, which can occur at the hot spot, the difference between the two codes will give an error of 100°F. When the fuel surface temperature is fixed, this will result in a 100°F lower prediction of the centerline temperature in FACTRAN. We have indicated this apparent nonconservatism to Westinghouse. In the letter NS-TMA-2026, dated January 12, 1979, Westinghouse proposed to incorporate the LASER-calculated power distribution shapes in FACTRAN to eliminate this non-conservatism. We find the use of the LASER-calculated power distribution in the FACTRAN code acceptable."* **Justification** The condition of concern (T(centerline) – T(surface) on the order of 3000°F) is expected for transients that reach, or come close to, the fuel melt temperature. As this applies only to the RCCA ejection transient, the LASER-calculated power distributions were used in the FACTRAN analysis of the RCCA ejection transient.
FORCE2 (See also MULTIFLEX) The FORCE2 program calculates the hydraulic forces that the fluid exerts on the vessel internals in the vertical direction by utilizing a detailed geometric description of the vessel components and the transient pressures, mass velocities, and densities computed by the MULTIFLEX code. The analytical basis for the derivation of the mathematical equations employed in the FORCE2 code is the conservation of linear momentum (one-dimensional). Note that the computed vertical forces in the LOCA forces analyses do not include body forces on the vessel internals, such as dead-weight or buoyancy. The dead-weight and other factors are part of the dynamic system model to which the LOCA forces are provided as an external load. When the vertical forces on the reactor pressure vessel internals are calculated, pressure differential forces, flow stagnation on, unrecoverable orifice losses across, and friction losses on, the individual components are considered. These force types are then summed together, depending upon the significance of each, to yield the total vertical force acting on a given component. References: 1. WCAP-8708-PA-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977. 2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977. Date of NRC Acceptance: See MULTIFLEX. SER Conditions: See MULTIFLEX.

Table A.9-1 (cont.)
Computer Code Description

LATFORC (See also MULTIFLEX)
The LATFORC computer code utilizes MULTIFLEX generated field pressures, together with geometric vessel information (component radial and axial lengths), to determine the horizontal forces on the vessel wall and core barrel. The LATFORC code represents the vessel region with a model that is consistent with the model used in the MULTIFLEX blowdown calculation. The downcomer annulus is subdivided into cylindrical segments, formed by dividing this region into circumferential and axial zones. The results of the MULTIFLEX/LATFORC analysis of the horizontal forces are typically stored on magnetic tape and are calculated for the initial 500 msec of the blowdown transient. These forcing functions serve as required input in determining the resultant mechanical loads on primary equipment and loop supports, vessel internals, and fuel grids.

References:
1. WCAP-8708-PA-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977.
2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977.

Date of NRC Acceptance: See MULTIFLEX.

SER Conditions: See MULTIFLEX.

LOFTTR2
The LOFTTR2 program includes the capability to model operator actions, an improved steam generator secondary side model and a more realistic tube rupture break flow model. The NRC approved the revised SGTR analysis methodology in 1987 and the methodology has been applied for the SGTR analyses for plants licensed after the Ginna SGTR event and incorporated in the BVPS-2 Licensing Basis.

Reference:
1. WCAP-10698-P-A, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," August 1987.

Date of NRC Acceptance: March 30, 1987, C. E. Rossi to Alan E Ladieu.

SER Conditions:
Section D, "Plant Specific Submittal Requirements" of Enclosure 1 of the safety evaluation for WCAP-10698-A, states that certain plant-specific input shall be provided when referencing the WCAP for licensing action. The required information was considered along with the initial application for the WCAP methodology to BVPS-2. (NRC Letter dated July 15, 1994)

Table A.9-1 (cont.)
Computer Code Description

LOFTRAN

The LOFTRAN computer program is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. LOFTRAN simulates up to four-loop systems by modeling the reactor vessel, hot and cold leg piping, steam generators (tube and shell sides), and pressurizer. The pressurizer heaters, spray, relief, and safety valves are also considered in the program. Point-model neutron kinetics and reactivity effects of the moderator, fuel, boron and rods are included. The secondary sides of the steam generators utilize a homogeneous, saturated mixture for the thermal transients, and a water level correlation for indication and control. The reactor protection system simulation includes reactor trips on neutron flux, overpower and overtemperature ΔT, high and low pressure, low flow, and high pressurizer water level. Control systems, including rod control, steam dump, feedwater control, and pressurizer pressure controls are also simulated. The safety injection system, including the accumulators, is also modeled.

LOFTRAN is a versatile program suited to accident evaluation and control studies as well as parameter sizing. It is also used in performing loss of normal feedwater anticipated transient without scram (ATWS) and loss-of-load ATWS evaluations and control systems analysis.

Reference:

1. WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), "LOFTRAN Code Description," April 1984.

Date of NRC Acceptance: July 29, 1983 (SER from C. O. Thomas (NRC) to E. P. Rahe (W).

SER Conditions and Justification:

1. "LOFTRAN is used to simulate plant responses to many of the postulated events reported in Chapter 15 of PSARs and FSARs, to simulate anticipated transients without scram, for equipment sizing studies, and to define mass/energy releases for containment pressure analysis. The Chapter 15 events analyzed with LOFTRAN are:

   - Feedwater System Malfunction
   - Excessive Increase in Steam Flow
   - Inadvertent Opening of a Steam Generator Relief or safety Valve
   - Steamline Break
   - Loss of External Load
   - Loss of Offsite Power
   - Loss of Normal Feedwater
   - Feedwater Line Rupture
   - Loss of Forced Reactor Coolant Flow
   - Locked Pump Rotor
   - Rod Withdrawal at Power
   - Rod Drop
   - Startup of an Inactive Pump
   - Inadvertent ECCS Actuation
   - Inadvertent Opening of a Pressurizer Relief or Safety Valve

Table A.9-1 (cont.) Computer Code Description
This review is limited to the use of LOFTRAN for the licensee safety analyses of the Chapter 15 events listed above, and for a steam generator tube rupture..." Justification For Beaver Valley, the LOFTRAN code was used in the analyses of only events specifically listed in the SER, as such, additional justification is not required.
MULTIFLEX (See also LATFORC, FORCE2, and THRUST) The analysis for LOCA hydraulic forces used the NRC-accepted MULTIFLEX computer code, which is the current Westinghouse analytical tool used for analyzing LOCA hydraulic forces. The code was used to generate the transient hydraulic forcing functions on the vessel and internals. This code was previously used for LOCA hydraulic forces analyses. MULTIFLEX 3.0 is an engineering design tool that is used to analyze the coupled fluid-structural interactions in a PWR system during the transient following a postulated pipe rupture in the main RCS. The thermal-hydraulic portion of the MULTIFLEX code is based on the one-dimensional homogeneous model expressed in a set of mass, momentum, and energy conservation equations. These equations are quasi-linear, first order, partial differential equations solved by the method of characteristics. The employed numerical method utilizes an explicit time scheme along the respective characteristics. MULTIFLEX considers the interaction of the fluid and structure simultaneously, whereby the mechanical equations of vibration are solved through the use of the modal analysis technique. MULTIFLEX 3.0 generates the input for the post-processing codes LATFORC, FORCE2, and THRUST. All applicable MULTIFLEX SER items have been addressed in this application. References: 1. WCAP-8708-PA-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977. 2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977. 3. WCAP-9735, Revision 2 (Proprietary) and WCAP-9736, Revision 1 (Non-Proprietary), "MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model," February 1998. 4. WCAP-15029-P-A, Revision 0 (Proprietary) and WCAP-15030-NP-A, Revision 0 (Non-Proprietary), "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions," January 1999.

Table A.9-1 (cont.)
Computer Code Description

NRC Acceptance:

U.S. NRC review and approval for the use of MULTIFLEX (1.0), LATFORC and FORCE2 codes documented in Reference 1 for PWR LOCA hydraulic forces calculations was originally provided in Reference 2. Reference 3 is an example of U.S. NRC reviewed and approved application of MULTIFLEX to steam generator LOCA hydraulic force calculations, as provided in Reference 4. Reference 5 is an example of the U.S. NRC reviewed and approved application of MULTIFLEX to the analysis of fuel assembly LOCA hydraulic force calculations, as provided in Reference 6. Reference 7 documents the changes in MULTIFLEX modeling features from version 1.0 to version 3.0. References 8 and 9 were supplemental submittals on behalf of BVPS-2 regarding the use of MULTIFLEX 3.0 in the LOCA hydraulic forces analysis. The MULTIFLEX 3.0 analysis was subsequently accepted as the analysis of record for BVPS-2. Subsequently, MULTIFLEX 3.0 was accepted by the U.S. NRC as part of the methodology to confirm acceptable baffle-barrel-bolting patterns, Reference 10, in the Reference 11 evaluation report. MULTIFLEX 3.0 was again accepted by the U.S. NRC as part of the methodology to confirm control rod insertion for D. C. Cook Units 1 and 2, Reference 12, in the Reference 13 evaluation report. Reference 14 documents the STHRUST code which has been used in loop piping LOCA hydraulic forces analyses since before the MULTIFLEX code was developed. There is no specific acceptance date for the THRUST code (the S was dropped when BLODWN-2 and MULTIFLEX replaced SATAN in providing the hydraulic data to THRUST), although the methodology has been documented in the Beaver Valley units FSAR for many years.

References:

1. WCAP-8708-P-A-V1/V2, *MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics.* September, 1977. (Proprietary) (Non-proprietary version: WCAP-8709-A-V1)
2. Letter, John F. Stolz (U.S. NRC) to C. Eicheldinger (Westinghouse), *Evaluation of Westinghouse Topical Reports WCAP-8708(P) and WCAP-8709(NP)*, June 17, 1977 (Enclosure – Topical Evaluation Report).
3. WCAP-7832-A (Non-Proprietary), "Evaluation of Steam Generator Tube, Tube Sheet, and Divider Plate Under Combined LOCA Plus SSE Conditions," P. De Rosa, W. Rinne, H. W. Massie, Jr., P. Mitchell, April 1978.
4. Letter, John F. Stolz (U.S. NRC) to C. Eicheldinger (Westinghouse), *Safety Evaluation of WCAP-7832(P) and WCAP-8709(NP)*, March 2, 1978 (Enclosure – Safety Evaluation Report).
5. WCAP-9401-P-A, *Verification Testing and Analyses of the 17x17 Optimized Fuel Assembly,* August 1981. (Proprietary) (Non-proprietary version: WCAP-9402-NP-A)
6. Letter, Robert L. Tedesco (U.S. NRC) to T. M. Anderson (Westinghouse), *Acceptance for Referencing Topical Report WCAP 9401(P)/WCAP 9402(NP)*, May 7, 1981.
7. WCAP-9735, Revision 2 (Proprietary) and WCAP-9736, Revision 1 (Non-Proprietary), *MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model*, February 1998.

Table A.9-1 (cont.) Computer Code Description
8. WCAP-11004-P/WCAP-11005 (NP), "*Comparison of Data for Beaver Valley Power Station, Unit 2 with WCAP-9735 Data, Prepared for NRC Review in Conjunction with Review of WCAP-9735, Docket No. 50-412*," D. R. Bhandari, K. Takeuchi, M. E. Wills, November 1985. 9. WCAP-11522 (Proprietary)/WCAP-11523 (Non-Proprietary), "*Response to NRC Questions on the LOCA Hydraulic Forces Analysis of the Beaver Valley Power Station, Unit 2, Prepared for NRC Review in Conjunction with Review of WCAP-9735, Docket No. 50-412*," D. C. Garner, M. P. Kachmar, M. R. Wengerd, June 1987. 10. WCAP-15029-P-A, *Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions*, December 1998. (Proprietary) (Non-proprietary version: WCAP-15030-NP-A) 11. Letter, T. H. Essig (U.S. NRC) to Lou Liberatori (WOG), Safety Evaluation of Topical Report WCAP-15029, "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions,' (TAC No. MA1152), November 10, 1998 (Enclosure 1 – Safety Evaluation Report). 12. WCAP-15245, *Control Rod Insertion Following a Cold Leg LBLOCA, D. C. Cook, Units 1 and 2*, May 28, 1999. (Proprietary) (Non-proprietary version: WCAP-15246) 13. Letter, John F. Stang (U.S. NRC) to Robert P. Powers (Indiana Michigan Power Company), *Issuance of Amendments – Donald C. Cook Nuclear Plant, Units 1 and 2 (TAC Nos. MA6473 and MA6474)*, December 23, 1999. 14. WCAP-8252, Revision 1, "*Documentation of Selected Westinghouse Structural Analysis Computer Codes*," K. M. Vashi, May 1977. SER Conditions: Note there are no specific SER restrictions on MULTIFLEX 3.0, LATFORC, FORCE2, and THRUST. However, the analyses have complied with the applicable SER restrictions on MULTIFLEX 1.0 and the Reference 10 methodology, including the use of the conservative 1 millisecond break opening time.

Table A.9-1 (cont.)
Computer Code Description

NOTRUMP/SBLOCTA (LOCTA-IV)

The approved codes for Appendix K small-break LOCA analyses are NOTRUMP and SBLOCTA. The NOTRUMP computer code is a one-dimensional general network code consisting of a number of advanced features. Among these features is the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flow limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat-transfer correlations. Additional features of the code are condensation heat-transfer model applied in the steam generator region, loop seal model, core reflux model, flow regime mapping, etc.

The SBLOCTA computer code is used to model the fuel rod response to the small-break LOCA transient. It models two rods in the hot assembly (hot and average), modeling simultaneous radial and axial conduction. Other modeling features include assembly blockage model due to cladding swell, and rupture and zirc/water reaction.

NOTRUMP is used to model the thermal-hydraulic behavior of the system and thereby obtain time-dependent values of various core region parameters, such as system pressure, temperature, fluid levels, and flow rates. These are provided as boundary conditions to SBLOCTA. SBLOCTA then uses these conditions and various hot channel inputs to calculate the rod heatup and ultimately, the peak cladding temperature (PCT) for a given transient. Additional variables calculated by SBLOCTA are cladding pressure, strain, and oxidation.

All applicable SER restrictions and limitations have been addressed in this application.

References:

1. WCAP-10079-P-A (Proprietary), "NOTRUMP, A Nodal Transient Small Break and General Network Code," August 1985.
2. WCAP-10054-P-A (Proprietary), "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," Lee et. al., August 1985.
3. WCAP-10054-P-A, Addendum 2, Revision 1 (Proprietary), "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," Thompson et. al., July 1997.
4. WCAP-8301 (Proprietary), "LOCTA-IV Program: Loss of Coolant Transient Analysis," F. M Bordelon et al., June 1974.

Dates of NRC Acceptance:
WCAP-10079-P-A, May 23, 1985; WCAP-10054-P-A, May 21, 1985; WCAP-10054-P-A2-R1, August 12, 1996

Table A.9-1 (cont.) Computer Code Description
SER Conditions: **WCAP-10054-P-A** <u>SER Wording (Page 8)</u> "To assure the validity of this application, the bubble diameter should be on the order of 10^{-1}-2 cm. As long as steam generator tube uncovery (concurrent with a severe depressurization rate) does not occur, this option is acceptable." <u>SER Compliance</u> Westinghouse complies with this restriction for all Appendix-K licensing basis calculations. Typical Appendix-K calculations do not undergo a significant secondary side system depressurization in conjunction with steam generator tube uncovery due to the modeling methodology utilized. <u>SER Wording (Page 14)</u> "The two phase multiplier used is the Thom modification of the Martinelli-Nelson correlation. This model is acceptable per 10 CFR Part 50 Appendix K for LOCA analysis at pressure above 250 psia" <u>SER Compliance</u> The original NOTRUMP model was limited to no less than 250 psia since the model, as contained in the NOTRUMP code, did not contain information below this range. Westinghouse extended the model to below 250 psia, as allowed by Appendix K paragraph I-C-2, and reported these modifications to the NRC via the 1995 annual reporting period (NSD-NRC-96-4639). <u>SER Wording (Pages 16-17)</u> "Axial heat conduction is not modeled." and "Deletion of clad axial heat conduction maximizes the peak clad temperature." <u>SER Compliance</u> The Westinghouse Small Break LOCA is comprised of two computer codes, the NOTRUMP code which performs the detailed system wide thermal hydraulic calculations and the LOCTA code which performs the detailed fuel rod heatup calculations. The NOTRUMP code does not model axial conduction in the fuel rod and therefore complies. The LOCTA code has always accounted for axial conduction as is clearly stated in WCAP-14710-P-A which supplements the original NOTRUMP documentation. <u>SER Wording (Page 21)</u> "The standard continuous contact model is not appropriate for vertical flow,..." <u>SER Compliance</u> The standard continuous contact flow links are not utilized when modeling vertical flow in the Appendix-K NOTRUMP Evaluation Model analyses; therefore, compliance is demonstrated. <u>SER Wording (Page 7 of enclosure 2)</u> "Per generic letter 83-35, compliance with Action Item II. K.3.31 may be submitted generically. We require that the generic submittal include validation that the limiting break location has not shifted away from the cold legs to the hot or pump suction legs." <u>SER Compliance</u> Westinghouse submitted WCAP-11145-P-A in support of generic letter 83-35 Action Item 11.K.3.31. As part of this effort, verification was provided which documented that the cold leg break location remains limiting.

Table A.9-1 (cont.) Computer Code Description
WCAP-10054-P-A, Addendum 2, Revision 1 <u>SER Wording (Page 3)</u> "It is stated in Ref. 5 that the range of injection jet velocities used in the experiments brackets the corresponding rates in small break LOCAs for Westinghouse plants and that the model will be used within the experimental range. Also in References 1 and 5 Westinghouse submitted analyses demonstrating that the condensation efficiency is virtually independent of RCS pressure and state that the COSI model will be applied within the pressure range of 550 to 1200 psia." <u>SER Compliance</u> The coding implementation of the COSI model correlation in the NOTRUMP model restricts the application of the COST condensation model to a default pressure range of 550 to 1200 psia and limits the injection flow rate to a default value of 40 lbm/sec-loop. The value of 40 lbm/sec-loop corresponds to the 30 ft./sec velocity utilized in the COSI experiments. As such, the default NOTRUMP implementation of the COSI condensation model complies with the applicable SER restrictions.
PAD 3.4/4.0 The NRC-approved PAD code, with NRC-approved models for in-reactor behavior, is used to calculate the fuel rod performance over its irradiation history. PAD is the principal design tool for evaluating fuel rod performance. PAD iteratively calculates the interrelated effects of temperature, pressure, cladding elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power. Fuel rod design and safety analyses are based on updated values (up to 100-percent helium gas release) for the integral fuel burnable absorber (IFBA) helium gas release model. PAD is a best-estimate fuel rod performance model. In most cases, the design criterion evaluations are based on a best-estimate plus uncertainties approach. A statistical convolution of individual uncertainties due to design model uncertainties and fabrication dimensional tolerances is used. As-built dimensional uncertainties are measured for some critical inputs (e.g., fuel pellet diameter), and when available, can be used in lieu of the fabrication uncertainties. References: 1. WCAP-12610-P-A, "VANTAGE + Fuel Assembly Reference Core Report," April 1995. 2. WCAP-10851-P-A, "Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations," August 1988. 3. WCAP-15063-P-A, Revision 1, with Errata (Proprietary), "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," J. P. Foster and S. Sidener, July 2000. Date of NRC Acceptance: 1. Letter from S. Richards (NRC) to H. A. Sepp (Westinghouse), "Safety Evaluation Related to Topical Report," WCAP-15063, Revision 1, "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," (TAC No. MA2086), April 24, 2000. SER Conditions: There are no SER restrictions applicable to this application.

Table A.9-1 (cont.) Computer Code Description
PHOENIX-P PHOENIX-P is a 2-dimensional, multi-group transport theory computer code. The nuclear cross-section library used by PHOENIX-P contains cross-section data based on a 70-energy-group structure derived from ENDF/B-VI files. PHOENIX-P performs a two-dimensional 70-group nodal flux calculation which couples the individual subcell regions (pellet, cladding, and moderator) as well as surrounding rods via a collision probability technique. This 70-group solution is normalized by a coarse energy group flux solution derived from a discrete ordinates calculation. PHOENIX-P is capable of modeling all cell types needed for PWR core design applications. Reference: 1. WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," T. Q. Nguyen et al., June 1988. Date of NRC Acceptance: May 17, 1988, Ashok Tadani to W. J. Johnson SER Conditions: There are no SER restrictions applicable to this application.
THRUST (See also MULTIFLEX) The THRUST program calculates the hydraulic forces that the fluid exerts on the reactor coolant loop. The THRUST code uses the MULTIFLEX LOCA pressure transient as input in the calculation of the loop forces. In the THRUST computer code, the loop piping is represented by a series of control volumes. The pressure forces are calculated by THRUST wherever there are changes in either loop area or direction. The LOCA loop forces are then transmitted to the appropriate structural analysis group where they are then combined with the other design-basis loads (i.e., seismic, thermal and system shaking loads) where they are used to qualify the reactor coolant loops under the design-basis loads. References: 1. WCAP-8708-P-A-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977. 2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977. Date of NRC Acceptance: See MULTIFLEX SER Conditions: See MULTIFLEX

Table A.9-1 (cont.)
Computer Code Description

TWINKLE
TWINKLE is a neutron kinetics code which solves the multidimensional, two-group transient diffusion equations using a finite-difference technique. The code contains a detailed six-region fuel-clad-coolant transient heat transfer model at each spatial point for calculating Doppler and moderator feedback effects. The code handles up to 8000 spatial points in one-, two- or three- dimensional rectangular geometry.

Reference:
1. WCAP-7979-P-A, "TWINKLE – A Multidimensional Neutron Kinetics Computer Code," January 1975.

Date of NRC Acceptance: July 29, 1974 (SER from D. B. Vassallo (U.S. Atomic Energy Commission) to R. Salvatori (Westinghouse))

SER Conditions & Justification
There are no conditions, restrictions, or limitations cited in the TWINKLE SER.

VIPRE
VIPRE-01 (VIPRE) is a three-dimensional subchannel code that has been developed to account for hydraulic and nuclear effects on the enthalpy rise in the core and hot channels. The VIPRE code is based on a knowledge and understanding of the heat transfer and hydrodynamic behavior of the coolant flow and the mechanical characteristics of the fuel elements. The use of the VIPRE analysis provides a realistic evaluation of the core performance and is used in the thermal-hydraulic analysis.

The VIPRE core model as approved by the NRC (Reference 1) is used with the applicable DNB correlations to determine DNBR distributions along the hot channels of the reactor core under all expected operating conditions. The VIPRE code is described in detail in Reference 2, including discussion on code validation with experimental data. The VIPRE modeling method is described in Reference 1, including empirical models and correlations used. The effect of crud on the flow and enthalpy distribution in the core is not directly accounted for in the VIPRE evaluations. However, conservative treatment by the VIPRE modeling method has been demonstrated to bound this effect in DNBR calculations.

References:
1. WCAP-14565-P-A and WCAP-15306-NP-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," Y. X. Sung et al, October 1999.
2. NP-2511-CCM-A, "VIPRE-01: A Thermal-Hydraulic Code for Reactor Core, Volume 1-3 (Revision 3, August 1989, Volume 4 (April 1987)," Electric Power Research Institute, C. W. Stewart et al.

Date of NRC Acceptance:
Letter from T. H. Essig (NRC) to H. Sepp (Westinghouse), "Acceptance for Referencing of Licensing Topical Report WCAP-14565, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal/Hydraulic Safety Analysis," (TAC No. M98666)," January 19, 1999.

Table A.9-1 (cont.)
Computer Code Description

SER Conditions & Justification

1. *"Selection of the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal."*

   Justification
   The NRC-approved WRB-2M correlation was used in the DNBR analyses. Justification of the WRB-2M correlation limit of 1.14 with the VIPRE code is provided in WCAP-14565-P-A.
   For the Beaver Valley EPU DNBR analyses, the plant specific hot channel factors for enthalpy rise and other fuel-dependent parameters that have been previously approved by the NRC have been assumed in these analyses.

2. *"Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE."*

   Justification
   The core boundary conditions for the VIPRE calculations are all generated from NRC-approved methodologies and computer codes. Conservative reactor core boundary conditions were justified for use as input to VIPRE as discussed in the safety evaluations. Continued applicability of the input assumptions is verified on a cycle-by-cycle basis using the Westinghouse reload methodology described in WCAP-9272/9273.

3. *"The NRC Staff's generic SER for VIPRE (Reference 2 of the SER) set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using WRB-1, WRB-2 and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of other CHF correlations not currently included in VIPRE will require additional justification."*

   Justification
   Justification on use of the W-3, WRB-1 and WRB-2M correlation with the VIPRE code is provided in WCAP-14565-P-A.

4. *"Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated design-basis accidents, including beyond-CHF heat transfer conditions. These evaluations are necessary to evaluate the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC Staff's generic review of VIPRE (Reference 2 of the SER) did not extend to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC Staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained."*

   Justification
   For the Beaver Valley EPU analyses, VIPRE is not used in the post-CHF.

Dose Methodologies and Computer Codes
BVPS-2 UFSAR Appendix 15A "Dose Methodology," as updated by Section 1.4.2 and Section 5.11 of the EPU LAR, provide information relative to the dose methodologies and computer codes which are applicable to both BVPS-1 and 2.

The dose calculation methodology and computer code information provided in Appendix 15A of the BVPS-2 UFSAR include the changes made to the licensing basis resulting from selective implementation of alternative source term methodology and use of ARCON96 for the development of associated on-site atmospheric dispersion factors to analyze the dose consequences of the Loss-of-Coolant and Control Rod Ejection accident. The above change in licensing basis has been previously reviewed and approved by NRC via Amendments 257/139 for BVPS-1 and 2, dated September 10, 2003.

LAR Section 1.4.2 notes that with the EPU application, alternative source term methodology and use of ARCON96 is being incorporated for the remaining dose consequence analyses.

LAR Section 5.11.9 identifies a couple of additional changes in dose assessment methodology. The accident model for the gaseous waste system rupture follows the guidance provided in Safety Guide 24, takes no credit for the charcoal delay beds, and utilizes 500 mrem TEDE (previously accepted by NRC for other applications) as the acceptance criteria. In addition, the BVPS-2 main steam line break credits a reduction in steam generator tube leakage in the defective steam generator to reflect the pressure reduction in the primary coolant at the time of RHR cut-in versus at the time of accident initiation.

LAR Table 1.0-2 lists the principal computer codes used to support the UFSAR analyses for the EPU Project. The table shows which codes have been previously approved and used for BVPS-1 and 2 and identifies which codes are being applied to BVPS-1 and 2 for the first time. As shown in Table 1.0-2, the principal computer codes being applied to BVPS-1 and 2 as part of the EPU Project have either been previously approved by the NRC, or the results of these codes have been previously accepted by NRC as they are consistent with accepted industry practice. NRC approved computer codes are used within any restrictions and limitations identified in the NRC safety evaluations for the topical reports relative to the computer codes and methodologies.

A.10 (Applicable to RSG & EPU)

Provide a tabulation of the thermal design parameters and compare them to values assumed in safety analyses to demonstrate that the safety analyses assumptions are conservative.

Response:

This question is answered by the EPU Licensing Report information and RAI responses as per the following: a) RAI A.1 that provides the key design inputs to accident analyses; b) EPU Licensing Report (LR) Sections 2.1.1.2, 2.1.1.3, and Tables 2.1-1 through 2.1-5 that define the initial PCWG conditions for both the current operation and for the extended power uprate; c) the response to RAI A.5 that provides the conservative biasing to initial parameters for each accident; d) the tables in Section 5.2.1 of the EPU LR for Best Estimate Large Break LOCA; and e) each accident analysis section (subsection of Chapter 5) of the EPU LR that defines the acceptance criteria for each event.

A.11 (Applicable to RSG & EPU)

Please confirm that only safety grade systems and components are credited in the re-analyses of all transients and accidents in the EPU report for BVPS-1 and 2.

Response:

With the exception of the steam generator tube rupture (SGTR) event at BVPS-1, only safety grade systems and components are credited in analyses of transients and accidents supporting the EPU submittal. For the SGTR event at BVPS-1, an operational response analysis was performed to demonstrate margin to steam generator overfill. This analysis credits the secondary heat removal system atmospheric steam dump valves during cooldown of the RCS to establish subcooling prior to RCS de-pressurization. These valves are not fully safety grade components and are powered by the station air system. They are capable of being manually operated locally in the event that control systems or station air is lost. Acceptable results were achieved, (i.e., no steam generator overfill occurs), in the operational assessment analysis when only local manual valve actuation was credited for the case where all station air is lost.

The pressurizer power operated relief valves (PORVs) may also be used during this event if normal pressurizer spray is unavailable for depressurization. These valves are also normally powered by the station air system but have a nitrogen backup system and can be operated from the control room in the event that station air is lost.

With the above noted exceptions, control grade systems are not credited in safety analyses unless their operation is detrimental to the results.

A.12 (Applicable to RSG & EPU)

Provide a quantitative evaluation of the impacts of the EPU on the ability of BVPS-1 and 2 to cope with a station blackout (SBO) event. The evaluation should address the capacities of the condensate storage tank, turbine-driven auxiliary feedwater pump, station batteries, and backup air supplies for air-operated valves for decay heat removal and RCS cooldown during the time period of an SBO.

Response:

The Beaver Valley Power Station (BVPS) Units 1 and 2 were evaluated against the requirements of the Station Blackout Rule, 10 CFR 50.63, using guidance from NUMARC 87-00 and Regulatory Guide 1.155. Using the guidance of Nuclear Utility Management and Resource Council (NUMARC 87-00), the BVPS blackout coping duration was determined to be 4 hours.

Under Station Blackout (SBO) conditions, a single electrical cross tie connects the 4160 V normal busses 1A, 1D, 2A and 2D of the BVPS-1 and 2. The normal to emergency 4160 V bus connections and the Emergency Diesel Generator (EDG) to the emergency 4160 V bus connections complete the circuit to the alternate AC power source. The design of the alternate AC power source and associated cross tie circuit is in conformance with the SBO Rule (10 CFR 50.63) and guidance provided by Regulatory Guide 1.155 and NUMARC 87-00.

<u>Class 1E Battery Capacity</u>
Station batteries, inverters and related distribution systems are available with capability to cope during the initial one hour period prior to alternate AC power source capability. The impact of EPU on the station electrical systems was provided in FENOC Letter L-05-078, dated May 26, 2005 response to RAI H.4 (Section 9.18.2) and H.10 (Section 10.7).

<u>Loss of Ventilation</u>
The impact of a four hour loss of ventilation due to a SBO has been evaluated for equipment both inside and outside containment.

Inside containment, temperatures resulting from a loss of ventilation are not increased due to the EPU. No additional heat sources have been identified following loss of ventilation as a result of the EPU. The existing sources of heat input remain bounding for the EPU. The Containment Air Recirculation (CAR) fans and Control Rod Drive Mechanisms (CRDM) fans are required to be shut-off following an SBO event for the current plant conditions and their shutdown requirement will not change for EPU.

Outside containment the existing steady state temperature calculations for the Control Room, Process Instrument Room, Battery Room Battery Room, West Emergency Switchgear Room, East Emergency Switchgear Room, Auxiliary Feedwater Pump Room, Charging Pump Cubicle and Intake Structure were reviewed. Existing calculations envelope the conditions anticipated to occur during EPU operation as they relate to Station Blackout.

Condensate Inventory for Decay Heat Removal/RCS Cooldown
Each unit's turbine-driven auxiliary feedwater (AFW) pump, which is supplied steam from the steam generators, is started automatically. The AFW turbine driven pumps are rated at 700 gpm (BVPS-1) and 750 gpm (BVPS-2). The AFW flow requirements of 375 gpm (BVPS-1) and 340 gpm (BVPS-2) can be supplied by each unit's respective turbine driven pump.

The EPU Technical Specification minimum usable volume of water contained in each unit's Primary Plant Demineralized Water Storage Tank (PPDWST) is being revised to 130,000 gallons. The BVPS original submittal (4/14/89) to the NRC, determined that 110,886 gallons of condensate are required for each unit for a 4-hour decay heat removal and plant cooldown. Subsequently, the BVPS supplemental SBO submittal (3/30/90), determined that 87,604 gallons would be needed for decay heat removal and cooldown to an average reactor coolant system temperature of 350°F. The NRC Safety Evaluation review of 10/23/90 established that the original determination of 110,886 gallons ensures excess inventory is available for station blackout recovery. For the power level increase to 2910 MWt a conservative 9.4% increase in the required PPDWST volume is required. Since this increased volume (i.e., ~122,000 gallons) is less than the proposed Technical Specification minimum PPDWST volume for both units, sufficient inventory is available for decay heat removal following SBO.

Compressed Air
The BVPS-1 and 2 do not rely on back-up air supplies since air operated valves will be manually operated. In addition, the EPU does not impact any air-operated valve or instrument credited in the current SBO analysis.

The existing design supports EPU as they relate to Station Blackout. No system modifications are required to support EPU to ensure BVPS-1 and 2 comply with the requirements of the SBO rule (10 CFR 50.63) and guidance provided by Regulatory Guide 1.155 and Nuclear Utility Management and Resource Council NUMARC 87-00.

A.13 (Applicable to EPU)

Matrix 8 of RS-001, NRC's review standard for extended power uprates, lists new fuel and spent fuel storage as areas of review, with respect to General Design Criterion (GDC) 62 "Prevention of criticality in fuel storage and handling." It is necessary to show that the assumptions in the BVPS-1 and 2 new fuel and spent fuel pool criticality analyses of the current licensing basis would be valid for EPU conditions.

a. **Do the current spent fuel pool criticality licensing bases of BVPS-1 and 2 include a commitment to 10 CFR 50.68? Has an exemption to the requirements of 10 CFR 70.24 been requested and approved? If so, please explain how the conditions in this exemption will not be violated as a result of the proposed EPU.**

Response:

The current spent fuel pool criticality licensing basis for BVPS-1 and 2 does not include a commitment to 10 CFR 50.68. The statements of consideration for changes to 10 CFR 70.24 and the new 10 CFR 50.68 rule (63FR63127 published 11/12/98 and effective 12/14/98) identified that the rulemaking does not affect the status of exemptions to the requirements of Section 70.24 that were previously granted by the NRC. A licensee currently holding an exemption to Section 70.24 could continue operation under its existing exemption and its current programs and commitments without any further action.

BVPS-1 and 2 were both granted an exemption to 10 CFR 70.24 prior to the initial publication of the direct final rule on December 3, 1997. Please refer to exemption letters of June 26, 1997 (Reference 1) and April 9, 1986 (Reference 2) for BVPS-1 and 2, respectively.

It is concluded that the exemption to 10 CFR 70.24 remains valid for both BVPS-1 and 2, and adequate measures are in place to ensure continued compliance under EPU conditions. The conditions of this exemption will not be affected as a result of the proposed EPU since, as identified in response to items b and c below for this RAI, the criticality analysis remain bounded, monitoring and enrichment limits are not altered by the EPU, and the spent fuel pool criticality analysis will not be affected by core design changes as a result of EPU.

References:

1. NRC letter to J. E. Cross, President Generation Group, "Issuance of Exemption From The Requirements of 10 CFR 70.24, Beaver Valley Power Station, Unit No. 1 (TAC No. M97469)," June 26, 1997.
2. NRC letter to J. J. Carey, Vice President, "Re: Issuance of NRC Special Nuclear Materials License No. SNM-1954 for Beaver Valley Power Station, Unit No. 2," April 9, 1986.

b. **The BVPS-1 and 2 Technical Specification (TS) Bases refer to the use of Westinghouse Topical Report, WCAP-14416, as part of the licensing basis. Address how the current criticality analyses are still bounding, given the higher enrichments needed for the EPU, and the non-conservatisms identified in the topical report. (References: Letter dated July 27, 2001 to Westinghouse from the NRC regarding axial burnup bias; Regulatory Issue Summary, RIS-01-012 dated May 18, 2001, "Nonconservatism in Pressurized Water Reactor Spent Fuel Storage Reactivity Equivalencing Calculations."**

Response:

The BVPS-2 spent fuel pool criticality analysis utilizes the Westinghouse topical report WCAP-14416. The BVPS-1 spent fuel criticality analysis utilized a Holtec report. Both spent fuel criticality analyses were performed at a maximum enrichment of 5.0 weight percent (wt%). This enrichment limit is not changing for the EPU and current core designs at both units have already incorporated fuel assembly enrichments of 4.95 wt%.

The non-conservatisms identified in RIS-01-012 (Westinghouse NSAL-00-015) were addressed in Beaver Valley Condition Report 00-4054. The criticality analysis for BVPS-2 to eliminate Boraflex credit in the spent fuel pool was being developed when this issue was identified. Westinghouse provided an additional evaluation to offset the non-conservative axial burnup bias calculations and this evaluation was referenced in the LAR submittal (L-01-044 dated March 28, 2001). The evaluation of the identified conservatism credit and axial bias penalty demonstrates that K_{eff} remains less than or equal to 0.95 when accounting for the presence of boron. In addition, K_{eff} remains less than or equal to 1.00 when not accounting for any boron presence for the analyses performed. The BVPS-1 spent fuel criticality analysis package developed in 1994 for the rerack of the spent fuel pool was reviewed as part of the corrective actions for CR 00-4054. The Holtec analysis includes a much more conservative axial burnup distribution compared to the Westinghouse methodology. As an example, for a 5.0 wt% enriched assembly at 40,000 MWD/MTU of burnup, the Holtec analysis utilizes a +1,430 pcm axial bias effect, while the Westinghouse methodology indicates a -243 pcm axial bias. Based on the evaluation of the Holtec analysis, the axial burnup bias was determined to be conservative.

The criticality analyses for both BVPS-1 and 2 remain bounded for the current licensed assembly enrichment of 5.0 wt% and the non-conservatisms identified in the topical report.

c. Address the effects of the changes in fuel characteristics and operating strategy on new fuel and spent fuel criticality analyses (e.g. how does the change in operation affect the assumptions used for burnup profiles/burnup credit? How does the new fuel geometry/characteristics affect criticality analyses?)

Response:

The new fuel analyses for BVPS-1 and 2 were performed for the current licensed assembly enrichment.

The spent fuel analyses for BVPS-1 and 2 were performed for the current licensed assembly enrichment and assembly average burnups. The fuel characteristics and operating strategy will remain essentially the same for EPU conditions as the current core conditions. Both units currently operate with assemblies enriched to 4.95 wt% and have reached cycle burnups of over 20,000 MWD/MTU (equivalent to EPU conditions). The burnup profiles for EPU cores will be similar to the current core designs. The additional burnup that may be realized for EPU will tend to flatten the burnup distribution lessening the axial burnup bias for burnup credit.

The Robust Fuel Assembly (RFA) fuel geometry/characteristics remain the same as the VANTAGE 5H fuel assemblies. The major change to the fuel assembly from VANTAGE 5H to RFA was the redesigned mid-grids and the addition of Intermediate Flow Mixing grids. These items do not impact the criticality analyses for the units.

Therefore, the new fuel and spent fuel criticality analyses will not be affected by core design changes introduced as a result of the EPU.

Sections 3.2, 5.3.6, and 9.1 Overpressure Protection During Power Operation

B.1 (Applicable to RSG & EPU)

One of the most significant impacts of any power uprate is on overpressure scenarios. The BVPS-1 and 2 EPU submittal does not address the analysis guidelines of SRP, Section 5.2.2, "Overpressure Protection," specifically SRP 5.2.2, Section II.A. Historically, virtually all Westinghouse plants have been licensed referring to WCAP-7769 (which explicitly identifies BVPS-1 and 2, operating at 2774 MWt, as plants covered by the report) as the basis for meeting this SRP guideline. However, BVPS-1 and 2, operating at the proposed uprated power of 2900 MWt, no longer fall in a class explicitly covered by WCAP-7769. The analyses described in the EPU application, Section 5.3.6.3, do not satisfy the SRP 5.2.2 guidelines. The NRC staff's safety evaluation report (SER) related to WCAP-7769 (Reference 6) limits the scope of its approval. Please provide, either (1) BVPS-1 and 2 analyses per SRP 5.2.2, II.A guidelines, or (2) identify existing analyses that apply to BVPS-1 and 2 which comply with SRP 5.2.2 guidelines.

Response:

The BVPS-1 and 2 EPU overpressure analyses are consistent with the requirements of SRP 5.2.2, which requires that the second safety grade reactor trip signal be credited for safety valve sizing calculations. This is consistent with the safety valve sizing procedure discussed in Section 2 of WCAP-7769. WCAP-7769 states, "For the sizing, main feedwater flow is maintained and no credit for reactor trip is taken." This analysis is typically performed prior to construction of the plant to provide a basis for the capacity requirements for the safety valves and the requirement of SRP 5.2.2 provides a conservative basis for the number and design of the valves.

However, WCAP-7769 goes on to say, "After determining the required safety valve relief capacities, as described above, the loss of load transient is again analyzed for the case where main feedwater flow is lost when steam flow to the turbine is lost... For this case, the basis for analysis are the same as described above except that credit is taken for Doppler feedback and appropriate reactor trip, other than direct reactor trip on turbine trip." This describes the analysis performed in Chapter 14 (BVPS-1) and 15 (BVPS-2) of the UFSAR which verifies that the overpressure limits are satisfied with the current design.

The analyses performed in support of the Beaver Valley EPU Project are not safety valve sizing calculations – no changes are being made to the safety valves as a result of this uprating. The loss of external electrical load/turbine trip event analysis performed for the EPU Project, presented in Section 5.3.6, demonstrates that the safety valves have adequate capacity to maintain peak primary pressure below 110% of design which satisfies the requirements of GDC-15. GDC-15 applies to "any condition of normal operation, including anticipated operational occurrences" which does not include a common mode failure of the first safety grade reactor trip signal.

The loss of external load/turbine trip RCS overpressure analysis is performed to demonstrate that, in the event of a sudden loss of the secondary heat sink, the associated increase in reactor coolant system temperature does not result in overpressurization of the RCS system.

Sections 3.2.1, 4.4, and 9.22.3 **Functional Design of the Control Rod Drive System**

C.1 (Applicable to RSG & EPU)

With respect to the analysis for uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power, Tables 5.3.3-1A and 5.3.3-1B, please provide the time sequence of events for BVPS-1 and 2, respectively. In the analysis for a slow RCCA withdrawal, the overtemperature ΔT trip is credited with terminating the event. Both tables indicate the RCCAs start to fall within 2 seconds of overtemperature ΔT trip condition being reached. Table 14D-3 of the BVPS-1 Updated Final Safety Analysis Report (UFSAR) states there is a 6-second delay associated with the overtemperature ΔT trip. Table 15.0-4 of the BVPS-2 UFSAR states there is a 10-second delay associated with the overtemperature ΔT trip. What changes have been made which reduced these delay times?

Response:

The BVPS-1 sequence of events for rod withdrawal at power event is given in Table 5.3.3-1A and the BVPS-2 sequence of events is given in Table 5.3.3-1B of the EPU Licensing Report.

The total Overtemperature ΔT trip delays have not decreased from the current analyses. The calculated reactor trip times (in seconds) presented in the subject tables are based on the modeling of the OTΔT trip setpoint (including delay times), and conservatively predict when the OTΔT setpoint is reached.

In addition, a 2 second delay is modeled to account for the delay from the time that the OTΔT trip is actuated until the RCCAs begin falling into the core. This 2 second time delay is also shown on the subject tables.

Sections 4.3 and 6.0 **Fuel System Design**

D.1 (Applicable to EPU)

In Section 4.3, "Fuel Assemblies," of the licensee's EPU request it is stated, "...seismic and LOCA [loss-of-coolant accident] analyses were performed for the fuel assemblies for the homogenous core of RFA [robust fuel assemblies] (w/IFMs [intermediate flow mixing])." In Section 6, "Fuel Analysis," it is stated, "...previously burned VANTAGE 5H fuel assemblies may be reinserted..." and "...reinserting VANTAGE 5H fuel assemblies into the core will be confirmed during the normal reload design process..." At EPU conditions, how are the seismic and LOCA analyses affected by the non-homogenous core of RFA and VANTAGE 5H fuel assemblies?

Response:

The seismic and LOCA analysis for the non-homogenous/transition cores (from 17x17 V5H without IFM to 17x17 RFA with IFM or RFA-2 with IFM) with EPU conditions was performed in addition to the seismic and LOCA analysis for the homogenous core of 17x17 RFA or RFA-2 with EPU conditions. The analysis addressed the case that the previously burned VANTAGE 5H fuel assemblies may be reinserted. The seismic and LOCA analysis for the homogenous and the non-homogenous/transition cores showed that the 17x17 RFA, RFA-2, and VANTAGE 5H fuel assemblies are acceptable for EPU conditions.

D.2 (Applicable to RSG & EPU)

In Section 4.3, of the licensee's EPU request, it is stated, "...the best estimate flow per fuel assembly will be slightly higher than the best estimate flow per assembly in previous analysis." What is the mechanism for the increased flow? Is this applicable to both units or just BVPS-1 with the replacement steam generators (RSGs)?

Response:

The reactor coolant system (RCS) best estimate flows (BEFs) were recalculated for EPU conditions in order to establish a BEF range that bounds operation of BVPS-1 and 2 with either Model 51, Model 51M or Model 54F steam generators with steam generator tube plugging (SGTP) levels between 0% and 22%, with 17x17 RFA fuel with IFMs or VANTAGE 5H fuel without IFMs, and with thimble plugs either installed or removed. As a result, the bounding EPU BEF range for BVPS-1 and 2 was initially defined as 90,800 gpm/loop (22% SGTP) to 97,500 gpm/loop (0% SGTP). For BVPS-1, the upper limit of the EPU BEF range was subsequently increased slightly from 97,500 to 97,800 gpm/loop to accommodate the final design of the Model 54F replacement steam generators. For comparison purposes, the BEF range for current power conditions is 88,700 gpm/loop (30% SGTP) to 96,400 gpm/loop (0% SGTP) for BVPS-1 and 88,900 gpm/loop (30% SGTP) to 96,600 gpm/loop (0% SGTP) for BVPS-2. The BVPS-2 BEF range changed due to the use of the bounding values for EPU.

D.3 (Applicable to EPU)

In Section 4.3, of the licensee's EPU request, it is stated, "...the fuel assembly holddown spring capacity was verified to still be acceptable." Did that analysis include the effects of fuel assembly growth due to irradiation and the increased growth expected at EPU conditions? Did that analysis include the effects of elevated core exit temperature?

Response:

Yes. The calculation for fuel hold-down conservatively assumed upper bound fuel assembly growth (75 GWD/MTU lead rod burnup) and includes increased growth from EPU conditions. The effect of greater fuel assembly growth would be to increase fuel assembly hold-down margin. The analysis conservatively assumed a core outlet temperature of 650°F versus the PCWG core outlet temperature input parameter of 621.4°F; also, it utilized the increased lift force input values generated for EPU conditions.

D.4 (Applicable to EPU)

The licensee's EPU request did not address fuel rod bowing considerations. With the increased irradiation of fuel rods expected as a result of EPU conditions, please provide an analysis of the effect of EPU conditions on fuel rod bowing.

Response:

Effects of fuel rod bowing on DNB have been addressed for EPU, and the evaluation is summarized in Section 6.1.3.3 of the EPU Licensing Report. The rod bow DNB effect on the 17x17 RFA or RFA-2 fuel is analogous to the 17x17 VANTAGE 5 and VANTAGE 5H fuels described in WCAP-10444-P-A (Reference 1) and Addendum 2 (Reference 2), respectively.

As indicated in Table 6.1-2 of the EPU Licensing Report, minimum DNBRs occur in the IFM spans of the 17x17 RFA or RFA-2 fuel. The presence of the IFM grids decreases the grid-to-grid spacing that improves the rod bow performance of the fuel assembly by adding additional restraint to the fuel rod. Based on predicted channel closure due to rod bowing using the NRC-approved evaluation method, the DNBR penalty in the IFM spans of the RFA fuel is zero. The predicted channel closure and the resultant rod bow DNBR penalty remain unchanged at the EPU conditions. The rod bow effect in the lower half of the RFA fuel containing no IFM grids is the same as the current 17x17 VANTAGE 5H fuel (Reference 2). There is no change in the rod bow penalty on the 17x17 VANTAGE 5H fuel for EPU.

References:

1. WCAP-10444-P-A (Proprietary)/WCAP-10445-NP-A (Non-Proprietary), "Westinghouse Reference Core Report VANTAGE 5 Fuel Assembly," September 1985.

2. WCAP-10444-P-A Addendum 2-A (Proprietary)/WCAP-10444-A Addendum 2-A (Non-Proprietary), "VANTAGE 5H Fuel Assembly," April 1988.

D.5 (Applicable to EPU)

In Section 6, Subsection, Grid Assemblies, of the licensee's EPU request, it is stated that IFM grids "... must accomplish this (*promote flow mixing*) without inducing clad wear beyond established limits. The IFMs must avoid interactive damage with grids from neighboring fuel assemblies during core loading and unloading conditions." Please provide an analysis on how these criteria are met, especially considering the increased flow per assembly at EPU conditions with respect to inducing clad wear beyond established limits.

Response:

The anti-snag outer strap design feature of the grid prevents interactive damage between grids from neighboring fuel assemblies during core loading and unloading conditions.

For EPU conditions, the flow is slightly increased (less than 1.5%). The VIPER loop test was based on the higher flow condition which is more than the mechanical flow (over 110%). The test condition cover the EPU flow conditions and the results show that the fuel rod clad wear is not beyond established limits.

D.6 (Applicable to EPU)

In Section 6, Subsection, Guide Thimble and Instrument Tubes, of the licensee's EPU request, it is stated that RFA thicker-walled thimble and instrumentation tubes, relative to VANTAGE 5H fuel assemblies improve "...stiffness and address incomplete rod insertion (IRI) considerations." Does the licensee anticipate EPU conditions to exacerbate IRI considerations? Given reinserted VANTAGE 5H fuel assemblies will not have the thicker-walled thimble and instrumentation tubes, how does the licensee intend to control these reinserts with respect to IRI considerations at EPU conditions?

Response:

For EPU conditions, the 17x17 RFA or RFA-2 fuel assembly burnup can still be below the Westinghouse Owner Group (WOG) recommended fuel assembly burnup limit (57,000 MWD/MTU). The IRI evaluation results of the 17x17 RFA or RFA-2 show that the design has a minimal IRI risk for 68,000 MWD/MTU fuel assembly burnup. If the 17x17 RFA or RFA-2 fuel assembly exceeds the WOG recommended burnup limit, an additional Incomplete Rod Insertion (IRI) risk assessment will be performed in accordance with the FENOC Fuel Cycle Process.

For reinserted 17x17 VANTAGE 5H fuel assemblies, it is recommended to locate the reinserted VANTAGE 5H fuel assemblies at non-RCCA locations. If the reinserted fuel assemblies have to be in the RCCA locations, the fuel assembly burnup should be below the WOG recommended burnup limit (52,000 MWD/MTU). If not, an additional IRI risk assessment will be performed.

D.7 (Applicable to EPU)

In Section 6, Subsection, Mechanical Performance, of the licensee's EPU request, it is stated, "...the addition of the three IFM grids do not significantly influence the RFA fuel assembly structural characteristics that were determined by prior mechanical testing." What was the physical configuration of the RFAs that were subjected to mechanical testing? What mechanical testing was conducted? What structural characteristics were determined by the mechanical testing? How does the mechanical testing that was performed correlate to the expected EPU conditions?

Response:

The physical configuration of the 17x17 RFA fuel assembly was a full size RFA with IFMs assembly. The mechanical test was performed to obtain the static and dynamic characteristics of the fuel assembly. Lateral vibration and impact tests were conducted to determine the structural characteristics (natural frequency and modal shapes) which were used to develop Finite Element Analysis (FEA) models. Based on the testing results, the simplified analytical FEA models of the fuel assembly were approved.

The analytical model shows that the RFA fuel assembly structural characteristics are not significantly influenced by the IFM grids.

For the EPU condition, the analytical models of the fuel assembly which were approved by the mechanical testing results are considered as no change because the EPU condition is bounded by the design limits (the fuel assembly average operating temperature is below 600°F, the fuel rod peak burnup is less than 62,000 MWD/MTU and the grid corrosion is less than 18%).

D.8 (Applicable to EPU)

In Section 6, Subsection, Core Components, of the licensee's EPU request, it is stated, "...core components for Beaver Valley are designed to be compatible with the RFA and VANTAGE 5H fuel assembly designs." How are the core components affected by EPU conditions? Please address each core component separately.

Response:

Core components in general are not significantly affected by power uprates like the one planned for BVPS-1 and 2. There are of course items that do affect some of the input parameters of the design analysis for the various core components and those will be discussed here. As the only core components that are currently in use in these facilities are the Enhanced Performance Rod Control Cluster Assemblies (EPRCCA), most of the discussion will be directly related to those items.

Rod Control Cluster Assembly Spider – The structural design of the RCCA spider is primarily controlled by the control rod drive mechanism stepping loads and the spider spring loads resulting from the spring deflection during a reactor trip. These loads will essentially not be affected by the change in power for the plant. The temperature at core outlet is only increased by 2°F which will have no significant effect on either of these loads.

The fluence for the RCCA will effectively increase by the same amount as the power rating increase, i.e., 9.4% relative to the original design power level. The only item of the spider that is affected by fluence is the spider spring. With the RCCA withdrawn, it is so far above the active fuel that no significant change in spring relaxation would occur.

Control Rodlet – The control rod has features which can be affected by an increase in power. Almost all of the time a control rod is held above or just slightly engaged into the active fuel elevation. Only the tips of the control rods see a significant amount of irradiation. With a EPU of 9.4% it would be expected that the fluence at the rodlet tip would increase approximately the same amount. Silver Indium Cadmium (Ag-In-Cd) swells due to irradiation that would increase at the EPU conditions. Silver swelling eventually fills the gap between the silver and the stainless outer cladding and then starts to push outward on the cladding resulting in clad hoop strain. When the cladding exceeds it's strain limit it can cause tip cracking in the cladding. Therefore, the increased fluence accumulation rate with EPU conditions would be expected to reduce the RCCA's lifetime of reactor operation when cladding cracking would be initiated.

Both Beaver Valley units have the EPRCCA which has several features to add margin to accommodate swelling and postpone cracking. The diameter of the Ag-In-Cd absorber is reduced at the bottom of the RCCA rodlets. This permits more swelling to occur before the absorber contacts the cladding. In addition, the cladding is specified to be manufactured using high purity material which decreases the sensitivity of the cladding to stress corrosion crack initiation and propagation. Even though the actual operating lifetime of the EPRCCA will be slightly reduced because of the increase in power, experience has shown that the reported design lifetime of 12 EFPY is conservative and should be met without incident even at these higher power ratings.

None of the other RCCA design features would be adversely affected by the EPU.

Other Core Components – No other core components are currently being used in either BVPS-1 or 2 but the effects of the EPU on other core components will be discussed since they could be used in the future. In general core components are evaluated for mechanical, nuclear and thermal & hydraulic considerations including structural integrity considerations, absorbtivity, peaking factors, boiling in the thimble and melting temperatures, etc.

The EPU maintains the same average reactor coolant temperature by decreasing the core inlet temperature by 2°F and increasing the core outlet temperature by the same 2°F. The mechanical and physical properties of the various components are almost the same and the effects on thermal and hydraulics would be insignificant.

The increase in power of 9.4% means that more heat will be generated in the various designs and the total fluence that the components will experience will be increased by approximately that same amount. For Wet Annular Burnable Absorbers for instance, the B10 in the pellets is designed to totally burn out so even if the rodlets see a higher fluence over a cycle, the pellet swelling and gas release for instance will be approximately the same. For most other core components, the springs, cladding and end plugs are made from stainless steels or inconels, which are not significantly affected by irradiation and in general have been evaluated by very high conservative estimates of fluence. The EPU will not violate the operation design lifetimes defined by previous generic evaluations.

In conclusion, core component operational design lifetimes for the EPU at BVPS-1 and 2 are fully maintained.

D.9 (Applicable to EPU)

In Section 6.3.3.3, "Clad Stress and Strain," the licensee indicates margin-to-stress and -strain limits are reduced at EPU conditions. The licensee concludes that stress and strain limits are met for EPU conditions. The licensee does not address the impact of the reduced stress and strain margins on fatigue cycles. Please provide an evaluation of the impact on the fatigue life of RFA and VANTAGE 5H fuel assemblies at EPU conditions.

Response:

The fuel rod design criterion for clad fatigue requires that, for a given strain range, the number of strain fatigue cycles are less than those required for failure, considering a factor of safety of 2.0 on the stress amplitude and a factor of safety of 20.0 on the number of cycles. The concern of this criterion is the accumulated effect of short-term cyclic, clad stress, and strain, which results from daily load follow operation.

Clad fatigue for both the RFA and VANTAGE 5H fuel was evaluated by using a limiting fatigue duty cycle consisting of daily load follow maneuvers. The RFA and VANTAGE 5H fuel rod fatigue evaluation showed that the cumulative fatigue usage factor is less than the design limit of 1.0. The results show that the EPU core will not impact the fuel's capability to meet clad fatigue limits for the EPU conditions.

D.10 (Applicable to EPU)

In Section 6.3.3.2, "Clad Corrosion," the licensee indicates margin-to-corrosion and hydrogen embrittlement limits are reduced at EPU conditions due to increased clad temperature. The licensee concludes that corrosion and hydrogen embrittlement limits are met for EPU conditions. The licensee does not address the impact of the increased clad temperature on the propensity for crud deposition on the cladding or the potential for increased chemical plate-out on the cladding due to the increased cladding temperature. Please provide an evaluation on propensity for crud deposition on the cladding and the potential for increased chemical plate-out on the cladding at EPU conditions.

Response:

The propensity for crud deposition and chemical plate-out on the cladding under EPU conditions is within the Westinghouse operating experience. The increase in core power and the potential for an increase in sub-cooled nucleate boiling is within the operating experience of Westinghouse plants, which include plants that operate at reactor power ratings equivalent to that of the EPU conditions for Beaver Valley. Maintaining good chemistry control by following the recommended industry standards in the primary system is important in minimizing crud deposition and chemical plate-out. This includes controlling the primary system pH at 6.9 or above to help minimize crud deposition, maintaining hydrogen over-pressurization to minimize the free oxygen in the system, and controlling impurities such as calcium, aluminum, magnesium, silica and other suspended solids within recommended Westinghouse limits. With primary system chemistry control being maintained in the Beaver Valley reactors under EPU conditions, the propensity for crud deposition and chemical plate-out will be minimized.

D.11 (Applicable to RSG & EPU)

In Section 6, Subsection, Fuel Assembly Design, of the licensee's EPU request, it is stated, "RFA-2 design includes an enhanced mid grid design that results in increased mid grid contact area with the fuel rod." This increased mid grid contact with the fuel rod is intended to provide improved fretting wear margin. Does the licensee anticipate EPU conditions to exacerbate fretting wear considerations? Does the licensee anticipate the increased flow due to the RSGs to exacerbate fretting wear considerations for BVPS-1? Does the licensee anticipate a synergy between RSG effects and EPU conditions to exacerbate fretting wear considerations for BVPS-1? Given reinserted VANTAGE 5H and RFA fuel assemblies will not have the improved fretting wear margin, how does the licensee intend to control these reinserts with respect to fretting wear considerations?

Response:

EPU conditions will have no impact or negligible impact on grid-rod fretting wear since EPU does not increase reactor coolant flow rate and fuel resident time, which are the parameters directly relative to the fretting wear. RSG or the synergy between RSG effects and EPU conditions will have slight impact on grid-rod fretting wear since RSG will slightly increase flow rate by 1.5%. For normal fretting wear, VIPER tests showed that the high flow rate caused high rod vibration and high fretting wear. The 17x17 RFA with IFMs design was tested in VIPER loop at very conservative flow rate, 13% higher than the highest best estimate flow of Westinghouse design 17x17 12-foot reactors. The test showed that the 17x17 RFA with IFMs design met the fretting wear criteria and the test flow covered the RSG effect. Also, the 17x17 RFA with IFMs has demonstrated good performance at many reactors, which include RSG effect and EPU conditions. The main improvement of the 17x17 RFA-2 design is increasing the fretting wear margin relative to the 17x17 RFA design. Therefore, the 17x17 RFA-2 design will have better fretting wear performance than the 17x17 RFA.

It is anticipated that fretting wear and fuel leaking may occur if some 17x17 V5H fuels are reinserted in BVPS. This is because of the generic design problems of 17x17 V5H and not caused by mixing core condition.

Reinsertion of any assemblies will be controlled by the core reload design process which includes an assessment of vulnerabilities, including fretting failure. Because of the fretting vulnerability of 17x17 V5H assemblies, their reinsertion for core designs is not expected.

D.12 (Applicable to EPU)

What post-irradiation tests and inspections are being incorporated to verify that operation at EPU conditions does not have an adverse impact on fuel design?

Response:

Post-irradiation tests and inspections have been planned and performed for the 17x17 RFA and RFA-2 fuel assemblies in Wolf Creek. Currently, Wolf Creek has a higher power level at 3565 MWt. Additionally, a comparison of the boiling rate for Beaver Valley EPU conditions and Wolf Creek was performed, and it was found that Wolf Creek has a higher boiling rate (600 $lb/hr/ft^2$) compared with the boiling rate of 500 $lb/hr/ft^2$ for Beaver Valley EPU conditions. Based on this information the post-irradiation tests and inspections at Wolf Creek can be applied to BVPS-1 and 2 at EPU conditions.

The FENOC core design process includes a risk assessment of changes in the core design that may impact fuel performance – chemistry, power, assembly design, etc. An operational impact evaluation is also performed to determine if any additional monitoring of the fuel is required. These reload design activities determine whether any post-irradiation tests or inspections are required for fuel cycles implementing the EPU conditions.

Section 5.2.2 LOCA

E.1 (Applicable to RSG & EPU)

Please provide the moderator-density feed back curve used in the small-break LOCA (SBLOCA) analyses. Also, what is the moderator temperature coefficient (MTC) used to generate the most limiting curve for SBLOCA analyses. What uncertainty is applied to this curve? If a positive MTC characterizes the units, please provide the core normalized power plots for the limiting breaks.

Response:

The BVPS-1 and 2 Technical Specifications do not allow for positive MTC at full power. The point kinetics model is not used in the small break LOCA analysis, therefore, these parameters do not apply to the small break LOCA analyses.

E.2 (Applicable to RSG & EPU)

What uncertainties in head and flow are applied to the high-pressure safety injection (HPSI) head flow curve provided in Table 5.2.2-2?

Response:

The High Head Safety Injection (HHSI) system at BVPS is configured to prevent runout of the HHSI pumps during low RCS pressure conditions such as those that exist during a Large Break LOCA event. This is accomplished by establishing a band of acceptable flows for the pumps in a test alignment versus pump performance. A range of minimum and maximum pump performance is established to construct this curve and this range of pump performance is also part of the acceptance criteria for testing. Each refueling outage, tests are performed to confirm that the pump performance falls within the assumed bands and the system flow setup is checked to confirm that throttling limits are met to prevent pump runout and that the safety injection paths are balanced within criteria assumed in the safety injection flow analysis.

The analysis that derives the system flow limits considers uncertainties on the flow measurement instruments used to check pump performance and set the system throttle limits. Uncertainties on the flow instruments used to balance the safety injection flow paths are also considered in the development of the curve provided in Table 5.2.2-2. Since the RCP seal injection path represents an open path from the safety injection system, the flow limits also affect system performance. Flow measurement uncertainties are also considered for this surveillance. Pump head uncertainties are also considered when establishing the maximum pump performance and minimum pump performance requirements. Table E.2-1 shows the uncertainty values (in percentage of flow) assumed in the EPU safety injection flow analysis.

Table E.2-1 Uncertainty Values				
	Total injection flow/pump performance *	Safety injection branch line flow	RCP seal injection flow	HHSI pump head
BVPS-1	0.2%	5.0%	3.5%	1%
BVPS-2	0.2%	4.2%	3.5%	1%
* Based on use of calibrated flow orifice and high accuracy differential pressure transmitter				

E.3 (Applicable to RSG & EPU)

Please provide a reference for, or an analysis of, the case of a severed emergency core cooling system (ECCS) line. Also, please provide the head versus flow curve for flow into the intact loops for this case. With a discharge coefficient of 1.0 on the pump side, what coefficient or break size on the discharge leg side of the break is the most limiting size? What is the break size that will preclude accumulator actuation under these conditions?

Response:

Small break LOCA analyses for BVPS-1 and 2 that included 6 inch equivalent diameter break sizes, the next largest size above the ECCS line size (5.187 inches), were performed prior to those reported in EPU LAR submittals (see Attachment A). All of the cases in these analyses had ECCS injection flows less than those used in the reported analyses. In addition, [ ][a,c] For both units, the 6 inch cases showed significant margin to the other analyzed breaks. As such, it was considered unnecessary to re-perform these cases for the EPU LAR submittal since the limiting break size is much smaller (3 inch and 2 inch for BVPS-1 and 2, respectively) than those of a severed ECCS line, even when spilling effects are considered. The flow vs. head curves used for these 6 inch break size analyses are provided in Table E.3-1.

As discussed above, the limiting size is not that of a severed ECCS line. The limiting sizes are what have been reported – a 2 inch equivalent break size for BVPS-2 and a 3 inch equivalent break size for BVPS-1.

A completely severed ECCS line will experience accumulator injection as a result of the particular break size itself given the ECCS piping layout of the Beaver Valley units. Break sizes smaller than 5.187 inches assume [

][a,c]

Table E.3-1
Flow vs. Head Curves

Unit 1 Injected Flows For Severed ECCS Line	
Pressure (psia)	Flow (lbm/s)
14.7	329.9
24.7	307.8
34.7	285.1
64.7	211.5
114.7	42.6
119.7	34.5
214.7	34.5
314.7	32.3
414.7	30.1
514.7	27.7
614.7	25.4
714.7	23.0
814.7	20.5
914.7	17.9
1014.7	15.3
1114.7	12.5
1214.7	9.5
1314.7	6.4
1414.7	3.1
1514.7	0.0

Unit 2 Injected Flows For Severed ECCS Line	
Pressure (psia)	Flow (lbm/s)
14.7	374.2
24.7	351.8
34.7	328.3
64.7	248.9
104.7	60.8
109.7	34.7
214.7	34.7
314.7	32.5
414.7	30.3
514.7	27.9
614.7	25.5
714.7	23.1
814.7	20.6
914.7	18.0
1014.7	15.4
1114.7	12.6
1214.7	9.6
1314.7	6.5
1414.7	3.1
1514.7	0.0

E.4 (Applicable to RSG & EPU)

What is the capacity of the condensate storage tank (CST)? How long can the operators delay a cooldown for the very small breaks such that shutdown cooling can be initiated prior to exhaustion of the CST? What operator guidance is provided to assure shutdown cooling can be successfully initiated following all small breaks? If the pressurizer refills during the cooldown trapping hot RCS water in the pressurizer, please explain what equipment is used to initiate shutdown cooling (reduce RCS pressure) should the RCS repressurize prior to achieving the entry temperature for operation of the residual heat removal system. If a fill and drain method is employed, is there sufficient CST inventory to initiate shutdown cooling? Please explain.

Response:

The proposed condensate storage tank (CST), otherwise known as the Primary Plant Demineralized Water Storage Tank (PPDWST), Technical Specification change for both

BVPS-1 and 2 requires a useable capacity of 130,000 gallons. The sizing basis for this tank is maintaining hot standby conditions for 9 hours with no RCPs running. There are no specific calculations that examine how long a cooldown could be delayed such that shutdown cooling can be initiated prior to exhaustion of the CST following a Small Break LOCA event since this is not the basis for tank sizing. This time can be conservatively estimated based on the amount of condensate required to cooldown to shutdown cooling entry temperature and to remove the integrated decay heat. This estimate conservatively ignores heat removal through the break flow. Using this method it is estimated that cooldown could be delayed approximately 4 hours and still be accomplished prior to exhaustion of the CST. It should be noted that the EOPs contain criteria to monitor the CST inventory. A CST level alarm is set to notify operators when approximately twenty minutes of inventory remain. Operators would then take steps to either supply condensate from other onsite storage tanks to the CST or align service water to the suction of the AFW pumps through an existing connection.

Operator guidance is provided in the EOPs so that shutdown cooling can be initiated for small break LOCA events. EOP ES-1.2, "Post LOCA Cooldown and Depressurization," provides the guidance for operators to achieve shutdown cooling entry conditions. The basic steps in this procedure for a very small break (with RCS subcooling margin available) are directed toward re-filling and establishing pressurizer level, reduction of safety injection, and placing normal charging in service. RCS flow is re-established if possible, and cooling and depressurizing the RCS to shutdown cooling entry conditions is initiated. Depressurization is accomplished through the use of normal pressurizer spray if a RCP is running, or through the use of a Power Operated Relief Valve or auxiliary spray if normal spray is unavailable. No fill and drain method is used in this procedure.

E.5 (Applicable to RSG & EPU)

The break spectrum of 1.5-, 2.0-, 3.0-, and 4.0-inch diameter breaks (0.012, 0.022, 0.049 and 0.087 ft^2) is much too coarse to assure that peak cladding temperature (PCT) and peak clad oxidation are captured. Since the accumulators inject during the 2-inch break for BVPS-2, please provide an analysis of a slightly smaller break where the RCS pressure decreases to just above the accumulator actuation pressure of 575 psia. What reduction in accumulator pressure would be necessary to preclude accumulator actuation for the 2-inch break?

Response:

The two inch case for BVPS-2 does experience accumulator injection as do all other breaks above this size. However, the two inch break size PCT occurs at about 3,100 seconds which is prior to accumulator injection. Moreover, the accumulators do not inject until approximately 15 minutes after the predicted PCT. Thus, the limiting case is turned around solely on pumped safety injection. As such, decreasing break size is considered unnecessary since the concern identified is already captured. In addition, decreasing break size below the two inch break reduces mass loss, thus reducing the degree of uncovery which is indicative of the 1.5 inch case presented.

Further reducing accumulator pressure is considered unrealistic and undesirable. The accumulators are already represented in what is considered to be an unrealistic, albeit conservative, lower bound technical specification minimum pressure. [

]a,c

The basis methodology of the NOTRUMP evaluation model is documented in References 1 and 2. Section 5.3.2 of Reference 2 shows the results of a break spectrum study performed for the generic licensing of the NOTRUMP Evaluation Model (EM). This evaluation break spectrum study consisted of cold leg breaks of equivalent diameters of 2, 3, 4, 5, and 6 inches. Additionally, References 1 and 3, investigated break spectrums of 2, 3, 4, and in some cases 6 inches. It should be noted that Reference 3 was published in response to post TMI-2 action items to demonstrate continued compliance to 10 CFR 50.46 on a generic basis. In this environment, the review of the NOTRUMP EM was carried out under significant scrutiny. In all these generic licensing submittals, the NRC staff issued Safety Evaluation Reports which did not question the resolution of the break spectrum. In addition, with the introduction of the original ECCS evaluation models in 1974, Westinghouse performed sensitivity studies (Reference 4) which included break size variations of 2, 3, 4, and 6 inch and larger equivalent diameters. Since then, Westinghouse has always analyzed SBLOCA break spectrums consisting of these increments. Thus, the practice of the application of the NOTRUMP EM is to stay within the resolution boundaries of this break spectrum.

The break spectrum analyzed for Beaver Valley was based on 1.5, 2, 3 and 4 inch cases. Note that a 1.5 inch case was analyzed for BVPS-2 to bound the break spectrum since the 2 inch case was limiting for BVPS-2. The 6 inch case is not reported since break sizes above 4 inches typically demonstrate good depressurization characteristics that allow a rapid amount of both accumulator injection and pumped ECCS inventory. This even holds true when the break is in the safety injection line and ECCS spilling assumptions assume containment back-pressure (see response to RAI E.3). This is illustrated in Figure 5.3-1 of Reference 2 and has been demonstrated many times. As such, the break spectrum analyzed is considered adequate for an evaluation model developed and licensed to Appendix K standards and associated conservatisms.

References:

1. WCAP-10054-P-A, Addendum 2, Rev 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," July 1997.

2. WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985.

3. WCAP-11145-P-A, "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," October 1986.

4. WCAP-8356, "Westinghouse Emergency Core Cooling System – Plant Sensitivity Studies," July, 1974.

a. **Since the 3-inch break for BVPS-1 is limiting and the PCT is terminated by accumulator injection, please reduce the break size such that the RCS pressure remains just above the accumulator actuation pressure and present the results. Also, please explain why the PCT would not increase for break sizes between 3 and 4 inches.**

Response:

The 2 inch transient PCT occurs at an RCS pressure that is about 125 psia above the accumulator gas cover pressure of 575 psia, a conservatively low value. A break size just above 2 inches would probably result in a RCS pressure closer to, but not reaching, the accumulator setpoint before PCT occurs. However, [

]^{a,c}

For breaks larger than 3 inches, the PCT is expected to decrease since depressurization of the RCS is favorable, which reduces break flow in the long run and increases pumped ECCS injection.

E.6 (Applicable to RSG & EPU)

The mixture level plot for the 2-inch breaks between 1400 and 2200 seconds looks numerically unstable. Please explain the reason for the erratic behavior in the mixture level plots during this time frame. Please provide the liquid level plot in the core for this break. Please reduce the time step for this case and show the mixture level for this case is converged. What is the PCT if the erratic jumps in mixture level are smoothed (extrapolate the smooth decrease in level from 1000 to 1400 through to 2200 seconds)? What time steps were used in the SBLOCA analyses?

Response:

The observed behavior is a result of the phenomena occurring in the transient. At approximately 1200 seconds, core uncovery is predicted to commence. As the core uncovers, the core exit vapor flow rates decrease thereby slowing the core level depletion. Since the broken loop pump suction piping (loop seal piping) has already cleared, the sub-cooled mixture in the downcomer region flows into the active fuel region attempting to form a manometric balance (Figure E.6-1). By approximately 2200 seconds, the two regions are nearing this equilibrium condition. Figure E.6-2 presents a comparison of the core exit vapor flow rate and the core/upper plenum mixture level. As can be seen from these two figures, the parameters of interest are following the same trends. The drops in level are a result of temporary loop seal plugging whereas the increases are a result of the plug being cleared. When the plug is cleared, there is an occasional liquid discharge to the cold leg piping which partially blocks the break vapor discharge path. This vapor escape path blockage results in a temporary pressurization of the downcomer region which drives additional flow into the active fuel region. As such, the predicted core mixture level behavior during this time frame is considered to be appropriate.

The core average void fraction in the active fuel region is shown in Figure E.6-3. The resulting collapsed liquid level in the active fuel region of the core is shown in Figure E.6-4.

A simulation was performed in which the maximum time step size was reduced [ ]^{a,c} As can be seen by reviewing Figure E.6-5, no significant differences in results were observed and the results are considered converged.

The removal of only the mixture level oscillations during the 1400 to 2200 second time frame (See Figure E.6-6) results in the same PCT as predicted for the reference case (1758°F). Note that the mixture level in this figure is offset by the elevation of the bottom of the active fuel region. It does however eliminate the temperature decrease observed in Figure 5.2.2-12B during the 1800-2000 second time frame (See Figure E.6-7).

The NOTRUMP code uses various time step sizes throughout the transient simulation. The time step size is controlled by the time step control algorithm as described in Section 10 of Reference 1. The maximum time step size is defined [ ]^{a,c} Table E.6-1 provides the maximum allowable time step size as a function of break size as utilized for Small Break LOCA (SBLOCA) analyses.

Reference:

1. WCAP-10079-P-A, "NOTRUMP A Nodal Transient Small Break and General Network Code," P. E. Meyer, August 1985.

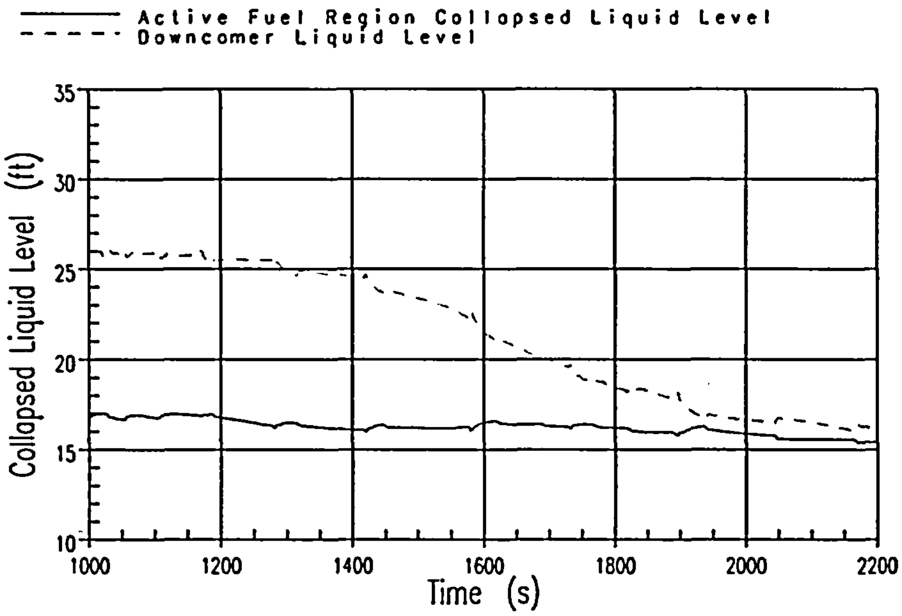

Figure E.6-1
BVPS-2 2-Inch Core Collapsed Liquid (Active Fuel Region) vs. Downcomer Collapsed Liquid

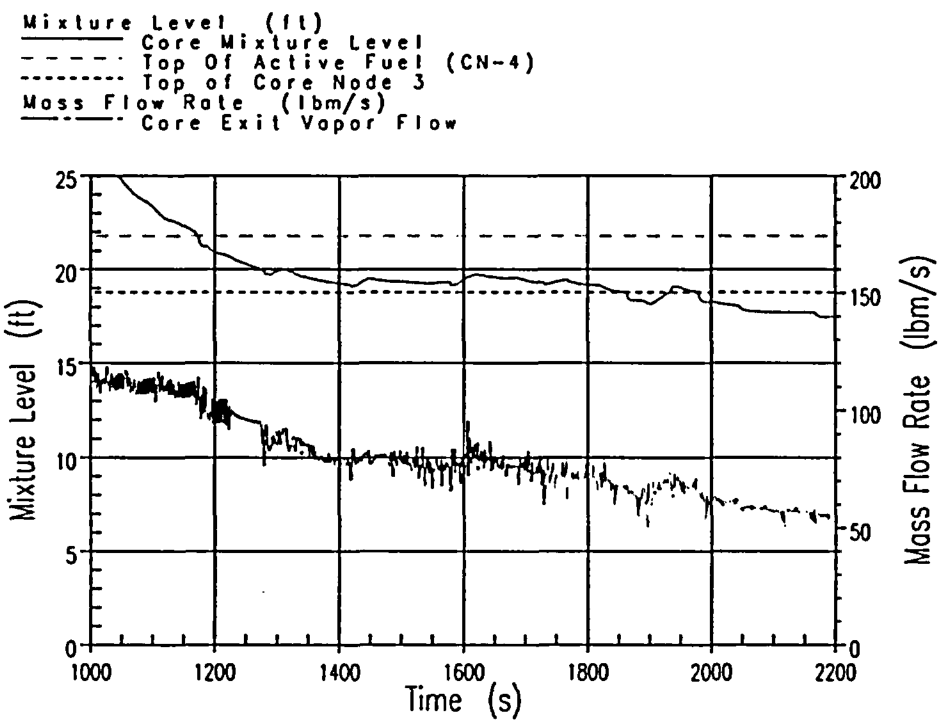

Figure E.6-2
BVPS-2 2-Inch Core/Upper Plenum Mixture vs. Core Exit Vapor Flow

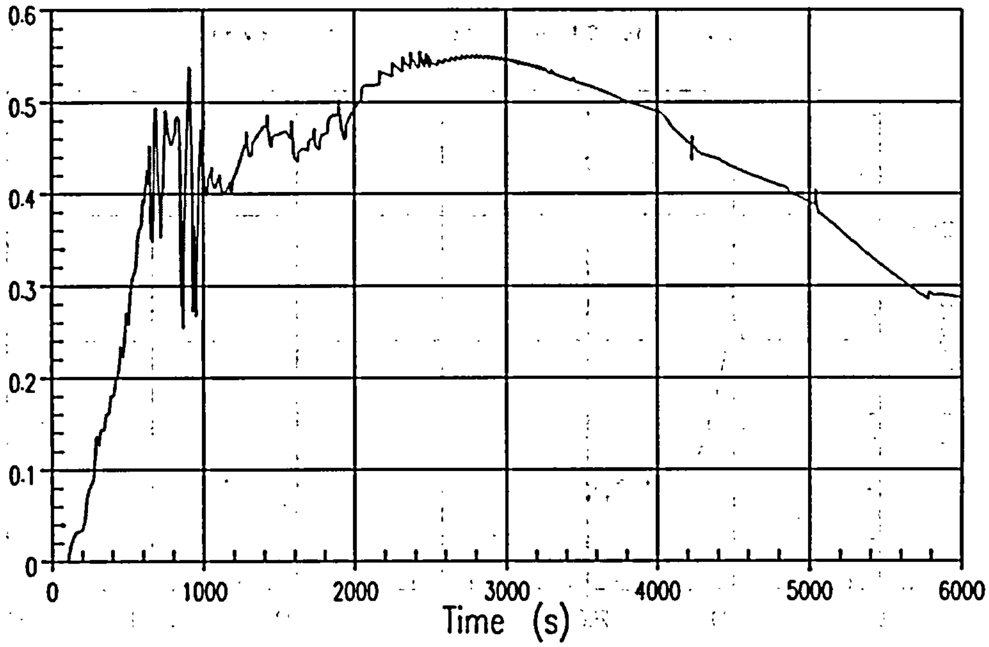

Figure E.6-3
BVPS-2 2-Inch Core Average Void Fraction (Active Fuel Region)

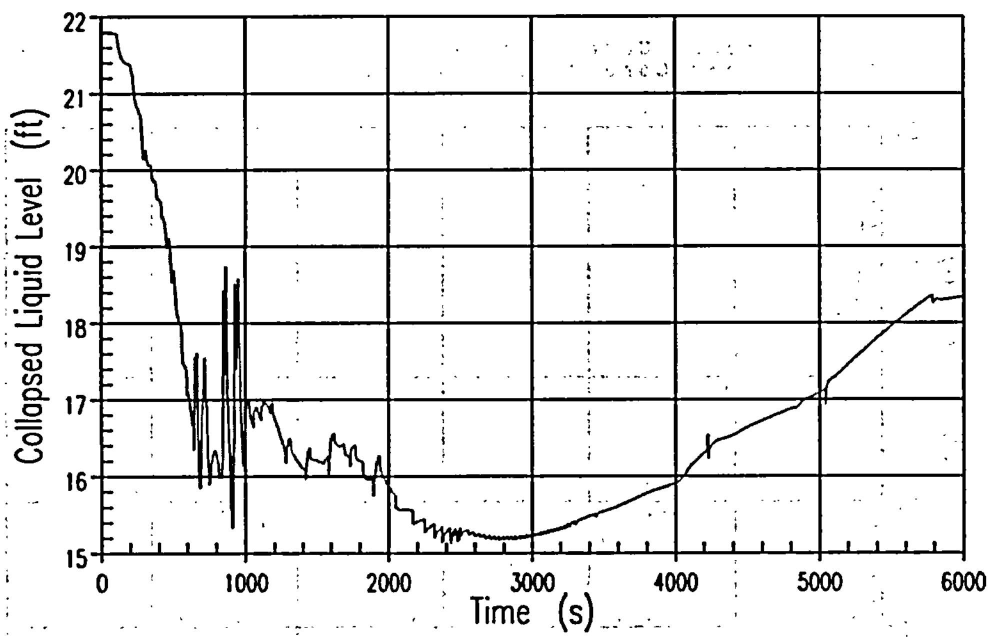

Figure E.6-4
BVPS-2 2-Inch Core Collapsed Mixture Level (Active Fuel Region)

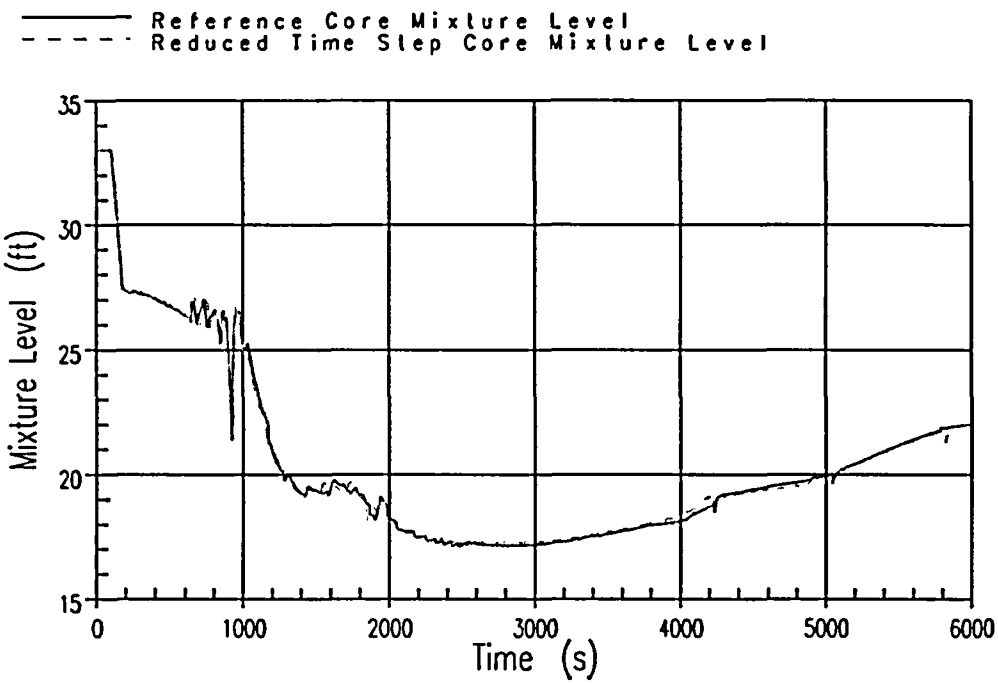

Figure E.6-5
BVPS-2 2-Inch Core Mixture Level (Reduced Maximum Time Step)

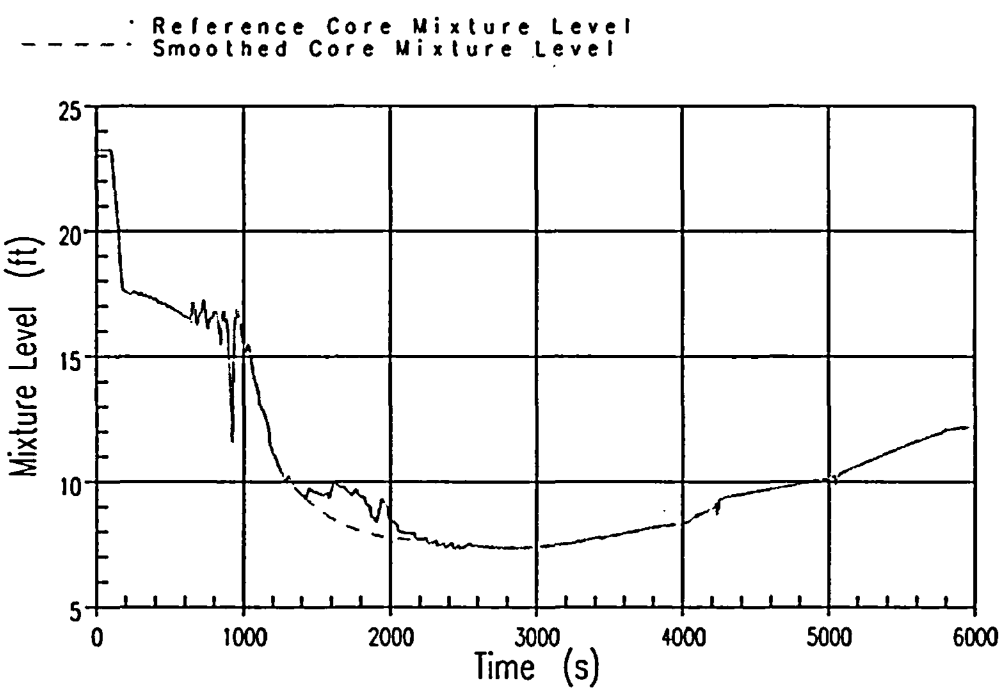

Figure E.6-6
BVPS-2 2-Inch Core Mixture Levels

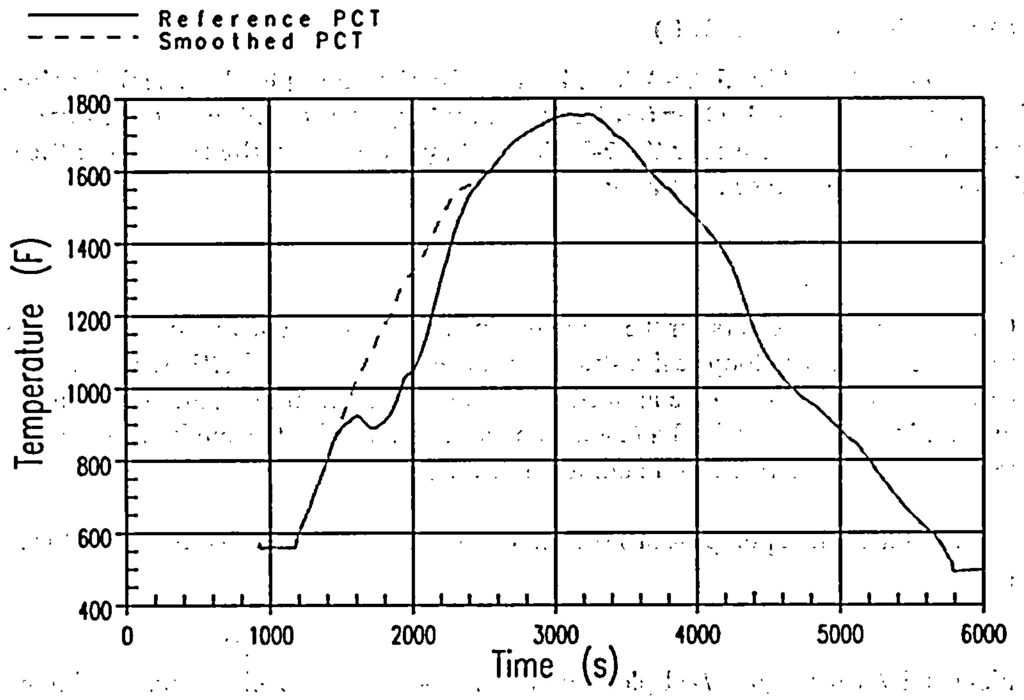

Figure E.6-7
BVPS-2 2-Inch PCT Response for Smoothed Core Mixture Level Response

Table E.6-1 NOTRUMP Maximum Allowable Time Steps	
Break Diameter	**Maximum Allowable Time Step Size**
<= 3 inches	0.25 sec
4 inches	0.14 sec
6 inches	0.06 sec
8 inches	0.04 sec

E.7 (Applicable to RSG & EPU)

For the 2-inch break, Tables 5.2.2-4 A and B identify the timing for loop seal clearing. Please identify how many loop seals clear (and any residual liquid remaining) for each break size. If more than one loop seal clears for the 2-inch break, please justify the clearing of the loop seals other than those upstream of the break.

Response:

Only one loop seal clears for the 1.5 and 2 inch break sizes, due to the application of the loop seal restriction. The loop seal restriction is an artifact of the NOTRUMP Evaluation Model (EM) which is applied to the lumped intact loops when clearing of all loop seals is not expected to occur. For the 3 and 4 inch breaks, both the faulted and lumped loop seals clear (See response to RAI E.19 for additional details).

The reactor coolant pump (RCP) suction cross-over leg in the NOTRUMP-EM is modeled as [

]^{a,c}

Figures E.7-1 through E.7-11 plots summarize the mixture level associated with the steam generator output plenum to horizontal cross-over leg piping with respect to time for BVPS-1 and 2.

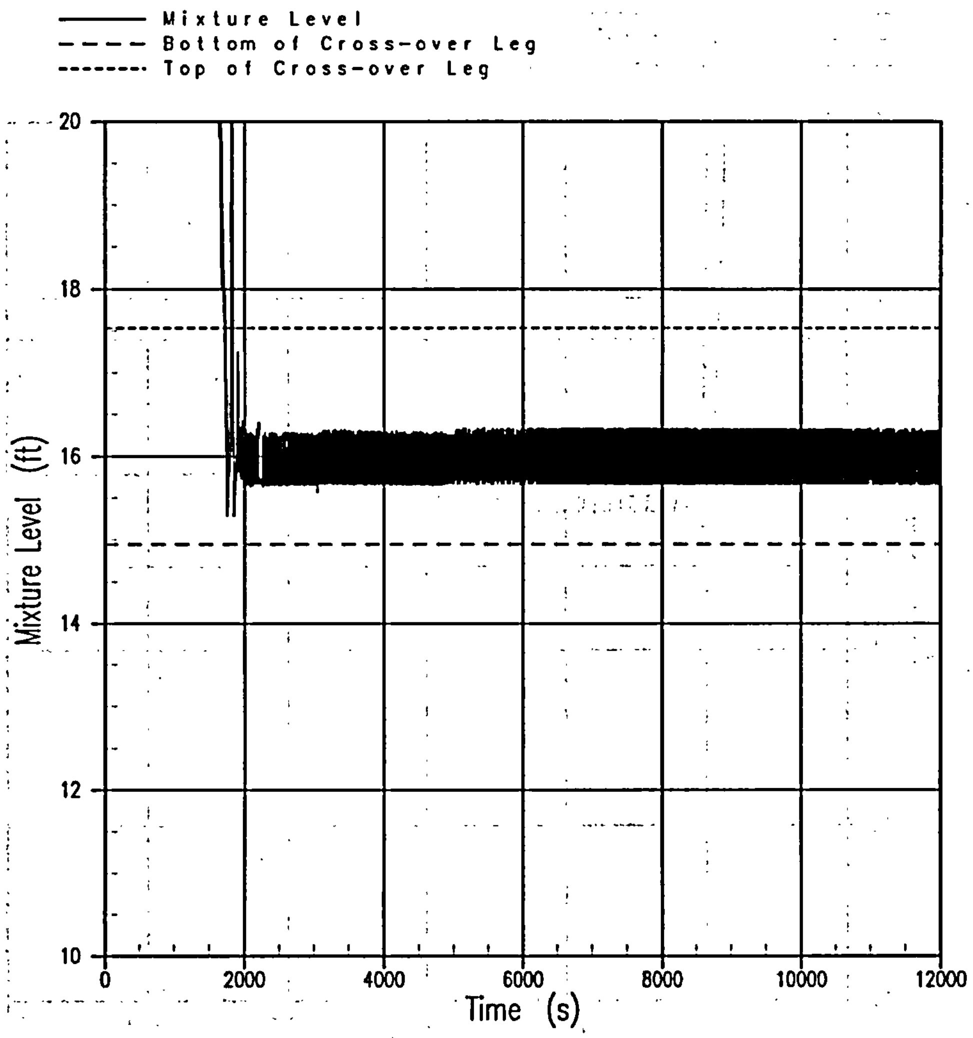

Figure E.7-1
BVPS-1 1.5-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

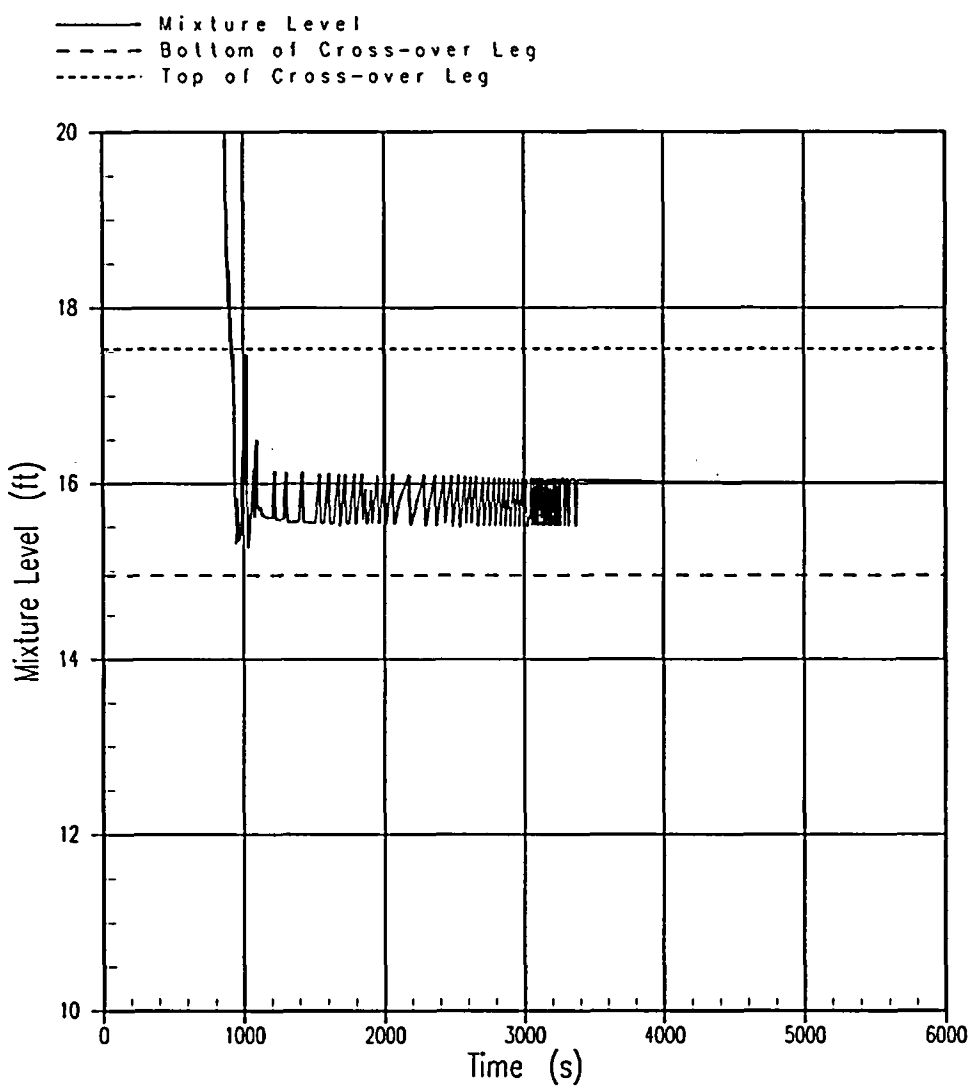

Figure E.7-2
BVPS-1 2-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

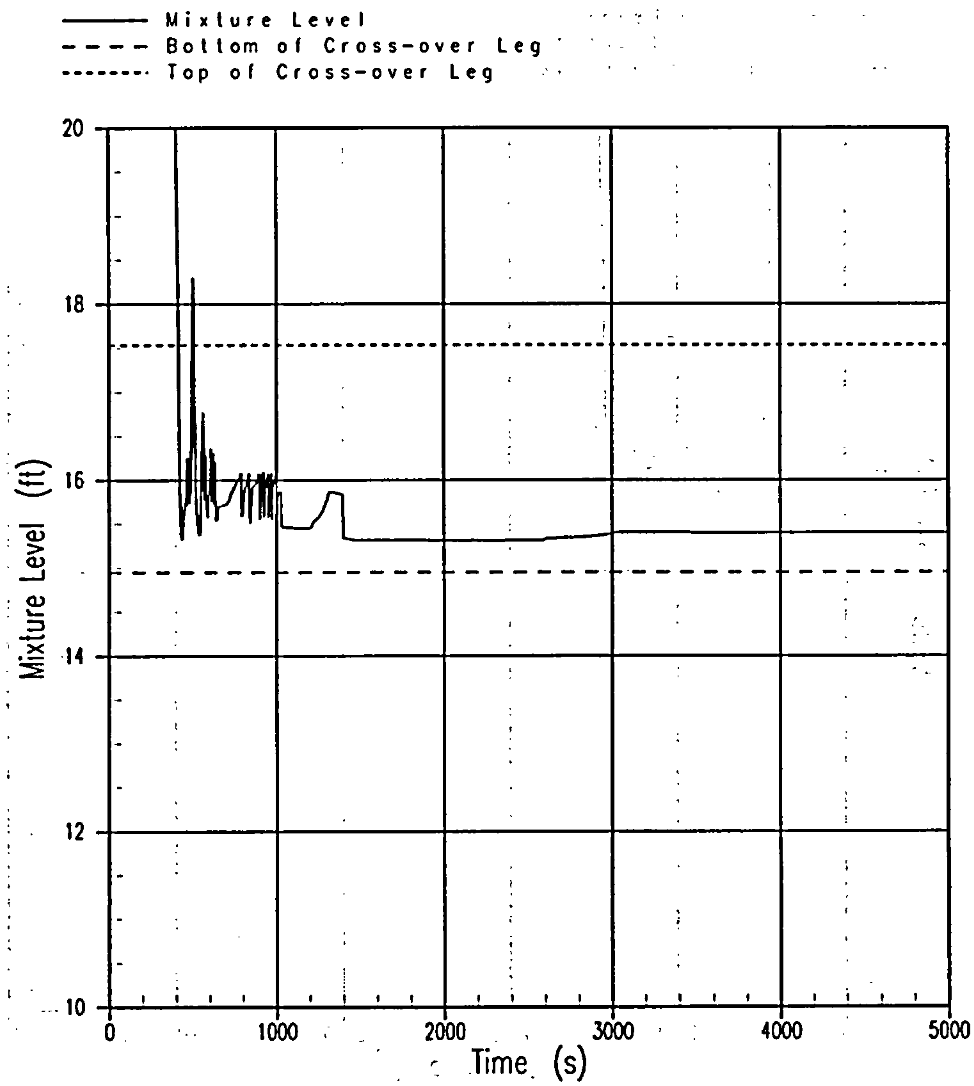

Figure E.7-3
BVPS-1 3-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

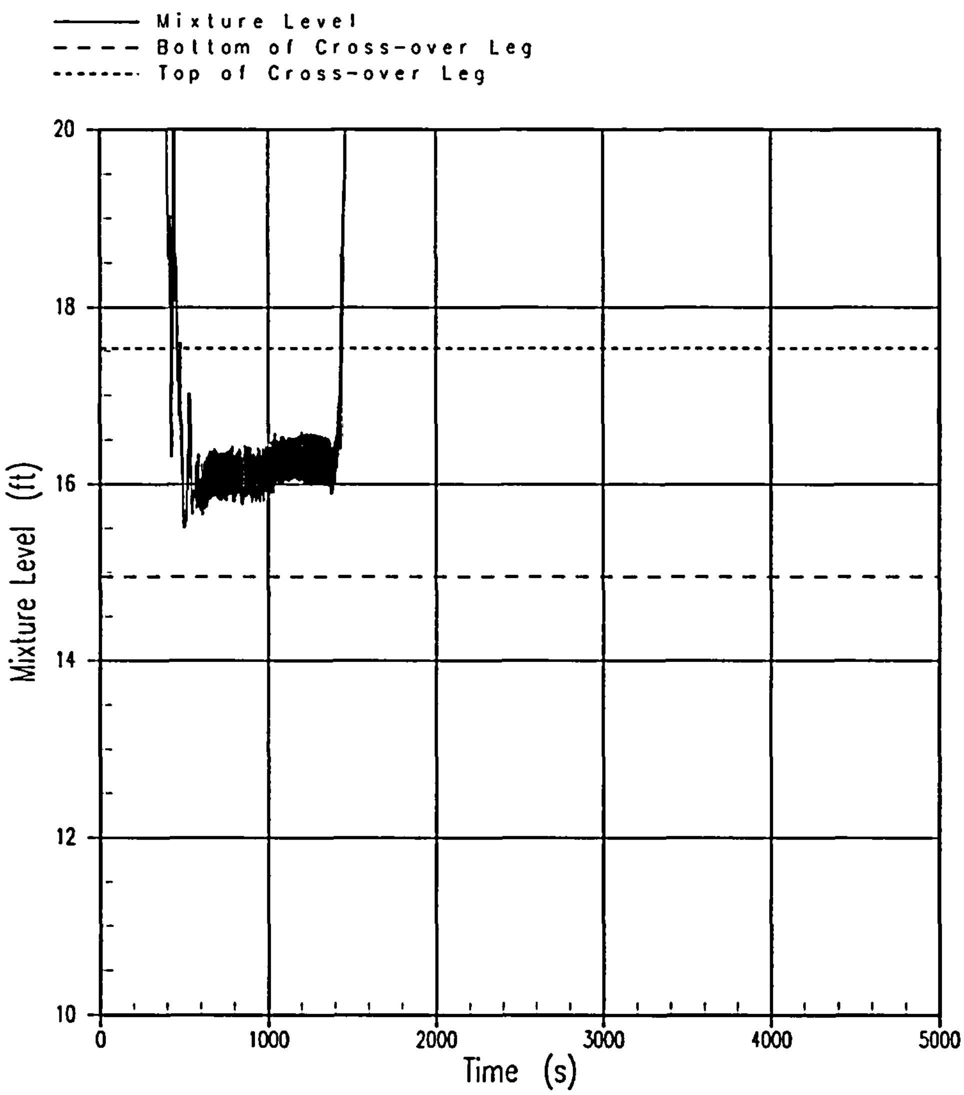

Figure E.7-4
BVPS-1 3-Inch Break
Lumped Intact Loop Pump Suction Cross Over Leg Liquid Level

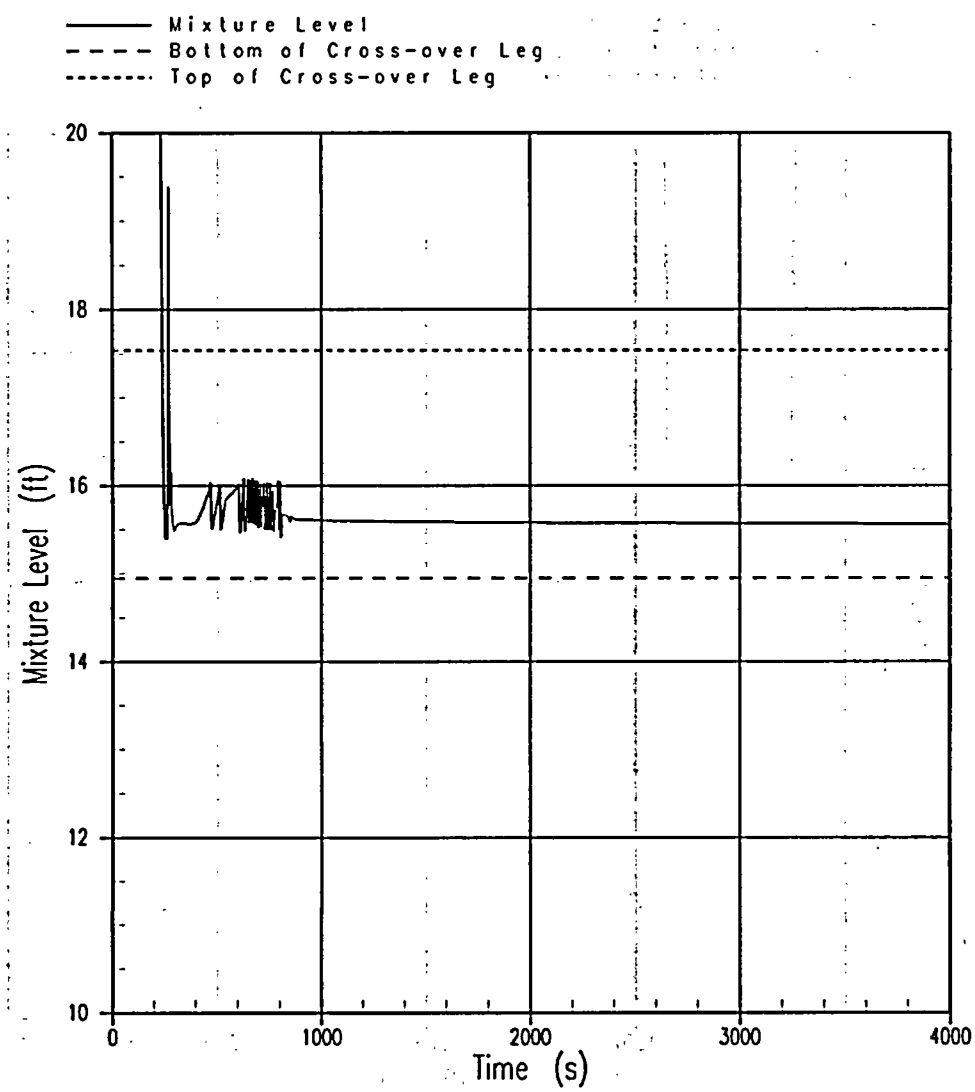

Figure E.7-5
BVPS-1 4-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

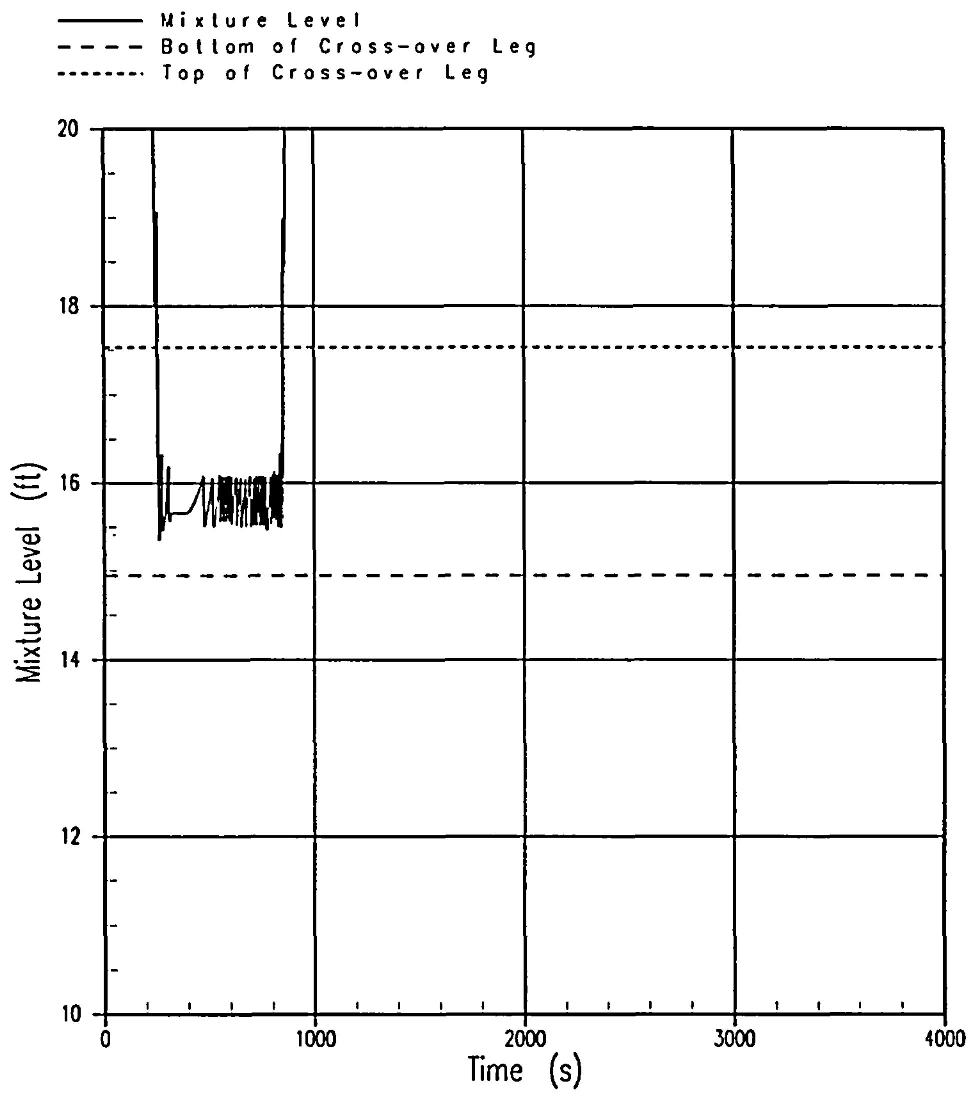

Figure E.7-6
BVPS-1 4-Inch Break
Lumped Intact Loop Pump Suction Cross Over Leg Liquid Level

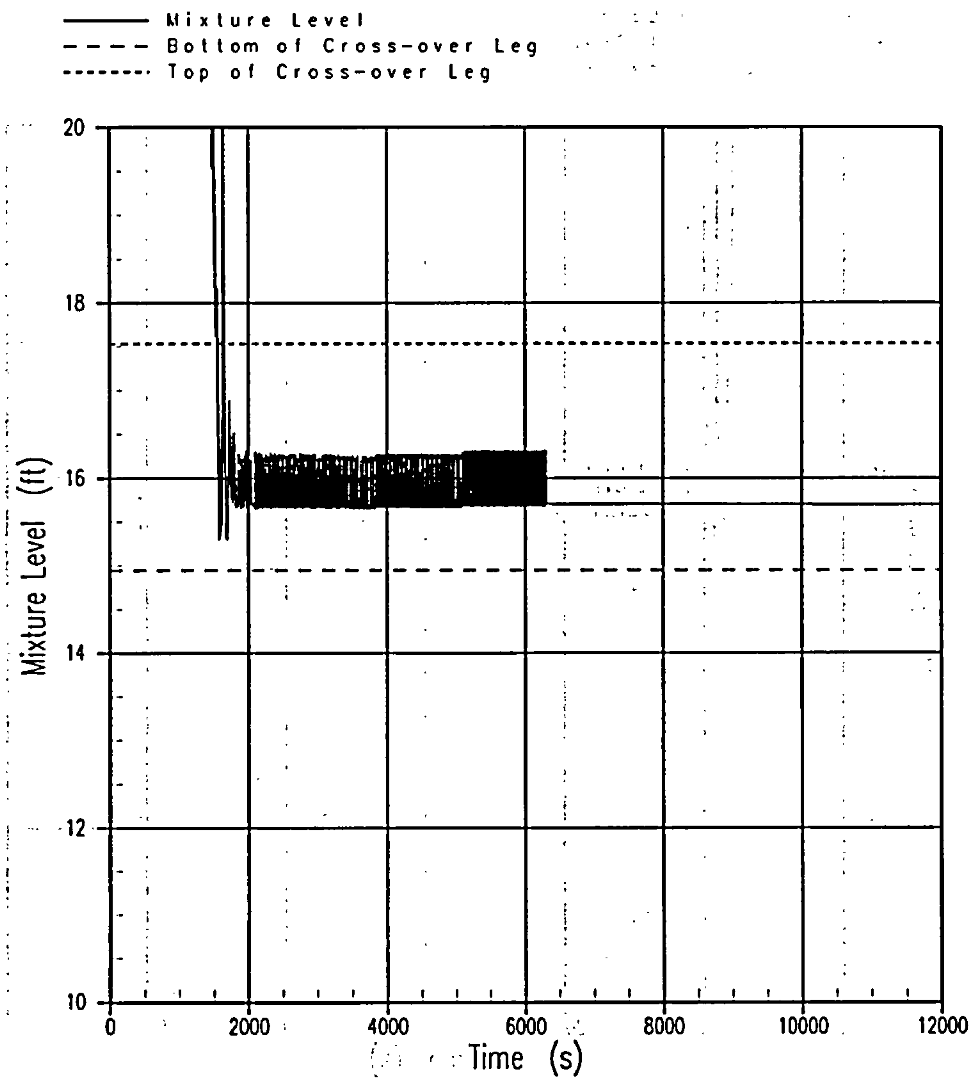

Figure E.7-7
BVPS-2 1.5-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

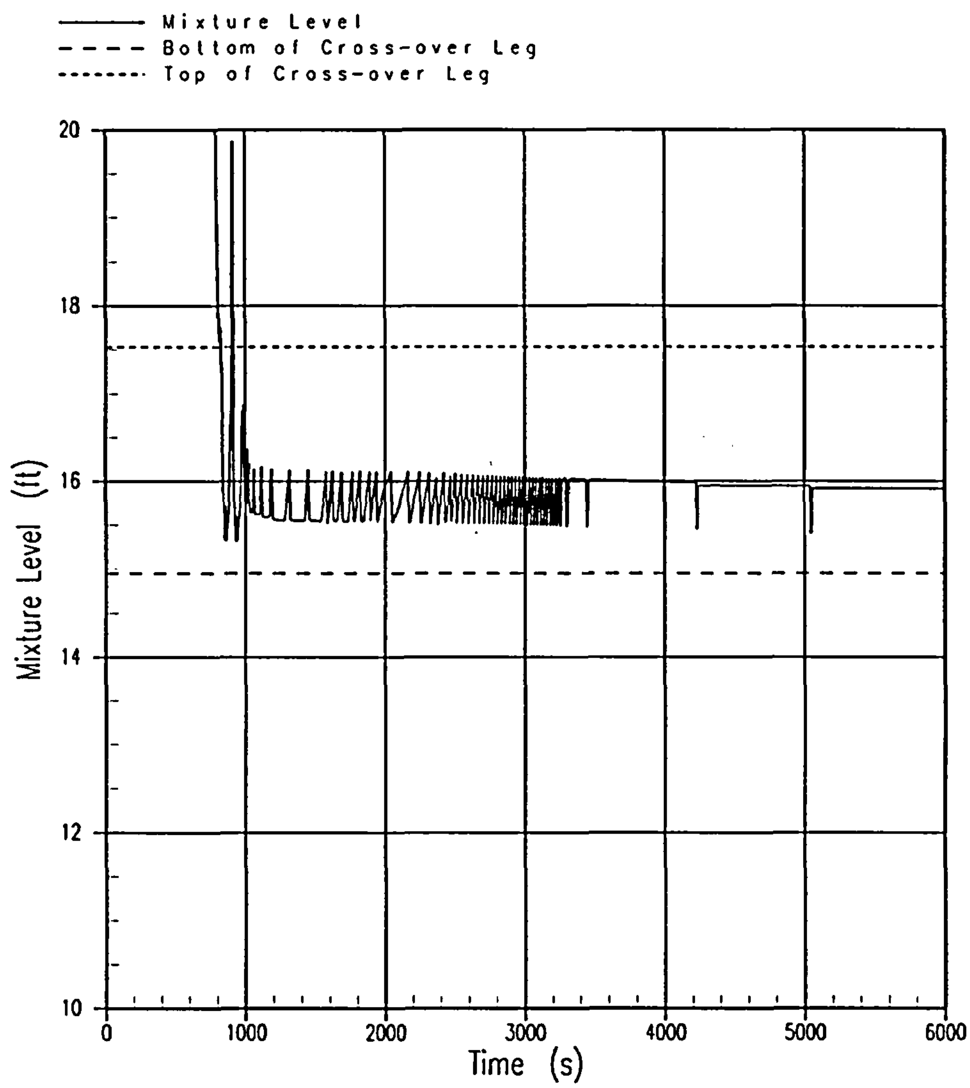

Figure E.7-8
BVPS-2 2-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

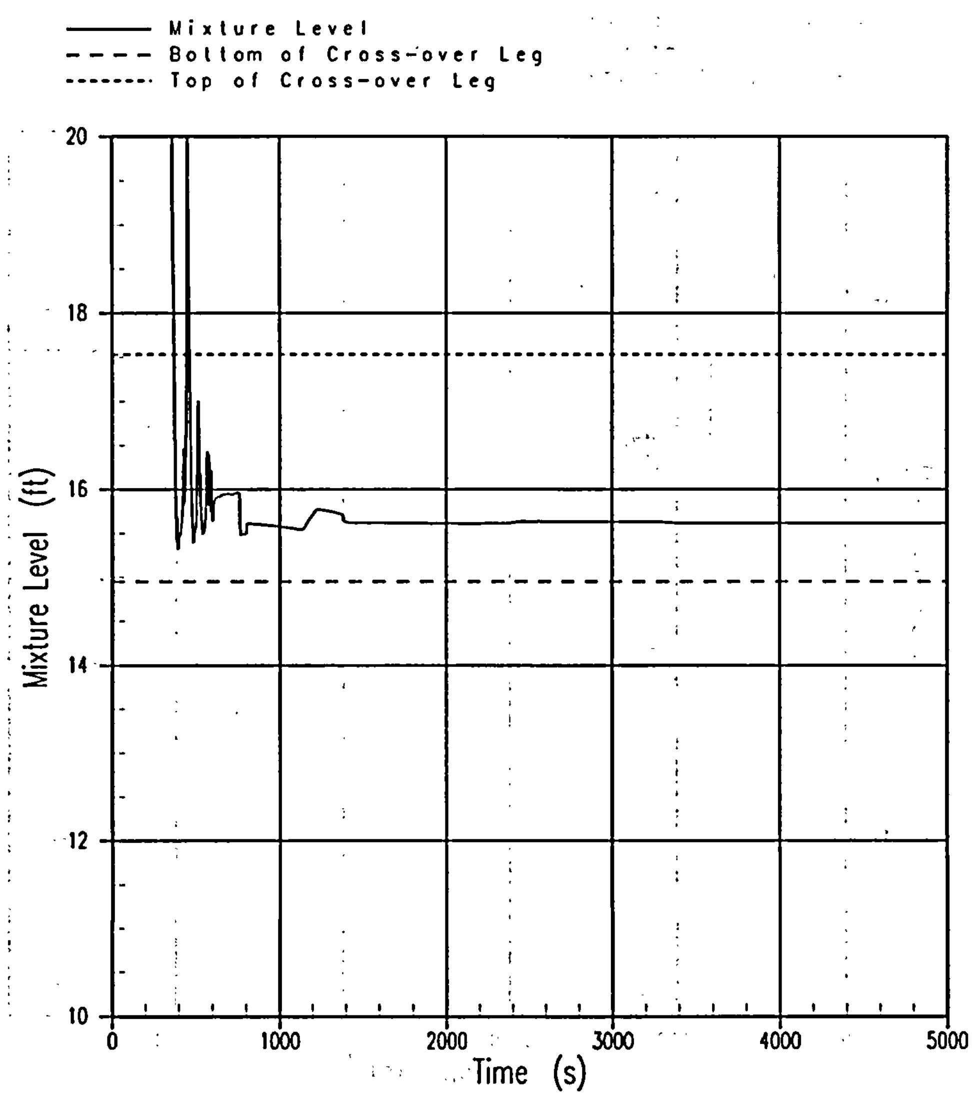

Figure E.7-9
BVPS-2 3-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

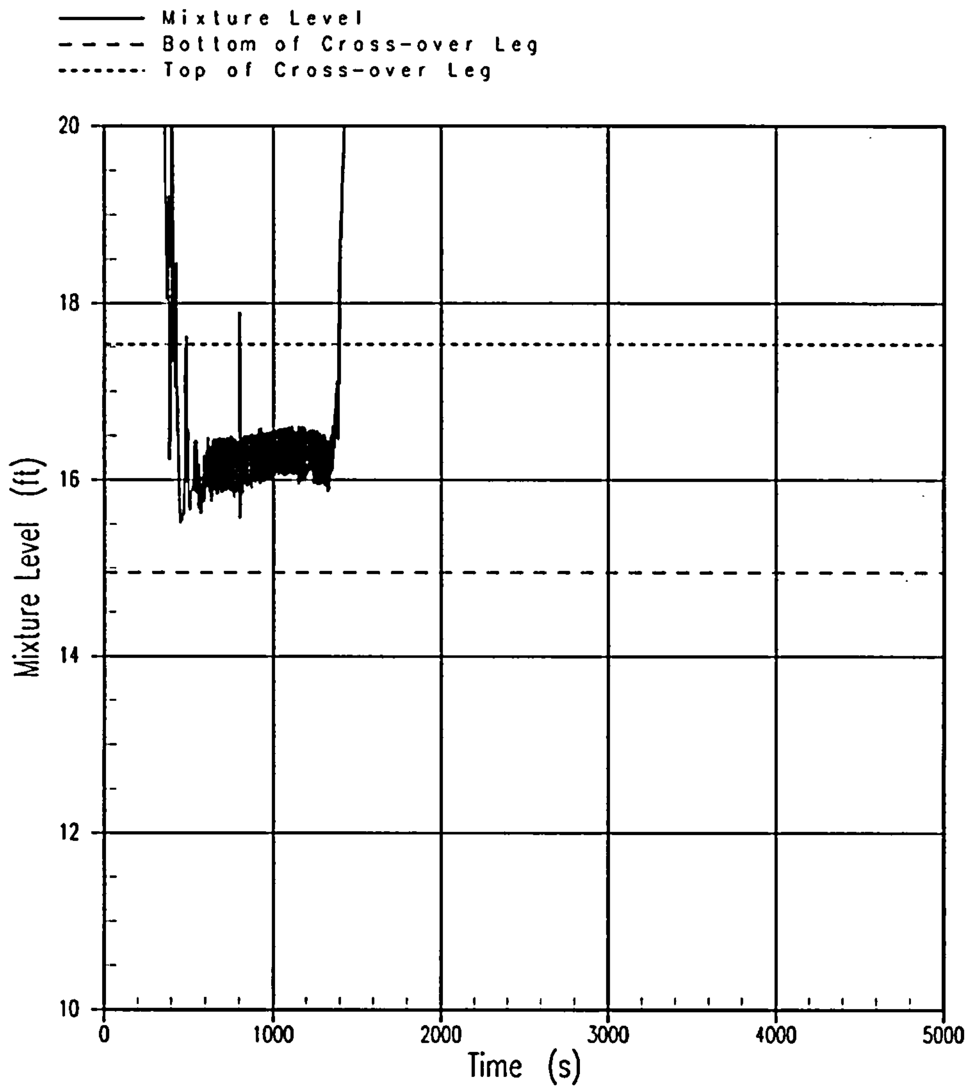

Figure E.7-10
BVPS-2 3-Inch Break
Lumped Intact Loop Pump Suction Cross Over Leg Liquid Level

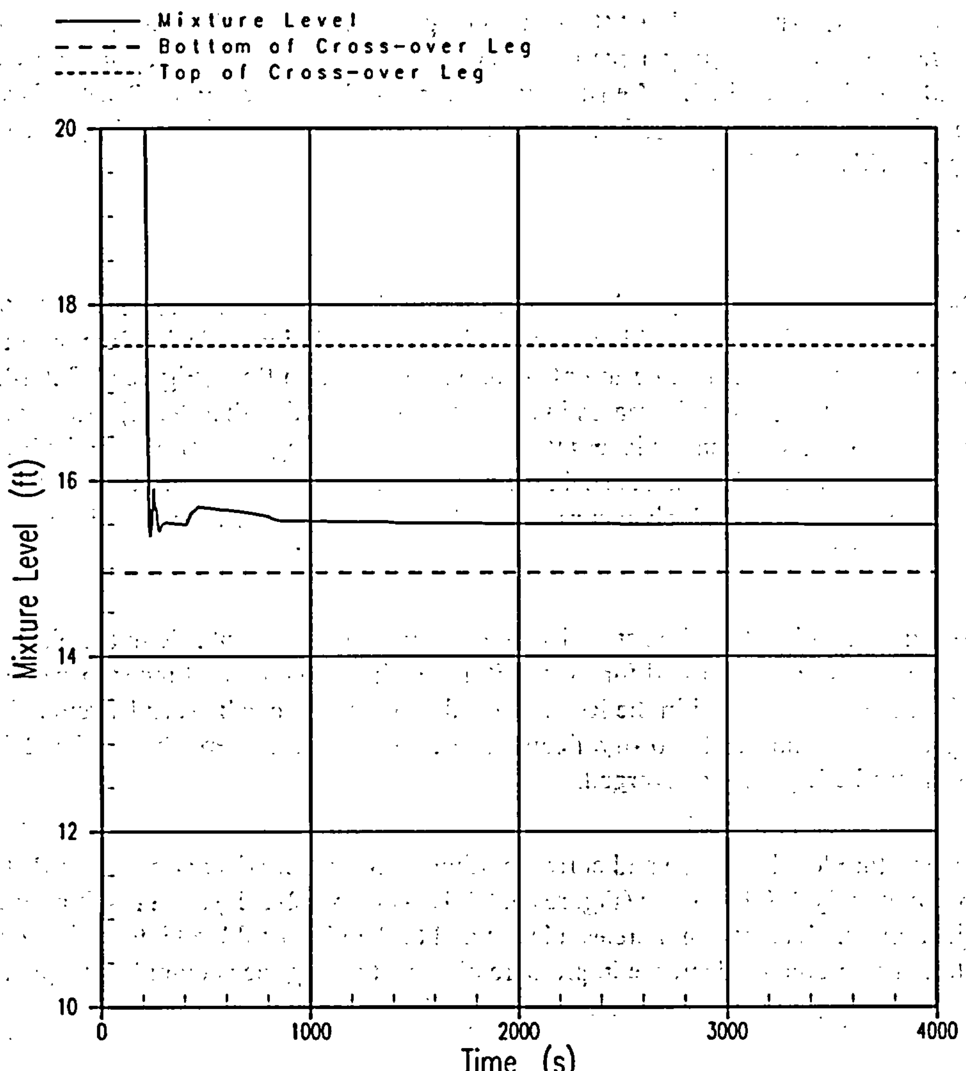

Figure E.7-11
BVPS-2 4-Inch Break
Broken Loop Pump Suction Cross Over Leg Liquid Level

E.8 (Applicable to RSG & EPU)

The mixture level plot for the 3-inch break also appears very erratic/unstable. Please demonstrate that the solution is converged by demonstrating that reducing the time steps does not decrease the mixture level during uncovery. What is the source of the high frequency oscillations that appear throughout the uncovery period? Please also explain why the two-phase level does not display a gradual increase as opposed to the erratic behavior at 3400 seconds in Fig. 5.2.2-16B. The sudden drop in RCS pressure at 3400 seconds suggests that either the solution is not converged or there is erroneous condensation taking place in the RCS. Please explain this behavior.

Response:

The mixture level responses observed in Figures 5.2.2-5A (BVPS-1) and 5.2.2-16B (BVPS-2) are consistent with the conditions observed in the simulations. Each of the mixture level increases corresponds to a period of accumulator injection flow (Figures 5.2.2-10A and E.8-1) whereas the subsequent decreases in level are due to the fact that the injection capability of the Safety Injection (SI) pumps is less than the inventory being discharged via the break (Figures E.8-2 and E.8-3). As such, the mixture level oscillations are consistent with the predicted injection/break characteristics and a reduction of the time steps is not considered to be necessary.

To further confirm that time step size does not play a significant role in the plant response, simulations were performed for each unit in which the maximum time step size was reduced to half the value utilized in the Reference calculation. As can be seen by reviewing Figures E.8-4 and E.8-5, no significant differences in results were observed and the results are considered adequately converged.

The mixture level increase and corresponding RCS pressure decrease observed at approximately 3400 seconds (Figures 5.2.2-16B and 5.2.2-15B) are a result of accumulator injection which results in increased intact and broken loop cold leg interfacial condensation rates. The predicted decrease in pressure observed during the accumulator injection period is approximately 25 psia which is considered to be reasonable.

The apparent "high frequency" oscillations observed in Figure 5.2.2-16B observed between approximately 3400 and 4100 seconds occur as a result of SI and Break flow rates coming into near equilibrium conditions. A review of the oscillations indicates the variations are on the order of 0.1 feet or 1.2 inches, which is considered to have an inconsequential effect on the transient results. In addition, the predicted Peak Cladding Temperature (PCT) for this simulation has occurred at approximately 2000 seconds (Figure 5.2.2-17B) for the BVPS-2 3-inch break such that this oscillation does not affect the predicted PCT.

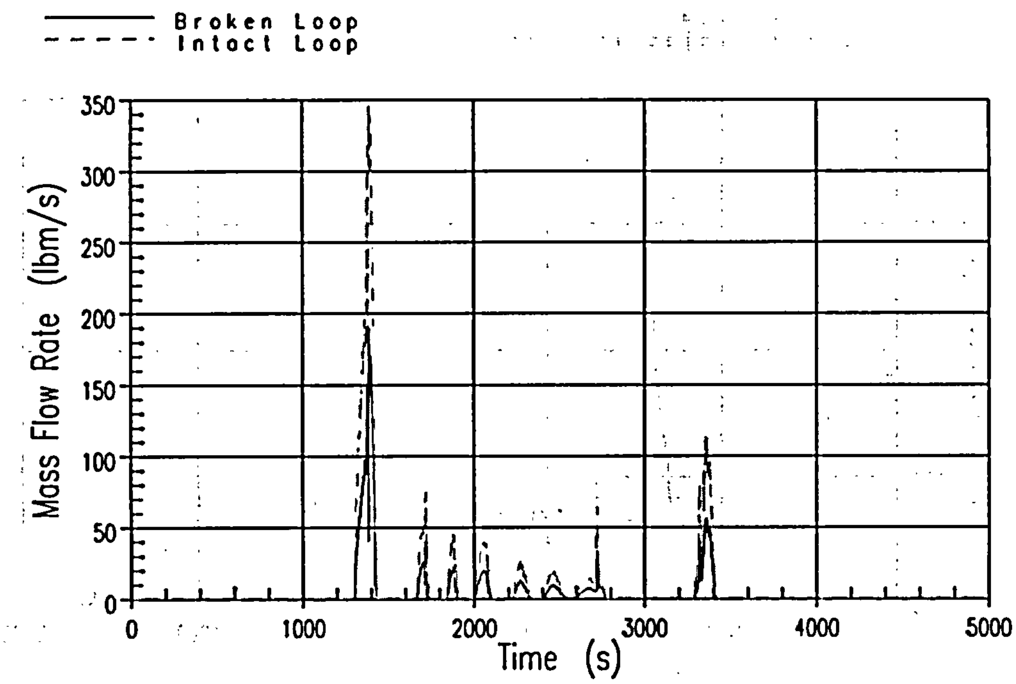

Figure E.8-1
BVPS-2 3-Inch Break, Loop Accumulator Flows

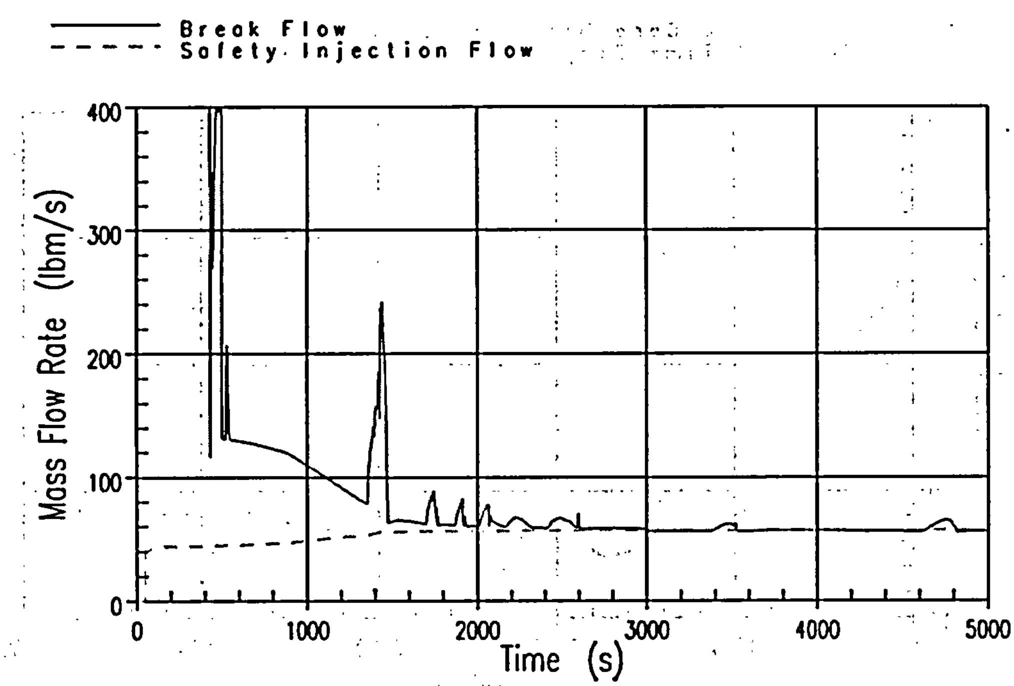

Figure E.8-2
BVPS-1 3-Inch Break, Total SI Flow vs. Break Flow

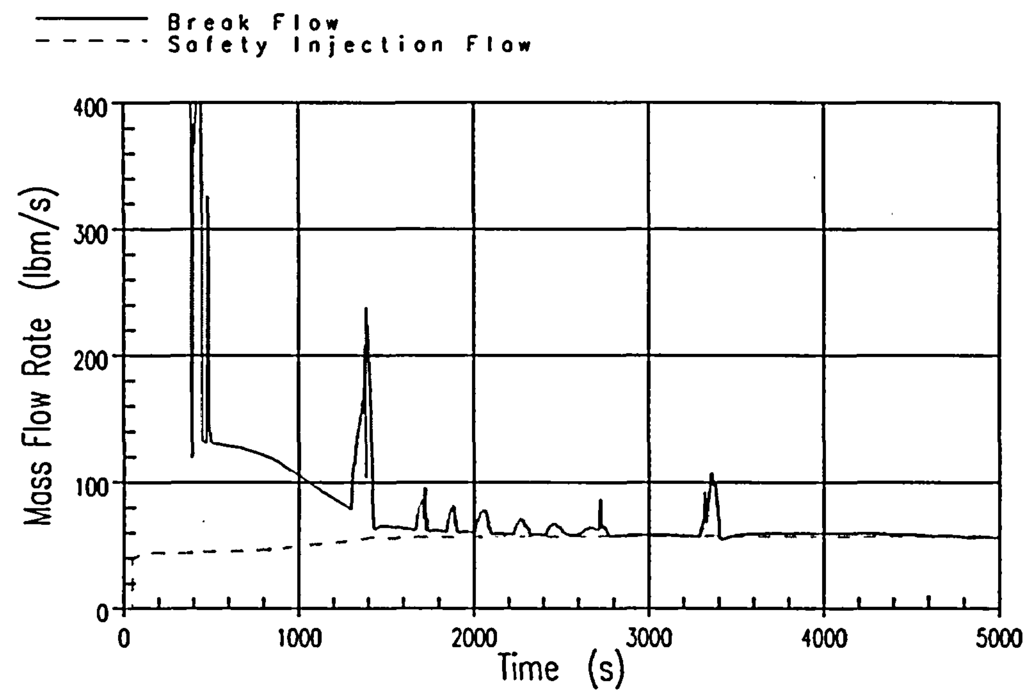

Figure E.8-3
BVPS-2 3-Inch Break, Total SI Flow vs. Break Flow

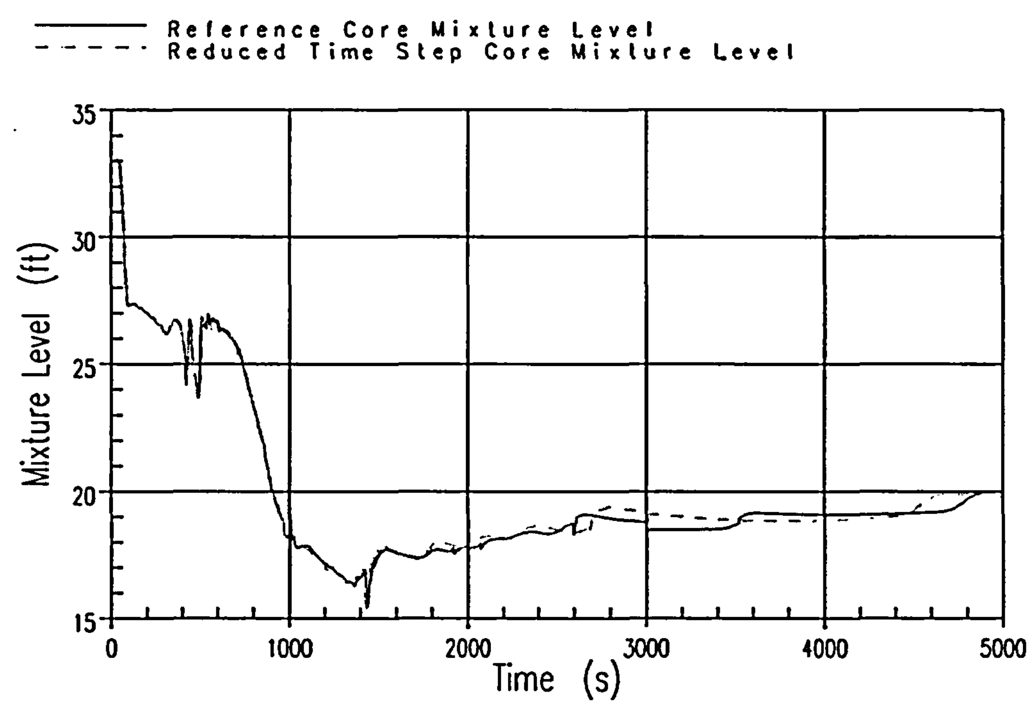

Figure E.8-4
BVPS-1 3-Inch Break, Time Step Effect

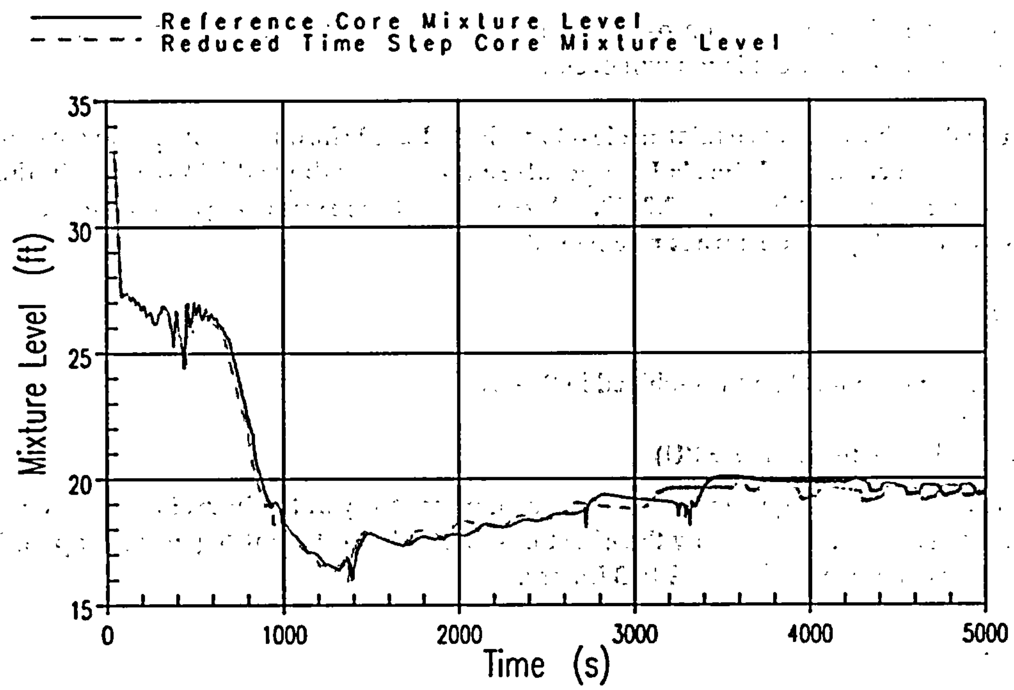

Figure E.8-5
BVPS-2 3-Inch Break, Time Step Effect

E.9 (Applicable to RSG & EPU)

The mixture level plot for the 3-inch break in Fig. 5.2.2-16B displays a steadily decreasing trend after 3400 seconds. Please provide the results of the analysis beyond 5000 seconds to show the level re-covers the top of the core. What is the effect on oxidation for a spot located above the two-phase level at about 21 ft.?

Response:

Toward the end of the 3 and 4-inch transients, break flow and ECCS flows are coming into an equilibrium condition. This causes a slowing of the depressurization of the RCS because the amount of inventory entering the system is nearly equal to the amount of inventory exiting the system, thus the net change in RCS inventory is essentially zero. This leads to a stagnation of the mixture level in the core. However, this situation is occurring nearly one hour into the transient, which is [

]a,c As such further extensions of these simulations are not considered necessary.

There will be no effect on oxidation because the clad temperatures are low enough that no significant further oxidation will occur.

a. **The 4-inch break core mixture level in Fig. 5.2.2-19 shows the top of the core uncovered at 4000 seconds and the clad temperature rising over the last 200 seconds in the temperature plot in Fig. 5.2.2-20. Please present the results beyond 4000 seconds that shows the top of the core is re-covered.**

Response:

The response for 9a was combined in 9 above.

E.10 (Applicable to RSG & EPU)

Was credit for the hot-leg nozzle gaps and/or alignment key at the barrel flange included in these analyses? If so, please show the effect of not crediting the hot-leg nozzle gap and/or alignment keys on break sizes of 2 to 3 inches.

Response:

The nozzle gaps and alignment keys [ ]^{a,c} in the small break LOCA analyses.

E.11 (Applicable to RSG & EPU)

What are the results of small breaks above 4 inches? Please provide analyses of break sizes up to and including 1.0 ft^2 (i.e., 0.2, 0.5, and 1.0 ft^2 cold leg breaks).

Response:

A six inch break size (~0.2 ft^2) was analyzed but not reported since it was found to be non-limiting (see RAI E.3 response). Breaks above this size (up to 1 ft^2) are non-limiting for BVPS-1 and 2 [

]^{a,c} Thus, the stored energy in the fuel, which is very significant in large break LOCA transients, has little significance for these small break LOCA break sizes.

E.12 (Applicable to RSG & EPU)

Please provide a plot of the subcooled level in the core for the 2- and 3-inch breaks.

Response:

The NOTRUMP EM is comprised of fluid nodes which assume a constant temperature in the mixture (liquid) region. As such, a "level" of subcooling can only be established at a node boundary. Review of both the 2 and 3 inch break transients shows that the lower most core node reaches saturation very quickly and remains that way for the entire transient, as would be expected. The node underneath that one is below saturation temperature the entire transient. Given this information and these constraints, the "level" of subcooling can be established as the core entrance.

E.13 (Applicable to RSG & EPU)

Please also provide a plot of the steaming rate at the two-phase surface for the 2- and 3-inch breaks.

Response:

Figures E.13-1 and E.13-2 provide this information for the limiting break size for each unit.

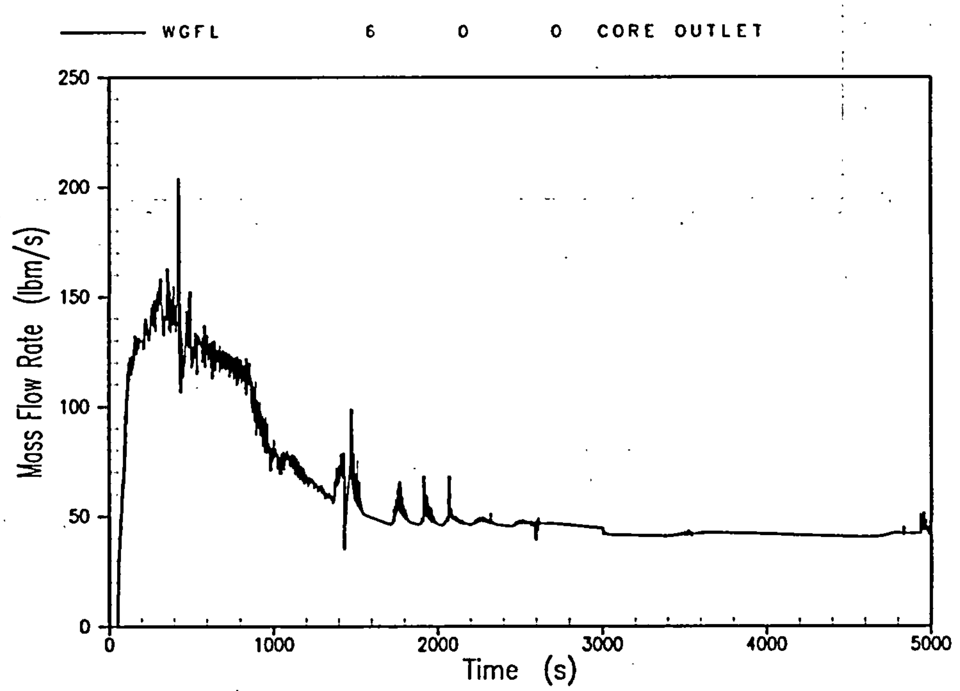

Figure E.13-1
BVPS-1 3-Inch Break Steaming Rate

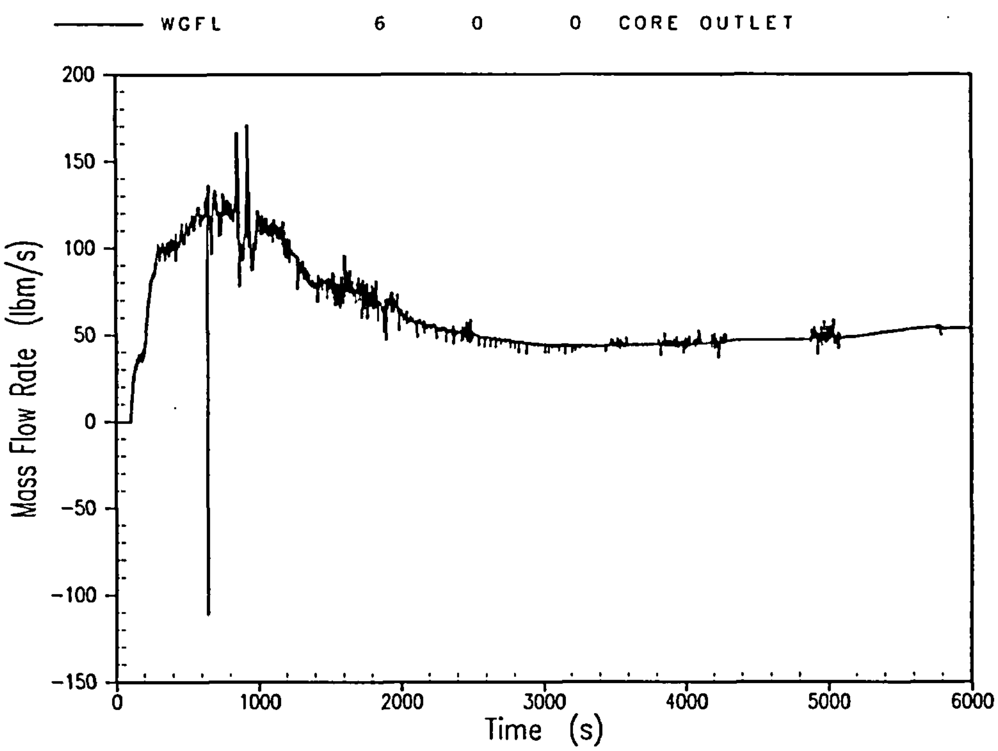

Figure E.13-2
BVPS-2 2-Inch Break Steaming Rate

E.14 (Applicable to RSG & EPU)

What is the two-phase surface void fraction for the 2- and 3-inch limiting breaks versus time?

Response:

Figures E.14-1 through E.14-8 provide the node mixture region void fractions from the bottom to the top of the core for each of the limiting breaks.

Note: When the mixture level drops below the bottom core node fluid boundary, the mixture region void fraction becomes zero for that node since there is no longer a mixture region. The void fractions for the uncovered portions of the core are tracked as the node vapor region void fractions.

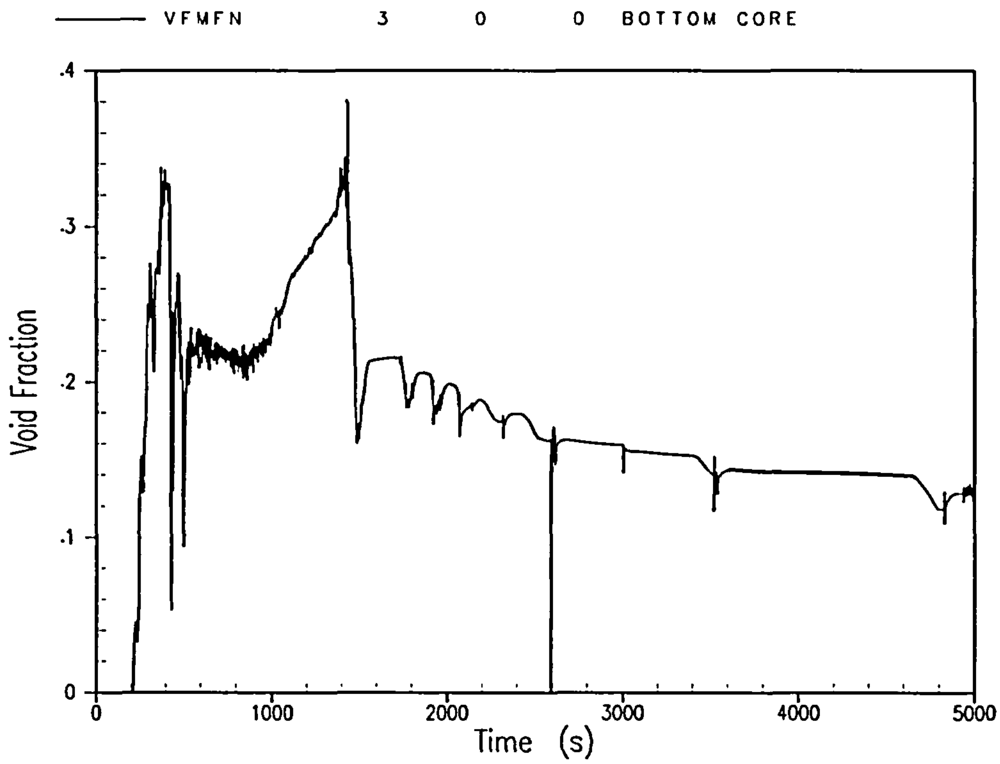

Figure E.14-1
BVPS-1 3-Inch Break Void Fraction

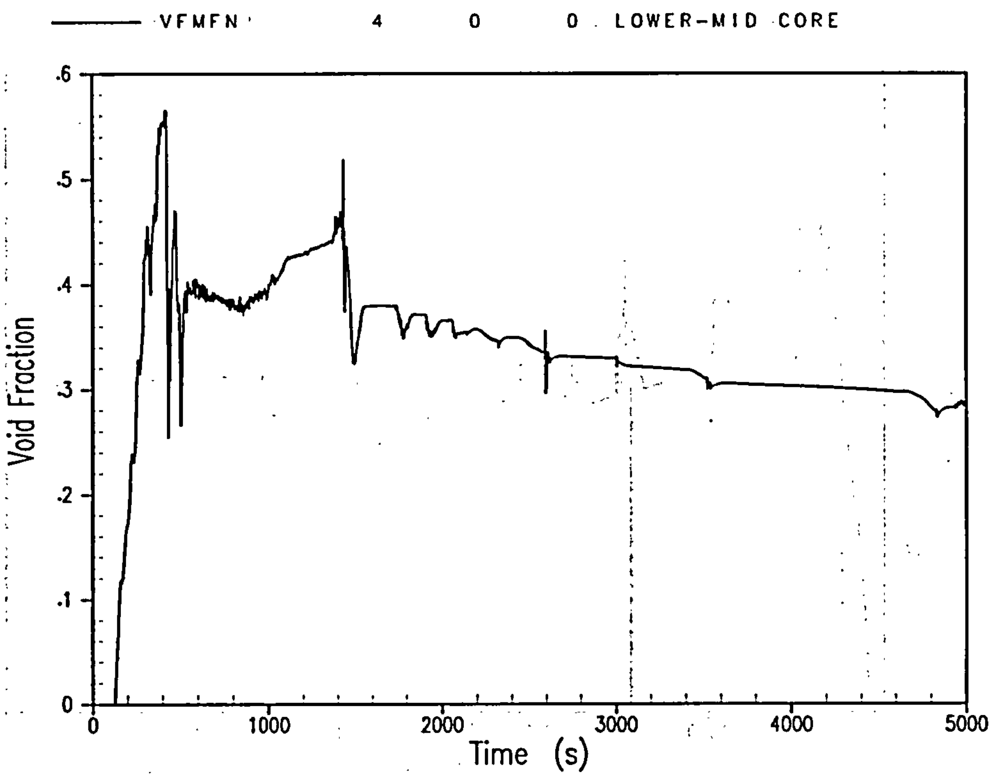

Figure E.14-2
BVPS-1 3-Inch Break Void Fraction

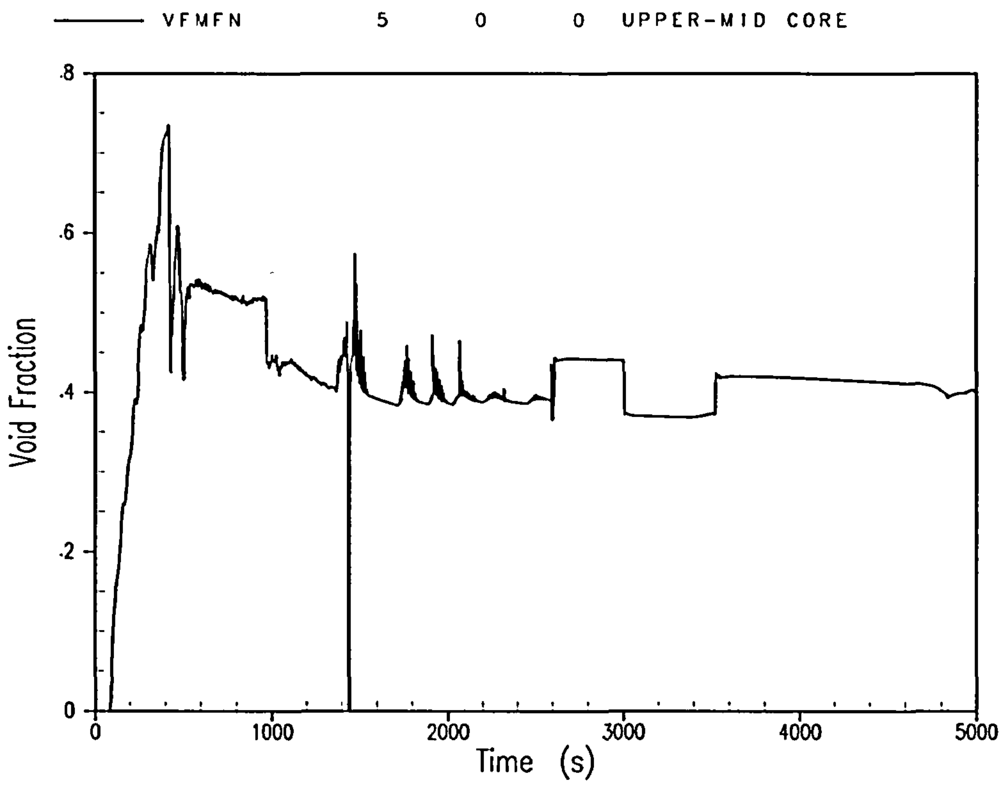

Figure E.14-3
BVPS-1 3-Inch Break Void Fraction

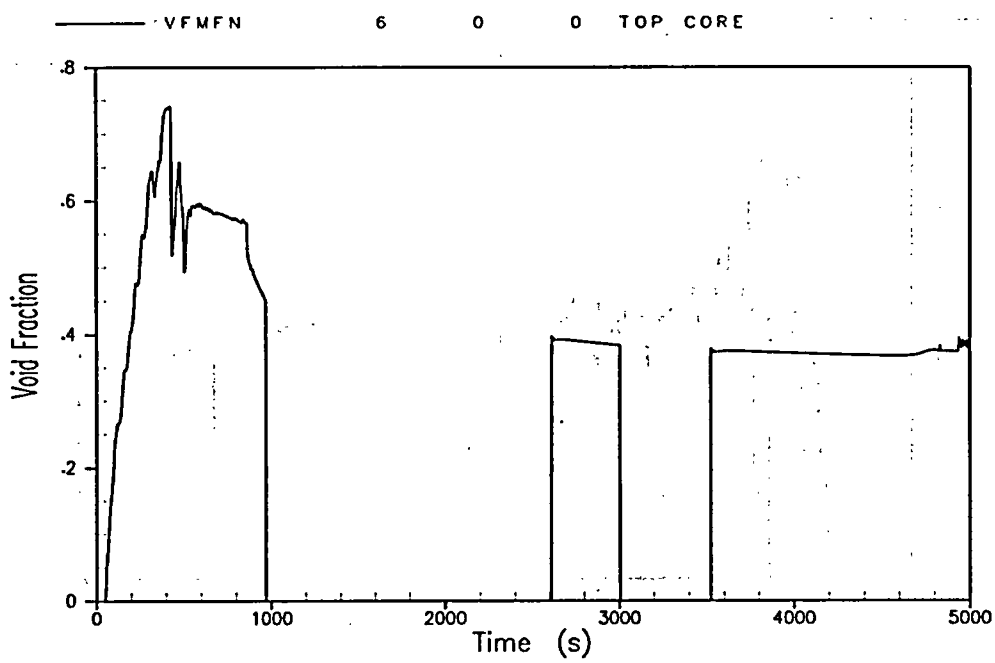

Figure E.14-4
BVPS-1 3-Inch Break Void Fraction

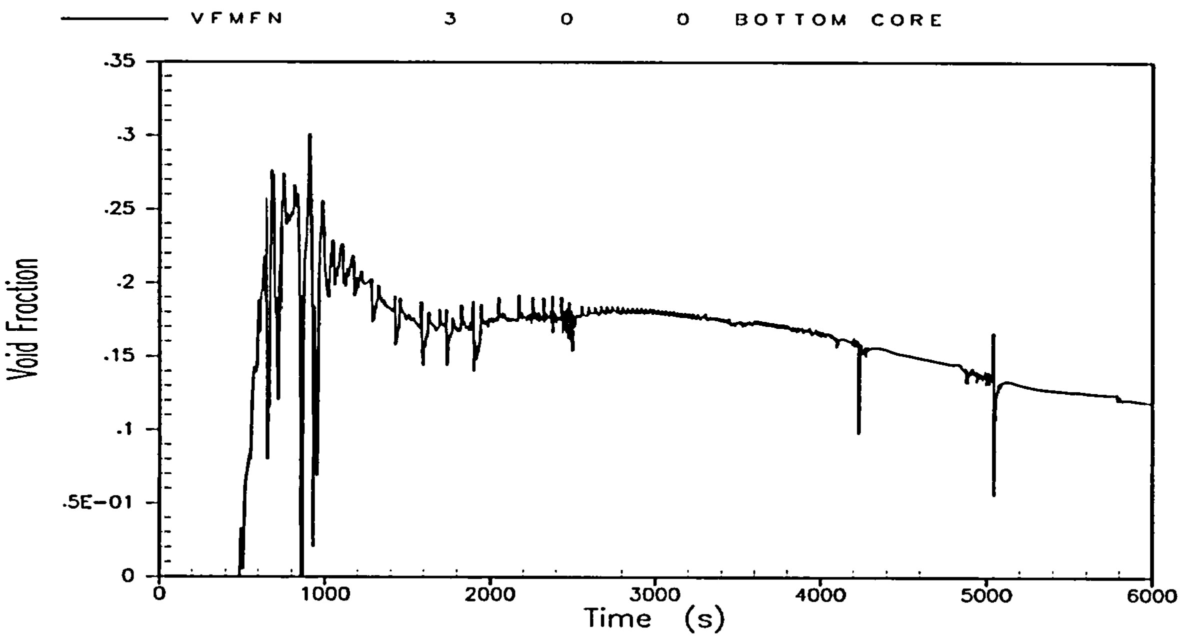

Figure E.14-5
BVPS-2 2-Inch Break Void Fraction

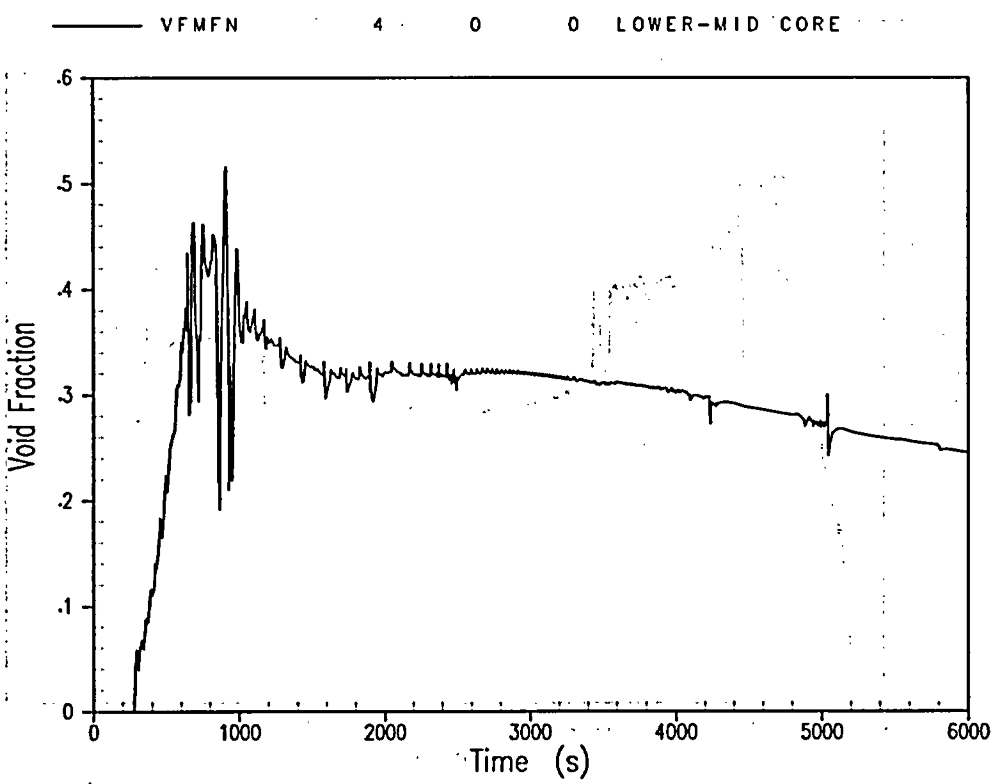

Figure E.14-6
BVPS-2 2-Inch Break Void Fraction

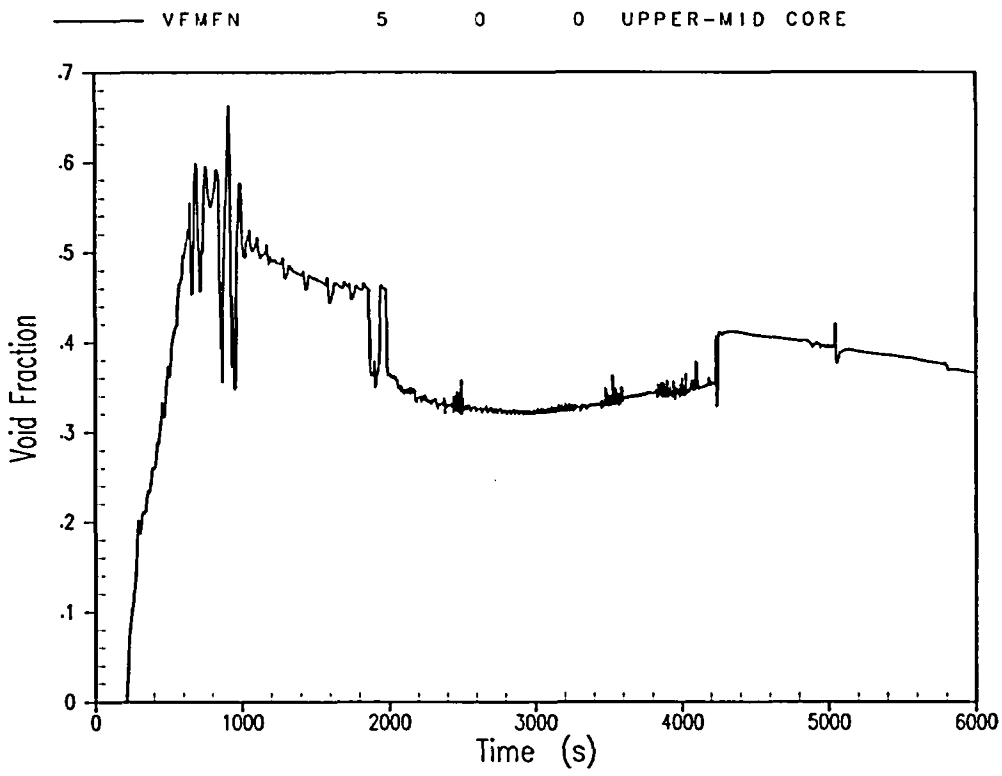

Figure E.14-7
BVPS-2 2-Inch Break Void Fraction

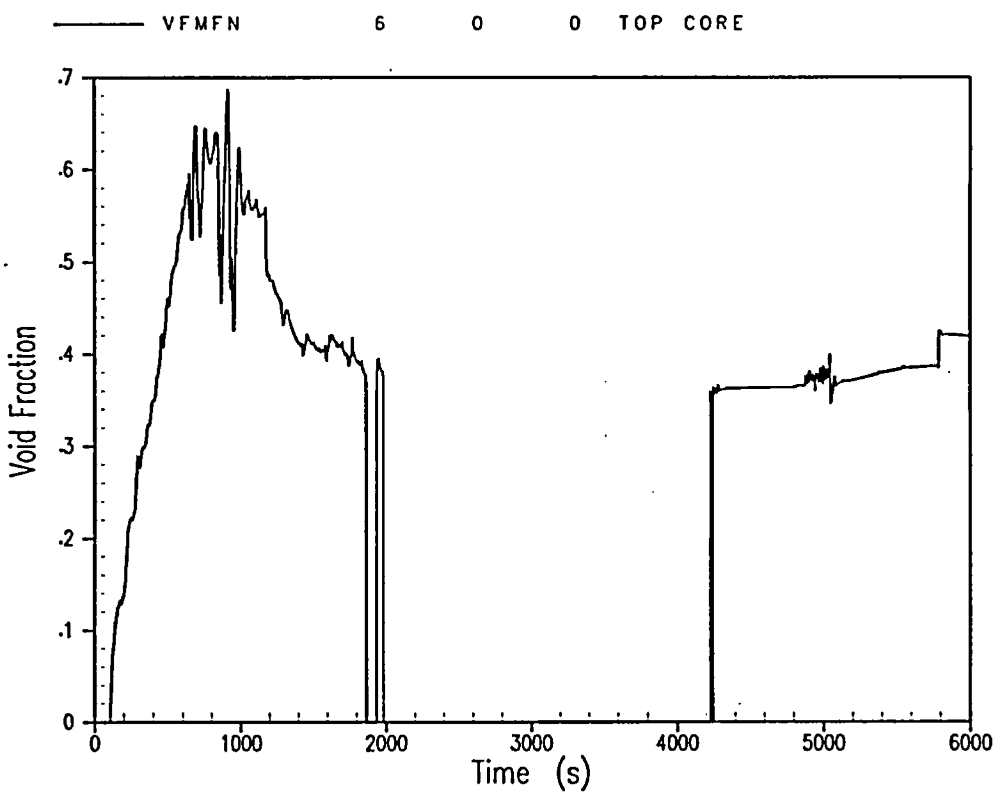

Figure E.14-8
BVPS-2 2-Inch Break Void Fraction

E.15 (Applicable to RSG & EPU)

Please provide the nodalization diagram for the NOTRUMP SBLOCA analyses applicable to BVPS-1 and 2.

Response:

The NOTRUMP noding diagram is shown in Figure E.15-1.

a,c

Figure E.15-1
NOTRUMP Noding Diagram

E.16 (Applicable to RSG & EPU)

Please explain how the broken loop vapor and liquid break flow rates are computed and where the break is located, relative to the injection nozzle. Is condensation credited in the broken loop injection section? Please explain.

Response:

The break flow model is described in Appendix-M of WCAP-10079-P-A. The details of the Safety Injection (SI) condensation model can be found in WCAP-10054-P-A and WCAP-10054-P-A Addendum 2, Rev. 1, including details regarding the improved SI condensation model and SI in the broken loop. Broken LOOP steam condensation as a result of safety injection is considered.

a. **Please provide a plot of the condensation rate in the cell containing the ECCS injection into the discharge leg for each of the breaks analyzed in this submittal.**

Response:

Figures E.16-1 through E.16-8 show the condensation mass flow rates for BVPS-1 and 2.

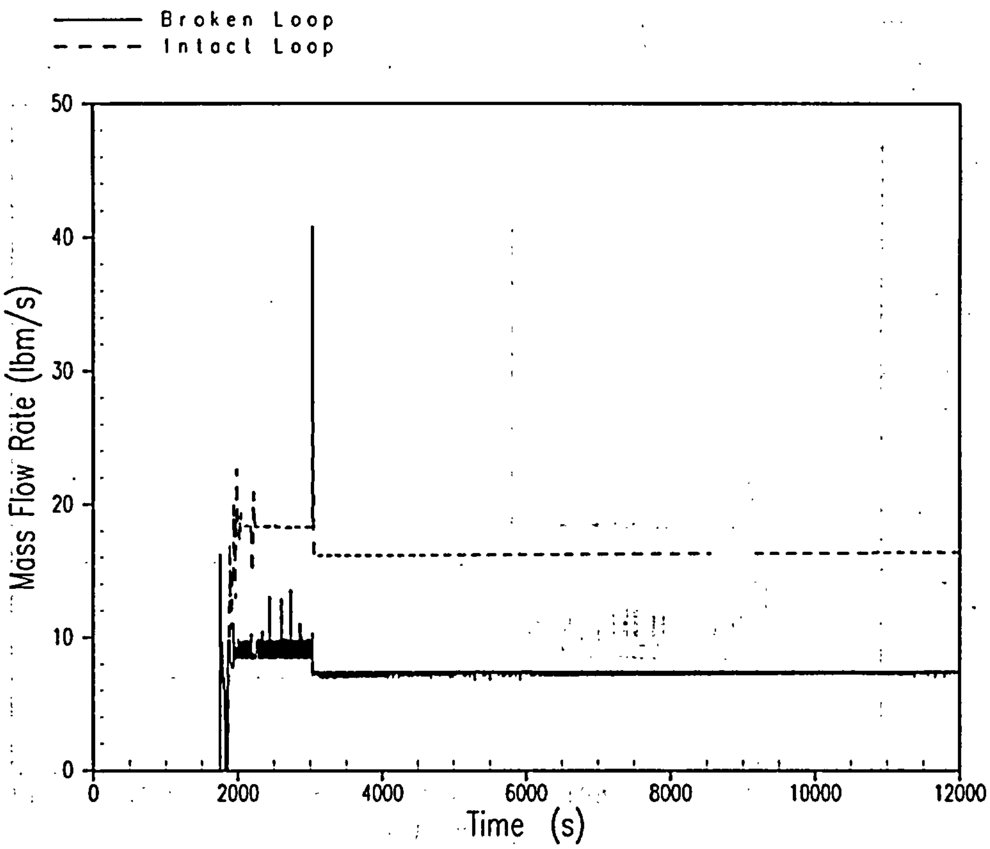

Figure E.16-1
BVPS-1 1.5-Inch Break Condensate Rate

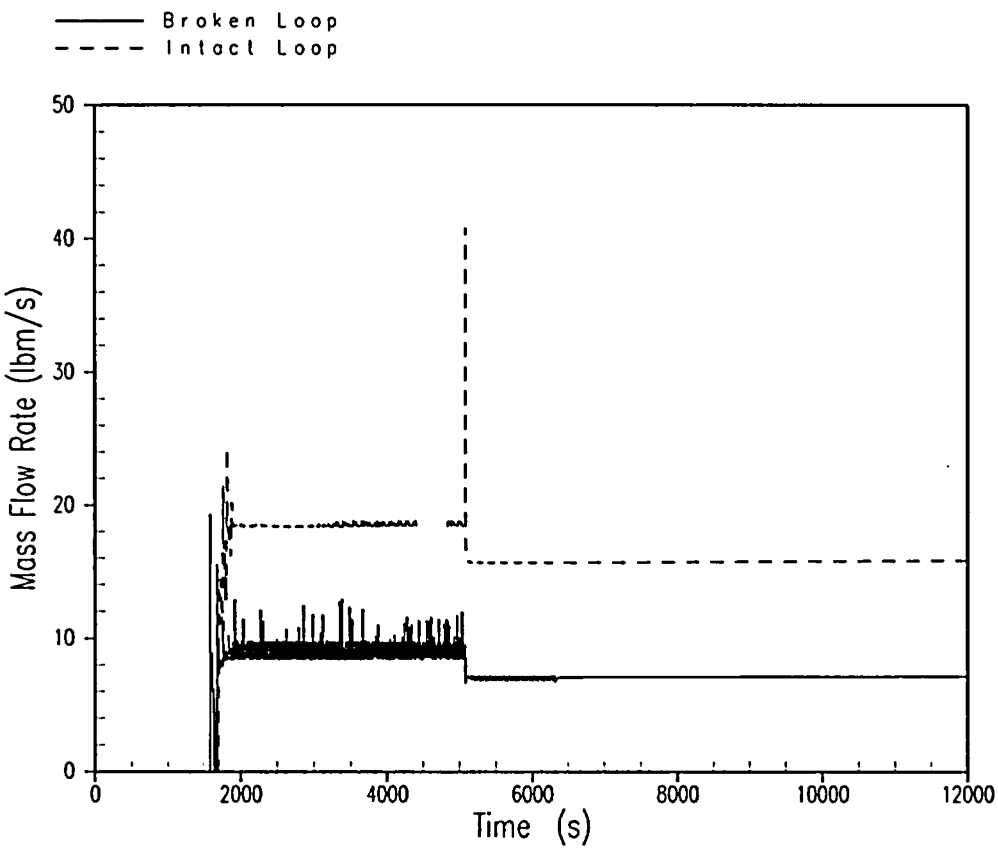

Figure E.16-2
BVPS-2 1.5-Inch Break Condensate Rate

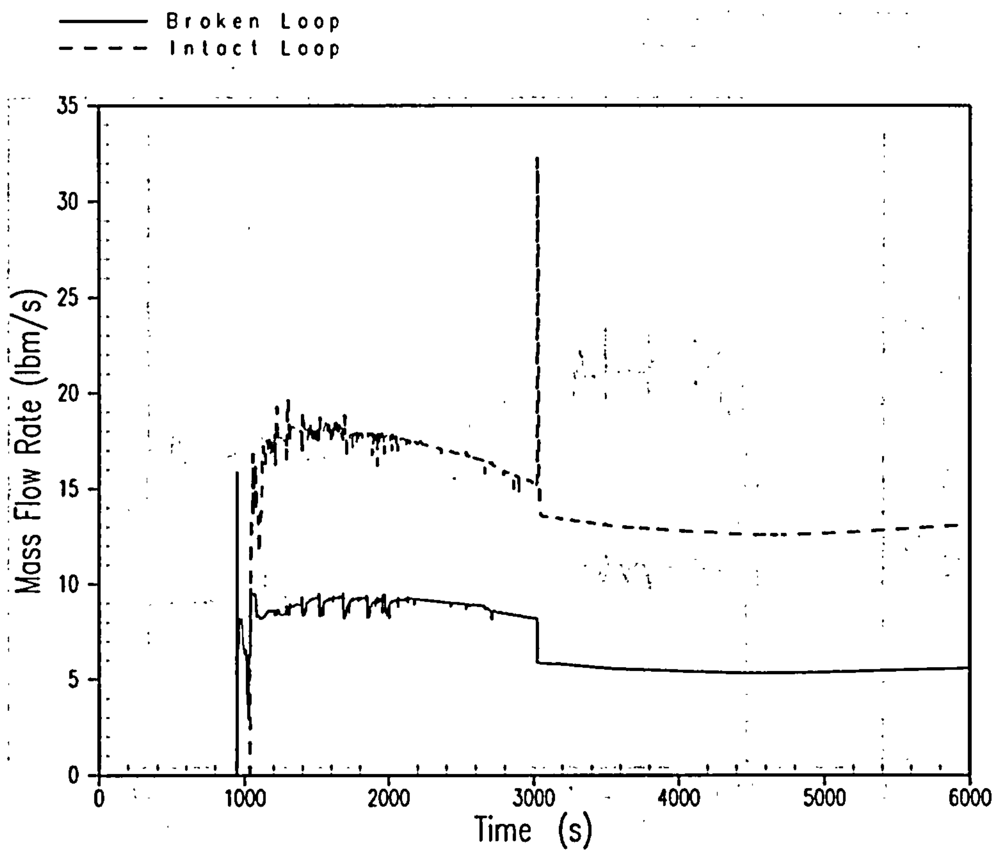

Figure E.16-3
BVPS-1 2-Inch Break Condensate Rate

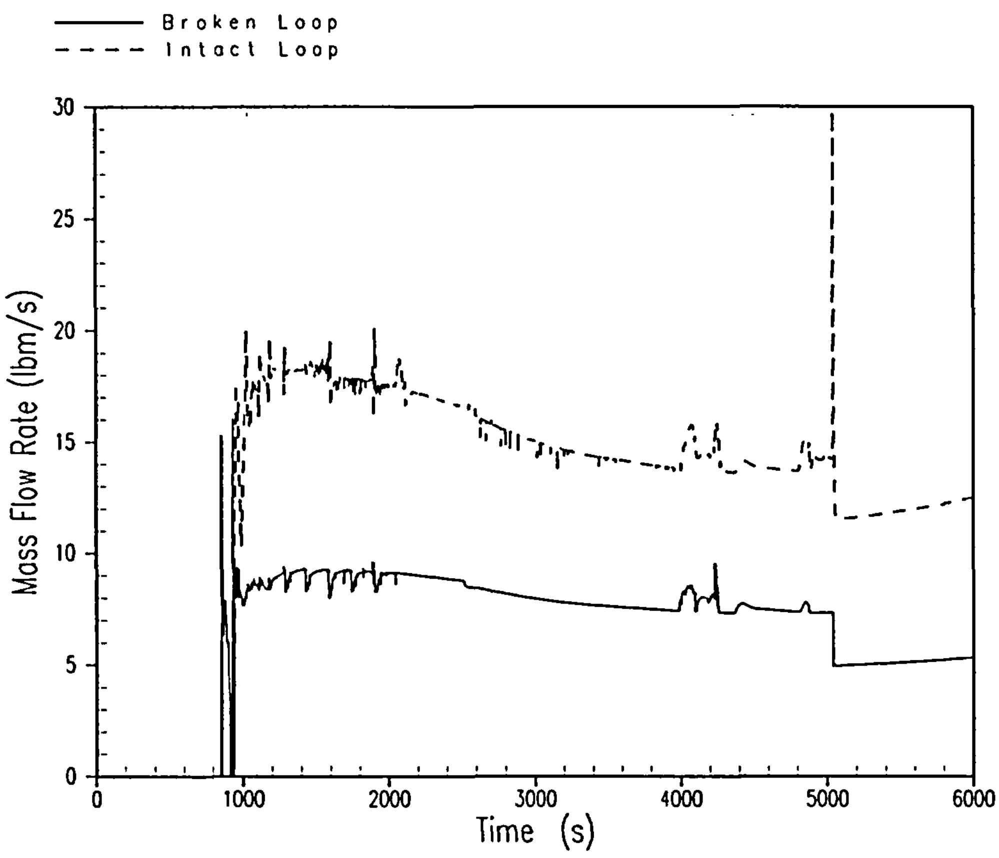

Figure E.16-4
BVPS-2 2-Inch Break Condensate Rate

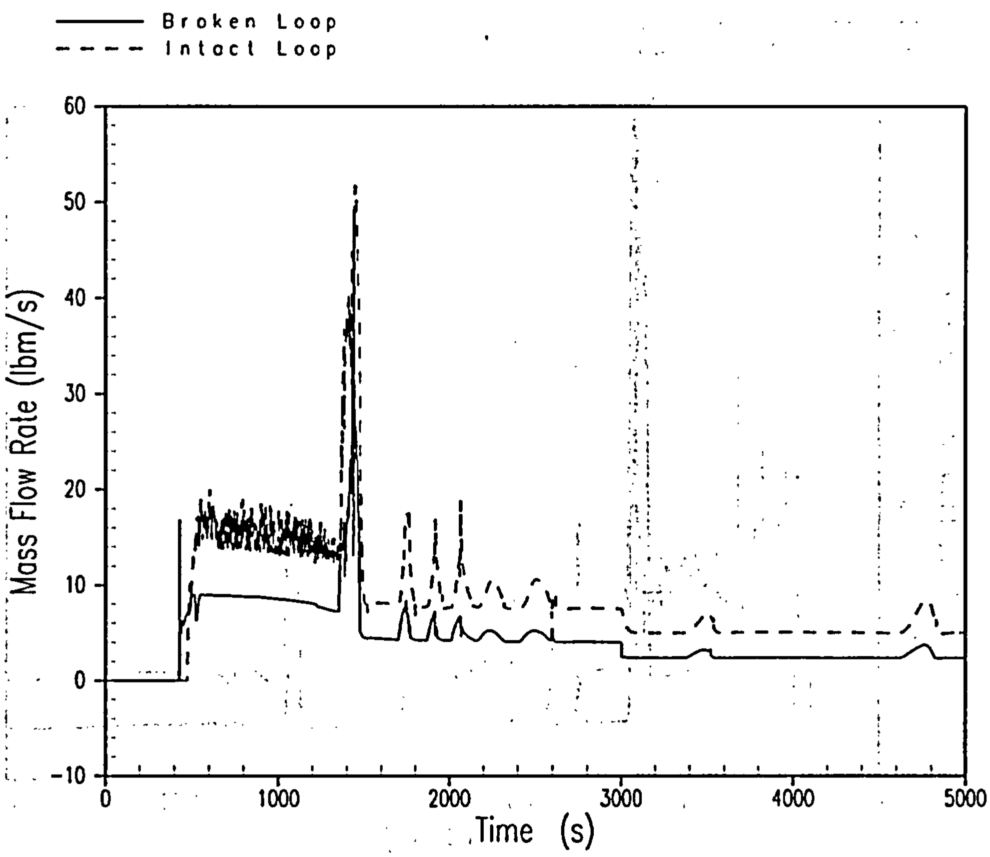

Figure E.16-5
BVPS-1 3-Inch Break Condensate Rate

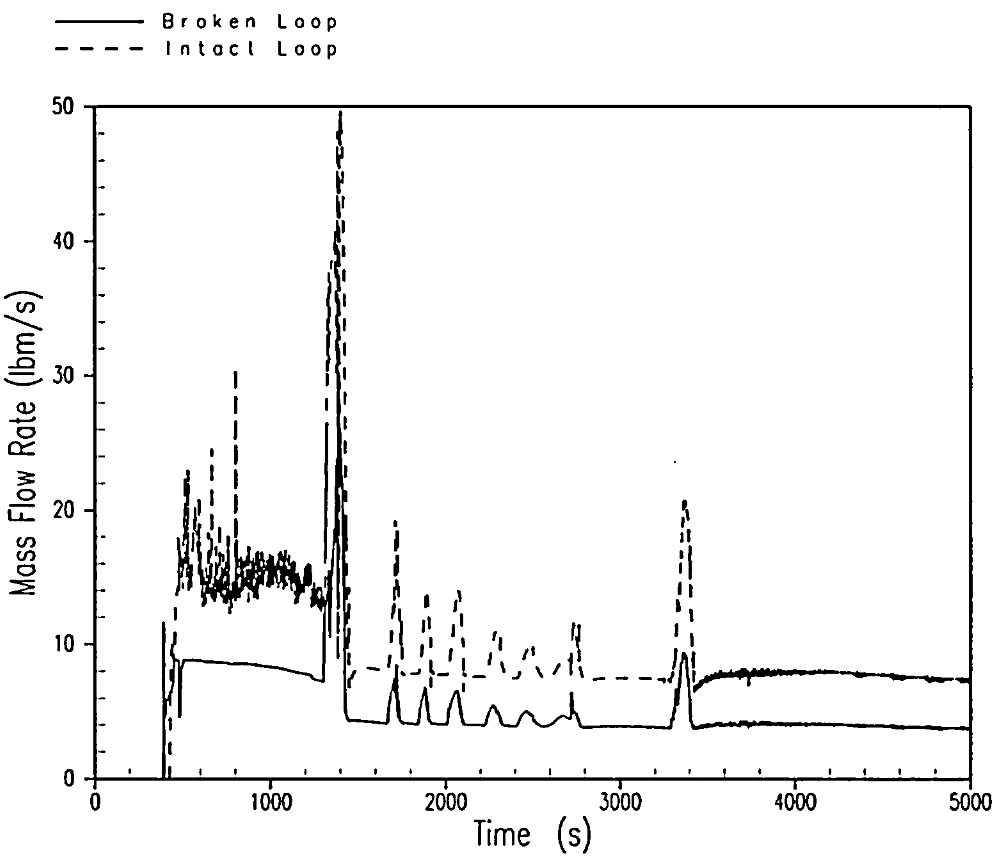

Figure E.16-6
BVPS-2 3-Inch Break Condensate Rate

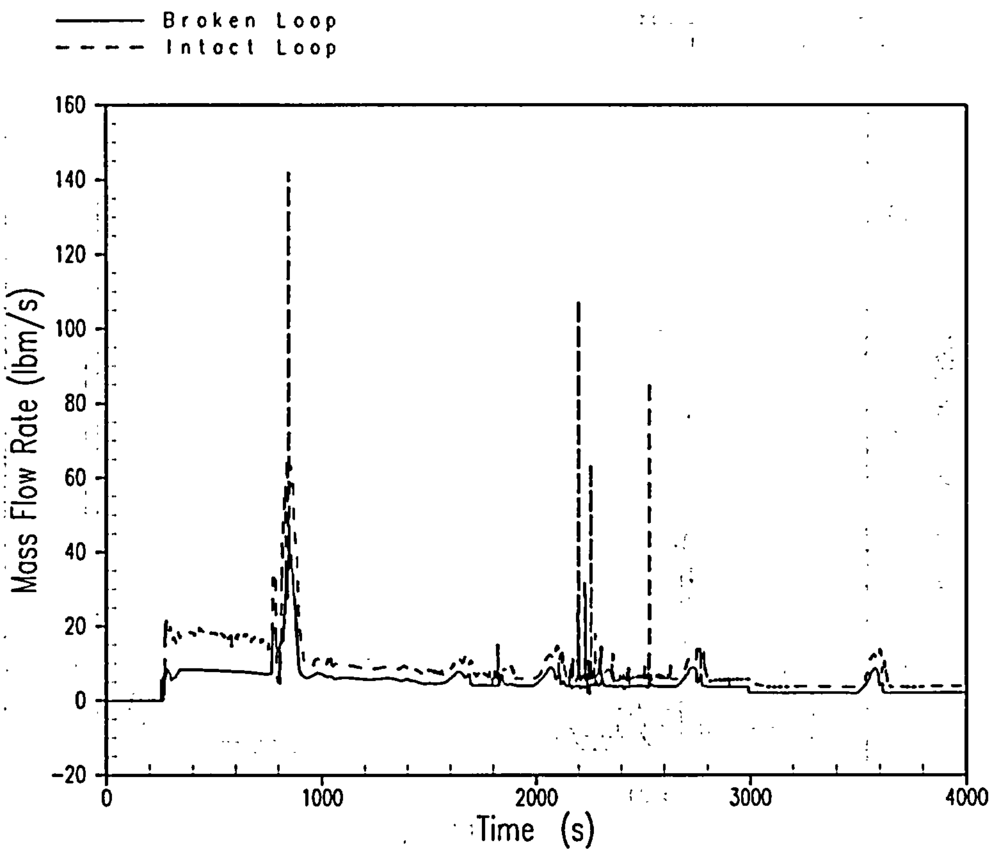

Figure E.16-7
BVPS-1 4-Inch Break Condensate Rate

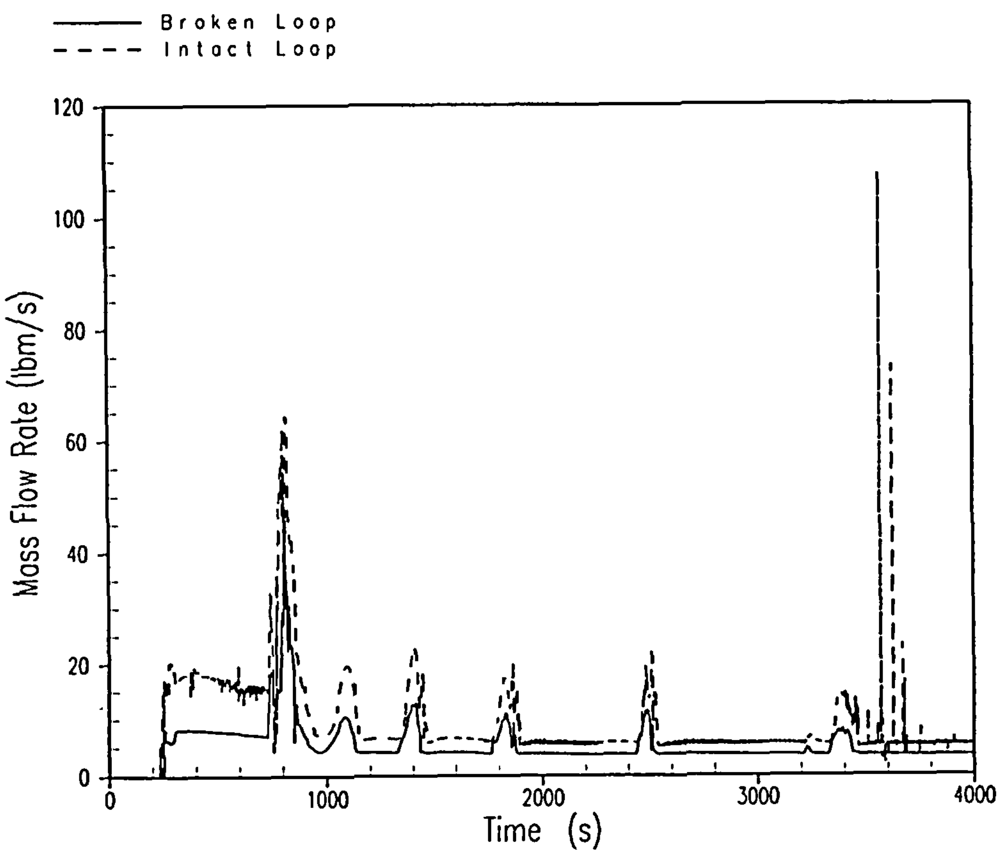

Figure E.16-8
BVPS-2 4-Inch Break Condensate Rate

E.17 (Applicable to RSG & EPU)

Once the RCS pressure drops below that of the secondary, does the model account for super-heating of the primary steam? How is the interaction between the ECCS injection and super-heated steam modeled in the discharge leg? Inspection of Figs. 5.2.2-7A and B suggest there is no reverse heat transfer modeled in the NOTRUMP Code. Please explain.

Response:

NOTRUMP accounts for the super-heating of primary steam via reverse heat transfer from the steam generators when the conditions exist that support its creation. A review of the EPU Licensing Report Figures 5.2.2-7A and B, and corresponding Figures 5.2.2-6A and B, indicate the reason that no significant reverse heat transfer is observed is a result of two factors. First, core uncovery and subsequent superheating of the primary steam (Figures E.17-1 and E.17-2) occurs which prevents reverse heat transfer for the steam generators from occurring. Secondly, even when reverse heat transfer is predicted, the addition of auxiliary feedwater (AFW) flow may also be occurring, which results in the compression of the secondary side vapor space. Both of these factors can result in a relatively constant secondary pressure that is at or above the steam generator safety valve opening pressure. For a break size in which the primary pressure drops below that of the secondary prior to core uncovery, reverse heat transfer is seen as observed in the BVPS-1 4-inch break during the period between approximately 300 seconds and 700 seconds (Figures E.17-3 and E.17-4). Again, the addition of AFW flow mitigates a portion the secondary depressurization effect due to secondary mass addition (Figure E.17-5). AFW addition is modeled until the specified control level is obtained.

Interaction of ECCS injection and super-heated steam is accounted for in the NOTRUMP proper interfacial heat transfer models. The basic non-equilibrium safety injection model is described in Section 3.3.1 of Reference 1. The modifications to account for the COSI condensation model are described in References 2 and 3. The direct vapor interaction [ ]^{a,c} coefficient as described in Section 3.3.1 of Reference 1.

References:

1. WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985.
2. WCAP-11767, "COSI SI/STEAM Condensation Experiment Analysis," March 1988.
3. WCAP-10054-P-A Addendum 2 Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," July 1997.

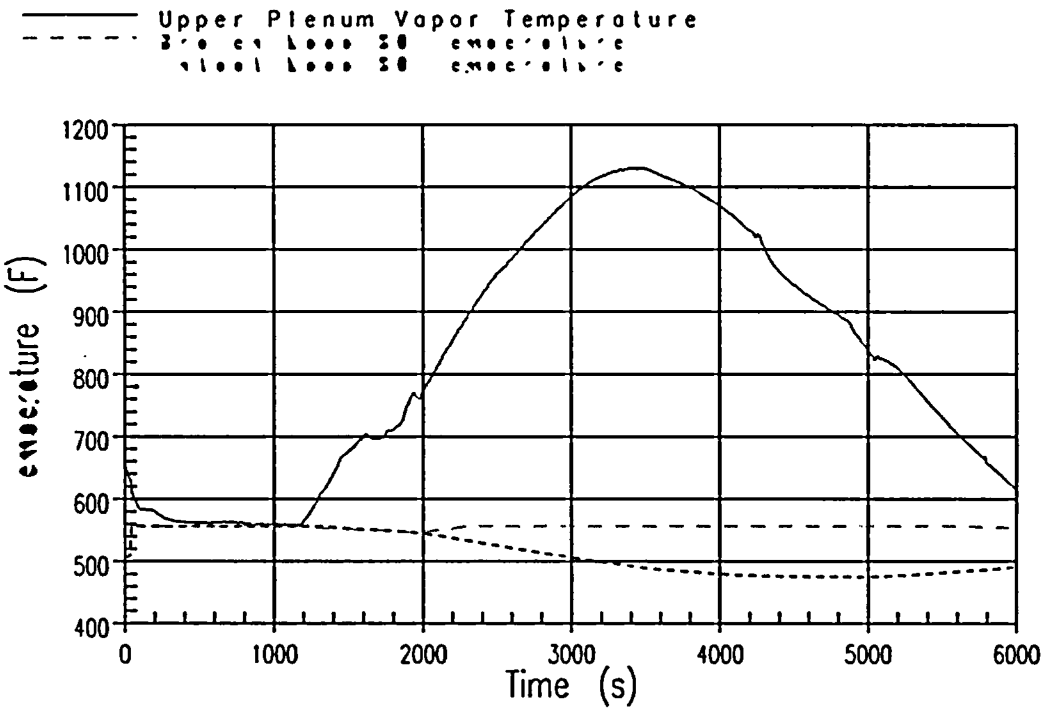

Figure E.17-1
BVPS-1 3-Inch Break Temperature Comparison

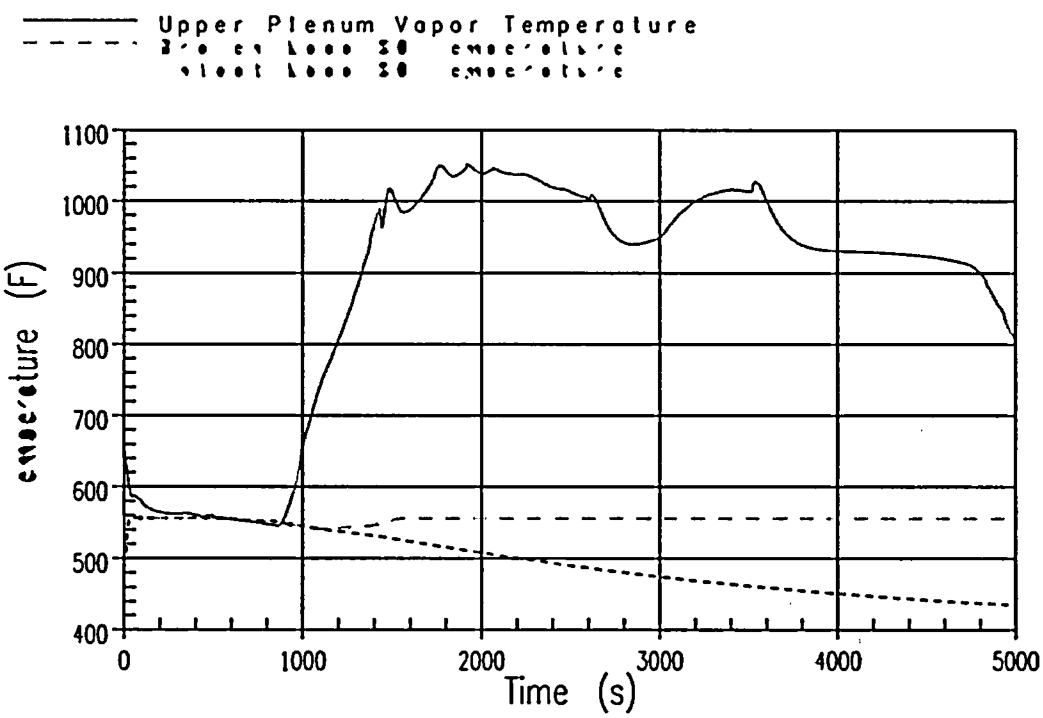

Figure E.17-2
BVPS-2 2-Inch Break Temperature Comparison

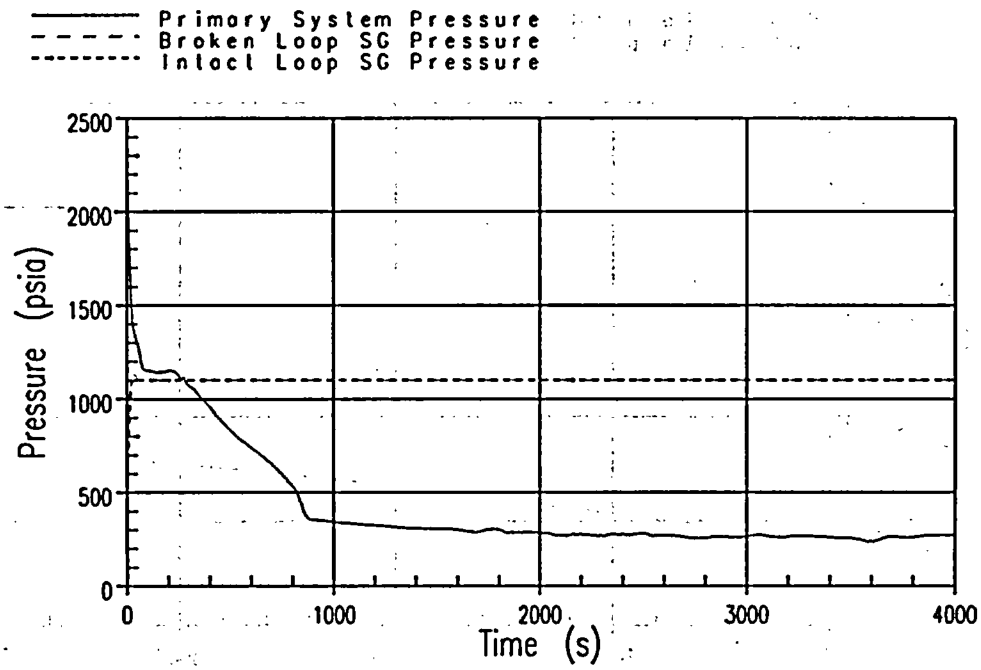

Figure E.17-3
BVPS-1 4-Inch Break Pressure Comparison

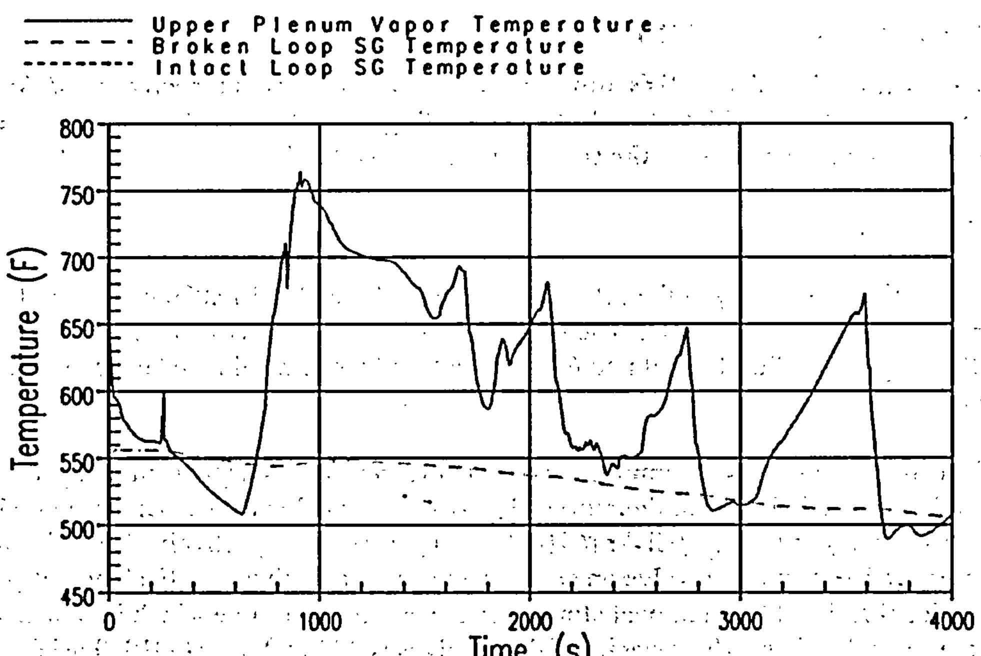

Figure E.17-4
BVPS-1 4-Inch Break Temperature Comparison

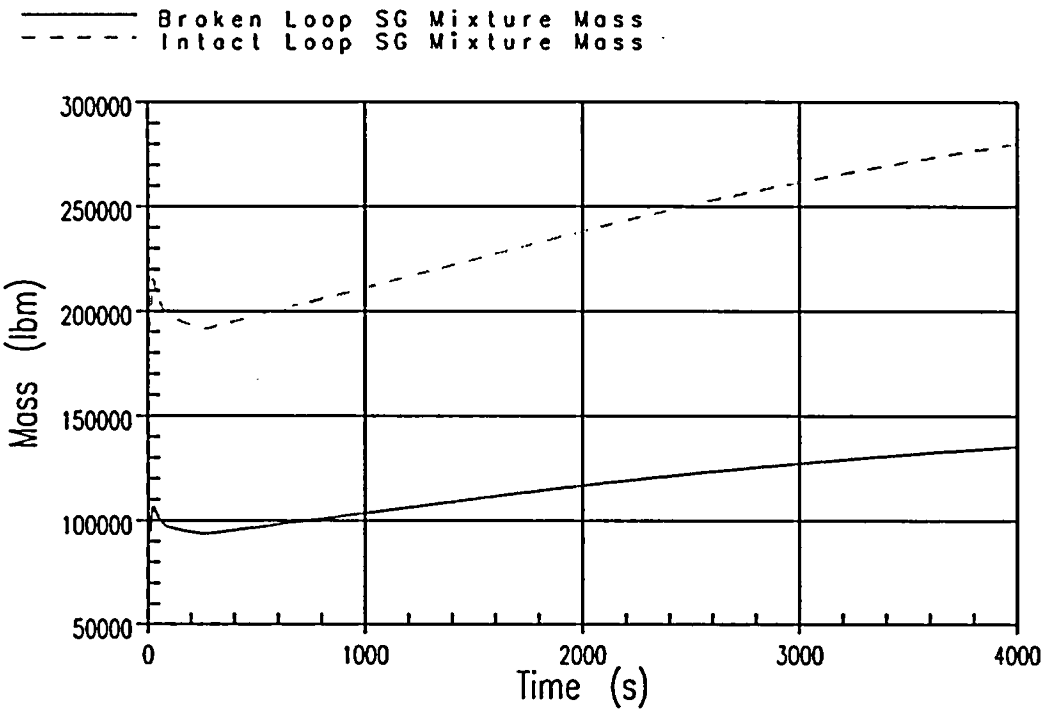

Figure E.17-5
BVPS-1 4-Inch Break Secondary Mass

E.18 (Applicable to RSG & EPU)

What are the capacities of the CSTs and atmospheric dump valves for each unit? What is the earliest cooldown time to achieve the shutdown cooling entry temperature and pressure following very small breaks using the secondary dump system?

Response:

The maximum capacity of the PPDWST at BVPS-1 and 2 is 169,000 gallons and 164,000 gallons, respectively. The EPU Project proposes a revised minimum capacity of 130,000 gallons of usable volume for both units, which is within the tank capacity at both units.

The capacity of the BVPS atmospheric steam dump valves is dependent on operating pressure and the installed piping configuration. The BVPS-1 and 2 valve capacities are 403,000 lb/hr (@ 1040 psia) and 235,000 lb/hr (@1040 psia) per valve, respectively. There is one atmospheric steam dump valve on each steam header at both units. Each unit also has an additional residual heat removal atmospheric steam release valve which is connected to all three steam headers. The capacity of these valves is 334,000 lb/hr (@1040 psia) and 480,000 lb/hr (@ 1040 psia) for BVPS-1 and 2, respectively.

The time to achieve the shutdown cooling entry temperature and pressure following very small breaks is dependent on a wide range of assumed conditions. Operator actions would follow the emergency operating procedures (EOPs), with plant cooldown and depressurization accomplished via EOP Procedure ES-1.2. Based on an estimate of the time to reach the initiation of cooldown step in this procedure (1 hour), and the time required to cool down at the maximum allowable rate (<100 F/hr), the entry temperature and pressure condition for shutdown cooling could be reached in approximately three hours.

E.19 (Applicable to RSG & EPU)

The latest SBLOCA analyses (Reference 3), for BVPS-1 and 2, identify the PCT for SBLOCA as 1894°F and 2105°F, respectively. Please provide the reference for, or present all of the key transient plots for these analyses. Please also explain why the PCT decreases 350°F when EPU conditions are assumed in the analyses. This report also lists many modifications to the SBLOCA models and discusses the results of sensitivity studies with NOTRUMP, for example, for variations in RCS pressure, auxiliary feedwater (AFW) flow, power distribution, etc., and time steps. Comparisons to SU-T-08 are also discussed. Please provide the results or the references presenting all of the key transient plots for these model changes and sensitivity studies. The plots should include the parameters listed on page 5-13 of Section 5.2.2, entitled "Small Break LOCA."

Response:

The actual reported PCT for BVPS-1 is 1849°F per Reference 1. See Attachment A.

The observed PCT decreases are a result of several primary factors. These are:

<u>Improved ECCS performance characteristics</u>

As part of the EPU analysis improved ECCS flow delivery characteristics were generated and applied (See response describing pump modifications in AB.1). A comparison of the pre and post EPU ECCS performance characteristics can be seen in Figures E.19-1 and E.19-2 for the limiting small break LOCA cases.

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Additionally, the BVPS-1 analysis modeled a slightly reduced Hot Assembly average power peaking factor which will result in additional analysis margin when compared to the pre-EPU conditions.

A discussion of the method of annual reporting chosen by FENOC in Reference 1 is provided in response to RAI E.21. This response also includes a discussion of the methodology employed with regards to 10 CFR 50.46 reporting as performed by Westinghouse. Additionally, some of the sensitivity studies mentioned are related to model changes that were implemented over 15 years ago. Time and experience have since proven either that parameters cited have an inconsequential effect on the design basis SBLOCA transient or a position of limiting direction has been established and incorporated into the evaluation model. The EPU analysis was performed with the latest version of the NOTRUMP EM and, thus, all 10 CFR 50.46 changes that were to be implemented on a forward-fit basis are included in the analyses. Additionally, results of time step studies have been provided for the BVPS-1 and 2 analyses in support of the responses associated with RAIs E.6 and E.8.

As requested, plots from the latest SUT-08 validation simulations with the NOTRUMP code are included in Attachment B, Semiscale Test Facility Simulation of Test S-UT-08 with NOTRUMP Code Version.

Reference:

1. L-04-144, "Beaver Valley Power Station, Units No. 1 and No. 2, BV-1 Docket No. 50 334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, 10 CFR 50.46 Report of Changes or Errors in ECCS Evaluation Models," L. W. Pearce (FENOC) to USNRC, 11/19/04.

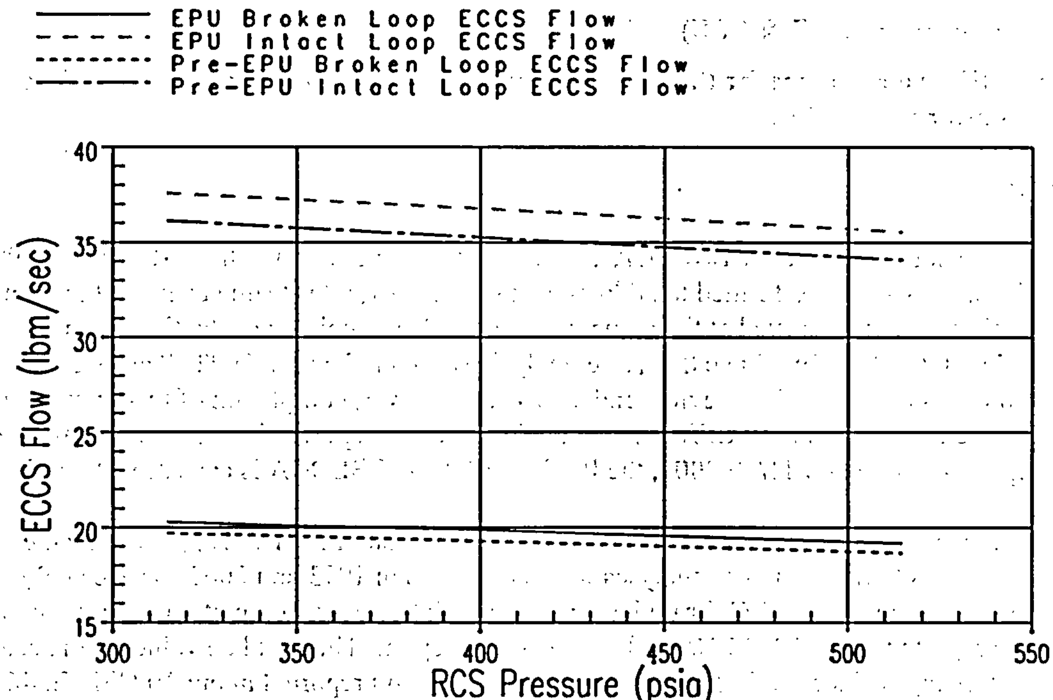

Figure E.19-1
BVPS-1 ECCS Flow Comparison

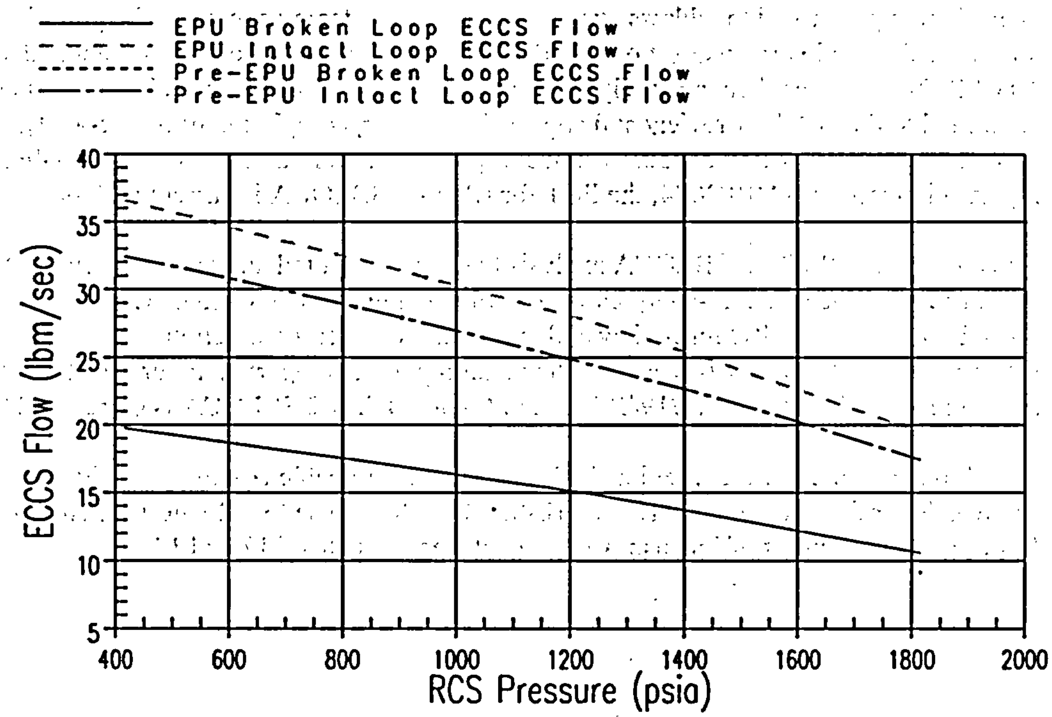

Figure E.19-2
BVPS-2 ECCS Flow Comparison

E.20 (Applicable to RSG & EPU)

Please identify the reference for the licensing analysis of record for operating at full power conditions prior to the EPU.

Response:

The most recent BVPS-1 LBLOCA analysis that was submitted to the NRC was in 1993. This analysis was performed to address changes in allowable steam generator tube plugging levels and was submitted at the request of the NRC although the evaluation was implemented under 10 CFR 50.59. Since then, a re-analysis was completed in 2002. This analysis was not submitted to the NRC for review and approval; however, completion of this re-analysis was reported in the BVPS 10 CFR 50.46 annual report. As reported in our 10 CFR 50.46 annual report submitted on 11/19/2004, the PCT for BVPS-1 LBLOCA is currently 1996°F.

The most recent BVPS-2 LBLOCA analysis that was submitted and approved by the NRC was in 1987. Since then re-analyses were completed in 1993 and 2002. These analyses were not submitted to the NRC for review and approval; however, completion of these re-analyses was reported in the BVPS 10 CFR 50.46 annual report. The absolute value of all accumulated PCT changes since the 1987 analysis exceeds 50°F. As reported in our 10 CFR 50.46 annual report submitted on 11/19/2004, the PCT for BVPS-2 LBLOCA is currently 2044°F.

The most recent BVPS-1 SBLOCA analysis that was submitted to the NRC was in 1993. This analysis was performed to address changes in allowable steam generator tube plugging levels and was submitted at the request of the NRC although the evaluation was implemented under 10 CFR 50.59. Since then, a reanalysis was completed in 2003. This analyses was not submitted to the NRC for review and approval, however, completion of this re-analysis was reported in the BVPS 10 CFR 50.46 annual report. As reported in our 10 CFR 50.46 annual report submitted on 11/19/2004, the PCT for BVPS-1 SBLOCA is currently 1849°F.

The most recent BVPS-2 SBLOCA analysis that was submitted and approved by the NRC was in 1987. Since then, re-analyses were completed in 1993 and 2003. These analyses were not submitted to the NRC for review and approval; however, completion of these re-analyses was reported in the BVPS 10 CFR 50.46 annual report. As reported in our 10 CFR 50.46 annual report submitted on 11/19/2004, the PCT for BVPS-2 SBLOCA is currently 2105°F.

The above information was previously docketed and applicable commitments identified in FENOC letter dated February 11, 2005 (L-05-006) "Response to a Request for Additional Information in Support of License Amendment Requests Nos. 317 and 190."

E.21 (Applicable to RSG & EPU)

Are the code modifications and analysis changes described in Reference 3 included in the BVPS-1 and 2 EPU submittal? Please explain. References 2, 3, and 4 of Section 5.2.2 do not appear to include the code changes and modifications listed in Reference 3, in which the PCTs were much higher than those at EPU conditions.

Response:

The analyses performed in support of the BVPS-1 and 2 EPU submittal incorporate all items described in the Reference 1 documentation.

The method of annual reporting chosen by FENOC is such that the identified changes are in some cases already included in the documentation as cited in the submittals. For example, the information pertaining to Safety Injection (SI) in the Broken Loop and the Improved Condensation Model have been specifically reviewed and approved for application by the NRC in Reference 2 and is cited as Section 5.2.2 Reference 4 in the Beaver Valley EPU submittal. The list of references included in the Reference 1 10 CFR 50.46 reporting does not reflect this fact. In other instances, the model changes described in the 10 CFR 50.46 report involve the addition of user convenience features and represent discretionary improvements performed to the codes.

The Section 5.2.2 References 2, 3 and 4 represent the currently licensed NOTRUMP Evaluation Model (EM). The 10 CFR 50.46 annual reporting describes error corrections and forward fit enhancements performed to these evaluation models. In most instances, the error corrections deal not with the documentation but with the coding of the models as described in the documentation. In all instances, when a new version of the NOTRUMP code is released, testing of the revisions, including regression testing, are performed. In the instance of error corrections, the effect for each plant is provided as part of the 10 CFR 50.46 annual reporting in which Westinghouse provides both the NRC and the licensees a description of the correction/change and an estimated effect on the evaluation model. All of the corrections listed in Reference 3 that pertain to the NOTRUMP SBLOCA EM have been communicated in this fashion. In addition, the correction/changes and communication thereof have all been done in accordance with the requirements of 10 CFR 50.46. If plant specific sensitivities are performed, those effects are reported by the affected plants.

The major differences in PCT between the Reference 1 analysis results and the EPU analysis results are not evaluation model corrections/changes but rather application of the evaluation model which is discussed in the response to RAI E.19.

References:

1. L-04-144, "Beaver Valley Power Station, Units No. 1 and No. 2, BV-1 Docket No. 50-334, License No. DPR-66, BV-2 Docket No. 50-412, License No. NPF-73, 10 CFR 50.46 Report of Changes or Errors in ECCS Evaluation Models," L. W. Pearce (FENOC) to USNRC, 11/19/04.
2. WCAP-10054-P-A Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," C. M. Thompson, et. al., July 1997.

E.22 (Applicable to RSG & EPU)

Please identify the location of the RCS pressure in the submittal plots.

Response:

The RCS pressure in the submittal plots for LOCA analyses presented in the EPU Licensing Report is defined at the top of the pressurizer.

E.23 (Applicable to RSG & EPU)

Please identify the hot rod pressure and fuel centerline/fuel average temperatures versus kw/ft for the limiting breaks presented in the submittal.

Response:

Figures E.23-1 and E.23-2 provide the requested information. The fuel centerline temperature is [ ]^{a,c}

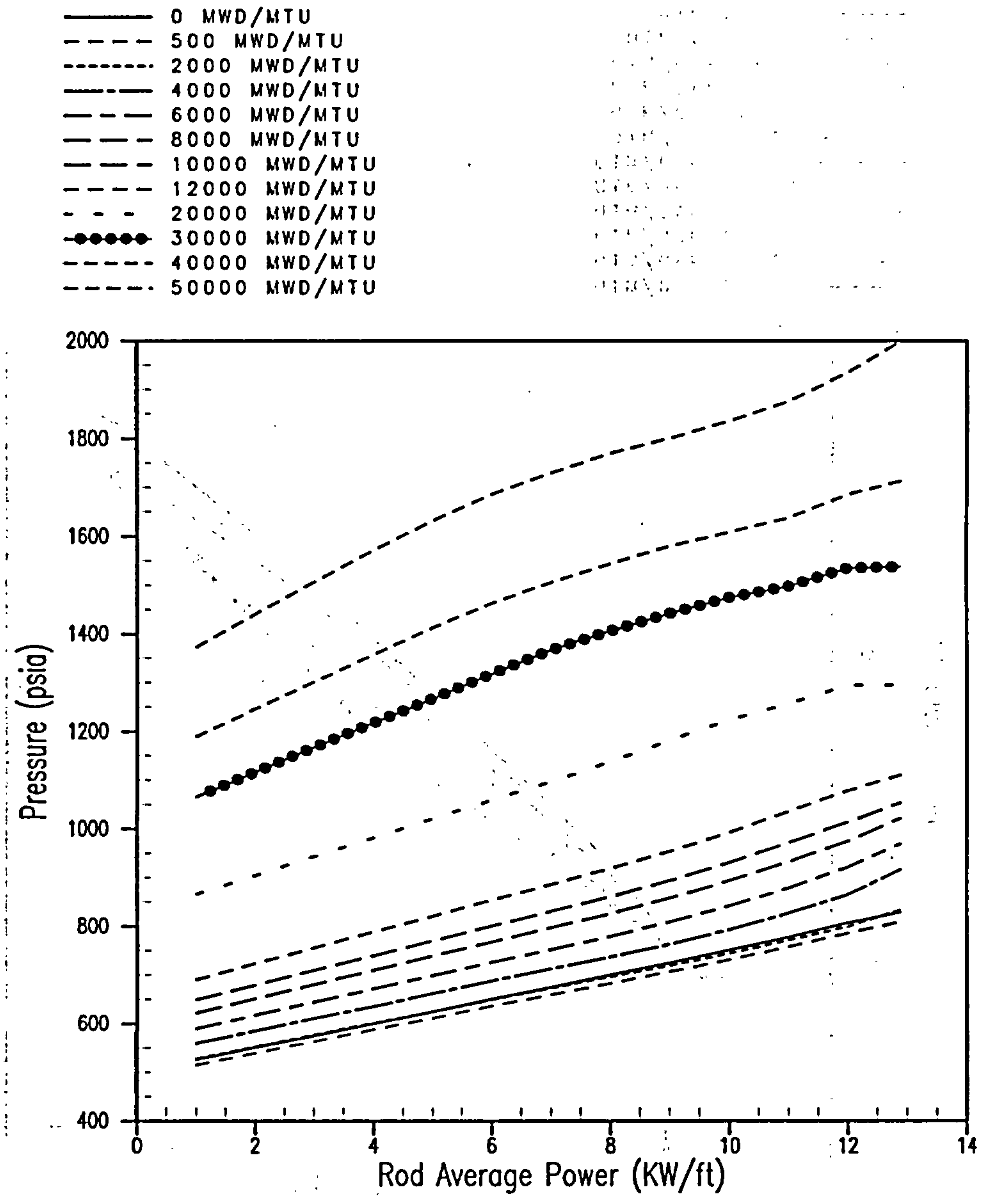

Figure E.23-1
BVPS-1 and 2 Hot Rod Pressure

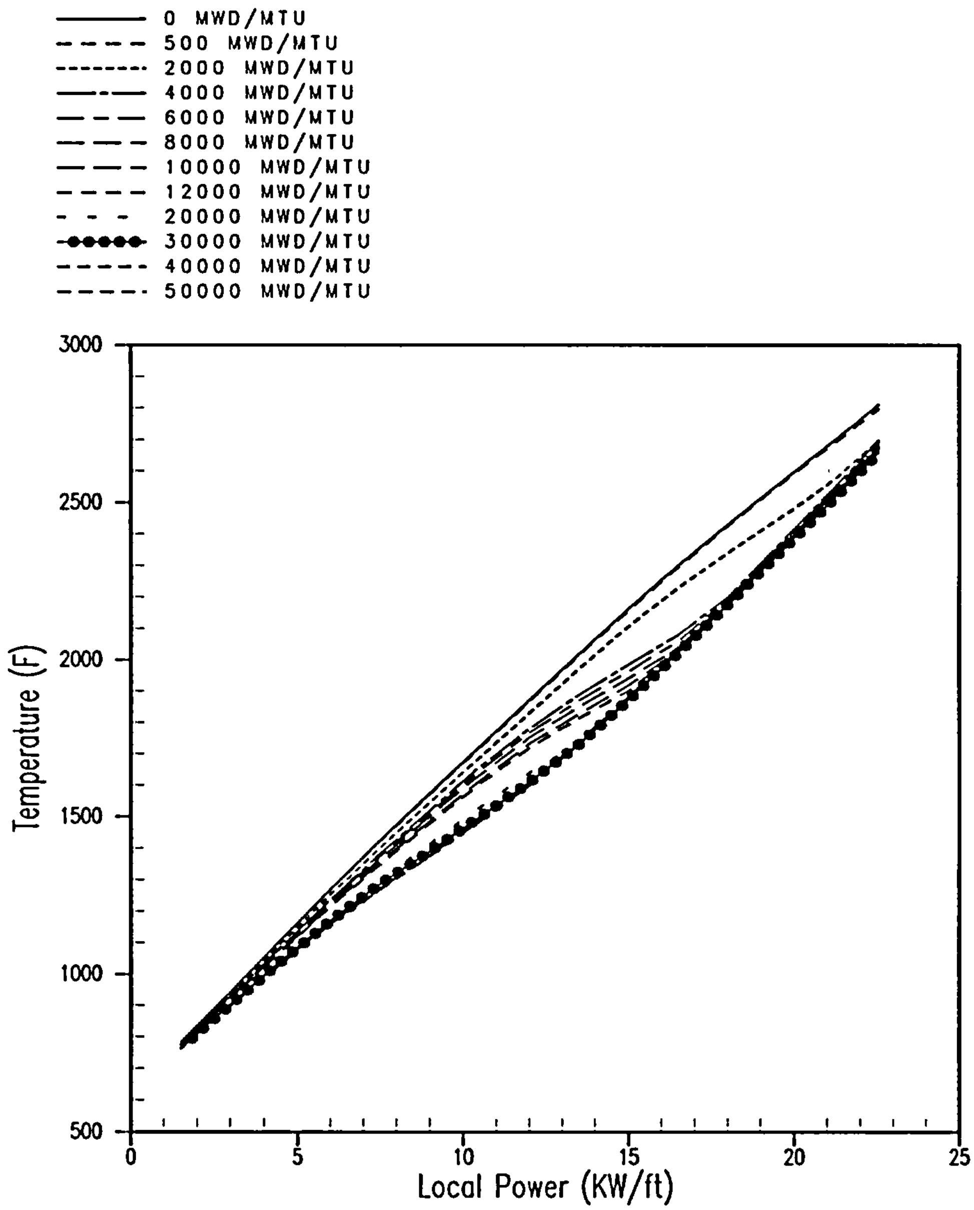

Figure E.23-2
BVPS-1 and 2 Fuel Average Temperature

E.24 (Applicable to RSG & EPU)

The build-up of boric acid in the core following the 2- and 3-inch breaks can increase appreciably and affect the liquid density in the core region (these breaks display core uncovery beyond 600 seconds). Please estimate the impact of the increased boric acid content on the mixture level, PCT, and oxidation for the limiting small breaks for BVPS-1 and 2.

Response:

As mixture level is directly related to void fraction, the bubble rise/flow regime are important. Increased boric acid content could affect bubble rise/flow regime via fluid density and surface tension.

With respect to fluid density, a bounding boric acid solution concentration causes a difference on the order of 10 percent (based upon 30 wt% vs. 0 wt% boric acid concentration). This would tend to increase relative buoyancy of the gas phase relative to liquid phase and hence increase bubble rise velocity and therefore reduce mixture level in the core region. However, the boric acid concentration calculated to occur at 4000 seconds corresponds to approximately a 10 wt% boric acid solution.

Published values of surface tension for boric acid solutions are difficult to obtain, [

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used in the Appendix-K method applied to BVPS-1 and 2 small break LOCA ECCS performance calculations.

E.25 (Applicable to RSG & EPU)

What are the accumulator and refueling water storage tank (RWST) maximum temperatures used in the analyses?

Response:

The maximum accumulator water temperature is 105°F, and the maximum RWST water temperature is 65°F.

E.26 (Applicable to RSG & EPU)

To show that the referenced generically approved LOCA analysis methodologies continue to apply specifically to the BVPS-1 and 2 plants, provide a statement that the licensee and its vendor have ongoing processes which assure that the ranges and values of the input parameters for the BVPS-1 and 2 LOCA analysis bound the ranges and values of the as-operated plant parameters. Furthermore, if the BVPS-1 and 2 plant-specific analyses are based on the model and or analyses of any other plant, then justify that the model(s) or analyses apply to BVPS-1 and –2 (e.g., if the other plant design has a different reactor vessel internals design, the model(s) wouldn't apply to BVPS-1 and 2).

Response:

Both FENOC and its LOCA analysis vendor (Westinghouse) have ongoing processes that [

][a,c] Furthermore, Beaver Valley plant-specific LOCA analyses are based on Beaver Valley specific models.

E.27 (Applicable to RSG & EPU)

The LOCA submittals did not address slot breaks at the top and side of the pipe. Please justify why these breaks are not considered for the BVPS-1 and 2 large-break LOCA (LBLOCA) submittals.

Response:

Break location was generically addressed during the development of the Best Estimate Large Break LOCA (BELBLOCA) methodology. Break type and size are specifically considered for the BVPS-1 and 2 LBLOCA transient simulations. These analyses concluded that the split break is limiting for BVPS-1 and the DECLG break is limiting for BVPS-2 in the short term. The uncertainties related to break type and size were included in the model uncertainties for the BVPS-1 and 2 BELBLOCA PCT.

For Small Break LOCA (SBLOCA) events, the effects of break location have been generically evaluated as part of the application of the NOTRUMP Evaluation Model (Reference 1). This document concluded that a break in the Reactor Coolant System (RCS) cold leg was limiting. Additionally, the effects of break orientation, which covers slot breaks, were considered during the evaluation of Safety Injection in the Broken Loop and application of the COSI Condensation Model (Reference 2). This work concluded that a break oriented at the bottom of the RCS cold leg piping was limiting with respect to Peak Cladding Temperature (PCT) in the short term.

While these references specifically address the short-term response to the LOCA break spectrum, the long-term effects associated with potential Reactor Coolant Pump (RCP) loop seal re-plugging core uncovery is addressed in the following.

A review of the analysis conditions associated with potential core uncovery due to loop seal re-plugging has previously been performed in Reference 3. Reference 3 documents the Westinghouse position with regards to the potential for Inadequate Core Cooling (ICC) scenarios following Large and Intermediate Break LOCAs as a result of loop seal re-plugging. Reference 3 concludes the following:

- The reactor coolant system response following a LOCA is a dynamic process and the expected response in the long term is similar to the response that occurs in the short term. This short term response has been analyzed extensively through computer analysis and tests and is well documented.
- Consideration of the physical mechanisms for liquid plugging of the pump suction leg U-bend piping following large and intermediate break LOCA at realistic decay heat levels precludes quasi steady-state inadequate core cooling conditions.
- It is important to emphasize that the operator guidance provided in the Emergency Response Guidelines includes actions to be taken in the event of an indication of a challenge to adequate core cooling following a LOCA.

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A review of the generic work performed in References 3 and 4, which includes discussions regarding the effectiveness of the prescribed post-LOCA recovery guidance provided in the Emergency Response Guidelines (ERGs), was performed for the BVPS-1 and 2 Extended Power Uprate (EPU) applications. As a result of this review, it can be concluded that post-LOCA core uncovery scenarios resulting from loop seal re-plugging do not constitute a significant concern to BVPS-1 and 2 plant safety.

References:

1. WCAP-11145-P-A, "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study With the NOTRUMP Code," S. D. Rupprecht, et al., 1986.
2. WCAP-10054-P-A Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," C. M. Thompson, et al., July 1997.
3. OG-87-37, "Westinghouse Owners Group (WOG) Post LOCA Long Term Cooling, Letter from Roger Newton (WOG) to Thomas Murley (NRC)," August 26, 1987.
4. NSD-NRC-97-5092, "Core Uncovery Due to Loop Seal Re-Plugging During Post-LOCA Recovery," Letter from N. J. Liparulo (W) to NRC, March, 1997.

E.28 (Applicable to RSG & EPU)

For BVPS-1 and 2, provide the LBLOCA analysis results tables and graphs to at least 1600 seconds to show that stable and sustained quench is established.

Response:

The following information shows that stable and sustained quench is established for the BVPS-1 and 2 Large Break LOCA analysis.

BVPS-1

In order to demonstrate stable and sustained quench, the WCOBRA/TRAC calculation for the maximum local oxidation analysis is extended to 1500 seconds. By the end of the transient, core quench has been established for several hundred seconds and extending the transient to 1600 seconds is therefore unnecessary.

Figure E.28-1 provides the peak cladding temperatures for the five (5) rods modeled in WCOBRA/TRAC. It is observed that quench occurs at approximately 500 seconds for the low power rod (rod 5), 620 and 650 seconds for the core average rods (rods 3 and 4), and later for the hot rod (rod 1) and hot assembly average rod (rod 2). Once quench is predicted to occur, the rod temperatures remain slightly above the fluid saturation temperature for the remainder of the simulation. It is noted that the maximum PCT is about 2350°F, which is above the 10 CFR 50.46 criterion of 2200°F. This is due to the bounding nature of the oxidation analysis in the approved methodology (WCAP-12945-P-A).

Figure E.28-2 provides a plot of the collapsed liquid level in the three (3) downcomer channels. A steady behavior is observed with the level in each channel continuing to increase toward the bottom of the cold leg at the end of the simulation.

Figure E.28-3 shows the collapsed liquid level in the four (4) core channels and indicates a gradual increase in the core liquid inventory over the last several hundred seconds of the simulation. This is consistent with the expected result based on the removal of the initial core stored energy and the gradual reduction in decay heat.

Finally, Figure E.28-4 presents the vessel liquid mass and indicates a stable and increasing trend beginning at about 700 seconds. This indicates that the increase in inventory due to the pumped safety injection is more than offsetting the loss of inventory through the break.

Based on these results, it is concluded that stable and sustained quench has been established for the BVPS-1 Large Break LOCA analysis.

BVPS-2

In order to demonstrate stable and sustained quench, the WCOBRA/TRAC calculation for the maximum local oxidation analysis is extended to 1500 seconds. By the end of the transient, core quench has been established for several hundred seconds and extending the transient to 1600 seconds is therefore unnecessary.

Figure E.28-5 provides the peak cladding temperatures for the five (5) rods modeled in WCOBRA/TRAC. It is observed that quench occurs at approximately 300 seconds for the low power rod (rod 5), 450 seconds for the core average rods (rods 3 and 4), and before 600 seconds for the hot rod (rod 1) and hot assembly average rod (rod 2). Once quench is predicted to occur, the rod temperatures remain slightly above the fluid saturation temperature for the remainder of the simulation.

Figure E.28-6 provides a plot of the collapsed liquid level in the three (3) downcomer channels. A steady behavior is observed with the level in each channel increasing toward the bottom of the cold leg for hundreds of seconds before the end of the simulation.

Figure E.28-7 shows the collapsed liquid level in the four (4) core channels and indicates a gradual increase in the core liquid inventory over the last several hundred seconds of the simulation. This is consistent with the expected result based on the removal of the initial core stored energy and the gradual reduction in decay heat.

Finally, Figure E.28-8 presents a stable and increasing trend of the vessel liquid mass, which indicates an increase in inventory due to the pumped safety injection. This is more than offsetting the loss of inventory through the break.

Based on these results, it is concluded that stable and sustained quench has been established for the BVPS-2 Large Break LOCA analysis.

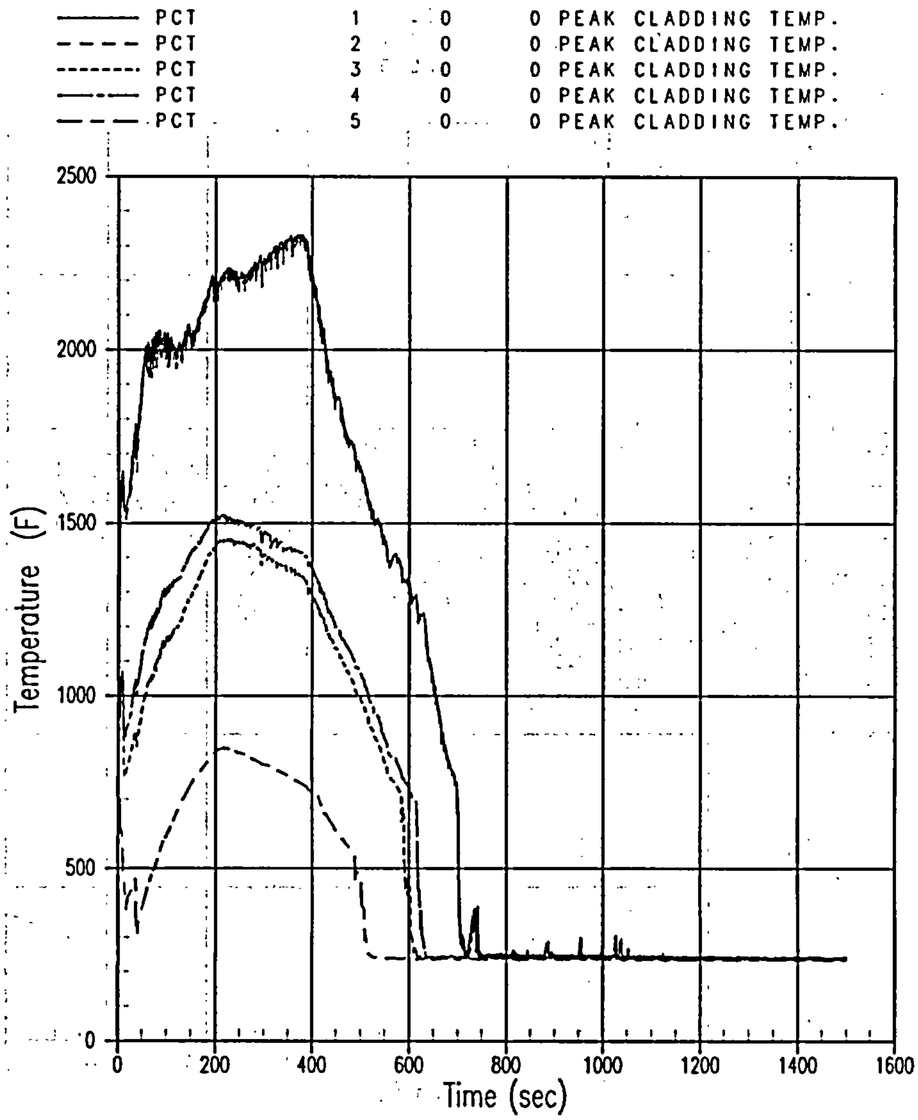


Figure E.28-1
BVPS-1 Peak Cladding Temperatures

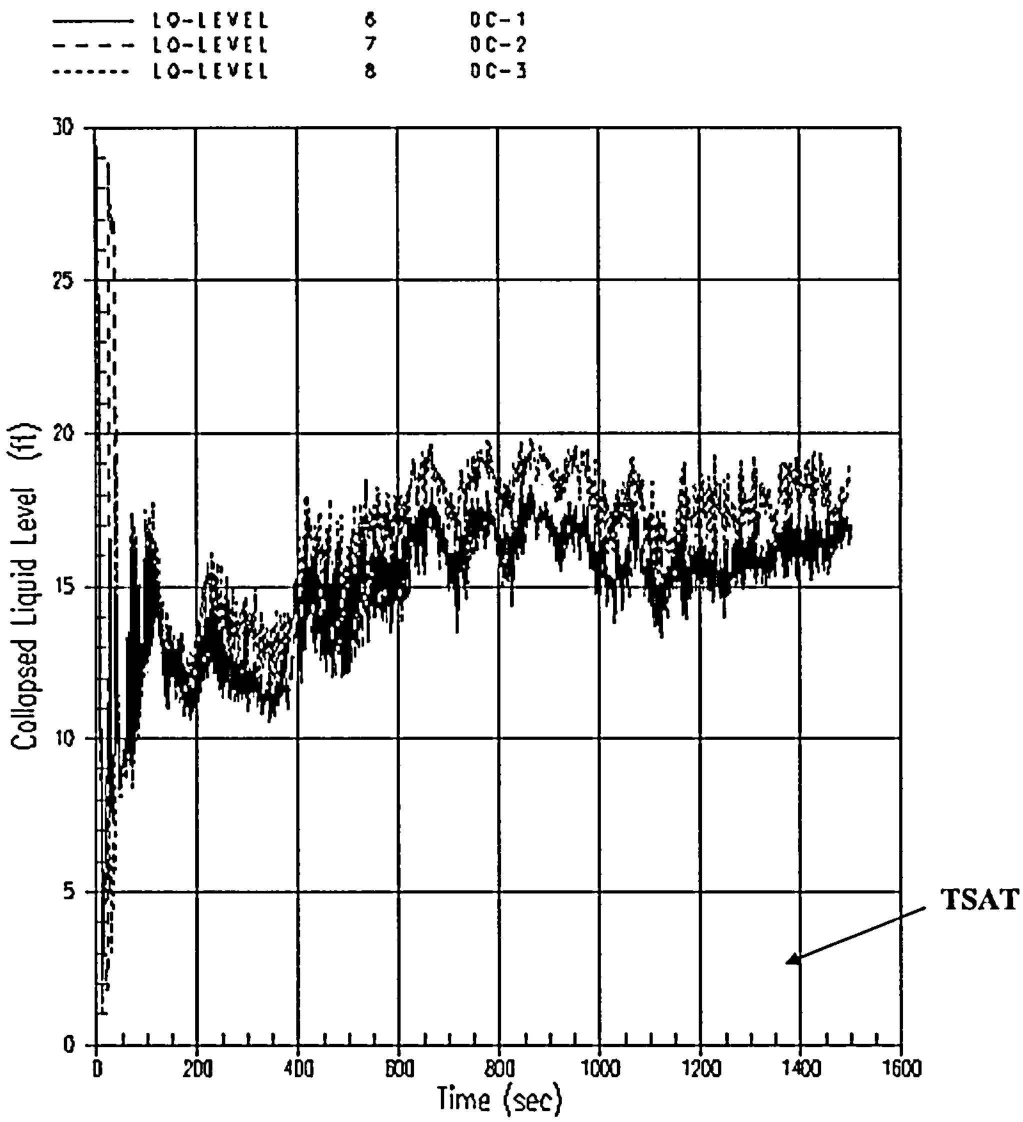


Figure E.28-2
BVPS-1 Downcomer Collapsed Liquid Levels

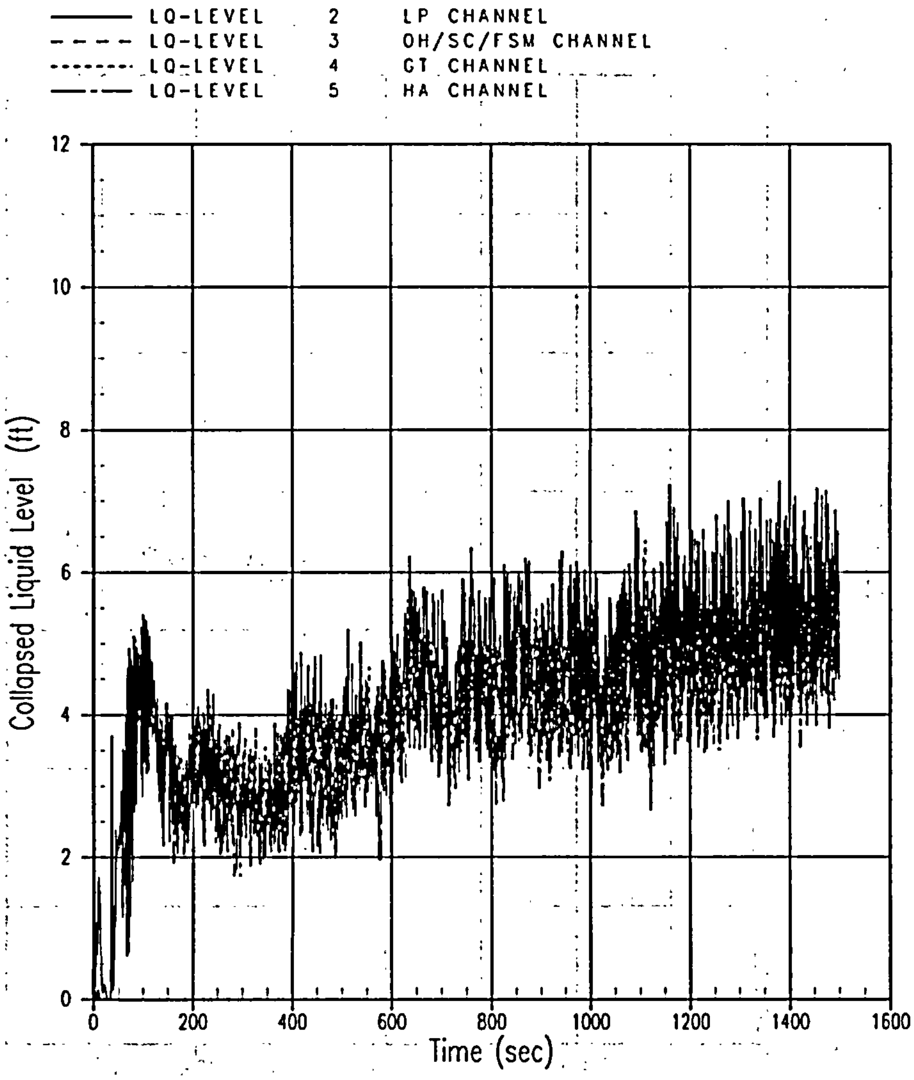


Figure E.28-3
BVPS-1 Core Collapsed Liquid Levels

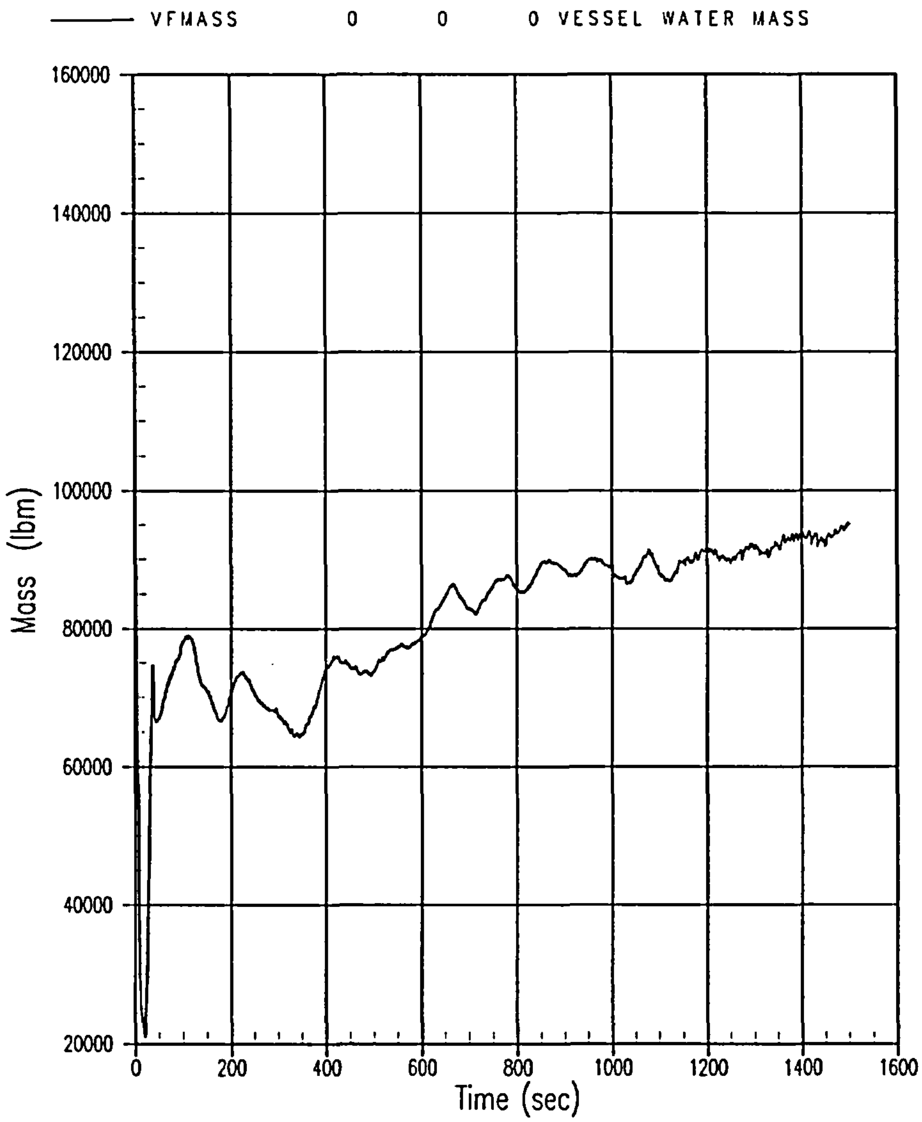


Figure E.28-4
BVPS-1 Vessel Liquid Mass

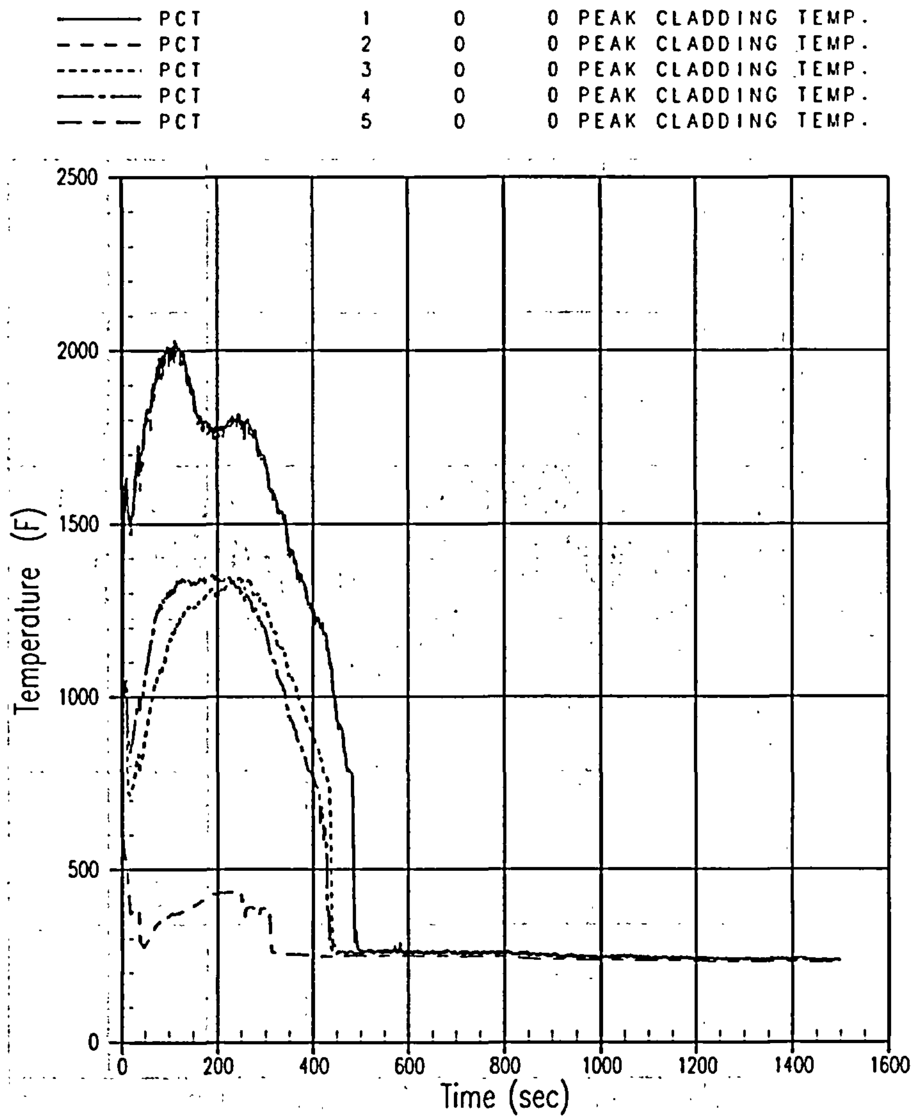


Figure E.28-5
BVPS-2 Peak Cladding Temperatures

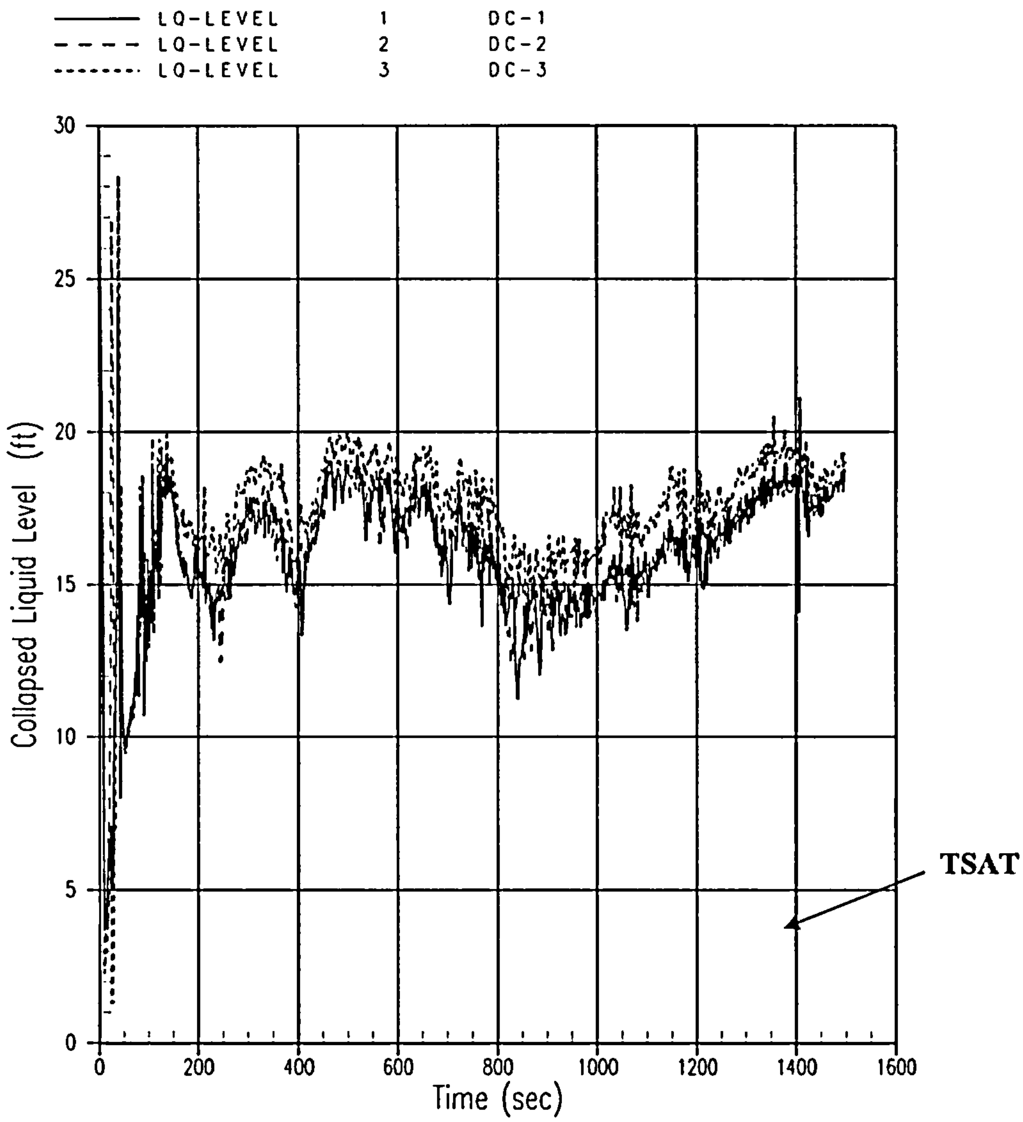


Figure E.28-6
BVPS-2 Downcomer Collapsed Liquid Levels

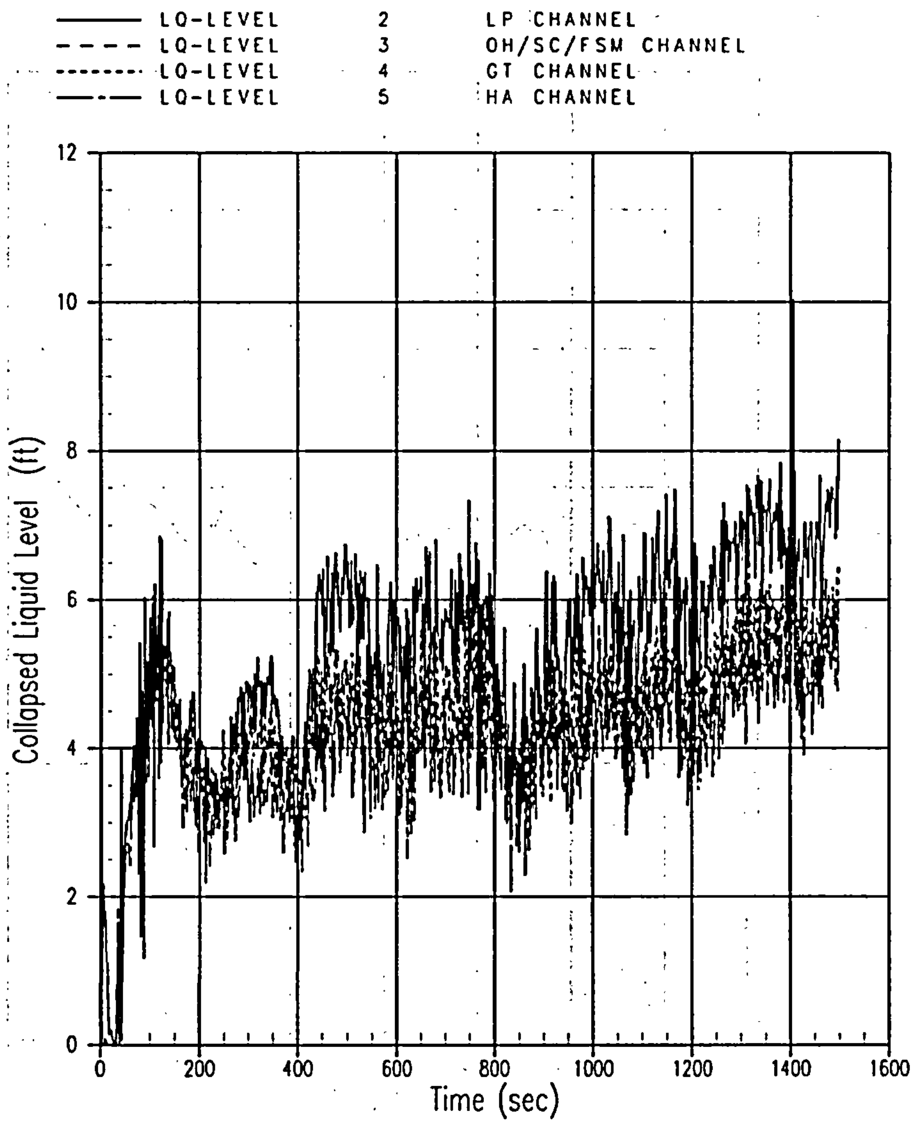


Figure E.28-7
BVPS-2 Core Collapsed Liquid Levels

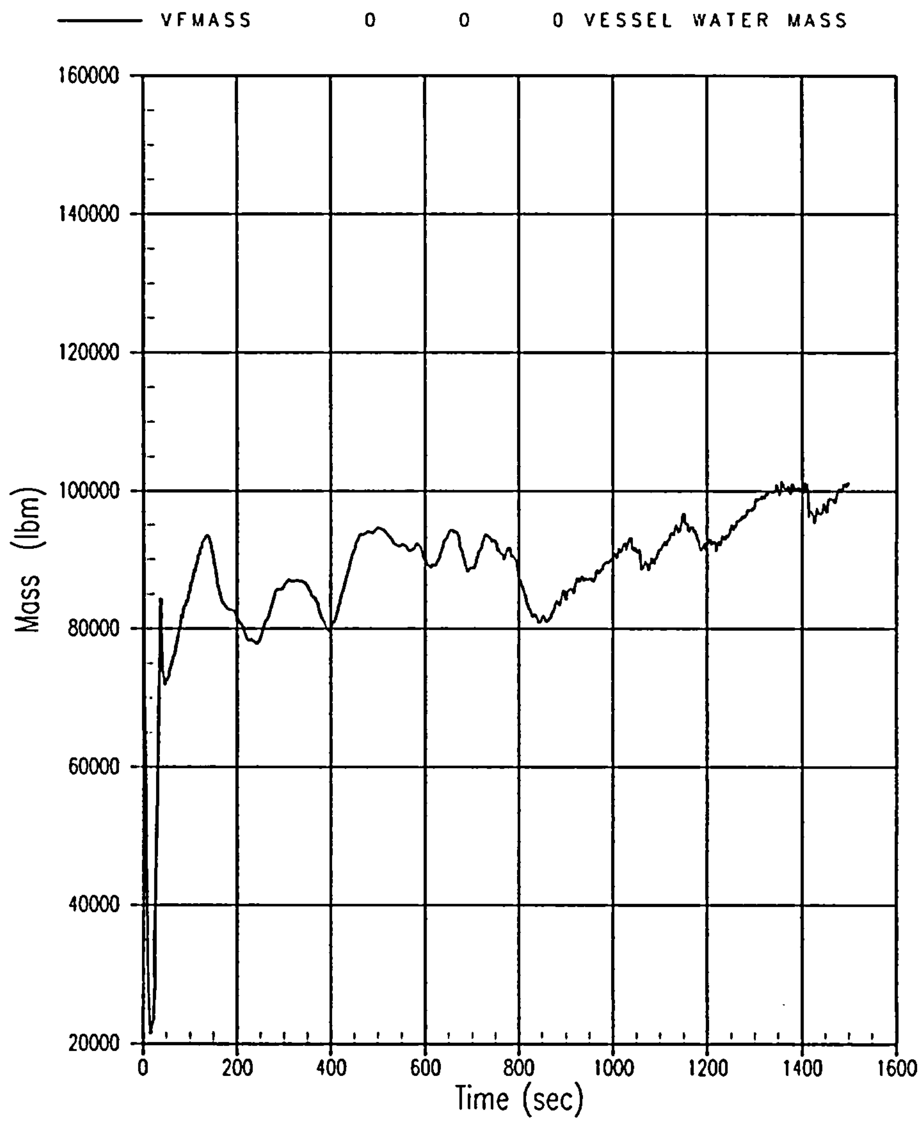


Figure E.28-8
BVPS-2 Vessel Liquid Mass

E.29 (Applicable to RSG & EPU)

It is not clear from LBLOCA and SBLOCA Figures what specific upper core plate is used for BVPS-1 and 2. Please identify the specific upper core plate design used in BVPS-1 and 2.

Response:

The Upper Core Plate region geometry (UCP) is similar for both units. In each unit, the UCP has a volume of approximately 10 ft^3 and a flow area of approximately 160 ft^2. Furthermore, both units have the same fuel design (17 x 17 RFA), and the same barrel/baffle region design applies in this region, reinforcing that the UCP region geometries are analogous.

E.30 (Applicable to RSG & EPU)

Tables provide LBLOCA and SBLOCA analyses results for the BVPS-1 and 2 EPU. Please provide all results (PCT, maximum local oxidation, and total hydrogen generation), for both LBLOCA and SBLOCA. For maximum local oxidation, include consideration of both pre-existing and post-LOCA oxidation, and cladding outside oxidation and post-rupture inside oxidation. Also include the results for fuel resident from previous cycles.

Response:

The results (peak cladding temperature (PCT), maximum local oxidation and total hydrogen generation) for the BVPS LBLOCA and SBLOCA EPU analyses are provided in Table E.30-1 for BVPS-1 and Table E.30-2 for BVPS-2. Additional information regarding the basis for the maximum local oxidation, including consideration of both pre-existing and post-LOCA oxidation, cladding outside and post-rupture inside oxidation is discussed below.

Table E.30-1
BVPS-1 EPU LOCA Analysis Results

	LBLOCA	**SBLOCA**
Peak Cladding Temperature	2144°F	1739°F
Maximum Local Transient Oxidation	8.77%	6.35%
Total Hydrogen Generation	<1%	<1%

Table E.30-2
BVPS-2 EPU LOCA Analysis Results

	LBLOCA	**SBLOCA**
Peak Cladding Temperature	1976°F	1759°F
Maximum Local Transient Oxidation	6.70%	7.90%
Total Hydrogen Generation	<1%	<1%

The pre-transient oxidation increases with burnup, from zero at beginning of life (BOL) to a maximum value at the discharge of the fuel (end of life, or EOL). The design limit 95% upper bound value for each of the fuel designs that will be included in the EPU cores is < 17%. The actual upper bound pre-transient values are expected to be well below this value.

LBLOCA

The maximum local transient oxidation for the BVPS EPU large break LOCA analyses is 8.77% for BVPS-1 and 6.70% for BVPS-2. Consistent with the NRC-approved methodology, these values were calculated using a LOCA transient whose nominal PCT exceeds the 95th percentile value for both the first and second reflood peaks. The limiting oxidation occurs at the second reflood PCT elevation and bounds the oxidation at the burst elevation which includes both outside and post-rupture inside oxidation.

The maximum local oxidation was calculated for fresh fuel at the beginning of the cycle. This represents the maximum amount of transient oxidation that could occur at any time in life. As burnup increases, the transient oxidation decreases for the following reasons:

1. The cladding creeps down towards the fuel pellets, due to the system pressure exceeding the rod internal pressure. This will reduce the initial stored energy at the hot spot by several hundred degrees relatively early in the first cycle of operation, and will tend to reduce the transient oxidation.

2. Later in life, the clad creep-down benefit still remains effective. In addition, with increasing irradiation, the power production from the fuel will naturally decrease as a result of depletion of the fissionable isotopes. Reductions in achievable peaking factors in the burned fuel relative to the fresh fuel are realized before the middle of the second cycle of operation. The achievable linear heat rates decrease steadily from this point until the fuel is discharged, at which point the transient oxidation will be negligible.

Based on the above discussion, the transient oxidation decreases from a maximum at BOL of 8.77% for BVPS-1 and 6.70% for BVPS-2 to a negligible value at EOL. Additional WCOBRA/TRAC and HOTSPOT calculations were performed at intermediate burnups, accounting for burnup effects on fuel performance data (primarily initial stored energy and rod internal pressure) and reductions in the assembly power. Further calculations credit predicted upper bound pre-transient oxidation values. The calculations support the conclusion that the sum of the transient and pre-transient oxidation remains below 17% at all times in life, for all fuel resident in the core. This confirms BVPS-1 and 2 conformance with the 10 CFR 50.46 acceptance criterion for local oxidation.

SBLOCA
The maximum local transient oxidation for the BVPS EPU small break LOCA analyses is 6.35% for BVPS-1 and 7.90% for BVPS-2. The limiting oxidation occurs at the burst elevation and includes both outside and post-rupture inside oxidation.

Additional SBLOCTA calculations were performed at intermediate burnups, accounting for burnup effects on fuel performance data (primarily initial stored energy and rod internal pressure) and reductions in the assembly power. Further calculations credit the predicted upper bound pre-transient oxidation values. The calculations support the conclusion that the sum of the transient and pre-transient oxidation remains below 17% at all times in life, for all fuel resident in the core. This confirms BVPS-1 and 2 conformance with the 10 CFR 50.46 acceptance criterion for local oxidation.

Section 5.2.3

F.1 (Applicable to EPU)

Section 5.2.3, "Hot Leg Switch Over," identifies the mixing volume as the core and upper plenum volume below the bottom elevation of the hot leg. Using the 1971 ANS decay heat standard with a multiplier of 1.2, an average void fraction in the mixing volume of about 65% (corresponding to about 3 hours into the event), and an RWST concentration of 2600 parts per million (ppm) boron, the NRC staff's preliminary calculations show that the precipitation time could be less than 2 hours (this is compared to the 6 hours switch over time identified as conservative for the EPU. The assumption of a collapsed liquid level to the bottom elevation of the hot leg (at all times) is not considered a valid assumption since the loop pressure loss (with the containment at 14.7 psia) will depress the two-phase region and, hence, quench front, well within the core just after and during late reflood. Certainly, for at least 1 to 2 hours after reflood, the mixture level may then only expand into the upper plenum after the decay heat steaming rate has deceased sufficiently. The mixing volume is not fixed at all times, which was identified in Section 5.2.3 of Reference 1, dated April 1975, as the modeling approach. With a 14.7 psia containment pressure, the boric acid buildup during the first hour following reflood of the core is expected to be quite rapid and could produce concentrations in excess of 30 wt% (weight percent) before the mixture expands into the upper plenum.

In view of these considerations, please review and justify all of the assumptions in the model calculations and re-compute the precipitation time (boron concentration versus time) given there is a steam void in the mixing volume. What is the boric acid concentration versus time when the mixing volume is calculated based on the loop resistance which governs the fluid balance between the downcomer and inner region of the vessel containing the core? The higher boric acid content in the core (liquid density) also needs to be taken into account when computing the time varying mixing volume. The SGs will add heat to the primary steam; this should also be taken into account in computing the loop resistance. It is recommended that only the liquid content in the mixing volume be used to calculate the boric acid concentration and that the void fraction be calculated as a function of time.

Response:

The major assumptions/justifications in the EPU Hot Leg Switchover (HLSO) analysis as originally submitted in the EPU LAR are given in Table F.1-1. An EPU HLSO re-analysis has been performed to address the NRC concerns described in this RAI. The re-analysis incorporated the following;

- 1.2 Multiplier on 1971 ANS Infinite Operation Decay Heat.
- Recalculated mixing volume to account for core and upper plenum voiding as a function of time.
- Liquid mixing volume that includes up to 50% of the lower plenum volume.
- Estimation of the effect of NaOH on the boric acid solubility limit. Note that margin from the presence of NaOH is not needed to demonstrate that boric acid precipitation will not occur.

Details of the re-analysis are provided in discussion that follows Table F.1-1.

Table F.1-1
BVPS-1 and 2 EPU HLSO Analysis Methodology Assumptions

Assumption	Conservative/ Non-conservative/ Other	Effect	Justification

a,c

Table F.1-1 (cont.) BVPS-1 and 2 EPU HLSO Analysis Methodology Assumptions			
Assumption	Conservative/ Non-conservative/ Other	Effect	Justification

a,c

Notes
1. The re-analysis used 1971 ANS, Infinite Operation with 20% Margin decay heat (i.e., 10 CFR 50.46 Appendix K)
2. The re-analysis included 50% of the lower plenum volume as part of the mixing volume.
3. The re-analysis cited the added margin due to the presence of NaOH.
4. The re-analysis included core voiding calculated using [ ]a,c, Appendix K decay heat.

Re-analysis Results

A comparison between units of the as-submitted HLSO analysis boric acid concentration transient is presented in Figures F.1-4 and F.1-8 for BVPS-1 and 2, respectively. The results indicate that while core and upper plenum voiding reduced the core region liquid volume especially early in the transient, credit for mixing in a portion of the lower plenum largely offsets the reduction. The change in decay heat (from 1971 ANS + 0% to 1971 ANS Infinite + 20%) have a direct effect on the calculated boric acid concentration rate of increase. The re-analysis shows that 6.5 hours and 6.0 hours are appropriate times for realigning to hot leg recirculation for BVPS-1 and 2, respectively. If all SI flow is aligned to the hot legs for BVPS-2 with no MOV failure, then realignment back to the cold legs will prevent boric acid precipitation for hot leg (HL) breaks (where the boric acid concentration begins to increase when all SI flow is realigned to the hot legs). If hot leg realignment occurs at 6.0 hours for BVPS-2, then an appropriate cycle-back time is 8 hours.

Mixture Level Assumptions

For the re-analysis, the core region liquid volume was adjusted for core and upper plenum voiding versus time as described below. The objective of the voiding calculations was to determine a conservative time-based liquid mixing volume for the boric acid calculations. Once a liquid mixing volume was calculated, its validity was confirmed by comparing it to the core and upper plenum liquid volume data from the large break LOCA transients used in the response to RAI E.28. Note that this approach does not rely on specific mixture level assumptions. For boric acid concentration calculations, liquid volume is more relevant than mixture level. [

][a,c]

Core Voiding Assumptions

The re-analysis calculated core region and upper plenum voiding as a function of time starting at 1000 seconds. Boric acid precipitation prior to this time is not a concern since, even with small core region liquid volumes, the boric acid precipitation limit could not be realistically reached in so short a duration. Core voiding was calculated using [

][a,c]

Comparison of Core and Upper Plenum Liquid Volume to Large Break LOCA Analysis

In order to assess the conservatism in the re-analysis core voiding calculations, a large break LOCA evaluation model break case was studied. Average core voiding information was extracted from the unit-specific large break WCOBRA/TRAC runs LOCA transient used in the response to RAI E.28. The average core voiding for these runs was then compared to the average core voiding used in the re-analysis. The comparison is shown in Figures F.1-1 and F.1-5.

As mentioned previously, the core and upper plenum voiding were calculated to conservatively estimate the liquid volume available for boric acid dilution. In order to assess the validity of the core and upper plenum liquid volume used in the re-analysis, the large break LOCA transients used in the response to RAI E.28 were inspected. A comparison was made between the core and upper plenum average voiding used in the re-analysis mixing volume to the core and upper plenum average voiding extracted from the WCOBRA/TRAC runs. The comparisons are shown on Figures F.1-2 and F.1-6 for BVPS-1 and 2, respectively. Figures F.1-2 and F.1-6 indicate that the core and upper plenum volume used in the reanalysis is conservative with respect to the actual core and liquid volume calculated in the large break LOCA WCOBRA/TRAC runs.

To summarize, the re-analysis calculated a time-based liquid mixing volume based on atmospheric conditions with consideration for core and upper plenum region voiding. The calculated liquid mixing volumes used in the re-analysis (Figures F.1-3 and F.1-7) are shown to be conservative when compared to liquid volumes extracted from large break LOCA evaluation model break case transients. The use of the large break LOCA evaluation model break case transients ensures that assumed core and upper plenum region liquid volume assumptions conservatively reflect the effects of [

]^{a,c}

Lower Plenum Mixing

The re-analysis assumed that some mixing will occur in the lower plenum long before the boric acid solubility limit is reached. For the re-analysis, the lower plenum volume was defined as the non-displaced volume inside the core below the active fuel and the non-displaced volume in the reactor vessel bottom head up to the elevation of the bottom of the radial keys at the bottom of the downcomer.

The MHI BACCHUS tests summarized in Reference 2 indicated that mixing between the core region and lower plenum initiates when the boric acid concentration difference between these regions is about 8.5 wt%. The MHI BACCHUS test data is applicable to BVPS-1 and 2 since the MHI test facility was designed to simulate a 3-loop PWR similar to the BVPS-1 and 2 designs. Reference 2 supports the assumption that 50% of the lower plenum volume will mix with the core region prior to reaching the boric acid solubility limit.

Early in the transient, with no mixing in the lower plenum, the core region boric acid concentration increases rapidly and would reach [

]^{a,c} within 1000 seconds. Once mixing between the core region and the lower plenum begins, the core boric acid concentration rate of increase will level off as the liquid volume in the lower plenum now participates in mixing process. The re-analysis assumes that this process will continue until there is mixing in 50% of the lower plenum. At this point in the transient, the boric acid concentration will resume its steady increase. This process, that is a delay in the increase in boric acid concentration due to lower plenum mixing, is shown in Figures F.1-4 and F.1-8.

Boric Acid Solubility Limit

The atmospheric boiling point and solubility limit for boric acid in water is shown in Table F.1-2 and Figure F.1-9 (data from Reference 3). Although the re-analysis assumed a core boiling point of 212°F for the purpose of calculating core boil-off, the actual boiling point of a saturated boric acid and water solution at atmospheric conditions is 218°F. The boric acid solubility limit at 212°F is 29.27 wt%. Reference 5 studied the effect of NaOH on the boric acid solubility and concluded that, in the presence of the expected sump NaOH concentrations, the boric acid solubility limit increases to [ ]a,c This increased boric acid solubility is not credited but is mentioned as additional margin to the realistic point at which boric acid precipitation would occur.

The Effect of Boric Acid Concentration on Core Region Liquid Density

Since the density of a boric acid/water solution increases with percentage of boric acid, there would be a liquid density difference between the core and downcomer. This density difference would be small early in the transient and would increase as the boric acid concentration increases in the core. There may also be some small offsetting density differences due to core/downcomer temperature differences. The net effect of a higher core liquid density as compared to the downcomer would be a lower flooding rate later in the boric acid concentration transient, well after core quench has occurred. Density differences (due to temperature or boric acid concentration) would have a beneficial effect on mixing.

The effect of downcomer-core density differences on the core and upper plenum liquid volume can be estimated using the boric acid concentration versus specific gravity plot shown in Figure F.1-10 (data from Reference 4). A 10 wt% boric acid solution has a specific gravity approximately 3% greater than the 1 wt% boric acid solution that would be in the downcomer. Based on a 60% core void fraction and a 30 wt% boric acid solution in the core, the core region liquid volume would be approximately 5.4% lower than otherwise predicted if this density difference is not recognized. This difference in mixing volume is small in comparison to the mixing volume margin discussed earlier in this response.

The Effect of SG Heat Addition

The SG heat addition would have the effect of increasing core pressure, thus reducing core mixture level, reducing void fraction, and increasing the boric acid solubility limit. Note that this effect would decrease and eventually stop with time, particularly if realistic Emergency Operating Procedure (EOP) actions are assumed. For early in the transient, the effect of SG heat addition on core and upper plenum liquid volume is reflected in the WCOBRA/TRAC run cases that were used to show the re-analysis mixing volume to be conservative.

References:

1. [

]a,c

2. Westinghouse Letter LTR-LIS-05-56, Revision 0, "Waterford 3 Uprate RAIs, Transmittal of Summary of MHI BACCHUS Tests," dated 02-03-05.
3. P. Cohen, P., 1969, Water Coolant Technology of Power Reactors, Chapter 6, "Chemical Shim Control and pH Effect," ANS-USEC Monograph.
4. "Boric Acid Application Guidelines for Intergranular Corrosion Inhibition," EPRI, Palo Alto, CA: 1987, NP-5558, page 2-27.
5. Increase in Solubility Limit as a Result of Sodium Hydroxide (NaOH) in the Containment Sump Water, Fauske Report, FAI/05-67 dated June 2005.

Table F.1-2 Solubility Limits of H_3BO_3 in H_2O [Cohen (1969)]			
Temperature, °C (°F)	Solubility g H3BO3/100 g of Solution in H_2O	Temperature, °C (°F)	Solubility g H3BO3/100 g of Solution in H_2O
P = 1 Atmosphere		75 (167)	17.41
0 (32)	2.70	80 (176)	19.06
5 (41)	3.14	85 (185)	21.01
10 (50)	3.51	90 (194)	23.27
15 (59)	4.17	95 (203)	25.22
20 (68)	4.65	100 (212)	27.53
25 (77)	5.43	103.3 (217.9)	29.27
30 (86)	6.34	$P = P_{SAT}$	
35 (95)	7.19	107.8 (226.0)	31.47
40 (104)	8.17	117.1 (242.8)	36.69
45 (113)	9.32	126.7 (260.1)	42.34
50 (122)	10.32	136.3 (277.3)	48.80
55 (131)	11.54	143.3 (289.9)	54.80
60 (140)	12.97	151.5 (304.7)	62.22
65 (149)	14.42	159.4 (318.9)	70.70
70 (158)	15.75	171 (339.8) = Congruent Melting of H_3BO_3	

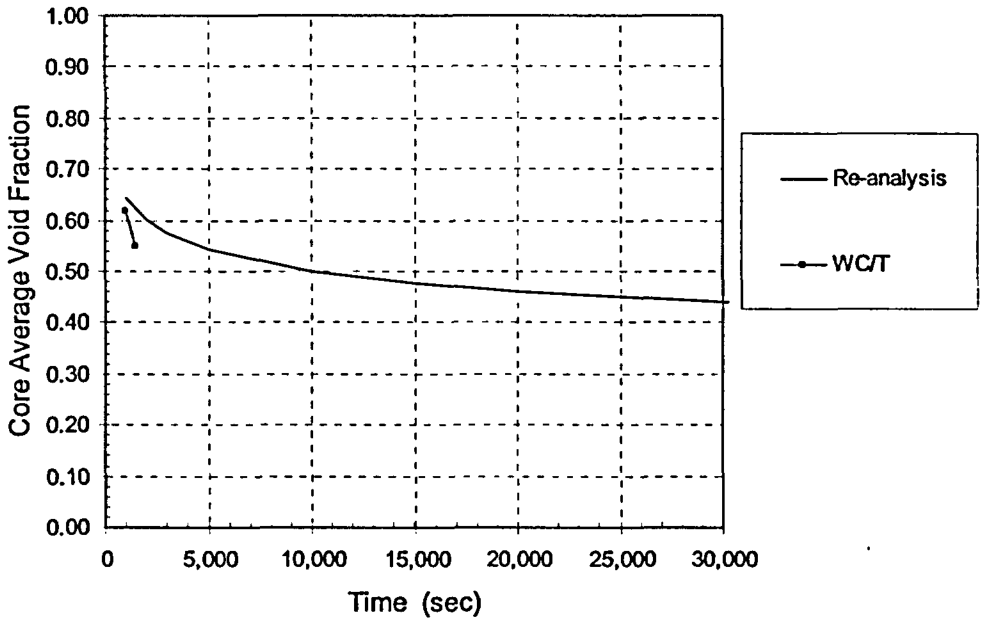


Figure F.1-1
BVPS-1 Core Average Voiding Comparisons

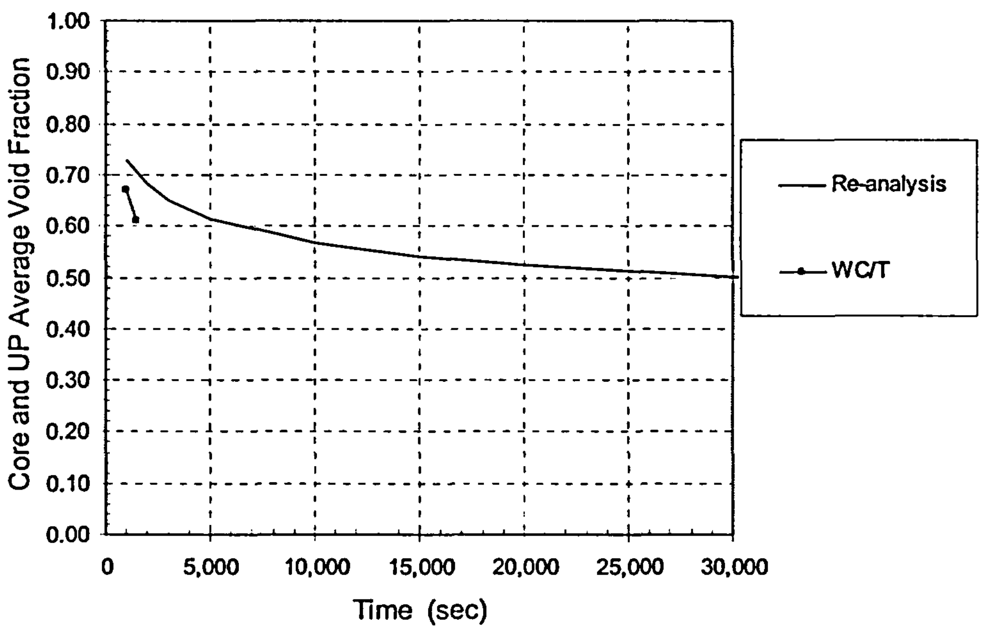


Figure F.1-2
BVPS-1 Core and Upper Plenum Average Voiding Comparisons

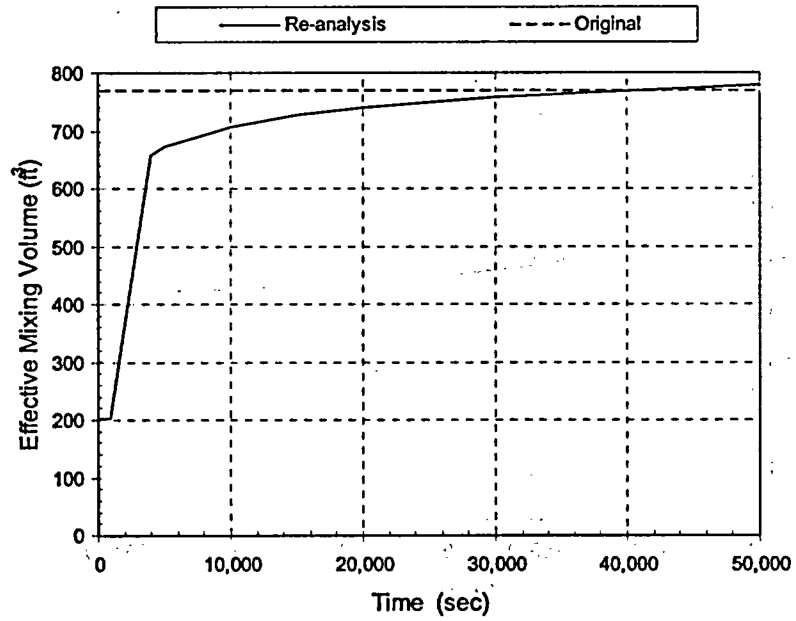


Figure F.1-3
BVPS-1 Mixing Volume vs. Time

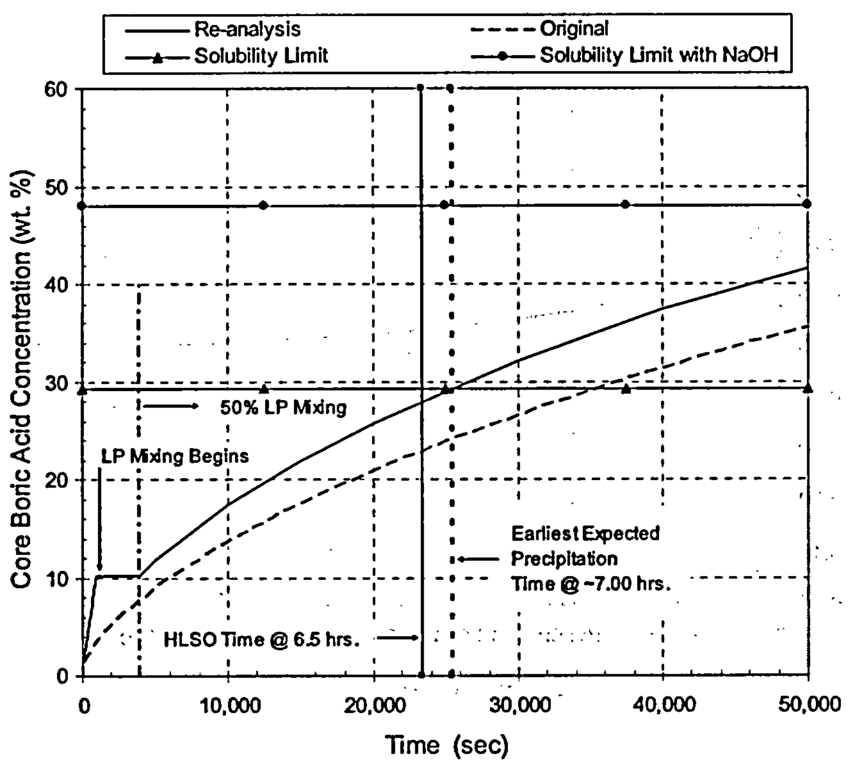


Figure F.1-4
BVPS-1 Boric Acid Concentration vs. Time

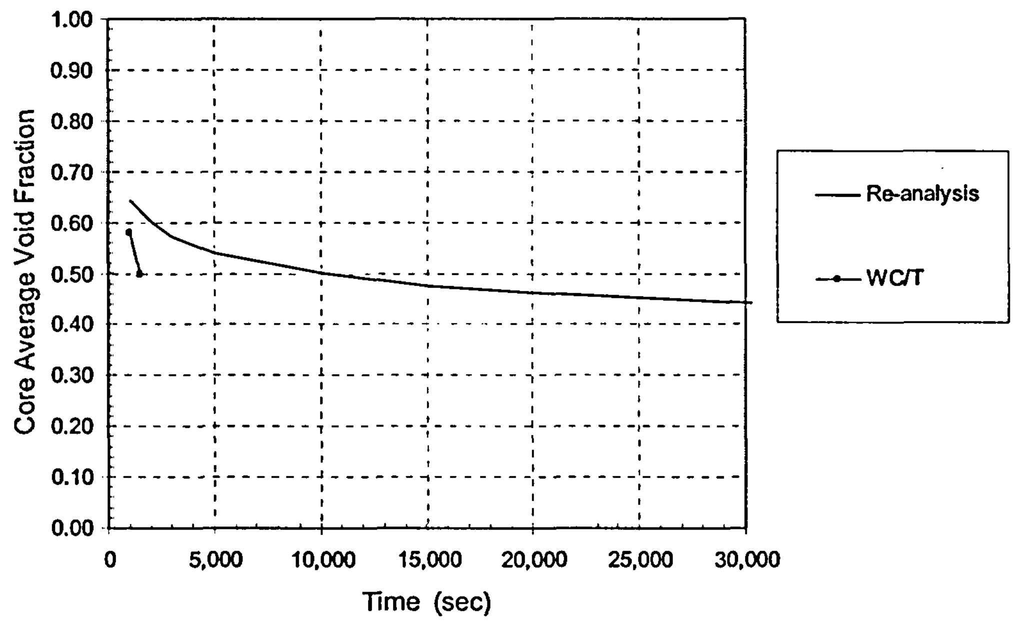


Figure F.1-5
BVPS-2 Core Average Voiding Comparisons

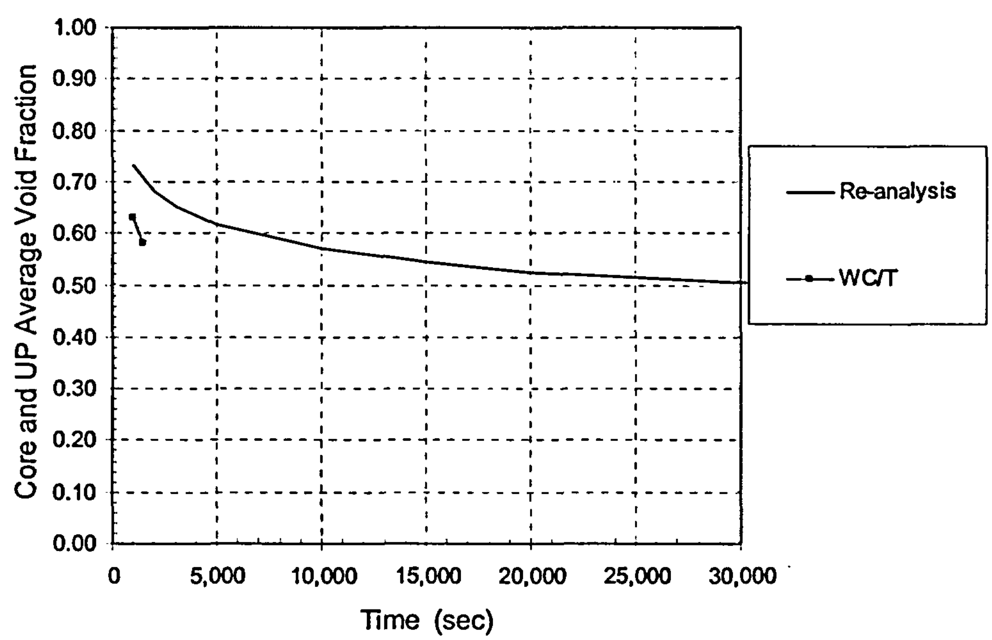


Figure F.1-6
BVPS-2 Core and Upper Plenum Average Voiding Comparisons

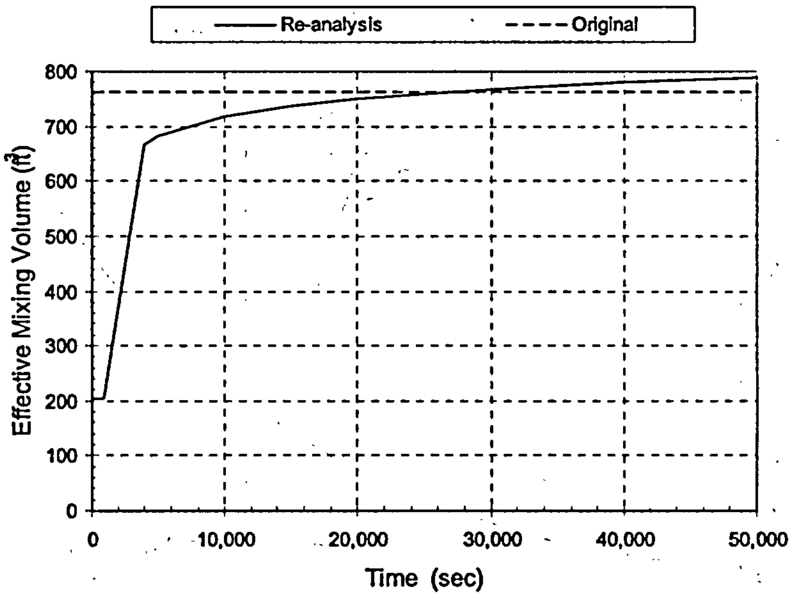


Figure F.1-7
BVPS-2 Mixing Volume vs. Time

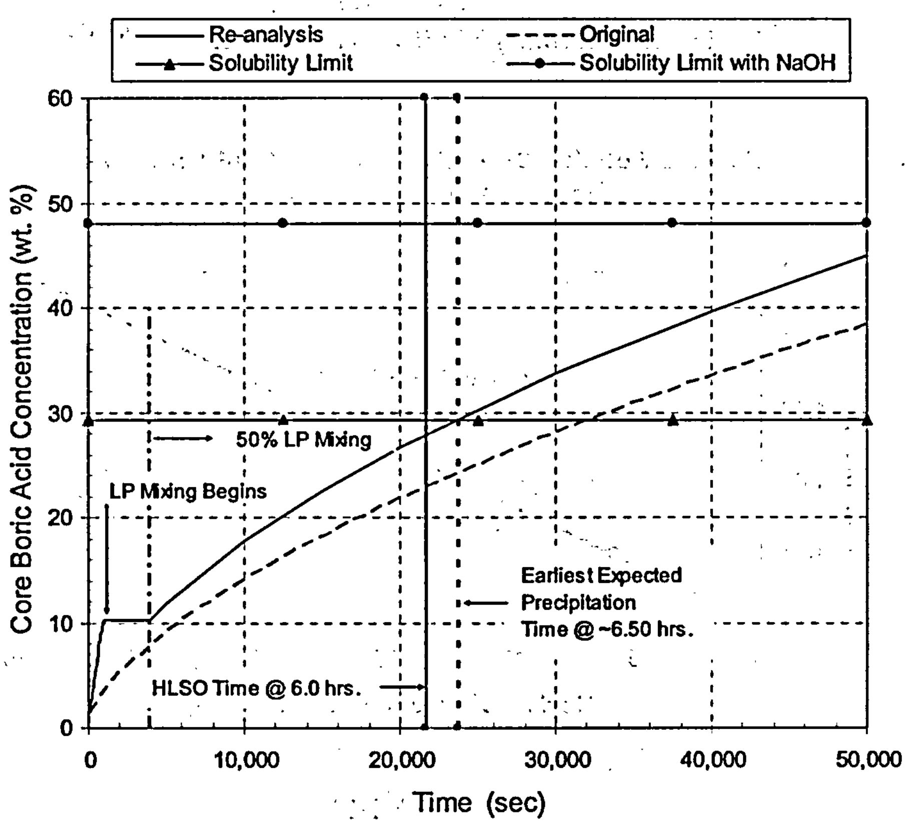


Figure F.1-8
BVPS-2 Boric Acid Concentration vs. Time

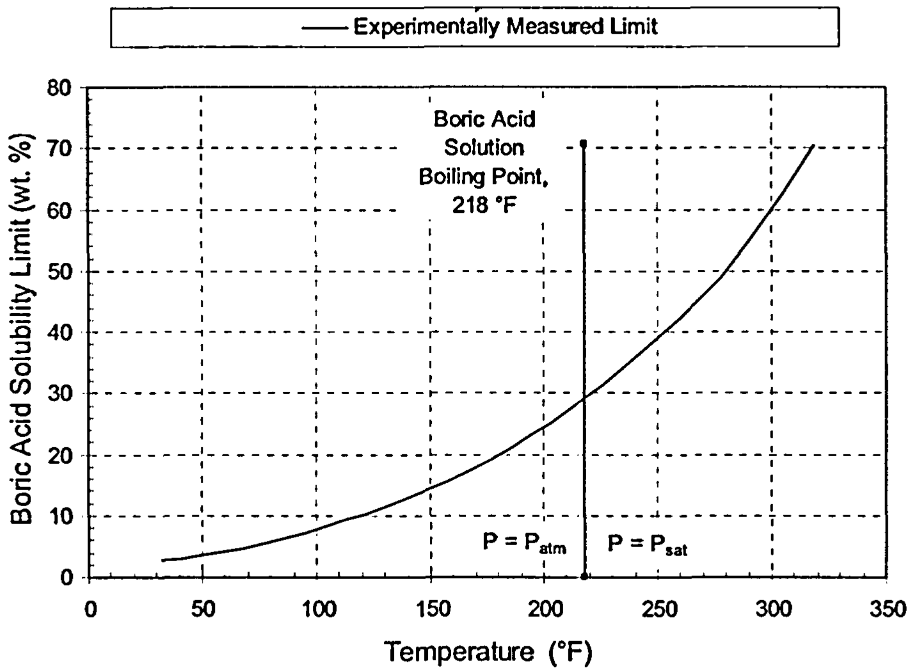


Figure F.1-9
Boric Acid Solubility Limit vs. Temperature [Cohen, 1969]

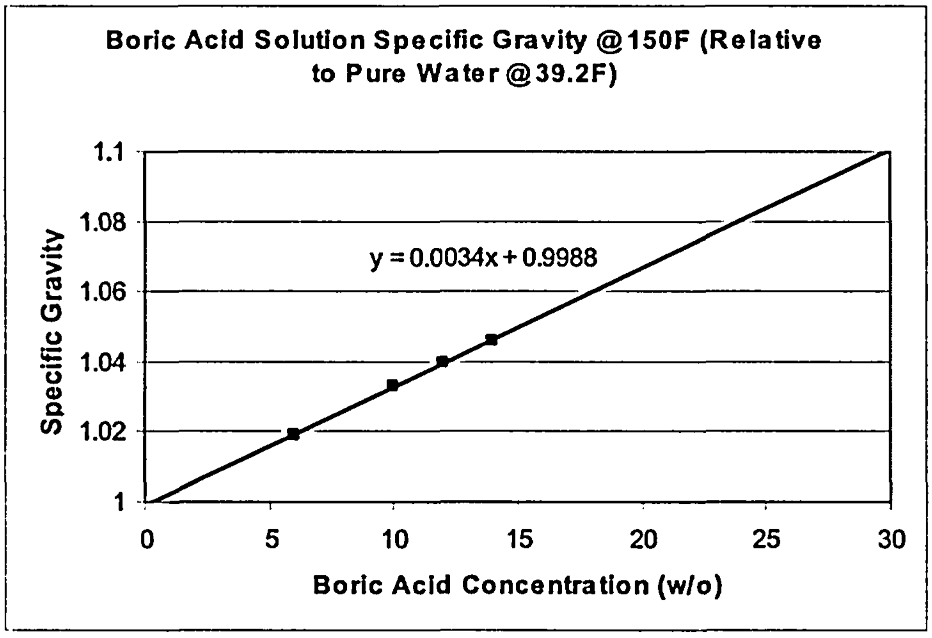


Figure F.1-10
Specific Gravity of Boric Acid – Water Solutions [EPRI NP-5558]

F.2 (Applicable to EPU)

What is the effect of placing the equivalent of a single-ended cold leg break as a slot on top of the discharge leg? In this situation, the loop seals will refill with ECCS injection, possibly preventing the mixing level from expanding very high into the upper plenum due to the increased resistance. Please compute the boric acid concentration versus time for this case. Please also explain the impact of downcomer boiling on these evaluations.

Response:

Loop sealing replugging for the large break LOCA described is unlikely because of the high loop vapor flow rates and the large steam vent area provided by the break. One of the possible mechanisms for loop seal filling is the backflow of SI water injected into the cold legs. In order for this backflow to occur it is necessary to already have injected enough SI water to have refilled the reactor vessel, including the core; a vessel refilled to this extent would have a mitigating effect on the core boric acid concentration transient. Further, the loop steam flow would need to be low enough that counter current flow limit does not occur. The consequences of post LOCA loop seal replugging were evaluated as reported in Reference 1. The expected system response would be a cyclic plugging and clearing and not a sustained core uncovery that could adversely impact core cooling.

Another possible mechanism for loop seal refilling is condensation in the steam generators during a small break LOCA event. In the unlikely event of a sustained core uncovery, the operators would follow prescribed emergency operating procedures to take actions that would disrupt the conditions necessary to sustain the core depression. Downcomer boiling during a LOCA scenario would have a small negative effect on the core flooding rate and would generally reduce the liquid volume in the core region. The effect of downcomer boiling [

]^{a,c}

One beneficial aspect of the scenario described is that a cyclic loop seal plugging would [

]^{a,c}

The core region boric acid concentration versus time for the scenario described (regardless of break size) is conservatively represented by the boric acid concentration calculated for the case of full RCS depressurization and voiding in the core, so long as [

]^{a,c} (for other small break LOCA discussion, see response to RAI F.6).

References:

1. Letter from Westinghouse to NRC, NSD-NRC-97-5092, "Core Uncovery Due to Loop Seal Re-Plugging During Post-LOCA Recovery, March 1997.
2. J. Tuunanen, et al., Experimental and analytical studies of boric acid concentrations in a VVER-440 reactor during the long-term cooling period of loss-of-coolant accidents, Nuclear Engineering and Design, Vol. 148, 1994, pp. 217-231

F.3 (Applicable to EPU)

Please provide the core inlet temperature versus time during the injection and recirculation phases of the analyses. What is the containment sump temperature and boric acid concentration versus time for these analyses?

Response:

The calculations assume that the core inlet temperature for both the injection and recirculation phase is 212°F. This assumption maximizes core boil-off in that no subcooling is credited.

No specific assumptions regarding containment sump temperature are assumed. The calculations make no differentiation between the injection and recirculation phase and assume that all core boil-off make-up is at the boron concentration of the sump. This is justified on the basis that the boron concentration of the injected SI would not be significantly different for the injection phase as compared to the recirculation phase. For example, during the injection phase, the concentration of the SI would be 2600 ppm, the RWST maximum boron concentration. During recirculation, the injected SI boron concentration would be the calculated boron concentration of the sump (shown in Figures F.3-1 and F.3-2).

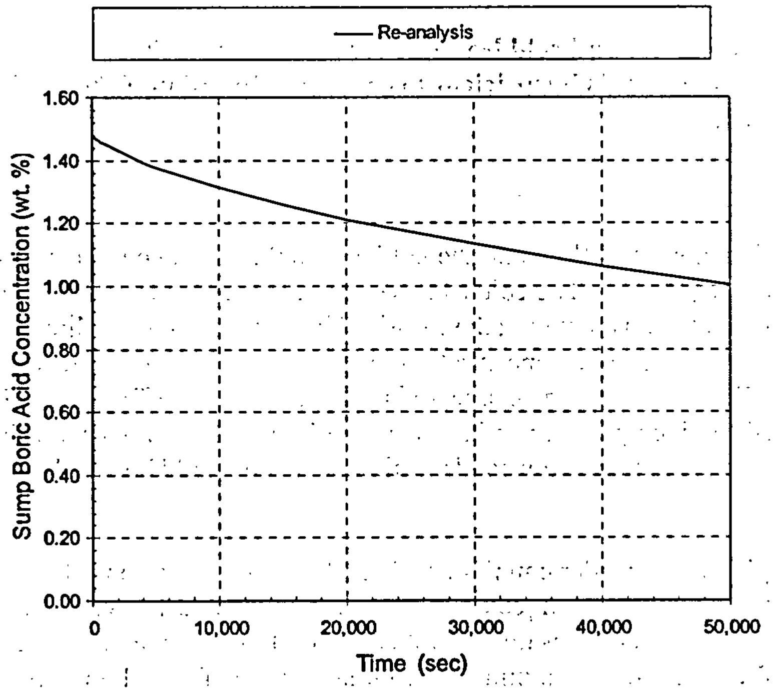


Figure F.3-1
BVPS-1 Sump Boric Acid Concentration vs. Time

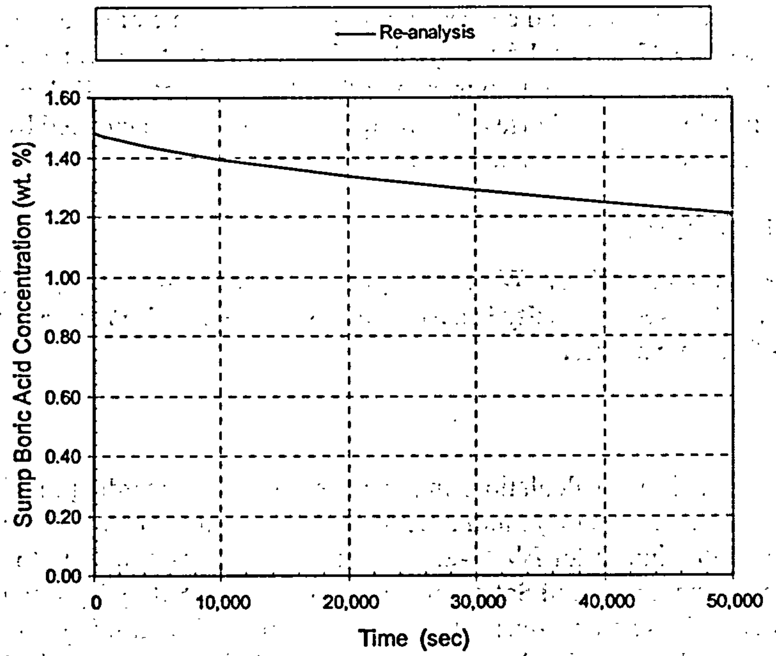


Figure F.3-2
BVPS-2 Sump Boric Acid Concentration vs. Time

F.4 (Applicable to EPU)

At the time of switch to hot and cold leg injection, please show that the boric acid concentration in the upper plenum or core is insufficient to cause precipitation if the minimum injection temperature is used.

Response:

The injection of cold SI flow into the hot legs would have two effects on the potential for boric acid precipitation. The cold SI flow would reduce the temperature of the liquid with which it interacts, thus reducing the localized boric acid solubility limit. The SI flow, being at a relatively low boric acid concentration, would dilute the boric acid solution with which it interacts. The net effect can be assessed by calculating the effect of the SI flow on the change in localized fluid temperature and boric acid solubility limit versus the change in localized boric acid concentration. Any condensation of steam would be an additional dilution mechanism.

For example, first consider conditions where the vessel mixture is at 218°F and 29.27 wt% boric acid solution and the injected SI flow is at 150°F and 1.5 wt% boric acid solution. In this example, steam condensation is not credited. Ignoring the density differences, a unit volume of injected SI flow mixing with a unit volume of vessel mixture would decrease the liquid temperature by 34°F (218 – (218+150) / 2). Figure F.1-9 from Section RAI F.1 can be used as a reference to estimate the effect of temperature on the boric acid solubility limit (i.e., 15 wt% per 50°F). Therefore, for a temperature decrease of 34°F, the boric acid solubility would decrease by 10 wt% (34°F / 50°F x 15). The same SI flow unit volume would decrease the boric acid concentration of a unit volume of core region fluid by 14 wt% (29.27 wt% – (29.27 wt% + 1.5 wt%) / 2)). This shows that the effect of the SI flow on reducing boric acid concentration is greater than the effect of the SI flow on reducing the boric acid solubility limit. Thus boric acid precipitation will not be induced by the safety injection flow if a minimum injection temperature is used.

F.5 (Applicable to EPU)

What is the time to recirculation? What pumped systems are operating to give this RWST drain time and what RWST capacity is assumed in the analyses? What are the minimum and maximum RWST temperatures.

Response:

The hot leg switchover calculations make no assumptions regarding the time to switch to sump recirculation. The minimum time to switch to cold leg recirculation is 25 minutes for BVPS-1 and 35 minutes for BVPS-2. The pumped systems operating to give this RWST drain time are the Low Head Safety Injection, High Head Safety Injection, and the Quench Spray system. These switchover times are based on maximum safeguards. Note that switchover to cold leg recirculation occurs prior to draining the RWST. Recirculation is initiated based on a level signal from the RWST after the tank is approximately 50% to 70% depleted depending on the unit. Following transfer to recirculation, the Quench Spray system continues to draw from the RWST until it is depleted. The maximum capacity of the RWST used in the hot leg switchover calculations is 441,000 gallons for BVPS-1 and 910,000 gallons for BVPS-2. In the HLSO analysis calculations, a RWST minimum temperature assumption is used to establish the density of the borated water in the RWST (chosen to maximize RWST density since the RWST is a boration source for the containment sump mixture). A minimum RWST temperature of 40°F was used to calculate the RWST density. The maximum allowable RWST temperature for EPU will be 65°F.

F.6 (Applicable to EPU)

Section 5.2.3 is incomplete. Please describe how boric acid precipitation is prevented for all small breaks up to and including those break sizes where simultaneous injection controls boric acid. What guidelines are provided in the emergency operating procedures (EOPs) to assure boric acid does not precipitate for small breaks? Please also describe the methods and inputs to the analysis used to address small breaks.

Response:

<u>Review of BVPS-1 and 2 Hot Leg Recirculation Procedure</u>

BVPS-1

For the EPU, for break sizes where the RCS depressurizes to below LHSI cut-in pressure, the SI flow will be realigned to the hot legs at hot leg switchover time. For cold leg breaks, where the boric acid concentration has been building up in the core, the hot leg SI flow will begin to dilute the core. For hot leg breaks, HHSI flow injected into the cold legs will provide core flushing flow so that the boric acid concentration in the core will not increase.

If the break size is so small that the RCS does not depressurize to below the LHSI cut-in pressure, it is highly unlikely that EOP ES-1.4 will be entered if the RCS is above the LHSI cut-in pressure for the following reasons;

- Hot leg recirculation can only be initiated through operator actions. Plant EOPs are typically structured such that hot leg recirculation is not likely to be initiated for breaks so small that the RCS fails to depressurize. If after a LOCA, the RCS pressure stays above the LHSI cut-in pressure, the EOPs instruct operators to cool down and depressurize the plant in a controlled manner prior to, or coincident with, transferring to cold leg recirculation. Since the specified hot leg switchover times are at least several hours after the LOCA, it is likely that the RCS will be well below the small break LOCA pseudo-equilibrium pressure by the time the hot leg switchover time is reached. Note that for extremely small breaks, the RWST may not empty and transfer to cold leg recirculation will not occur. Hot leg recirculation will be initiated only after the SI system has been aligned to cold leg recirculation.

- Recent Emergency Response Guidelines (ERG) changes (Reference 1) now require that when entering cold leg recirculation subsequent to or during plant cooldown and depressurization, operators are to consult with plant engineering staff regarding the need to switch to hot leg recirculation (at the designated hot leg switchover time). Given the procedures for plant cooldown and depressurization and the guidance in the ERG background documents, it is unlikely that switchover to hot leg recirculation would occur at RCS pressures above the LHSI cut-in pressure.

BVPS-2

For breaks where the RCS depressurizes to below LHSI cut-in pressure, all SI is normally realigned to the hot legs at hot leg switchover time. For cold leg breaks, where the boric acid concentration has been building up in the core, the HL SI flow will begin to dilute the core. For hot leg breaks, all SI flow will be realigned back to the cold legs after the designated cycling time. Realignment back to the cold legs will prevent boric acid precipitation for HL breaks were the boric acid concentration begins to increase when all SI flow is realigned to the hot legs. At hot leg switchover time, in case of an motor-operated valve (MOV) failure in the LHSI-to-HL flow path, LHSI is returned to the cold legs. In this case, simultaneous HL/CL injection will provide sufficient core dilution flow for either HL or CL breaks and no later realignment is necessary.

If the break is so small that the RCS does not depressurize to below the LHSI cut-in pressure, and EOP ES-1.4 is entered, then the HHSI flow will be injected into the hot legs. As noted previously, it is highly unlikely that EOP ES-1.4 will be entered if the RCS is above the LHSI cut-in pressure.

Small Break LOCAs and the Potential for Boric Acid Precipitation

With concerns for the potential for boric acid precipitation, small break scenarios can be viewed from two perspectives; the short term and long term. In the short term (< 2 hours after the initiating event) the calculation of the core boric acid is bounded by the re-analysis calculations that assume complete RCS depressurization. This is supported by a comparison of the re-analysis core and upper plenum liquid volume to the core and upper plenum liquid volume data extracted from the unit-specific small break LOCA NOTRUMP break cases. This comparison is represented by the core average voiding and core and upper plenum average voiding plots in Figures F.6-1 through F.6-4.

In the long term, realistic long term cooling small break scenarios cannot be evaluated without consideration of operator actions to depressurize and cool down the reactor. These actions would occur under EOP ES-1.2 Post-LOCA Cooldown and Depressurization. Significant to the potential for boric acid precipitation, the ES-1.2 actions would promote timely RCS depressurization to RHR cut-in pressure, thus providing a core flushing flow. ES-1.2 actions would also reduce the rate of boric acid buildup in the core through SG condensation and reflux.

In either the short term or long term, RCS pressures above atmospheric pressure are non-limiting transients for boric acid precipitation since the boric acid solubility limit is significantly higher at higher temperatures. The effect of temperature on the boric acid solubility limit is shown in Table F.1-2 and Figure F.1-9 in the response to RAI F.1. For example at 58 psig and a saturation temperature 305°F, the boric acid solubility limit is approximately 62 wt%. This is twice the solubility limit at atmospheric conditions. Furthermore, at higher pressures, the core boiloff will be reduced because of the higher saturation liquid enthalpies at higher pressures, thus increasing the sensible heat of the injected water available to remove decay heat.

Reference:

1. Westinghouse Letter ERG-00-001, "ERG MAINTENANCE PROGRAM, RESPONSE TO FEEDBACK ITEM DW-93-034," A. David Lounsbury, March 2, 2000.

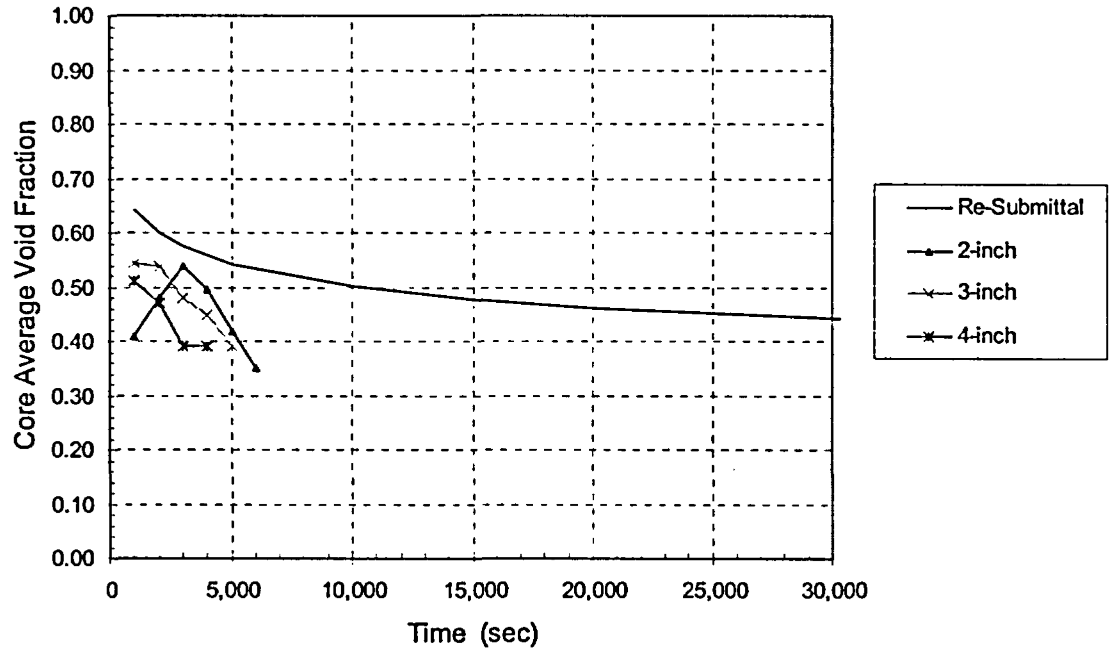


Figure F.6-1
BVPS-1 Core Average Voiding Comparisons

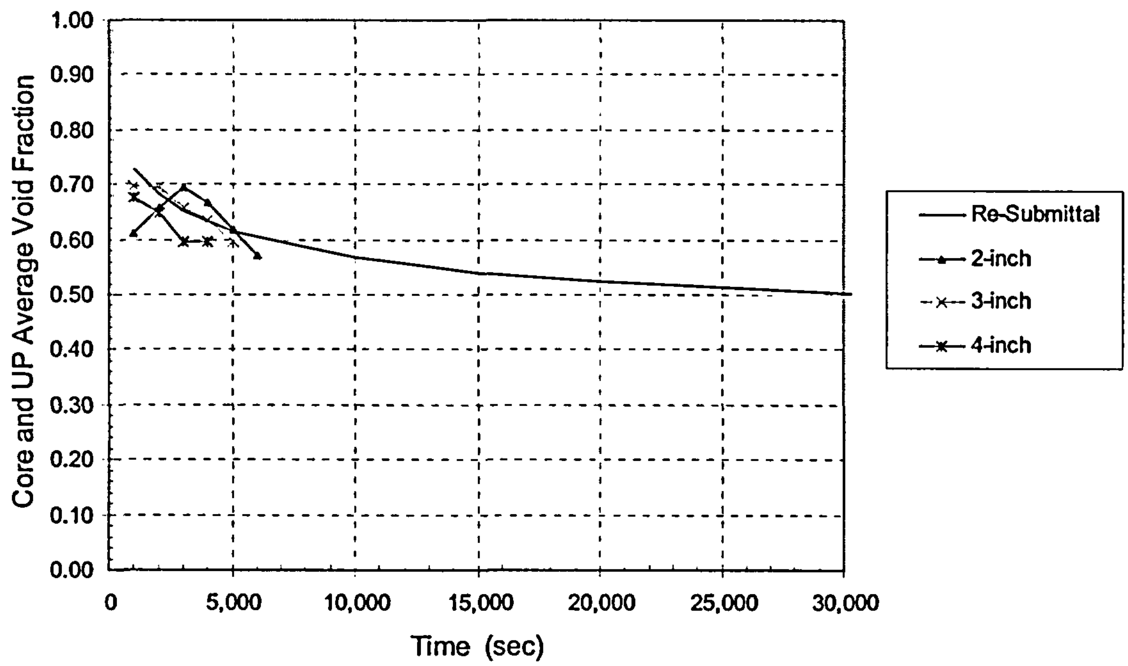


Figure F.6-2
BVPS-1 Core and Upper Plenum Average Voiding Comparisons

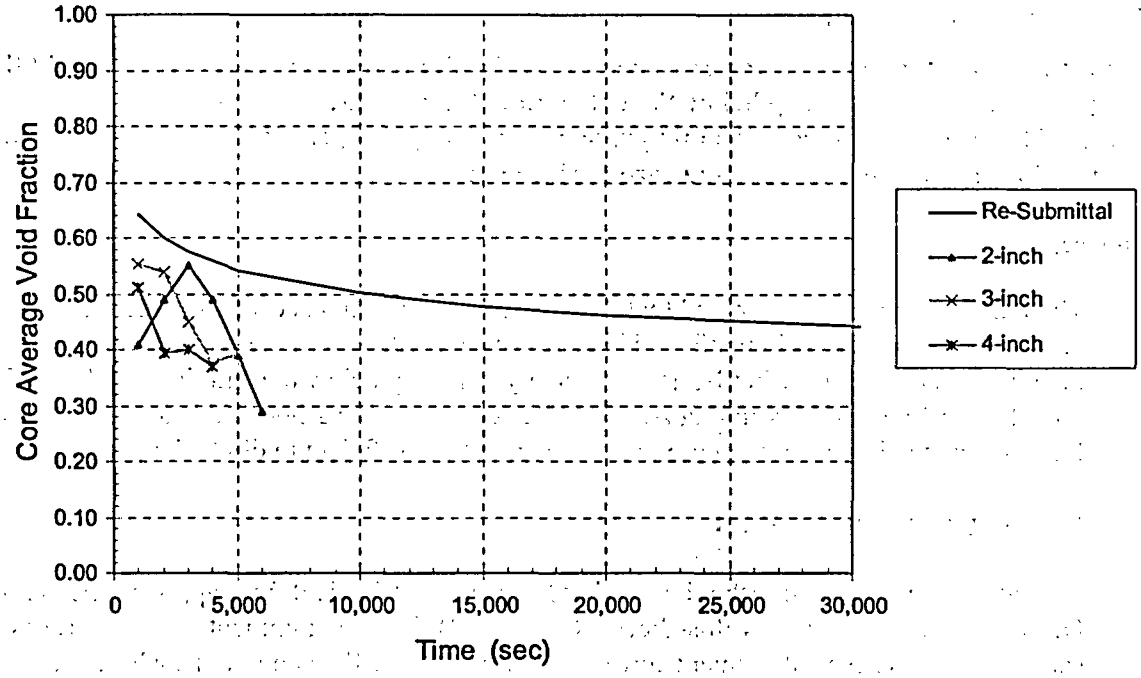


Figure F.6-3
BVPS-2 Core Average Voiding Comparisons

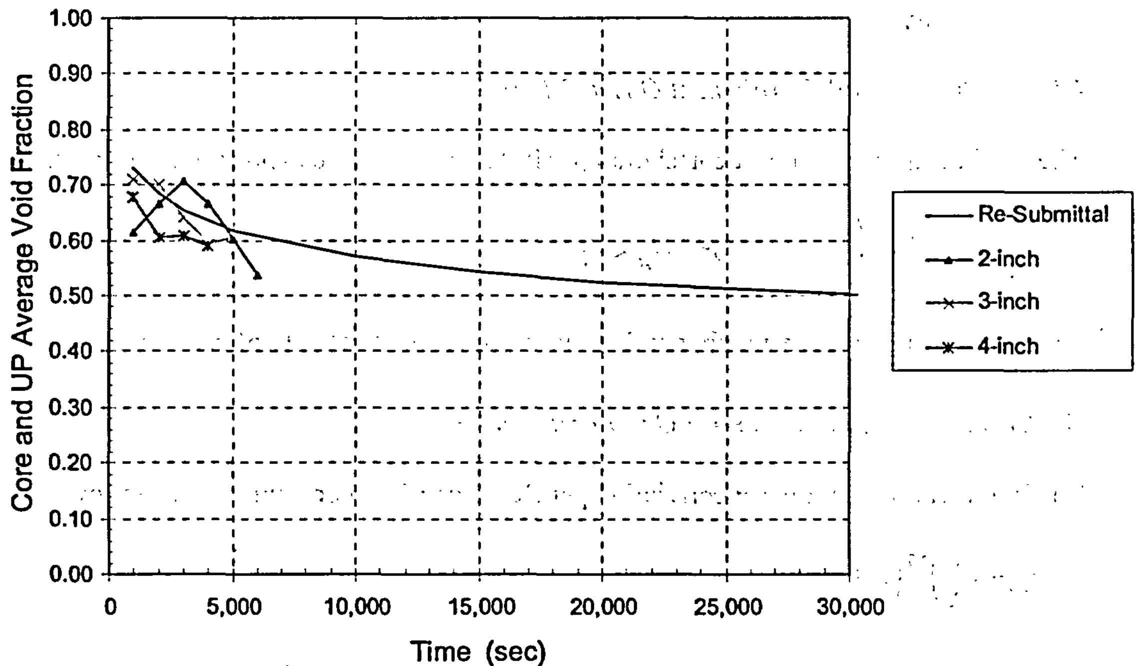


Figure F.6-4
BVPS-2 Core and Upper Plenum Average Voiding Comparisons

F.7 (Applicable to EPU)

What is the earliest time the switch can be made to simultaneous injection? When would the hot leg steam velocity first drop below the entrainment threshold? At what time during the event would the core decay heat steaming rate be low enough to permit the hot side injection to exceed boil-off sufficiently to flush the core for large breaks?

Response:

The HLSO reanalysis determined that 2 hours is an analytically acceptable time for the earliest switchover to hot leg recirculation. This is consistent with entrainment calculations (see below) that show that the hot leg steam velocity will drop below the entrainment threshold after 1 hour 30 minutes assuming Appendix K decay heat. At 2 hours, the hot leg injected flow will be well in excess of core boil-off and will be sufficient to dilute the core.

Liquid Entrainment Threshold

The liquid entrainment threshold in the hot leg can be established from applying the Ishii-Grolmes (Reference 1) or Wallis-Steen (Reference 2) liquid entrainment onset criteria as shown below. These entrainment correlations are valid for flow conditions where the liquid phase does not take up a significant volume of the pipe (such as in the hot legs in post-LOCA) and viscous effects in the liquid are not dominant, that is, that the liquid phase is in the turbulent regime. Note that the correlations have very similar form; however, the Ishii-Grolmes entrainment onset criterion uses liquid phase viscosity whereas Wallis-Steen uses gas phase viscosity.

Ishii-Grolmes Liquid Entrainment Onset Criterion

The liquid entrainment onset correlation per Reference 1 can be expressed as follows:

$$j_g \geq N_\mu^{0.8}\left(\frac{\rho_f}{\rho_g}\right)^{0.5}\left(\frac{\sigma}{\mu_f}\right) \qquad \text{for} \quad N_\mu < \tfrac{1}{15}$$

where N_μ is the viscosity number and j_g is the superficial velocity of gas phase.

Wallis-Steen Liquid Entrainment Onset Criterion

The liquid entrainment onset correlation per Reference 2 can be expressed as follows:

$$j_g \geq \pi_2\left(\frac{\rho_f}{\rho_g}\right)^{0.5}\left(\frac{\sigma}{\mu_g}\right)$$

where π_2 represents dimensionless gas velocity. Steen suggested a value of 2.46E-04 for π_2, however, a more conservative value of 2.0E-04 will be used for this calculation.

The following properties of saturated liquid and gas phases of water at atmospheric conditions (14.7 psia) are used in the above correlations:

σ = surface tension of liquid = 4.03E-03 lbf/ft
μ_f = viscosity of liquid = 5.93E-06 lbf-s/ft^2
μ_g = viscosity of gas = 2.56E-07 lbf-s/ft^2
ρ_f = density of liquid = 59.8 lbm/ft^3
ρ_g = density of gas = 0.0373 lbm/ft^3

Liquid Entrainment Threshold in Terms of Hot Leg Superficial Steam Velocity

Using the above properties as input, the following results are obtained for the liquid entrainment threshold in terms of superficial steam velocity in the hot leg:

$$j_{g,ISHII-GROLMES} = 86.6 \text{ ft/s} \quad \text{with} \quad N_\mu = 0.000756$$
$$j_{g,WALLIS-STEEN} = 126 \text{ ft/s}$$

Applying the lower value of 86.6 ft/s obtained from Ishii-Grolmes with comparable steam flow in each hot leg, the following total core steam mass flow rate at the entrainment threshold becomes:

$$\dot{m}_{coresteam} = j_{g,ISHII-GROLMES} \cdot 3 \cdot A_{hotleg} \cdot \rho_g = 44.47 \text{ lbm/s}$$

where for a single hot leg, A_{hotleg} = 4.59 ft^2.

The decay heat fraction can be related to the core steam mass flow rate as follows, where PWL is the licensed power of 2900 MWt and 0.6% calorimetric uncertainty is applied.

$$\dot{m}_{coresteam} = \left[PWL(1.006) \cdot P/P_0 \cdot \tfrac{948 Btu/s}{Mw}\right]/(h_{fg} + \Delta h_{sub})$$

For the BVPS units with no subcooling and atmospheric conditions, a decay heat fraction is obtained.

$$P/P_0 = 0.0156 \text{ Decay Heat Fraction}$$

This decay heat fraction corresponds to approximately 5500 seconds after shutdown for Appendix K decay heat and approximately 3600 seconds for 1979 ANS+2σ decay heat. Therefore, steam flow in the hot legs should drop below the entrainment threshold at about 1 hours 30 minutes based upon the Appendix K decay heat function.

[

]^{a,c}

References:

1. Ishii, M.; Grolmes, M. A., *Inception Criteria for Droplet Entrainment in Two-Phase Concurrent Film Flow*, AIChE Journal, Vol. 21, No. 2, pp. 308-319, 1975.
2. Wallis, G. B., *One-Dimensional Two-Phase Flow*, pp. 390-393, 1969.

F.8 (Applicable to EPU)

What is the minimum flushing flow to arrest the build-up of boric acid when switch over is determined?

Response:

The theoretical minimum flow to provide core flushing flow is flow in excess of core boiloff such that the forced flow through the core will remove boron at a rate greater than what is being left behind due to boiloff. The exact multiplier is dependent on the assumed boron concentration of the core region at switchover and the boron concentration of the injected SI flow. If the core region was at 27.53 wt% boric acid, and the injected SI flow was at 2600 ppm, the dilution flow boiloff multiplier would be 1.06. Note that any condensation effect of the injected hot leg SI flow would reduce the required flow.

At 6.5 hours and 6.0 hours, assuming Appendix K decay heat, core boiloff will be 223 gpm and 227 gpm respectively. These SI flow capabilities are at 14.7 psia, the limiting condition for boric acid solubility concerns. For BVPS-1, the hot leg injected flow will be in excess of the boiloff. For BVPS-2, the hot leg injected flow will be in excess of 263.8 gpm.

F.9 (Applicable to EPU)

What is the bottom elevation of the loop seal pipes (suction legs) and the top elevation of the active core?

Response:

The bottom elevation of the loop seal pipes is 14.95 ft relative to the inside bottom of the reactor vessel. The top elevation of the active core is 21.86 ft relative to the inside bottom of the vessel. Consequently, the bottom elevation of the loop seal pipes is 6.91 ft below the top of the active fuel. This elevation is valid for both units.

F.10 (Applicable to EPU)

Please provide the loop friction and geometric pressure losses coefficients, and pressure drops, from the top of the active fuel to the hot legs, SGs, and cold leg piping to the downcomer at the exit of the discharge leg inlet nozzles. Also, please provide the reactor coolant pump (RCP) locked rotor K-factor. Please provide the mass flow rate, hydraulic diameter, flow area, fluid density, and temperature for the key pressure loss components in the loop from the top of the active fuel through the hot legs to the outlet of the discharge leg at steady-state full power conditions. These would include:

a. top of active fuel to hot leg nozzle
b. hot leg inlet nozzle
c. hot leg
d. SG inlet plenum nozzle
e. SG inlet plenum
f. tube sheet inlet
g. SG tubes
h. SG u-bend
i. SG outlet
j. SG outlet plenum nozzle
k. suction leg
l. RCP inlet and outlet
m. discharge leg
n. reactor vessel (RV) inlet nozzle

Response:

Table F.10-1 provides information for BVPS-2. At EPU conditions, BVPS-1 has replacement steam generators (RSGs), which will have no tube plugging. BVPS-2 has original steam generators (OSGs), which have a small amount of tube plugging. The BVPS-2 configuration is assumed to be limiting, so the values for BVPS-2 are provided here.

Other data not provided in the table is listed here. The RCP locked rotor K-factor is [ ]^{a,c} ft/gpm^2 but is not used in the EPU LOCA analyses. Consistent with Regulatory Guide 1.157, a locked rotor need not be assumed unless it is calculated to occur. As demonstrated in response to RAI 5-47 of WCAP-12945-P-A, flywheel failure is not expected to occur, and a locked rotor need not be assumed. The hot leg nozzle loss coefficient is [ ]^{a,c} ft/gpm^2. The cold leg nozzle loss coefficient is [ ]^{a,c} ft/gpm^2. Finally, the loss coefficient from the top of the active fuel to the hot leg nozzle is [ ]^{a,c} ft/gpm^2.

The table provides the hydraulic diameter, flow area, and loss coefficient for the hot leg, steam generator, suction leg, reactor coolant pump, and cold leg. These data points are sufficient to answer the loop friction and geometric pressure losses coefficients question for Beaver Valley.

Table F.10-1 EPU Conditions			
Parameter	Hydraulic Diameter (ft)	Flow Area (ft²)	Loss Coefficient (ft/gpm²)
Hot Leg			a,c
SG Inlet			
SG Tubes, Inlet to U-Bend			
SG U-Bend			
SG Tubes, U-Bend to Outlet			
SG Outlet			
Pump Suction Leg			
Cold Leg			

(1) Values based on 0% SGTP.

F.11 (Applicable to EPU)

What decay heat multiplier is applied to the 1971 ANS decay heat standard in the evaluations?

Response:

As originally submitted, the boric acid precipitation analyses used a decay heat multiplier of 1.0. All recirculation flow evaluations (for both core cooling and core flushing flow) used a multiplier of 1.2 consistent with the 10 CFR 50.46 Appendix K requirement. The supplemental boric acid precipitation re-analyses (discussed in response to F.1) used a decay heat multiplier of 1.2 consistent with the 10 CFR 50.46 Appendix K requirement.

F.12 (Applicable to EPU)

What is the effect of sump debris on precipitation and mixing throughout the mixing volume? Please explain.

Response:

Sump debris studies have concluded that particulate containment sump debris ingested into the ECCS during operation in the recirculation phase will settle in the lower plenum. This could affect the potential for boric acid precipitation in that the entire lower plenum liquid volume would not be available for diluting the boric acid. Since mixing in only 50% of the lower plenum is being credited, the calculations already include some level of lower plenum mixing non-participation. For the re-analysis, the volume of the lower plenum not being credited is [ ]^{a,c} ft^3. For a perspective on debris in the lower plenum, it can be noted that it would take approximately [ ]^{a,c} ft^3 of debris to fill the lower plenum to the top of the upper tie plate. This volume, which would be in the region least likely to participate in the core region mixing, is less than the lower plenum volume already being excluded in the calculations.

The total amount of sump debris that is estimated to settle out in the reactor vessel lower plenum is both plant- and scenario-specific. It depends upon the following plant-specific parameters and features: debris generation, [

]^{a,c} As an example, a scenario-specific condition related to debris generation is that a postulated large break Loss of Coolant Accident (LOCA) would generate more debris than a postulated small break LOCA.

<u>Section 5.3.2</u> <u>Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition</u>

G.1 (Applicable to RSG & EPU)

Section 5.3.2.5 states, "The results and conclusions of the analysis performed for the uncontrolled RCCA bank withdrawal from a subcritical condition for the NSSS [nuclear steam supply system] power of 2910 MWt bound and support operation at the current NSSS power of 2697 MWt, thus supporting the staged implementation of EPU at Beaver Valley Unit 1 and Beaver Valley Unit 2." Was the analysis performed for the uncontrolled RCCA bank withdrawal from a subcritical condition for BVPS-1, -2, or both?

Response:

One Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition analysis was performed to cover both BVPS units. Where parameters differed from BVPS-1 to -2, the more conservative value was used resulting in a single analysis that is conservative for both units.

G.2 (Applicable to RSG & EPU)

The sequence of events for this event (Table 5.3.2-1) is identical to the sequence of events for this event in the BVPS-1 UFSAR (Table 14.1-2) and very similar to the sequence of events for this event in the BVPS-2 UFSAR (Table 15.4-1). Was this event re-analyzed for the EPU? If yes, then what EPU-related factors would make a re-analysis necessary?

Response:

The event was specifically reanalyzed for the EPU. A single analysis was performed which conservatively bounds both BVPS units (see response to RAI G.1). The transient is very fast such that the sequence of events from case to case is not expected to change significantly. The analysis generates transient statepoints that are used to perform a detailed DNBR calculation. The power portion of the statepoint is given as a fraction of the nominal power, which is then applied to the uprated core power of 2900 MWt. Since, the DNBR calculation at the higher core power is required, the transient statepoints were regenerated. However, the impact of the EPU on the statepoints is minimal as seen in the sequence of events.

Section 5.3.3 Uncontrolled RCCA Bank Withdrawal at Power

H.1 (Applicable to RSG & EPU)

Discuss, or cite discussions of, the effect that the EPU would have upon the core limits, protection lines, and overtemperature ΔT trip setpoint calculations used in the BVPS-1 and 2 uncontrolled RCCA bank withdrawal at power event analyses.

Response:

The core thermal limits were recalculated for this project due to numerous changes – increased core power level, a different DNB correlation and the use of VIPRE vs. THINC. The BVPS-1 steam generator replacement did not impact the core limits. Also, as part of the Beaver Valley EPU Project, the calculation of the Overtemperature ΔT (OTΔT) and Overpower ΔT (OPΔT) protection lines was revisited and the setpoints were recalculated. It was also decided to make the BVPS-1 and 2 setpoints the same. This was possible due to the elimination (analytically) of the lead/lag on measured ΔT for BVPS-2, which makes the BVPS-1 and 2 OTΔT and OPΔT setpoint equations the same. Also, other parameters impacting the OTΔT and OPΔT setpoints are the same, or very similar, for the two units. Where differences between the units exist, the more conservative values are used, which results in a single set of setpoints that is conservatively applicable to both BVPS units. The adequacy of the OTΔT setpoints to ensure that the DNB design basis is met is confirmed via analyses, including that of the Uncontrolled Rod Cluster Control Assembly (RCCA) Bank Withdrawal at Power (RWAP) event.

H.2 (Applicable to RSG & EPU)

In Table 5.3.3-1A for BVPS-1, the uncontrolled RCCA bank withdrawal at power analysis assumes a low reactivity insertion rate of 0.4 pcm/sec, and Table 5.3.3-1B for BVPS-2, assumes a low reactivity insertion rate that is five times higher (2.0 pcm/sec) for the same accident. What is the minimum possible reactivity insertion rate for each plant?

Response:

Reactivity (positive) insertion rates would be dependent upon various parameters include RCCA speed during its withdraw from the core. At BVPS, automatic RCCA withdraw capability has been defeated. Thus, RCCA withdraw would be performed under direct operator control. Any automatic rod withdraw sequence that would occur would be quickly identified by the operating staff and actions taken to stop the transient.

For the subject analysis, the maximum possible reactivity insertion rate was determined to be less than 110 pcm/sec. This value is confirmed during each reload evaluation. The minimum possible reactivity insertion rate could approach 0 pcm/sec. Thus, a large spectrum of reactivity insertion rates from 110 pcm/sec to less than 1.0 pcm/sec was analyzed for both Beaver Valley units.

The results presented in the licensing report are intended to show an example of a "fast" transient and a "slow" transient. For BVPS-1, the "slow" transient presented was 0.4 pcm/sec and, for BVPS-2, the "slow" transient presented was the 2 pcm/sec case. This was not intended to imply that the case presented was the slowest reactivity insertion rate possible. Likewise, the "fast" transient presented for both units modeled 80 pcm/sec but the maximum reactivity insertion rate analyzed was 100 pcm/sec.

H.3 (Applicable to RSG & EPU)

Figures 5.3.3-7A through 5.3.3-9B indicate that the uncontrolled RCCA bank withdrawal at power analyses meet the Condition II acceptance criterion pertaining to fuel clad damage, due to reactor trips demanded by the overtemperature ΔT and high nuclear flux trip logic. There is little or no information regarding the other two criteria, which pertain to RCS overpressure and escalation of the accident to a more serious event.

a. RCS overpressure: Show that there is no possibility of RCS overpressurization, assuming that the power-operated relief valves (PORVs) are not available.

Response:

The RWAP analysis is performed for the primary purpose of demonstrating the adequacy of the High Neutron Flux and OTΔT reactor trip functions in preventing the violation of the DNBR safety analysis limit. For that reason, pressure control mechanisms, such as pressurizer sprays and power-operated relief valves (PORVs), are assumed to operate as designed to minimize the calculated DNBR for the event.

To address RCS overpressurization concerns for this event, Westinghouse performed a generic analysis of this event assuming operation of these control systems, utilizing bounding values for several key input parameters. The results of this generic analysis, which considers 2-loop, 3-loop and 4-loop Westinghouse-designed plants, demonstrate that adequate protection would be provided through the use of the High Neutron Flux and High Pressurizer Pressure reactor trip functions in conjunction with the Positive Flux Rate Trip (PFRT) reactor trip function. This last function is typically not explicitly modeled in safety analysis since most utilities do not perform response time testing on it. However, the generic work performed to address RWAP overpressurization takes credit for the function's availability (confirmed by surveillance requirements that ensure its operability) without placing any requirement on its response time. The generic work concluded that the presence of these three protection functions ensure that overpressurization following a RWAP, assuming all automatic pressure control features are unavailable, is bounded by other Condition II transients. As such, the analysis methodology for this event focuses on the limiting acceptance criterion for this event (i.e., DBNR) and assumes both pressurizer sprays and PORVs are available.

A review of the key input assumptions made in the generic overpressurization analysis was performed as part of the Beaver Valley EPU Project and it was confirmed that the generic analysis continued to apply to Beaver Valley with the EPU Project.

It should be noted that the generic method described above has been reviewed and approved by the NRC in Amendments 167 and 168 for the Diablo Canyon Nuclear Plant, Units 1 and 2, dated April 22, 2004, TAC Nos. MB8080, ADAMS Accession Number ML041180285 (see Section 3.6 of the NRC Safety Evaluation).

b. **Escalation of the accident to a more serious event: Provide analyses results for each plant's minimum possible reactivity insertion rate; assuming various initial power levels and minimum reactivity feedback, to show that the pressurizer would not fill before the reactor is tripped.**

Response:

The RWAP cases most likely to result in pressurizer filling, as currently analyzed for BVPS-1 and 2, are those that assume a low level of reactivity insertion. Westinghouse typically uses the criterion of preventing pressurizer filling to demonstrate that various Condition II incidents would not generate a more serious incident without other incidents occurring independently. The RWAP analyses performed do not credit the high pressurizer water level trip. Only High Neutron Flux and Overtemperature ΔT are explicitly credited. The high pressurizer water level trip would preclude pressurizer filling; thus, the generic Westinghouse analysis methodology for the RWAP event does not consider pressurizer filling as an acceptance criterion for this event. Furthermore, the approach to a water-solid condition for these low reactivity insertion RWAP cases would be slow, making the response time for said reactor trip function not as critical (continued demonstration of the operability of the trip function would suffice for the purposes of this analysis). Based on this, the RWAP analysis is performed for the primary purpose of demonstrating that the adequacy of the High Neutron Flux and OTΔT reactor trip functions in preventing the violation of the DNBR safety analysis limit, without explicit consideration of the high pressurizer water level reactor trip function, which would yield slightly less limiting DNBR results.

Section 5.3.4 RCCA Misalignment

I.1 (Applicable to RSG & EPU)

Section 5.3.4 states (1), "the effect of a power increase on these generic statepoints has been previously addressed for other Westinghouse designed PWRs," and (2) "the generic statepoints were evaluated and found to be applicable to the EPU." Show that generic statepoints apply to BVPS-1 and 2.

Response:

The methodology for the dropped rod event, WCAP-11394-P-A (Reference 3 of licensing report Section 5.3.4.6) involves applications in three analysis areas; 1) the transient statepoints, 2) the DNB (thermal-hydraulic) analysis and 3) the nuclear analysis. The transient (analysis) statepoints are based on a conservative generic 3-loop model while the DNB (thermal-hydraulic) and nuclear analysis portions of the event were performed at BVPS-1 and 2 EPU specific conditions.

In generating the transient analysis statepoint conditions of Step 1, the generic Dropped Rod analysis methodology (WCAP-11394-P-A) was followed to make use of existing "generic" 3-loop dropped rod statepoints that were confirmed to be representative for BVPS-1 and 2 at EPU conditions. The selection of generic 3-loop transient statepoints is based on a review of the key pertinent plant conditions that influence the transient statepoint limiting conditions. These are: 1) rod control system characteristics, 2) core reactivity coefficients (i.e., MTCs), 3) dropped rod worth and 4) control bank reactivity insertion. The rod control system characteristics were first examined to ensure that the generic 3-loop rod control system response following a dropped rod provides a faster (more limiting) response than BVPS-1 and 2. By providing a more immediate rod control system response following a rod drop, the 3-loop model generates more limiting transient statepoints conditions (i.e., higher core heat flux, higher temperature and lower pressure). The transient statepoints are then provided and analyzed (as part of the thermal-hydraulic (DNB) and nuclear analysis portion of the event) for a range of core reactivity coefficients (i.e., MTCs), dropped rod worths and control bank reactivity insertion conditions that bound the operating/EPU conditions of BVPS-1 and 2. By satisfying these key pertinent operating/EPU conditions, the generic dropped rod transient statepoints are confirmed to be conservative (i.e., representative) and applicable for BVPS-1 and 2 at EPU conditions.

I.2 (Applicable to RSG & EPU)

Describe the plant-specific analyses or evaluations that were conducted for BVPS-1 and 2, which lead to the conclusion that, "Results of the analysis show that a RCCA Misalignment event, with or without a reactor trip, does not adversely affect the core."

Response:

In performing the accident analysis specific acceptance criteria evaluation (Steps 2 and 3 of response to I.1), the nuclear analysis (FΔH) and thermal-hydraulic (DNB) analyses are performed at BVPS-1 and 2 EPU specific conditions. These analyses are done based on the transient statepoint conditions generated in Step 1 of response to I.1. As noted, these transient statepoints are generated following the methodology developed in WCAP-11394-P-A which does not credit some reactor trip functions for event mitigation (e.g., no credit taken for negative flux rate, overtemperature or overpower reactor trip functions). The only reactor trip modeled in the generation of the transient statepoints is the low pressurizer pressure reactor trip function, and that trip occurs in only some of the cases generated. Therefore, in demonstrating that the event specific criteria are successfully met for BVPS-1 and 2 at EPU conditions, only a portion of the event analysis conditions actually credit reactor trip.

<u>Section 5.3.5</u> <u>Uncontrolled Boron Dilution</u>

J.1 (Applicable to RSG & EPU)

For Modes 4, 5, and 6, the BVPS-1 and 2 EPU application indicates an inadvertent boron dilution is "...prevented by administrative controls which isolate the primary grade water system isolation valves from the chemical and volume control system [CVCS], except during planned boron dilution or makeup activities." What, if any, EPU-related changes have been made to the administrative controls for Modes 4, 5, and 6, which prevent an inadvertent boron dilution.

Response:

No changes to the administrative controls which prevent boron dilution in Modes 4, 5, and 6 are required for EPU. The administrative controls are contained in Technical Specification 3.1.2.9 for both BVPS-1 and 2. No changes to these Technical Specifications have been included in EPU submittal.

J.2 (Applicable to RSG & EPU)

The EPU application indicates that an inadvertent boron dilution in Mode 3 provides the operator with the least amount of time to take action and terminate the event. Please describe the assumptions and analysis that were used to reach this conclusion.

Response:

There are four critical parameters in a boron dilution calculation. These are the dilution flow rate, the active RCS volume, the initial boron concentration and the critical boron concentration. The dilution flow rate is the same for all three cases (i.e., Modes 1, 2 and 3) for both units. The active RCS volumes assumed in Modes 1 and 2 include the upper head and the Mode 3 volume does not include the upper head. So a portion of the difference between the Mode 1/Mode 2 calculations and Mode 3 is due to the active RCS volume assumption. The initial and critical boron concentration assumptions for each Mode are confirmed during the reload process. The Mode 3 initial and critical concentrations are typically the most difficult to meet. Thus, in order to facilitate future reload evaluations, the Mode 3 initial and critical concentrations were adjusted so that the analytical limit of 15 minutes is met. Using overly conservative boron concentrations in the Mode 3 boron dilution calculation gives the core designers more flexibility during subsequent reload evaluations. In summary, the two differences that make the Mode 3 case more limiting are the reduced active RCS volume and the conservative boron concentration assumptions.

J.3 (Applicable to RSG & EPU)

The EPU application discussion on the Mode 1 boron dilution, while on automatic rod control states, "The rod insertion limit alarms (low and low-low settings) alert the operator at least 15 minutes prior to criticality." As the reactor is already critical at this time, please clarify this statement.

Response:

The statement should say "prior to a loss of shutdown margin". The revised wording provides more clarity to this statement.

J.4 (Applicable to RSG & EPU)

How much shutdown margin is preserved at the low and low-low settings for the rod insertion limit alarms?

Response:

Per the Technical Specifications, the shutdown margin at the rod insertion limits is ≥ 1.77%. No calculation of the shutdown margin was specifically performed at the low or low-low limit setpoints. Since the shutdown margin at the insertion limits is greater than 1.77% and the low and low-low limit setpoints are above the insertion limits, then the available shutdown margin at the low and low-low limit setpoints would also be greater than 1.77%.

<u>Section 5.3.6</u> <u>Loss of External Electrical Load and/or Turbine Trip</u>

K.1 (Applicable to RSG & EPU)

Provide transient curves of SG water level and feedwater flow (normal feedwater and AFW flow) for both BVPS-1 and 2.

Response:

The loss of load/turbine trip event is simulated by decreasing both the steam flow and feedwater flow to zero immediately after initiation of the event. That is, a step decrease in feedwater and steam flow (over an interval of 0.01 seconds) from the initial flow to a zero flow condition is modeled. In addition AFW is not assumed. Transient plots of normal and auxiliary feedwater would show zero flow and are, therefore, not provided.

LOFTRAN does not calculate the SG water level but does provide SG mass. Therefore, a plot of the SG mass is provided for the limiting loss of load (LOL) DNB and RCS Pressure cases for both BVPS-1 (Figures K.1-1 and K.1-2) and BVPS-2 (Figures K.1-3 and K.1-4).

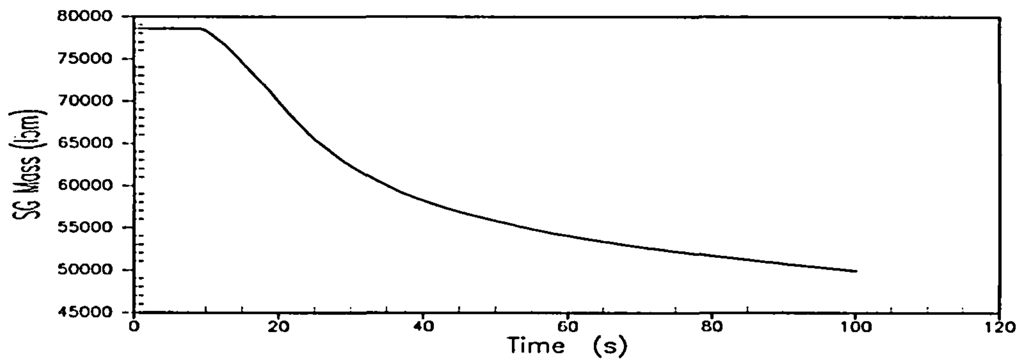


Figure K.1-1
BVPS-1 Limiting DNB Case – SG Mass vs. Time

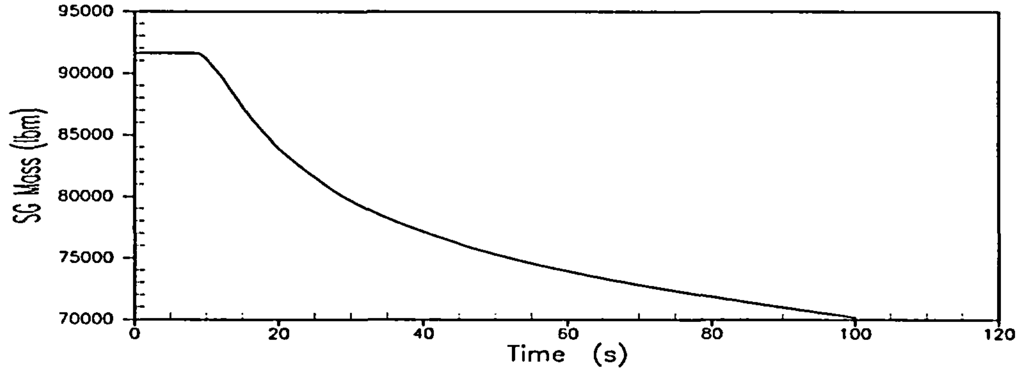


Figure K.1-2
BVPS-1 Limiting RCS Pressure Case – SG Mass vs. Time

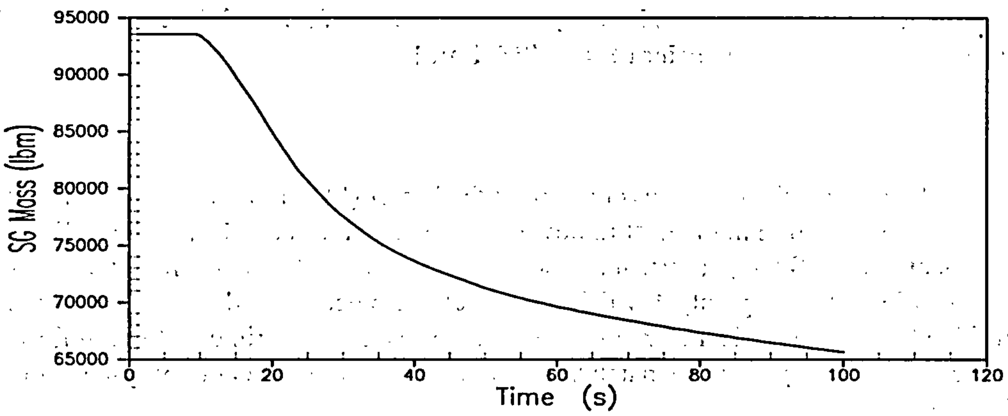


Figure K.1-3
BVPS-2 Limiting DNB Case – SG Mass vs. Time

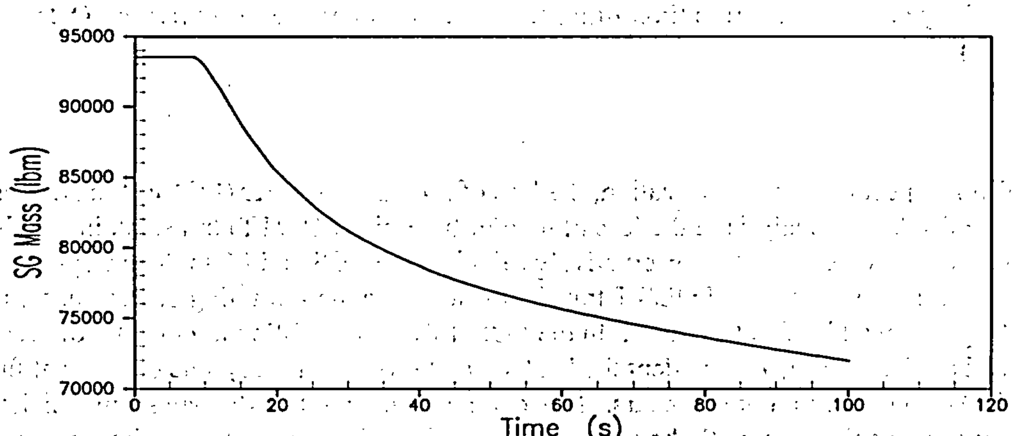


Figure K.1-4
BVPS-2 Limiting RCS Pressure Case – SG Mass vs. Time

Section 5.3.7 Loss of Normal Feedwater

L.1 (Applicable to RSG & EPU)

Provide a quantitative evaluation to verify the conclusion made in Section 5.3.7.5, that with respect to departure from nucleate boiling (DNB), the loss of normal feedwater event is bounded by the loss of load transient for BVPS-1 and 2.

Response:

Both of these transients, the loss of normal feedwater (LONF) and loss of load (LOL), represent a reduction in the heat removal capability of the secondary system. For the LONF transient, the RCS temperature increases gradually as the steam generators boil down to the low-low level trip setpoint, at which time reactor trip occurs, and is immediately followed by turbine trip. With nuclear power dropping at nearly the same time that steam flow drops, there is very little power mismatch between the primary and secondary systems to force a RCS heatup.

For the LOL transient, the turbine trip is the initiating event, and the power mismatch between the primary and secondary is much more severe. This results in a more severe RCS heatup in the LOL transient than for the LONF transient. Therefore, the LOL transient, which resulted in a minimum DNBR that remained above the safety analysis limit (SAL) (minimum DNBR of 2.23 for BVPS-1 and 1.83 for BVPS-2 versus DNBR SAL of 1.55), will always be more severe with respect to the minimum DNBR criterion than the LONF transient.

L.2 (Applicable to RSG & EPU)

Provide the results of an analysis for the loss of normal feedwater transient concerning peak system pressure using initial conditions and assumptions which will maximize the peak primary and secondary system pressures (including the assumption of the pressurizer PORVs inoperable)

Response:

With respect to overpressurization, the loss of normal feedwater (LONF) transient analysis is bounded by the analysis of the loss of load/turbine trip (LOL/TT) transient, in which assumptions are made to conservatively calculate the RCS and Main Steam System (MSS) pressure transients. The LOL/TT transient results in a more limiting power mismatch between the primary and secondary sides. In the LOL/TT analysis, following the loss of secondary load (and assuming a coincident feedwater isolation), the primary side operates at full power (100.6%) until rod motion occurs. This contrasts with the LONF analysis in which the turbine trip occurs coincident with the reactor trip. Having a longer period of primary-to-secondary power mismatch results in a more severe RCS and MSS heatup and pressurization. Based on this, a LONF case that maximizes the peak RCS or MSS pressure is not explicitly analyzed.

L.3 (Applicable to RSG & EPU)

Discuss the provisions made in plant EOPs for controlling AFW at the beginning of the event to prevent excess cooldown during this event.

Response:

From a safety analysis standpoint, other excessive cooldown events are analyzed and are more limiting. The feedwater malfunction events are analyzed for cooldown caused by excessive feedwater flow to one steam generator and for feedwater to all steam generators that has bypassed a feedwater heater. However, the core response for the main steamline break accident results in the most excessive cooldown (up to a full break of a steamline and full capacity auxiliary feedwater). The main steamline break is a Condition IV event analyzed until automatically-actuated mitigation systems turn the event around, but the steamline break has the same acceptance criteria as the Condition II loss of normal feedwater event and therefore the steam line break analysis bounds the potential excessive cooldown during a loss of normal feedwater.

Different Beaver Valley emergency operating procedures adequately instruct the operators to control steam generator level and auxiliary feedwater flow rate. The loss of main feedwater procedure quickly directs the operator to emergency operating procedure E-0, "Reactor Trip or Safety Injection." In procedure E-0, if cooldown continues, operators are to reduce the total feed flow to minimize cooldown. Other Beaver Valley emergency operating procedures protect against excessive cooldown as follows:

a. ECA-0.0, Loss of All AC Power. Step 19 directs the operator to control SG level/control AFW.

b. ES-0.2, Natural Circulation. Step 5 directs the operator to control the cooldown rate and maintain a SG level band.

c. F-0.4, Vessel Integrity Fault Tree. The first status checkpoint in the status tree is to check for a greater than 100 degree Fahrenheit cooldown in the last 60 minutes.

d. Attachments to the emergency operating procedures define the acceptable reactor vessel pressure/temperature curve and the acceptable cooldown range.

Section 5.3.8 **Loss of Non-Emergency AC [alternating current] Power to the Plant Auxiliaries**

M.1 (Applicable to RSG & EPU)

Explain the difference in assumptions made for BVPS-1 and 2, as stated in Section 5.3.8.2.e of the EPU report.

Response:

For loss of normal feedwater and loss of AC power analyses, a spectrum of cases is analyzed. Cases with both minimum (0%) and maximum (22%) steam generator tube plugging, cases at the extremes of the average temperature range (with uncertainties applied conservatively) and cases with the pressurizer pressure uncertainty applied in both directions. For BVPS-1 and 2, cases at both extremes of the feedwater temperature range (400°F and 455°F) were also considered. Out of all of these cases, the case with the most limiting results was reported for each unit. For BVPS-1, the limiting case modeled low nominal temperature and pressure minus uncertainties (i.e., 570.5°F and 2210 psia), 0% steam generator tube plugging and a feedwater temperature of 400°F. For BVPS-2, the limiting case modeled high nominal temperature plus uncertainty, nominal pressure minus uncertainty (i.e., 588.5°F and 2205 psia), 0% steam generator tube plugging and a feedwater temperature of 400°F.

There are small differences between BVPS-1 and 2 in the magnitude of the volumes in the sub-nodes in the RCS and in the ΔPs around the RCS loop but these are not significant in terms of the loss of AC power results. The significant difference between BVPS-1 and 2 is the steam generators. The BVPS-1 Model 54F steam generators are larger (approximately 3000 ft^2 more heat transfer surface area) than the BVPS-2 Model 51M steam generators and the lower level tap on the Model 54F is about 66 inches lower than the Model 51M. The low-low level trip safety analysis limit (SAL) is 0% narrow range span (NRS) for BVPS-2 and 5% NRS for BVPS-1. Considering the reduced lower level tap for BVPS-1, the BVPS-1 trip SAL is about 60 inches lower than the BVPS-2 trip SAL. The Model 54F steam generator results in a greater initial steam generator mass and the lower trip SAL results in a lower steam generator mass corresponding to the low-low level steam generator trip setpoint, which translates to a much later trip for the BVPS-1 replacement steam generators. A later trip means more full power seconds of heat to remove and subsequently more severe analysis results. The minimum auxiliary feedwater flow rate for each unit is 489 gpm (163 gpm/generator). The entire 489 gpm is modeled for BVPS-1 but only 400 gpm was needed for BVPS-2 to meet the acceptance criterion.

M.2 (Applicable to RSG & EPU)

Provide a quantitative evaluation to verify the conclusion made in Section 5.3.8.5 of the EPU report that, with respect to DNB, the loss of non-emergency AC power transient is bounded by the loss of flow transient for BVPS-1 and 2.

Response:

The DNB consequences of a loss of non-emergency AC power are similar to those of a loss of normal feedwater event with the additional effect of the reduced core flow caused by the loss of power to the reactor coolant pumps. However, the loss of non-emergency AC power event is bounded by the complete loss of flow event. The RCS flow coastdown is the initiating fault in the complete loss of flow event and reactor trip occurs after the flow has already been degraded. In the loss of non-emergency AC power event, the flow coastdown occurs after reactor trip. Thus, no DNB calculations are performed for the loss of non-emergency AC power analysis. In the loss of non-emergency AC power analysis, assumptions are made to maximize the resultant pressurizer water level.

M.3 (Applicable to RSG & EPU)

Provide the results of an analysis for the loss of non-emergency AC power transient concerning peak system pressure using initial conditions and assumptions which will maximize the peak primary and secondary system pressures (including the assumption of the pressurizer PORVs inoperable).

Response:

For a loss of non-emergency AC power event, turbine trip occurs after reactor trip, whereas, in the loss of load/turbine trip analysis, the turbine trip is the initiating fault. Therefore, the primary to secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the loss of load/turbine trip than for a loss of non-emergency AC power event. For this reason, no attempt is made in the loss of non-emergency AC power analysis to maximize primary or secondary pressure. On the other hand, assumptions are made in the loss of load/turbine trip analysis to maximize primary and secondary pressures (including assuming that the pressurizer PORVs are inoperable). In the loss of non-emergency AC power analysis, assumptions are made to maximize the resultant pressurizer water level. One of these assumptions is that the pressurizer PORVs are available. A lower primary system pressure results in a higher peak pressurizer water volume.

Section 5.3.9 Excessive Heat Removal Due To Feedwater System Malfunctions

N.1 (Applicable to RSG & EPU)

In Table 5.3.9-1, which presents the analysis results of the excessive feedwater flow cases, turbine trip is represented as the automatic protection system action which prevents DNB. The associated transient plots indicate that the departure from nucleate boiling ratio (DNBR) is predicted to stabilize at some minimum level that is above the minimum DNBR specified acceptable fuel design limit (SAFDL), consistent with stabilized primary system power and temperature conditions. Actually, the SG high-level turbine trip provides protection against SG overfill, not DNB, and demonstrates that (1) the turbine would not be damaged by excessive moisture carryover, and (2) the event would not develop into a more serious event (e.g., a steamline rupture due to the weight of water in the steam lines). Protection against DNB is provided by the overtemperature ΔT trip in the loss of feedwater heater cases. Therefore, one cannot conclude that, "The decrease in feedwater temperature transient due to the failure of one or more low-pressure heaters is similar to the feedwater flow increase event discussed in detail in this section." Since SG overfill and subsequent escalation of this event into a Condition III or IV event are not mentioned, one cannot conclude that, "The protection features presented in Section 5.3.9.2 provide mitigation of the feedwater system malfunction transient such that the above criteria are satisfied." Please expand Section 5.3.9 to address these differences in the low-temperature and high-flow aspects of the feedwater malfunction cases, and show how timely protection is provided to satisfy all the Condition II acceptance criteria.

Response:

As can be seen from Table 5.3.9-1, the minimum DNBR for the feedwater flow increase cases occurs prior to the initiation of rod motion. This demonstrates that the reactor trip on turbine trip is not required for core protection. Assuming this reactor trip function to be operable is consistent with the fact that the feedwater malfunction event is a reactor coolant system (RCS) cooldown transient. If this trip is not assumed, the transient following turbine trip and feedwater isolation on hi-hi steam generator water level will resemble a loss of normal feedwater, an RCS heatup event, with steam generator level decreasing until a reactor trip occurs on low-low steam generator water level. The steam generator high level turbine trip provides protection against steam generator overfill, which helps preclude damage to the turbine blades due to excessive moisture carryover. Credit for the steam generator high level trip ensures termination of the excessive main feedwater addition.

For the feedwater temperature reduction cases, the minimum DNBR occurs soon after the initiation of rod motion following reactor trip on overpower ΔT, thus demonstrating that reactor trip is required for core protection. Following reactor trip, main feedwater flow is automatically isolated on a partial feedwater isolation signal. For this analysis, main feedwater was conservatively assumed to be terminated by a low pressurizer pressure safety injection (SI) signal, which provides a full feedwater isolation signal that closes the feedwater control valves and also trips the main feedwater pumps. The time sequences of events for the limiting feedwater temperature reduction cases (with manual rod control) are provided in Table N.1-1. Corresponding transient responses are presented in Figures N.1-1 through N.1-3 for BVPS-1 and Figures N.1-4 through N.1-6 for BVPS-2. Note that a very conservative feedwater temperature reduction of 155°F was analyzed, although the actual temperature reduction resulting from bypassing the low pressure feedwater heaters is expected to be less than 70°F. This overly conservative assumption caused the feedwater temperature reduction event to be slightly more limiting than the feedwater flow increase event with respect to the minimum departure from nuclear boiling ratio (DNBR). Historically, the feedwater flow increase event was more limiting, and therefore only this case was discussed in detail in the UFSAR.

The feedwater malfunction transients do not present a serious challenge to the RCS and main steam system (MSS) pressure limits, and are therefore not modeled to maximize the peak RCS and MSS pressures. With respect to peak RCS and MSS pressures, the feedwater malfunction transients are bounded by the loss of load/turbine trip transient.

With respect to the event propagation acceptance criterion (event should not generate a more serious plant condition without other faults occurring independently), it is shown to be met by demonstrating the feedwater malfunction event does not result in a pressurizer water-solid condition. Satisfying this criterion provides assurance that the pressurizer safety valves remain operable since the discharge of water through these valves is precluded if this criterion is met. As indicated by Figures N.1-3 and N.1-4, this event does not significantly challenge the pressurizer fill criterion.

Table N.1-1
Time Sequence of Events – Excessive Heat Removal Due to Feedwater System Malfunction – Temperature Reduction

Event	BVPS-1 (Model 54F SGs) Time (seconds)	BVPS-2 (Model 51M SGs) Time (seconds)
Low pressure feedwater heaters are bypassed	0.0	0.0
OPΔT reactor trip setpoint reached	42.6	43.5
Rod motion begins	44.6	45.5
Minimum DNBR occurs	45.0	45.9
Low pressurizer pressure safety injection setpoint reached (1745 psia (BVPS-1), 1760 psia (BVPS-2))	77.7	77.3
Feedwater isolation valves begin to close	87.7	84.3

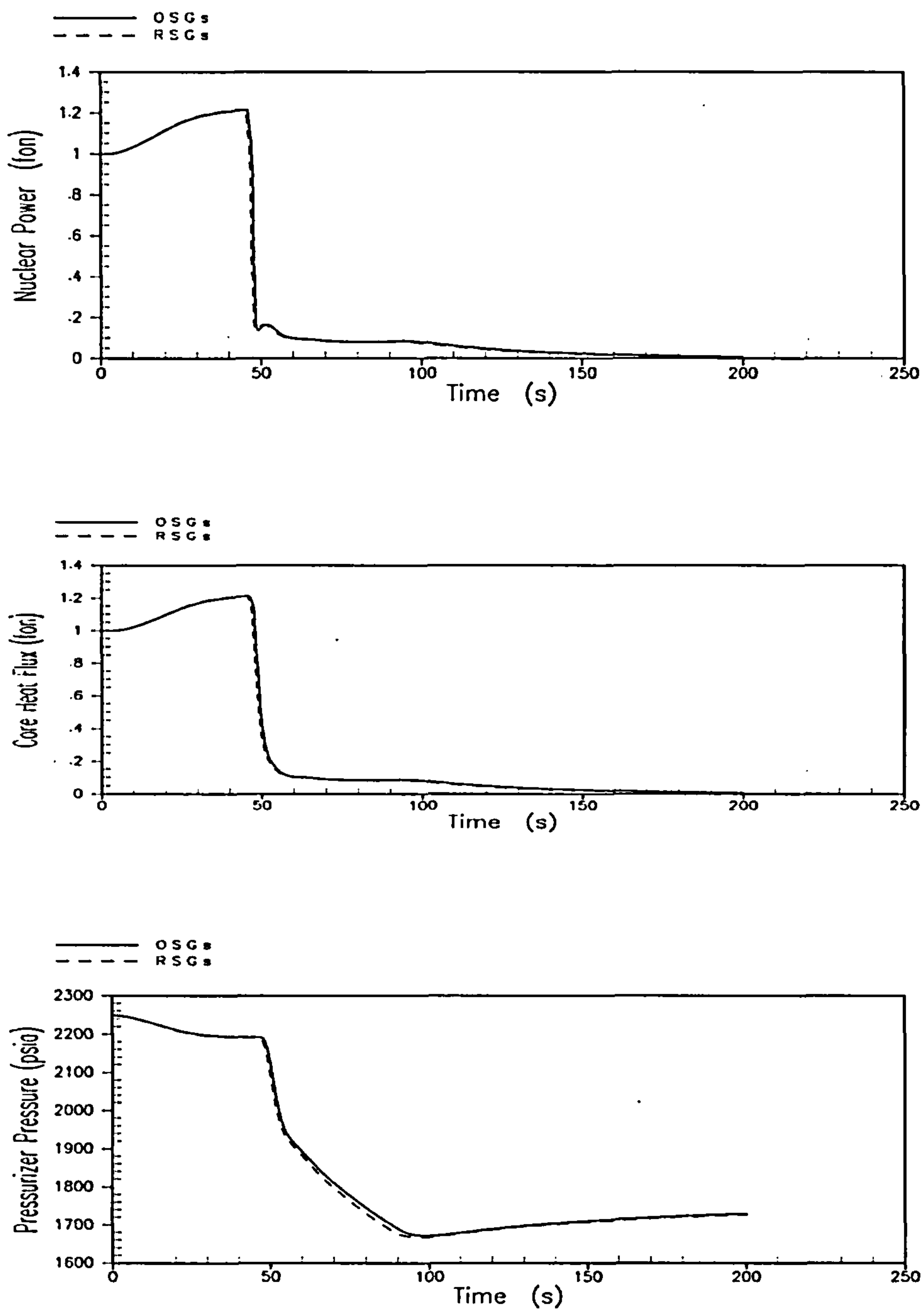
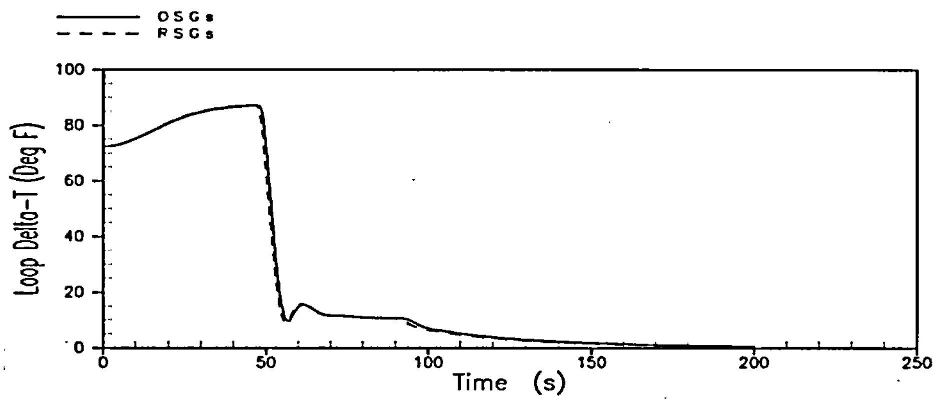
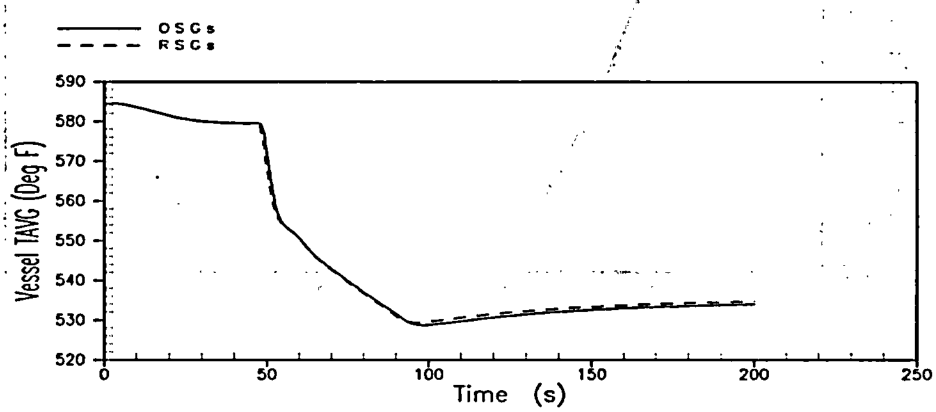


Figure N.1-1
BVPS-1 – FWM at Full Power, Manual Rod Control, Feedwater Temperature Reduction Case – Comparison of OSGs and RSGs





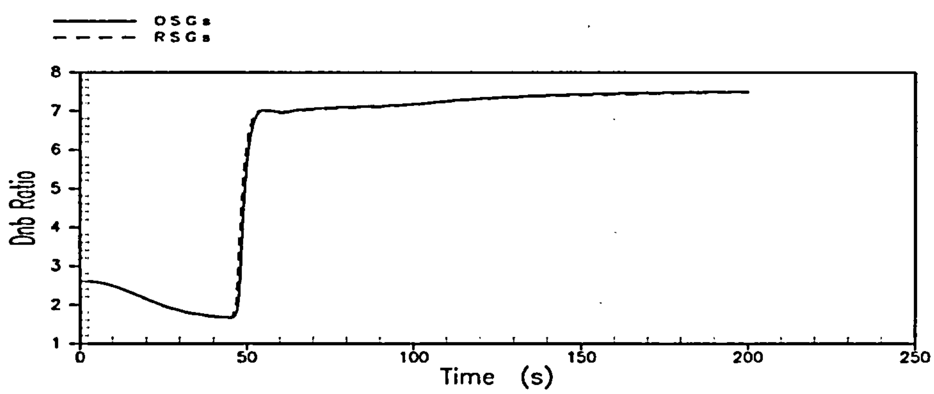


Figure N.1-2
BVPS-1 – FWM at Full Power, Manual Rod Control, Feedwater Temperature Reduction Case – Comparison of OSGs and RSGs

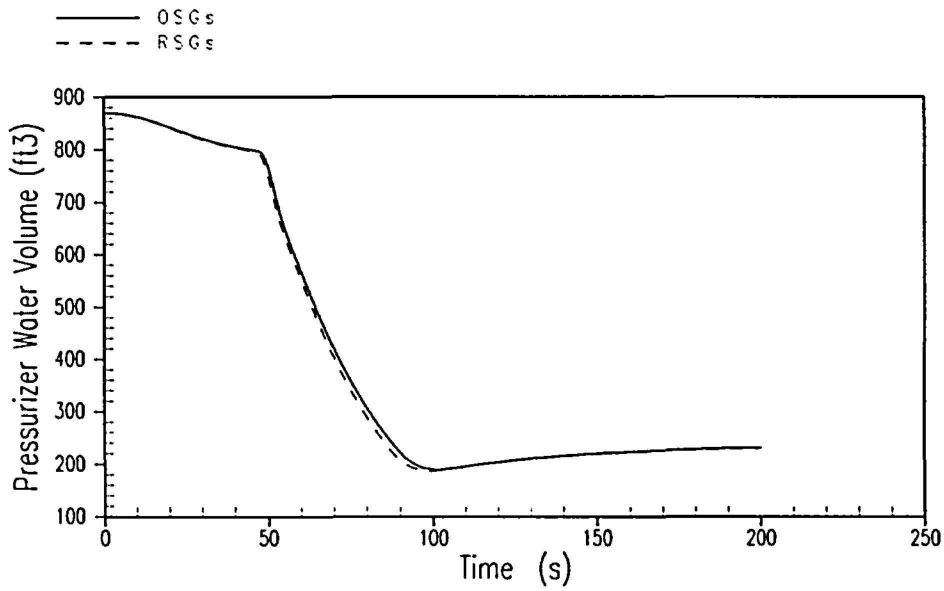
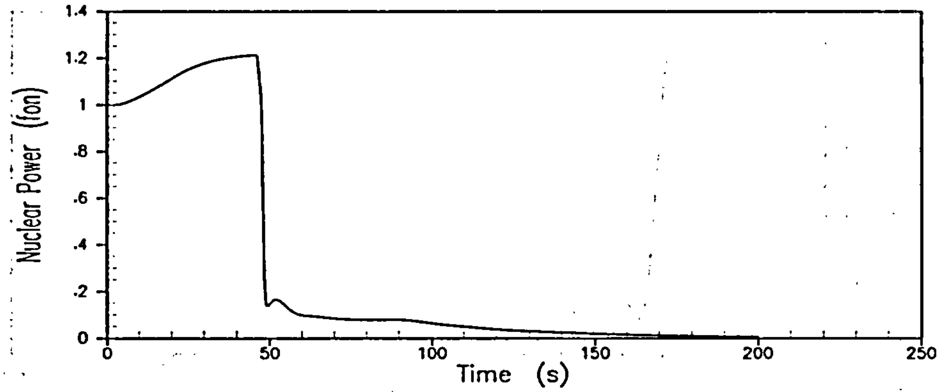
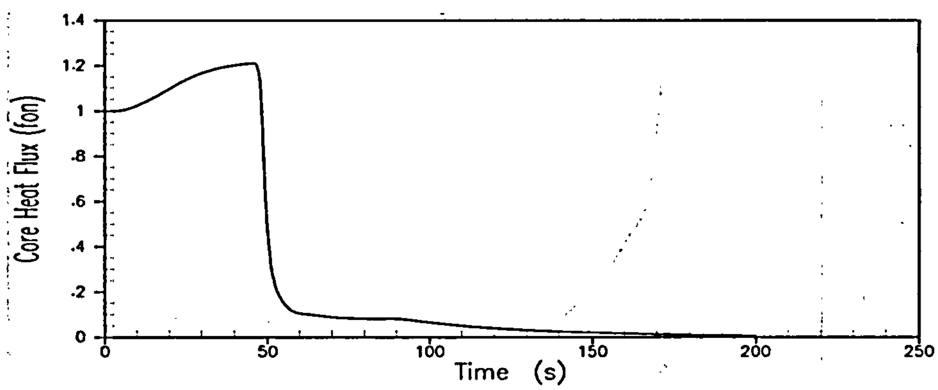


Figure N.1-3
BVPS-1 – FWM at Full Power, Manual Rod Control, Feedwater Temperature Reduction Case – Comparison of OSGs and RSGs





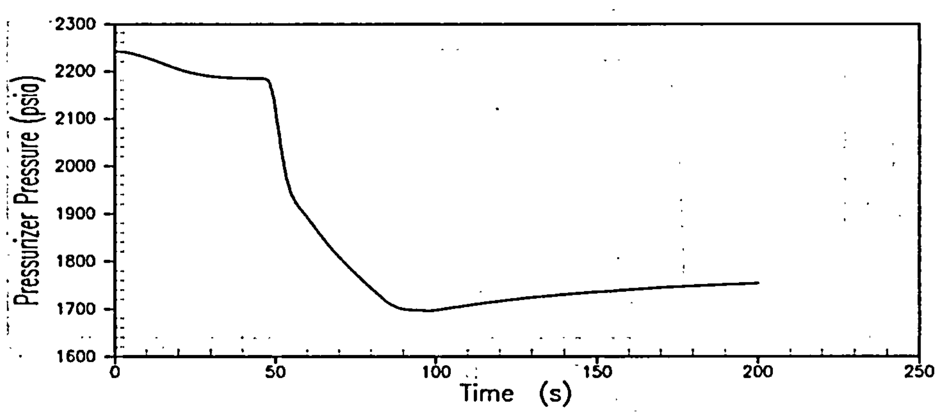


Figure N.1-4
BVPS-2 – FWM at Full Power, Manual Rod Control, Feedwater Temperature Reduction Case

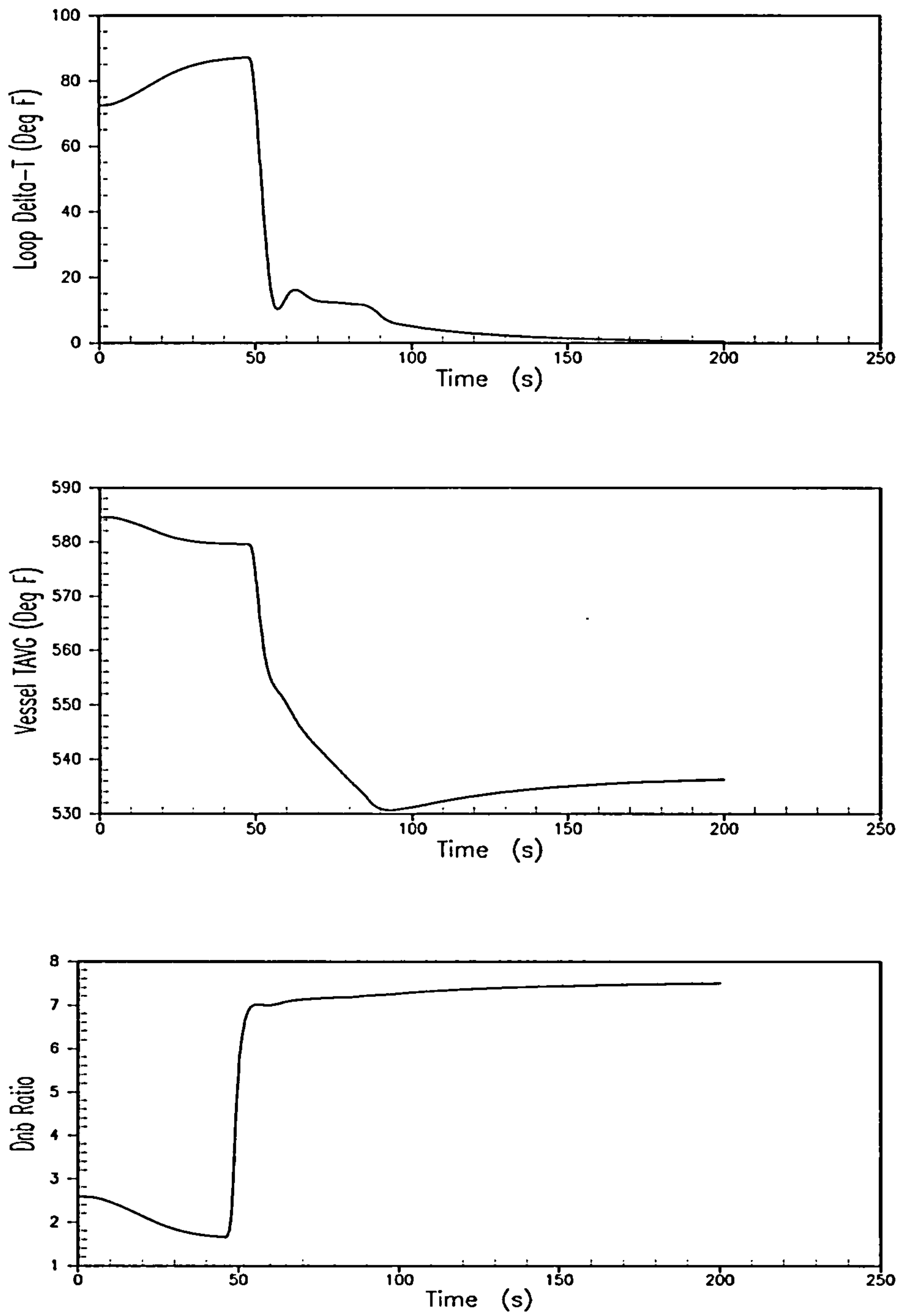


Figure N.1-5
BVPS-2 – FWM at Full Power, Manual Rod Control, Feedwater Temperature Reduction Case

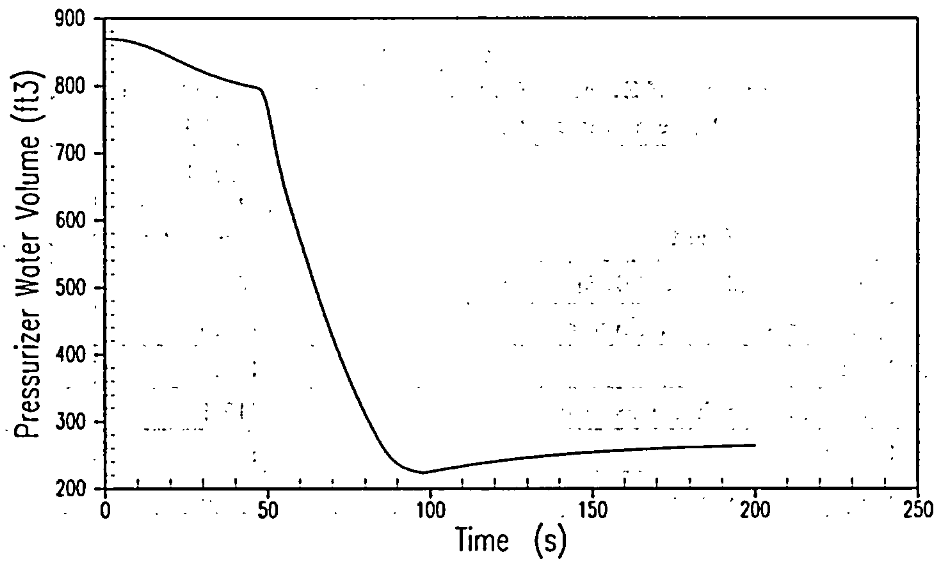


Figure N.1-6
BVPS-2 – FWM at Full Power, Manual Rod Control,
Feedwater Temperature Reduction Case

N.2 (Applicable to RSG & EPU)

Include a comparison of the transient response to this event for BVPS-1 for both the original SGs (OSGs) and the RSGs at the EPU conditions.

Response:

Table N.2-1 provides a time sequence of events comparison between BVPS-1 OSGs and RSGs for the limiting feedwater flow increase event. Corresponding transient response comparisons are presented in Figures N.2-1 through N.2-3.

Table N.2-1
Time Sequence of Events – Excessive Heat Removal Due to Feedwater System Malfunction – Flow Increase (BVPS-1)

Event	BVPS-1 (Model 51 SGs) Time (seconds)	BVPS-1 (Model 54F SGs) Time (seconds)
One main feedwater control valve fails full open	0.0	0.0
Hi-Hi steam generator water level trip setpoint is reached	109.6	108.9
Minimum DNBR occurs	112.0	111.0
Turbine trip occurs due to hi-hi steam generator level	112.1	111.4
Rod motion begins	114.1	113.4
Feedwater isolation valves closed	119.6	118.9

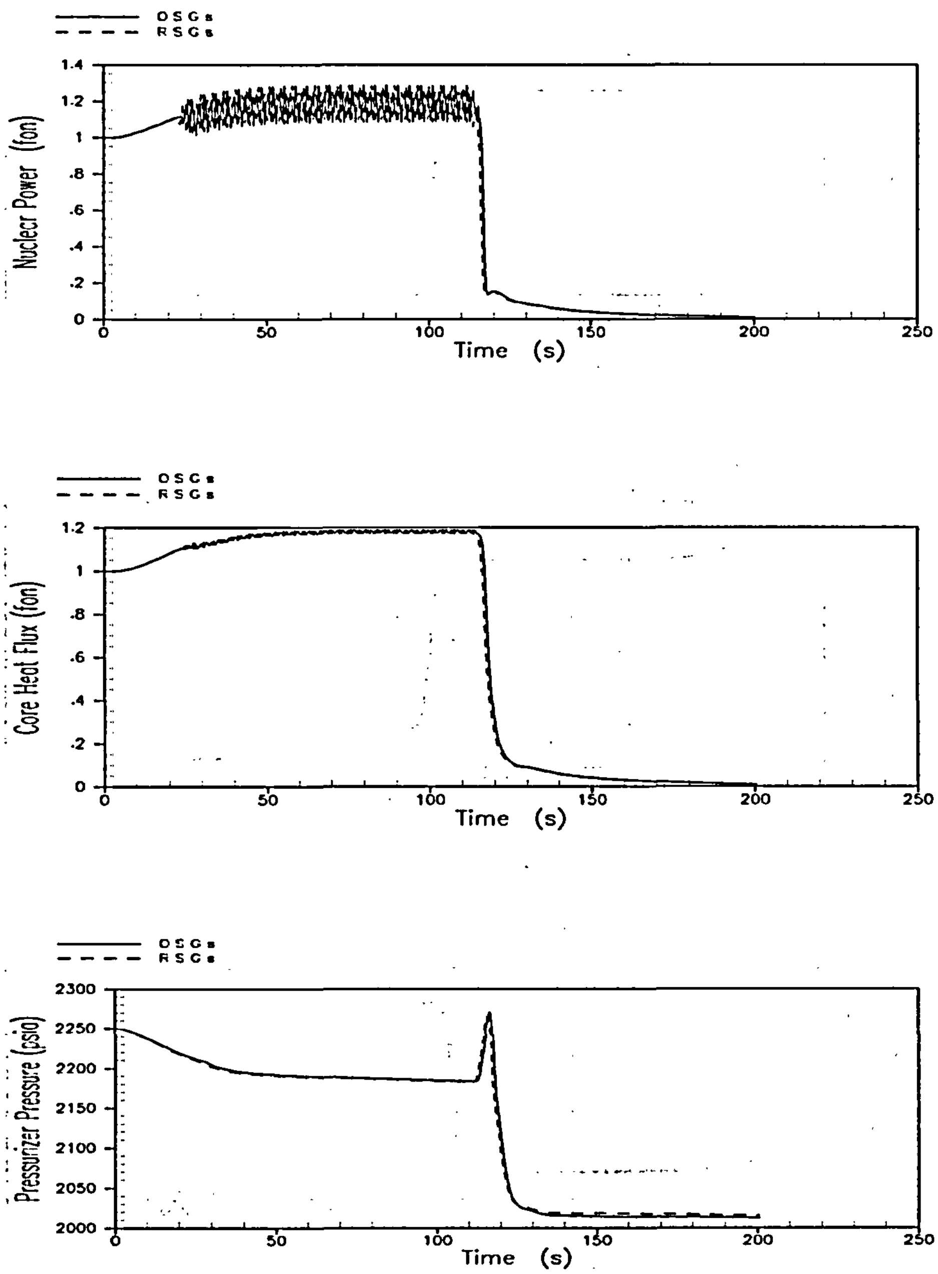


Figure N.2-1
BVPS-1 – FWM at Full Power, Automatic Rod Control, Feedwater Flow Increase Case – Comparison of OSGs and RSGs

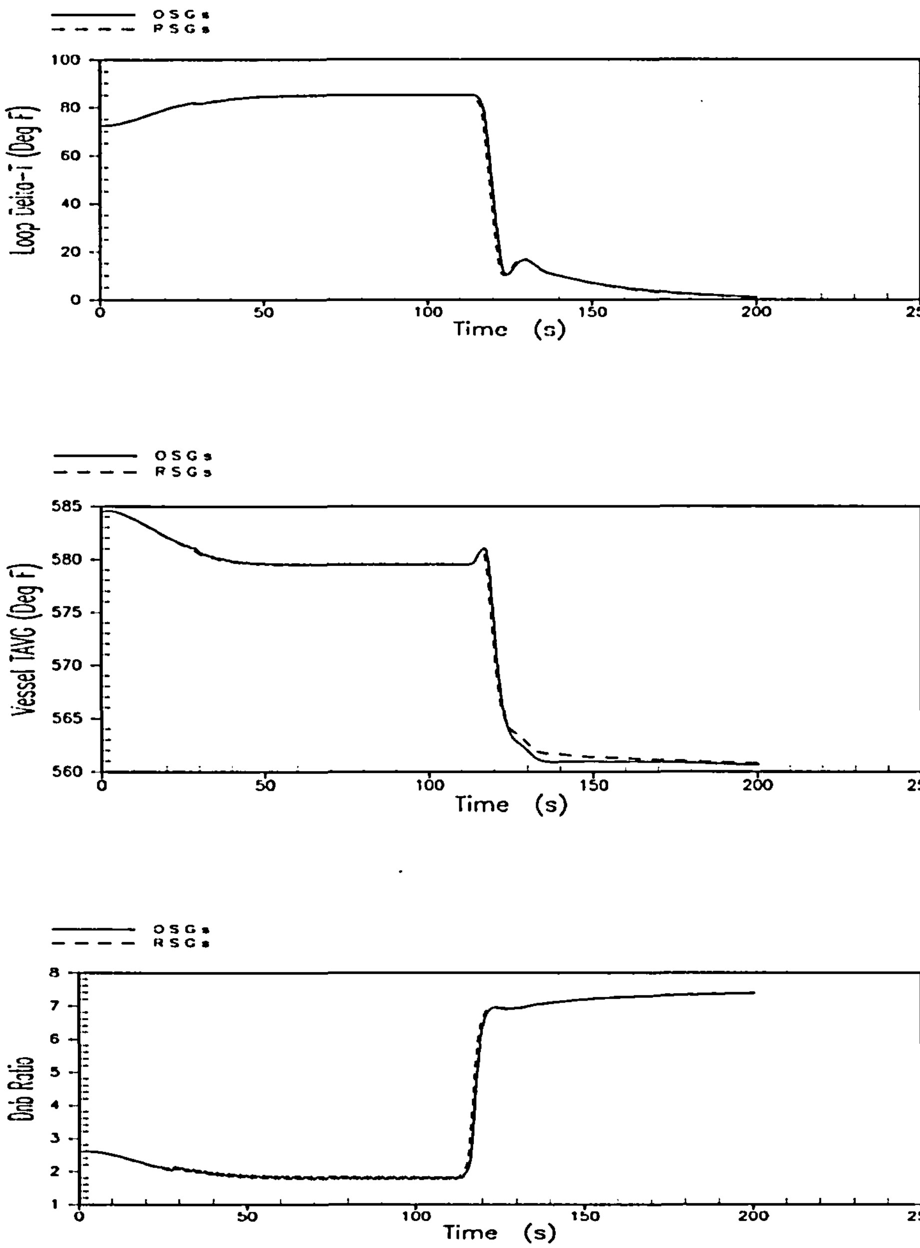


Figure N.2-2
BVPS-1 – FWM at Full Power, Automatic Rod Control, Feedwater Flow Increase Case – Comparison of OSGs and RSGs

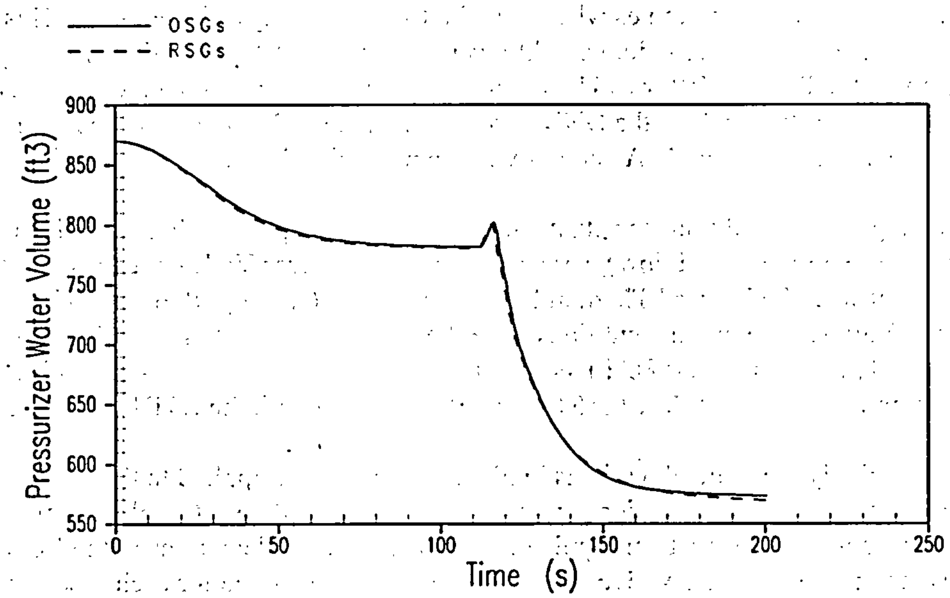


Figure N.2-3
BVPS-1 – FWM at Full Power, Automatic Rod Control, Feedwater Flow Increase Case – Comparison of OSGs and RSGs

Section 5.3.10 **Excessive Load Increase Incident**

O.1 (Applicable to RSG & EPU)

How was it determined that a reactor trip does not occur, if an analysis was not performed?

Response:

This event is typically very non-limiting – no reactor trip is generated and the DNB design basis is seldom challenged. As such, an alternate methodology has been developed which very conservatively determines whether a plant specific analysis is required. This method applies conservatively bounding conditions in generating statepoints that are compared directly to the Beaver Valley EPU core thermal limits. If the statepoint conditions remain above the conditions where the DNBR would equal the EPU safety analysis DNBR limit, no further analysis is required. A summary of the method follows.

Bounding initial conditions for plant parameters which impact DNBR conditions (i.e., power, temperature, pressure and flow) were determined for Beaver Valley at EPU conditions consistent with the Revised Thermal Design Procedure (RTDP) DNB methods employed for Beaver Valley. The initial conditions were the licensed EPU core power (2900 MWt), high nominal T_{avg} temperature (580°F), nominal RCS pressure with measurement bias (2242.5 psia) and minimum measured flow (266,800 gpm), consistent with the RTDP DNB methods.

Conservatively bounding deviations in plant parameters are applied to the Beaver Valley initial conditions. The deviations are derived from a bounding set of plant analysis results with appropriate conservatisms applied. By applying these deviations to the Beaver Valley initial conditions, a conservative set of statepoints are generated for each case examined. Table O.1-1 shows the deviations applied to the initial conditions that address various cases examined (note that a consistent RCS flow rate is assumed).

Table O.1-1
Deviations Applied to the Initial Conditions

Case	Feedback	Rod Control	Change in Power (fraction of nominal)	Change in Average Temperature (°F)	Change in Primary Pressure (psia)
1	Minimum	Manual	+0.10	+0.0	-350
2	Maximum	Manual	+0.14	+0.0	-150
3 and 4	Both *	Automatic	+0.16	+6.0	-100

* The case represents the worst results from cases analyzed with both minimum and maximum reactivity feedback.

The combined Beaver Valley EPU initial conditions and bounding deviations (i.e., statepoints) were compared directly to the Beaver Valley EPU core thermal limit lines that represent the locus of conditions when the DNBR is equal to the DNBR limit value for the EPU. The comparison showed that margin between the bounding statepoint conditions and core thermal limits exist which demonstrate that the minimum DNBR conditions associated with an excessive load increase incident for Beaver Valley at EPU conditions meet the EPU safety analysis DNBR limit.

O.2 (Applicable to RSG & EPU)

How were the statepoints, that were evaluated for DNBR, selected or determined?

Response:

The statepoints are based on historical excessive load increase incident analyses for Westinghouse 2-loop, 3-loop and 4-loop plants. Four scenarios are considered – minimum and maximum reactivity feedback with the plant in manual and automatic rod control. For each scenario, the most limiting results from all the historical analyses were considered when creating the generic statepoints. The statepoints are based on analyses from approximately 20 different Westinghouse plants, and are comprised of the most limiting temperature, pressure and power that result at any time during the transient. Additional conservatism is then added to the statepoints and they are combined with the actual plant conditions and compared to the core thermal limits. If the statepoints are less than the core thermal limits, then no plant specific analysis is needed and the DNB design basis is met.

O.3 (Applicable to RSG & EPU)

Please describe the stabilized condition that is reached by the plant, following the initial load increase, and compare that to the results of the load increase analysis in the current licensing basis, which is analyzed at a relatively lower power level.

Response:

Four scenarios are considered – minimum and maximum feedback with manual and automatic rod control. Table O.3-1 gives the limiting EPU statepoints for the four scenarios. The current licensing basis for both Beaver Valley units used the same methodology that was used for the EPU compared to the previous excessive load increase incident analysis results for BVPS-1 and 2. Thus, the only differences in the statepoints are that the temperatures are 3.8°F lower for the current licensing basis (the maximum nominal T_{avg} is 576.2°F for the current licensing basis and 580.0°F for the EPU) and the power is higher (the fractional power is the same but the real power – fractional times nominal – is higher). The stabilized condition reached for each case is presented in Table O.3-1.

Table O.3-1 Limiting EPU Statepoints					
Case	**Feedback**	**Rod Control**	**New Equilibrium Power Level (Fraction of Nominal)**	**Highest Average Temperature (°F)**	**Lowest Primary Pressure (psia)**
1	Minimum	Manual	+1.10	580	1892.5
2	Maximum	Manual	+1.14	580	2092.5
3 and 4	Both *	Automatic	+1.16	586	2142.5
* The case represents the worst results from cases analyzed with both minimum and maximum reactivity feedback.					

O.4 (Applicable to RSG & EPU)

With respect to peak pressure, it is stated that the excessive load increase accident is bounded by the loss of electrical load/turbine trip analysis. Please explain how an event in which steam flow is cut off can bound an event in which steam flow is increased.

Response:

The loss of load event is the most limiting non-LOCA event with respect to peak pressure. For the excessive load increase event, pressure decreases during the event. Therefore, the excessive load increase event peak pressure is bounded by that resulting from the loss of load event.

Section 5.3.11 **Inadvertent Opening of a Pressurizer Relief or Safety Valve**

P.1 (Applicable to RSG & EPU)

Section 5.3.11.5 concludes, "The results of the analysis show that the pressurizer low pressure and overtemperature ΔT trip reactor protection system signals provide adequate protection against the RCS depressurization event since the minimum DNBR remains above the safety analysis limit throughout the transient." The analysis in Section 5.3.11 indicates DNB protection is provided by the low pressurizer pressure trip; but there is no test of the overtemperature ΔT trip. Please provide an analysis of the RCS depressurization event that demonstrates the overtemperature ΔT trip provides adequate protection against DNB.

Response:

The intent of the statement in Section 5.3.11 is to convey that acceptable analysis results were obtained with credit for only two protective functions. The analyses performed for BVPS-1 and 2 for the EPU model only the low pressurizer pressure and OTΔT trip functions. The analyses demonstrate that all applicable acceptance criteria are met. For this event, the low pressurizer pressure trip was reached first. It is not necessary to assume a common mode failure in the protection system in an analysis of a Condition II event.

P.2 (Applicable to RSG & EPU)

The amendment request states, "An accidental depressurization of the reactor coolant system (RCS) could occur as a result of an inadvertent opening of a pressurizer relief valve. To conservatively bound this scenario, the Westinghouse methodology models the failure of a pressurizer safety valve since a safety valve is sized to relieve approximately twice the steam flowrate of a relief valve and will allow a much more rapid depressurization upon opening." BVPS-1 and 2 are equipped with three PORVs. If all three PORVs were to open, then the resulting relief rate would be about 50% greater than the analyzed safety valve relief flow rate. Verify that there is no single failure in the instrumentation and control system, and there is no operator error that would cause all three PORVs to open.

Response:

The pressurizer PORV instrumentation and control system was designed with multiple power sources, separation of cabling, and controls with two independent trains for activation. No single failure mechanism has been identified that would cause all three PORVs to open. One PORV is normally operated in automatic by the pressurizer master pressure controller using channel PT-444 as input. The other two PORVs are normally operated in automatic using channel PT-445. All three PORVs would automatically open only on a valid high pressurizer pressure condition. The PORVs at both units are designed to fail closed. In addition, the PORVs at both units receive an automatic close signal on a lower than normal RCS operating pressure as detected by 2 of 3 safety related pressure channels.

The PORVs, if manually opened, would be performed under operator control in response to validated plant conditions and/or as directed by emergency operating procedures. Physically, there are 3 switches, one for each PORV, such that an operator could not open all 3 PORV's with a single action. There are no procedures that direct the operator to open all 3 PORV's to initiate an accidental depressurization.

P.3 (Applicable to RSG & EPU)

Confirm that an accidental actuation of pressurizer spray would not cause a more rapid depressurization of the RCS than the analyzed case.

Response:

The RCS depressurization analysis performed for BVPS-1 and 2 simulates a stuck open pressurizer safety valve (PSV) as the initiating event, and therefore reflects the most conservative depressurization of the RCS for these plants. The accidental opening of a pressurizer power operated relief valve (PORV) or spray valve, which is defined as an ANS Condition II event, is considered to be the only credible failure mode for the RCS depressurization event. If a pressurizer PORV or spray valve were to fail open, the event would eventually be terminated by the operator by closing either the failed valve or an isolation valve in the affected path. According to the Westinghouse methodology, the accidental depressurization of the RCS is bounded by simulating a stuck open PSV. The safety valve has a much larger capacity than a PORV or spray valve and therefore simulates the most conservative depressurization that could potentially occur. It should be noted that a stuck open PSV is considered to be a small break LOCA, defined as a Condition III event; for a stuck open PSV, the RCS is unisolatable. The attached plot compares the pressure transient for the stuck open PSV with that for accidental opening of the pressurizer spray valves for BVPS-2. Figure P.3-1 demonstrates that modeling a stuck open PSV is bounding for the RCS depressurization event. A similar result would be expected for BVPS-1.

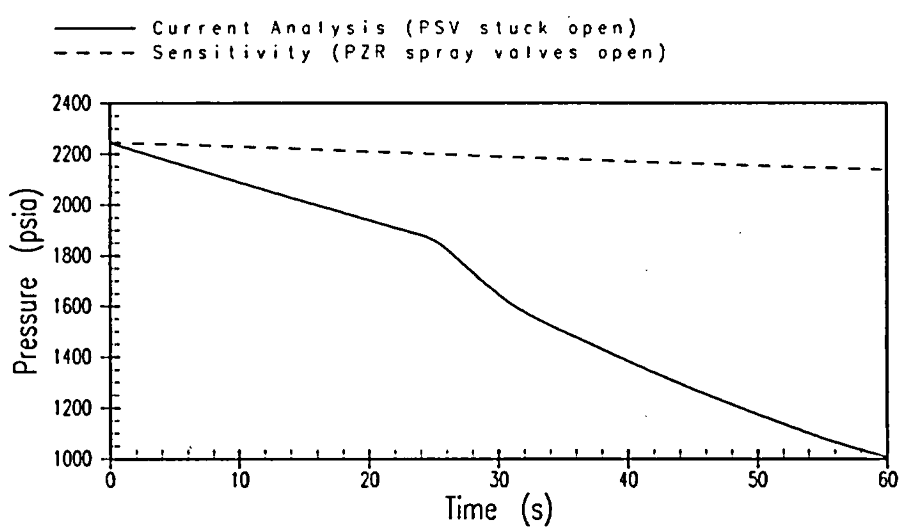


Figure P.3-1
BVPS-2 EPU RCS Depressurization

<u>Section 5.3.12</u> <u>Major Rupture of a Main Steam Pipe</u>

Q.1 (Applicable to RSG & EPU)

Section 15.1.5.2 of the BVPS-2 UFSAR states, "Since the steam generators are provided with integral flow restrictors with a 1.4 ft^2 throat area, any rupture with a break area greater than 1.4 ft^2, regardless of location, would have the same effect on the NSSS as the 1.4 ft^2 break." Section 5.3.12.2 of the application states, "For Beaver Valley Unit 2, a 1.069 ft^2 break was analyzed for the Model 51M OSGs since they are designed with a flow restrictor built into the steam exit nozzle." Please explain and document this change in break size, from the UFSAR analysis.

Response:

A 1.4 square foot steam generator flow restrictor area has been a standard manufacturing parameter for most of the steam generators manufactured since integral flow restrictors were incorporated. The fact that the BVPS-2 steam generators have flow restrictors that are 1.069 square foot was discovered during the extended power uprate analysis process. The steamline break core response analysis at hot zero power is worse with a larger flow restrictor area. Therefore, the main steam line analysis presented in the BVPS-2 UFSAR is overly conservative.

Q.2 (Applicable to RSG & EPU)

Provide the EPU moderator density coefficient curves for BVPS-1 and 2, and compare them to the current licensing basis moderator density coefficient curves.

Response:

The density coefficient is a function of both moderator density and boron concentration so depicting this as a curve would require a 3D graph. However, the equations can easily be shown. The density coefficients used for the EPU HZP SLB analyses in the point kinetics LOFTRAN model are as follows:

BVPS-1 – Coefficient (Δk/gm/cc) = $0.7350 - 0.5925 * \rho - 0.000126 * C_B$
BVPS-2 – Coefficient (Δk/gm/cc) = $0.9798 - 0.7929 * \rho - 0.000168 * C_B$

Where ρ is the moderator density in gm/cc and C_B is the boron concentration in ppm.

These are identical to the coefficients used in the current licensing basis analyses. The reactivity model is confirmed using a detailed ANC calculation once per cycle during the reload evaluation. The intent of the cycle specific calculation is to confirm that the LOFTRAN point kinetics model remains conservative. If the ANC calculations match the LOFTRAN calculations to within a specified tolerance, then the calculations are acceptable and the more limiting (i.e., higher) power level between the LOFTRAN calculated power and the ANC calculated power is used in the DNBR calculation. If the match is inadequate, then the coefficients are adjusted up or down as necessary, and the process is repeated until the two codes are in agreement. Note that this iteration was done for BVPS-1 several years ago, which is why the coefficients differ for the two units.

Q.3 (Applicable to RSG & EPU)

For the DNB analyses, how were the "limiting points in the transient" determined?

Response:

The limiting points in the transient are determined first by selecting the time step in the transient with the maximum return to power. Where there are multiple time steps with the same maximum return to power, the following criteria are used, in the following order: (1) the time step with the lowest temperature; (2) the time step with the highest pressure; and (3) the time step with the lowest critical boron.

If after reviewing these criteria, there is still ambiguity on the limiting time step, then multiple time steps are analyzed completely to determine which has the most severe consequences (highest peaking factors, lowest DNBR) and the results from the time step with the most severe consequences are then documented.

Q.4 (Applicable to RSG & EPU)

How was it determined that the case with offsite power available was limiting? If analyses were performed, please describe the key input assumptions and values, and results.

Response:

The case with offsite power available is always more limiting than the case without offsite power. This is due to the continued forced cooling when offsite power is available. This continued cooling results in a lower coolant temperature and greater reactivity feedback due to the large assumed end-of-life density coefficient.

Q.5 (Applicable to RSG & EPU)

Section 5.3.12.4 states, "The analysis demonstrates that this criterion is met by showing that the minimum DNBR does not go below the limit value at any time during the transient." What are the minimum and limiting DNBR values? Please provide transient plots of DNBR for BVPS-1 and 2.

Response:

Transient plots of DNBR are not available. Transient statepoints (temperature, pressure, power and flow) are generated and the limiting statepoint is identified (see response to RAI Q.3). A single DNBR calculation is then performed using that limiting statepoint. The minimum DNBR and DNBR limit values are as follows:

BVPS-1	minimum DNBR for RFA fuel = 2.48	DNBR limit = 1.61
BVPS-1	minimum DNBR for V5H fuel = 2.41	DNBR limit = 1.45

BVPS-2 minimum DNBR for RFA fuel = 1.80 DNBR limit = 1.61
BVPS-2 minimum DNBR for V5H fuel = 1.74 DNBR limit = 1.45

Q.6 (Applicable to RSG & EPU)

Please explain, in physical terms, why the minimum DNBR value is reached 7 seconds before the peak power is reached, for BVPS-1, whereas the minimum DNBR value is reached almost 30 seconds after the peak power is reached, for BVPS-2.

Response:

The peak power is reached before the time of minimum DNBR for both Beaver Valley units – 7.0 seconds before for BVPS-1 and 29.6 seconds before for BVPS-2. Therefore, this comment is incorrect. The reason for the difference between the units is explained as follows. The LOFTRAN code prints the heat flux to three decimal places. For BVPS-1, the peak heat flux is 0.115 which it hits at 348.8 seconds and stays at the same value until 359.4 seconds. Thus, the heat flux is between ~0.1145000001 and ~0.1154999999 for 10.6 seconds. The LOFTRAN code also identifies the time when the absolute peak is reached which is 352.4 seconds and the code is not limited to the number of decimal places printed in the statepoint. The entire statepoint is transmitted to Core Technologies for their DNB evaluation and the entire statepoint is considered (see response to RAI Q.3). Given the same heat flux from 348.8 to 359.4 seconds, the worst DNB results were for 359.4 seconds. This is because the transient has been allowed to continue for 7 more seconds and other fluid conditions have deviated further from nominal (e.g., RCS temperatures have decreased an additional ~0.5°F). Similarly for BVPS-2, the peak heat flux is 0.110 (to three decimal places) which is first reached at 181.8 seconds and stays at that value until 232.8 seconds. The absolute peak occurs at 203.2 seconds. The minimum DNBR occurs at 232.8 seconds because the statepoint heat flux is the same as at 203.2 seconds and the other fluid conditions have deviated further from nominal.

Q.7 (Applicable to RSG & EPU)

Please provide SG mass transient plots for BVPS-1 and 2.

Response:

The steam generator mass transient from the limiting hot zero power steamline break case for BVPS-1 is given in Figure Q.7-1 and the steam generator mass transient from the limiting hot zero power steamline break case for BVPS-2 is given in Figure Q.7-2. Note that the plots are different due to a difference between the two units. At BVPS-1, a steamline isolation signal may not close the MSIV bypass valves in the time specified for the MSIVs by the Technical Specifications. In order to conservatively account for this, it is assumed that these valves will not close which results in a small amount of blowdown from the unfaulted steam generators for the duration of the transient. This is why the intact steam generator mass decreases after isolation. This issue does not apply to BVPS-2 because the MSIV bypass valves for BVPS-2 will close in the time specified for the MSIVs by the Technical Specifications. Note that this is an overly conservative assumption because the valves close – just not in the time specified in the Technical Specifications. The small rise in intact steam generator mass for the BVPS-1 transient is again due to this small blowdown from the beginning of the transient. From t=0 until the time of feedline isolation, feed flow is greater than steam flow so the mass increases.

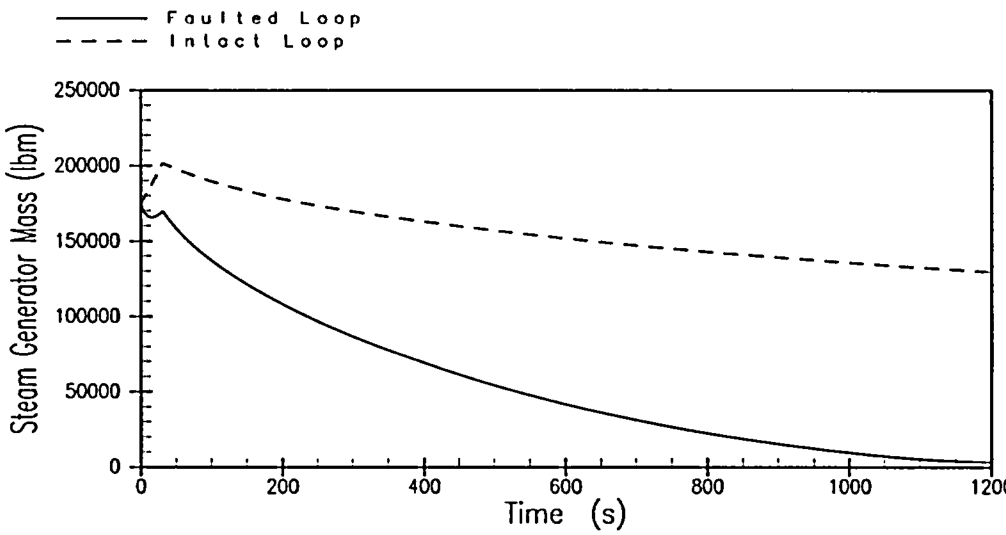


Figure Q.7-1
BVPS-1 Limiting HZP SLB Case – Steam Generator Mass vs. Time

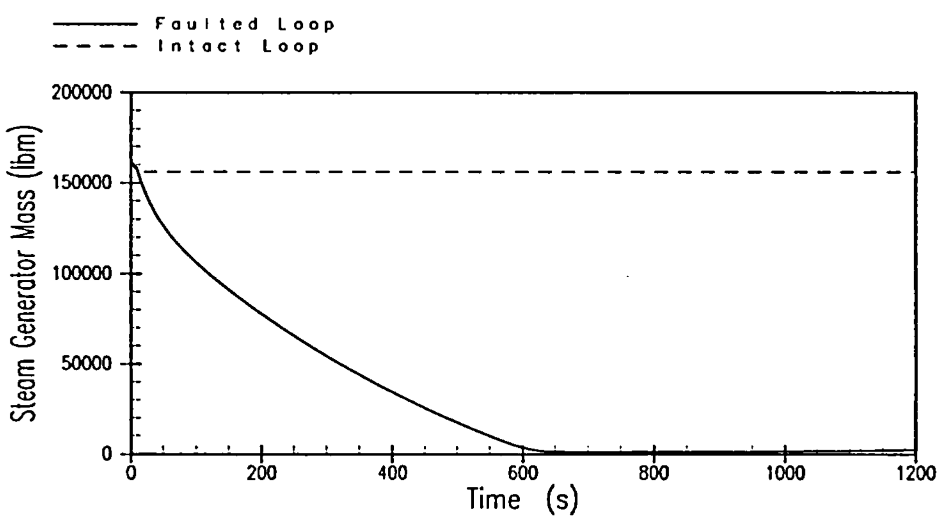


Figure Q.7-2
BVPS-2 Limiting HZP SLB Case – Steam Generator Mass vs. Time

Q.8 (Applicable to RSG & EPU)

Please provide the following transient plots for BVPS-1:

nuclear power
pressurizer pressure
feedwater flow
core mass flow
steam flow
steam generator pressure
reactor vessel inlet temperature
reactor vessel average temperature
core boron concentration
pressurizer water volume

Response:

The following transient plots are provided for the limiting hot zero power steamline break case for BVPS-1. Figure Q.8-1 – Nuclear Power vs. Time, Figure Q.8-2 – Pressurizer Pressure vs. Time, Figure Q.8-3 – Feedwater flow (including AFW) vs. Time, Figure Q.8-4 – Core Mass Flow vs. Time, Figure Q.8-5 – Steam Flow vs. Time, Figure Q.8-6 – Steam Generator Pressure vs. Time, Figure Q.8-7 – Reactor Vessel Inlet Temperature vs. Time, Figure Q.8-8 – Reactor Vessel Average Temperature vs. Time, Figure Q.8-9 – Core Boron Concentration vs. Time and Figure Q.8-10 – Pressurizer Water Volume vs. Time.

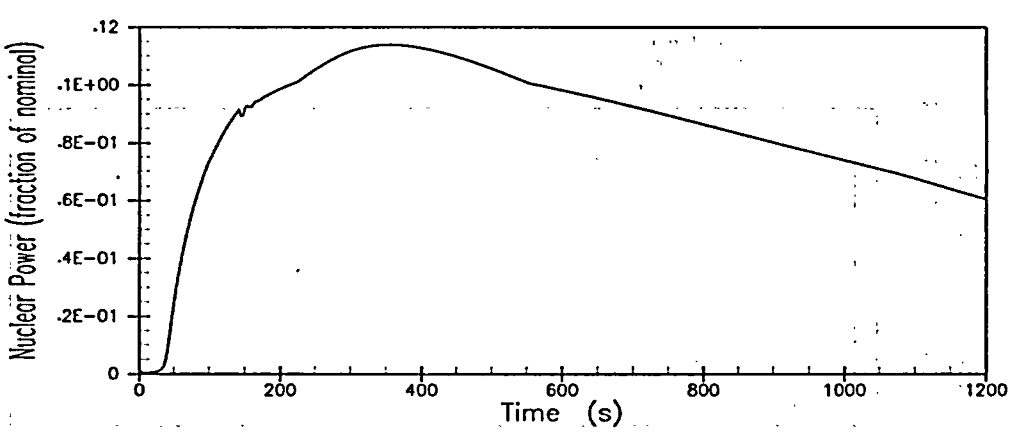


Figure Q.8-1
BVPS-1 Limiting HZP SLB Case – Nuclear Power vs. Time

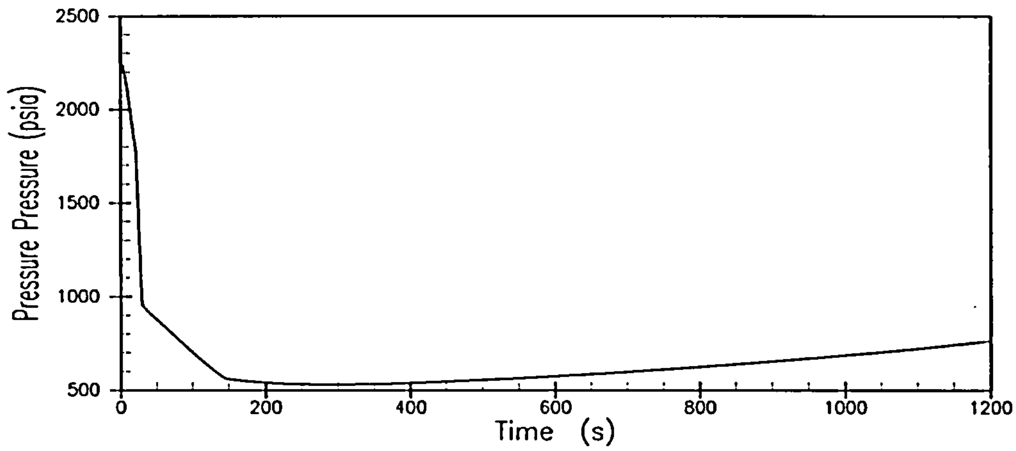


Figure Q.8-2
BVPS-1 Limiting HZP SLB Case – Pressurizer Pressure vs. Time

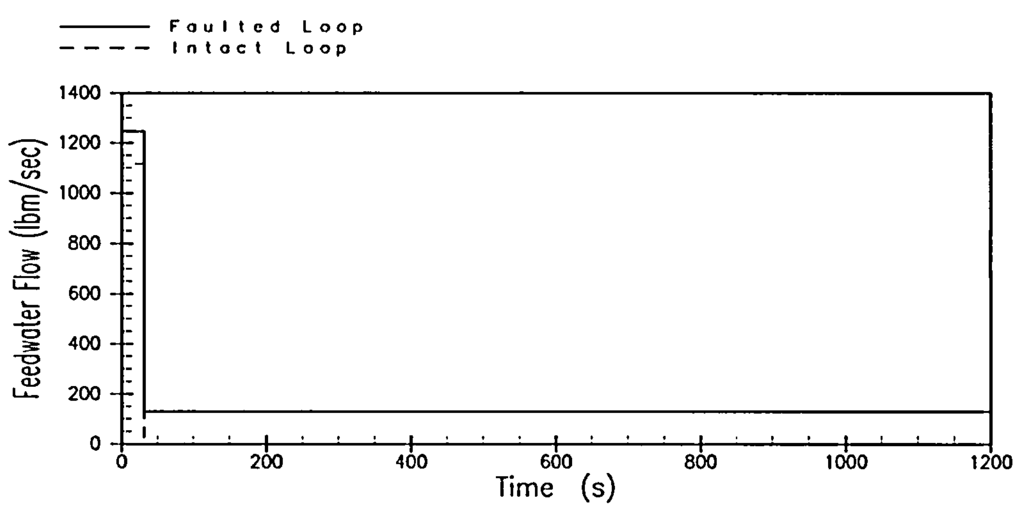


Figure Q.8-3
BVPS-1 Limiting HZP SLB Case – Feedwater flow (including AFW) vs. Time

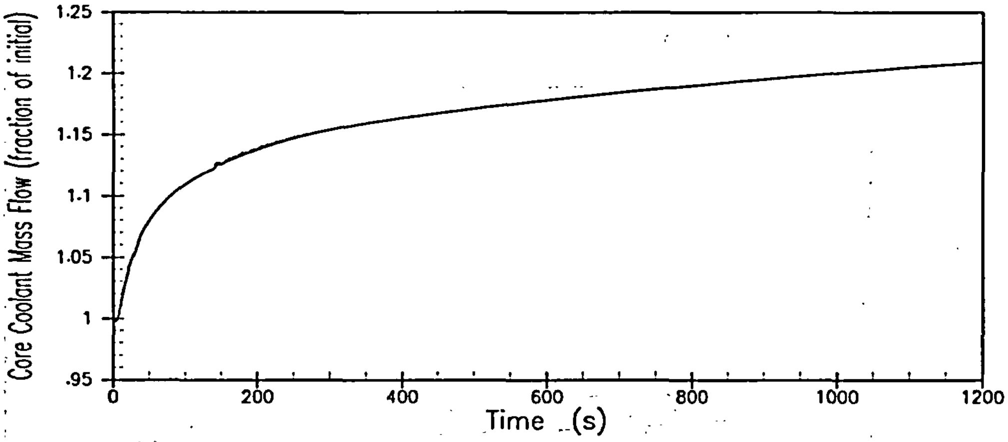


Figure Q.8-4
BVPS-1 Limiting HZP SLB Case – Core Mass Flow vs. Time

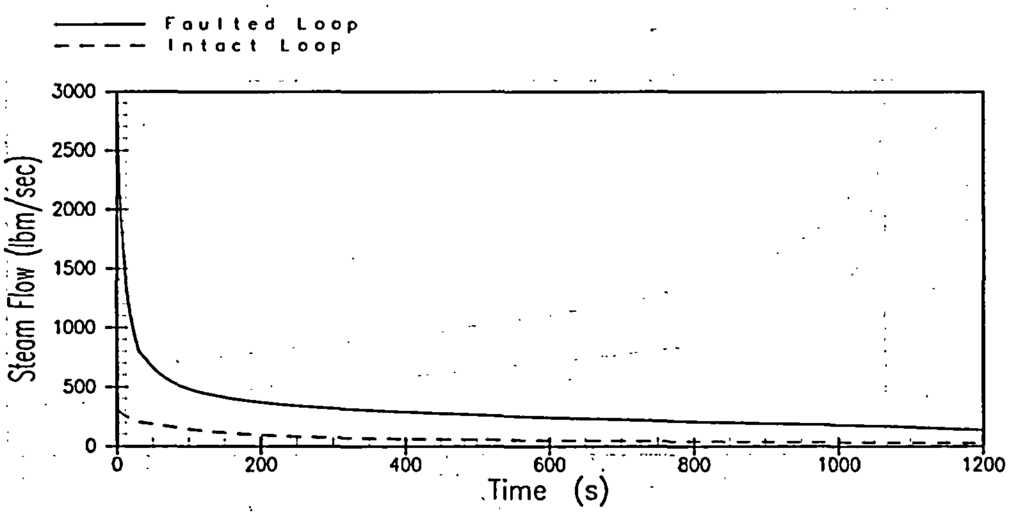


Figure Q.8-5
BVPS-1 Limiting HZP SLB Case – Steam Flow vs. Time

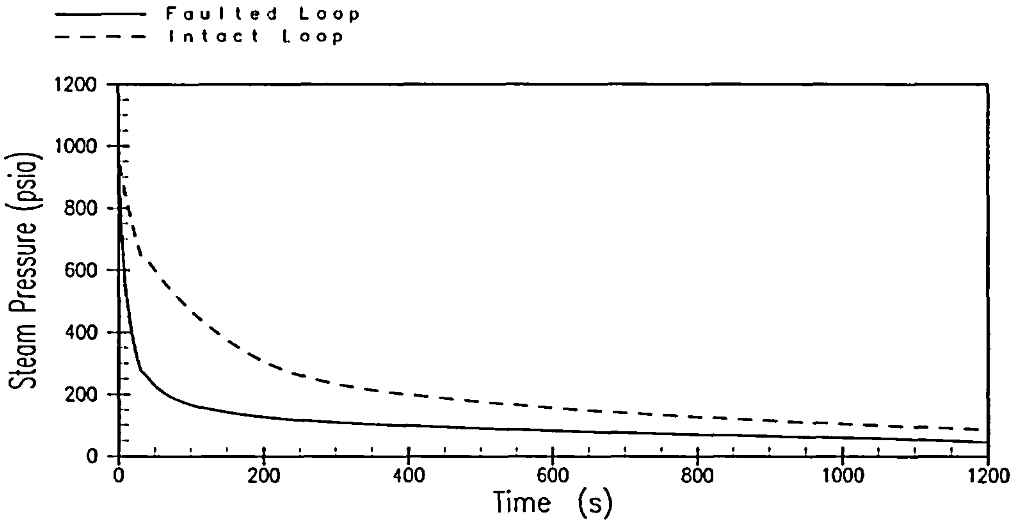


Figure Q.8-6
BVPS-1 Limiting HZP SLB Case – Steam Generator Pressure vs. Time

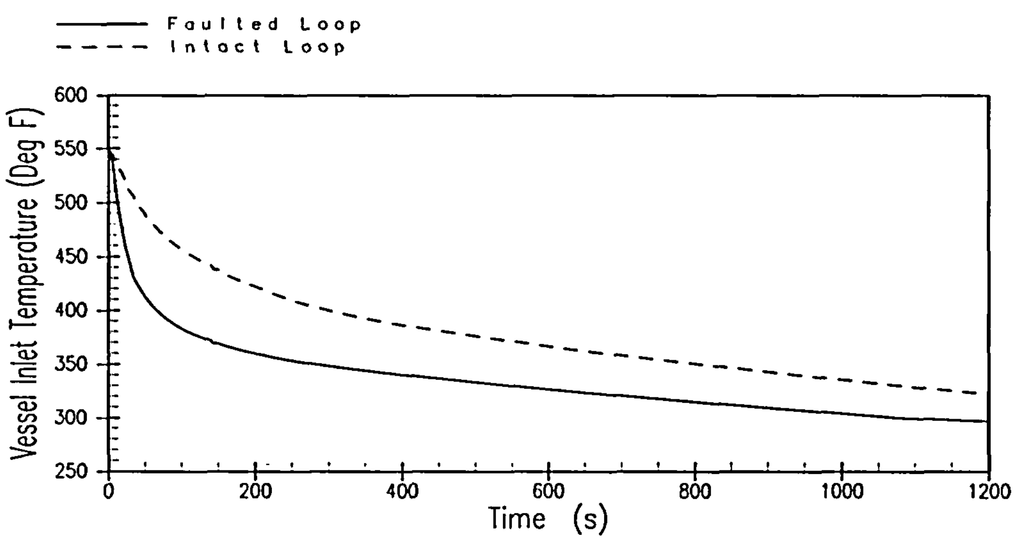


Figure Q.8-7
BVPS-1 Limiting HZP SLB Case – Reactor Vessel Inlet Temperature vs. Time

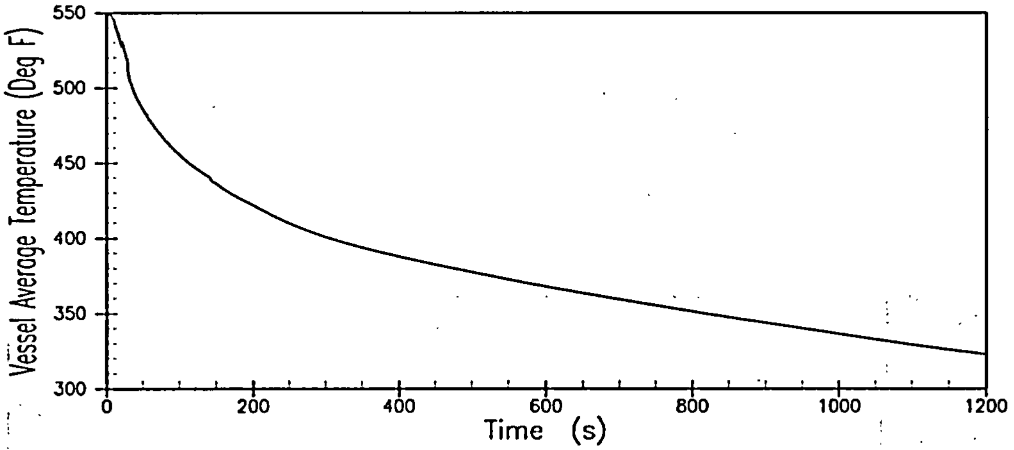


Figure Q.8-8
BVPS-1 Limiting HZP SLB Case – Reactor Vessel Average Temperature vs. Time

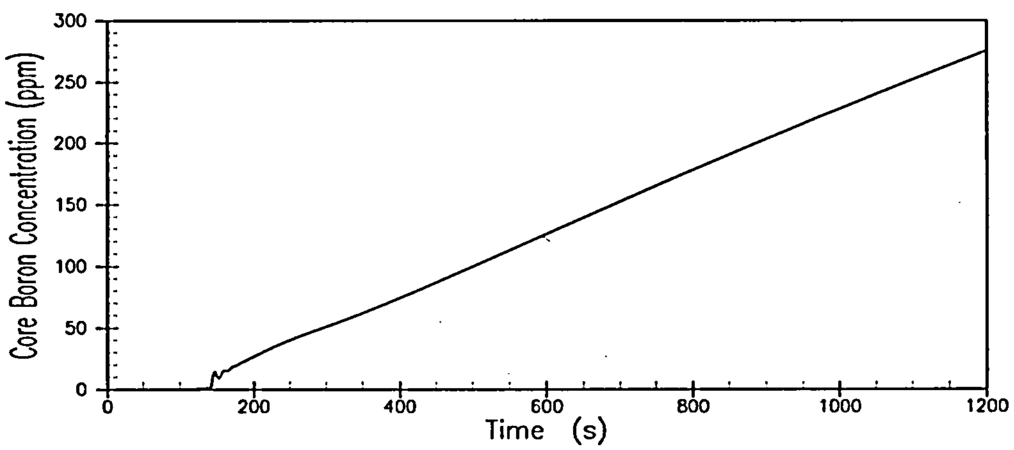


Figure Q.8-9
BVPS-1 Limiting HZP SLB Case – Core Boron Concentration vs. Time

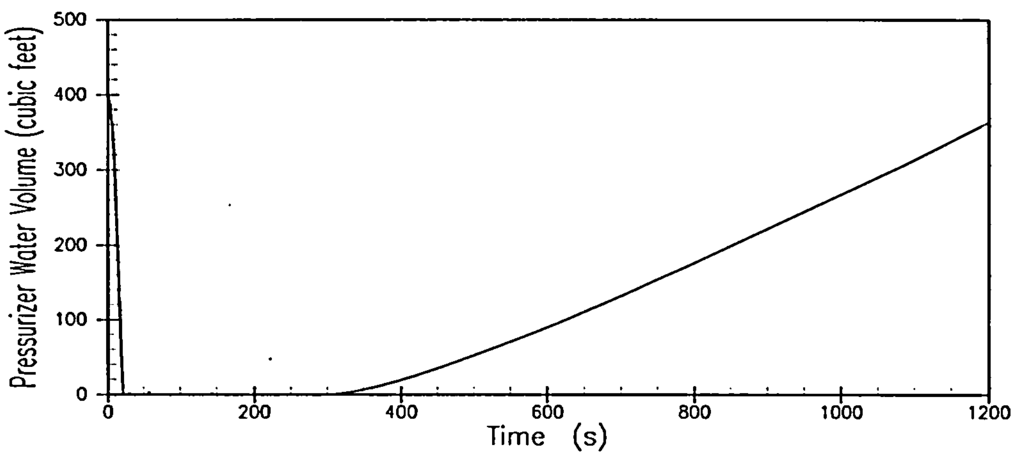


Figure Q.8-10
BVPS-1 Limiting HZP SLB Case – Pressurizer Water Volume vs. Time

Q.9 (Applicable to RSG & EPU)

Please provide the following transient plots for BVPS-2:

reactor coolant system pressure
integrated SI flow

Response:

The following transient plots are provided for the limiting hot zero power steamline break case for BVPS-2. Figure Q.9-1 – Reactor Coolant System Pressure vs. Time and Figure Q.9-2 – Integrated SI Flow vs. Time

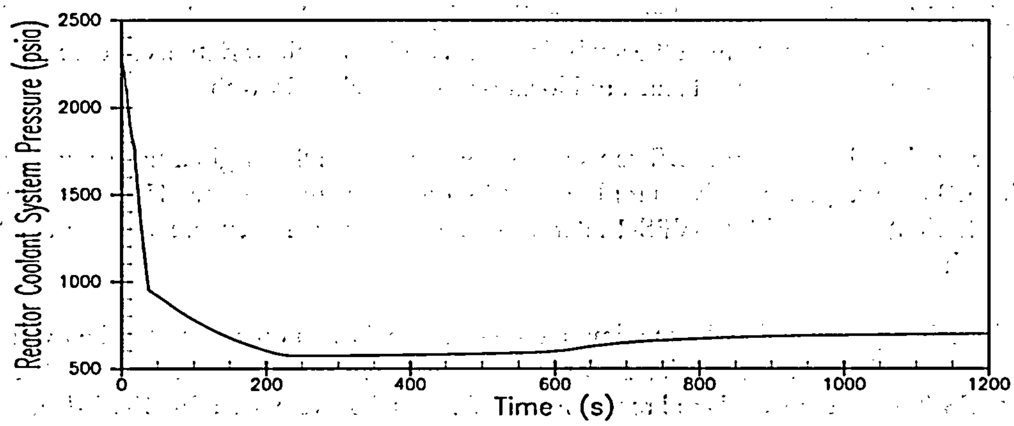


Figure Q.9-1
BVPS-2 Limiting HZP SLB Case – Reactor Coolant System Pressure vs. Time

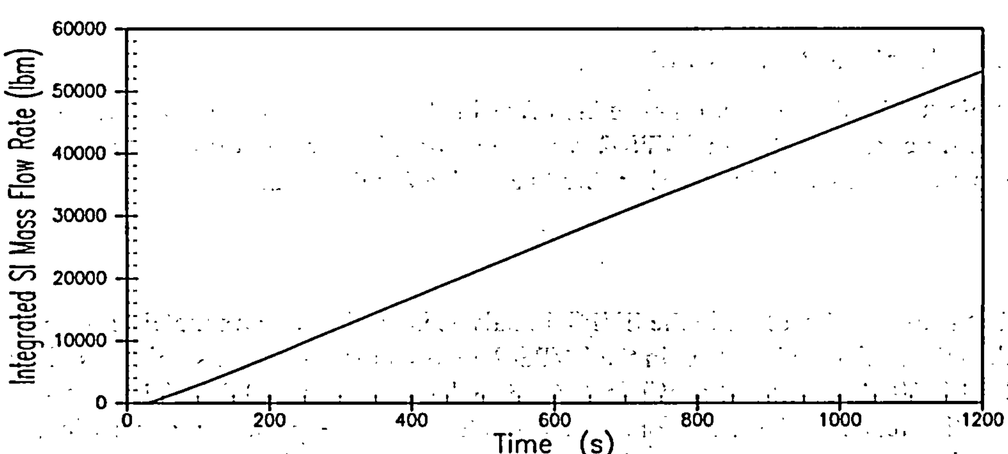


Figure Q.9-2
BVPS-2 Limiting HZP SLB Case – Integrated SI Flow vs. Time

Q.10 (Applicable to RSG & EPU)

Please explain why the maximum core heat flux is about the same for both units, despite the fact that the break size for BVPS-1 is more than 30% larger than the break size for BVPS-2.

Response:

The reactivity coefficients (moderator, boron and power coefficients) that are assumed in the main steamline break (MSLB) core response analysis are calculated assuming the most reactive control rod stuck in its fully withdrawn position. These coefficients are modified in the conservative direction so that the coefficients used in the analysis bound the values as calculated. A reactivity check is made at statepoints with the core design code to verify that the total reactivity insertion from the start of the transient to the statepoint predicted by the LOFTRAN code is greater than that predicted by the core design code. This reactivity check assures that conservatism in the analysis covers cycle to cycle variations in core reactivity kinetics coefficients, worst stuck rod locations and stuck rod worth.

The stuck-rod reactivity coefficients that were assumed in the original licensing basis HZP MSLB core response analyses for both BVPS-1 and 2 were the same. However, the stuck-rod coefficients assumed for BVPS-1 later needed to be changed to ensure a proper reactivity match.

The primary reason that the maximum core heat flux is about the same for the two units, despite the fact that the break size for BVPS-1 is more than 30% larger than the break size for BVPS-2, is that the stuck-rod reactivity coefficients that were used for BVPS-1 differ from those used for BVPS-2. Specifically, the BVPS-2 stuck-rod coefficients (SRCs) would result in a larger positive reactivity insertion for a given cooldown than the positive reactivity insertion that would be seen for the same cooldown with the BVPS-1 SRCs. As a result, if the SRCs that were assumed for BVPS-2 were also assumed for BVPS-1, the maximum core heat flux for BVPS-1 would have been 18.3%, as opposed to 11.5%.

Q.11 (Applicable to RSG & EPU)

Please explain why the maximum core heat flux in BVPS-1 is reached about 156 seconds after the maximum core heat flux in BVPS-2 is reached, despite the fact that the break size for BVPS-1 is more than 30% larger than the break size for BVPS-2.

Response:

The peak core heat flux in the BVPS-1 analysis is reached approximately 156 seconds later than the peak core heat flux in the BVPS-2 analysis for two reasons. First, as discussed in RAI Q.10, the stuck-rod coefficients (SRCs) that were assumed for BVPS-2 result in a larger positive reactivity insertion for a given cooldown than the positive reactivity insertion that would be seen for the same cooldown with the BVPS-1 SRCs. As such, if the SRCs that were assumed for BVPS-2 were assumed for BVPS-1, the core heat flux would increase at a much faster rate, reaching its peak at 251.8 seconds (approximately 108 seconds sooner).

Second, BVPS-1 has a Boron Injection Tank (BIT) that contains the same low boron concentration solution as the rest of the SI piping. BVPS-1 has a larger effective volume (~120 ft^3) than BVPS-2 that needs to be purged of the low boron concentration solution (conservatively assumed to be at 0 ppm and minimum enthalpy) before the high concentration solution from the Refueling Water Storage Tank (RWST) reaches the core. Hence, at a point in the transient when a borated solution is reaching the core for BVPS-2, the unborated water is still being injected into the core for BVPS-1.

Therefore, if this additional purge volume were eliminated for BVPS-1, along with assuming the BVPS-2 SRCs for BVPS-1, the peak core heat flux would occur at 179.2 seconds.

Q.12 (Applicable to RSG & EPU)

Tables 5.3.12-1A and 5.3.12-1B provide the sequence of events for the main steamline break (MSLB) event. These tables list the timing when secondary pressure reaches the low steam pressure safety injection setpoint (SIS) (BVPS-1 – 460 psia, BVPS-2 – 338 psia). Subsequent engineered safety features actuations system (ESFAS) actuations occur 8, 27, and 30 seconds after the SIS actuation signal. The sequence of events does not appear to include any delay time between the time the setpoint is reached to the time that the actuation signal is generated. Please describe where these delays are addressed.

Response:

As defined in the Technical Specifications, an Engineered Safety Feature (ESF) response time is the time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function. The delay times that are assumed for steamline isolation, safety injection, and feedwater isolation are designed to correspond to ESF response times, which include not only valve stroke times and/or pump start-up times, but also sensor and logic times. Also, the information that is provided in Tables 5.3.12-1A and 5.3.12-1B should have been described as "X seconds after SIS actuation setpoint reached" instead of "X seconds after SIS actuation signal."

Q.13 (Applicable to RSG & EPU)

During an MSLB, the depressurization of the faulted SG may promote an increase in main feedwater delivery. Describe the model of the feedwater flow into the faulted SG. Include a plot illustrating main and AFW flow (lbm/sec) throughout the event.

Response:

Although the transient is initiated from HZP condition, it is conservatively assumed that HFP main feedwater flow is maintained to each of the three SGs until the main feedwater isolation action is complete. Additionally, to further promote the cooldown, maximum AFW system flow is also conservatively assumed to be fed asymmetrically to the faulted loop only throughout the entire transient. The minimum AFW enthalpy is assumed in the model. Figures Q-13.1 and Q-13.2 show the main feedwater flow and AFW flow throughout the event, respectively, for BVPS-1, and Figures Q.13-3 and Q.13-4 show the main feedwater flow and AFW flow throughout the event, respectively, for BVPS-2.

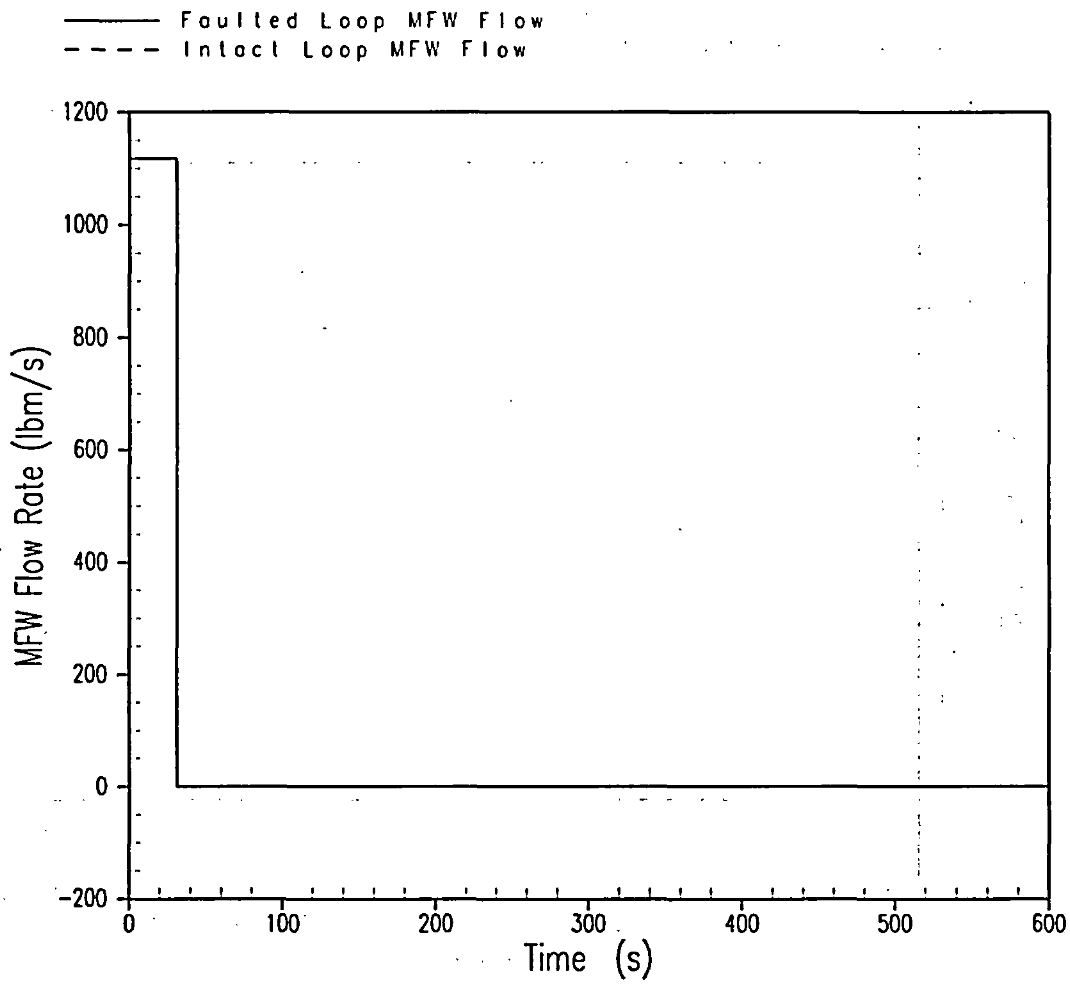


Figure Q.13-1
BVPS-1 MFW Flow

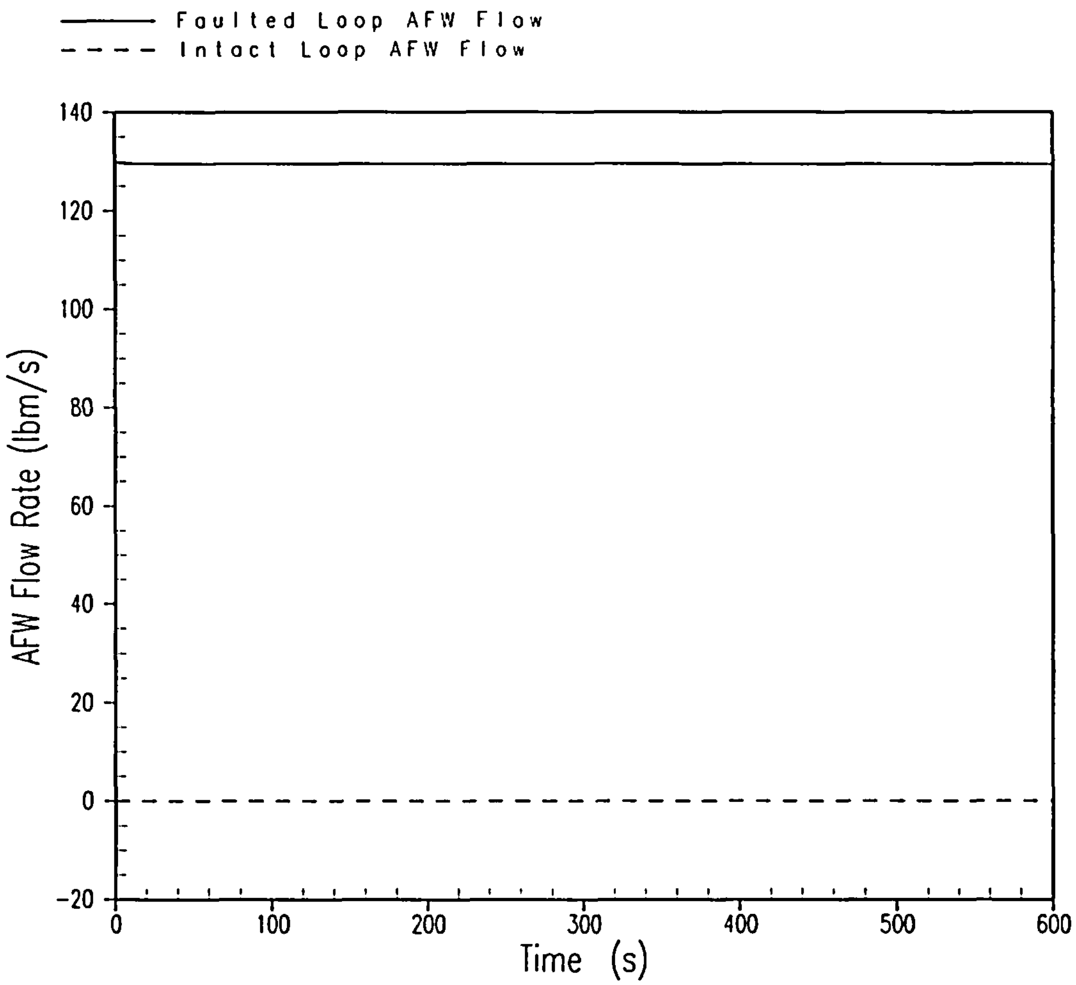


Figure Q.13-2
BVPS-1 AFW Flow

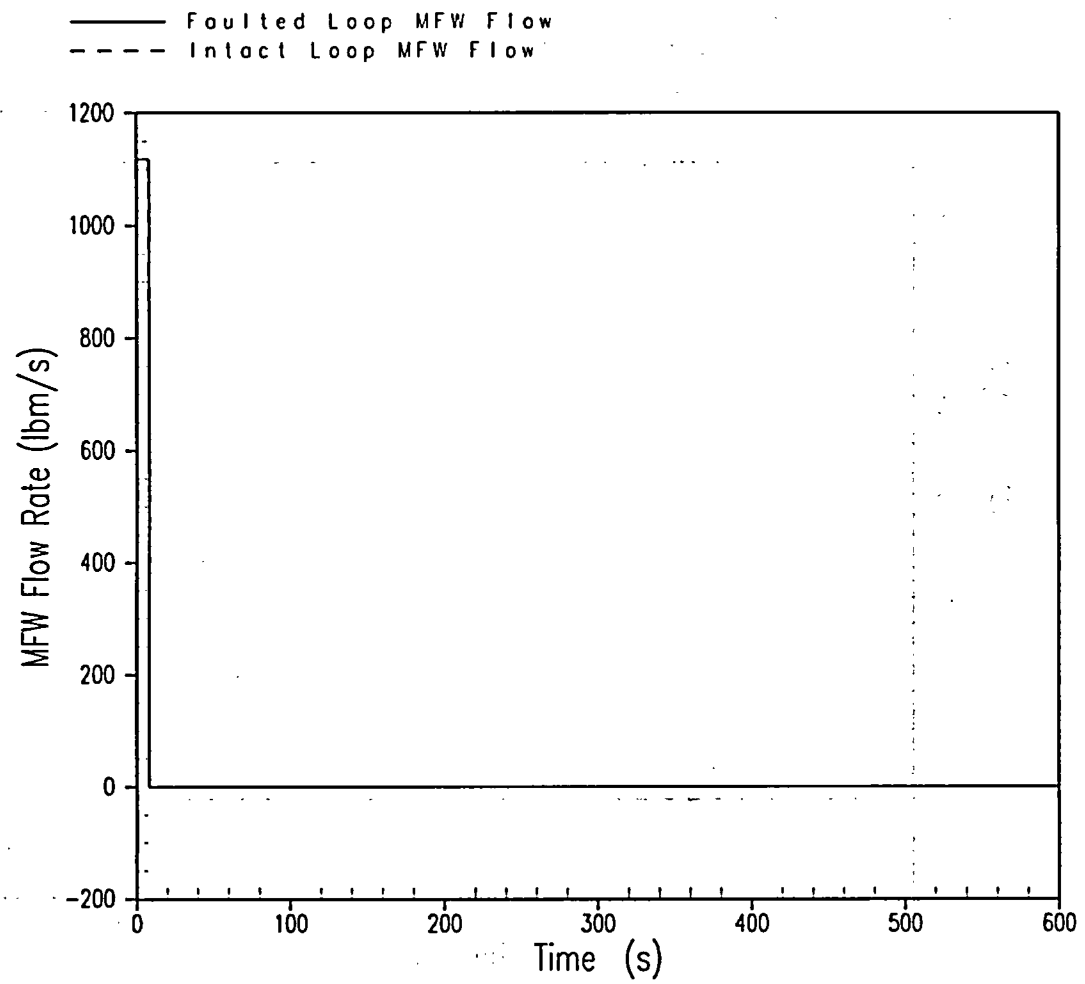


Figure Q.13-3
BVPS-2 MFW Flow

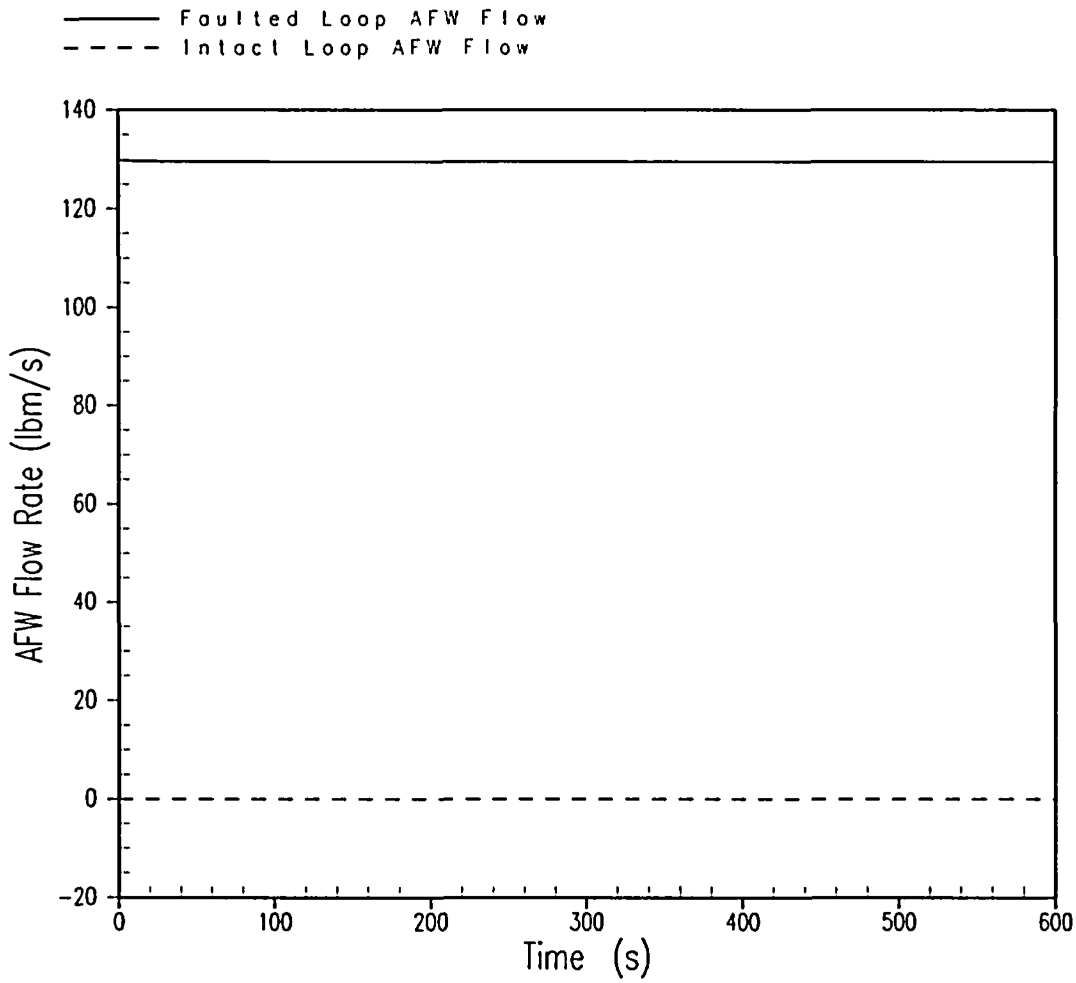


Figure Q.13-4
BVPS-2 AFW Flow

Q.14 (Applicable to RSG & EPU)

The UFSAR provides significantly more information on the selection of initial conditions, input parameters, and analysis assumptions. Please update the application MSLB analyses to include this level of detail or indicate where differences between the UFSAR analyses and this submittal exist. Include a discussion of potential single active failures.

Response:

The initial condition, input parameters and analysis assumptions used in the HZP MSLB core response analysis presented in the application are consistent with those presented under the "Method of Analysis" in Section 14.2.5.1.2 of the BVPS-1 UFSAR and Section 15.1.5.2 of the BVPS-2 UFSAR with the following exceptions.

For BVPS-1, the power coefficient, Figure Q.14-1 (described as Figure 14.2-4 in the UFSAR) and safety injection curve, Figure Q.14-2 (described as Figure 14.1-42 in the UFSAR) changed slightly as presented herein. Also, the maximum break size considered at the outlet of the steam generator was changed from 4.6 ft^2 to 1.4 ft^2 due to integral flow restrictors in the RSG design. As such, only one break size was examined instead of two. Separate cases were examined assuming unisolatable steam paths that could potentially occur after receiving a steamline isolation signal.

The most restrictive single failure for the BVPS-1 HZP MSLB core response analysis remains unchanged as a single failure in the safety injection system.

For BVPS-2, the K_{eff} versus average coolant temperature curve, Figure Q.14-3 (described as Figure 15.1-11 in the UFSAR) and power coefficient, Figure Q.14-4 (described as Figure 15.1-15 in the UFSAR) changed slightly as presented herein. The additional changes were as follows:

- the safety injection delay time was changed from 12 seconds to 27 seconds
- the concentration of the borated water from the RWST was changed from 2000 ppm to 2400 ppm
- the maximum effective break size was changed from 1.4 ft^2 to 1.069 ft^2
- the cases with one reactor coolant loop out of service have been eliminated

Also, the most restrictive single failure for the BVPS-2 HZP MSLB core response analysis remains unchanged as a single failure in the safety injection system.

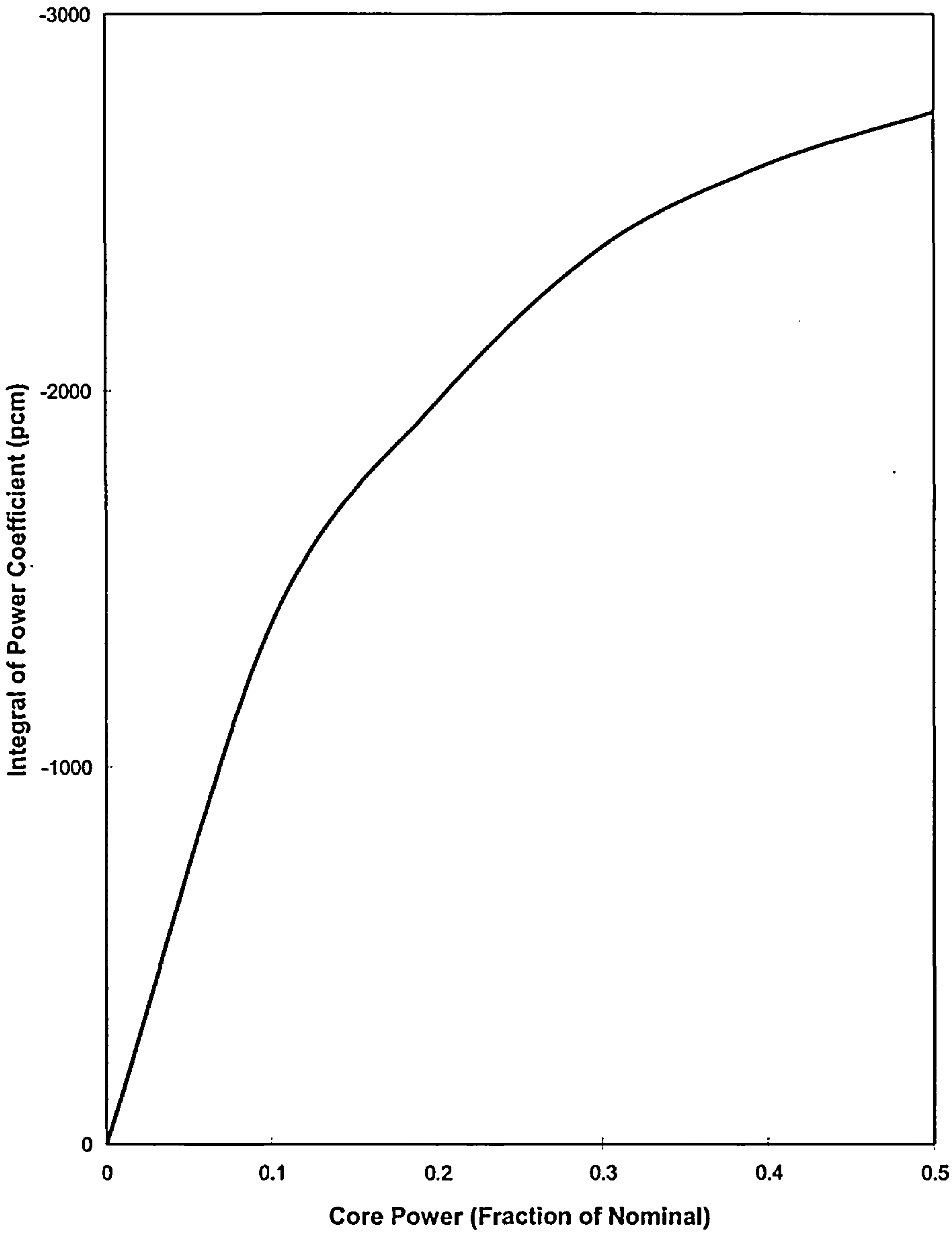


Figure Q.14-1
BVPS-1 Power Coefficient

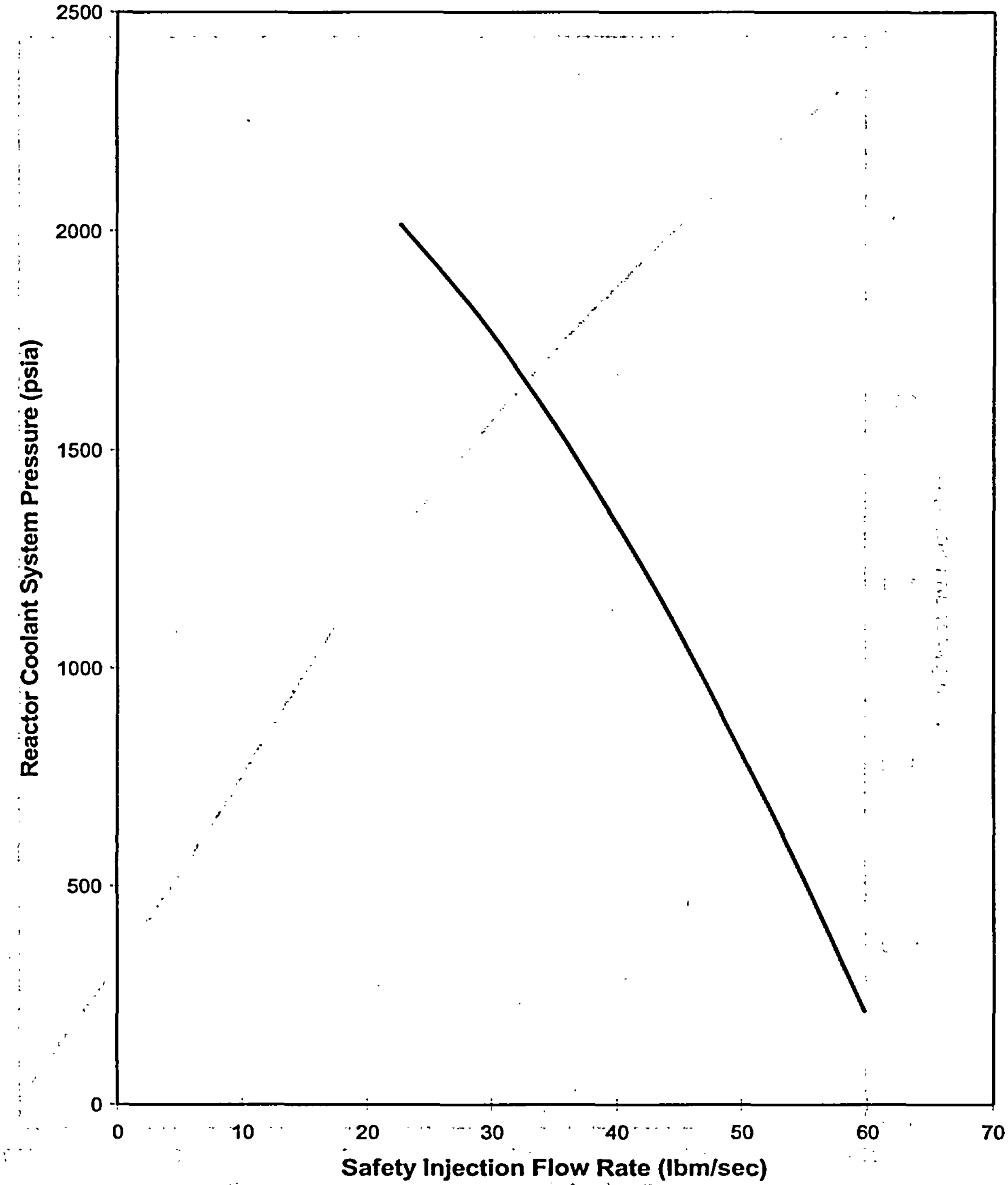


Figure Q.14-2
BVPS-1 Safety Injection Curve

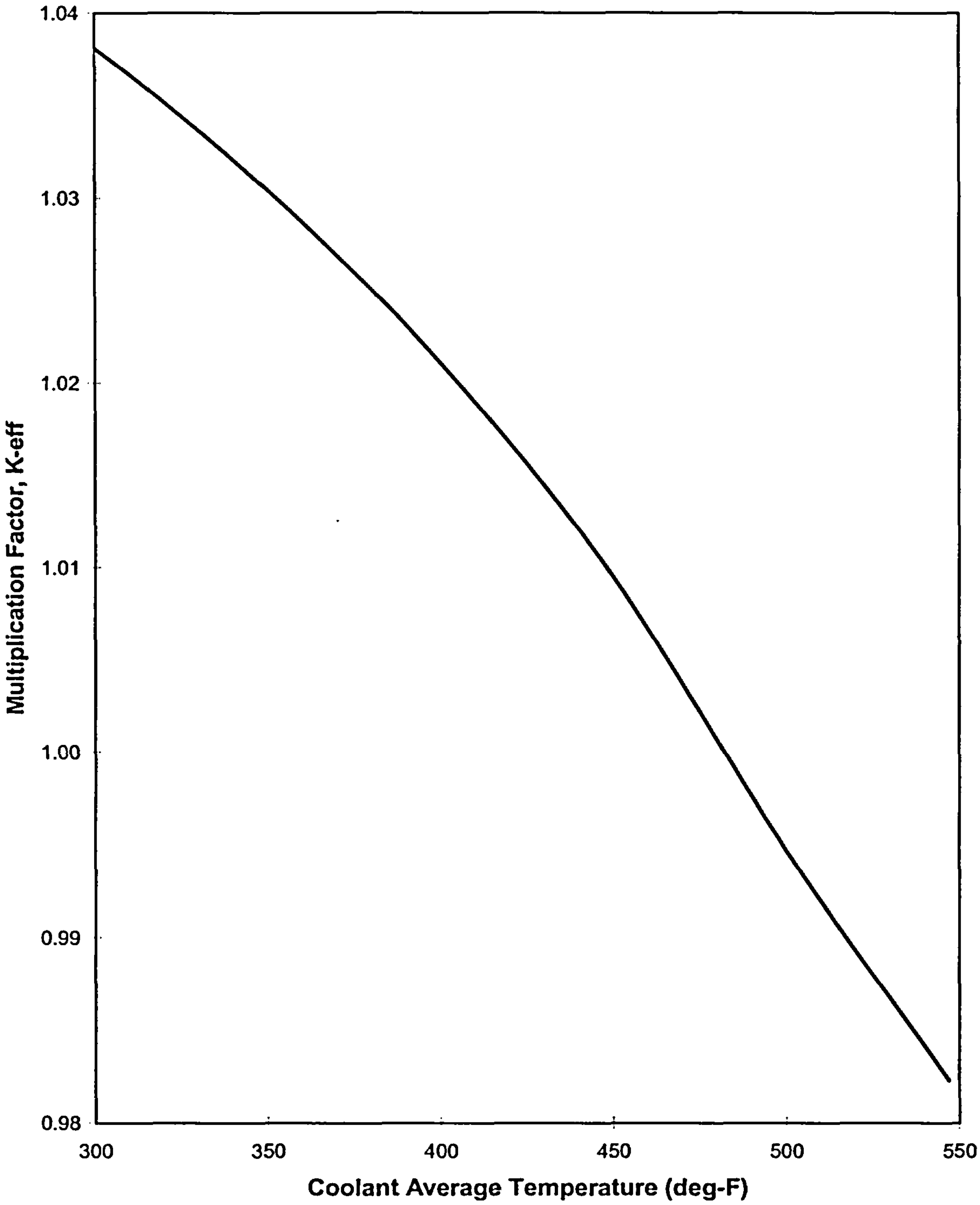


Figure Q.14-3
BVPS-2 Coolant Temperate Curve

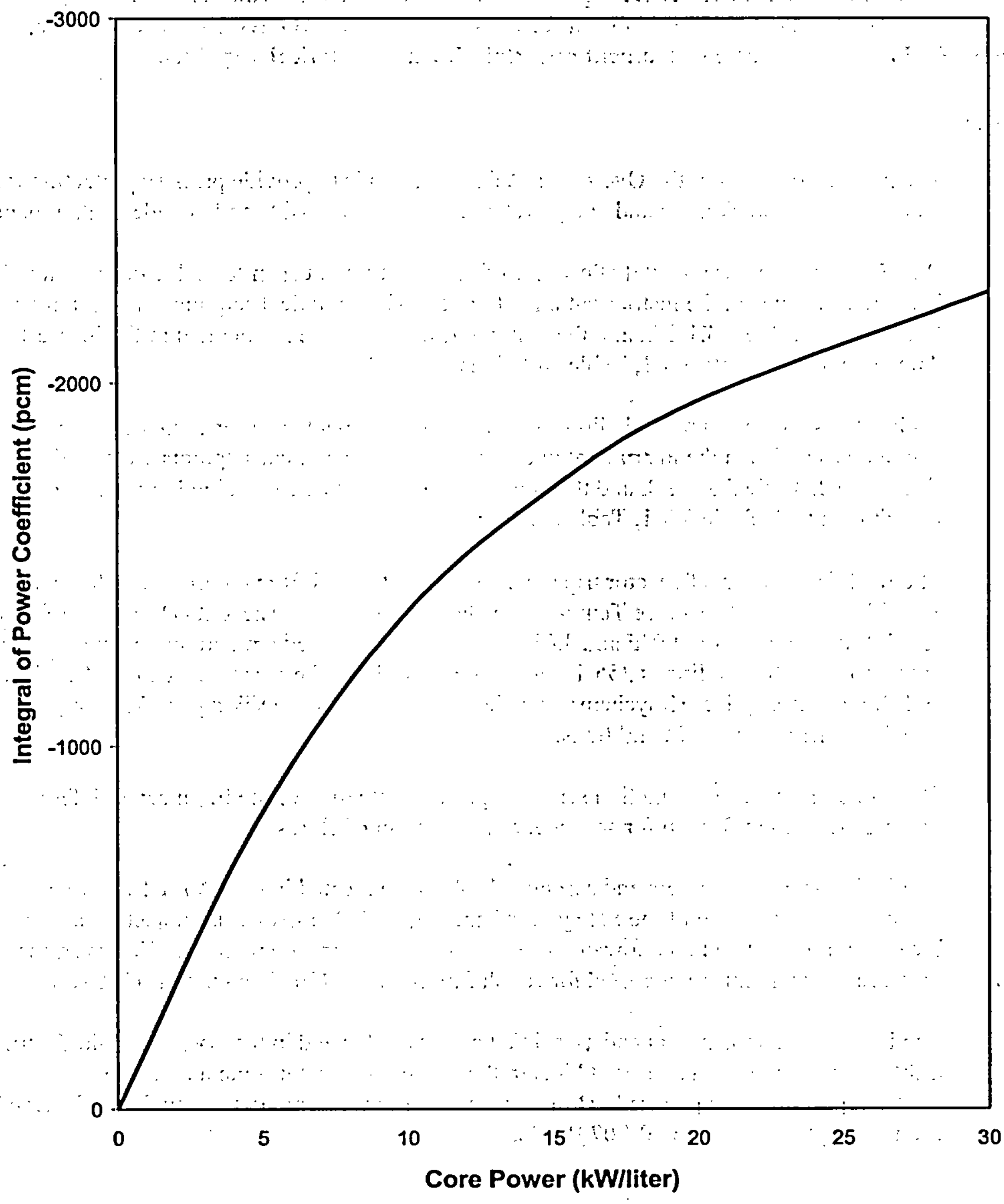


Figure Q.14-4
BVPS-2 Power Coefficient

Q.15 (Applicable to RSG & EPU)

Demonstrate that the credited reactor protection system (RPS) trip functions and supporting instrumentation and cables are qualified for a harsh containment environment. Further, quantify the environmental instrument uncertainties and analytical setpoints.

Response:

The primary function of the Overpower ΔT reactor trip is to provide primary protection for main steamline break mass and energy release events, both inside and outside containment.

BVPS-1 has an environmental allowance of 0.5% instrument span for cable degradation that is treated as a bias in the instrument uncertainties. The analytical setpoints are contained in Enclosure 2, Table 5.3.1-2A, and the nominal trip setpoints are contained in Enclosure 1, Attachment C-1, Table 3.3-1, Table Notations A and B.

BVPS-2 has an environmental allowance of 0.3% instrument span for cable degradation that is treated as a bias in the instrument uncertainties. The analytical setpoints are contained in Enclosure 2, Table 5.3.1-2B, and the nominal trip setpoints are contained in Enclosure 1, Attachment C-2, Table 3.3-1, Table Notations A and B.

The RPS Overpower ΔT reactor trip receives its input signal from environmentally qualified Weed Instruments Resistance Temperature Detectors (RTDs). These RTDs are qualified for Harsh Environments of 500°F and 3.03 E08 RADs. The Weed temperature elements remain qualified for EPU conditions 355°F and 2.55 E08 RADs. The associated cables (Continental and Brand Rex), splices (Raychem), and electrical penetrations (Viking and Westinghouse) remain qualified for EPU conditions.

Steamline Pressure Low function serves as primary actuation of the Engineered Safety Features Actuation System for secondary system piping failures.

The ITT Barton transmitters and associated cables are located in the BVPS-1 Auxiliary Feedwater Pump Room of the Safeguards Building such that neither is subject to the steam break environment and no allowances for adverse conditions are required. However, the pressure transmitters are qualified for Harsh Environment 420°F and 6.80 E07 RADs.

The ITT Barton transmitters and associated cables are located in the BVPS-2 Main Steam Cable Vault such that neither is subject to the steam break environment and no allowances for adverse conditions are required. However, the pressure transmitters are qualified for Harsh Environment 420°F and 6.80 E07 RADs.

Q.16 (Applicable to RSG & EPU)

Demonstrate that fuel clad failure does not occur as a result of high local power density during the return-to-power near the vicinity of the stuck RCCA. Quantify the local peaking factors in the area under the stuck RCCA.

Response:

The demonstration of an acceptable minimum DNBR has been taken to be the necessary and sufficient demonstration that fuel clad failure does not occur as a result of the high local power density during return to power near the vicinity of the stuck RCCA.

Core Design calculations of the HZP MSLB transient with the highest worth rod stuck out of the core included the analysis of several possible worst stuck rods and the evaluation of several different transient time steps to confirm that the limiting condition was indeed captured for each of the two units. A review of these calculations show that the limiting local peaking factor (Fq) was bounded by a value of 25.0 for the various time steps and configurations.

Q.17 (Applicable to RSG & EPU)

The VANTAGE 5H and RFA fuel assemblies employ different critical heat flux (CHF) correlations and a different DNBR limit. Further, the location of the mid-span mixing vanes introduces an axial-dependency to the CHF correlation.

a. The local conditions experienced during an MSLB may be outside the applicability of the WRB-1 and WRB-2M CHF correlations. Please describe the use of these correlations during the MSLB event. If the W-3 correlation is being employed, demonstrate its applicability to both the VANTAGE 5H and RFA fuel assemblies at these MSLB local conditions.

Response:

The MSLB is assumed to start from hot zero power conditions, which is outside the applicable range of WRB-1 and WRB-2M correlations. The W-3 correlation is used with DNBR multiplier of 0.88 for 17x17 VANTAGE 5H and RFA-2 fuel assemblies. For use in the MSLB analysis, the W-3 correlation with a limit of 1.45 for pressure between 500 and 1000 psi, has been approved by the NRC [WCAP-9226-P-A, February 1998].

b. **Quantify the most severe shift axial power distribution (AXPD) during a cooldown event and how the core thermal-hydraulic models account for this shift. Include in this discussion the calculation of DNBR with an axial-dependent CHF correlation.**

Response:

The axial power distribution for the hot assembly (highest power assembly) at the limiting steamline break (SLB) statepoint is edited out from the ANC calculation and provided to Thermal-Hydraulic Design in a format suitable for use in THINC analyses. This format includes 38 equally-spaced axial mesh intervals. Figure Q.17-1 is a graph of a typical hot assembly axial power distribution from one of the HZP SLB cases analyzed as part of the EPU. For this case, the corresponding axial offset is about + 65%.

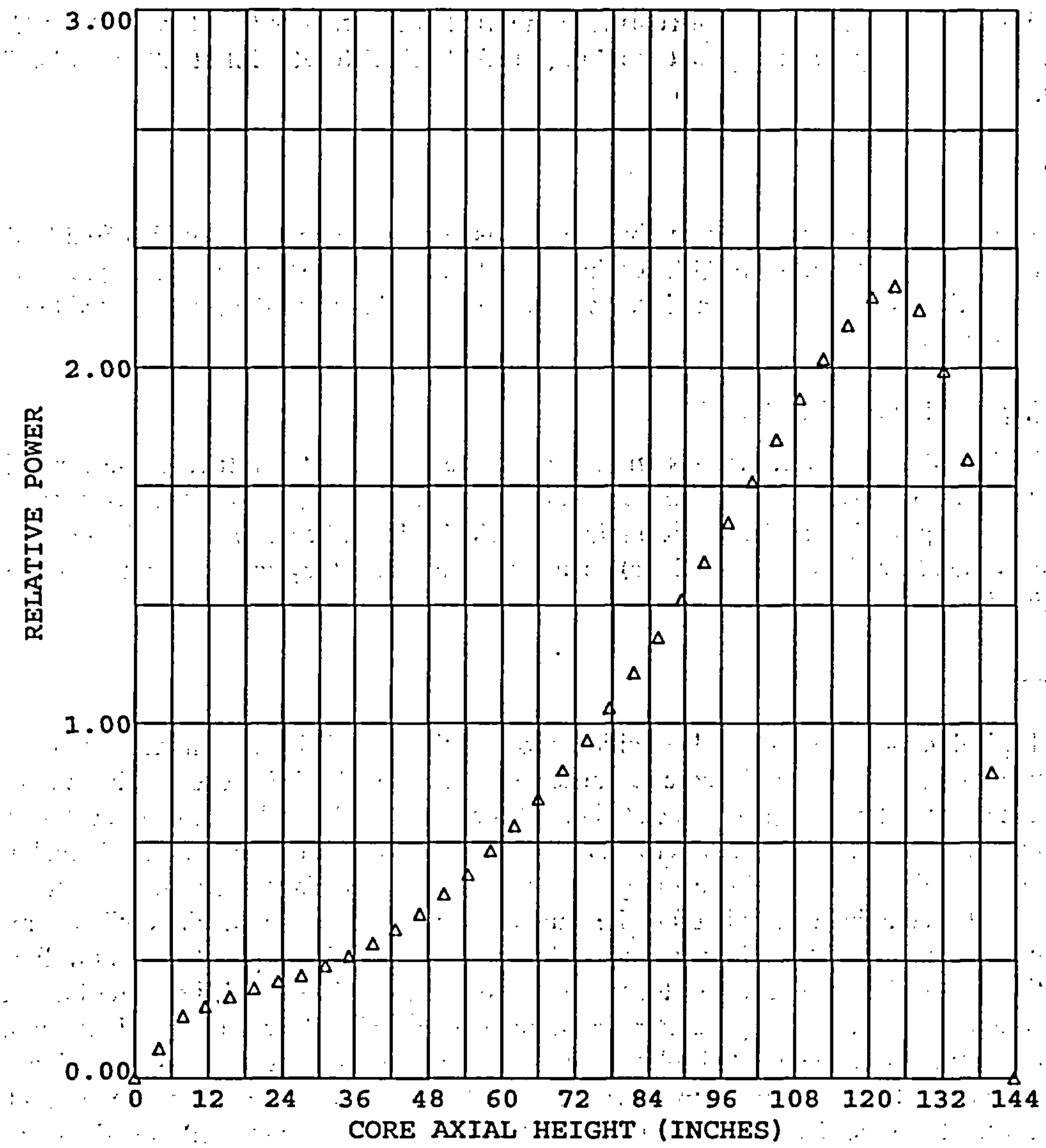


Figure Q.17-1
Typical Hot Assembly Axial Power Shape

Q.18 (Applicable to RSG & EPU)

Figure 5.3.12-3B depicts SG pressure during the MSLB event. The trend in faulted SG pressure does not appear to support reaching the 338 psia SIS setpoint at 1.0 seconds. Please discuss.

Response:

The Low Steam Pressure protective function is lead/lag compensated with a 50/5 lead/lag. Figure 5.3.12-3B of the EPU Licensing Report shows actual steam generator pressure and the protection (safety injection and steamline isolation) is based on the compensated low steam pressure signal.

Q.19 (Applicable to RSG & EPU)

Initial SG liquid mass inventory has an impact on the results of the return-to-power MSLB event. Tables 5.3.1-4A/B lists the initial condition uncertainties on indicated SG water level. Describe the application of these uncertainties to the initial indicated level and how plant operations (i.e., technical specifications) ensure that the inventory assumed in the analysis is maintained.

Response:

Typically, there are no initial condition uncertainties included in the initial steam generator water level assumed in the core response analysis of a HZP MSLB event. The initial steam generator water level (and associated mass) is assumed to be at the nominal level for HZP. If the initial steam generator water level were assumed to be at the nominal HZP level including uncertainties, there would be a larger steam generator secondary side water inventory that would need to be depleted before the faulted steam generator would "dry out" (assuming the break is unisolatable). However, since the peak core heat flux typically occurs well before the time at which steam generator tube uncovery occurs, and the extended period of time over which the faulted steam generator would blow down before "dry out" is well after transient turnaround from the borated solution reaching the core, applying an initial condition uncertainty to the initial steam generator water level would have essentially no impact on the transient results. This is what was seen in the case of the BVPS-1 HZP MSLB core response analysis where the initial steam generator water level (and associated mass) was assumed to be an atypical value corresponding to the nominal level including uncertainties. From the transient results, it was seen that this assumption had no impact on the peak core heat flux. The BVPS-2 HZP MSLB core response analysis assumed the initial steam generator water level (and associated mass) was at value consistent with the typical assumption of the nominal level at HZP conditions without uncertainties.

Steam Generator level is normally maintained at the nominal setpoint by the steam generator level control program. Redundant narrow range level indications are provided for each steam generator and annunciators are provided to alert the operating staff of deviations in nominal steam generator narrow range level.

Section 5.3.14 **Complete Loss of Forced Reactor Coolant Flow**

R.1 (Applicable to RSG & EPU)

Provide the results of an analysis of the loss-of-flow transient concerning peak system pressure using initial conditions and assumptions which will maximize the peak primary and secondary system pressures (including the assumption of the pressurizer PORVs inoperable).

Response:

With respect to the overpressure evaluation, the loss of flow events are bounded by the loss of load/turbine trip (LOL/TT) events, in which assumptions are made to conservatively calculate the RCS and MSS pressure transients. For the loss of flow events, turbine trip occurs following reactor trip, whereas for the LOL/TT event, the turbine trip is the initiating fault. Therefore, the primary to secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the LOL/TT event. For this reason, it is not necessary to calculate the maximum RCS or MSS pressures for the loss of flow events.

Section 5.3.15 **Single Reactor Coolant Pump Locked Rotor**

S.1 (Applicable to RSG & EPU)

Explain the differences in the assumptions for BVPS-1 and 2.

Response:

There are no differences in the analysis assumptions; however, these plants have different steam generators and other parameter differences which could account for differences in the results.

S.2 (Applicable to RSG & EPU)

Provide the DNB transient curves for BVPS-1 and 2.

Response:

Transient plots of DNBR are not available. Transient statepoints (RCS flow, hot channel heat flux, and average channel heat flux – given in terms of fraction of initial) per time increment for initial conditions (core average heat flux, volumetric flow, core inlet temperature, and pressurizer pressure) are generated. The limiting statepoint is determined and a single DNBR calculation is then performed using that limiting statepoint.

S.3 (Applicable to RSG & EPU)

How many fuel pins were calculated to be subject to a DNBR that is below the safety limit of 1.55? Compare and discuss this to the number failed fuel pins that are assumed for calculation of radiological consequences (20%).

Response:

The number of failed pins in the radiological consequences analysis is considered the acceptance criteria for the locked rotor event. The actual percentage of fuel rods in DNB is predicted to be less than 20% for both Beaver Valley units. There was no calculation of the specific number of fuel rods in DNB. The conclusion was that the 20% limit was met for either Beaver Valley unit using a generic fuel census ($F_{\Delta H}$ vs. percentage of rods). Subsequent reload evaluations will continue to demonstrate that the 20% assumption in the radiological calculation remains a valid assumption. Cycle-specific analysis is performed to obtain the percentage of fuel rods subject to DNB using the reload design fuel census from Nuclear Design. The rod census is used to evaluate the number of rods in the core with an $F_{\Delta H}$ greater than the $F_{\Delta H}$ that gives minimum DNBR equal to the safety analysis limit of 1.55. All rods with such an $F_{\Delta H}$ or greater are assumed to be in DNB.

S.4 (Applicable to RSG & EPU)

Describe the limiting single failures assumed in the locked rotor accident for the DNB case and for the peak pressure case.

Response:

The limiting single failure for this event (both cases) is assumed to be the failure of one train of the reactor protection system.

S.5 (Applicable to RSG & EPU)

Confirm that the acceptance criteria listed in Section 5.3.15.4 of the EPU report are consistent with the current licensing bases of BVPS-1 and 2.

Response:

The acceptance criteria that are listed in Section 5.3.15.4 of the EPU Licensing Report are consistent with the current licensing bases of BVPS-1 and 2 except for the 20% rods-in-DNB limit, which is 18% for the current licensing basis. Note that a revised radiological consequences analysis was performed assuming 20% failure (see Table 5.11.9-6 of the LAR) and involved the use of an Alternative Source Term.

S.6 (Applicable to RSG & EPU)

Confirm that a concurrent loss-of-offsite power (LOOP) is assumed in the analysis for a locked rotor accident.

Response:

The locked rotor analyses for both BVPS-1 and 2 assume a concurrent loss of offsite power.

Section 5.3.16 **Rupture of a Control Rod Drive Mechanism [CRDM] Housing/Rod Cluster Control Assembly Ejection**

T.1 (Applicable to EPU)

Verify that the peak reactor coolant pressure could not cause RCS stresses to exceed the faulted-condition stress limits (i.e., BVPS-1 and 2, under EPU conditions, continue to be addressed in the generic evaluation of Reference 4).

Response:

WCAP-7588 describes the analyses performed to generically demonstrate that the RCCA ejection event is not a limiting event with respect to RCS overpressure. The limiting case for overpressure (beginning-of-life, hot full power, with an ejected rod worth in excess of $1) was analyzed and the result was peak pressure is well within the acceptance criteria.

Since the ejected rod worths that support the Beaver Valley EPU are bounded by the values used in the WCAP-7588 overpressure study, and based on the confirmation obtained from additional studies performed for a limiting plant at uprated conditions, the overpressure results of WCAP-7588 remain valid for BVPS-1 and 2 at the EPU conditions.

Section 5.3.17 Major Rupture of a Main Feedwater Pipe

U.1 (Applicable to RSG & EPU)

Demonstrate that the credited RPS trip functions and supporting instrumentation and cables are qualified for a harsh containment environment. Further, quantify the environmental instrument uncertainties and analytical setpoints.

Response:

The primary function of the Steam Generator Water Level Low-Low reactor trip is to provide primary protection for Loss of AC Power (Station Blackout), Loss of Normal Feedwater Flow, and feedwater System Pipe Break. This function also serves an Engineered Safety Features Actuation System to actuate Auxiliary Feedwater System on Low-Low level.

BVPS-1 has an environmental allowance of 0.5% instrument span for cable degradation that is treated as a bias in the instrument uncertainties. A 6.0% instrument span bias associated with the transmitter exposure to adverse environment. For a large feedline break an allowance of 2.2% instrument span is used, and for small and intermediate feedline breaks a 5.0% instrument span allowance are associated with reference leg heat-up effects. The analytical setpoints are contained in Enclosure 2, Table 5.3.1-1A, and the Technical Specification Allowable Values are contained in Enclosure 1, Attachment A-1, Table 3.3-1, Functional Unit 14, and Table 3.3-3, Functional Unit 7. The nominal trip setpoint values are contained in Attachment C-1.

BVPS-2 has an environmental allowance of 1.7% instrument span for cable degradation that is treated as a bias in the instrument uncertainties. A 4.5% instrument span bias associated with the transmitter exposure to adverse environment. For a large feedline break an allowance of 3.1% instrument span is used, and for small and intermediate feedline breaks a 6.1% instrument span allowance are associated with reference leg heat-up effects. The analytical setpoints are contained in Enclosure 2, Table 5.3.1-1B, and the nominal trip setpoints are contained in LAR 2A-197, where the Low-Low nominal setpoint is 20.5% instrument span and the Technical Specification Allowable Value is 20% instrument span.

The BVPS-1 and 2 Steam Generator Level Transmitters (ITT Barton Model 764) are qualified for Harsh Environments of 420°F and 6.8 E07 RADs. The associated cables (Continental and Brand Rex), splices (Raychem), and electrical penetrations (Viking and Westinghouse) remain qualified for EPU conditions.

U.2 (Applicable to RSG & EPU)

To illustrate the break spectrum cases investigated, provide a plot of break size versus peak RCS pressure and break size versus peak pressurizer liquid level.

Response:

The break size considered for BVPS-1 is 0.922 ft^2, which is the area of the Model 54F feedwater ring assembly and represents the largest break that can exist for a Model 54F steam generator. The break sizes considered for BVPS-2 are 0.717 ft^2, which is the sum of the flow areas of the j-tubes on the feedwater ring, and 1.36 ft^2, which is the area accounting for a failure of the non-safety Model 51M steam generator feedwater ring assembly.

For BVPS-1, pressurizer pressure and water volume for the 0.922 ft^2 break are given in Figure 5.3.17-3A (with offsite power case) and Figure 5.3.17-8A (without offsite power case). For BVPS-2, pressurizer pressure and water volume for the 0.717 ft^2 break are given in Figure 5.3.17-2B (with offsite power case) and for the 1.36 ft^2 break are given in Figure 5.3.17-8B (without offsite power case).

U.3 (Applicable to RSG & EPU)

Section 5.3.17.2 of the EPU report states that "PORVs are assumed to be operable."

a. **Describe the safety function and mitigating actions performed by the PORVs during the postulated feedwater line break (FWLB) event.**

Response:

In the FWLB analysis, the pressurizer PORVs perform no safety function and do not perform any mitigating actions.

b. **Describe the operability requirements for the PORVs.**

Response:

In the FWLB analysis, the pressurizer PORVs are modeled for conservatism. PORV operation results in a lower RCS pressure and subsequently a lower saturation temperature. The acceptance criterion for this event is that the core remains covered. Westinghouse conservatively demonstrates that the core remains covered by maintaining the margin to saturation. A lower saturation temperature makes the acceptance criteria more difficult to meet. Thus, the PORVs are modeled, not to mitigate the transient, but to lower the saturation temperature. Assuming the PORVs are not operable will yield less limiting FWLB results.

c. **Repeat the UFSAR, Section 15.2.8.2.1, PSV operability analyses at the EPU conditions for both BVPS-1 and 2. Include a description of inputs and assumptions and identify the limiting FWLB case with respect to PSV operability for each unit.**

Response:

First, PSV operability is not a concern for a FWLB event because FWLB is a Condition IV event. Preventing pressurizer filling is not a Condition IV acceptance criterion. A previous licensing basis analysis for BVPS-2 predicted that the pressurizer would fill. Thus, an additional case was done to show, on a better estimate basis, that the pressurizer would not fill. This case has been presented in the UFSAR since that time. Note that this additional case was not done for the current licensing basis for either BVPS-1 or BVPS-2 because the current licensing basis analyses do not predict filling. For the EPU analyses, pressurizer filling is not predicted in the design basis FWLB cases for either BVPS unit. Thus, additional analyses are not necessary. UFSAR Section 15.2.8.2.1 will be deleted because it is no longer applicable.

U.4 (Applicable to RSG & EPU)

To account for instrument uncertainties, a reactor trip on low-low SG level is credited in the FWLB event at an analytical setpoint of 0% nuclear rated steam. Discuss the modeling uncertainty of LOFTRAN to predict indicated SG liquid level (in both faulted and intact SGs) under the dynamic conditions experienced during a FWLB event for both the Model 54F and 51M SG designs.

Response:

In the question, note that "nuclear rated steam" should be "narrow range span."

The LOFTRAN code does not calculate an indicated steam generator liquid level. Rather, the initial steam generator mass and the steam generator mass at the low-low level analysis setpoint are user inputs based on more detailed steam generator design code calculations. This is acknowledged in the LOFTRAN topical report evaluation (WCAP-7907-P-A, "LOFTRAN Code Description," April 1984) by the following excerpt:

"Reactor trip and auxiliary feedwater start on steam generator water level are based on a user-input value of an equivalent secondary side mass. This value is based on a more detailed steam generator model which computes steam generator water mass at the reactor trip level setpoint."

U.5 (Applicable to RSG & EPU)

Provide a plot of indicated SG liquid level for all three SGs for a range of break sizes to demonstrate that a low-low water level signal (required to start motor-driven AFW pumps) is achieved in two SGs.

Response:

First, as discussed in the response to RAI U.4, the LOFTRAN code does not calculate an indicated steam generator liquid level. For a typical Westinghouse plant, the progression of the feedwater line break (FWLB) transient is as follows: The water level in the faulted loop's steam generator decreases to the low-low analysis setpoint and initiates reactor trip and actuates the motor-driven auxiliary feedwater (AFW) pumps. Following reactor trip, the steam generator level in each of the intact steam generators collapses due to the loss of voids with sudden decrease in heat transfer. When the levels in the intact steam generators fall to the low-low level analysis setpoint due to the loss of voids in the steam generators and to steam blowdown through the faulted steam generator to the break, the turbine-driven AFW pump is actuated.

The Beaver Valley units operate differently than that described above. Reactor trip would initiate and the turbine-driven AFW pump would actuate on a low-low water level signal in the faulted steam generator. The two motor-driven AFW pumps would start when the steam generator water level in 2 out of 3 steam generators drop to the low-low level subsequent to reactor trip/turbine trip. In the BVPS-2 FWLB analyses, motor-driven AFW pump flow is actuated on a low-low water level in the faulted steam generator. This is acceptable given the short time window (2 seconds) from the low-low water level signal to reactor trip, and given that the level collapse in the intact steam generators (to the low-low water level) occurs shortly after reactor trip/turbine trip. As for BVPS-1, AFW is actuated on a low steam line pressure safety injection signal.

U.6 (Applicable to RSG & EPU)

Justify the timing of the LOOP for BVPS-1 and 2. For clarity, separately identify trip setpoint reached, reactor trip breakers opening, CRDM holding coil decay, and LOOP on the sequence of events table.

Response:

For the FWLB analyses that model a loss of offsite power (LOOP), it is assumed that the LOOP occurs as a consequence of instability on the power grid caused by the unit trip. It is typically assumed that reactor coolant pump (RCP) coastdown occurs 2 or 3 seconds following the turbine trip, which occurs as a result of the reactor trip; a 2-second delay was assumed for Beaver Valley. This is a reasonable assumption in that the sequence of turbine trip–generator trip–grid instability–loss of power to the RCPs would not occur instantaneously. However, for this transient the RCP coastdown delay time is not an important or critical parameter. The transient results would be negligibly affected if a zero delay time were assumed in the analysis. Note also that the results of the FWLB with LOOP case (RCPs coast down) are less limiting than the results of the FWLB without LOOP case (no RCP coastdown).

U.7 (Applicable to RSG & EPU)

Provide plots of feedline break flow rate (lbm/sec) and enthalpy and AFW flow rate (lbm/sec) into each SG.

Response:

See attached plots – Figures U.7-1 through U.7-8.

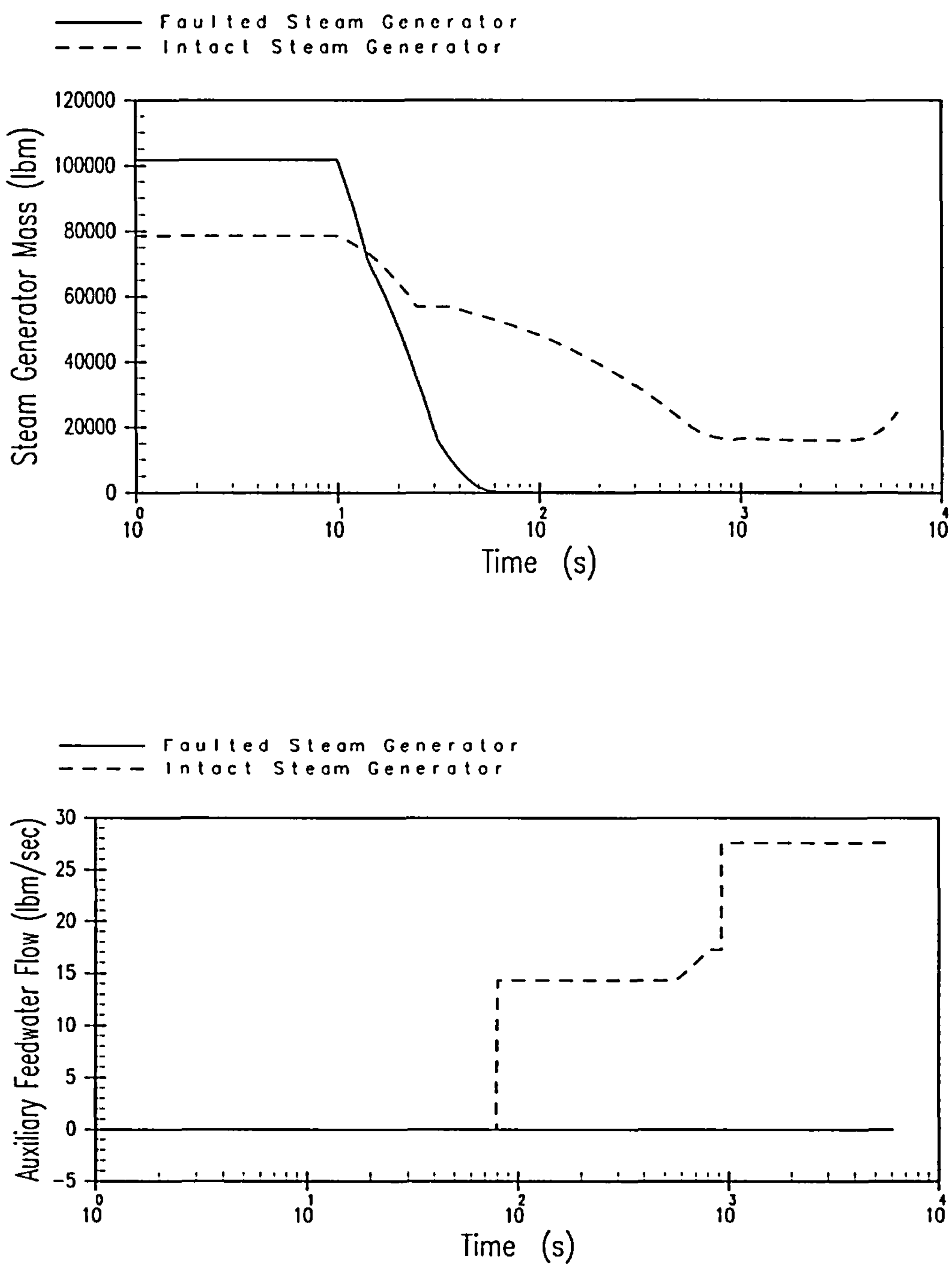
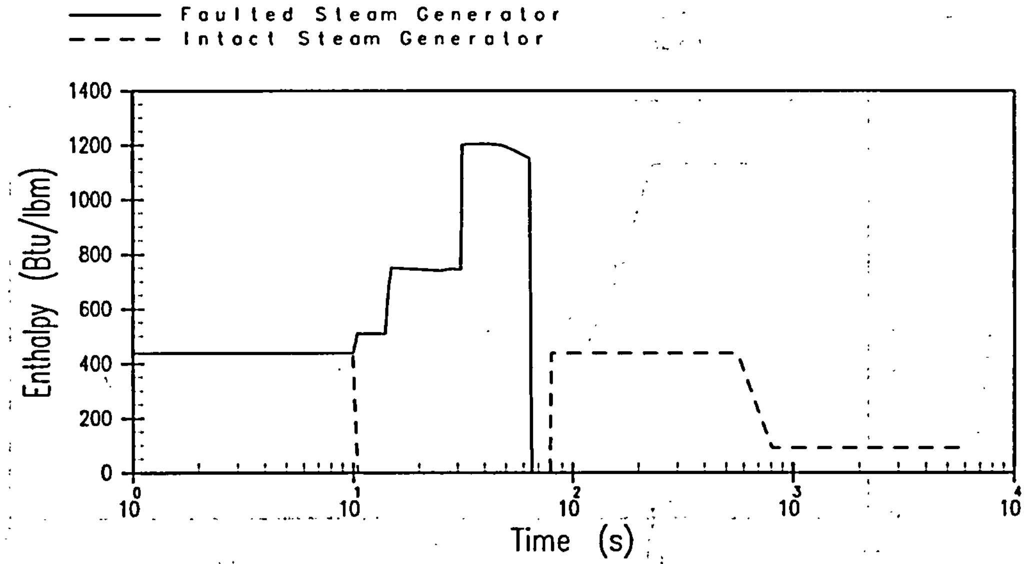


Figure U.7-1
BVPS-1 – FWLB With Offsite Power – SG Mass and AFW Flow Rate



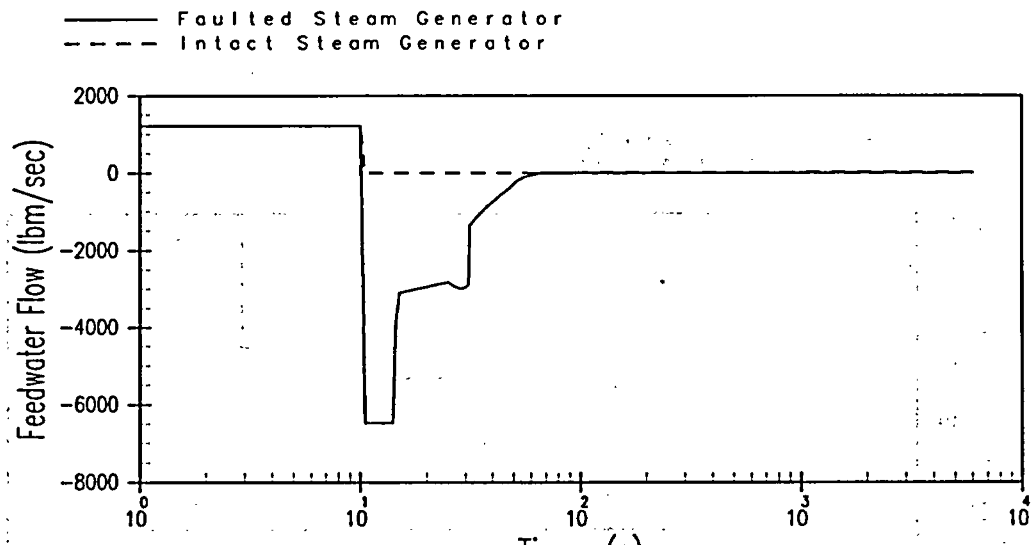


Figure U.7-2
BVPS-1 – FWLB With Offsite Power – Break Enthalpy and Break Flow Rate

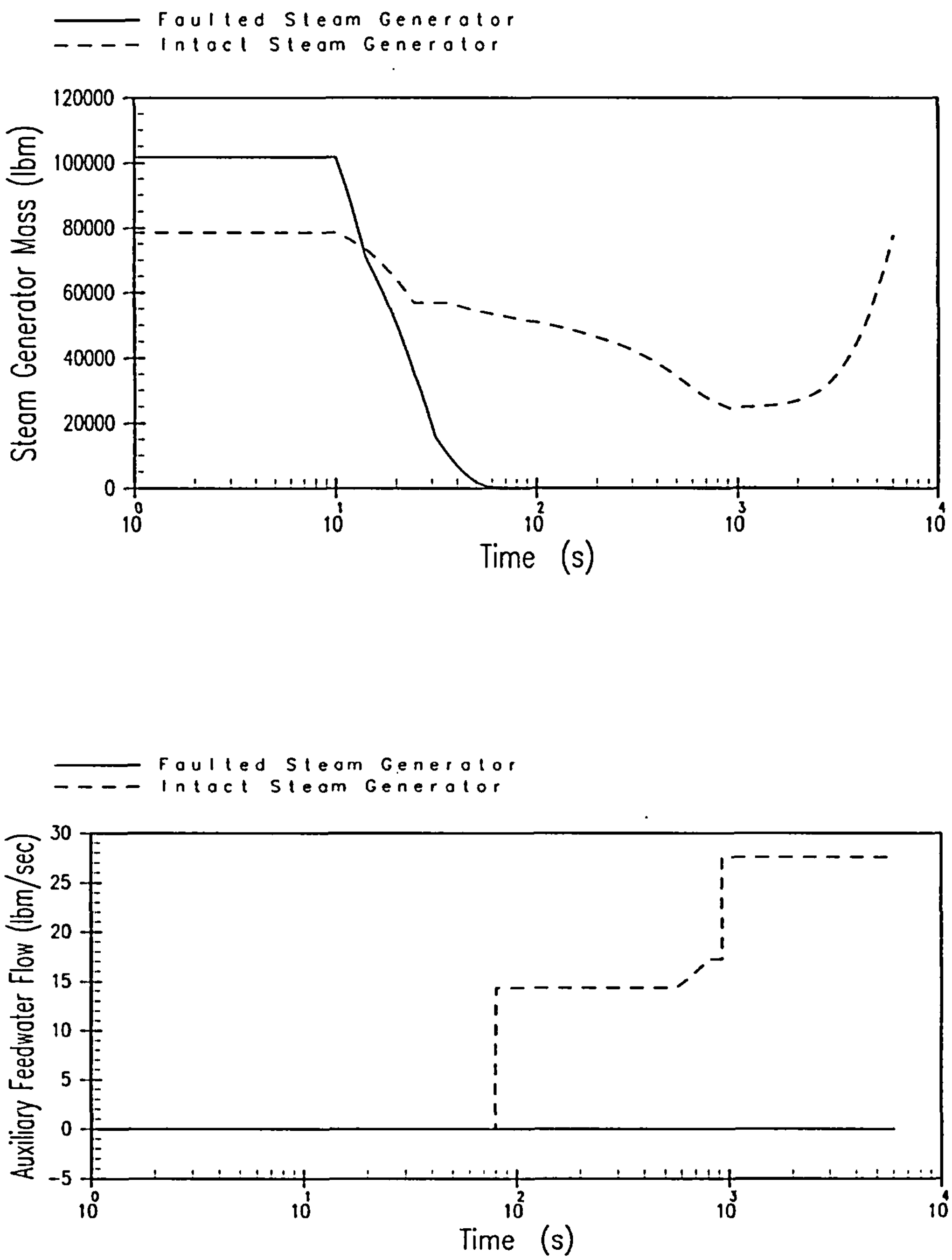
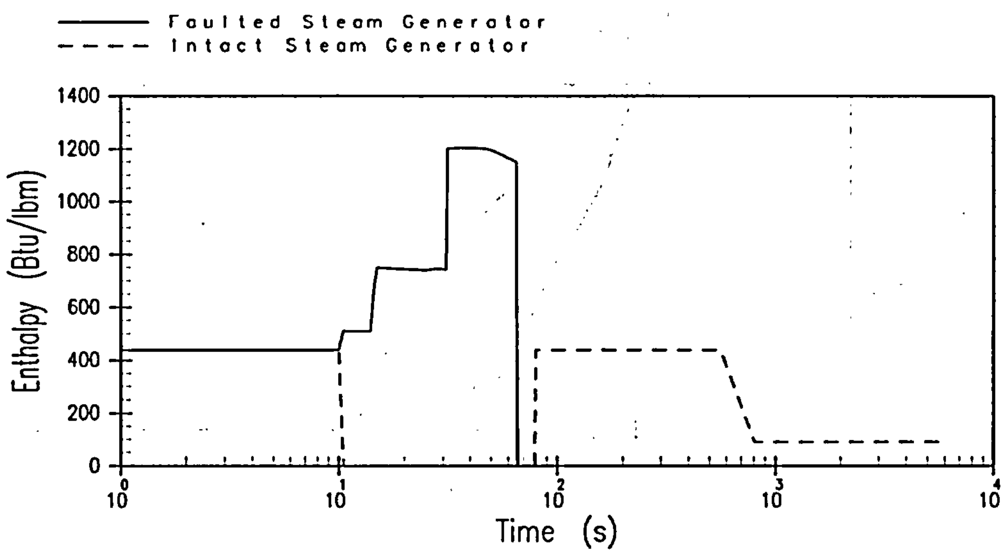


Figure U.7-3
BVPS-1 – FWLB Without Offsite Power – SG Mass and AFW Flow Rate



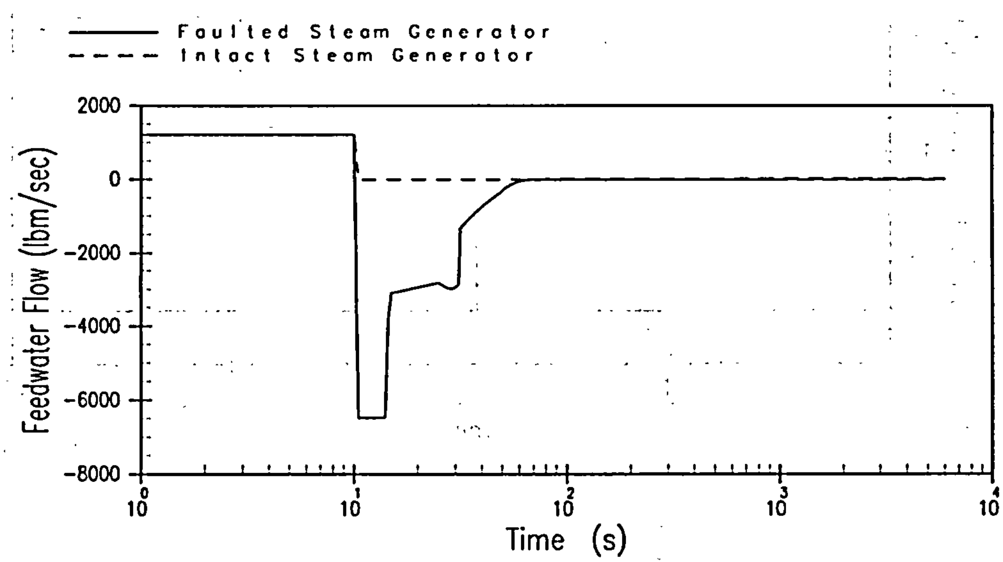


Figure U.7-4
BVPS-1 – FWLB Without Offsite Power – Break Enthalpy and Break Flow Rate

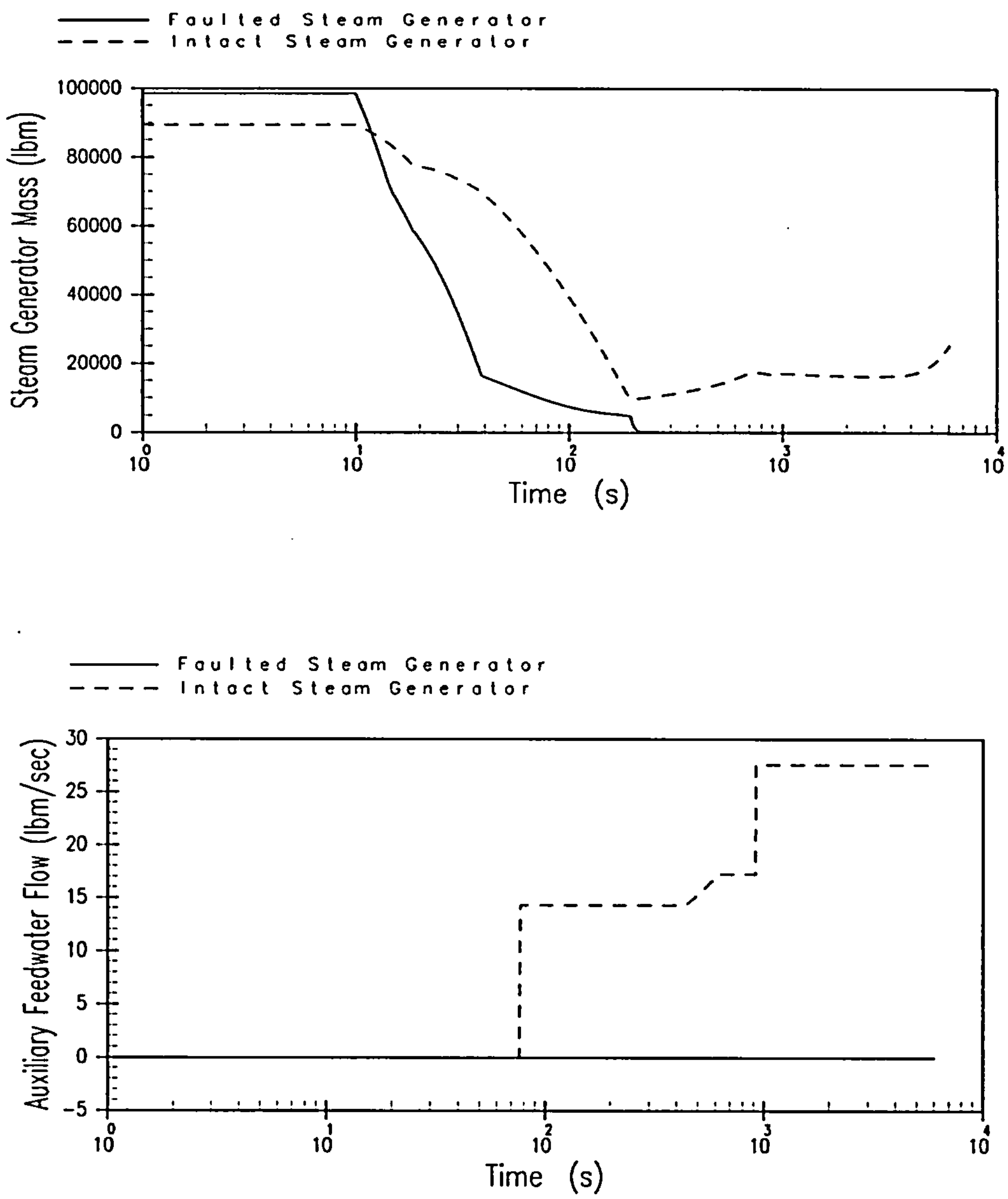
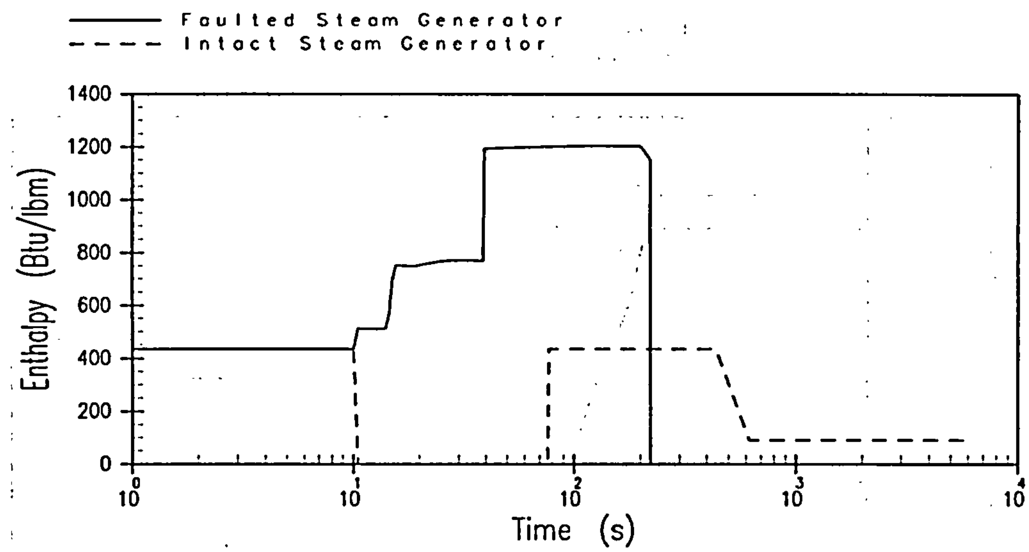


Figure U.7-5
BVPS-2 – FWLB With Offsite Power – SG Mass and AFW Flow Rate



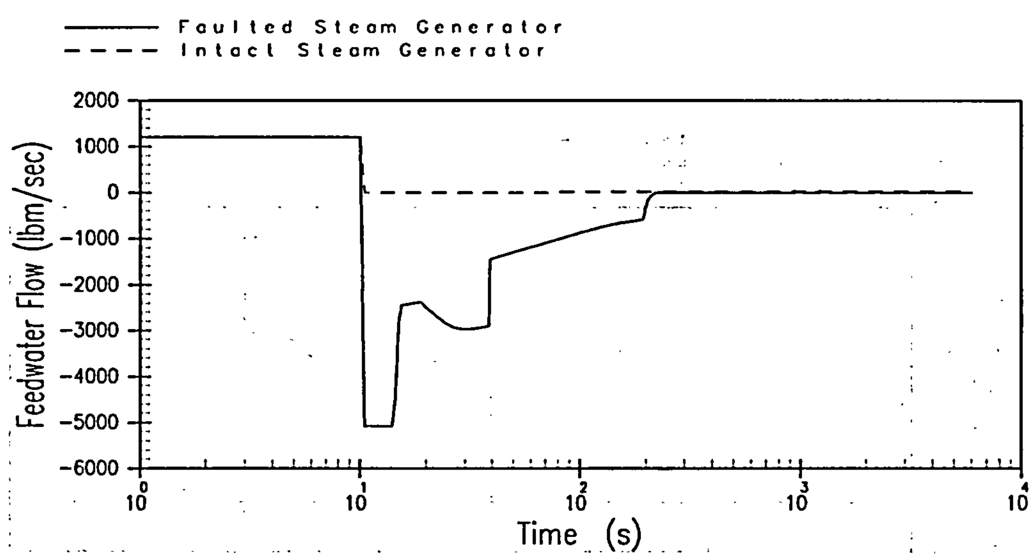
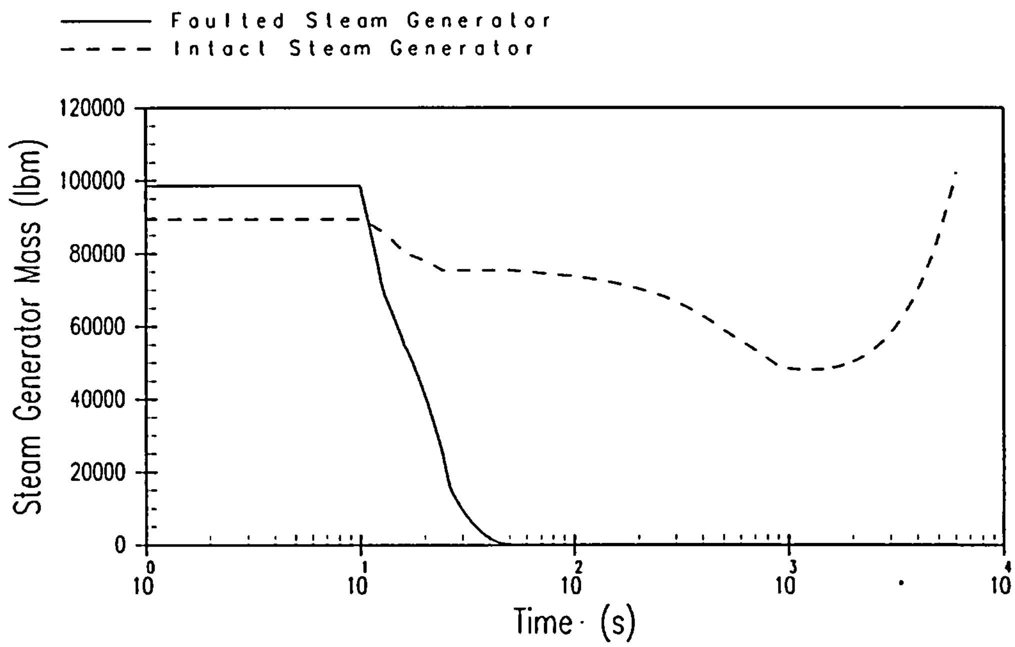


Figure U.7-6
BVPS-2 – FWLB With Offsite Power – Break Enthalpy and Break Flow Rate



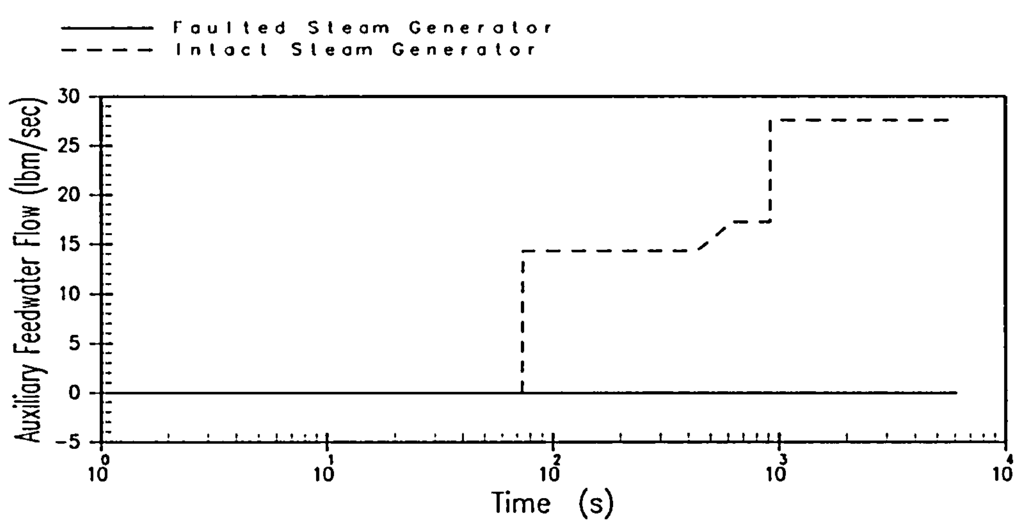


Figure U.7-7
BVPS-2 – FWLB Without Offsite Power – SG Mass and AFW Flow Rate

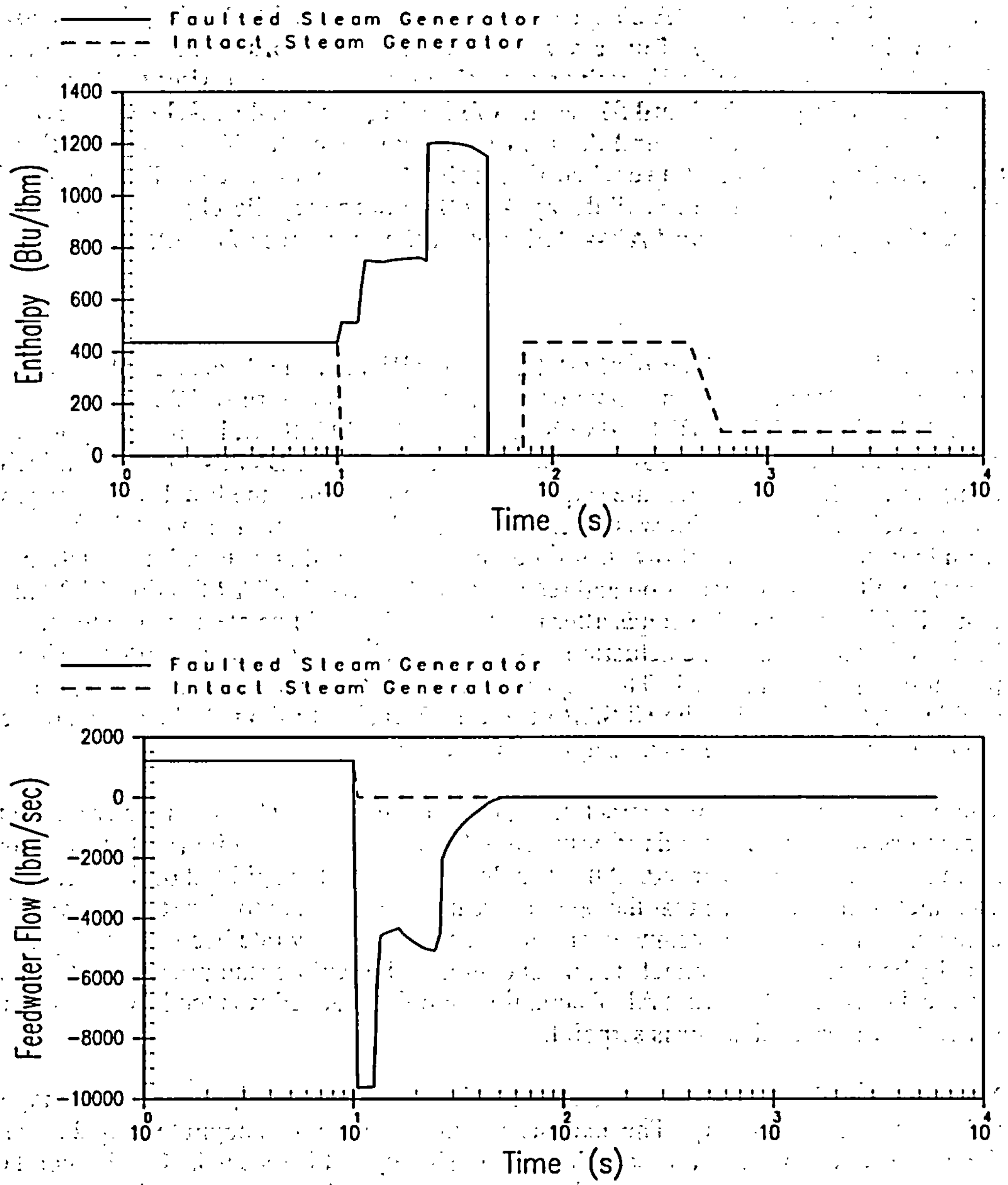


Figure U.7-8
BVPS-2 – FWLB Without Offsite Power – Break Enthalpy and Break Flow Rate

U.8 (Applicable to RSG & EPU)

UFSAR, Section 15.2.8.2 states, "A 60-second delay was assumed following the low-low level signal to allow time for start-up of the emergency diesel generators and the auxiliary feedwater pumps." Table 5.3.17-1A has AFW delivery starting 60 seconds following the low steamline pressure setpoint being reached and 57 seconds following the low-low SG water level. Please discuss the AFW pump start time and delivery (lbm/sec) for both BVPS-1 and 2. For clarity, separately identify trip setpoint(s) reached (including low-low for each SG), reactor trip breakers opening, CRDM holding coil decay, LOOP, emergency diesel generator start, load sequencing, AFW pump start, and AFW delivery on the sequence of events table.

Response:

BVPS-2 UFSAR 15.2.8.2 correctly states that for BVPS-2, a 60-second delay was assumed following the low-low steam generator water level signal before AFW is started. This is reflected in Table 5.3.17-1B for BVPS-2. The BVPS-2 UFSAR, licensing report sequence of events table and analyses are all consistent and correct. For BVPS-1, the dynamically compensated low steam pressure setpoint was reached before the low-low steam generator water level analysis setpoint was reached. Thus, AFW actuation resulted from the SI signal from low steam pressure. Low steam pressure results in SI and steamline isolation. Any SI signal results in AFW actuation and reactor trip. BVPS-1 UFSAR Section 14.2.5.2.2 states that AFW is initiated 60 seconds after reactor trip. It would be clearer to state that AFW begins 60 seconds after the actuation setpoint is reached or 60 seconds after the low steamline pressure setpoint is reached. The sequence of events tables in the licensing report (Table 5.3.17-1A) and in the UFSAR (Table 14.2.2) clearly show AFW begins 60 seconds after the low steamline pressure setpoint is reached.

The AFW assumptions for BVPS-1 are 250 gpm split equally between the two intact steam generators starting 60 seconds after the first AFW actuation setpoint (in this case low steamline pressure) is reached. All other flow is assumed to spill out of the break. At 15 minutes, it is assumed that the operator realigns the system to divert flow away from the break and into the intact steam generators such that the flow rate becomes 400 gpm split equally between the two intact steam generators. The AFW assumptions for BVPS-2 are identical except that the first AFW actuation setpoint reached was the low-low steam generator water level analysis setpoint.

No explicit analysis assumptions are made with respect to the trip breakers opening or the CRDM holding coil decay. The analysis assumes that the rods begin to drop 2 seconds after the low-low steam generator water level analysis setpoint is reached. The 2 second delay accounts for signal processing, breakers opening and coil delay. Similarly, no explicit assumptions are made in the analysis with respect to the EDG start, the load sequencing or the AFW pump start. It is assumed that the AFW pumps are delivering full flow 60 seconds after the actuation setpoint is reached. The 60 second delay covers EDG start, load sequencing and AFW pump start. Also, no credit is taken in the analysis for AFW flow as the AFW pump gets up to speed. The analysis assumes a step change from no flow to full flow at 60 seconds. The analysis also conservatively accounts for the "hot" feedwater which must be purged from the system before the relatively "cold" auxiliary feedwater reaches the intact steam generators. This is shown in the sequence of events tables for both units (Tables 5.3.17-1A and 5.3.17-1B). For the cases without offsite power available, the reactor coolant pumps are assumed to coast down 2 seconds after rod motion and an additional 10 second delay is added to the safety injection actuation time.

<u>Section 5.3.18</u> **<u>Spurious Operation of the Safety Injection (SI) System at Power</u>**

V.1 (Applicable to EPU)

Section 5.3.18 and Tables 5.3.20-3A and 5.3.20-3B indicate that the pressurizer is predicted to fill; but there are no corresponding plots at the end of Section 5.3.18. Please provide plots depicting the plant transient conditions following a spurious SI at-power event, for both BVPS-1 and 2. In particular, please provide transient plots of pressurizer water level (or volume), encompassing the time at which the pressurizer becomes water-solid.

Response:

The transient plots of nuclear power, core average coolant temperature, pressurizer pressure, pressurizer water volume, pressurizer safety valve water relief, and pressurizer water temperature for the BVPS-1 spurious SI case with pressurizer heaters are provided as Figures V.1-1 through V.1-6. The transient plots of the same parameters for the BVPS-1 spurious SI case without pressurizer heaters are provided as Figures V.1-7 through V.1-12. For the BVPS-2 spurious SI event, the same parameter transients are provided as Figures V.1-13 through V.1-18 for the case with heaters, and Figures V.1-19 through V.1-24 for the case without heaters.

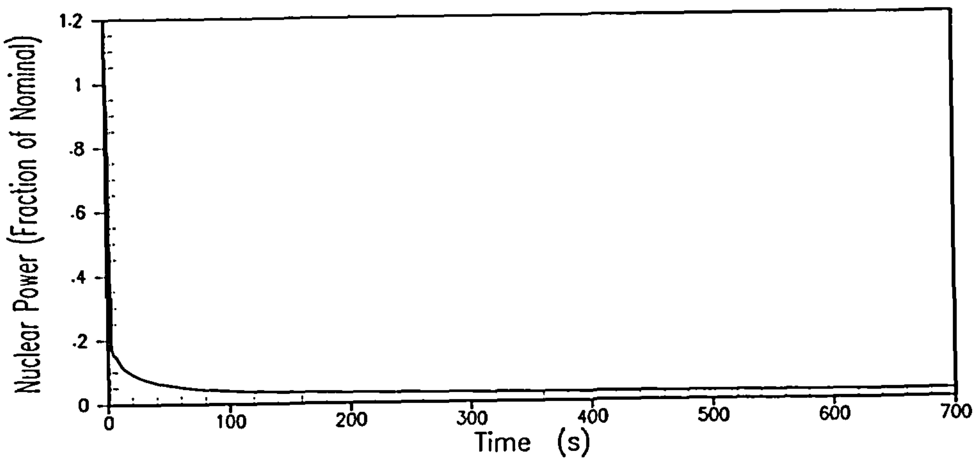


Figure V.1-1
BVPS-1 Spurious SI with Pressurizer Heaters On – Nuclear Power vs. Time

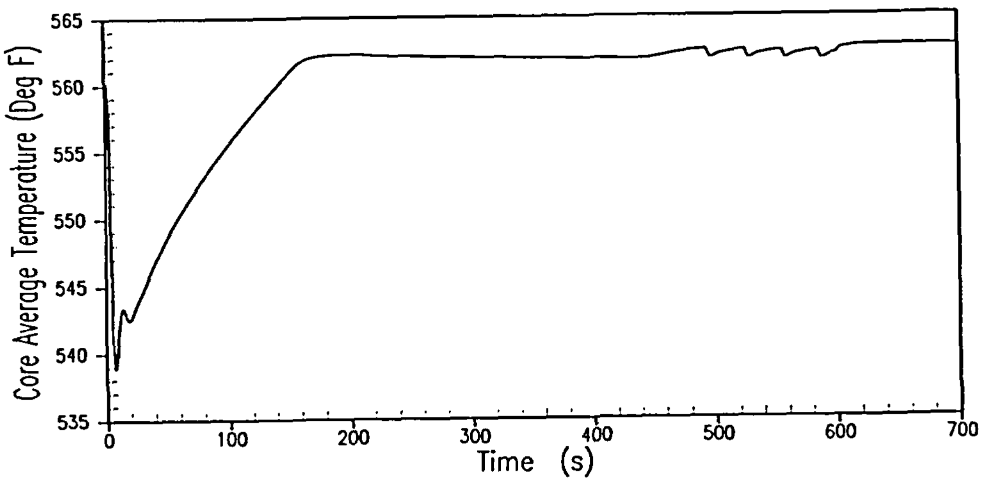


Figure V.1-2
BVPS-1 Spurious SI with Pressurizer Heaters On –
Core Average Coolant Temperature vs. Time

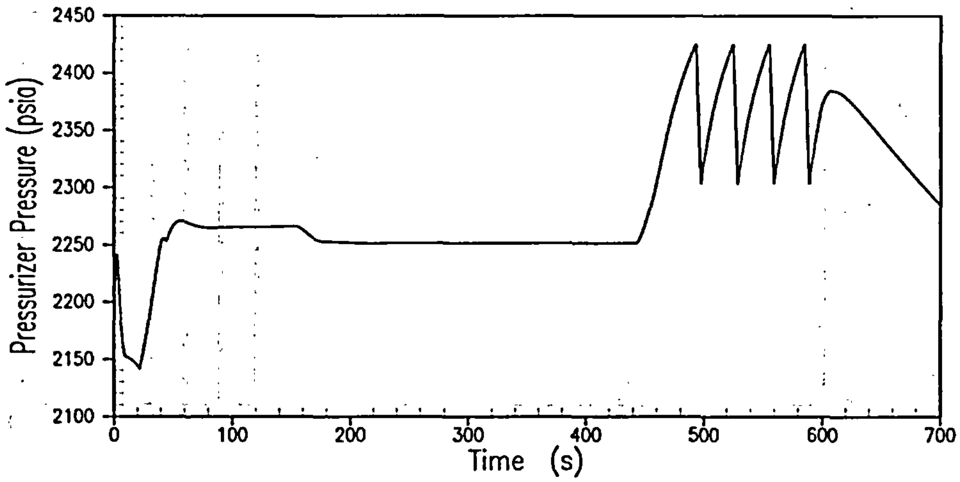


Figure V.1-3
BVPS-1 Spurious SI with Pressurizer Heaters On – Pressurizer Pressure vs. Time

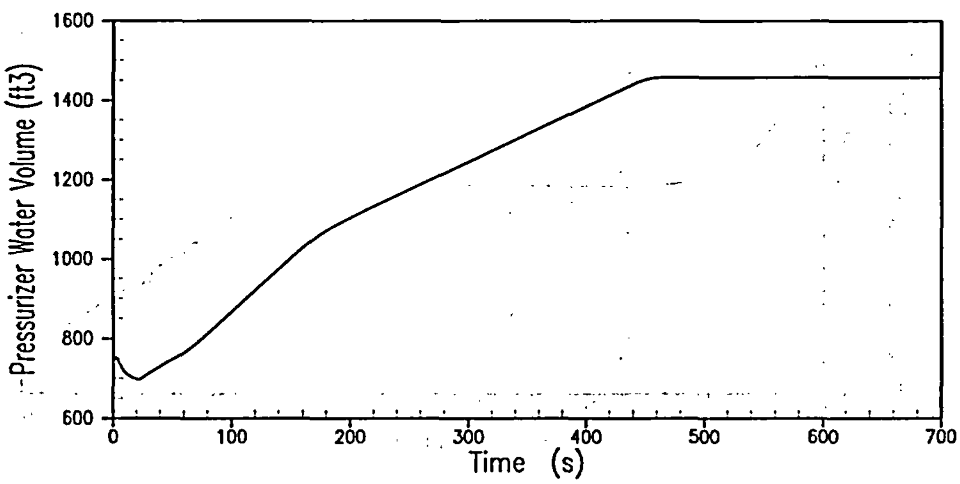


Figure V.1-4
BVPS-1 Spurious SI with Pressurizer Heaters On – Pressurizer Water Volume vs. Time

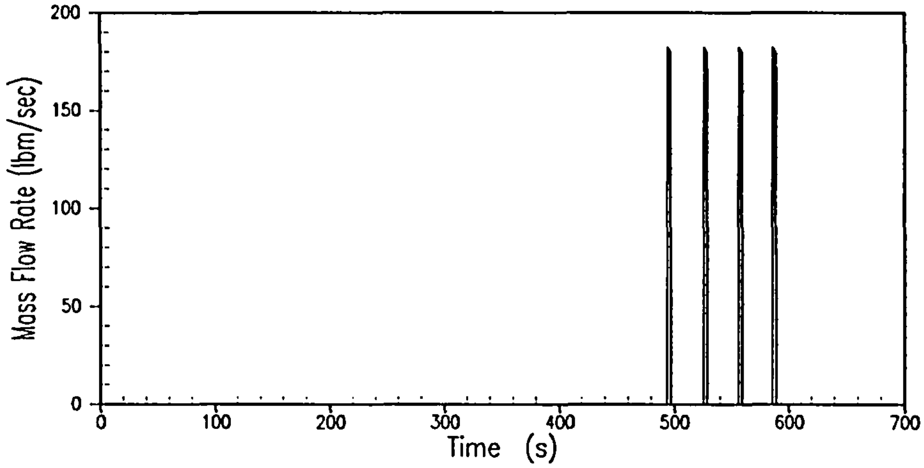


Figure V.1-5
BVPS-1 Spurious SI with Pressurizer Heaters On –
Pressurizer Safety Valve Water Relief vs. Time

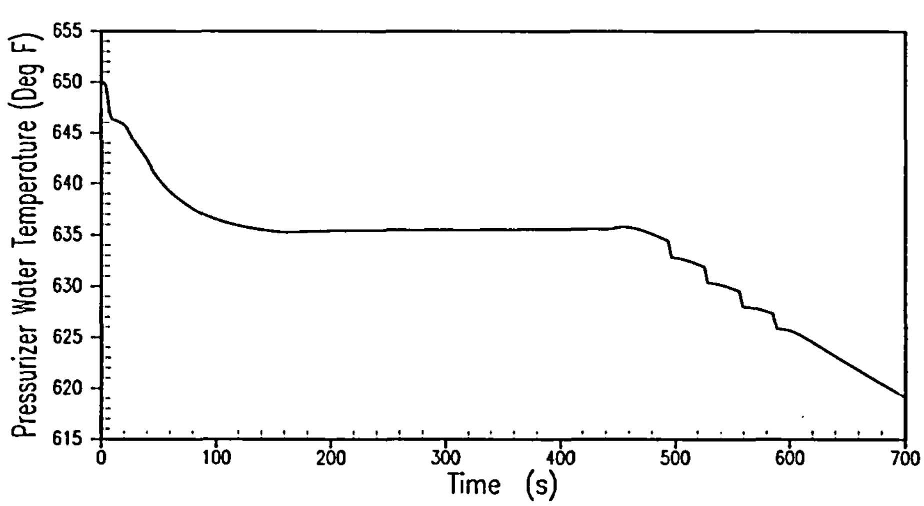


Figure V.1-6
BVPS-1 Spurious SI with Pressurizer Heaters On –
Pressurizer Water Temperature vs. Time

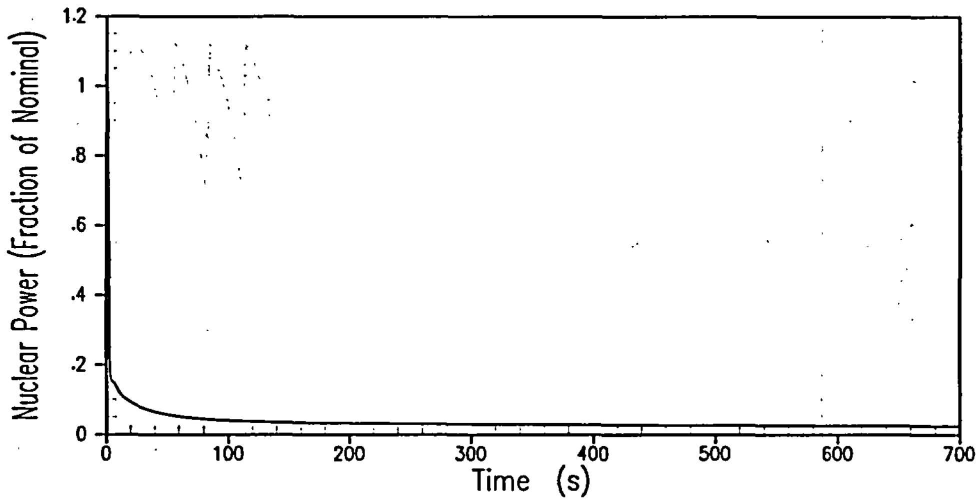


Figure V.1-7
BVPS-1 Spurious SI with Pressurizer Heaters Off – Nuclear Power vs. Time

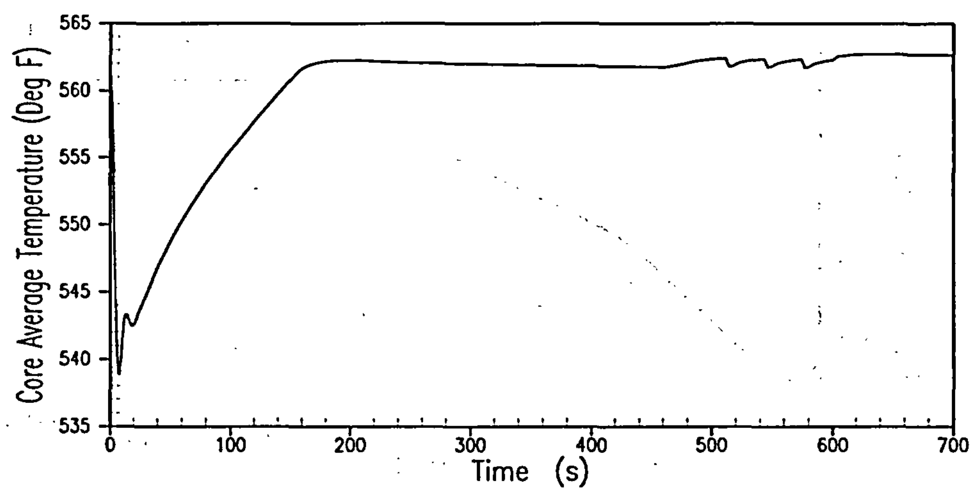


Figure V.1-8
BVPS-1 Spurious SI with Pressurizer Heaters Off –
Core Average Coolant Temperature vs. Time

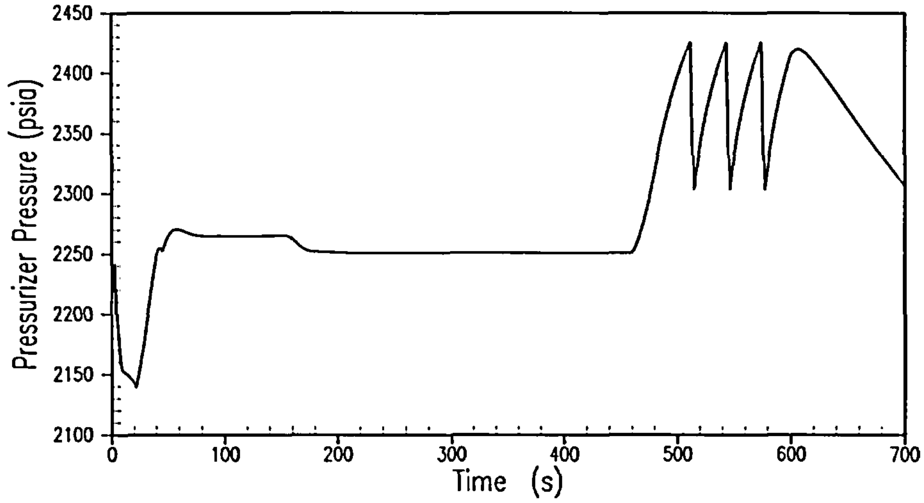


Figure V.1-9
BVPS-1 Spurious SI with Pressurizer Heaters Off – Pressurizer Pressure vs. Time

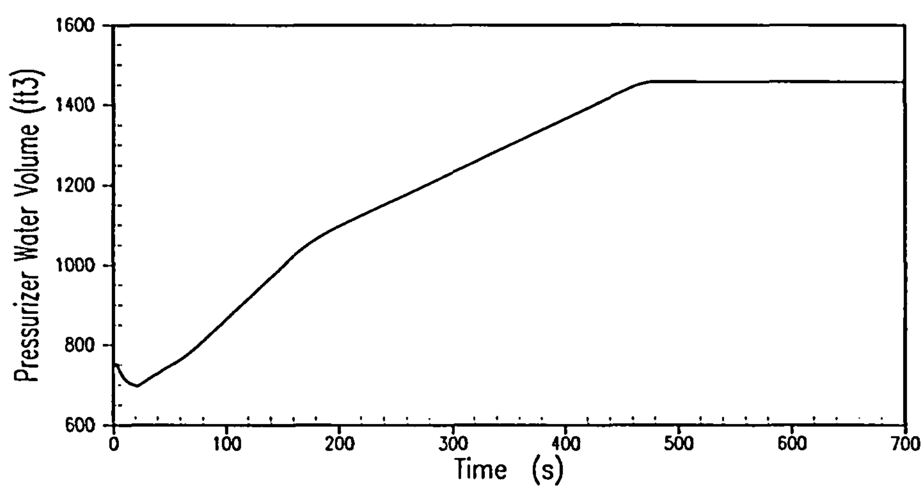


Figure V.1-10
BVPS-1 Spurious SI with Pressurizer Heaters Off – Pressurizer Water Volume vs. Time

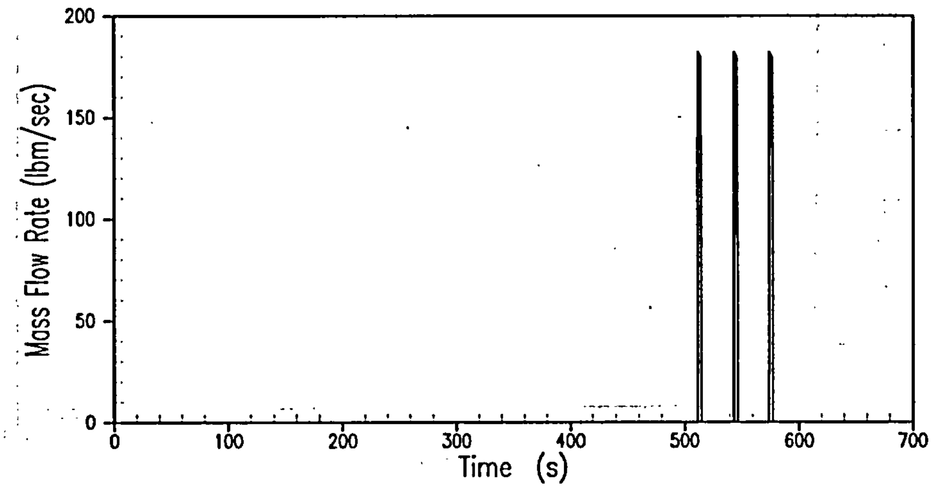


Figure V.1-11
BVPS-1 Spurious SI with Pressurizer Heaters Off – Pressurizer Safety Valve Water Relief vs. Time

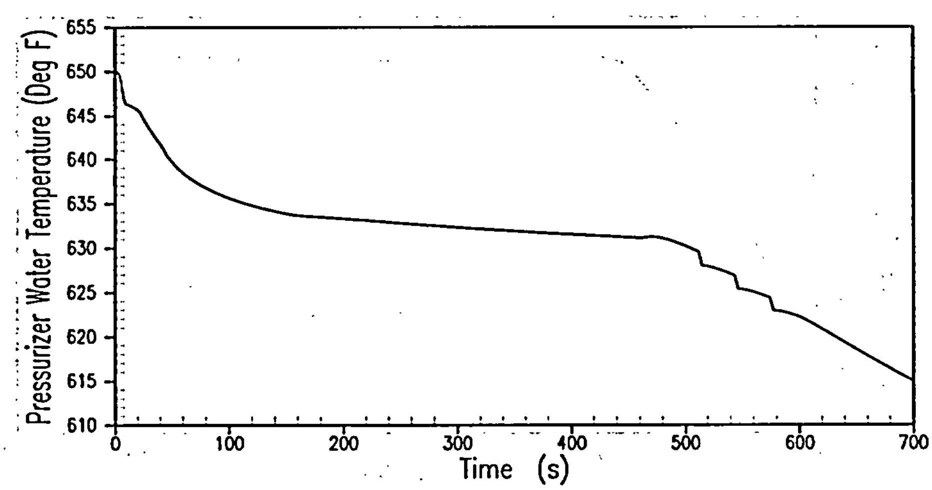


Figure V.1-12
BVPS-1 Spurious SI with Pressurizer Heaters Off – Pressurizer Water Temperature vs. Time

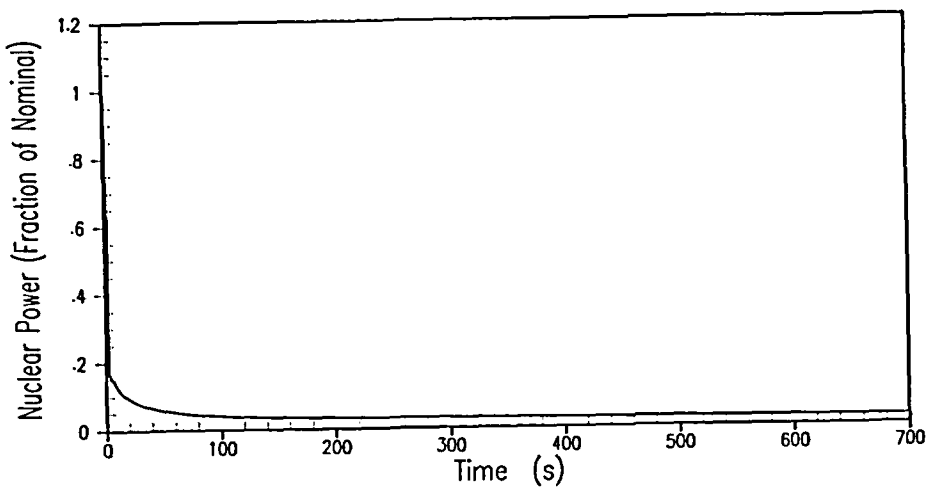


Figure V.1-13
BVPS-2 Spurious SI with Pressurizer Heaters On – Nuclear Power vs. Time

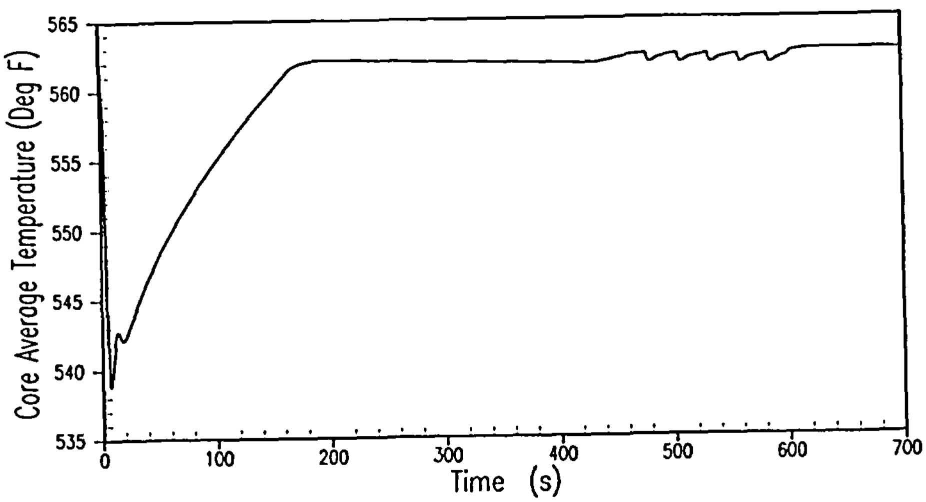


Figure V.1-14
BVPS-2 Spurious SI with Pressurizer Heaters On –
Core Average Coolant Temperature vs. Time

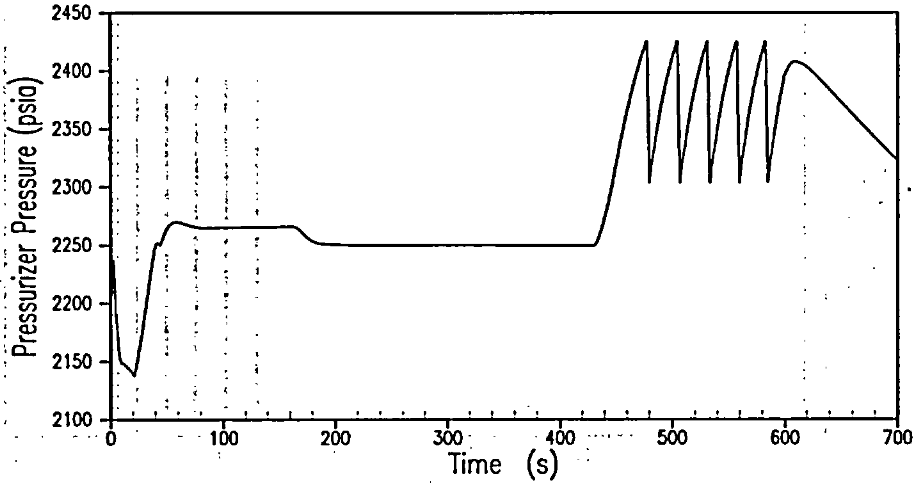


Figure V.1-15
BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Pressure vs. Time

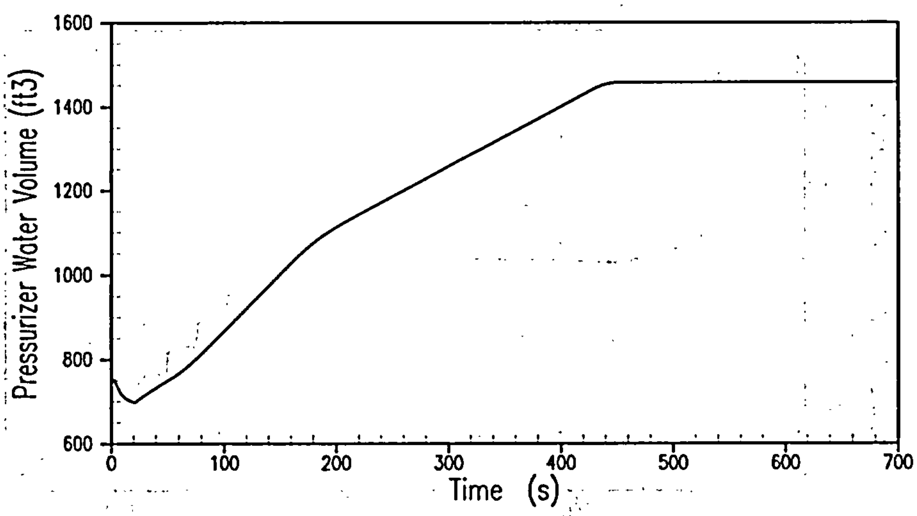


Figure V.1-16
BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Water Volume vs. Time

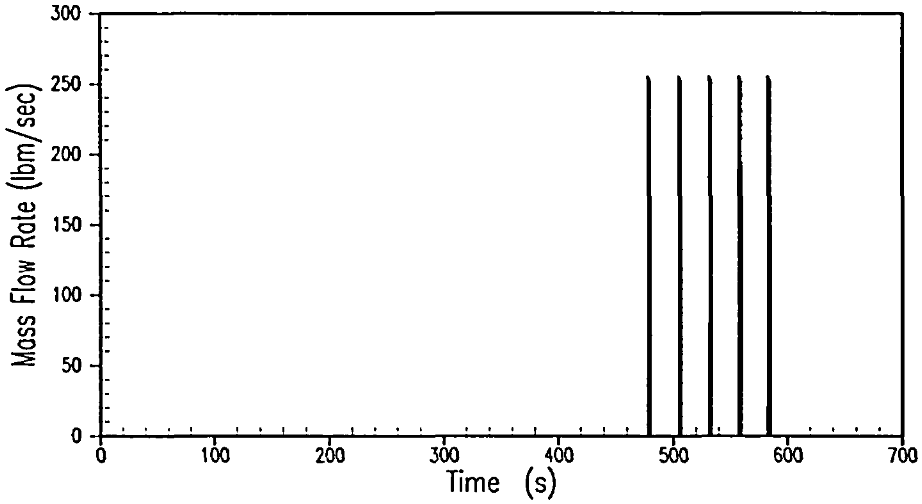


Figure V.1-17
BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Safety Valve Water Relief vs. Time

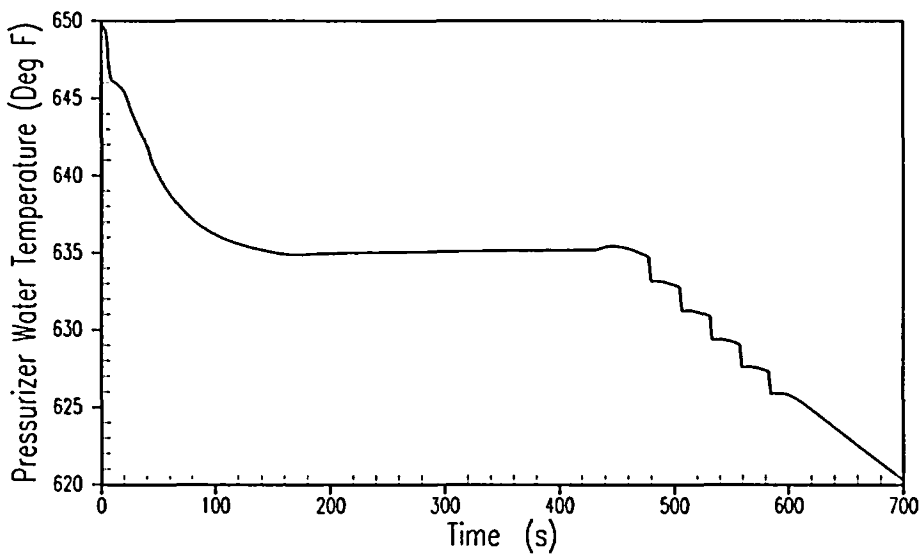


Figure V.1-18
BVPS-2 Spurious SI with Pressurizer Heaters On – Pressurizer Water Temperature vs. Time

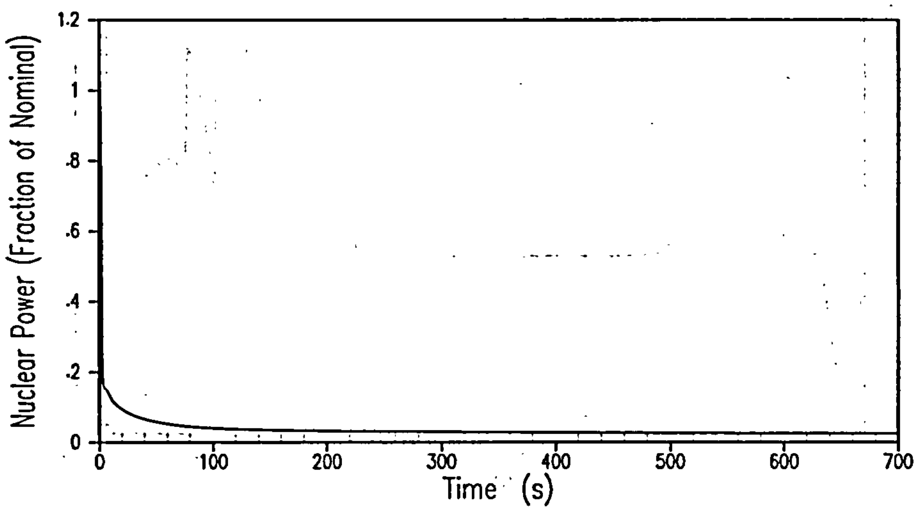


Figure V.1-19
BVPS-2 Spurious SI with Pressurizer Heaters Off – Nuclear Power vs. Time

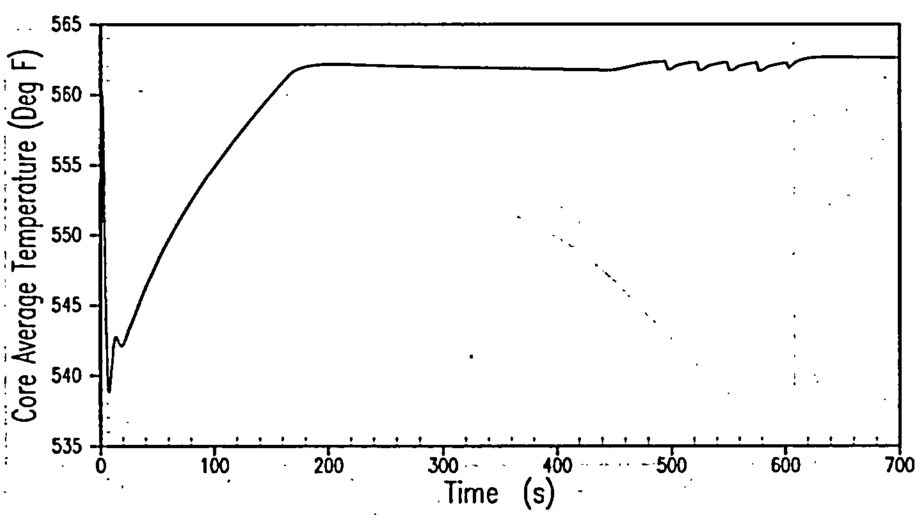


Figure V.1-20
BVPS-2 Spurious SI with Pressurizer Heaters Off –
Core Average Coolant Temperature vs. Time

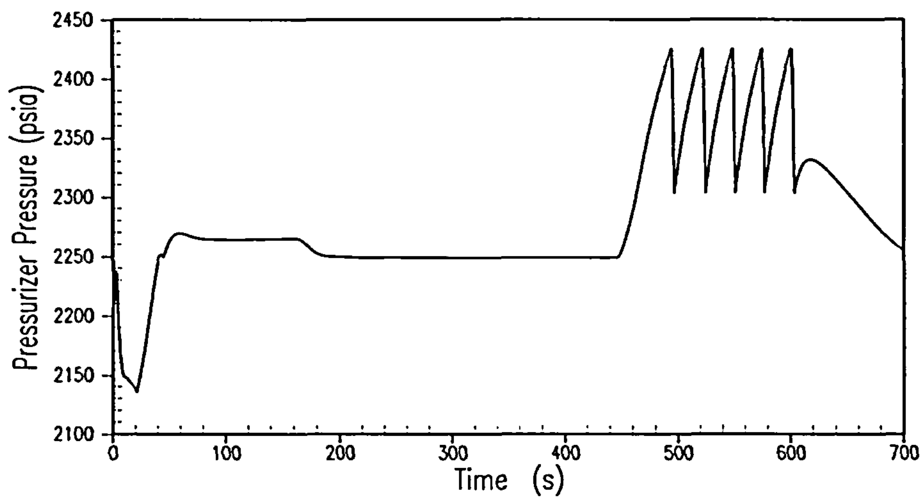


Figure V.1-21
BVPS-2 Spurious SI with Pressurizer Heaters Off – Pressurizer Pressure vs. Time

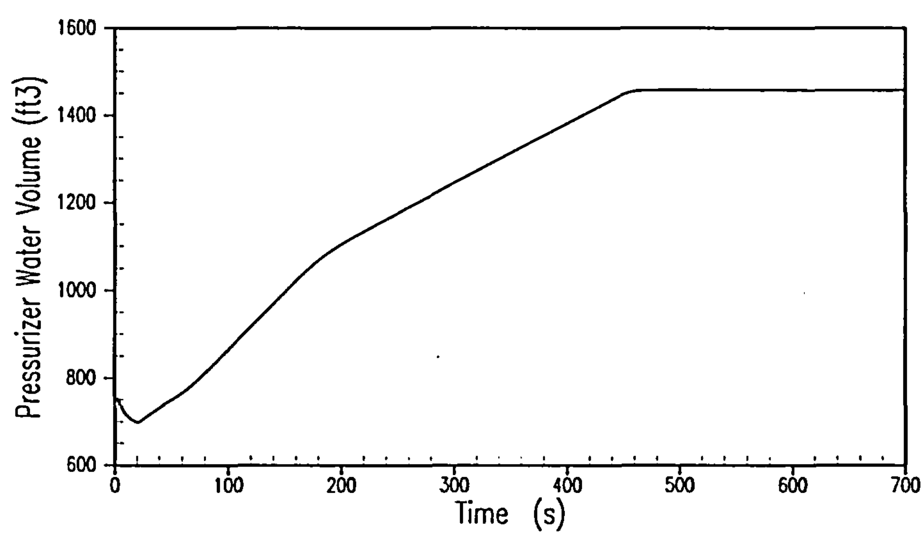


Figure V.1-22
BVPS-2 Spurious SI with Pressurizer Heaters Off – Pressurizer Water Volume vs. Time

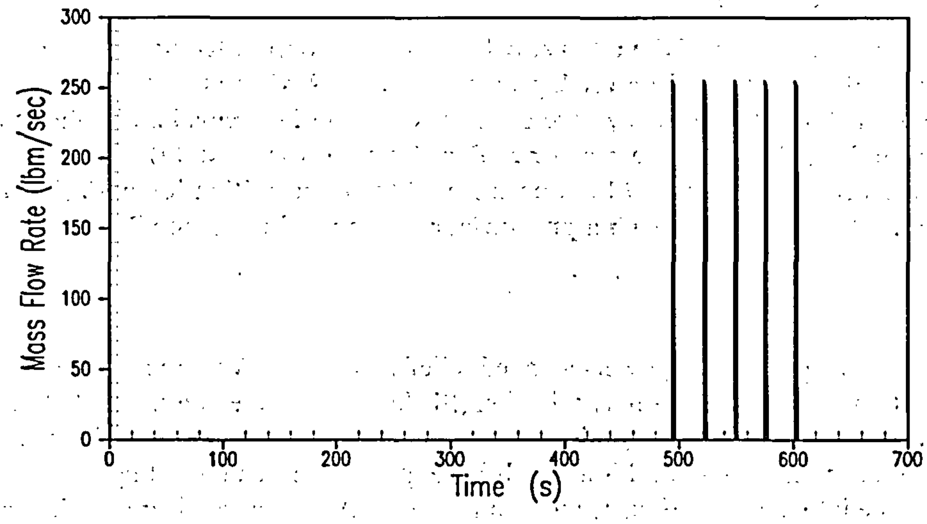


Figure V.1-23
BVPS-2 Spurious SI with Pressurizer Heaters Off – Pressurizer Safety Valve Water Relief vs. Time

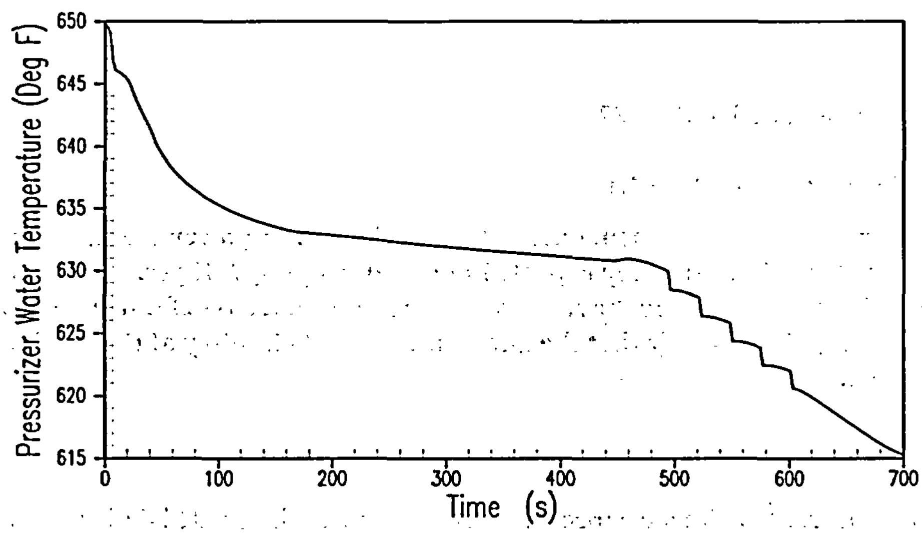


Figure V.1-24
BVPS-2 Spurious SI with Pressurizer Heaters Off – Pressurizer Water Temperature vs. Time

V.2 (Applicable to EPU)

In the EPU report, Note 8.8 of the table entitled, "Information in Response to the NRC's Review Standard for Extended Power Uprates – RS-001, Revision 0," states that, "For the inadvertent operation of emergency core cooling system and chemical and volume control system malfunctions that increase reactor coolant inventory events: (a) non-safety-grade power-operated relief valves should not be credited for event mitigation and, (b) pressurizer level should not be allowed to reach a pressurizer water-solid condition."

Response:

Although the pressurizer power-operated relief valves (PORVs) are not credited for event mitigation, the maximum safety injection (SI) flow causes the pressurizer to become water-solid before the end of the 10-minute operator action time period. Showing the pressurizer does not become water-solid is a simplified approach for demonstrating the event does not propagate into a more serious Condition III event. As the pressurizer was shown to fill in the BVPS-1 and 2 spurious SI analyses, an alternate approach was taken to demonstrate the event does not propagate into a more serious event. The alternate approach was to perform a pressurizer safety valve (PSV) operability assessment that determined the PSVs would remain operable for the duration of temporary water relief prior to operator action to terminate safety injection. This confirms that the reactor coolant system pressure boundary will remain intact.

V.3 **(Applicable to EPU)**

How do the BVPS-1 and 2 spurious SI at-power event analyses meet the requirements specified in this Note?

Response:

Response discussed in RAI V2.

V.4 **(Applicable to RSG & EPU)**

The pressurizer PORVs might open, during the spurious SI at-power event, when the pressurizer is water-solid. Are they expected to reseat properly? If yes, state how they, and their associated discharge piping, have been qualified for water relief during a spurious SI at power event. Also, please verify that the automatic control circuitry of these valves meets Class 1E requirements.

Response:

The pressurizer PORVs are expected to re-seat properly if actuated during the inadvertent safety injection. The valve design will accommodate either steam or water discharge. The relief valves on both units close automatically upon loss of power to the solenoid or instrument air (BVPS-1 only—BVPS-2 PORVs do not utilize air pressure as a motive medium). The PORVs receive automatic closure signals to close when the high pressure signal to open the valves is re-set. There is a motor-operated block valve, powered by safety busses, that serve as backup isolation valves for each PORV. The block valves are powered from a power source, i.e., 480 volt AC power, which is diverse from the 125 volt DC powered PORVs.

The associated discharge piping for the safety and relief valves has been analyzed for the simultaneous opening of either the safety valves or relief valves, including the valve inlet loop seal water slugs. The piping has not been analyzed for the EPU conditions of water solid discharge through the valves during a spurious SI event. This analysis will be completed prior to implementation of EPU.

The control circuitry for the PORVs is considered control grade and does not meet Class 1E requirements. Automatic opening of the PORVs is not credited in any safety analysis unless operation of the valves is detrimental to the results.

V.5 (Applicable to RSG & EPU)

If the pressurizer PORVs don't open during the spurious SI at-power event, then the PSVs might open when the pressurizer is water-solid. Describe and document the PSV operability analyses that indicate these valves can be expected to reseat properly.

Response:

The qualification of the pressurizer safety valves for each Beaver Valley unit is based on the thermal and hydraulic (T&H) conditions during the spurious safety injection and comparing these conditions to the test conditions for the valves during the EPRI tests. The T&H conditions determined the amount of valve seat lift and how many cycles were required and their frequency. Cases included T&H conditions with and without crediting pressurizer heaters. The spurious safety injection conditions were compared to the EPRI qualification for Target Rock (BVPS-1) and Crosby (BVPS-2) safety valves. Analyses determined that EPRI test conditions (Reference EPRI NP-2770-LD, Volumes 8 and 9, Project V102-2, Interim Report, March 1983) bound the operating conditions for the valves during a spurious safety injection, and the valves will reseat properly.

V.6 (Applicable to RSG & EPU)

How was the current licensing basis for the spurious SI at-power event established (e.g., by 10 CFR 50.59 evaluation or by NRC staff review and approval)? If by 10 CFR 50.59 evaluation, then please provide a copy of the 10 CFR 50.59 evaluation. If by NRC staff review and approval, then please cite the applicable license amendment.

Response:

BVPS-1

The following documents identify the current licensing basis for spurious SI at power events at BVPS-1, and a summary of changes that established the licensing basis relative to the questions in this section associated with RCS overpressure protection, including references to NRC/SER approvals and/or 50.59 evaluations, as applicable:

- Current licensing basis:

  UFSAR Section 14.1.16, Spurious Operation of SI System at Power, describes the current licensing basis for spurious operation of the safety injection system at power. In addition, licensing basis for RCS overpressure protection includes Technical Specification 3.4.3 for the Pressurizer Code Safety Valves.

- Summary of Applicable Changes:

  - Technical Specification changes related to GL 90-06, (Generic Issue 70 – PORV & block valve reliability and Generic Issue 94 – Additional low temperature overpressure protection), License Amendment 187 and NRC SER dated 5/15/95.
  - License Amendment No. 115 added additional actions to be taken if a pressurizer safety valve discharged water due to an overpressure event, and NRC SER dated 9/8/87 (TAC #63369).
  - NRC SER dated 11/10/86 Completion of Review, NUREG 0737 Item II.D.1 Safety/Relief Valves (TAC 44562), BVPS-1 Performance Testing of Relief and Safety Valves.
  - NRC SER dated 9/14/83 NUREG 0737 Items II.K.3.1 – Automatic PORV Isolation and II.K.3.2 – Report on PORV's for BVPS-1.
  - NRC SER dated April 4, 1983 discussing the BVPS-1 overpressure protection system.

BVPS-2

The following documents identify the current licensing basis for spurious SI at power events at BVPS-2, and a summary of changes that established the licensing basis relative to the questions in this section associated with RCS overpressure protection, including references to NRC/SER approvals and/or 50.59 evaluations, as applicable:

- Current licensing basis:

  UFSAR Section 15.5.1, Inadvertent Operation of ECCS During Power Operation describes the current licensing basis for spurious operation of the safety injection system at power. In addition, licensing basis for RCS overpressure protection includes Technical Specification 3.4.3 for the Pressurizer Code Safety Valves.

- Summary of Applicable Changes:

  - Technical Specification changes related to GL 90-06, (Generic Issue 70 – PORV & block valve reliability and Generic Issue 94 – Additional low temperature overpressure protection), License Amendment 76 and NRC SER dated 9/18/95.
  - Revision 12 to UFSAR Section 15.5.1, performed under 50.59 evaluation dated 3/19/99* (Ref Condition Report #980894), which included the Pressurizer Code Safety Valve (PSV) Operability Assessment.

- License Amendment No. 39 added additional actions to be taken if a pressurizer safety valve discharged water due to an overpressure event, and NRC SER dated 10/15/91 (TAC #M76478).
- NRC SER dated 9/13/89 Completion of Review, NUREG Item II.D.1 Safety/Relief Valves (TAC 62894), BVPS-2.
- NRC SER dated 4/10/87 (SER Confirmatory Item #11), NUREG 0737 Item II.D.1 Safety/Relief Valves for BVPS-2.
- BVPS-2 SER (NUREG 1057, Oct. 1985) Section 15.5.1, Inadvertent Operation of ECCS During Power Operation – page 15-14.

* Note: Copy of 10 CFR 50.59 Evaluation included as Attachment C of Enclosure 1.

V.7 (Applicable to RSG & EPU)

Please supply the ECCS flow delivery rate, as a function of RCS pressure, that was assumed for the spurious SI at-power event analyses. Compare this flow delivery rate to that assumed in the current licensing basis analyses of BVPS-1 and 2.

Response:

The maximum safety injection flow rates assumed for the spurious SI event analyses are shown in the Tables A.1-19A, A.1-19B, and A.1-19C in the response to RAI A.1.

V.8 (Applicable to RSG & EPU)

Analyze or evaluate the CVCS malfunction that does not change the RCS boron concentration. Show that this event will not fill the pressurizer before the operator can shut off the charging flow.

Response:

It is FENOC's policy to evaluate the applicability and consequences of Westinghouse Nuclear Safety Advisory Letters (NSALs) through its Corrective Action System. Westinghouse identified that the UFSAR analyses for the loss of offsite power or loss of normal feedwater events had not historically mechanistically modeled the operation of the charging and letdown systems. This was communicated to BVPS in NSAL-00-013. The loss of offsite power scenario bounds a CVCS malfunction event with respect to filling the pressurizer. Through the corrective action program, a corrective action documented that an analysis demonstrated that the pressurizer will not fill in more than 10 minutes for the current power operation (adequate time for operator action for this Condition II event to isolate charging or stop charging pumps). The condition was also analyzed using the extended power uprate (EPU) conditions and showed that both units have 10 or more minutes to isolate charging (or establish outflow from the RCS). The EPU analysis is conservative, compared to the current power operation, because of the higher power level and because the high side of the RCS T_{avg} window (for the uprate) results in a higher pressurizer level initial condition.

The analyses performed for this NSAL are based on extremely conservative design inputs. For example:

a. Instrument air is conservatively assumed lost to the charging flow and letdown isolation valves instantaneously. This is not realistic because the instrument air reservoirs inside and outside containment will maintain charging flow control (with instrument air, the charging flow control valve will close trying to maintain pressurizer level) and letdown will remain open, at least via the letdown relief valve, for some period of time. Also, BVPS-1 has an automatically-started, diesel powered redundant instrument air system to keep these valves in service.

b. The loss of offsite power starts both high head safety injection pumps and it is assumed that they operate for the duration of the event at the maximum emergency diesel frequency.

   It is noted that this event, contrary to the RAI question, does change the boron concentration. On decreasing volume control tank level, the charging pump suction will switch over to the refueling water storage tank, and the RCS boron concentration will increase.

Section 5.3.19 Steam System Piping Failure at Full Power

W.1 (Applicable to RSG & EPU)

Demonstrate that the credited RPS trip functions and supporting instrumentation and cables are qualified for a harsh containment environment. Further, quantify the environmental instrument uncertainties and analytical setpoints.

Response:

The primary function of the Overpower ΔT reactor trip is to provide primary protection for main steamline break mass and energy release events, both inside and outside containment.

BVPS-1 has an environmental allowance of 0.5% instrument span for cable degradation that is treated as a bias in the instrument uncertainties. The analytical setpoints are contained in Enclosure 2, Table 5.3.1-2A, and the nominal trip setpoints are contained in Enclosure 1, Attachment C-1, Table 3.3-1, Table Notations A and B.

BVPS-2 has an environmental allowance of 0.3% instrument span for cable degradation that is treated as a bias in the instrument uncertainties. The analytical setpoints are contained in Enclosure 2, Table 5.3.1-2B, and the nominal trip setpoints are contained in Enclosure 1, Attachment C-2, Table 3.3-1, Table Notations A and B.

The RPS Overpower ΔT reactor trip receives its input signal from environmentally qualified Weed Instruments Resistance Temperature Detectors (RTDs). These RTDs are qualified for Harsh Environments of 500°F and 3.03 E08 RADs. The Weed temperature elements remain qualified for EPU conditions 355°F and 2.55 E08 RADs. The associated cables (Continental and Brand Rex), splices (Raychem), and electrical penetrations (Viking and Westinghouse) remain qualified for EPU conditions.

Steamline Pressure Low function serves as primary actuation of the Engineered Safety Features Actuation System for secondary system piping failures.

The ITT Barton transmitters and associated cables are located in the BVPS-1 Auxiliary Feedwater Pump Room of the Safeguards Building such that neither is subject to the steam break environment and no allowances for adverse conditions are required. However, the pressure transmitters are qualified for Harsh Environment 420°F and 6.80 E07 RADs.

The ITT Barton transmitters and associated cables are located in the BVPS-2 Main Steam Cable Vault such that neither is subject to the steam break environment and no allowances for adverse conditions are required. However, the pressure transmitters are qualified for Harsh Environment 420°F and 6.80 E07 RADs.

W.2 (Applicable to RSG & EPU)

The VANTAGE 5H and RFA fuel assemblies employ different CHF correlations and are subject to different DNBR limits. Further, the location of the mid-span mixing vanes introduces an axial-dependency to the CHF correlation.

a. **The local conditions experienced during an MSLB may be outside the applicability of the WRB-1 and WRB-2M CHF correlations. Please describe the use of these correlations during the MSLB event. If the W-3 correlation is being employed, demonstrate its applicability to both the VANTAGE 5H and RFA fuel assemblies at these MSLB local conditions.**

Response:

The MSLB at full power conditions results in much higher RCS pressures during the transient than the MSLB at zero power. At these conditions (RCS pressure ≥ ~1500 psia), the WRB-1 and WRB-2M correlations are applicable. For the fuel spans above the first mixing vane grid, the WRB-1 correlation is used for VANTAGE 5H assemblies, while the WRB-2M correlation is used for RFA assemblies.

The W-3 correlation is valid for the conditions seen during the MSLB at full power as well as the MSLB at zero power (RCS pressure ≥ ~500 psia). The W-3 correlation is used for the lower spans of the fuel assembly below the first mixing vane grid. The VANTAGE 5H and RFA assemblies are virtually identical at this location, such that the W-3 correlation applies to either fuel type.

b. **Quantify the most severe shift axial power distribution (AXPD) during a cooldown event and how the core thermal-hydraulic models account for this shift. Include in this discussion the calculation of DNBR with an axial-dependent CHF correlation.**

Response:

The axial power distribution for the hot assembly (highest power assembly) at the limiting HFP steamline break statepoint is taken from the ANC calculation and provided to Thermal-Hydraulic Design in a format suitable for use in VIPRE analyses. This format includes 38 equally-spaced axial mesh intervals. Attached is a graph (Figure W.2-1) of a typical hot assembly axial power distribution from one of the HFP SLB cases analyzed as part of the EPU. The axial power shapes from all of the BVPS-1 and 2 HFP MSLB calculations were very similar and no one shape stood out as being most limiting.

The Revised Thermal Design Procedure (RTDP) was utilized for the DNB analysis for the MSLB at full power event. In this methodology, the system analysis is based on nominal conditions and the uncertainties are statistically addressed via the DNB analysis/limit. However, this is only done for the WRB-1 and WRB-2M correlations. The W-3 correlation was used for DNBR calculations below the first mixing vane grid, with uncertainties applied to the thermal-hydraulic system statepoints.

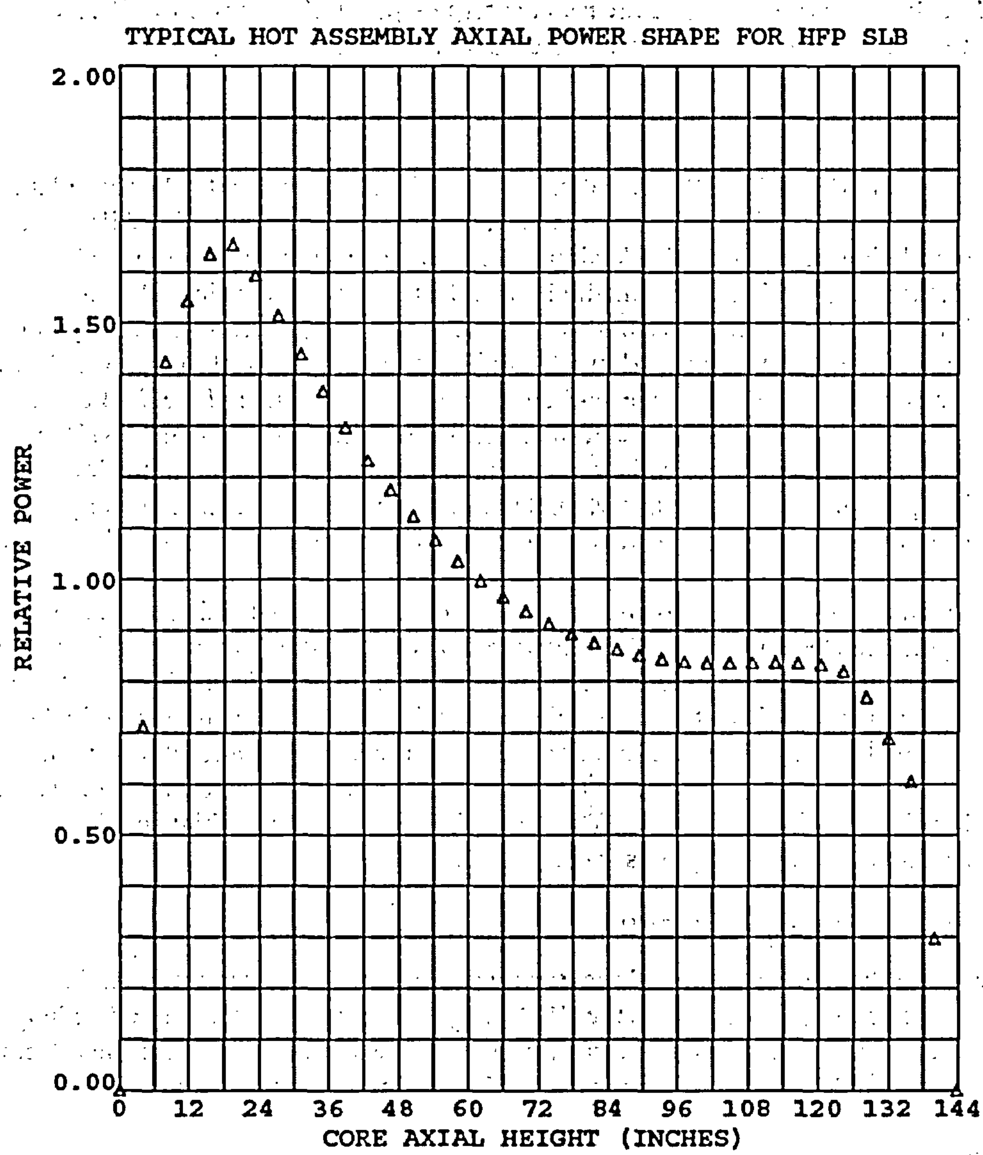


Figure W.2-1
Typical Hot Assembly Axial Power Shape for HFP MSLB

W.3 (Applicable to RSG & EPU)

Section 5.3.19.3(b) states that uncertainties on power, temperature, pressure, flow, etc., are being applied to the limiting statepoints in the W-3 DNBR calculations. Please quantify this application of uncertainties. Note that if the application of uncertainties to the initial conditions impacts the timing of the reactor trip or point of minimum DNBR, then this application may be non-conservative. Please discuss.

Response:

The HFP MSLB DNBR calculations were divided into two parts. For calculations above the first (lowest) mixing vane grid, the WRB-1 correlation was used for V5H and the WRB-2M correlation was used for RFA, along with Revised Thermal Design Procedure (RTDP) methodology. With RTDP methodology, the uncertainties are included in the DNBR Design Limits. The minimum DNBRs were above the RTDP DNBR Safety Analysis Limits. For calculations below the first (lowest) mixing vane grid, the WRB-1 and WRB-2M correlations are not applicable. Thus, the W-3 correlation was used. Use of the W-3 correlation, as applied here, required the use of Standard Thermal Design Procedure (STDP). With STDP, the uncertainties are applied directly to the input parameters used in the VIPRE calculations, i.e., pressure minus uncertainty, inlet temperature plus uncertainty, power plus uncertainty and use of Thermal Design Flow. The minimum DNBRs were above the W-3 correlation limit.

The transient conditions (called statepoints) were calculated and provided to Thermal-Hydraulic Design for DNBR calculations. The application of uncertainties to the statepoints used in the DNBR calculations does not impact the calculations of transient conditions. It should be noted that, if the applicable uncertainties were applied to the initial conditions assumed in the transient calculations, the event would reach a reactor trip setpoint earlier, resulting in less severe statepoints compared to the application of the uncertainties to the limiting time in the transient. Therefore, the use of nominal initial conditions in the transient calculation of the statepoints is conservative.

W.4 (Applicable to RSG & EPU)

Demonstrate that the credited ΔT reactor trip functions have accounted for instrumentation (e.g., resistance temperature detector (RTD)) delay/lag times and asymmetric loop temperatures in a conservative manner. If applicable, demonstrate that the effects of excore temperature shadowing have been included in all reactor trip functions.

Response:

The non-LOCA analyses explicitly model the individual components of the instrumentation delays and lag times (such as the RTDs, the filters and the delay from reaching the trip setpoint until the rods begin to fall into the core). In addition, the RCS loop temperature asymmetry was explicitly modeled as an initial condition.

With respect to the effects of temperature shadowing, the excore detectors (specifically the high neutron flux reactor trip setpoint) are only credited in heatup events. A heatup event will result in an increase in T_{cold} with a corresponding decrease in coolant density. The decrease in coolant density would result in an increased indicated power signal as more neutrons reach the excore detectors due to the reduction in shielding. This would result in an earlier reactor trip than modeled in the safety analyses. Therefore, the effects of temperature shadowing are conservatively ignored, since it would result in an earlier trip and less severe results for the heatup events.

W.5 (Applicable to RSG & EPU)

Does the 2.0-second delay time for the overpower ΔT reactor trip function include the CRDM holding decay time?

Response:

The 2.0-second delay time for the Overpower ΔT reactor trip function includes the CRDM holding decay time.

W.6 (Applicable to RSG & EPU)

To illustrate the break spectrum cases investigated, provide a single plot of break size versus reactor trip time (including applicable delays) for all of the credited reactor trip functions.

Response:

Figures W.6-1 and W.6-2 show the reactor trip time (time of rod motion, including applicable delays) versus the break size for the HFP MSLB event for BVPS-1 and 2, respectively. The figures demonstrate that larger break sizes trip on the low steamline pressure SI reactor trip, intermediate break sizes trip on Overpower ΔT reactor trip, and the small break sizes do not induce a reactor trip. Rather, for the small breaks, a new equilibrium condition is reached at a slightly higher power level below any of the reactor trip function setpoints.

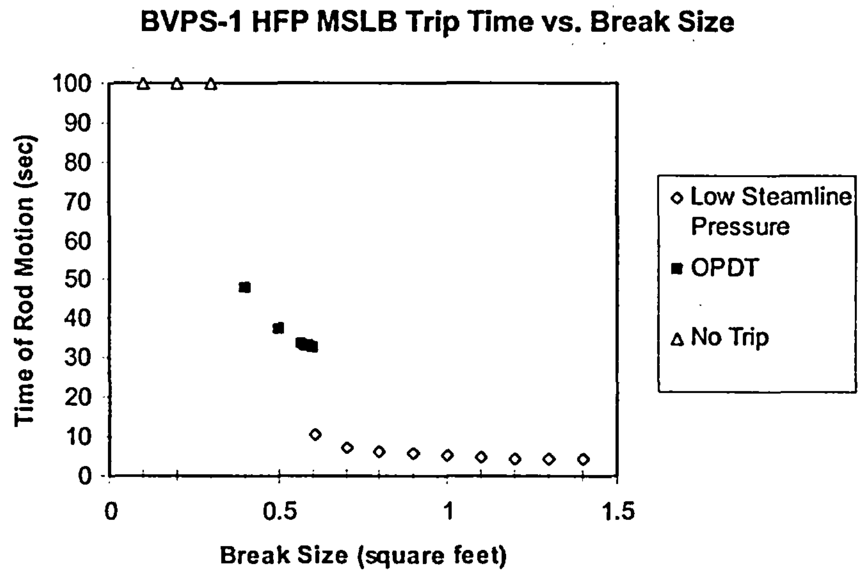


Figure W.6-1
BVPS-1 Reactor Trip Time vs. MSLB Size

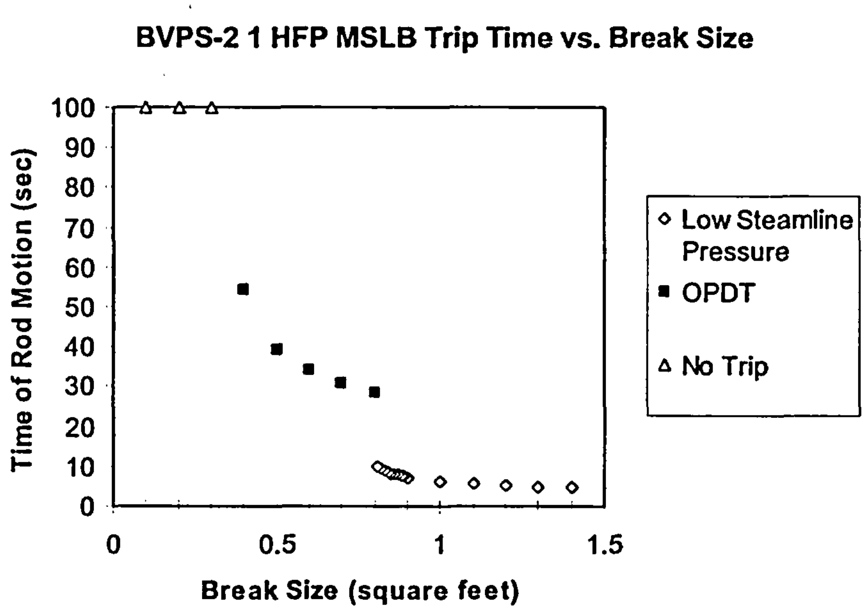


Figure W.6-2
BVPS-2 Reactor Trip Time vs. MSLB Size

W.7 (Applicable to RSG & EPU)

Demonstrate that a HFP MSLB case including a single failure and/or LOOP would be less limiting that the cases presented in Section 5.3.19.

Response:

The HFP MSLB event is terminated by reactor trip. For post-reactor trip considerations, the HZP MSLB event presents a bounding analysis. For the HFP MSLB event, the worst single failure is the failure of one protection train, as other failures (such as a failure in the engineered safety features, a failure of a main steam isolation or feedwater line isolation valve, etc.) would occur beyond the time of reactor trip and are not relevant to the event as analyzed. These types of failures, including the loss of offsite power, are considered in the analysis of the HZP MSLB event which examines post-reactor trip.

Section 5.4 Steam Generator Tube Rupture

X.1 (Applicable to RSG & EPU)

In the EPU report for BVPS-1, the SG tube rupture (SGTR) accident analysis is based on the assumption that the leak flow from the RCS to secondary side of the SG is terminated 30 minutes following the event initiation. The resulting break flow mass transfer is then used to calculate the radiological consequences of the SGTR. Inherent in this evaluation is the assumption that the operator can terminate the break flow in 30 minutes. Plants with similar designs to BVPS-1 have reported to the NRC that, in simulator exercises, the operators demonstrated that the time to terminate the break flow exceeded the 30-minute assumption. The longer period of time needed to isolate the SG with the tube rupture could lead to an increase in radiological releases from that which was assumed when the SG was isolated within 30 minutes of event initiation.

Either verify that the 30-minute operator action assumption is valid for BVPS-1 and 2, or provide the results of a re-analysis for SGTR accident with conservative assumptions including a most limiting single failure, a coincident LOOP, and operator actions according to plant EOPs. These re-analyses of SGTRs should address both offsite dose and SG overfill issues.

Response:

A condition report was written in the 1990's that documented that more than 30 minutes was required to terminate radioactive steam release from the ruptured steam generator. Through the implementation of corrective actions, the number was revised to 51 minutes and the UFSAR was changed via the 10 CFR 50.59 process. Even though the break termination time increased, it was determined that the mass and radioactivity transport analysis, based on the assumptions that depressurize and terminate break flow in 30 minutes, actually resulted in a higher offsite dose because the primary to secondary break flow is higher than the case that terminated releases in 51 minutes. Since the licensing basis offsite dose basis is based on the more conservative 30 minute termination methodology, the 30 minute termination methodology is still the basis documented in the EPU Licensing Report for the offsite dose calculation and confirmed for the Extended Power Uprate.

In addition to the 30 minute licensing basis steam generator tube rupture analysis reported in the EPU Licensing Report, a supplemental steam generator tube rupture analysis has been performed for BVPS-1 that includes the most limiting single failure, a coincident LOOP, and operator actions in accordance with the plant EOPs. This supplemental analysis was performed to develop thermal and hydraulic input for use in radiological dose analysis. This supplemental analysis confirmed the conservatism of the dose calculations based on the original 30 minute termination.

For the EPU conditions, two separate analyses were performed for assessing steam generator overfill. One case used the range of initial PCWG parameters, LOFTTR2 approved methodology including loss of offsite power (LOOP), operator action times for each critical mitigating action taken from simulator crew EOP response time data for the SGTR, and local operation of both atmospheric steam dump valves. The second operational assessment was based on nominal PCWG initial conditions and operator action simulator crew data. This case evaluated the spectrum of limiting single failures including a atmospheric dump valve, failure of the automatically actuated, diesel-powered instrument air subsystem (actuated due to the LOOP and shutdown of the primary instrument air compressors), and a failure of an auxiliary feedwater isolation valve. All cases did not fill the steam generator.

In summary, the BVPS-1 supplemental analysis addresses both thermal and hydraulics for dose and margin to steam generator overfill.

X.2 (Applicable to RSG & EPU)

Discuss the limiting single failure assumed in the case concerning SG overfill. Compare the assumed single failure with: 1) failure of an atmospheric dump valve (ADV) in the intact SG which causes slower RCS cooldown and increased cumulative leak flow from the RCS to the SGs, and 2) failure of AFW flow control which causes a more severe SG overfill transient.

Response:

Three single failure scenarios were considered in the BVPS-1 supplemental steam generator tube rupture analysis for margin to steam generator overfill analysis: 1) a single failure of the instrument air supply requiring local operation of the intact steam generator atmospheric relief valves (ARVs) for cooldown, 2) a single failure of a steam generator ARV to open on demand at the time of RCS cooldown, and 3) a single failure of the auxiliary feedwater isolation valves to close on demand. The limiting single failure scenario in the BVPS-1 supplemental steam generator tube rupture margin to steam generator overfill analysis is the failure of an ARV to open on demand at the time of cooldown initiation.

For BVPS-2 licensing basis steam generator tube rupture analysis, two single failure cases were analyzed: 1) Orange Bus power supply failure which results in a loss of control room operation of the ARV and, 2) Purple Bus power supply failure resulting in loss of the plant residual heat release valve (RHRV). The EPU analysis indicates that a loss of either power bus results in a similar margin to steam generator overfill. Recent evaluations performed in support of the EPU examining a failure of the auxiliary feedwater isolation valves to close on demand determined that the time required to isolate the auxiliary feedwater valves was reasonable when crediting local operator action.

As noted above, the loss of cooldown capacity is the limiting single failure with respect to margin to steam generator overfill for both BVPS-1 and 2.

X.3 (Applicable to RSG & EPU)

Discuss the limiting single failure assumed in the case concerning offsite dose. Compare the assumed single failure with a stuck open ADV in the failed SG after it is automatically opened following the event.

Response:

The limiting single failure in the thermal and hydraulic for dose analysis is a failed open Atmospheric Dump Valves (ADV) on the ruptured steam generator that is assumed to fail open at the time of ruptured steam generator isolation. This single failure was assumed in both the BVPS-1 supplemental steam generator tube rupture thermal and hydraulics for dose analysis and in the BVPS-2 licensing basis steam generator tube rupture thermal and hydraulics for dose analysis.

The steam generator tube rupture methodology used in the BVPS-1 and 2 EPU analyses determined that the limiting single failure for radiological consequences is a failure of the ADV (i.e., fail open) on the ruptured steam generator at the time of ruptured steam generator isolation. The scenario of a failure of an ADV at accident initiation was not considered.

X.4 (Applicable to RSG & EPU)

Confirm that a concurrent LOOP is assumed in the SGTR analysis.

Response:

The steam generator tube rupture analyses performed for the BVPS EPU assume a LOOP concurrent with reactor trip.

X.5 (Applicable to RSG & EPU)

Confirm that the operator actions assumed in the SGTR analysis are consistent with the BVPS-1 and 2 EOPs.

Response:

The operator actions assumed in the SGTR analysis are consistent with the BVPS-1 and 2 EOPs. These operator actions and corresponding EOP steps are as follows:

- Isolate AFW flow to the ruptured SG. This action is accomplished in E-3, "Steam Generator Tube Rupture," Step 5 (BVPS-1 and 2) that checks ruptured SG level.
- Isolate steam flow (close MSIV) from the ruptured SG. This action is accomplished in E-3, "Steam Generator Tube Rupture," Step 4 (BVPS-1 and 2) that isolates flow from the ruptured SG.
- Initiate cooldown from the intact SGs via the main steam system after MSIV closure. This action is accomplished in E-3, "Steam Generator Tube Rupture," (Step 8, BVPS-1; Step 7, BVPS-2) that initiates RCS cooldown.

- Initiate RCS depressurization (open pressurizer PORV) after completion of the cooldown. This action is accomplished in E-3, "Steam Generator Tube Rupture," Step 18 (BVPS-1 and 2) that depressurizes the RCS to minimize break flow and refills the pressurizer.
- Terminate SI (isolate the high head safety injection flow path) after completion of RCS depressurization. This action is accomplished in E-3, "Steam Generator Tube Rupture," Step 20 (BVPS-1 and 2) that checks if SI flow should be terminated.
- Isolate ruptured SG ADV (which is assumed to fail open after its MSIV has closed). If the ruptured SG atmospheric steam dump valve fails open after its MSIV is closed in E-3, then the left hand page item that checks if any SG pressure is dropping in an uncontrolled manner will initiate a transition to E-2, "Faulted Steam Generator Isolation." In E-2, Step 5 (BVPS-1 and 2) will isolate the atmospheric steam dump valve on the ruptured SG.
- Supplement PPDWST volume during the 8 hour cooldown to RHR initiation conditions. This action is accomplished by a left hand page item in E-3, "Steam Generator Tube Rupture," (BVPS-1 and 2). The operator monitors PPDWST level, and upon reaching the low level alarm, then makeup is initiated to the tank.

X.6 (Applicable to RSG & EPU)

Describe EOP steps that would provide early control of AFW flow in feeding the ruptured SG to prevent SG overfill.

Response:

Isolation of AFW flow to a ruptured SG is desired when narrow range level reaches the indicating range to limit any release from the ruptured SG. During a SGTR, the operator transitions from E-0, "Reactor Trip or Safety Injection," to E-3, "Steam Generator Tube Rupture," at Step 15 in E-0. The step to isolate flow from the ruptured SG is the fifth step in E-3. However, as a preemptive action, the operator is permitted to isolate AFW flow to the ruptured SG. Preemptive actions are action steps in the EOPs that are performed early to stabilize plant parameters. Preemptive actions are only performed with the Shift Manager or the Unit Supervisor concurrence and after the Immediate Action Steps are performed.

<u>Section 5.8</u> **<u>Anticipated Transients Without SCRAM (ATWS)</u>**

Y.1 (Applicable to RSG & EPU)

Provide the results of analyses and/or evaluations performed for the loss-of-load ATWS at BVPS-1 and 2, assuming the EPU power level, and an MTC of -5.5 pcm/°F. If from analyses, provide transient plots and sequence of events tables denoting the time and value of peak RCS pressure. If from evaluations, describe the methods and values that were used.

Response:

The limiting loss of load ATWS (Table Y.1-1) case was rerun assuming the EPU power level and an MTC of -5.5 pcm/°F. The peak RCS pressure obtained for this loss of load ATWS case is 3060 psia. The time sequence of events for this case along with the transient plots are provided below. Figure Y.1-1 shows nuclear power and core heat flux, Figure Y.1-2 shows the RCS pressure and pressurizer water volume, Figure Y.1-3 shows the reactor vessel inlet temperature and RCS flow and Figure Y.1-4 shows the steam pressure.

Table Y.1-1
Time Sequence of Events
Loss of Load ATWS

Event	Time (sec)
Turbine trip occurs	0 to 1.0
Main feedwater flow terminated	4.0
Auxiliary feedwater flow initiated	60.0
Peak RCS pressure reached (3060 psia) [versus RCS pressure limit of 3215 psia]	120.0

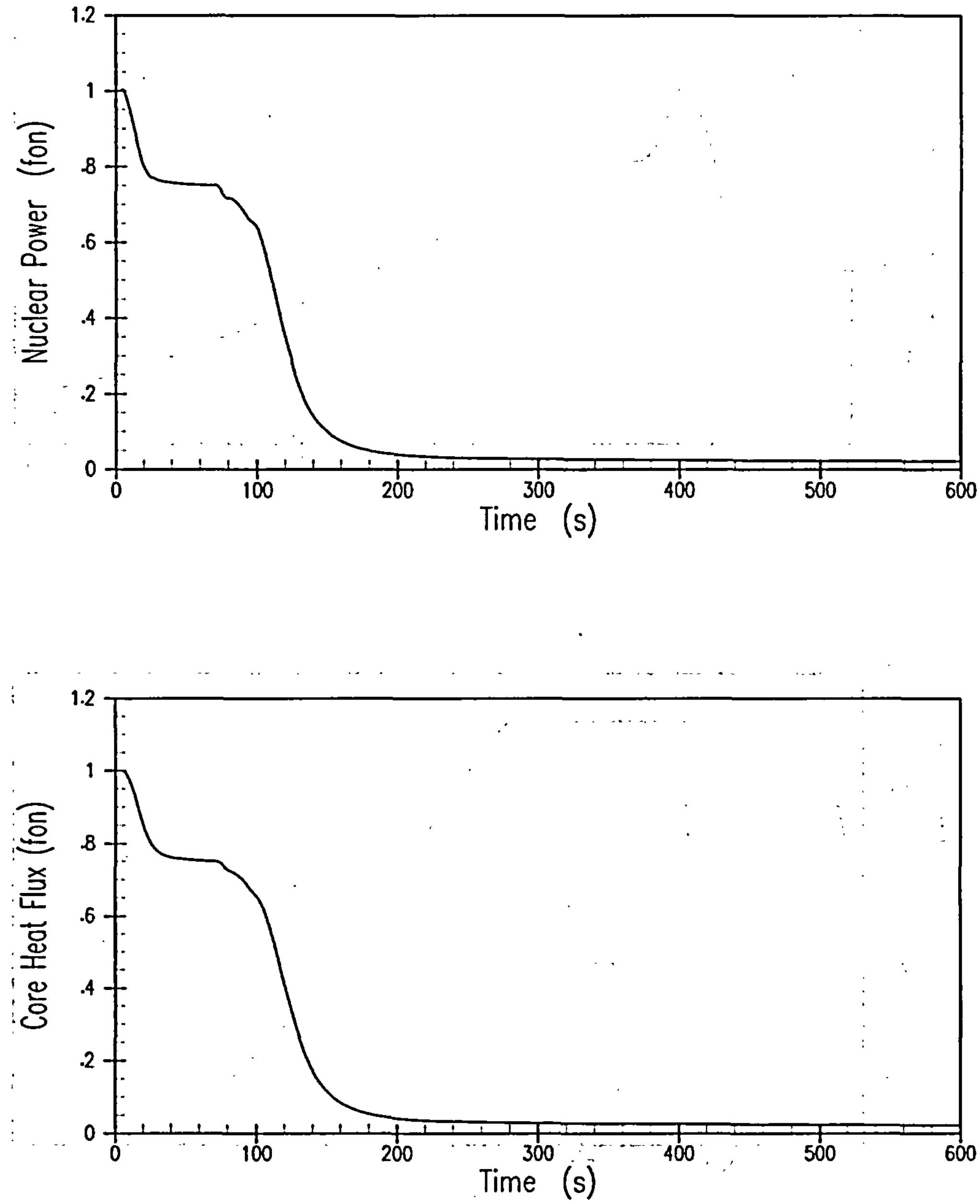
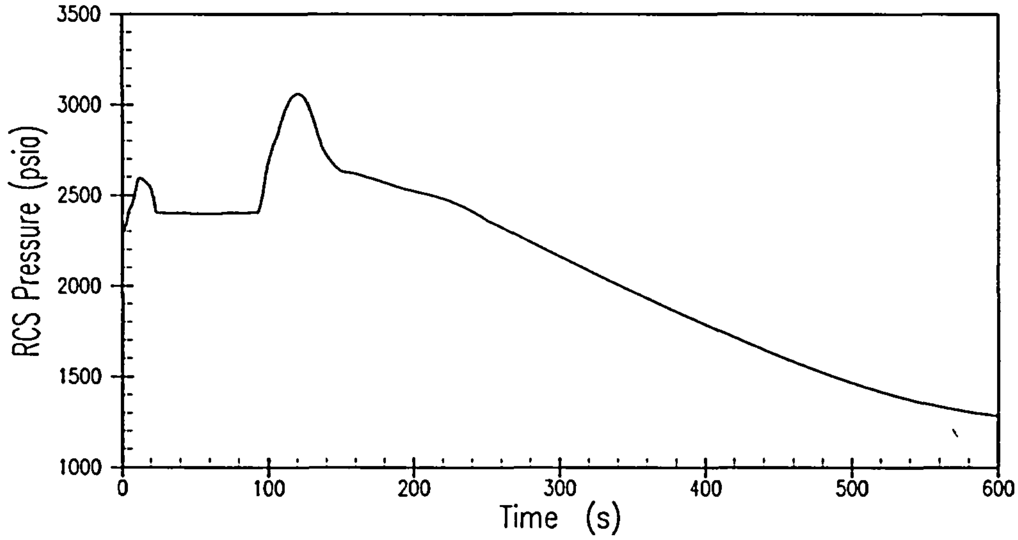


Figure Y.1-1
Nuclear Power and Core Heat Flux vs. Time for LOL ATWS



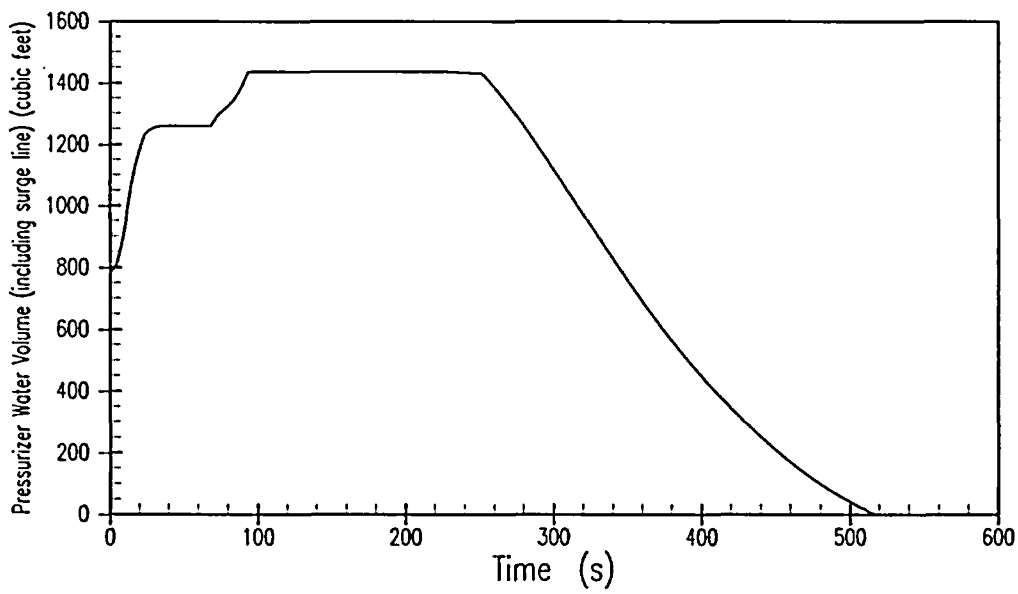
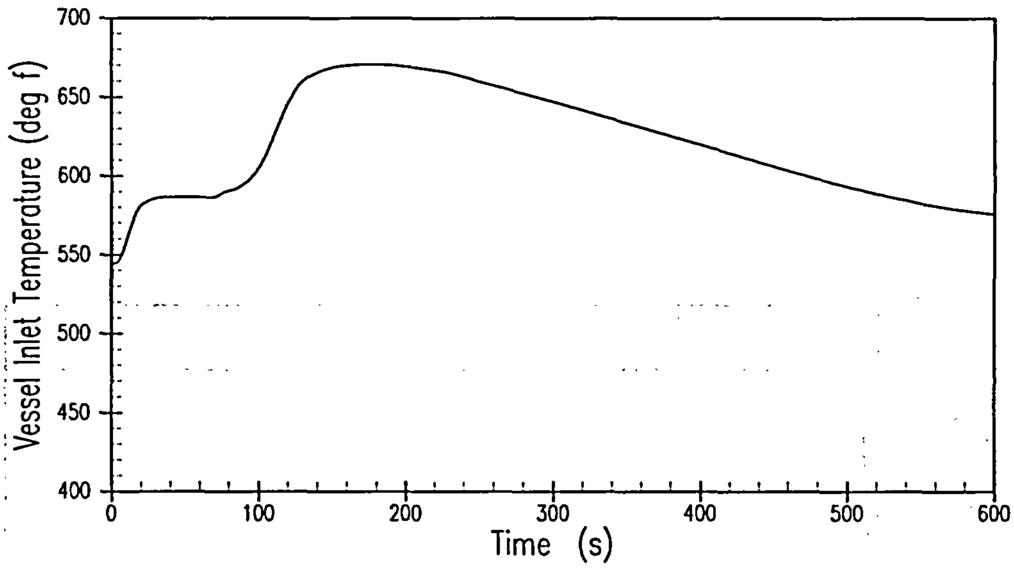


Figure Y.1-2
RCS Pressure and Pressurizer Water Volume vs. Time for LOL ATWS



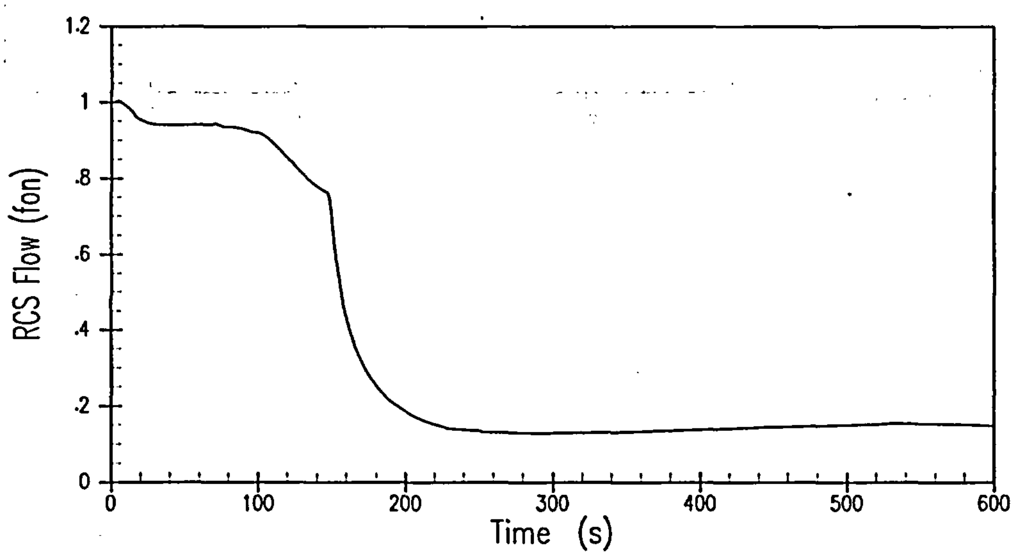


Figure Y.1-3
Vessel Inlet Temperature and RCS Flow vs. Time for LOL ATWS

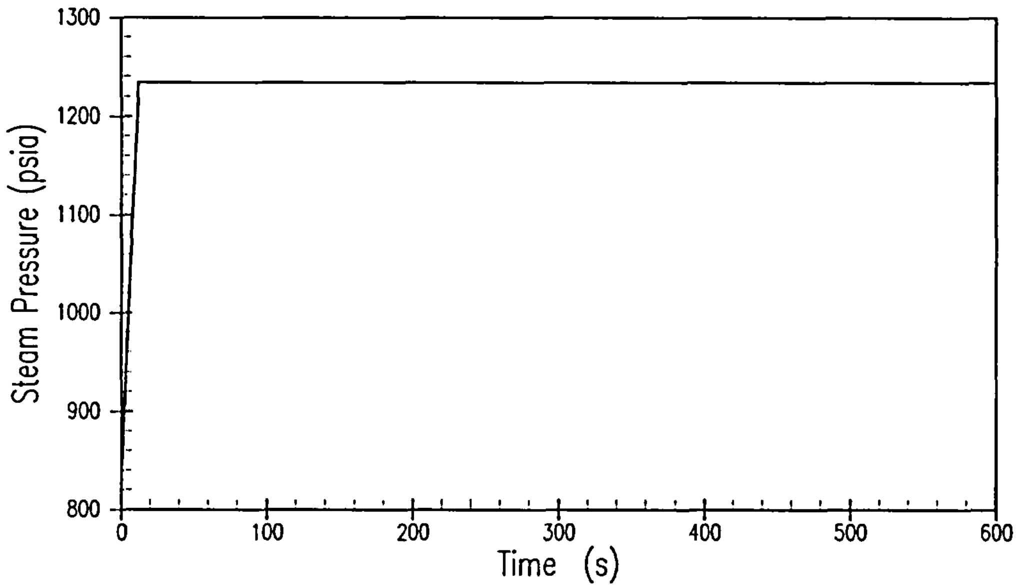


Figure Y.1-4
Steam Pressure vs. Time for LOL ATWS

Y.2 (Applicable to RSG & EPU)

Verify that the maximum differential pressure, across the tubesheet and tubes of the Model 54F RSG, matches or exceeds the value listed in Appendix C of WCAP-8330 (Reference 5).

Response:

The maximum allowable primary to secondary differential pressure for BVPS-1 Model 54F RSGs is 3276 psi, at 700°F. The limiting ATWS events are the loss of load and loss of normal feedwater ATWS transients. Analysis inputs from NS-TMA-2182 for these events were modified to reflect the EPU/RSGs with the current Beaver Valley full power conditions. The Figures Y.2-1 and Y.2-2 show the primary to secondary side differential pressure for the loss of load and loss of normal feedwater ATWS transients, respectively. The maximum primary to secondary differential pressure for the loss of load transient is 1676 psi; the maximum primary to secondary differential pressure for the loss of normal feedwater transient is 2433 psi. For both cases, the differential pressure was maintained below the 3276 psi limit.

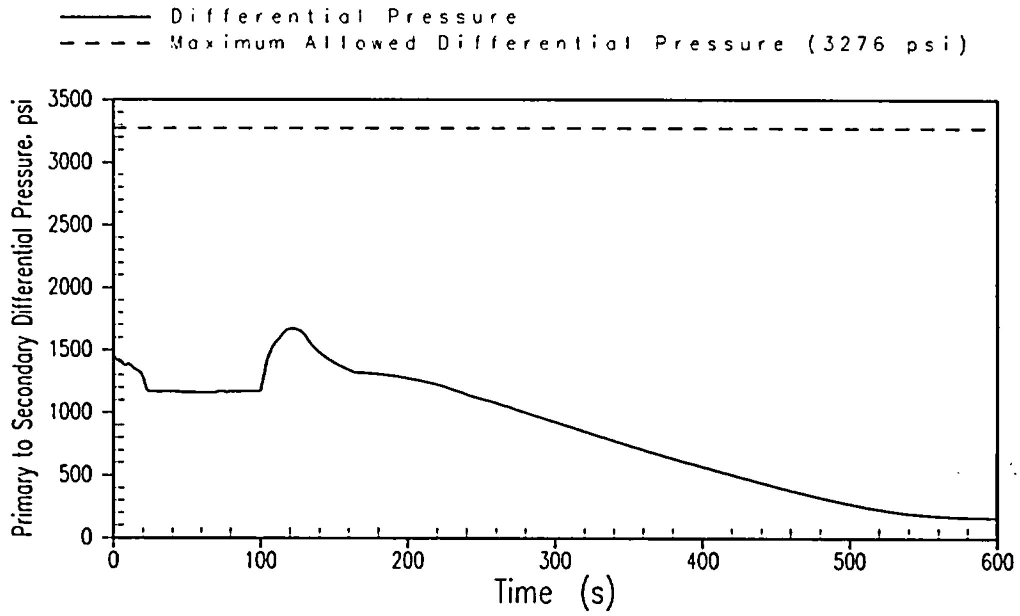


Figure Y.2-1
Primary to Secondary Differential Pressure for the Loss of Load ATWS

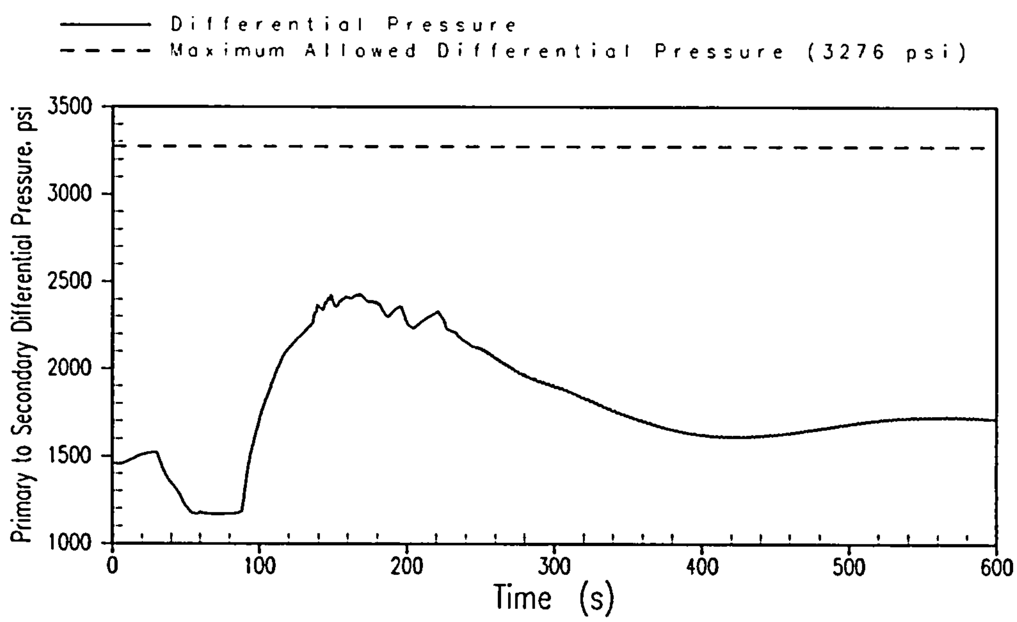


Figure Y.2-2
Primary to Secondary Differential Pressure for the Loss of Normal Feedwater ATWS

Section 6.1 **Thermal-Hydraulic Design**

Z.1 (Applicable to RSG & EPU)

Define the limits of "high flow" and "low flow," as used in Table 6.1-1.

Response:

Generically in thermal-hydraulic analyses, the nominal core pressure is assumed to be the pressurizer pressure plus 20 psi. However, for transients with reduced flowrate, the core pressure is conservatively assumed as the pressurizer pressure plus 10 psi. In Table 6.1-1, "high flow" and "low flow" refer to those conditions in which different core pressure values are used, as indicated above. For example, the loss of flow and locked rotor accidents are considered "low flow" conditions. There are not specific "high flow" and "low flow" limits.

Z.2 (Applicable to RSG & EPU)

Review of the thermal-hydraulic design in Section 6.1 led to the thermal-hydraulic parameters of the SGs in Section 4.7. Why is Section 4.7.1, "Beaver Valley Unit 1 Replacement Steam Generators," omitted from the proprietary version of WCAP-16307? (It is included in the non-proprietary version.)

Response:

The fuel thermal-hydraulic design information and evaluations presented in Section 6.1 are based in part on the Extended Power Uprate (EPU) Power Capability Working Group (PCWG) parameters presented in Section 2.1.1. Table 2.1.1-2 and Table 2.1.1-3 provide the EPU PCWG parameters that incorporate the thermal-hydraulic performance of the BVPS-1 replacement steam generators and BVPS-2 original steam generators, respectively. The review of the fuel thermal-hydraulic design information in Section 6.1 should not be dependent on the information contained in Section 4.7.

EPU Licensing Report Section 4.7.1 is not included in WCAP-16307-P (proprietary) or WCAP-16307-NP (non-proprietary) since Section 4.7.1 does not include proprietary information. This section provides qualitative information for the BVPS-1 replacement steam generators since, as stated in the introduction to this section, the licensing acceptability of replacing the Model 51 original steam generator components with Model 54F replacement steam generator components is being evaluated under the provisions of 10 CFR 50.59. The Model 54F replacement steam generator components are being designed to the EPU conditions (970 MWt/replacement steam generator). Additional replacement steam generator design information is provided in WCAP-16415-NP, "Beaver Valley Power Station Unit 1 Replacement Steam Generator Component Report," which was included as Enclosure 3 to BVPS-1 LAR 320 submitted with FENOC letter L-05-069 dated April 13, 2005.

Section 6.2 Nuclear Design

AA.1 (Applicable to EPU)

The evaluation provided in the BVPS-1 and 2 EPU report is based on an EPU RTP equilibrium condition. However, transition conditions may be more limiting. Conditions in which feed assemblies have excess reactivity, in anticipation of the EPU, may be more limiting. The first or second cycle at the EPU RTP may be more limiting, especially if the once and twice burned assemblies were not manufactured with increased reactivity. How does the licensee intend to manage the transition from the current BVPS-1 and 2 RTP of 2689 MWt to the EPU RTP of 2900 MWt? Please confirm the limiting condition and it's acceptability.

Response:

As discussed in Section 6.2.3 of the EPU Licensing Report, conceptual models were developed for transition cycles as well as for the equilibrium cycle as part of the evaluation of the EPU. As discussed in the third paragraph of Section 6.2.3 "(the) observed variation in these loading pattern (LP) dependent parameters during the power transition to an equilibrium cycle with EPU conditions are typical of the normal cycle-to-cycle variations for non-transition fuel reloads." Because these transition cycles showed no tendency to be more limiting than the equilibrium cycle, there was no reason to include transition-cycle specific data in Table 6.3-1. However, the EPU evaluation does include the consideration of, and the modeling of, transition cycles.

Planning for the EPU has been underway at the plant since at least 2002, so recent reload designs on the Beaver Valley units have been carried out with the intent of minimizing the transition to the full EPU condition. These designs have incorporated feed fuel assemblies enriched to 4.95 wt%, which are the maximum reactivity assemblies possible under the current enrichment licensing limits. Region 18B for BVPS-1, fed in Cycle 16, and Region 13B for BVPS-2, fed in Cycle 11, were enriched to 4.95 wt%. So, the scenario referred to in the question, that feed Region assemblies more reactive than those assumed in the equilibrium cycle would be required in operating transition cycles, has been foreseen by the incorporation of assemblies containing the highest possible reactivity in the current operating cycles.

It should be noted that the Beaver Valley units have had significant cycle-to-cycle variations in energy requirements in recent operating cycles whose impact on the reload design was at least as great as the transition to the EPU conditions will be. For example, BVPS-2 Cycle 9 was designed for energy production of 17000 MWD/MTU and this was followed in Cycle 10 with a design with an energy production of 20435 MWD/MTU. The core design for Cycle 10 was able to accommodate this 20% increase in cycle energy production.

As discussed in the introduction to Section 6, "Fuel Assembly Design," it also should be noted that the recent reload designs have also incorporated the Westinghouse 17 X 17 Robust Fuel Assembly (RFA) fuel design, which will be the fuel design going forward in the EPU, so there will be no transition effects due to a change in fuel type. The Beaver Valley units operating cores will have already completed the transition to full cores of the RFA design fuel prior to EPU implementation.

Since operating cycles already incorporate assemblies with the maximum possible reactivity, reactivity management for actual operating transition cycles would be primarily accomplished by changing the number of feed assemblies required for the reload design. The use of a greater number of feed assemblies than assumed for the equilibrium cycle introduces no new or unusual safety issues for the transition cycles.

Consider the following example. Assume an 18-month operating cycle (540 calendar days and a 25-day refueling outage. Also assume that the plant runs at 98% capacity during the cycle and that the core loading is about 72.5 MTU. Then, a typical cycle length would be 18720 MWD/MTU for a core power of 2689 MWt and 20190 MWD/MTU for a core power of 2900 MWt. For a 60-assembly feed region and a 18720 MWD/MTU cycle length, the feed region would have discharge burnup of about 49000 MWD/MTU while for a 64-assembly feed region and a 20190 MWD/MTU cycle length, the feed region would have a discharge burnup of about 49500 MWD/MTU, only 500 MWD/MTU higher. So, by adding four additional feed assemblies, about the same discharge burnup can be maintained, and so there will be no major increase in reactivity required for transition cycles. That is, about the same average enrichment will be required for both transition and equilibrium cycles after the EPU is implemented.

AA.2 (Applicable to EPU)

In Table 6.2-1, "Key Safety Parameters," the most positive MTC is indicated to be + 2 pcm/°F. The current licensing basis for BVPS-1 and 2 is for the MTC to be less positive than + 2 pcm/°F for power levels up to 70% of RTP, with a linear ramp to 0.0 pcm/°F at 100% of RTP. Please verify that the MTC listed in Table 6.2-1 continues to be less positive than + 2 pcm/°F for power levels up to 70% of RTP, and ramps to 0.0 pcm/°F at 100% of RTP.

Response:

The current moderator temperature coefficient licensing basis for BVPS-1 and 2 was used in the evaluation of the EPU condition.

Please refer to Figure AA.2-1. Plotted on this figure is the all rods out moderator temperature coefficient as a function of core average relative power. The data on this graph are from calculations performed at 150 MWD/MTU and 2000 MWD/MTU, which are typically limiting conditions. The calculations were done using the equilibrium cycle model (EQCY) from the EPU analysis and using the model from the BVPS-2 Cycle 12 (U2C12 -- operating cycle) reload design.

The figure shows that the all rods out moderator temperature coefficient changes virtually linearly between the values at HZP and HFP. Therefore, if the MTC limit is met at HZP and if the MTC meets the -5.5 pcm/°F value at HFP which was committed to by FENOC as part of the implementation of the positive moderator temperature coefficient technical specification, then the MTC limit will be met at all intervening power levels. Because the behavior is essentially identical for the equilibrium EPU model and for the current cycle operating model, it can be concluded that this behavior can be expected for any transition cycles as well. Rodded moderator temperature coefficients are more negative than the all rods out moderator temperature coefficient, so the all rods out behavior is more relevant in showing that the most positive limits are met.

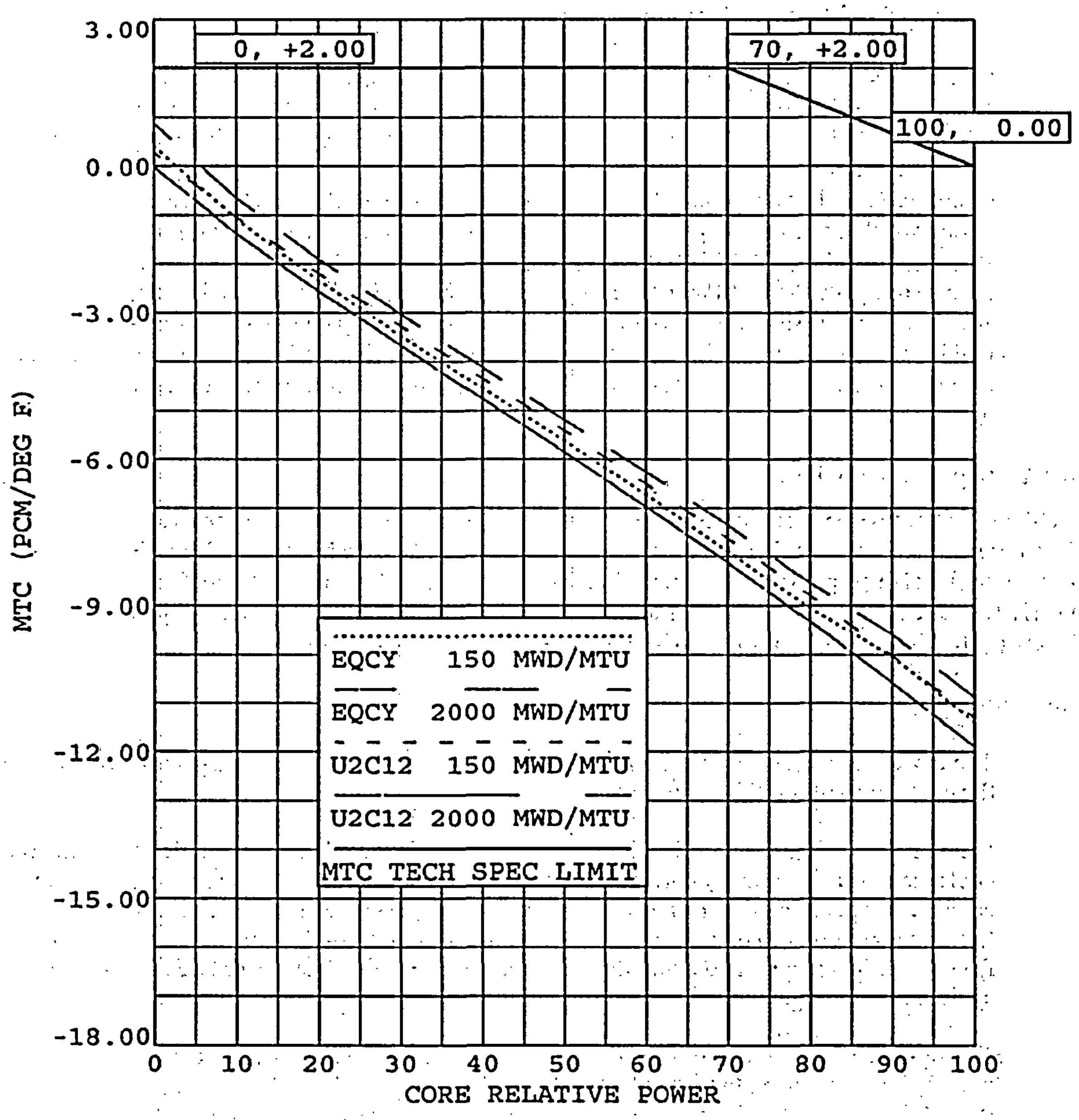


Figure AA.2-1
MTC versus Power

AA.3 (Applicable to EPU)

Table 6.2-1 indicates only the reactor core power and core average linear heat rate are being affected by the EPU. Please confirm the impact of the EPU on other key safety parameters not listed in Table 6.2-1. Please include transition conditions.

Response:

The intent of Table 6.2-1 is to address the safety parameters included in Table 3.2, "Core Reactivity Parameters and Coefficients," in WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985, supplemented with a few other parameters relevant to the EPU.

Table 6.2-1 of the EPU is intended to demonstrate that the ranges of these design and safety parameters from WCAP-9272-P-A are continuous during the transition from the current operating condition to the EPU condition. These were denoted as "key" safety parameters because, while not completely inclusive, this list represented those which were significant enough to be called out specifically in WCAP-9272-P-A. Because the ranges of these parameters are the same for both the current condition and for the equilibrium cycle of the EPU condition, it was judged very likely that they would also be the same for any transition cycles as well.

AA.4 (Applicable to EPU)

Please confirm the licensee's commitment, in Section 6.2.3, to maintain the key safety parameters listed in Table 6.2-1 within the bounds listed in Table 6.2-1 through the use of fuel management techniques. Please include transition conditions.

Response:

The EPU reload designs would be performed by Westinghouse for FENOC in accordance with WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," S. L. Davidson, (Ed.), July 1985, as well as all other plant-specific licensing requirements and commitments, as documented in recent Reload Safety Evaluations for BVPS-1 and 2. All loading patterns used for both transition and equilibrium design cycles for these units would have to meet all of these requirements, as well as the specific design methodology requirements documented in the Westinghouse METCOM Core Design manual. Adherence to these licensed methodologies will provide the requested confirmation. Of course, in addition, the reload designs would meet all relevant plant technical specifications.

AA.5 (Applicable to EPU)

Section 6.2.3.2 states, "Because the core and vessel average temperatures are being maintained approximately at the current levels, the other components that contribute to the calculation of the shutdown margin, like the moderator temperature defect and the rod worths, should not be affected by the EPU in any systematic way." Factors other than temperature may affect shutdown margin, moderator temperature defect, and rod worth. The fuel management techniques required to maintain the key safety parameters listed in Table 6.2-1 will require changes to those factors; e.g., enrichment, integral fuel burnable absorber loading, and critical boron concentration. Please provide an evaluation of the synergistic effects of all the changes on shutdown margin, power defect, moderator temperature defect, rod worth, and other reactivity contributors. Please include transition conditions.

Response:

As discussed in the fourth paragraph of Section 6.2.3.2, "BVPS has generally shown shutdown margin well above the minimum requirement of 1770 pcm, (the) increase in power defect (due to the EPU) can be readily accommodated." To be specific, a review of recent Beaver Valley reload designs shows that calculated shutdown margins have more than adequate margin to the limit. For example, recent plant operation data reports show that available SDM for BVPS-2, Cycle 12, to be 3.90% at BOL and 2.92% at EOL, compared to a limit of 1.77% and available SDM for BVPS-1, Cycle 17, to be 3.70% at BOL and 2.81% at EOL, compared to a limit of 1.77%. Similar shutdown margins were calculated for preceding operating cycles on the Beaver Valley units. There are no credible physical mechanisms associated with the EPU that would lead to the loss of 1.0% of shutdown margin.

A review of the evaluation methodology for shutdown margin will be beneficial to describe the effects that enrichment, IFBA loading and critical boron concentration will have on the shutdown margin under EPU conditions. The arguments which will be discussed are equally applicable to equilibrium and transition cycles. The shutdown margin evaluations referred to in the preceding paragraph were performed using the standard Westinghouse METCOM 3D Shutdown Margin Evaluation methodology in which the various physical effects contributing to the calculation are implicitly included in the calculation. For the purposes of this discussion, it is more appropriate to look at the older "2D effects methodology," as reported in older plant operation data reports. This older methodology is almost exactly equivalent to the 3D methodology, but the various physical contributions to the shutdown margin are broken out explicitly.

In this methodology, the available shutdown margin is evaluated by subtracting the reactivity requirements from the total available rod worth, where the total available rod worth is 90% of the total rod worth minus the worst stuck rod. The reactivity requirements include the sum of the total power defect and the rod insertion allowance, where the rod insertion allowance represents the amount of rod worth which would be unavailable during insertion because the control banks were already inserted to the rod insertion limit. The total power defect is the sum of the Doppler power defect, the moderator temperature defect and a term due to the redistribution of the flux between full power and zero power.

The question requests an assessment of the impact of enrichment, integral fuel burnable absorber loading and the critical boron concentration on the above effects.

(i) Enrichment – as discussed in the response to RAI AA.1, there will not be a significant change in enrichment after implementation of the EPU, so there will be no cycle-specific impact of enrichment on the components of the shutdown margin.

(ii) Integral fuel burnable absorber (IFBA) loading – IFBA loading affects primarily the moderator temperature coefficient (MTC) and defect (MTD) and the rod worths at the beginning of the cycle (BOC). At the end of the cycle (EOC), the IFBA has been completely depleted and there would be no cycle specific impact of the IFBA on the components of the shutdown margin. The IFBA loading affects the MTC and MTD at BOL primarily by its effect on the critical boron concentration. The higher the critical boron concentration, the less negative the MTC and MTD. However, it should be noted that the technical specification limit for MTC will remain at a +2 pcm/°F at HZP after the EPU is implemented. So, the number of IFBA will change from reload design to reload design as needed to maintain the MTC less than the technical specification limit. Therefore, the MTD will stay about the same from cycle to cycle as the number of IFBA is adjusted to maintain the MTD within the technical specification limit.

The rod worths at BOL are impacted by IFBA in two ways: (a) The IFBA affects the power distribution at BOL by shifting power away from any rodded feed fuel assemblies containing IFBA and into rodded burned fuel; (b) IFBA reduces the critical boron concentration at BOL and so reduces the competitive absorption that the control rods would encounter from the effect of the soluble boron in the coolant, at least for the burned assemblies that are rodded. Both of these effects increase the worth of control rods going into burned fuel compared to those control rods going into feed fuel assemblies containing IFBA. So, by adjusting the loading pattern to put more burned assemblies under control rods, the core designer can increase the rod worth needed to produce the required shutdown margin.

(iii) Critical boron concentration – the impact of the critical boron concentration on the shutdown margin cannot be completely disentangled from the impact of IFBA because the designer can control the critical boron concentration by adding or subtracting IFBA. It should be noted that this is a BOL effect because the shutdown margin at EOL is evaluated with 0 ppm of soluble boron in the coolant.

The critical boron concentration impacts the total power coefficient (TPC) and the total power defect (TPD). The TPD is actually the sum of five effects. Two of the effects, the coolant void defect and the system pressure defect, are small and not impacted by the critical boron concentration. The Doppler power coefficient (DPC) and the Doppler power defect (DPD) are not sensitive to the critical boron concentration, but will be impacted slightly by the EPU. Recent plant operation data reports for the Beaver Valley units show that the DPC at HFP is typically on the order of -8.5 pcm/pct%. The EPU will add 7.8% to the total core power of the units, so the

DPD should increase by about -8.5 * 7.8 ~ -66 pcm due to the EPU. The Moderator Temperature Defect (MTD) has been discussed previously. Not much change is anticipated in the MTD because the IFBA will be increased as needed to maintain the MTC within the technical specification limit. As mentioned in Section 6.2.3.2, because the core and vessel average temperatures are being maintained approximately at the current levels, there will be little or no change to the MTD due to any changes in the temperature range. The final component of the TPD is the reactivity change due to the change in axial power shape from HZP to HFP. This is not likely to be affected significantly after the implementation of EPU either at BOL or EOL, because the HZP temperature remains the same after the EPU. Therefore, the only change in the total power defect due to the uprating comes not from the critical boron concentration per se, but only from an anticipated increase in the Doppler power defect due to an increased power range between HZP and HFP after the EPU.

Section 9.4 **Emergency Core Cooling System**

AB.1 (Applicable to EPU)

Section 9.4.1 of the EPU report indicated that the charging/SI pumps are being modified to improve the ECCS performance and flow rates to support the EPU. Provide the details of these pump modifications, and the tests performed for the modified ECCS pumps.

Response:

The charging/SI pumps are modified by installation of new rotating assemblies. The new rotating assemblies extend the maximum allowable runout flow of the pumps from 560 gpm to 580 gpm. This allows for less system throttling to prevent runout and therefore higher safety injection flows for all accident conditions. The pumps have been tested by the pump vendor up to the runout limit to characterize hydraulic performance as well as NPSH requirements. The pumps are also tested following installation in the plant. These tests consist of pump performance measurements at normal operating flows while the plant is operating and near runout conditions during refueling outages.

REFERENCES:

1. Pearce, L. W., FirstEnergy Nuclear Operating Company (FENOC), Letter to NRC, "Beaver Valley Power Station, Unit No. 1 and 2, License Amendment Request Nos. 302 and 173," October 4, 2004.

2. NRC Review Standard RS-001, Revision 0, "Review Standard for Extended Power Uprates," December 2003.

3. Pearce, L. W., FENOC, Letter to NRC, "10 CFR 50.46 Report of Changes or Errors in ECCS Evaluation Models," November 19, 2004.

4. Risher, D. H., Westinghouse, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods," WCAP-7588; Rev. 1A, January 1975.

5. Westinghouse, WCAP-8330, "Westinghouse Anticipated Transients Without Trip Analysis," August 1974.

6. Richardson, J. E., NRC, Letter to Herrmann, T. E., Westinghouse Owners Group, "Acceptance for Referencing of Licensing Topical Report" WCAP-12910, "Pressurizer Safety Valve Set Pressure Shift," February 19, 1993.

L-05-112 Enclosure 1, Attachment A

Summary Report for Beaver Valley Units 1 and 2 (DLW/DMW)

Small Break LOCA Licensing Basis Analyses

Attachment A

Summary Report for Beaver Valley Units 1 and 2

SBLOCA Licensing Basis Analyses

Small Break LOCA

Introduction

This section contains information regarding the Small Break Loss-of-Coolant Accident (SBLOCA) licensing basis analyses for BVPS-1 at 2803 MWt core power and for BVPS-2 at 2689 MWt core power. BVPS-1 was analyzed at the higher power level as part of a planned power uprate. An evaluation was performed to show that the higher power level for BVPS-1 bounds current plant operation. The purpose of analyzing the Small Break LOCA is to demonstrate conformance with the 10 CFR 50.46 (Reference 1) requirements. Important input assumptions, as well as analytical models and analysis methodology for the Small Break LOCA are contained in subsequent sections. Analysis results are provided in the form of tables and figures, as well as a more detailed description of the limiting transient. The analyses have shown that no design or regulatory limit related to the Small Break LOCA would be exceeded.

Input Parameters and Assumptions

The important plant conditions and features for BVPS-1 and BVPS-2 are listed in Table 1A and Table 1B, respectively. Several additional considerations are discussed below.

Figures 1A and 1B depict the hot rod axial power shapes modeled in the Small Break LOCA analyses. These shapes were chosen because they represent a distribution with power concentrated in the upper regions of the core (the axial offset is +13%). Such a distribution is limiting for Small Break LOCA since it minimizes coolant swell while maximizing vapor superheating and fuel rod heat generation at the uncovered elevations. The chosen power shape has been conservatively scaled to a standard 2-line segment K(Z) envelope for BVPS-1 and BVPS-2 based on the peaking factors shown in Tables 1A and 1B.

Figures 2A, 2B, 2C and 2D provide the SI flow versus pressure curves modeled in the Small Break LOCA analyses. The flow from one High Head Safety Injection (HHSI) pump was used in the analyses, as well as the flow from one Low Head Safety Injection (LHSI) pump for the 6-inch break cases.

Description of Analyses and Evaluations

Analytical Model

The requirements for an acceptable ECCS evaluation model are presented in Appendix K of 10 CFR 50. For LOCAs due to small breaks, less than 1 square foot in area, the Westinghouse NOTRUMP Small Break LOCA Emergency Core Cooling System (ECCS) Evaluation Model (References 2, 3, and 4) is used. The Westinghouse NOTRUMP Small Break LOCA ECCS Evaluation Model was developed to determine the RCS response to design basis Small Break LOCAs, and to address NRC concerns expressed in NUREG-0611 (Reference 5).

The Westinghouse Small Break LOCA ECCS Evaluation Model consists of the NOTRUMP and LOCTA-IV computer codes. The NOTRUMP code is employed to calculate the transient depressurization of the Reactor Coolant System (RCS), as well as to describe the mass and energy release of the fluid flow through the break. Among the features of the NOTRUMP code are: calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes, regime-dependent drift flux calculations in multiple-stacked fluid nodes and regime-dependent heat transfer correlations. These features provide NOTRUMP with the capability to accurately calculate the mass and energy distribution throughout the RCS during the course of a Small Break LOCA.

The RCS model is nodalized into volumes interconnected by flow paths. The broken loop is modeled explicitly, while the intact loops are lumped together into a second loop. Transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum. The multi-node capability of the program enables explicit, detailed spatial representation of various system components which, among other capabilities, enables a calculation of the behavior of the loop seal during a Small Break LOCA. The reactor core is represented as heated control volumes with associated phase separation models to permit transient mixture height calculations.

Fuel cladding thermal analyses are performed with a version of the LOCTA-IV code (Reference 3) using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam flow and mixture level as boundary conditions. The LOCTA-IV code models the hot rod and the average hot assembly rod, assuming a conservative power distribution that is skewed to the top of the core. Figure 3 illustrates the code interface for the Small Break Model.

Analysis

The Small Break LOCA licensing basis analyses considered four different break cases for BVPS-1 as indicated by the results in Table 3A and four different break cases for BVPS-2 as indicated by the results in Table 3B. For BVPS-1, a break spectrum of 1.5-, 2-, 3- and 6-inch breaks was considered and the 2-inch break was found to be limiting. For BVPS-2, a break spectrum of 2-, 3-, 4- and 6-inch breaks was considered and the 3-inch break was found to be limiting.

The most limiting single active failure used for a Small Break LOCA is that of an emergency power train failure which results in the loss of one complete train of ECCS components. In addition, a Loss-of-Offsite Power (LOOP) is postulated to occur coincident with reactor trip. This means that credit may be taken for at most one high head safety injection (HHSI) pump. In the analyses for BVPS-1 and BVPS-2, one HHSI pump is modeled, and additionally one LHSI pump is modeled for the 6-inch break cases only. In the Small Break LOCA analysis performed for both units, the ECCS flow is delivered to both the intact and broken loops at the RCS backpressure for breaks smaller than the cold leg HHSI nozzle (1.5-, 2-, and 3-inch breaks for BVPS-1 and 2-, 3-, and 4-inch breaks for BVPS-2). For breaks larger than the HHSI nozzle (6-inch break for BVPS-1 and for BVPS-2), the ECCS flow is delivered to the intact and broken loops with 0 psi (containment pressure) backpressure. These broken and intact loop SI flows are illustrated in Figure 2A, Figure 2B, Figure 2C and Figure 2D. The LOOP and the failure of a diesel generator to start is the limiting single failure for Small Break LOCA. The single failure assumption is extremely limiting due to the fact that one train of SI, one motor driven auxiliary feedwater (AFW) pump, and power to the reactor coolant pumps (RCPs) are all modeled to be lost. Any other active single failure would not result in a more limiting scenario since increased SI flow would improve the overall transient results.

Prior to break initiation, the plant is at full power (100.6%) equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. Other initial plant conditions in the analysis are given in Table 1A or Table 1B. Subsequent to the break opening, a period of reactor coolant system blowdown ensues in which the heat from fission product decay, the hot reactor internals, and the reactor vessel continues to be transferred to the RCS fluid. The heat transfer between the RCS and the secondary system may be in either direction and is a function of the relative temperatures of the primary and secondary conditions. In the case of continuous heat addition to the secondary during a period of quasi-equilibrium, an increase in the secondary system pressure results in steam relief via the steam generator safety valves.

When a Small Break LOCA occurs, depressurization of the RCS causes fluid to flow into the loops from the pressurizer resulting in a pressure and level decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure reactor trip setpoint, conservatively modeled as 1935 psia, is reached. LOOP is postulated to occur coincident with reactor trip. A safety injection signal is generated when the pressurizer low-pressure safety injection setpoint, conservatively modeled as 1745 psia for BVPS-1 and 1760 psia for BVPS-2, is reached. Safety injection flow is delayed 27 seconds after the occurrence of the low-pressure condition. This delay accounts for signal processing, diesel generator start up and emergency power bus loading consistent with the loss-of-offsite power coincident with reactor trip, as well as the pump acceleration and valve delays.

The following countermeasures limit the consequences of the accident in two ways:

1. Reactor trip and borated water injection supplement void formation in causing a rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay. No credit is taken in the Small Break LOCA analysis for the boron content of the injection water. However, credit is taken in the Small Break LOCA analysis for the insertion of Rod Cluster Control Assemblies (RCCAs) subsequent to the reactor trip signal, considering the most reactive RCCA is stuck in the full out position. A rod drop time of 2.7 seconds was used while also considering an additional 2 seconds for the signal processing delay time. Therefore, a total delay time of 4.7 seconds from the time of reactor trip signal to full rod insertion was used in the Small Break LOCA analysis.

2. Injection of borated water provides sufficient flooding of the core to prevent excessive cladding temperatures.

During the earlier part of the Small Break transient (prior to the postulated loss-of-offsite power coincident with reactor trip), the loss of flow through the break is not sufficient to overcome the positive core flow maintained by the reactor coolant pumps. During this period, upward flow through the core is maintained. However, following the reactor coolant pump trip (due to a LOOP) and subsequent pump coastdown, a period of core uncovery occurs. Ultimately, the Small Break transient analysis is terminated when the top of the core is recovered and ECCS flow provided to the RCS exceeds the break flow rate, preventing additional core uncovery and subsequent rod heatup.

The core heat transfer mechanisms associated with the Small Break transient include the break itself, the injected ECCS water, and the heat transferred from the RCS to the steam generator secondary side. Main Feedwater (MFW) is conservatively isolated in 10 seconds for BVPS-1 (consisting of a 3 second signal delay time and a 7 second main feedwater isolation valve stroke time) and 7 seconds for BVPS-2 (consisting of a 2 second signal delay time and a 5 second main feedwater isolation valve stroke time) following the generation of the pressurizer low-pressure SI signal. Additional makeup water is also provided to the secondary using the auxiliary feedwater (AFW) system. An AFW actuation signal is derived from the pressurizer low-pressure SI signal, resulting in the delivery of AFW system flow 60 seconds after the generation of the SI signal. The heat transferred to the secondary side of the steam generator aids in the reduction of the RCS pressure.

Should the RCS depressurize to approximately 575 psia (accumulator minimum pressure), the cold leg accumulators begin to inject borated water into the reactor coolant loops.

Acceptance Criteria and Results

The acceptance criteria for the LOCA are described in 10 CFR 50.46 (Reference 1) as follows:

1. The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

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

Criteria 1 through 3 are explicitly covered by the Small Break LOCA analysis.

For criterion 4, the appropriate core geometry was modeled in the analysis. The results based on this geometry satisfy the Peak Clad Temperature (PCT) criterion of 10 CFR 50.46 and consequently, demonstrate that the core remains amenable to cooling.

For criterion 5, Long-Term Core Cooling (LTCC) considerations are not directly applicable to the Small Break LOCA transient analysis addressed in this section.

The acceptance criteria were established to provide a significant margin in ECCS performance following a LOCA.

In order to determine the conditions that would produce the most limiting Small Break LOCA case (as determined by the highest calculated peak cladding temperature), four break cases were examined for BVPS-1 and for BVPS-2. These cases were investigated to capture the most severe postulated Small Break LOCA event. The following discussions provide insight into the analyzed conditions.

Limiting Temperature Conditions

The RCS temperature analyzed was based on a vessel average temperature of 580.0°F for Unit 1. However, the analysis can be considered applicable over the range 566.2 – 580.0°F. For Unit 2, the RCS temperature analyzed was based on a vessel average temperature of 576.2°F. The analyses support a ±4°F T_{avg} uncertainty. The analyses showed that the 2-inch break case is limiting for BVPS-1 and the 3-inch break case is limiting for BVPS-2. The limiting case transients are discussed below.

Limiting Break Case

The results of Reference 6 demonstrate that the cold leg break location is limiting with respect to postulated cold leg, hot leg and pump suction leg break locations. The PCT results are shown in Table 3A and Table 3B. Inherent in the Small Break analysis are several input assumptions (see Table 1A and Table 1B), while Table 4A and Table 4B provide the key transient event times.

For the Small Break LOCA licensing basis analyses, the limiting case for BVPS-1 was the 2-inch break case and the limiting case for BVPS-2 was the 3-inch break case. A summary of the transient response for the limiting case is shown in Figures 4A through 14A and Figure 4B through Figure 14B for BVPS-1 and BVPS-2, respectively. These figures present the response of the following parameters.

- RCS Pressure
- Core Mixture Level
- Core Exit Vapor Temperature
- Broken Loop and Intact Loop Secondary Pressure
- Break Vapor Flow Rate
- Break Liquid Flow Rate
- Broken Loop and Intact Loop Accumulator Flow Rate
- Broken Loop and Intact Loop Pumped Safety Injection Flow Rate
- Peak Clad Temperature
- Hot Spot Fluid Temperature
- Rod Film Heat Transfer Coefficient

Upon initiation of the limiting 2-inch break for BVPS-1 and the limiting 3-inch break for BVPS-2, there is an initial rapid depressurization of the RCS followed by an intermediate equilibrium at approximately 1150 psia (see Figure 4A and Figure 4B). For BVPS-1, the limiting 2-inch break depressurizes, but does not reach the accumulator injection setpoint of 575 psia (see Figures 4A and 10A). For BVPS-2, the limiting 3-inch break depressurizes to the accumulator injection setpoint of 575 psia at approximately 1115 seconds (see Figure 10B). During the initial period of the Small Break transient, the effect of the break flow rate is not sufficient to overcome the flow rate maintained by the reactor coolant pumps as they coast down. As such, normal upward flow is maintained through the core and core heat is adequately removed. Following reactor trip, the removal of the heat generated as a result of fission product decay is accomplished via a two-phase mixture level covering the core. The core mixture level and peak clad temperature transient plots for the limiting break calculations are illustrated in Figures 5A and 5B and 12A and 12B, respectively. These figures show that the peak clad temperature occurs near the time when the core is most deeply uncovered and the top of the core is being cooled by steam. This time is characterized by the highest vapor superheating above the mixture level (refer to Figure 6A and 6B). For BVPS-1 the limiting time-in-life was determined to be 15000 MWD/MTU. For BVPS-2 the limiting time-in-life was determined to be 2500 MWD/MTU.

A comparison of the flow provided by the safety injection system to the intact and broken loops can be found in Figure 11A and 11B. The cold leg break vapor and liquid mass flow rates are provided in Figures 8A and 8B and 9A and 9B, respectively. Figures 13A and 13B and 14A and 14B provide additional information on the fluid temperature at the PCT elevation and hot rod surface heat transfer coefficient at the PCT elevation, respectively. Figures 7A and 7B depict the secondary side pressure for both the intact and broken loops for the limiting break case.

Additional Break Cases

Studies documented in Reference 6 have determined that the limiting Small Break transient occurs for breaks of less than 10-inches in diameter in the cold leg. To demonstrate that the 2-inch diameter break for BVPS-1 and the 3-inch diameter break for BVPS-2 were the most limiting, calculations were also performed with break equivalent diameters of 1.5-, 3- and 6-inches for BVPS-1 and 2-, 4- and 6-inches for BVPS-2. For BVPS-1, the limiting PCT is captured by the 1.5-, 2-, 3-, and 6-inch break spectrum. For BVPS-2, the limiting PCT is captured by the 2-, 3-, 4- and 6-inch break spectrum. The results of these break spectrum cases are given in Table 3A and Table 3B. Figures 15A through 23A address the non-limiting cases (1.5, 3- and 6-inch) analyzed for BVPS-1. Figures 15B through 23B address the non-limiting cases (2-, 4-, and 6-inch) for BVPS-2. The plots for each of the additional non-limiting break cases include:

1. RCS Pressure
2. Core Mixture Level
3. Peak Clad Temperature

For BVPS-1, the PCTs for each of the additional breaks considered are shown in Table 3A. These PCTs are less than the limiting 2-inch break case. For BVPS-2, the PCTs for each of the additional breaks considered are shown in Table 3B. These PCTs are less than the limiting 3-inch break case.

Transient Termination

The 10 CFR 50.46 criteria continue to be satisfied beyond the end of the calculated transient due to the following conditions:

1. The RCS pressure is gradually decreasing or leveled off.

2. The net mass inventory is increasing.
3. The core mixture level is recovered, or recovering due to increasing mass inventory.
4. As the RCS inventory continues to gradually increase, the core mixture level will continue to increase and the fuel cladding temperatures will continue to decline indicating that the temperature excursion is terminated.

Conclusions

The Small Break LOCA analyses considered a break spectrum of 1.5-, 2-, 3-, and 6-inch diameters for BVPS-1 and 2-, 3-, 4- and 6-inch diameters for BVPS-2. For BVPS-1, a peak cladding temperature of 1849°F was calculated for the 2-inch break case at the limiting time-in-life of 15000 MWD/MTU. For BVPS-2, a peak cladding temperature of 2105°F was calculated for the 3-inch break case at the limiting time-in-life of 2500 MWD/MTU.

The analyses presented in this section show that the accumulator and safety injection subsystems of the Emergency Core Cooling System, together with the heat removal capability of the steam generator, provide sufficient core heat removal capability to maintain the calculated peak cladding temperatures for Small Break LOCA below the required limit of 10 CFR 50.46. Furthermore, the analyses show that the local cladding oxidation and core wide average oxidation are less than the 10 CFR 50.46 limits.

References

1. "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors," 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3, January 1974, as amended in Federal Register, Volume 53, September 1988.

2. Meyer, P. E., "NOTRUMP - A Nodal Transient Small Break and General Network Code," WCAP-10079-P-A, (proprietary) and WCAP-10080-NP-A (non-proprietary), August 1985.

3. Lee, N. et al., "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," WCAP-10054-P-A (proprietary) and WCAP-10081-NP-A (non-proprietary), August 1985.

4. Thompson, C. M. et al., "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," WCAP-10054-P-A, Addendum 2, Rev. 1, July 1997 (proprietary) and WCAP-10081-NP, Addendum 2, Rev.1 [non-proprietary], October 1995.

5. "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse - Designed Operating Plant," NUREG-0611, January 1980.

6. Rupprecht, S. D. et al., "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," WCAP-11145-P-A (proprietary), October 1986 and WCAP-11372-A (non-proprietary).

Table 1A BVPS-1 Input Parameters Used in the Small Break LOCA Analysis	
Input Parameter	**Value**
Core Rated Thermal Power-100%, MWt (1)	2803
Calorimetric Uncertainty, %	0.6
Fuel Type	17 X 17 Robust Fuel Assembly (RFA)
Total Core Peaking Factor, F_Q	2.40
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	1.62
Hot Assembly Average Power Factor, P_{HA}	1.46
Maximum Axial Offset, %	+13
Initial RCS Loop Flow, gpm/loop	82,840
Initial Vessel T_{avg}, °F	Max: 580.0 Min: 566.2
Initial Pressurizer Pressure (plus uncertainties), psia	2300
Reactor Coolant Pump Type	Model 93A with Weir
Pressurizer Low-Pressure Reactor Trip Setpoint, psia	1935
Reactor Trip Signal Delay Time, seconds	2.0
Rod Drop Delay Time, seconds	2.7
Auxiliary Feedwater Temperature (Maximum), °F	120
Number of AFW Pumps Available Following a LOOP	1 Motor Driven
AFW Flow (Minimum) to all 3 Steam Generators, gpm (2)	489 (163 gpm/SG * 3)
AFW Flow Delay Time (Maximum), seconds	60
AFW Actuation Signal	Pressurizer Low-Pressure Safety Injection
Steam Generator Type	Model 51
Maximum AFW Piping Purge Volume, ft^3	168
Steam Generator Tube Plugging (Maximum), % (3)	22
Maximum MFW Isolation Signal Delay Time, seconds	3
MFW Control Valve Isolation Ramp Time, seconds	7
MFW Isolation Signal	Pressurizer Low-Pressure Safety Injection

Notes: (1) Core power of 2803 MWt bounds current plant operation.
(2) AFW flow was evaluated at 97 gpm/SG with no PCT penalty.
(3) SGTP was evaluated at 30% with no PCT penalty.

Table 1A (continued)
BVPS-1 Input Parameters Used in the Small Break LOCA Analysis

Input Parameter	Value
Steam Generator Secondary Water Mass, lbm/SG	101,000
Containment Spray Flowrate for 2 Pumps, gpm	5340
RWST Deliverable Volume (Minimum), gallons	317,000
ECCS Configuration	1 HHSI pump, faulted line injects to RCS pressure; 1 HHSI and 1 LHSI, faulted line injects to containment pressure for 6-inch break
ECCS Water Temperature (Maximum), °F	105
Pressurizer Low-Pressure Safety Injection Setpoint, psia	1745
SI Flow Delay Time, seconds	27
ECCS Flow vs. Pressure	See Tables 2A and 2B
Initial Accumulator Water/Gas Temperature, °F	105
Initial Nominal Accumulator Water Volume, ft^3	957
Minimum Accumulator Pressure, psia	575

Table 1B
BVPS-2 Input Parameters Used in the Small Break LOCA Analysis

Input Parameter	Value
Core Rated Thermal Power-100%, MWt	2689
Calorimetric Uncertainty, %	0.6
Fuel Type	17 X 17 Robust Fuel Assembly (RFA)
Total Core Peaking Factor, F_Q	2.40
Hot Channel Enthalpy Rise Factor, $F_{\Delta H}$	1.62
Hot Assembly Average Power Factor, P_{HA}	1.42
Maximum Axial Offset, %	+13
Initial RCS Loop Flow, gpm/loop	82,840
Initial Vessel T_{avg}, °F	576.2
Initial Pressurizer Pressure (plus uncertainties), psia	2280
Reactor Coolant Pump Type	Model 93A with Weir
Pressurizer Low-Pressure Reactor Trip Setpoint, psia	1935
Reactor Trip Signal Delay Time, seconds	2.0
Rod Drop Delay Time, seconds	2.7
Auxiliary Feedwater Temperature (Maximum), °F	120
Number of AFW Pumps Available Following a LOOP	1 Motor Driven
AFW Flow (Minimum) to all 3 Steam Generators, gpm	294 (98 gpm/SG *3)
AFW Flow Delay Time (Maximum), seconds	60
AFW Actuation Signal	Pressurizer Low-Pressure Safety Injection
Steam Generator Type	Model 51M
Maximum AFW Piping Purge Volume, ft^3	125.7
Steam Generator Tube Plugging (Maximum), %	25
Maximum MFW Isolation Signal Delay Time, seconds	2
MFW Control Valve Isolation Ramp Time, seconds	5
MFW Isolation Signal	Pressurizer Low-Pressure Safety Injection
Steam Generator Secondary Water Mass, lbm/SG	102,000
Containment Spray Flowrate for 2 Pumps, gpm	4450
RWST Deliverable Volume (Minimum), gallons	328,000

Table 1B (continued) BVPS-2 Input Parameters Used in the Small Break LOCA Analysis	
Input Parameter	**Value**
ECCS Configuration	1 HHSI pump, faulted line injects to RCS pressure; 1 HHSI and 1 LHSI, faulted line injects to containment pressure for 6-inch break
ECCS Water Temperature (Maximum), °F	55
Pressurizer Low-Pressure Safety Injection Setpoint, psia	1760
SI Flow Delay Time, seconds	27
ECCS Flow vs. Pressure	See Tables 2C and 2D
Initial Accumulator Water/Gas Temperature, °F	105
Initial Nominal Accumulator Water Volume, ft^3	1025
Minimum Accumulator Pressure, psia	575

Table 2A BVPS-1 Safety Injection Flows Used in the Small Break LOCA Analysis (1 HHSI pump, faulted loop injects to RCS pressure)		
RCS Pressure (psia)	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)
14.7	36.960	19.997
214.7	36.960	19.997
314.7	36.133	19.721
414.7	35.112	19.211
514.7	34.091	18.659
614.7	33.043	18.066
714.7	31.995	17.514
814.7	30.947	16.935
914.7	29.844	16.328
1014.7	28.685	15.694
1114.7	27.527	15.032
1214.7	26.341	14.411
1314.7	25.044	13.708
1414.7	23.720	12.963
1514.7	22.396	12.260
1614.7	20.935	11.446
1714.7	19.390	10.619
1814.7	17.818	9.750

Table 2B BVPS-1 Safety Injection Flows Used in the Small Break LOCA Analysis (1 HHSI and LHSI pump, faulted loop injects to Containment pressure – 6-inch break size)		
RCS Pressure (psia)	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)*
14.7	329.85	0
24.7	307.83	0
34.7	285.11	0
64.7	211.54	0
114.7	42.642	0
119.7	34.533	0
214.7	34.533	0
314.7	32.271	0
414.7	30.064	0
514.7	27.747	0
614.7	25.375	0
714.7	22.976	0
814.7	20.493	0
914.7	17.928	0
1014.7	15.308	0
1114.7	12.494	0
1214.7	9.543	0
1314.7	6.426	0
1414.7	3.116	0
1514.7	0	0
*Note: Since the break is postulated along the HHSI line, no ECCS flow is assumed in the faulted loop.		

Table 2C BVPS-2 Safety Injection Flows Used in the Small Break LOCA Analysis (1 HHSI pump, faulted loop injects to RCS pressure – 2-, 3- and 4-inch break sizes)		
RCS Pressure (psia)	Intact Loop (lbm/sec)	Broken Loop (lbm/sec)
14.7	35.5	18.5
214.7	34.1	17.8
414.7	32.4	17.0
614.7	30.6	16.0
814.7	28.8	15.0
1014.7	26.8	14.0
1214.7	24.7	12.9
1414.7	22.5	11.8
1614.7	20.1	10.5
1814.7	17.4	9.1
2014.7	14.4	7.5
2214.7	10.6	5.6
2414.7	3.4	1.8
2614.7	0.0	0.0

Table 2D BVPS-2 Safety Injection Flows Used in the Small Break LOCA Analysis (1 HHSI pump and LHSI pump, faulted loop injects to Containment pressure – 6-inch break size)		
RCS Pressure (psia)	**Intact Loop (lbm/sec)**	Broken Loop (lbm/sec)*
14.7	377.7	0
24.7	355.1	0
34.7	331.3	0
64.7	250.9	0
104.7	60.7	0
109.7	34.5	0
114.7	34.4	0
164.7	33.9	0
214.7	33.3	0
414.7	30.5	0
614.7	24.1	0
814.7	17.3	0
1014.7	10.1	0
1214.7	2.3	0
1414.7	0	0

*Note: Since the break is postulated along the HHSI line, no ECCS flow is assumed in the faulted loop.

Table 3A BVPS-1 SBLOCTA Results					
	1.5-inch BOL	**2-inch BOL**	**3-inch BOL**	**6-inch BOL**	**2-inch 15,000 MWD/MTU**
PCT (°F)	1092	1823	1760	1498	1849
PCT Time (s)	7808	3702	1411	2073	3563
PCT Elevation (ft)	11.50	12.00	11.75	11.75	12.00
Burst Time (s)	N/A	N/A	N/A	N/A	3561
Burst Elevation (ft)	N/A	N/A	N/A	N/A	12.00
Max. Local ZrO_2 (%)	0.09	5.83	4.08	0.54	10.95
Max. Local ZrO_2 Elev. (ft)	11.50	12.00	12.00	11.75	12.00
Core-Wide Avg. ZrO_2 (%)	N/A	0.38	0.30	N/A	0.00

Table 3B
BVPS-2 SBLOCTA Results

	2-inch BOL	3-inch BOL	4-inch BOL	6-inch BOL	3-inch 2500 MWD/MTU
PCT (°F)	1882	1967	1505	785	2105
PCT Time (s)	3225	1397	768	344	1395
PCT Elevation (ft)	12.00	12.00	11.50	10.50	12.00
Burst Time (s)	N/A	N/A	N/A	N/A	1392
Burst Elevation (ft)	N/A	N/A	N/A	N/A	12.00
Max. Local ZrO_2 (%)	6.51	5.67	0.47	0.00	11.66
Max. Local ZrO_2 Elev (ft)	12.00	12.00	11.50	10.50	12.00
Core-Wide Avg. ZrO_2 (%)	0.41	0.40	N/A	0.00	0.33

Table 4A BVPS-1 NOTRUMP Results				
Event Time (sec)	**1.5-inch**	**2-inch**	**3-inch**	**6-inch**
Break Initiation	0	0	0	0
Reactor Trip Signal	57.4	30.2	12.7	4.6
S-Signal	75.3	42.2	21.4	10.4
SI Flow Delivered	102.3	69.2	48.4	37.4
Loop Seal Clearing(1)	1623	883	403	73
Core Uncovery	4845	1155	865	1341
Accumulator Injection	N/A	N/A	1300	276
PCT Time	7808	3563	1411	2073
Core Recovery(2)	> TMAX	> TMAX	> TMAX	> TMAX

Notes:

(1) Loop seal clearing is defined as break vapor flow > 1 lb/s.

(2) For the cases where core recovery is > TMAX, basis for transient termination can be concluded based on the following: (1) The RCS system pressure is decreasing which will increase SI flow, (2) Total RCS system mass is increasing due to SI flow exceeding break flow, and (3) Core mixture level has begun to increase and is expected to continue for the remainder of the accident.

Table 4B
BVPS-2 NOTRUMP Results

Event Time (sec)	2-inch	3-inch	4-inch	6-inch
Break Initiation	0	0	0	0
Reactor Trip Signal	26.8	11.5	6.8	3.9
S-Signal	38.2	19.2	11.4	7.4
SI Flow Delivered	65.2	46.2	38.4	34.4
Loop Seal Clearing(1)	961	449	236	113
Core Uncovery	1201	629	406	263
Accumulator Injection	3417	1114	595	279
PCT Time	3225	1397	768	344
Core Recovery(2)	>TMAX	>TMAX	>TMAX	352

Notes:

(1) Loop seal clearing is defined as break vapor flow > 1 lb/s.

(2) For the cases where core recovery is > TMAX, basis for transient termination can be concluded based on the following: (1) The RCS system pressure is decreasing which will increase SI flow, (2) Total RCS system mass is increasing due to SI flow exceeding break flow, and (3) Core mixture level has begun to increase and is expected to continue for the remainder of the accident.

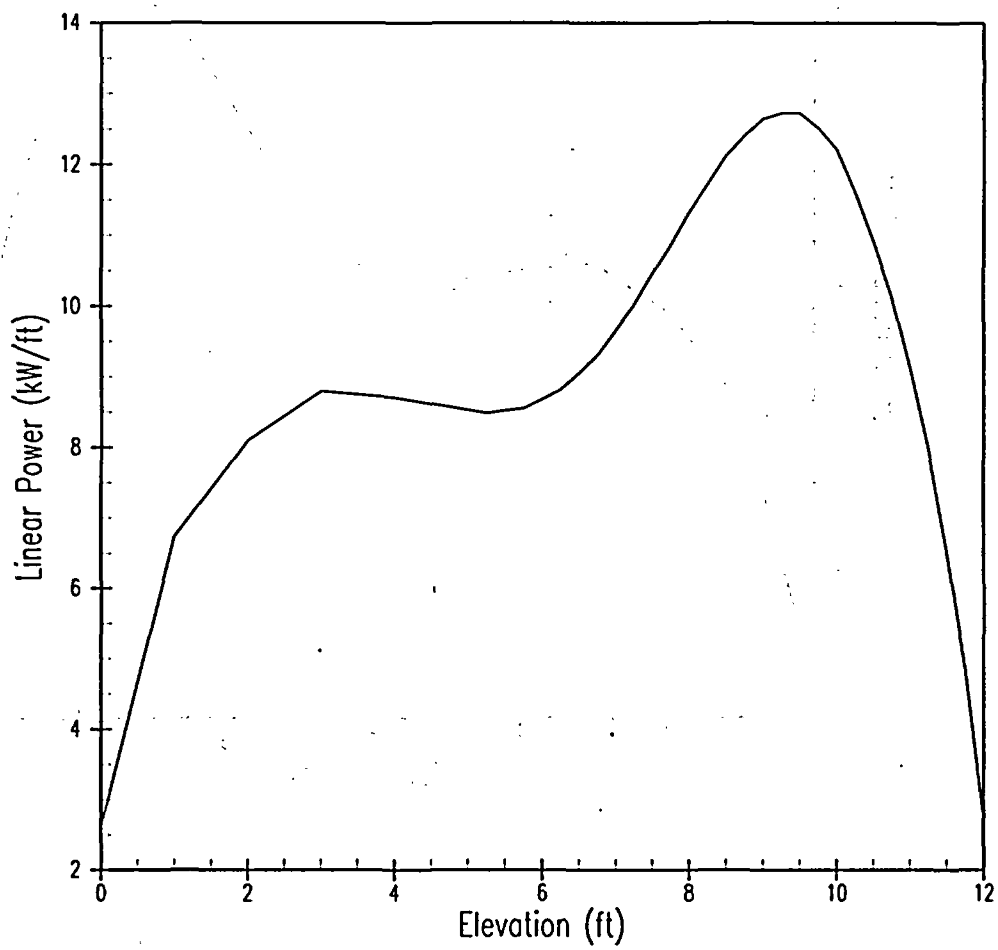


Figure 1A
BVPS-1 Small Break Hot Rod Power Shape

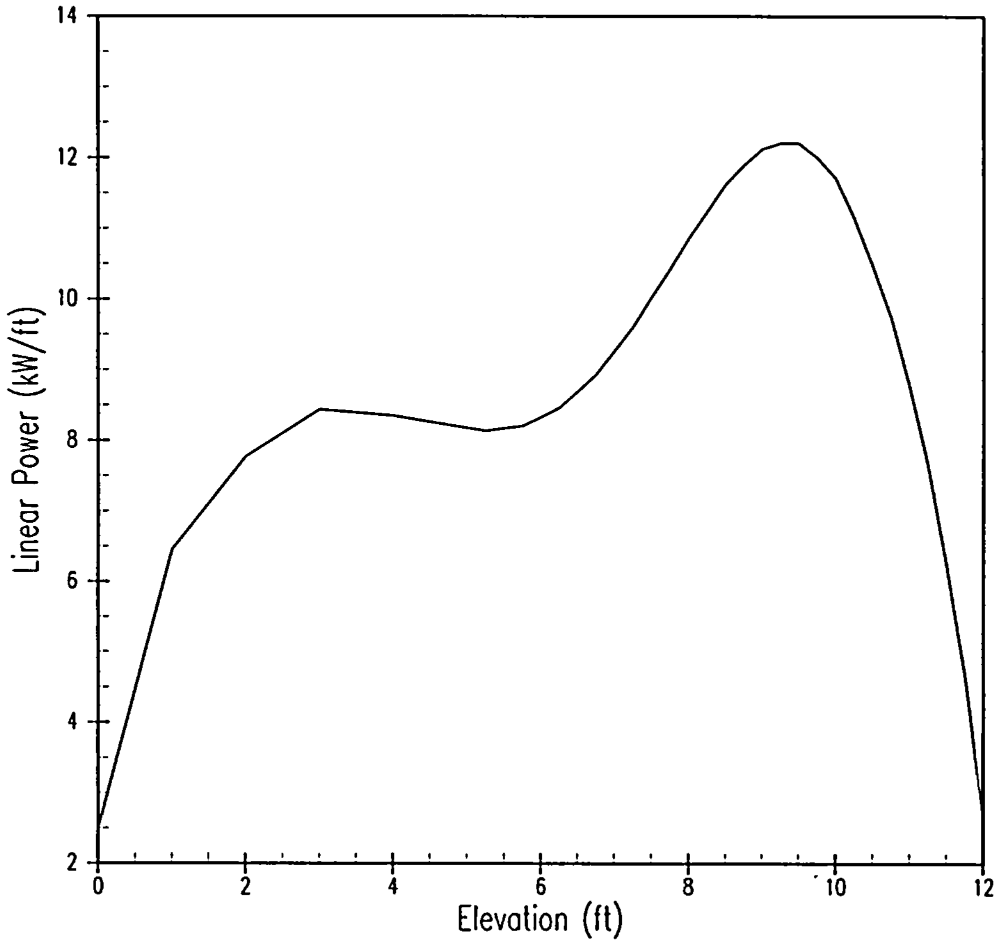


Figure 1B
BVPS-2 Small Break Hot Rod Power Shape

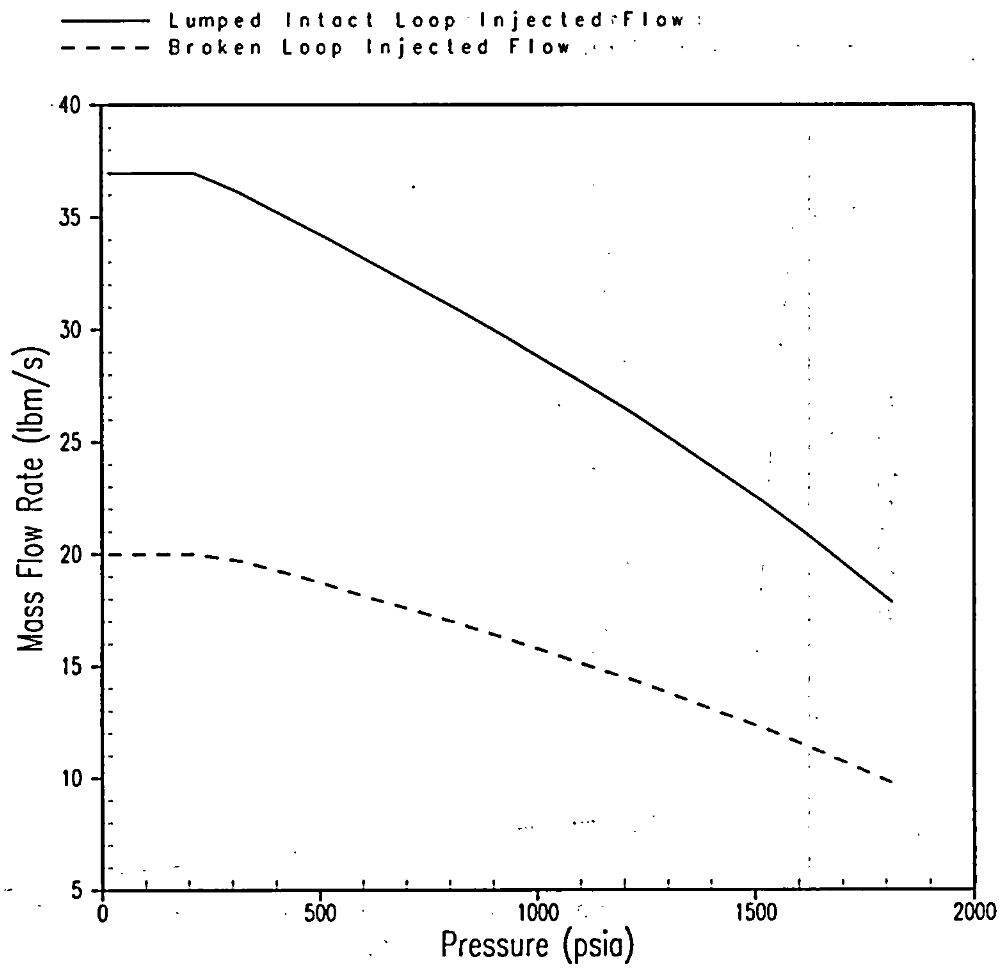


Figure 2A
BVPS-1 Small Break LOCA Safety Injection Flows
(1 HHSI pump, faulted loop injects to RCS pressure)

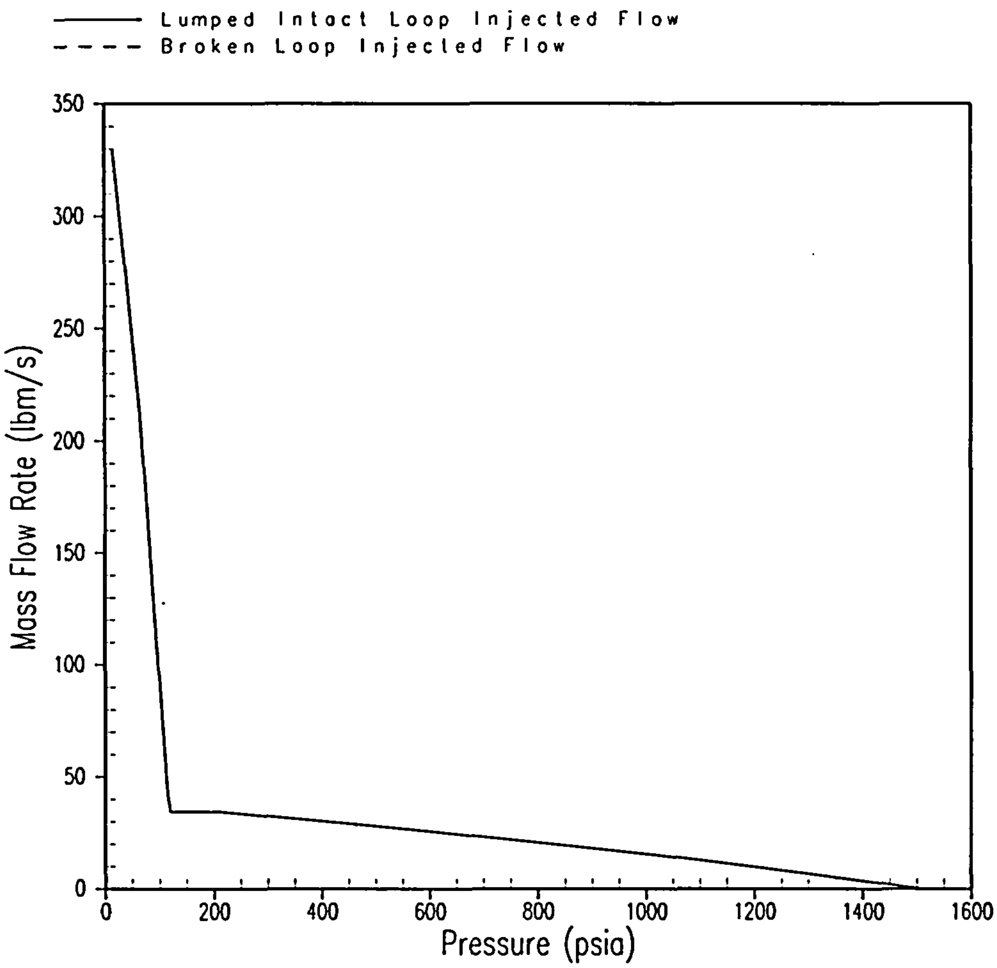


Figure 2B
BVPS-1 Small Break LOCA Safety Injection Flows
(1 HHSI pump and LHSI pump, no ECCS flow in faulted loop – 6-inch break)

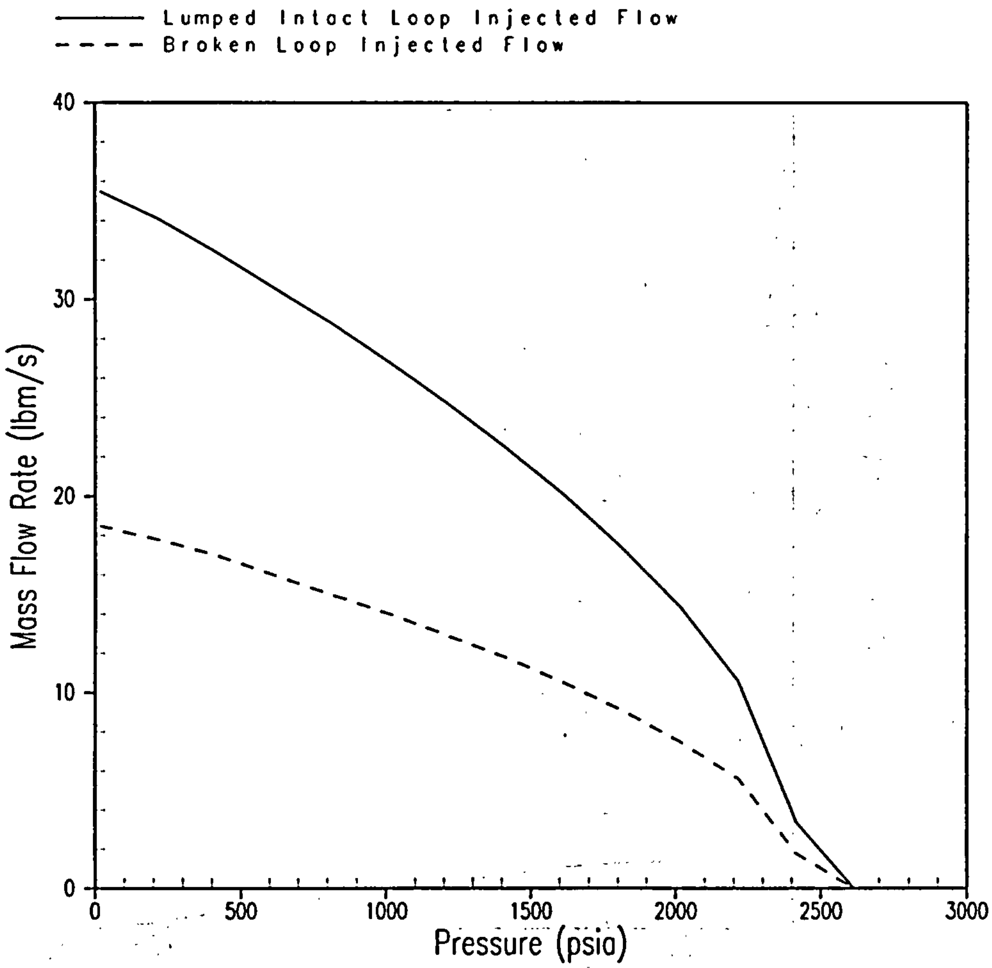


Figure 2C
BVPS-2 Small Break LOCA Safety Injection Flows
(1 HHSI pump, faulted loop injects to RCS pressure)

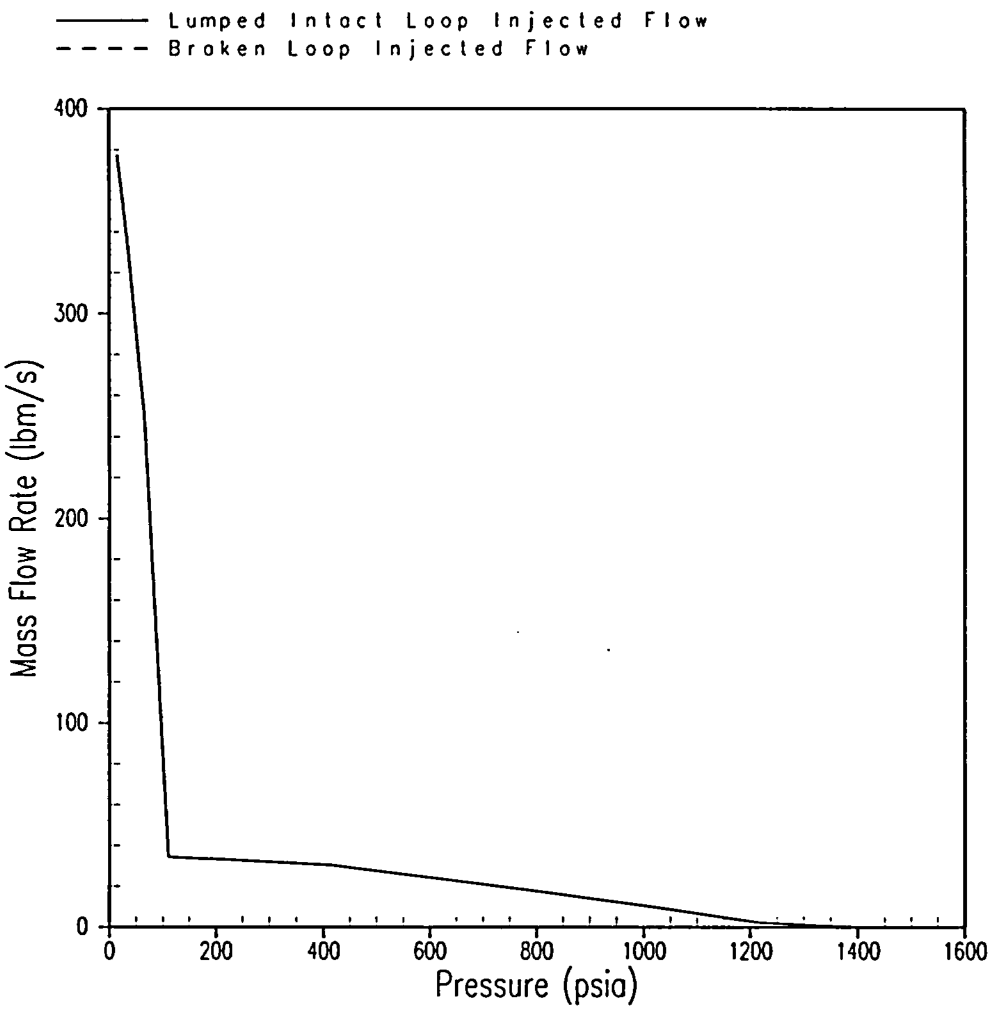


Figure 2D
BVPS-2 Small Break LOCA Safety Injection Flows
(1 HHSI pump and LHSI pump, faulted loop injects to containment pressure – 6-inch break)

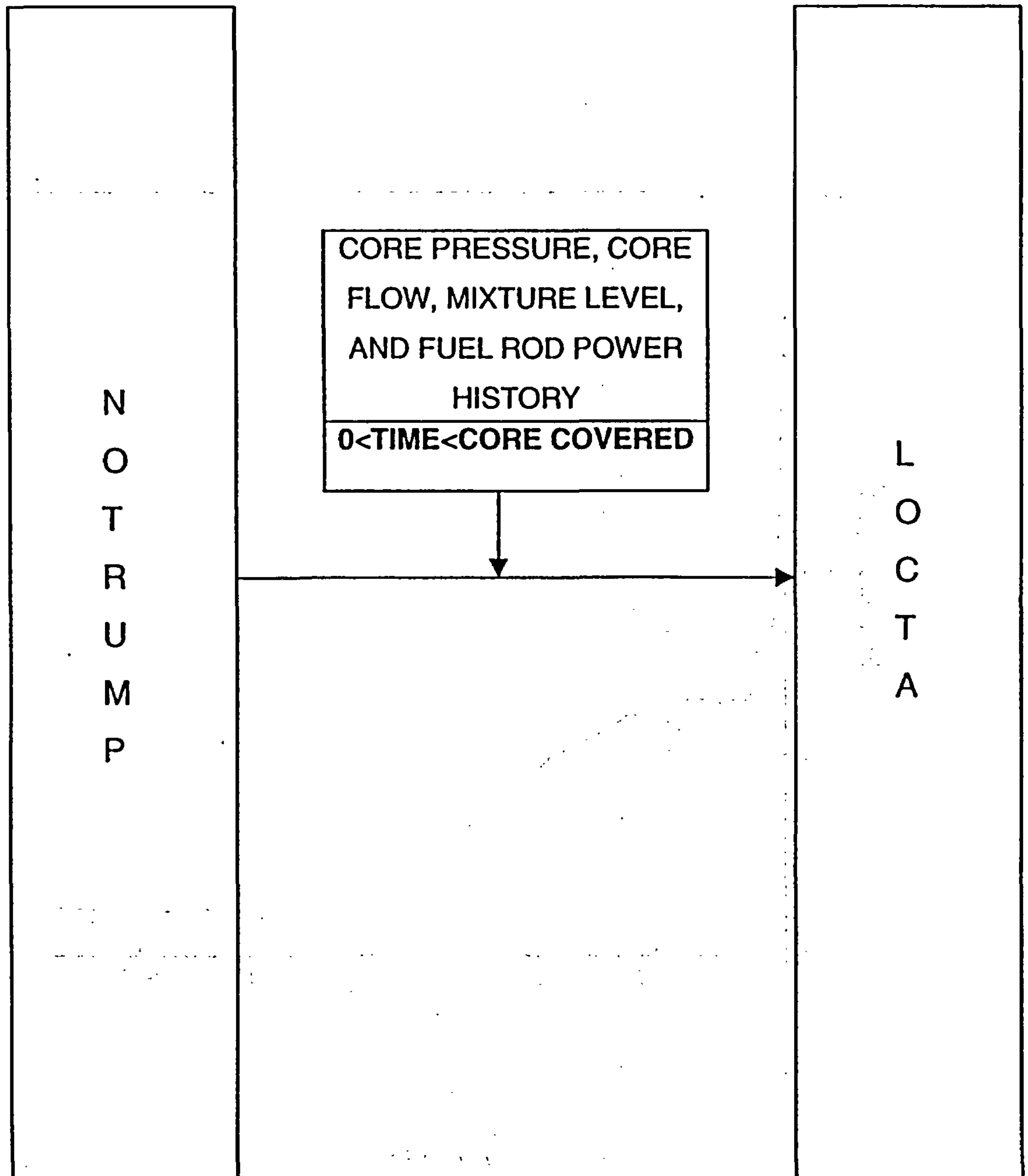


Figure 3
Code Interface Description
for Small Break Model

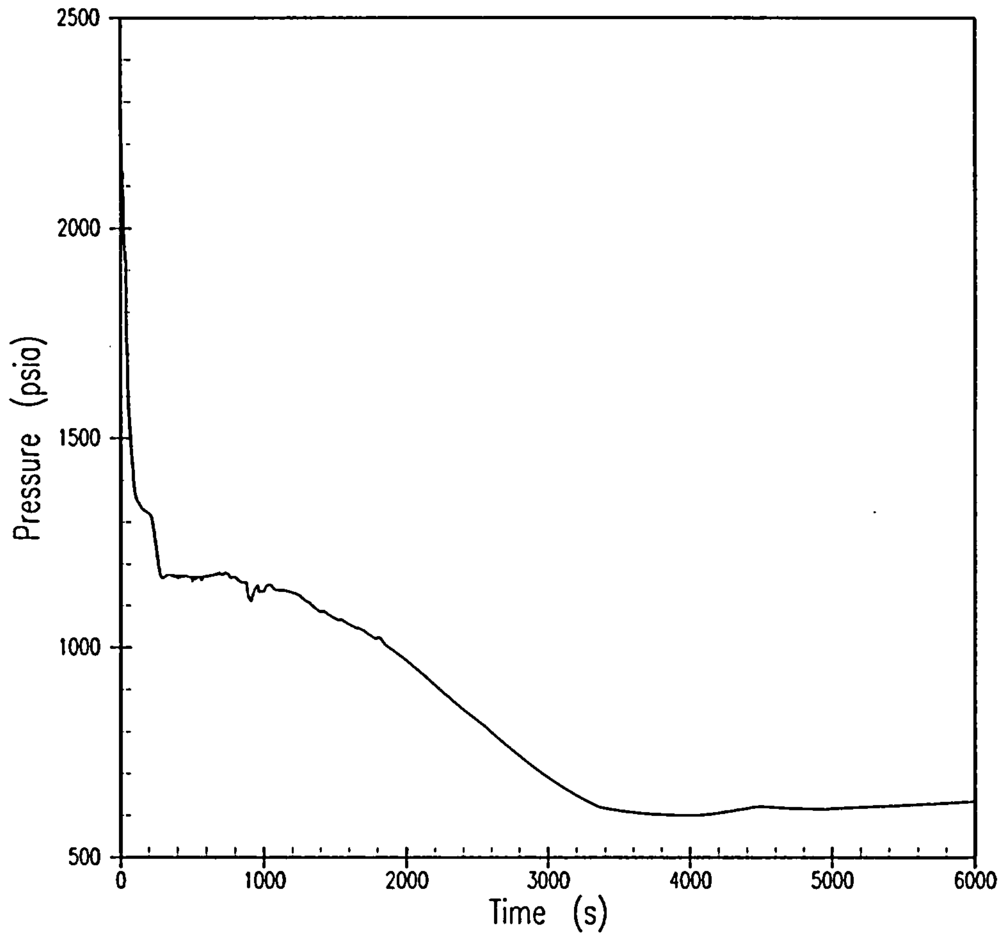


Figure 4A
BVPS-1 2-inch Break
RCS Pressure

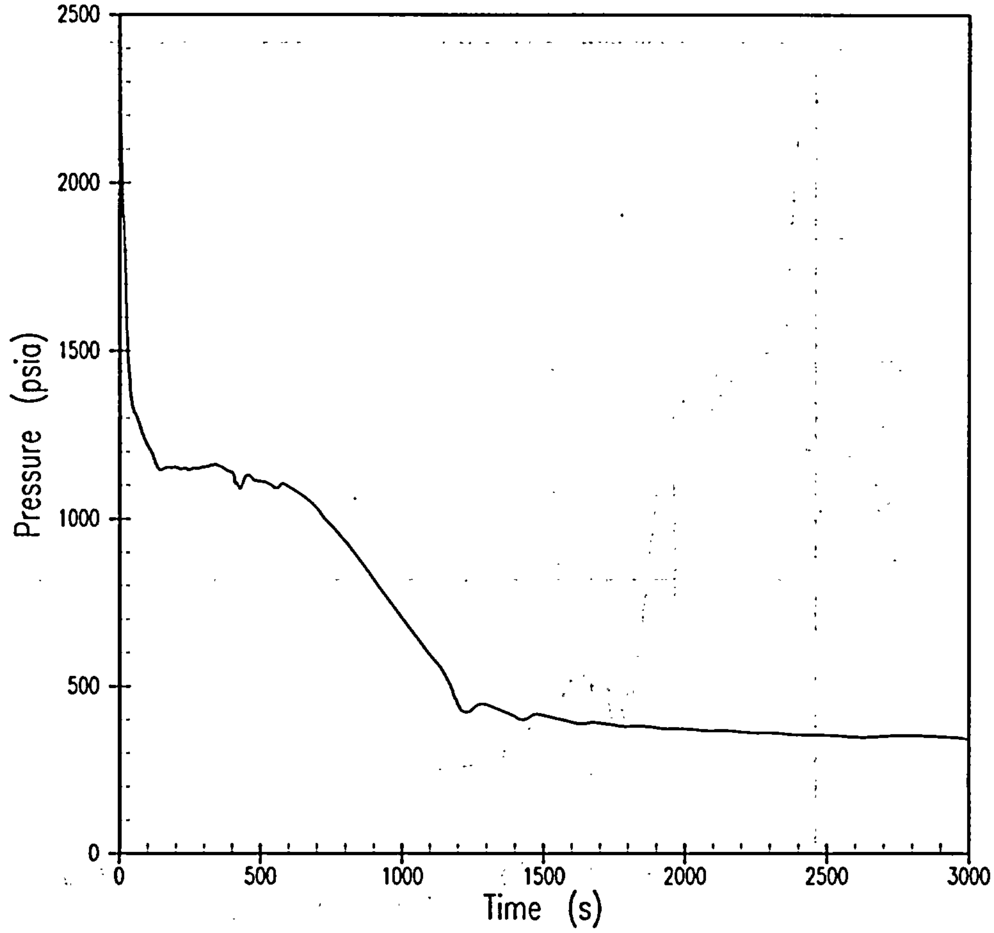


Figure 4B
BVPS-2 3-inch Break
RCS Pressure

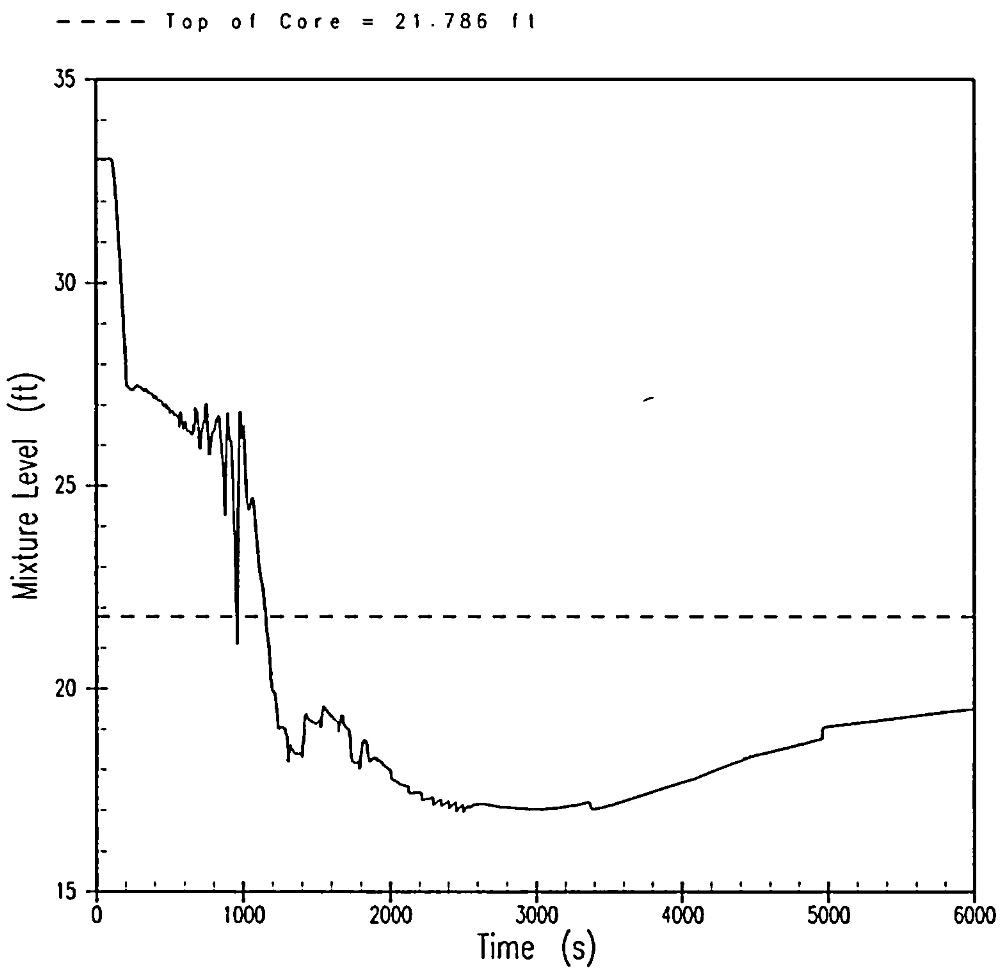


Figure 5A
BVPS-1 2-inch Break
Core Mixture Level

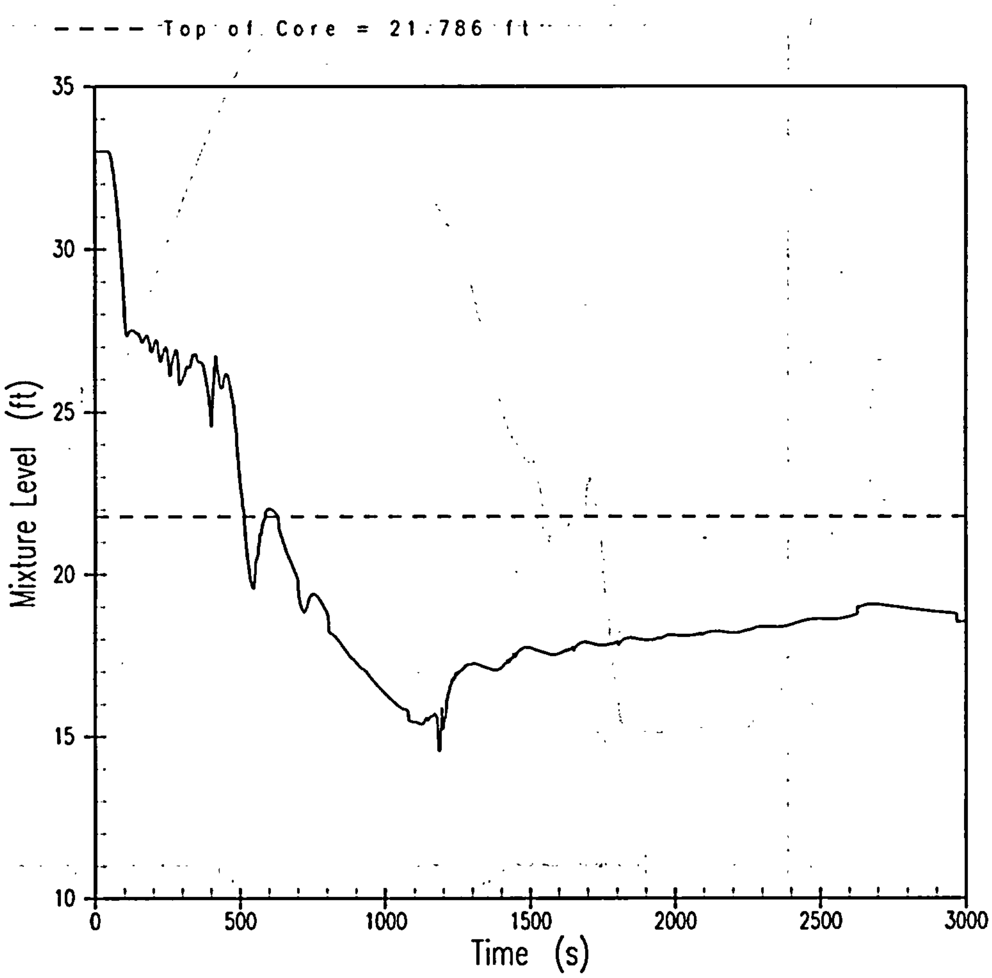


Figure 5B
BVPS-2 3-inch Break
Core Mixture Level

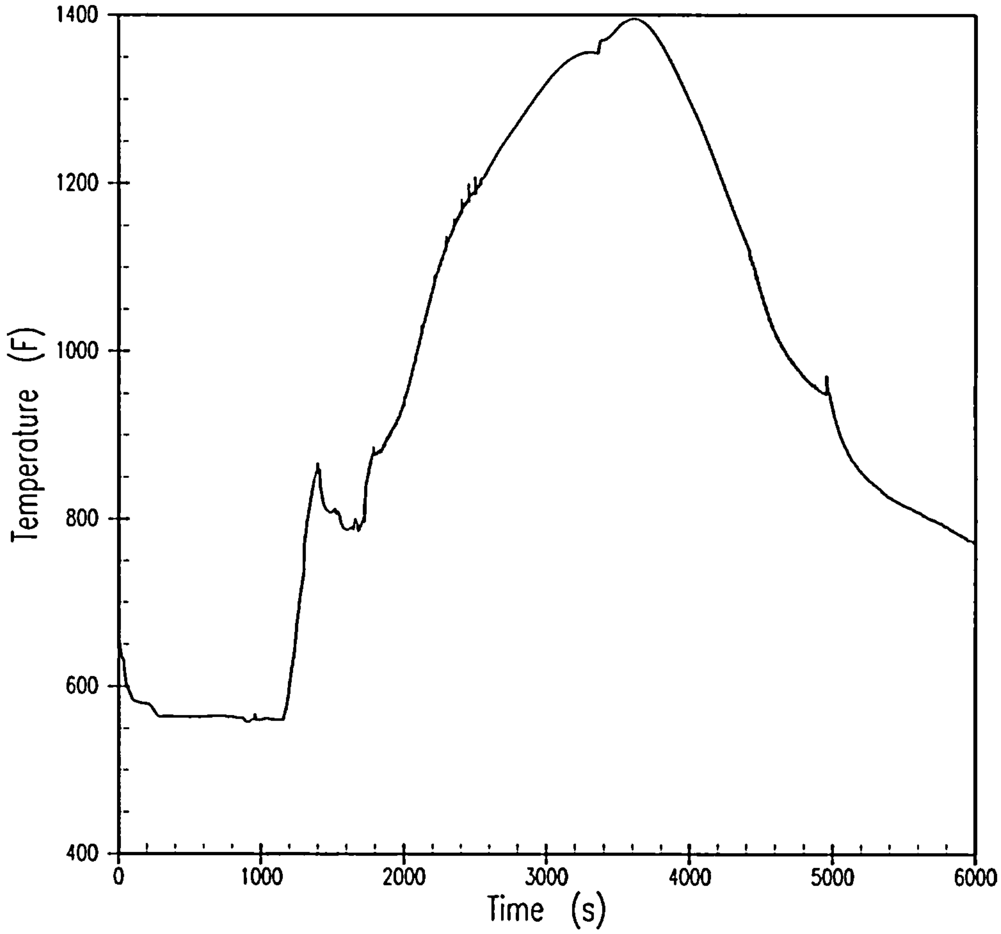


Figure 6A
BVPS-1 2-inch Break
Core Exit Vapor Temperature

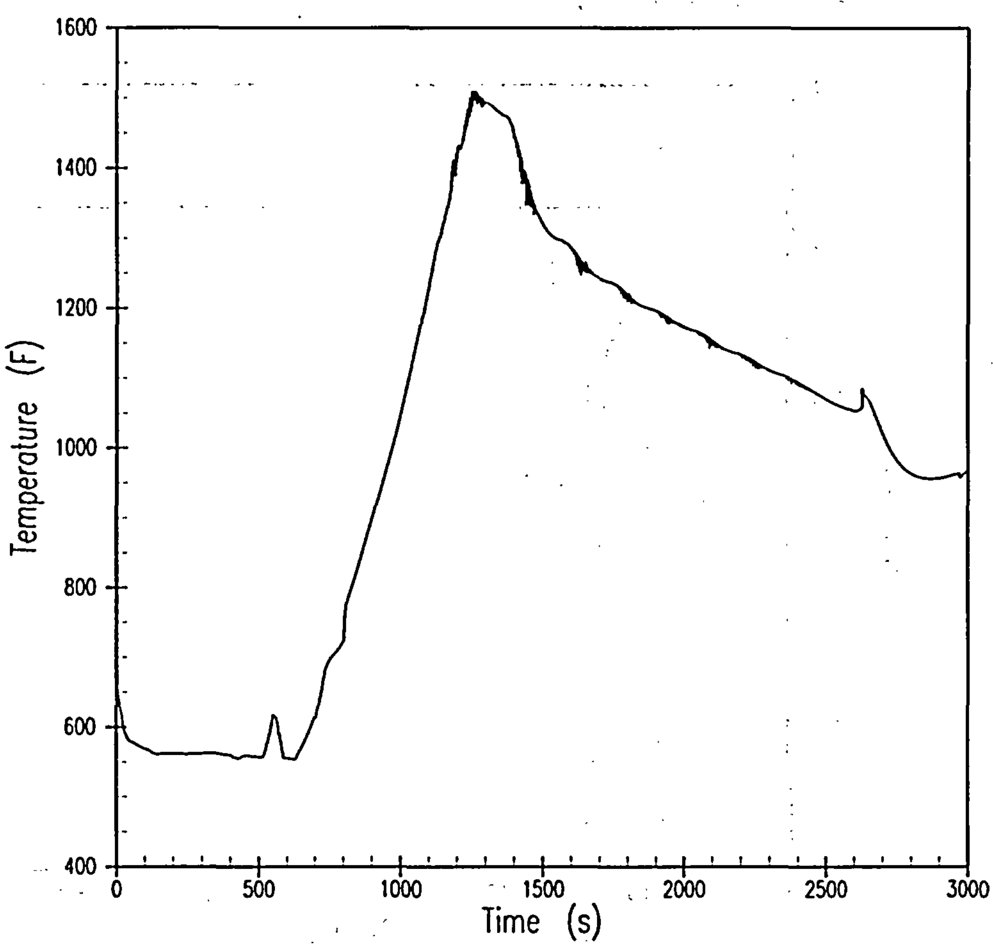


Figure 6B
BVPS-2 3-inch Break
Core Exit Vapor Temperature

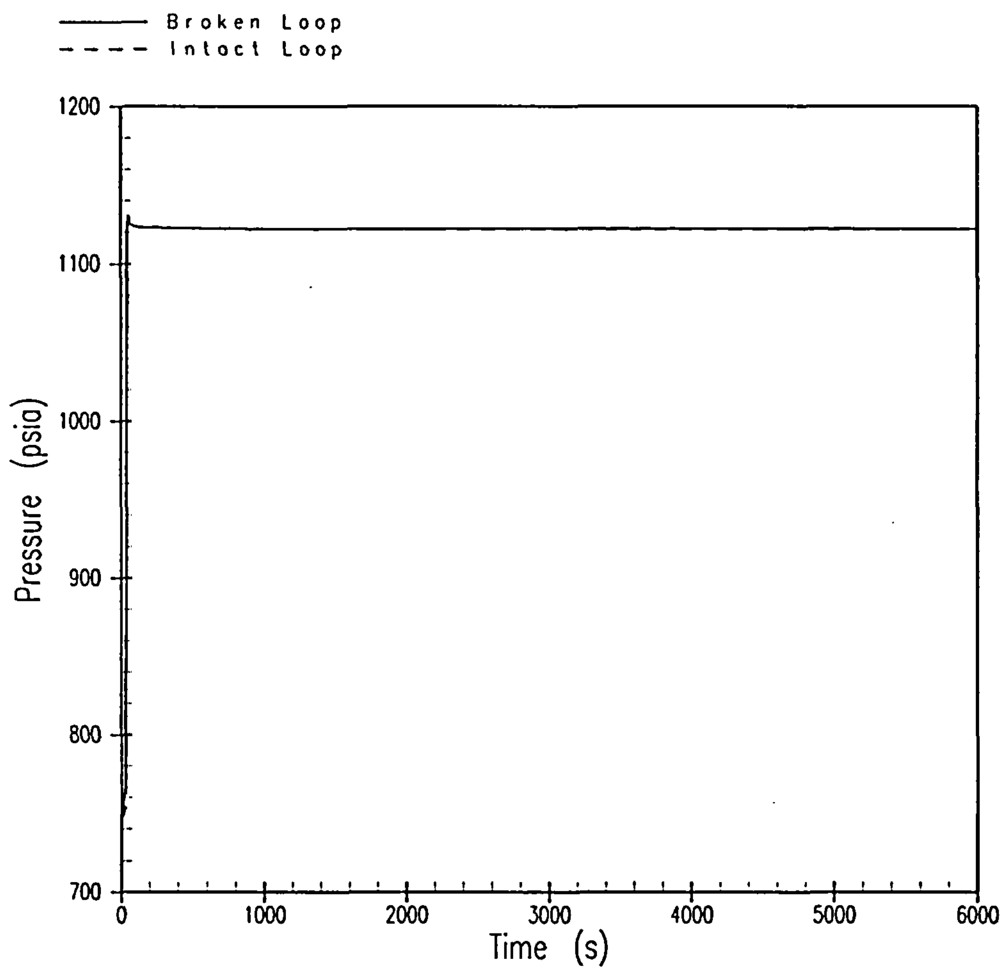


Figure 7A
BVPS-1 2-inch Break
Broken Loop and Intact Loop Secondary Pressure

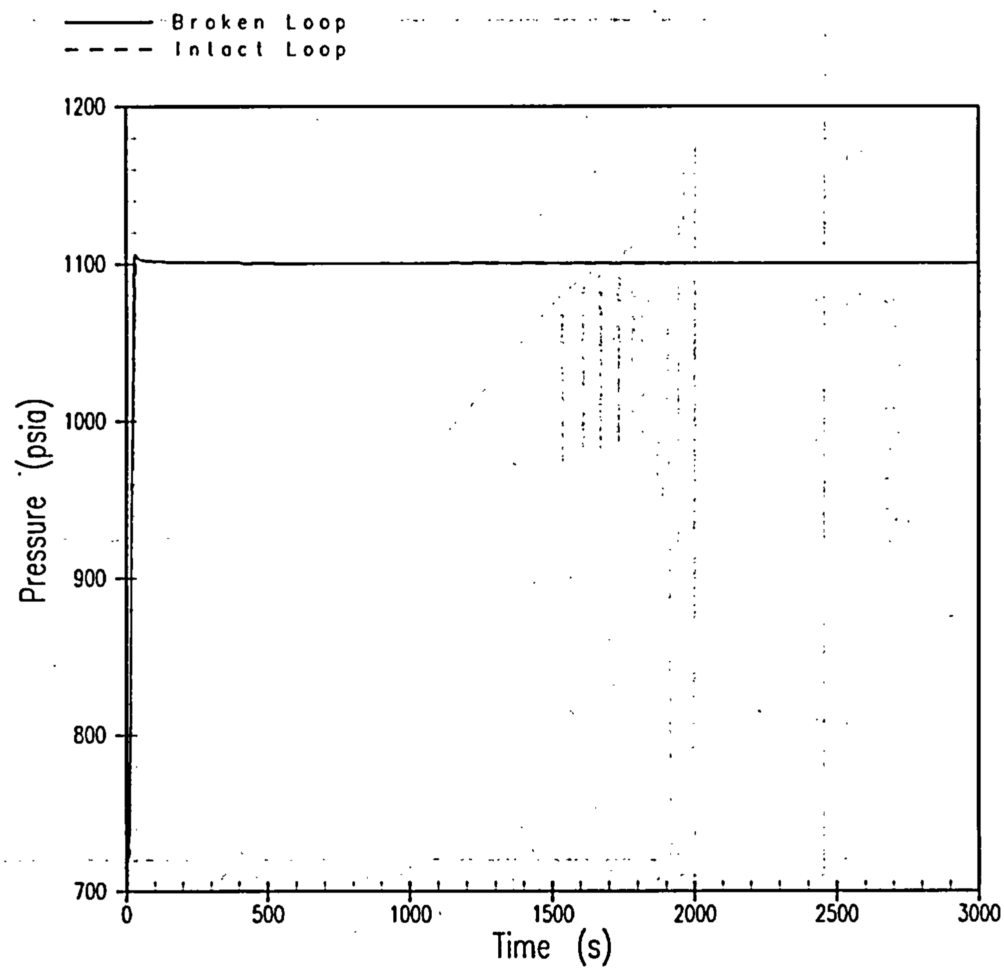


Figure 7B
BVPS-2 3-inch Break
Broken Loop and Intact Loop Secondary Pressure

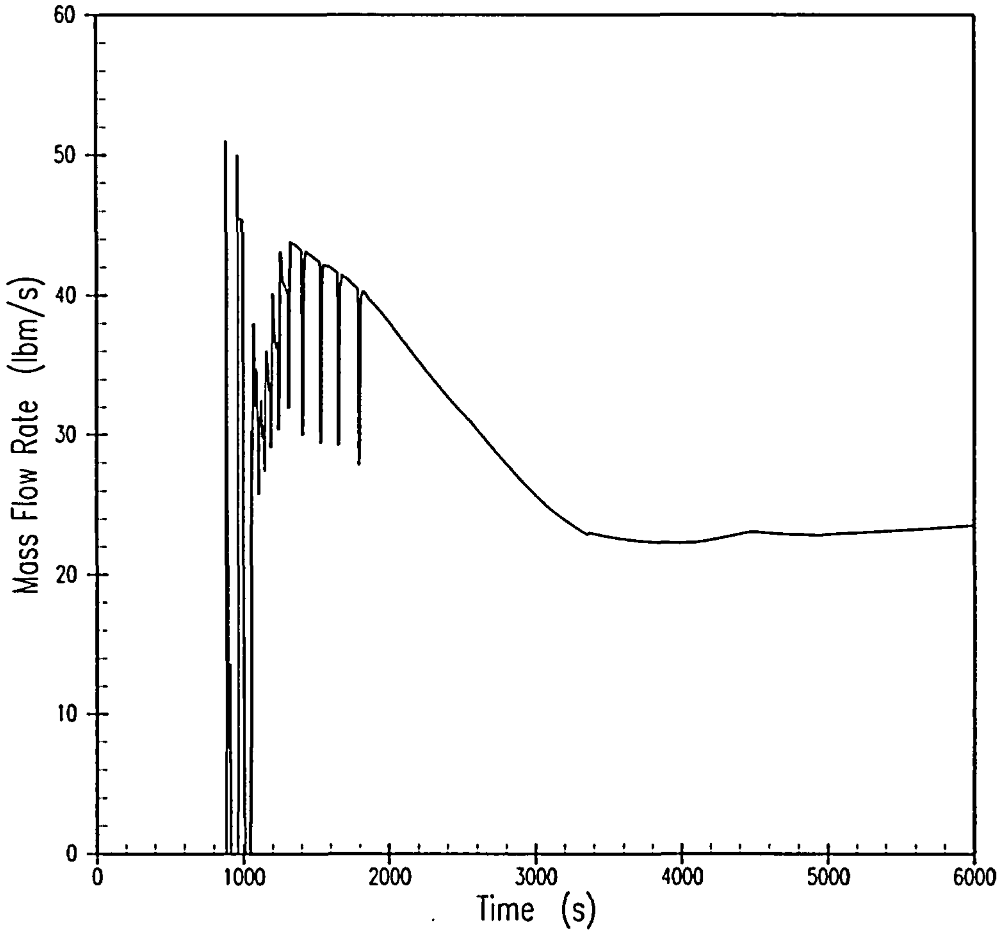


Figure 8A
BVPS-1 2-inch Break
Break Vapor Flow Rate

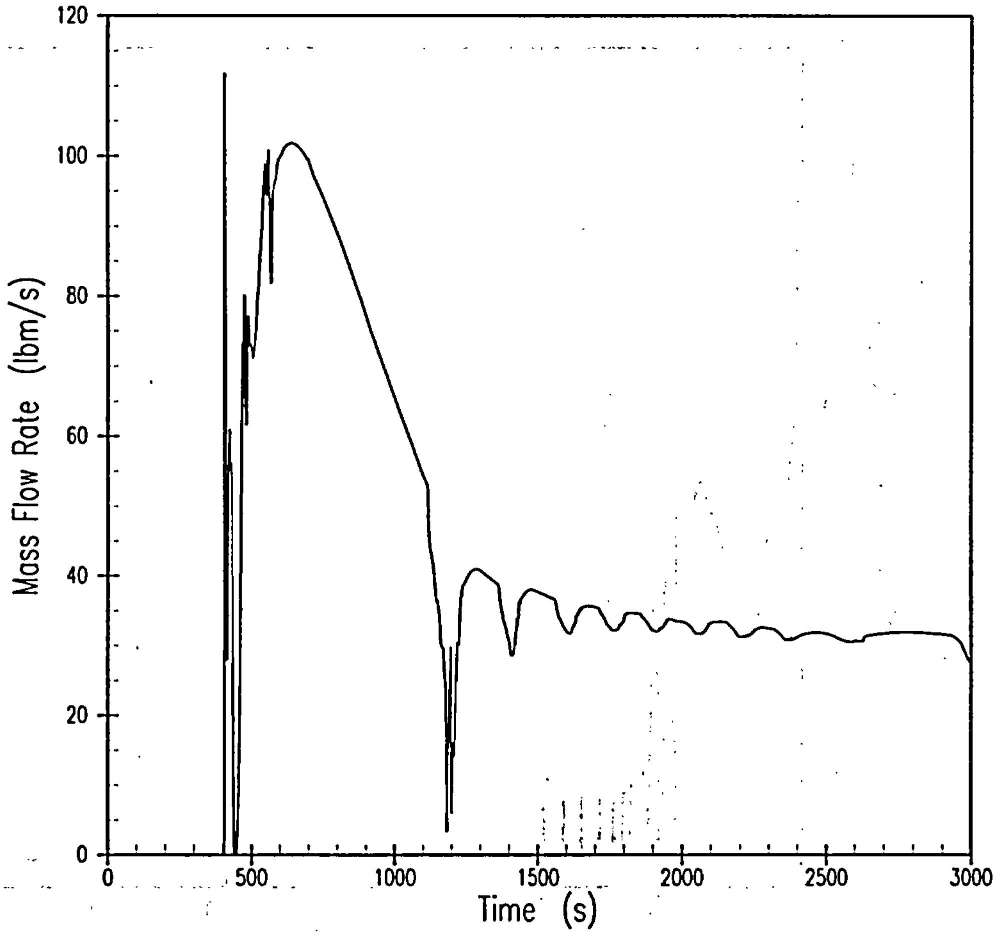


Figure 8B
BVPS-2 3-inch Break
Break Vapor Flow Rate

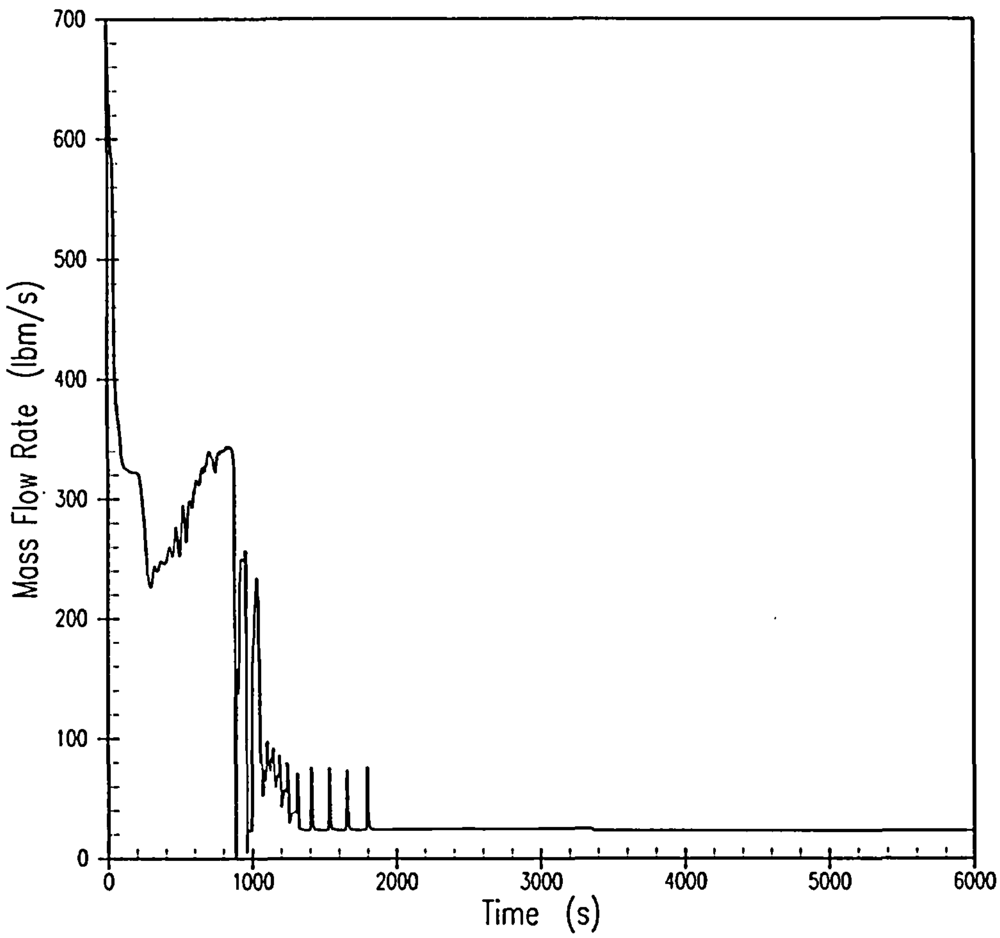


Figure 9A
BVPS-1 2-inch Break
Break Liquid Flow Rate

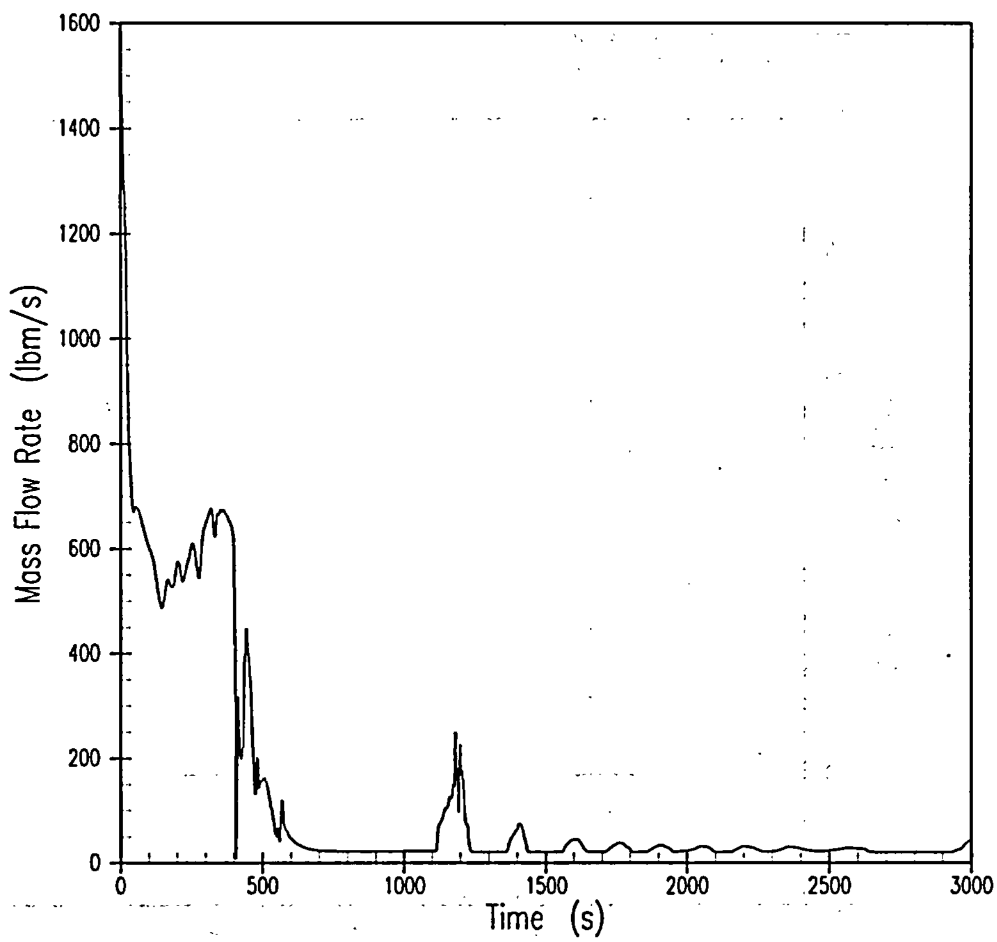


Figure 9B
BVPS-2 3-inch Break
Break Liquid Flow Rate

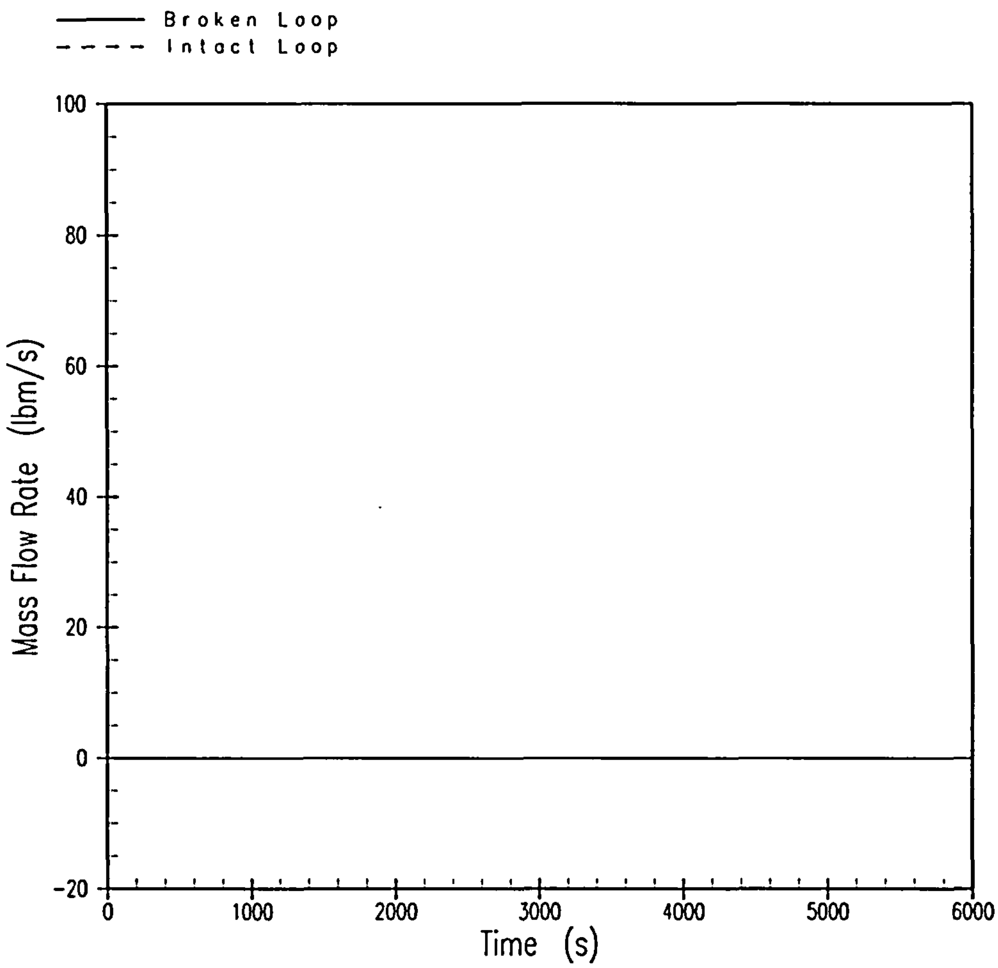


Figure 10A
BVPS-1 2-inch Break
Broken Loop and Intact Loop Accumulator Flow Rate

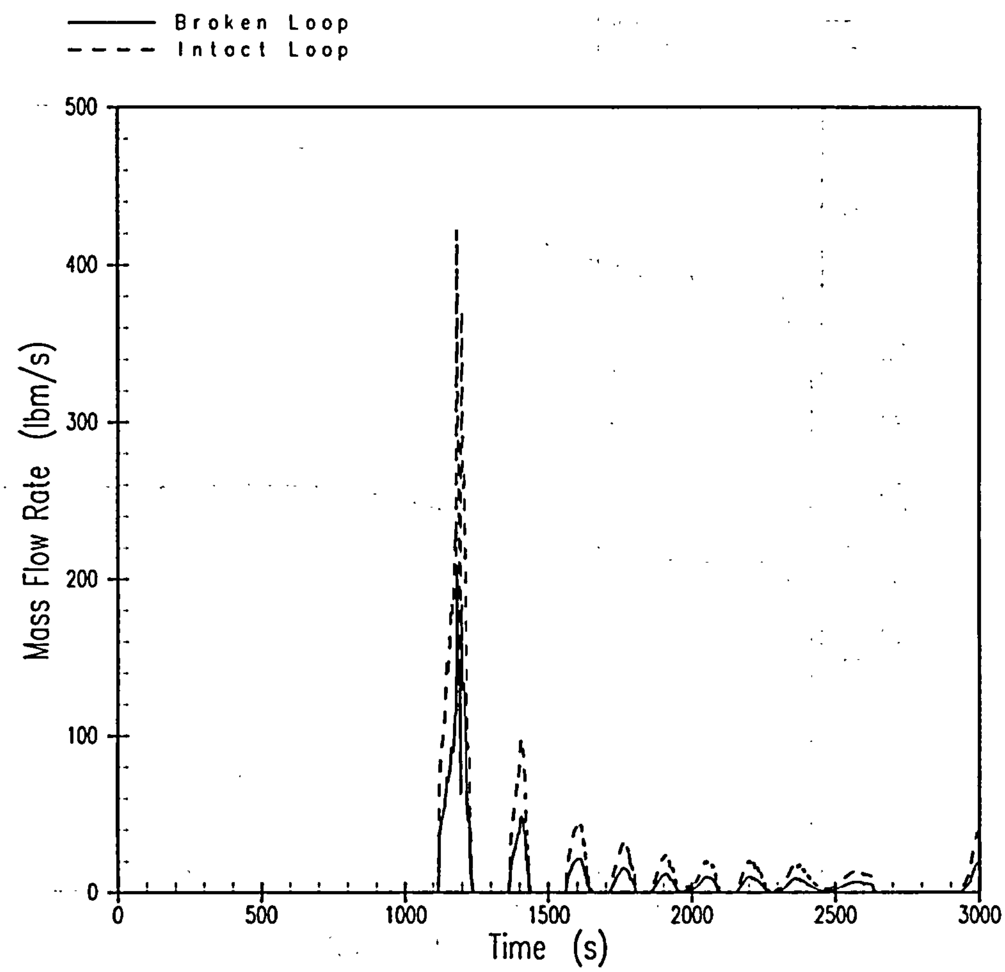


Figure 10B
BVPS-2 3-inch Break
Broken Loop and Intact Loop Accumulator Flow Rate

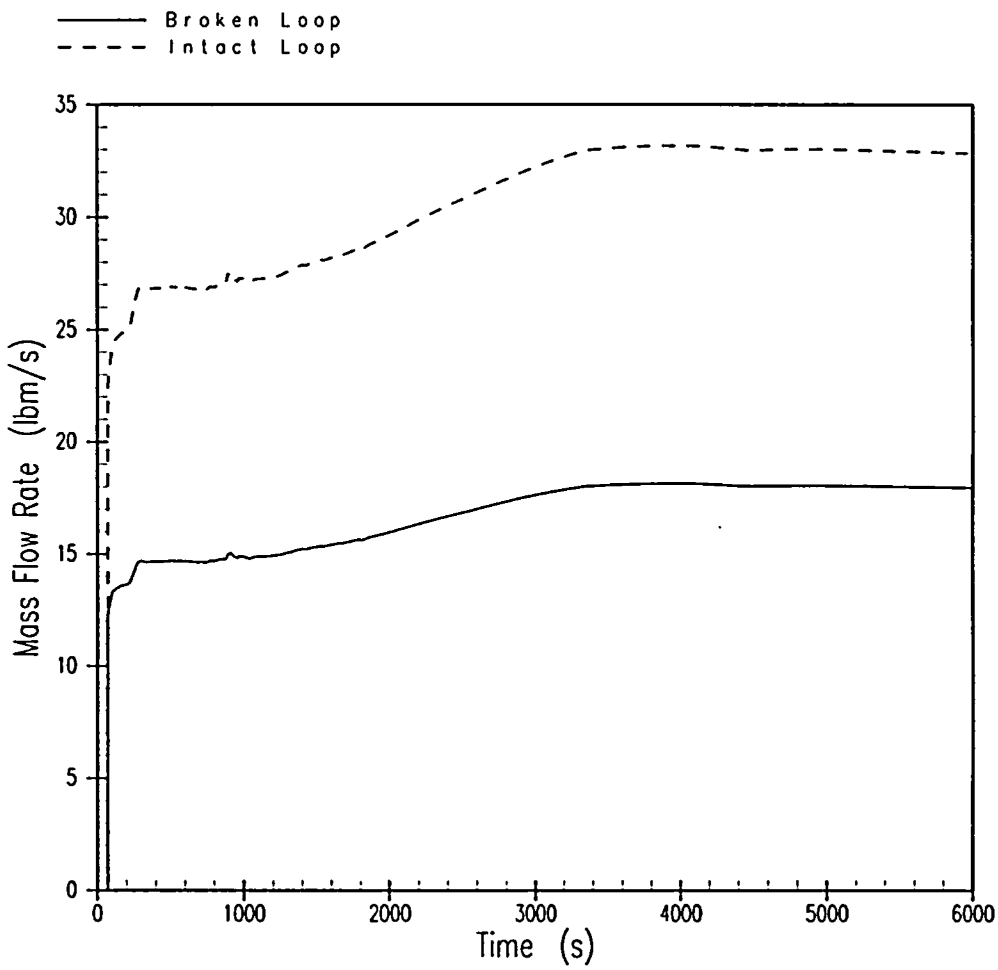


Figure 11A
BVPS-1 2-inch Break
Broken Loop and Intact Loop Pumped Safety Injection Flow Rate

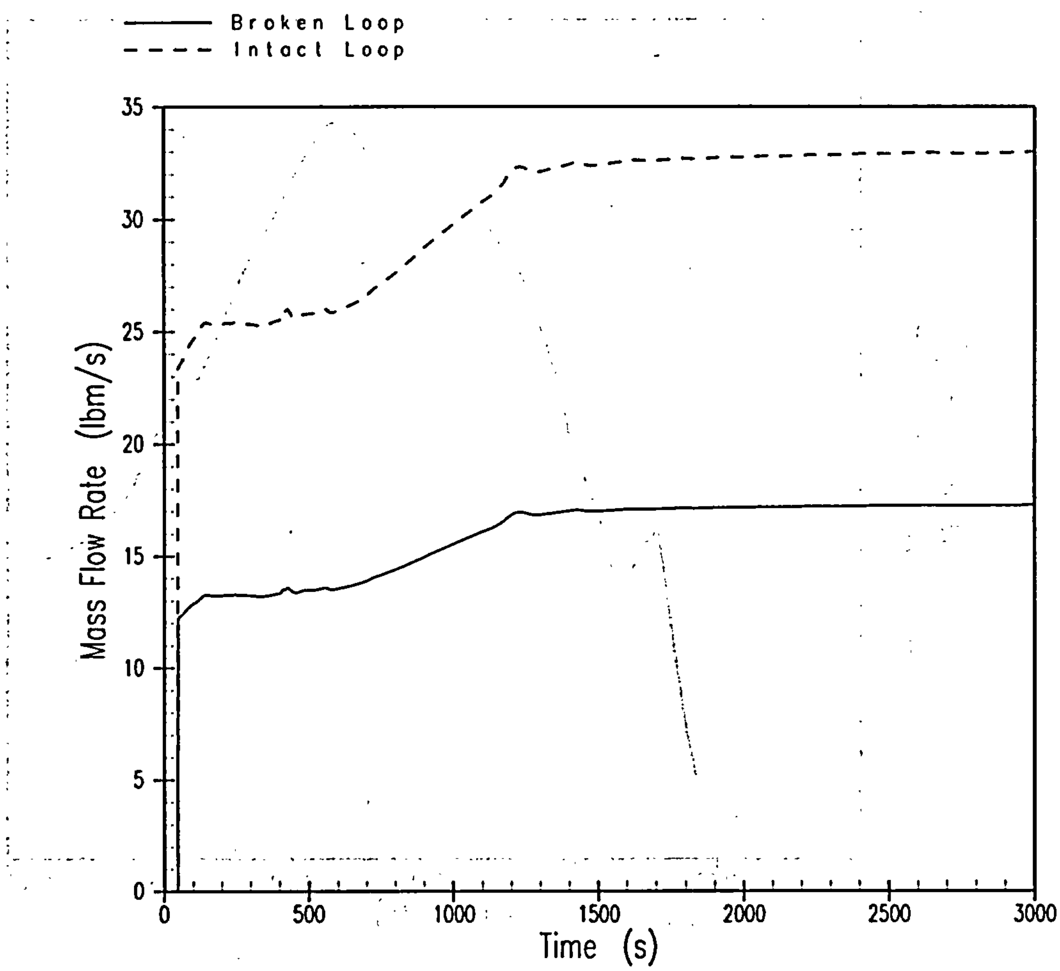


Figure 11B
BVPS-2 3-inch Break
Broken Loop and Intact Loop Pumped Safety Injection Flow Rate

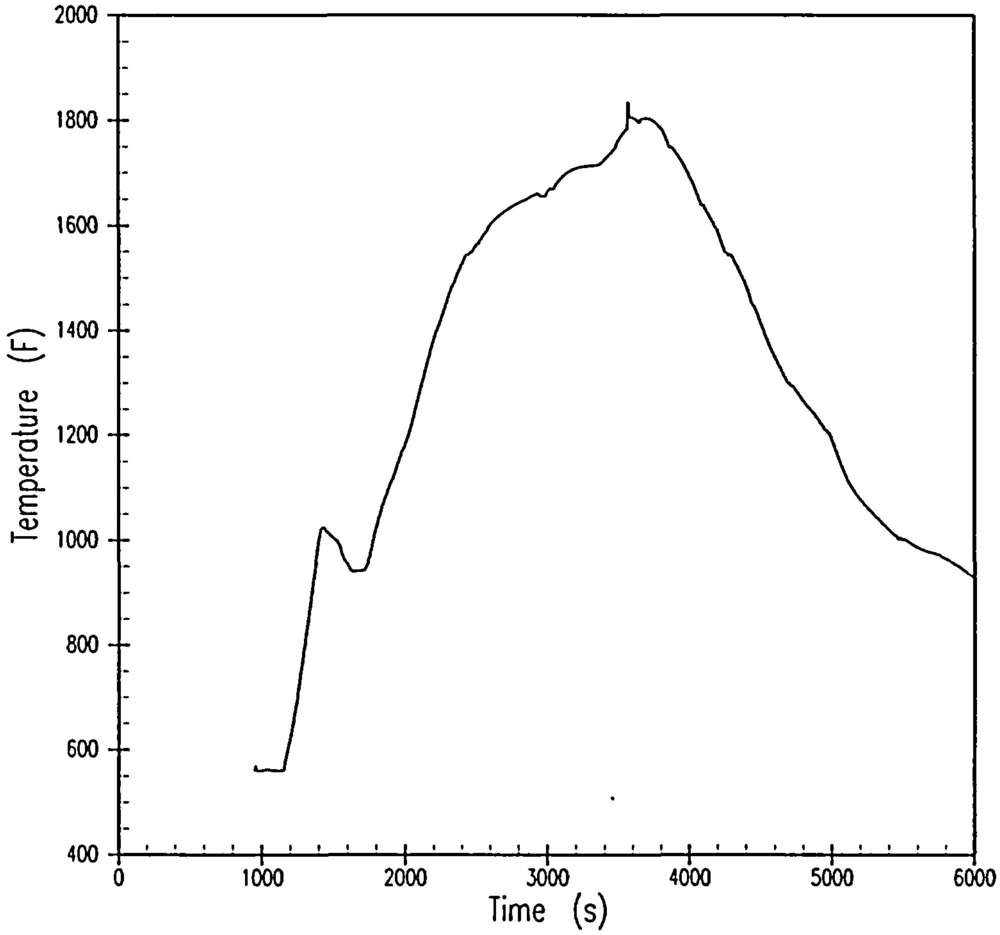


Figure 12A
BVPS-1 2-inch Break
Peak Clad Temperature

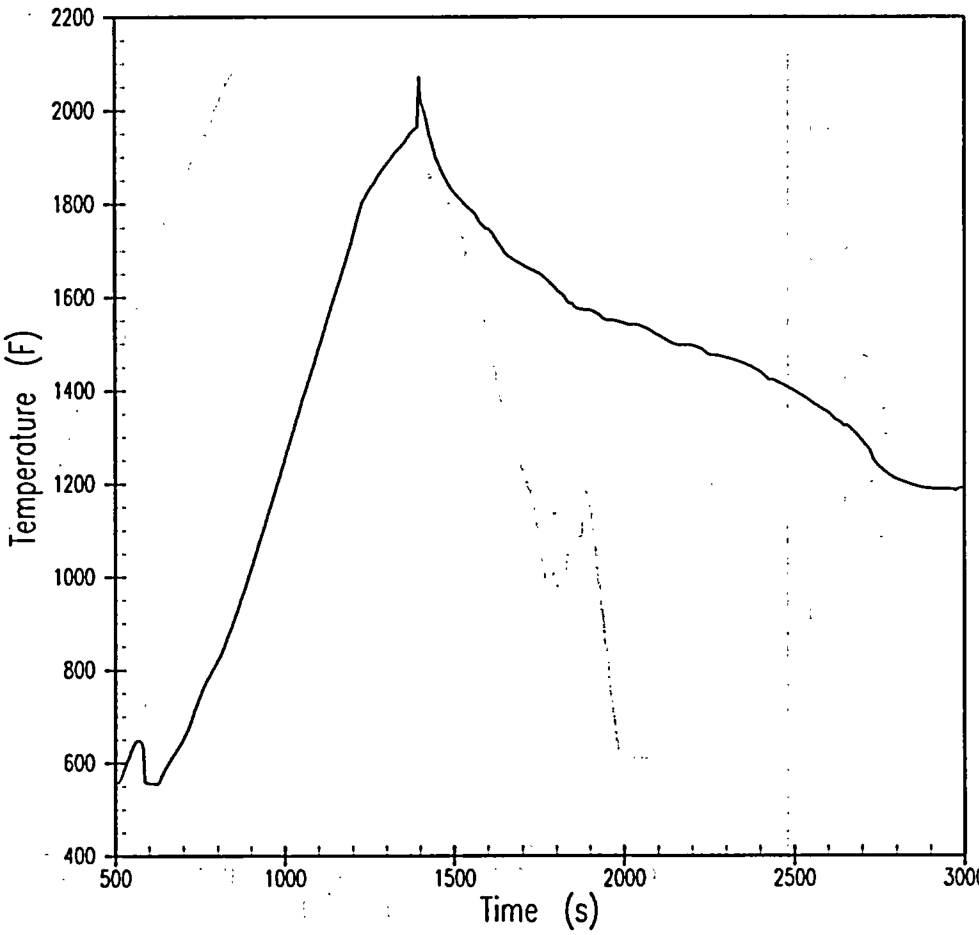


Figure 12B
BVPS-2 3-inch Break
Peak Clad Temperature

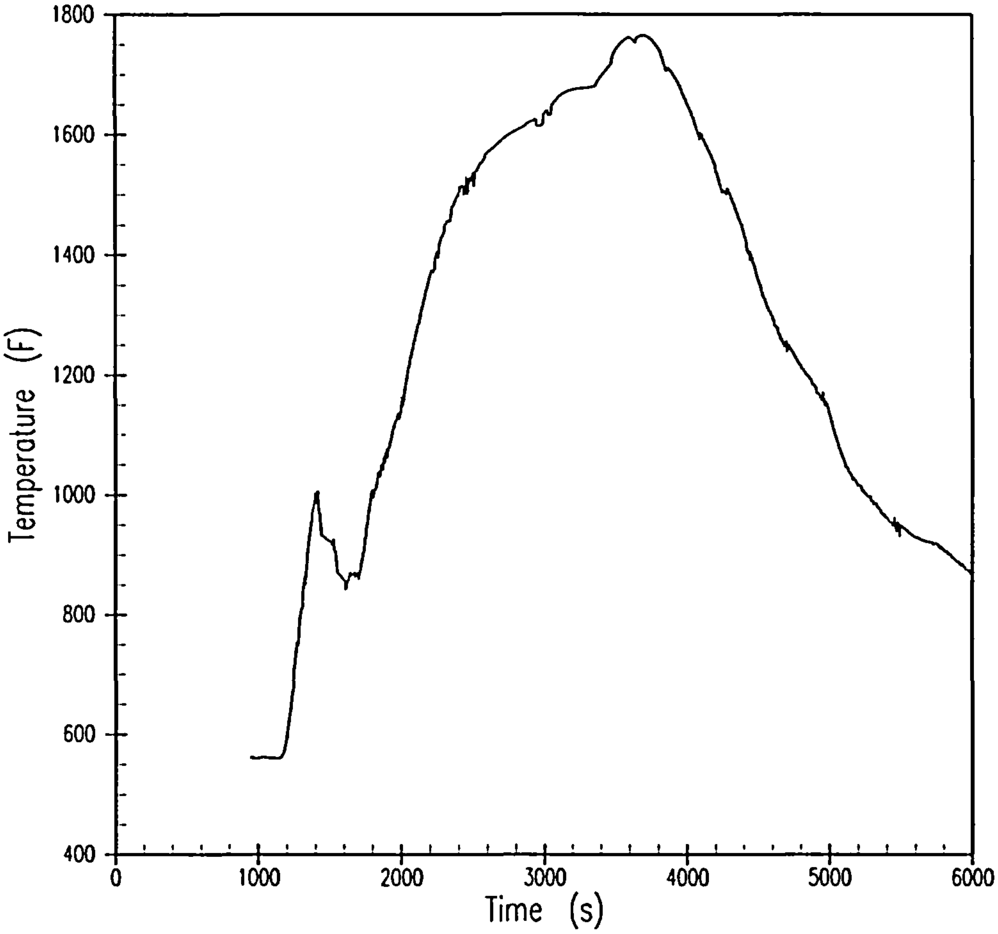


Figure 13A
BVPS-1 2-inch Break
Hot Spot Fluid Temperature

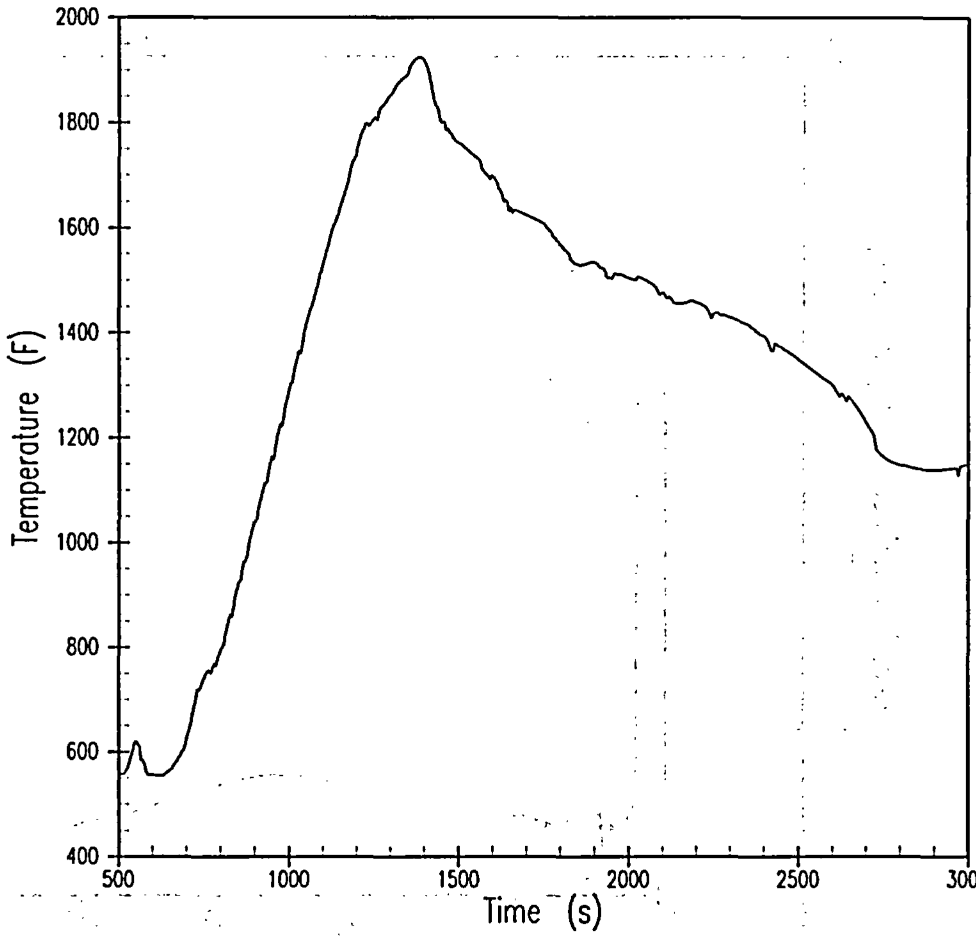


Figure 13B
BVPS-2 3-inch Break
Hot Spot Fluid Temperature

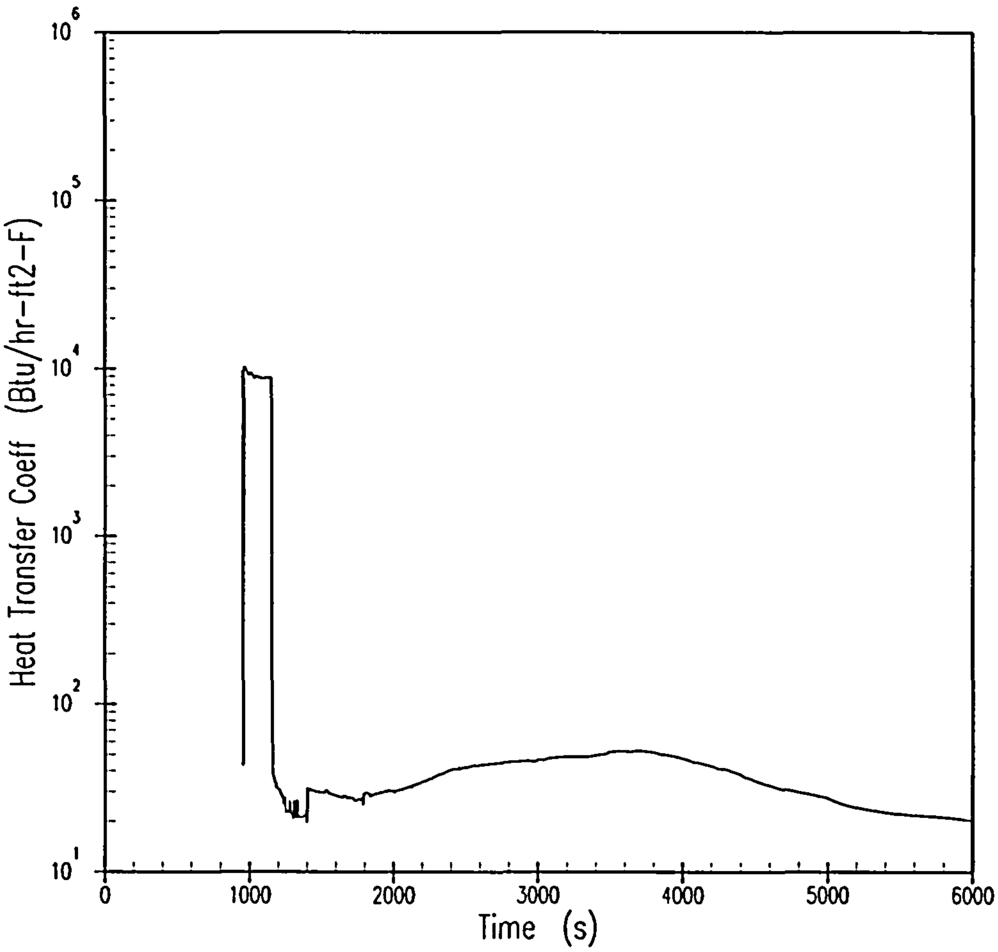


Figure 14A
BVPS-1 2-inch Break
Rod Film Heat Transfer Coefficient

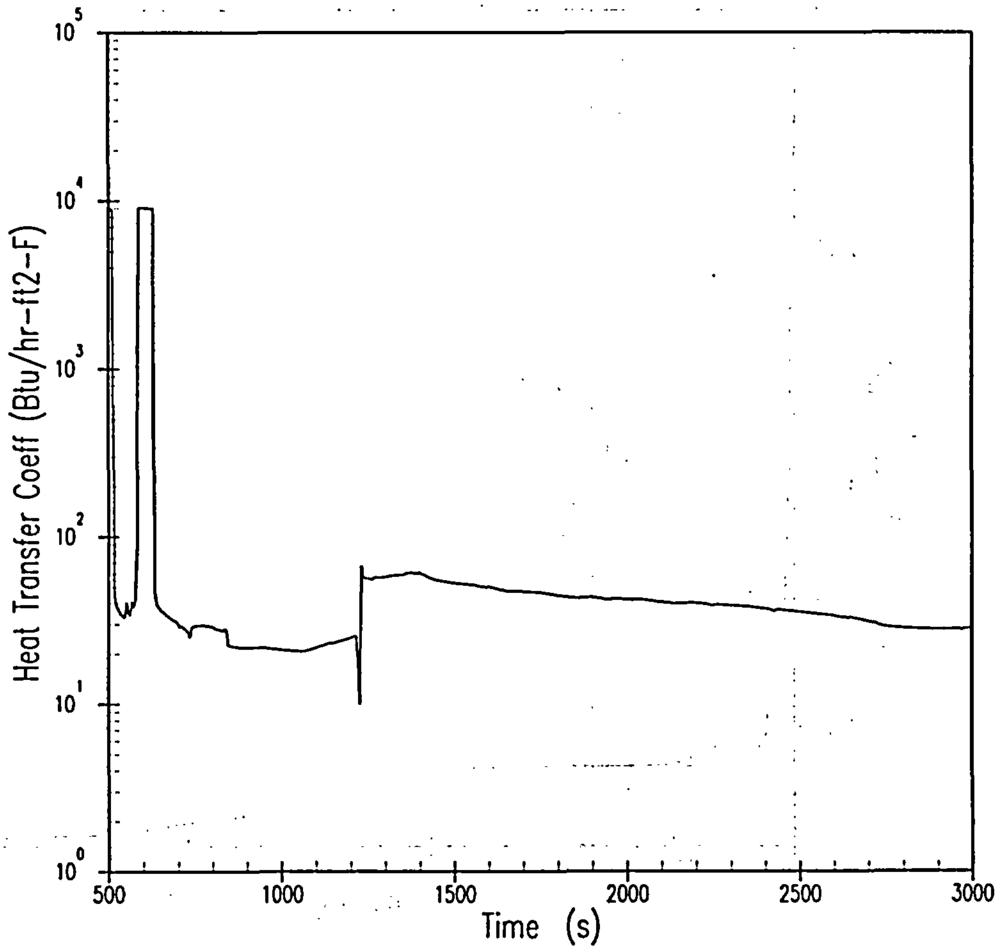


Figure 14B
BVPS-2 3-inch Break
Rod Film Heat Transfer Coefficient

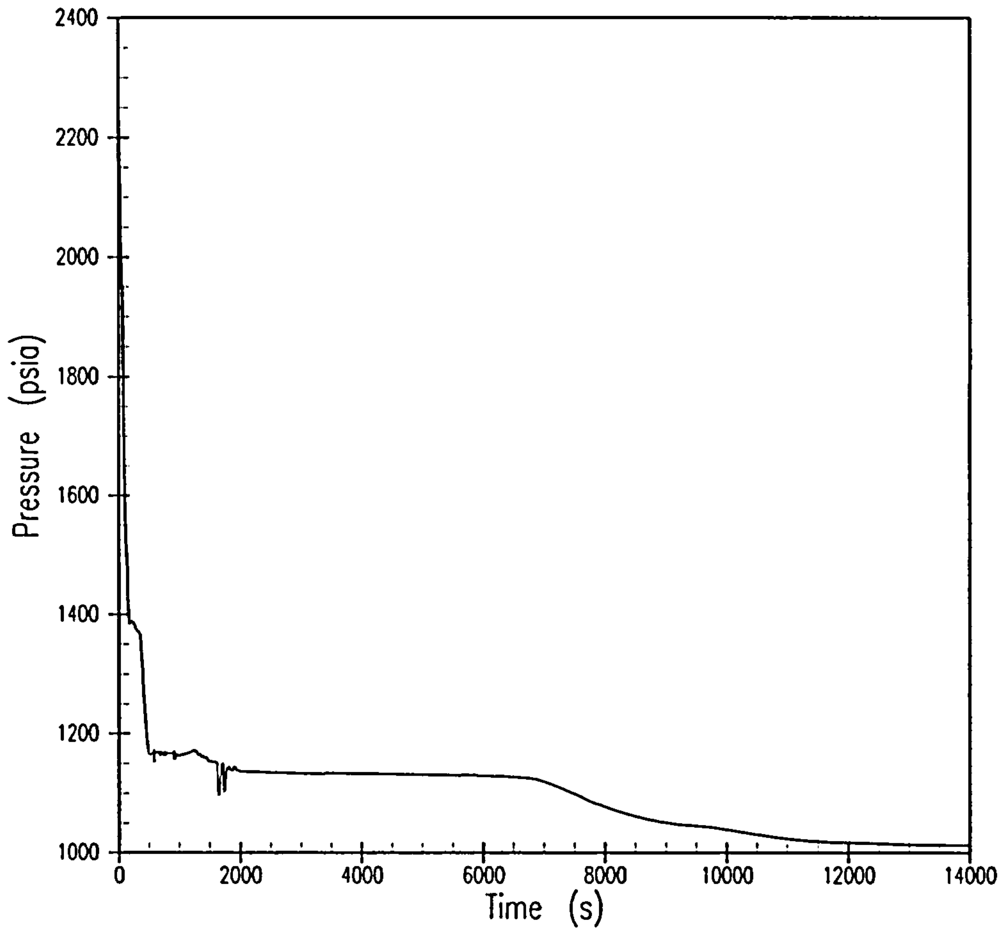


Figure 15A
BVPS-1 1.5-inch Break
RCS Pressure

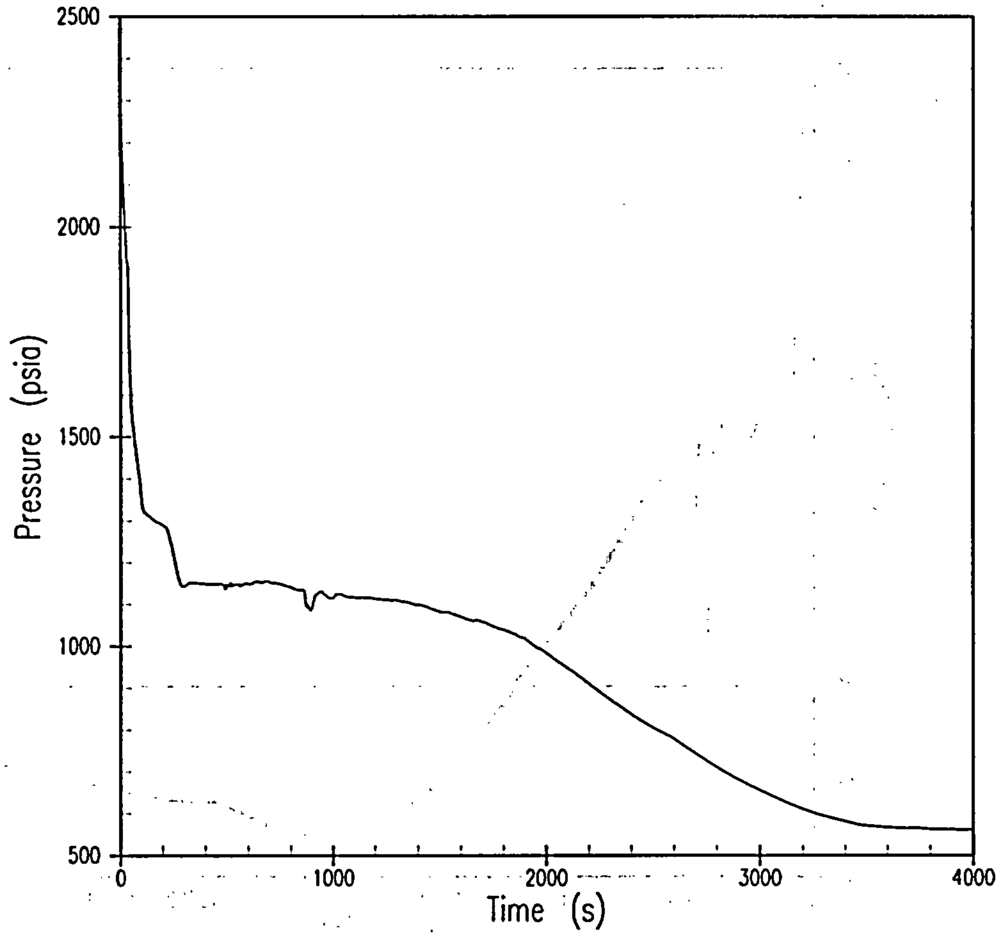


Figure 15B
BVPS-2 2-inch Break
RCS Pressure

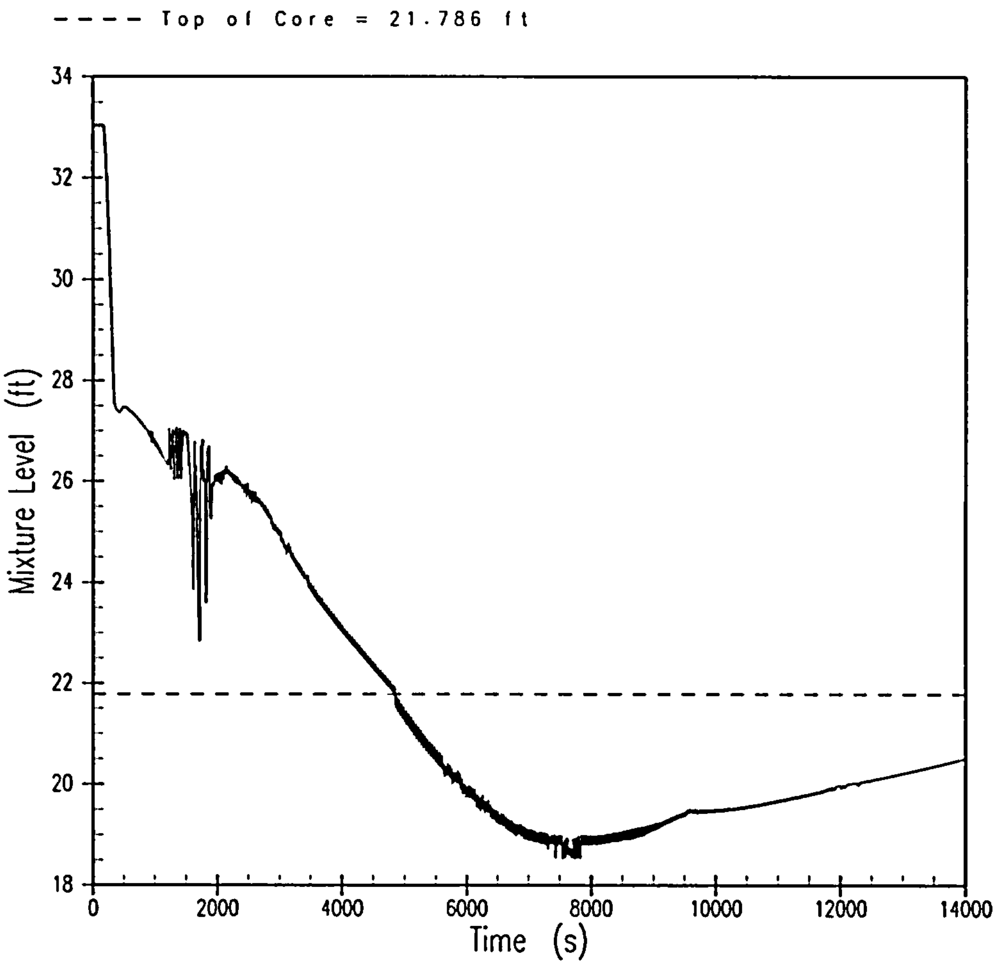


Figure 16A
BVPS-1 1.5-inch Break
Core Mixture Level

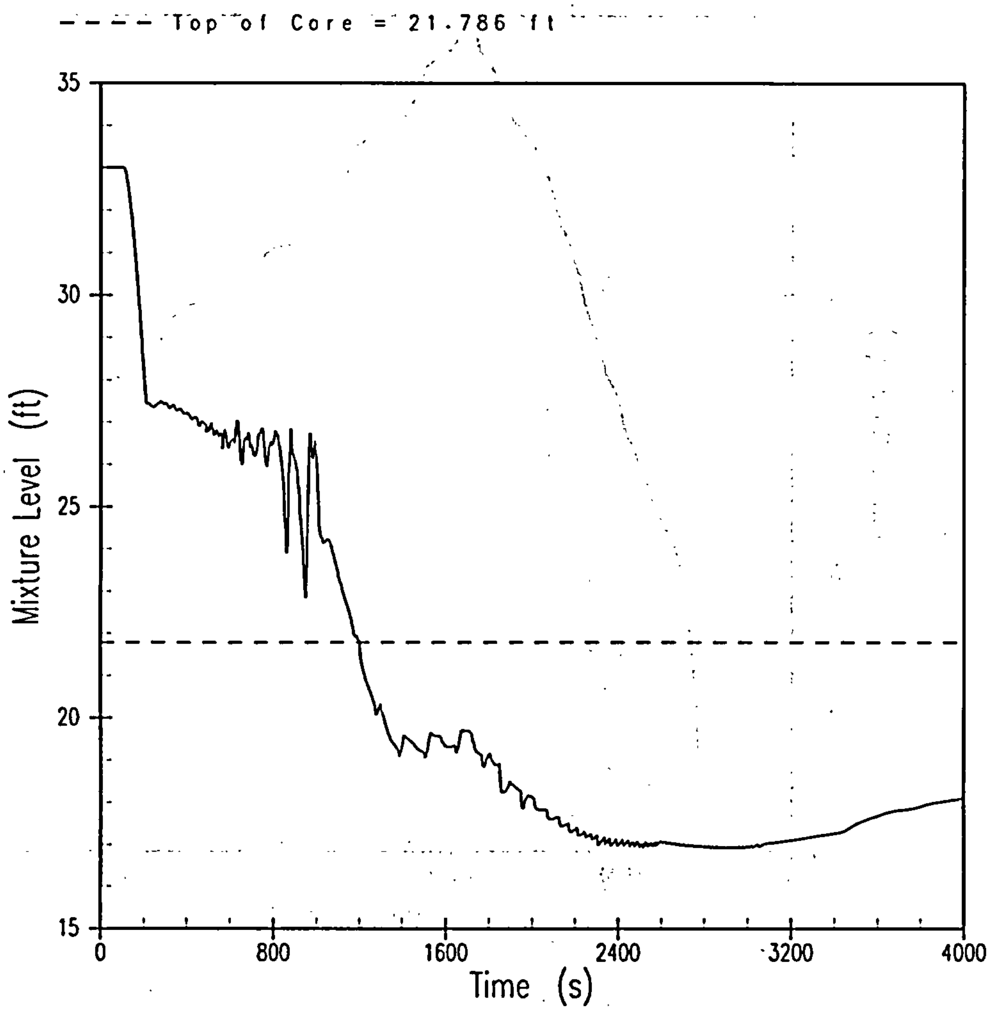


Figure 16B
BVPS-2 2-inch Break
Core Mixture Level

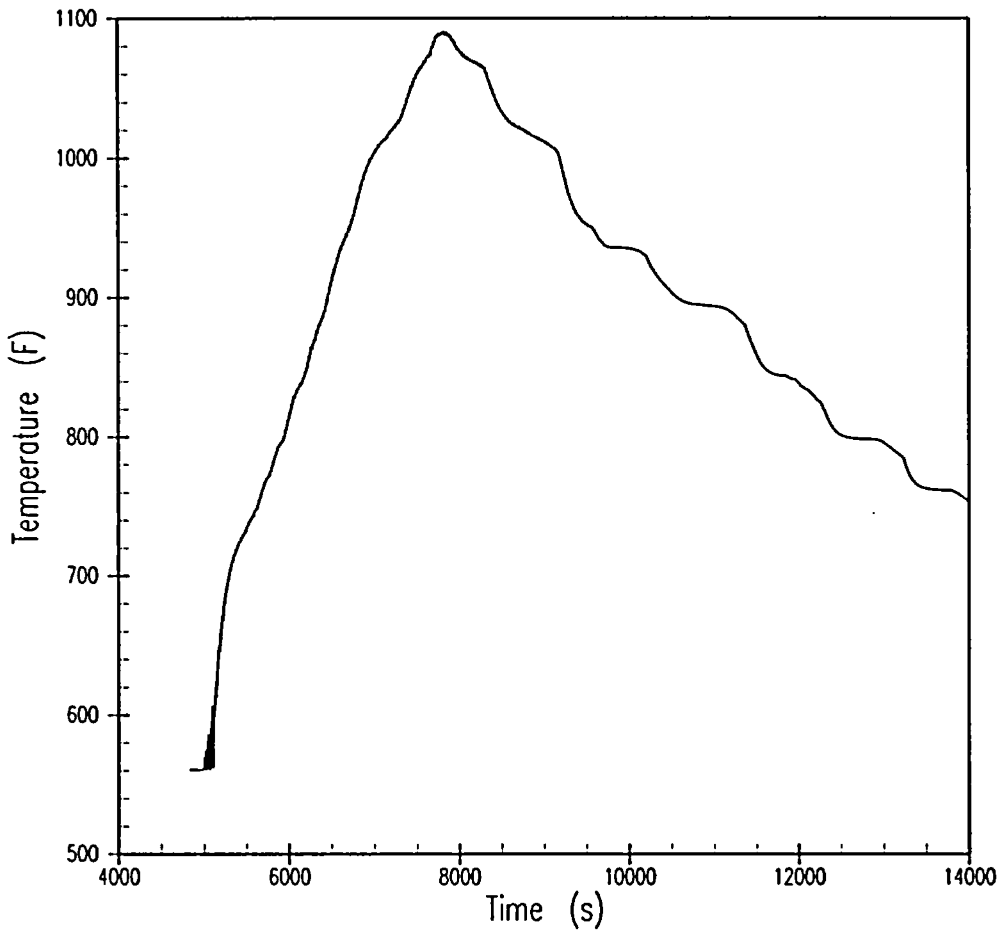


Figure 17A
BVPS-1 1.5-inch Break
Peak Clad Temperature

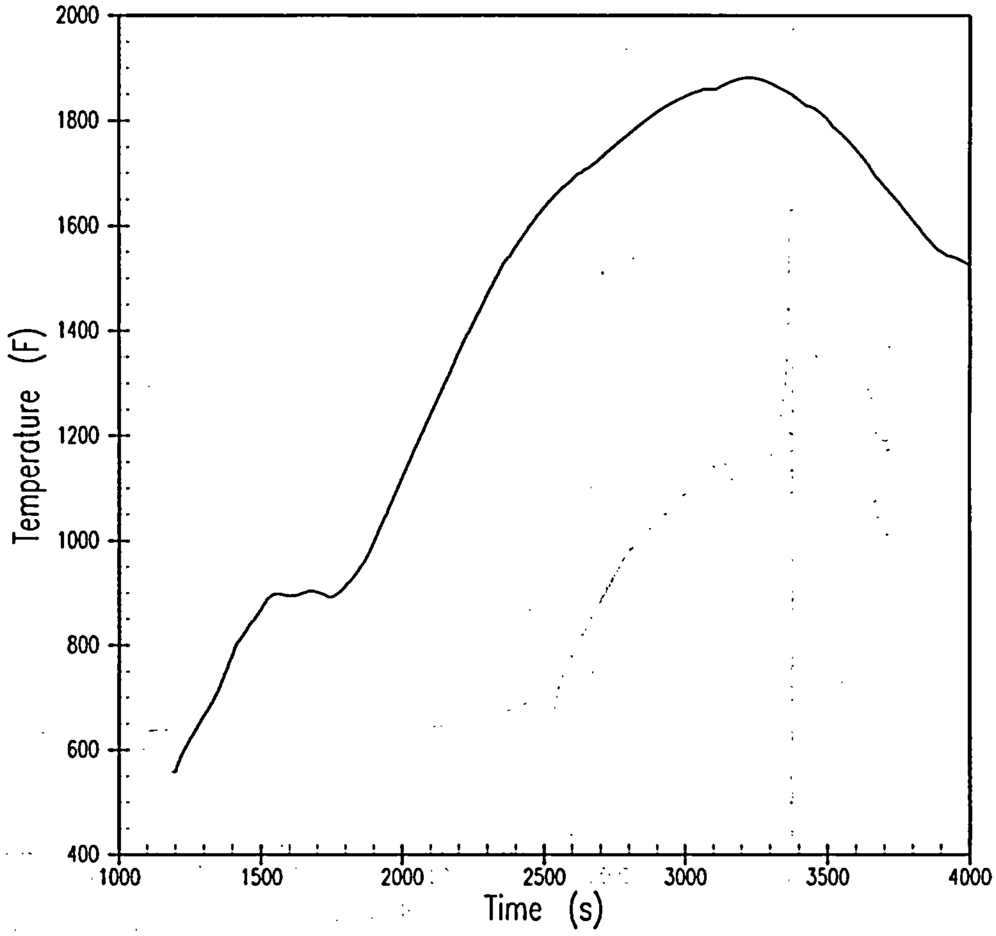


Figure 17B
BVPS-2 2-inch Break
Peak Clad Temperature

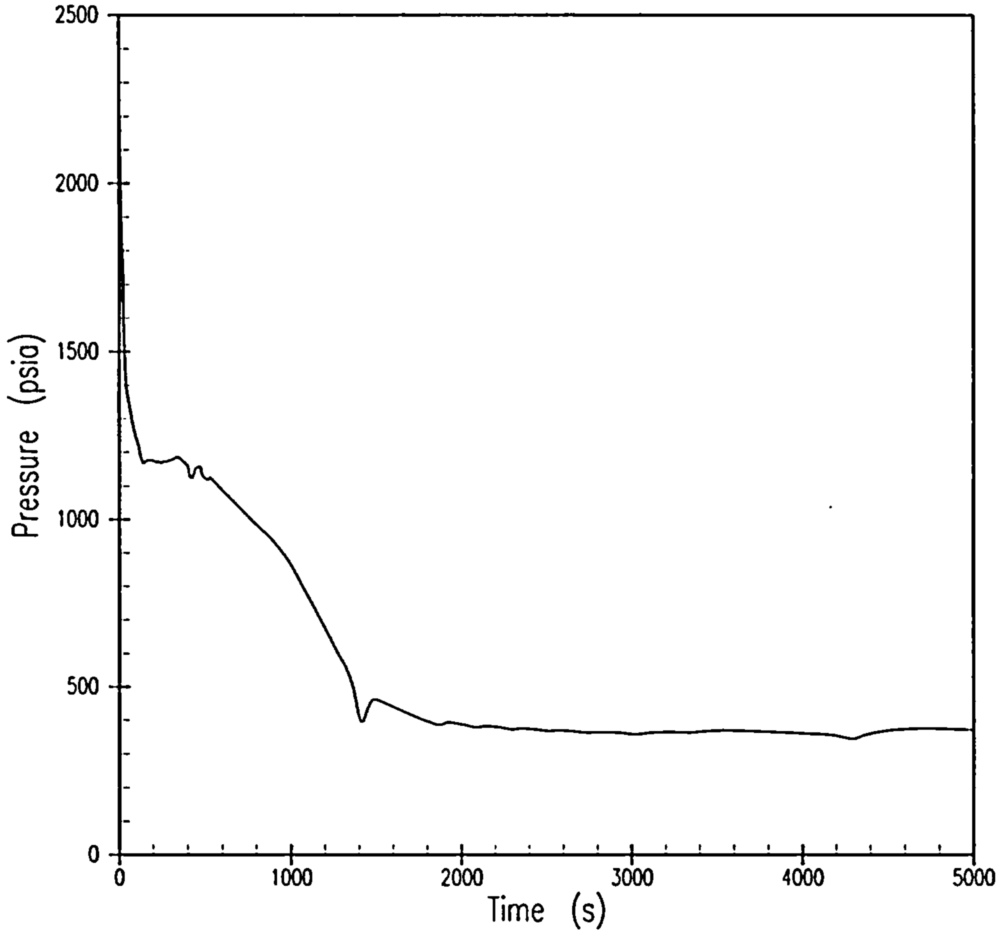


Figure 18A
BVPS-1 3-inch Break
RCS Pressure

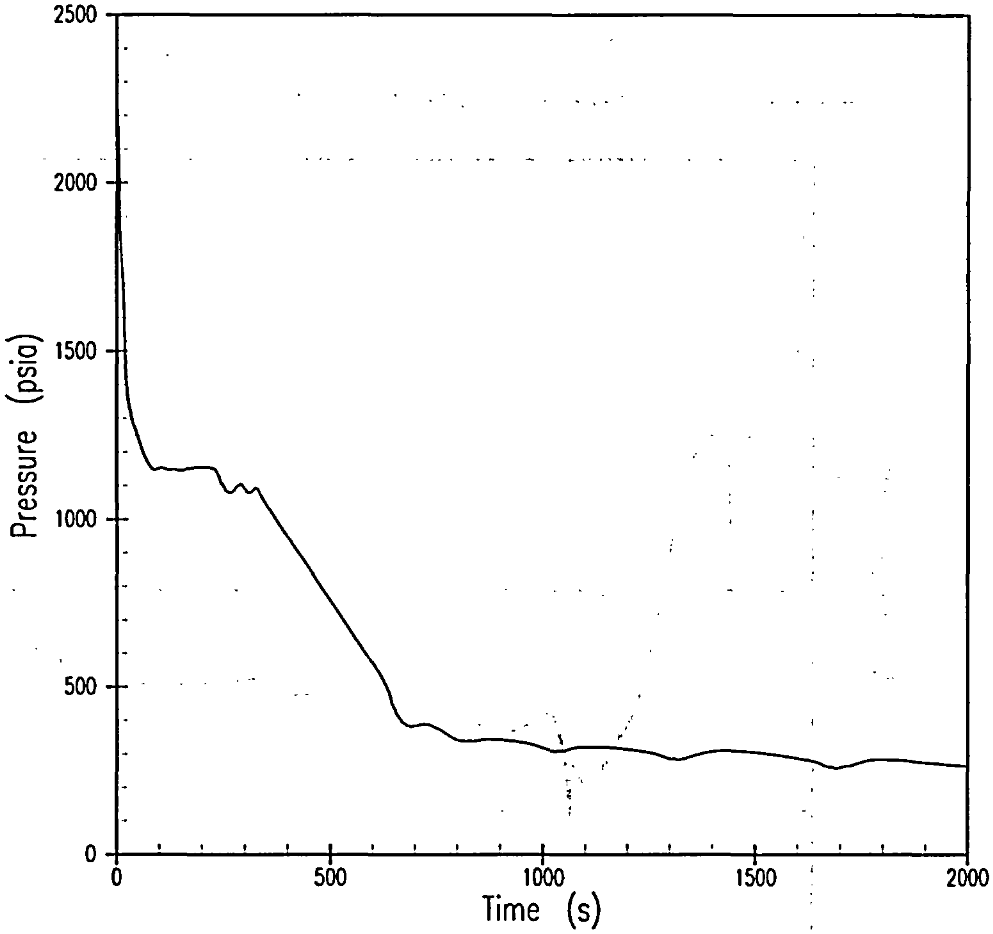


Figure 18B
BVPS-2 4-inch Break
RCS Pressure

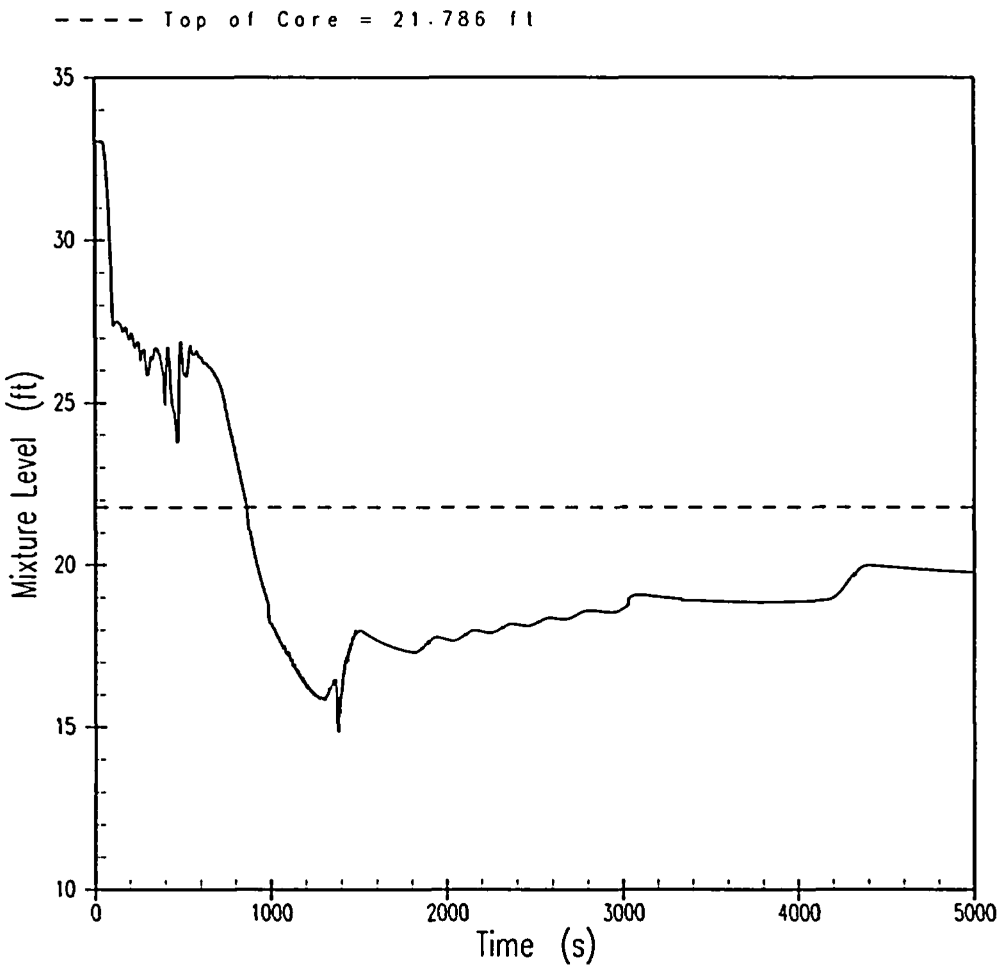


Figure 19A
BVPS-1 3-inch Break
Core Mixture Level

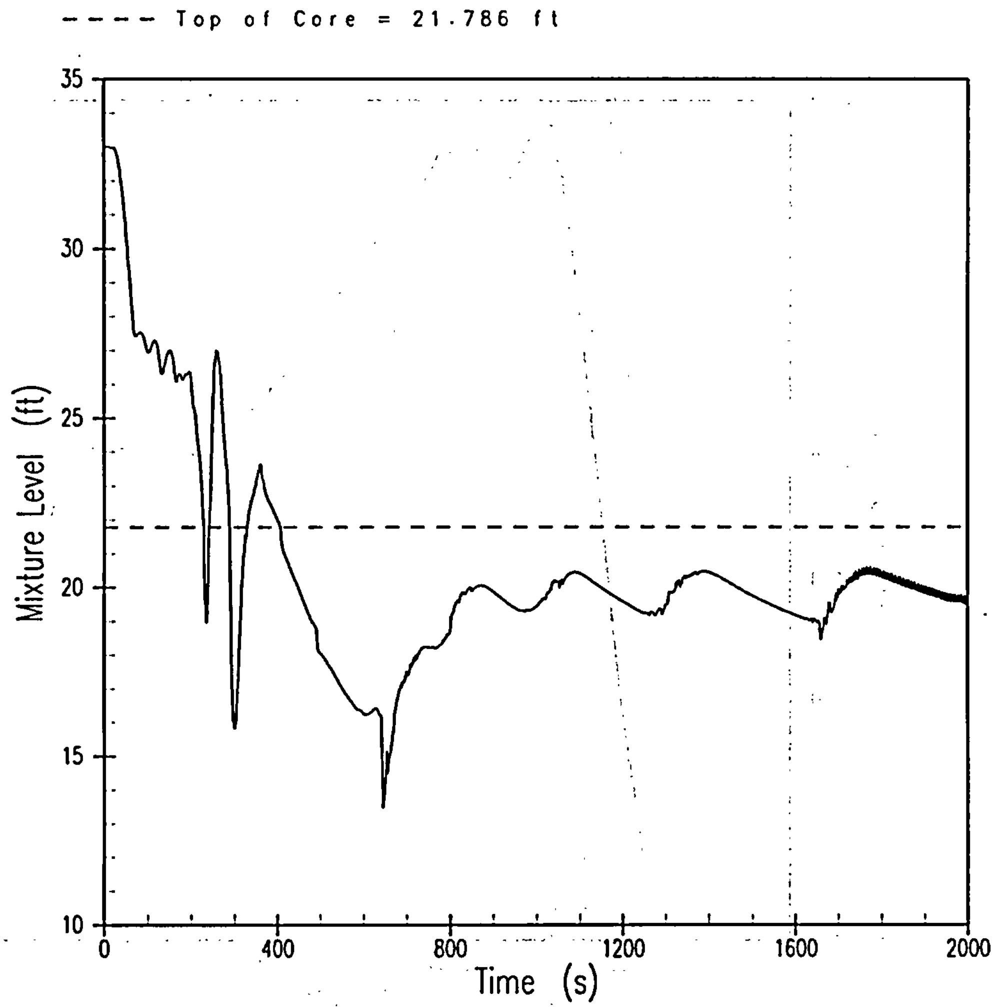


Figure 19B
BVPS-2 4-inch Break
Core Mixture Level

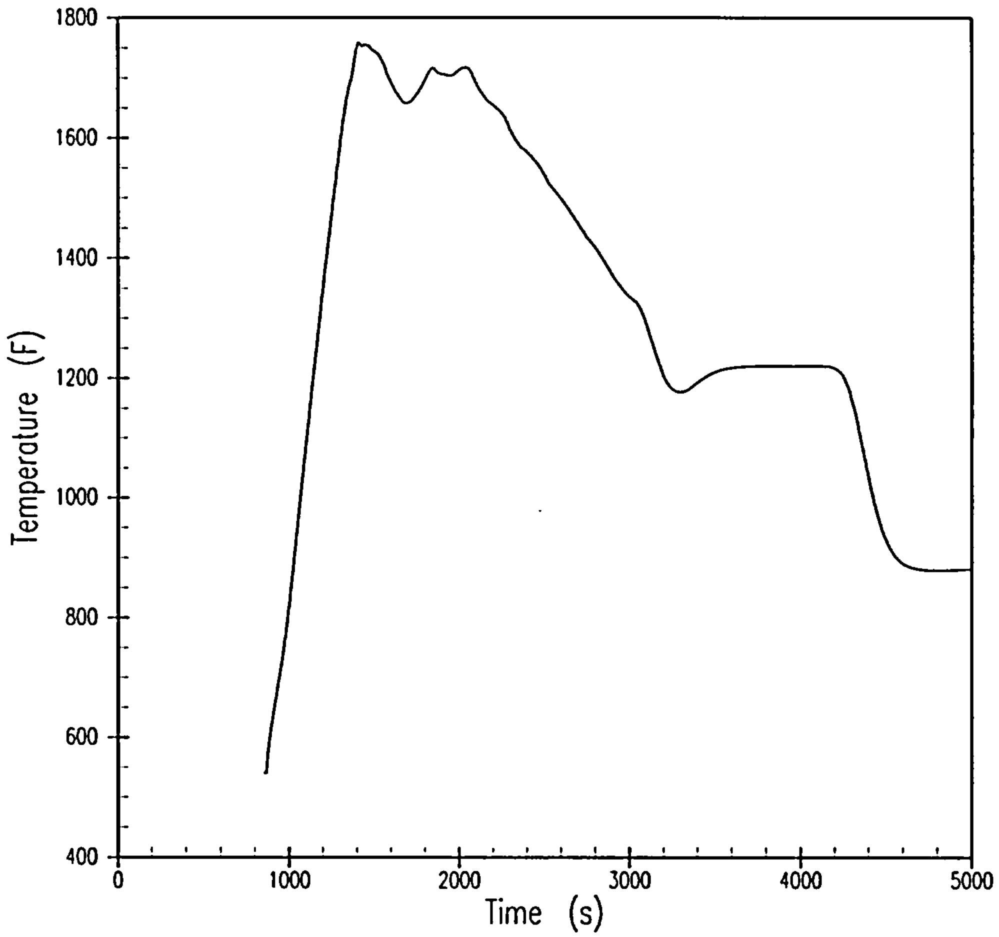


Figure 20A
BVPS-1 3-inch Break
Peak Clad Temperature

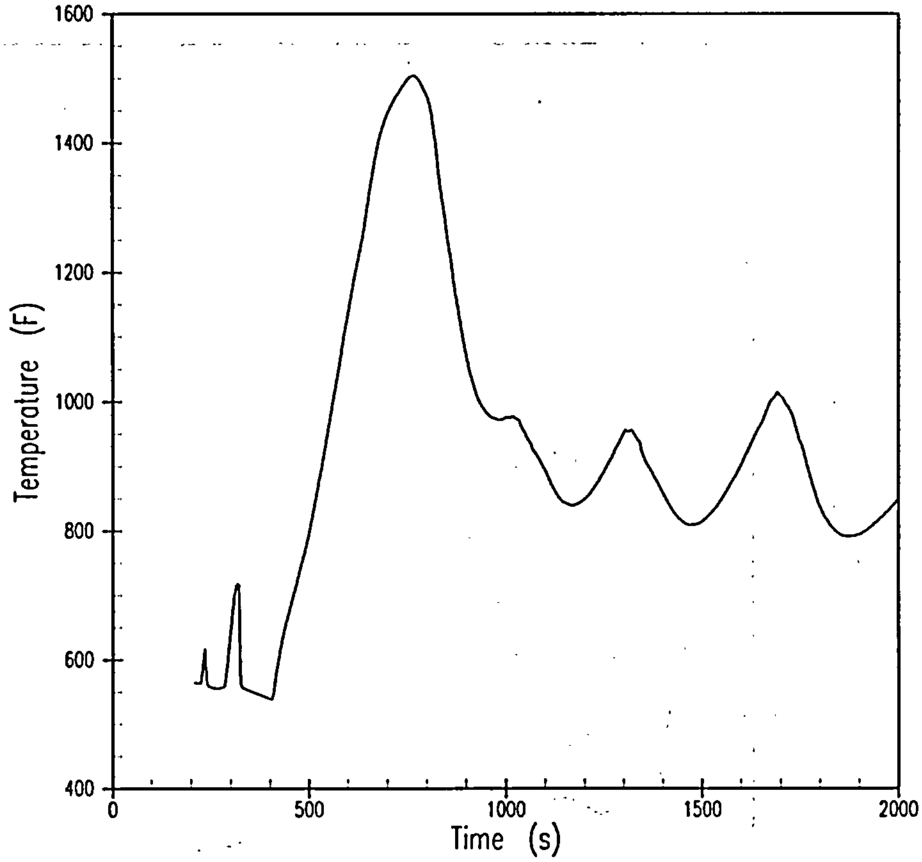


Figure 20B
BVPS-2 4-inch Break
Peak Clad Temperature

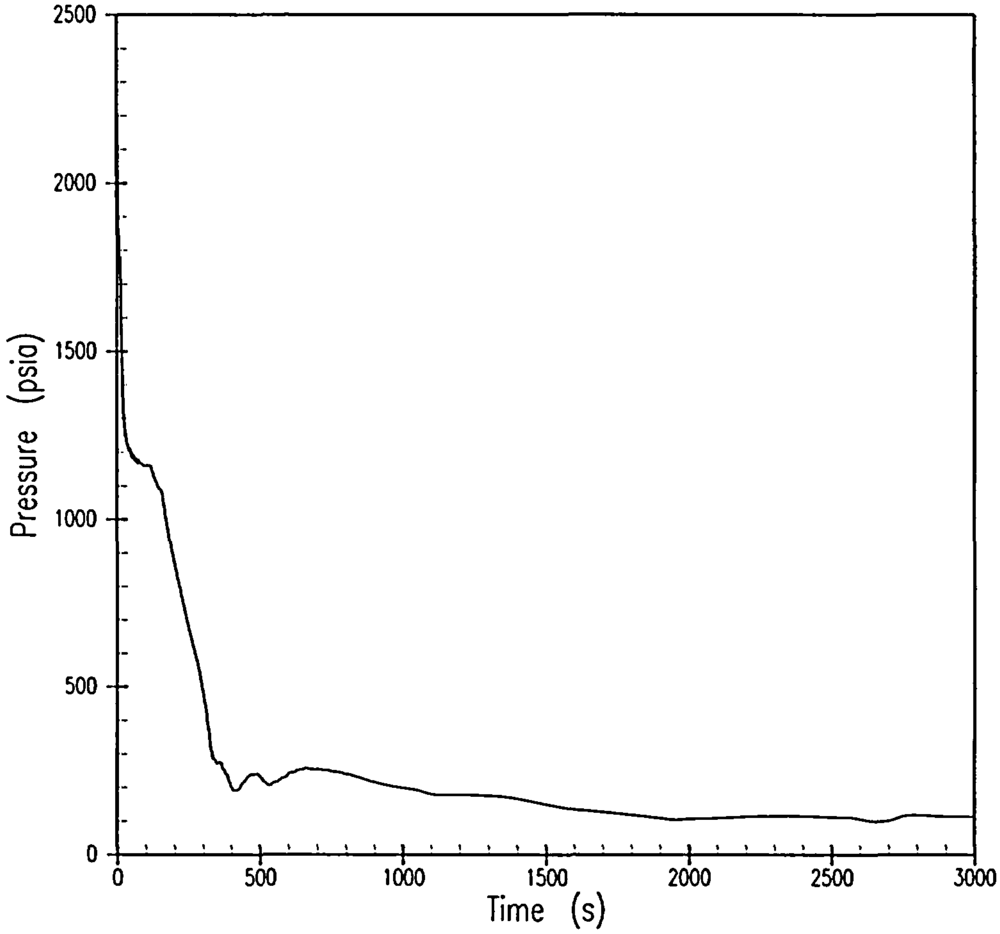


Figure 21A
BVPS-1 6-inch Break
RCS Pressure

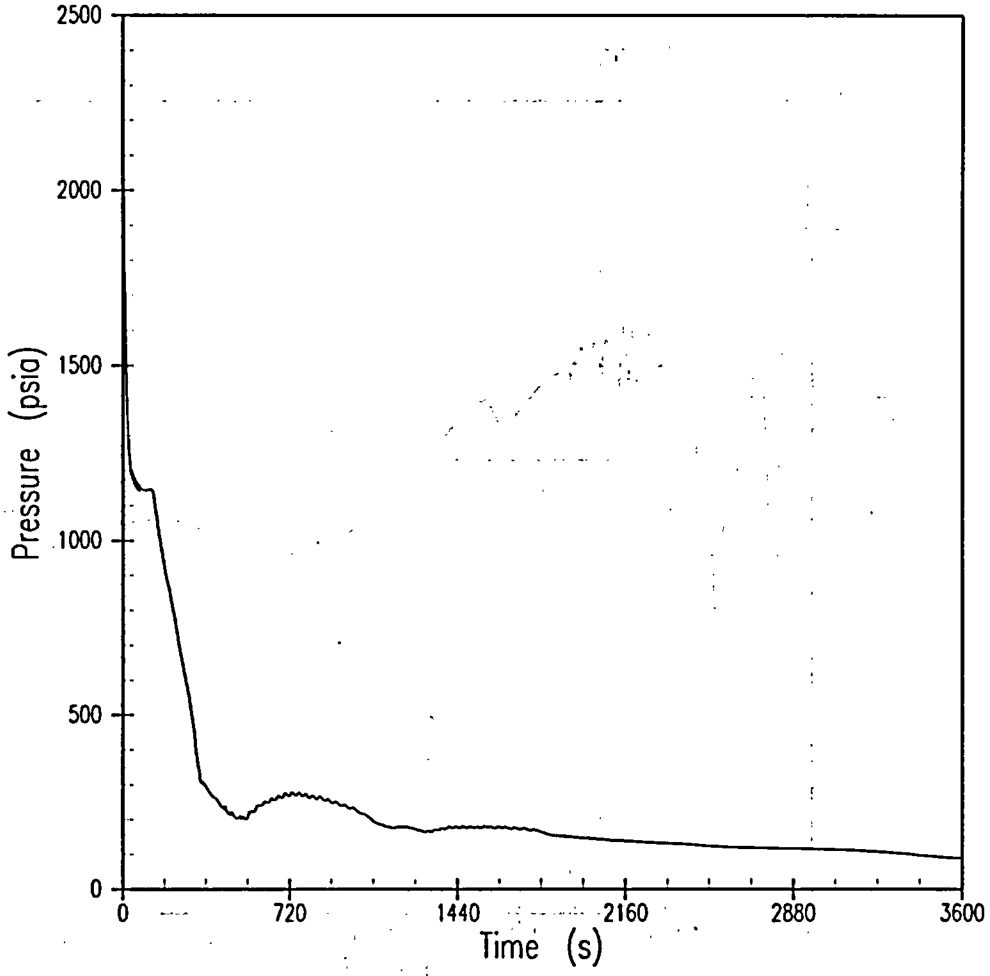


Figure 21B
BVPS-2 6-inch Break
RCS Pressure

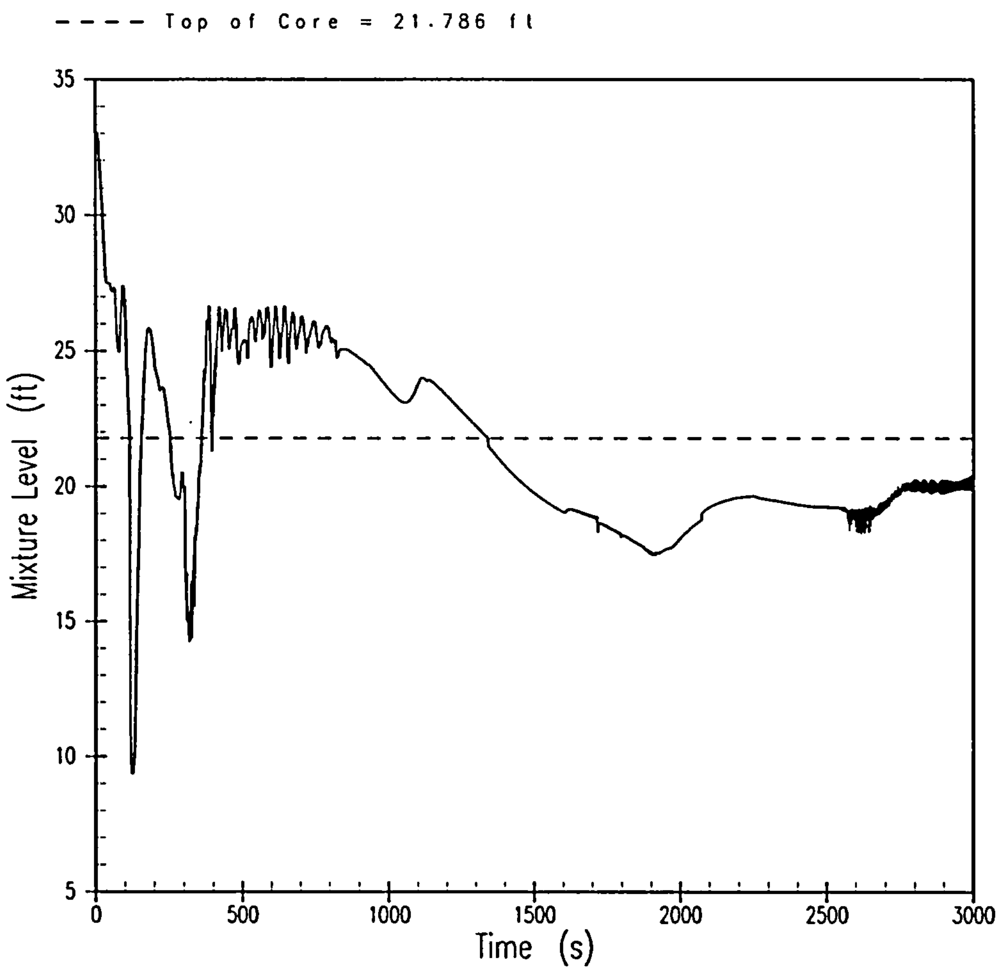


Figure 22A
BVPS-1 6-inch Break
Core Mixture Level

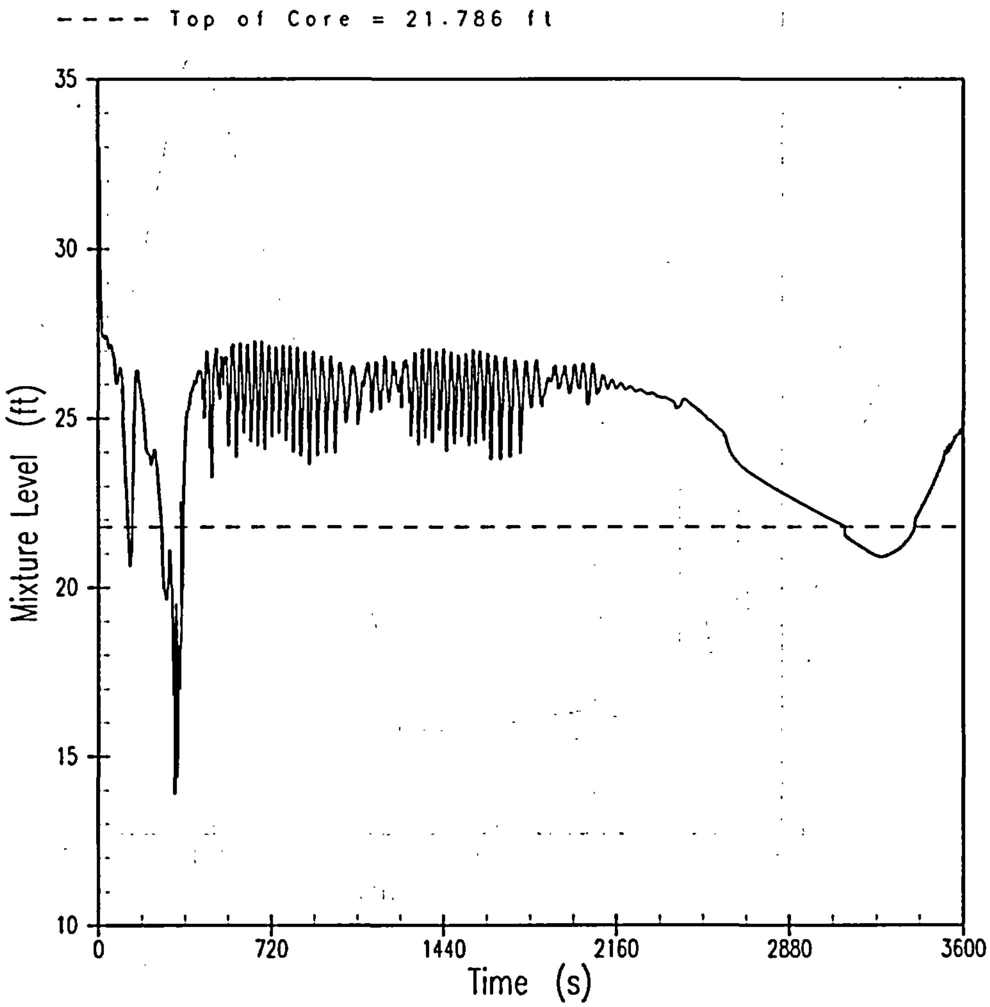


Figure 22B
BVPS-2 6-inch Break
Core Mixture Level

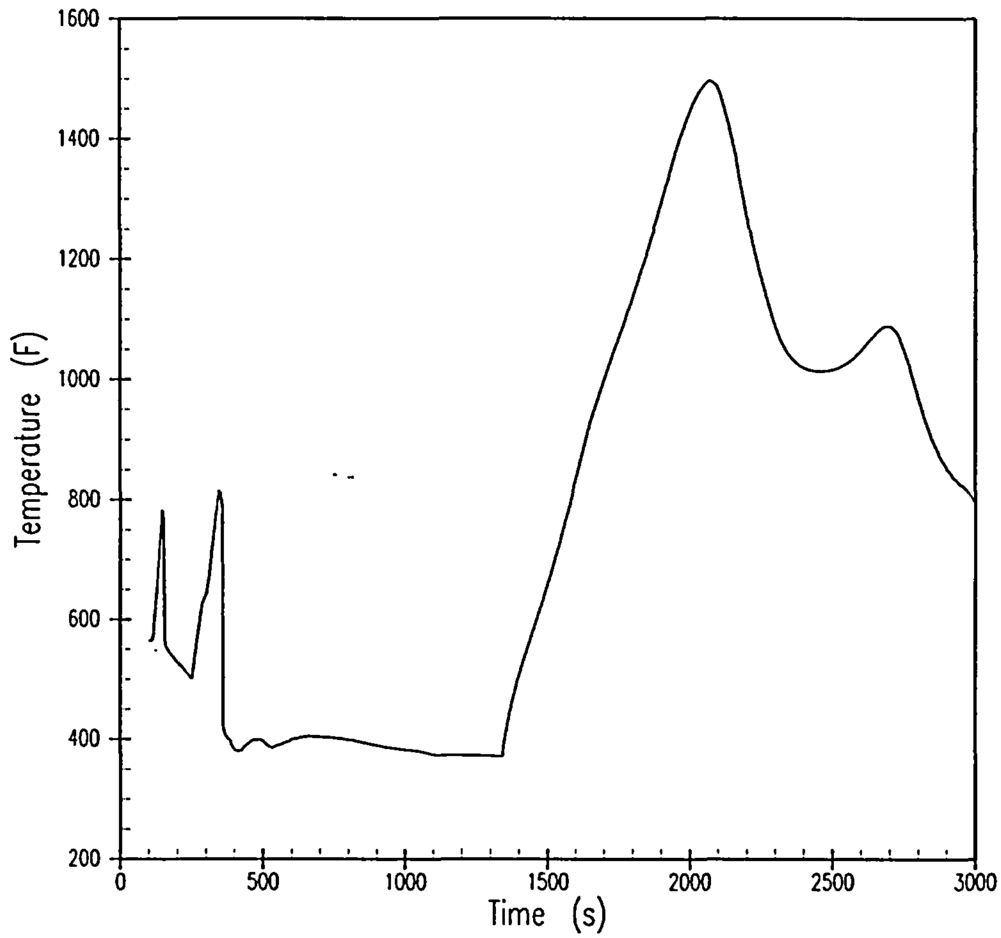


Figure 23A
BVPS-1 6-inch Break
Peak Clad Temperature

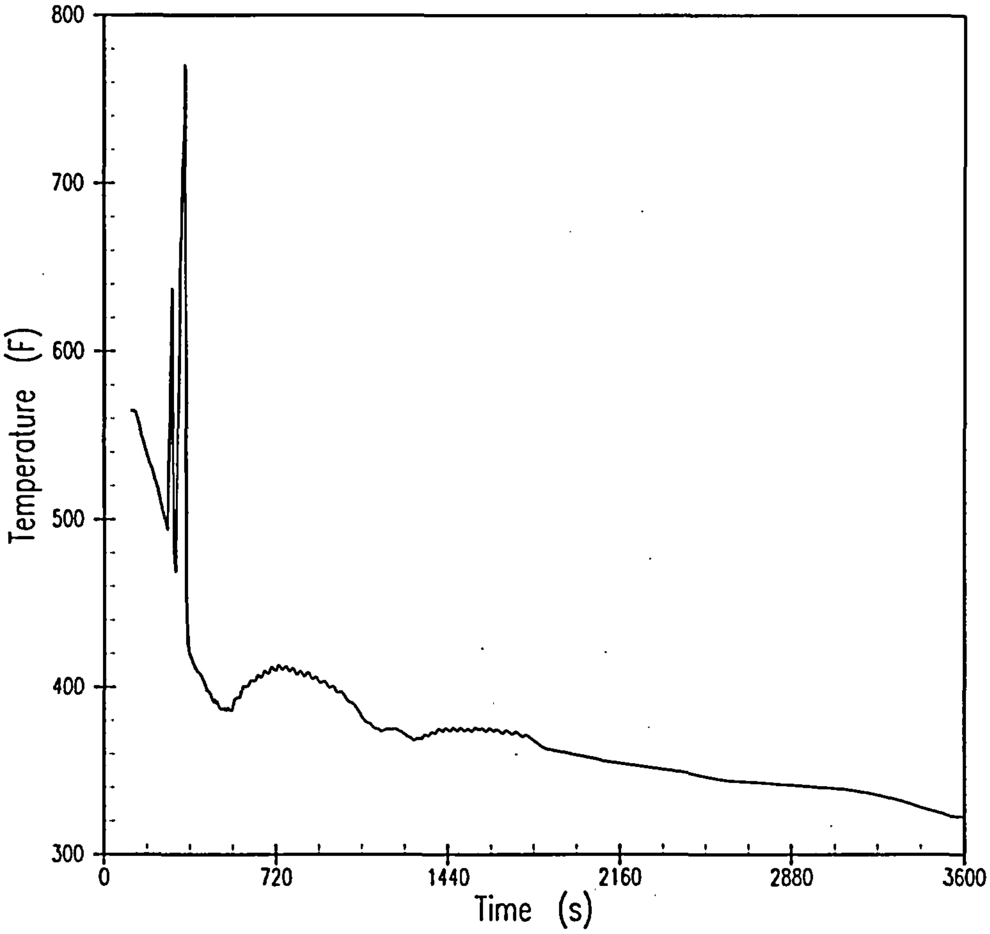


Figure 23B
BVPS-2 6-inch Break
Peak Clad Temperature

L-05-112 Enclosure 1, Attachment B

SUT-08, Semi-Scale Validation Simulation Test

See Enclosure 2, Attachment B, since Attachment B is entirely Proprietary.

L-05-112 Enclosure 2

Affidavit CAW-05-2021

Westinghouse

Westinghouse Electric Company
Nuclear Services
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Pittsburgh, Pennsylvania 15230-0355
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

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Direct fax: (412) 374-4011
e-mail: greshaja@westinghouse.com

Our ref: CAW-05-2021

July 1, 2005

APPLICATION FOR WITHHOLDING PROPRIETARY INFORMATION FROM PUBLIC DISCLOSURE

Subject: Responses to NRC EPU LOCA and LOCA Related RAIs and Hot Leg Switchover RAIs and Attachment B:

- LOCA Related: E.3, E.5, E.5a, E.6, E.7, E.9, E.9a, E.10, E.11, E.15, E.17, E.19, E.23, E24, E.26 , E27
- Hot Leg Switchover: F.1, F.2, F.7, F.10, F.12
- Attachment B " SUT-08 Semi-ScalScale Validation Simulation Test"

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-05-2021 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by FirstEnergy Nuclear Operating Company.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-05-2021, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: B. Benney
L. Feizollahi

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)
J. J. DeBlasio
R. Surman
S. Sarver (Beaver Valley)

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

PATRICIA L. CROWN COMMONWEALTH OF PENNSYLVANIA NOTARY PUBLIC

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed
before me this 7th day
of July, 2005

Patricia L. Crown
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Patricia L. Crown, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Feb. 7, 2009
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in "brackets" in EPU "Responses to NRC LOCA Related RAIs E.3, E.5, E.5a, E.6, E.7, E.9, E.9a, E.10, E.11, E.15, E.17, E.19, E.23, E24, E.26, E.27 and Hot Leg Switchover RAIs F.1, F.2, F.7, F.10, F.12" and Attachment B (Proprietary) dated July 1, 2005, for Beaver Valley Power Station, being transmitted by the FirstEnergy Nuclear Operating Company (FENOC) letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse for the Beaver Valley Units 1 and 2 is expected to be applicable for other licensee submittals in response to certain NRC requirements for LOCA & Hot Leg Switchover for EPU conditions.

This information is part of that which will enable Westinghouse to:

(a) Provide documentation of the calculation and methodology.

(b) Assist the customer in obtaining NRC approval by responding to NRC.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of LOCA and Hot Leg Switchover at EPU conditions.

(b) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design and licensing a similar product.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculations and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).