FENOC
FirstEnergy Nuclear Operating Company

James H. Lash
Site Vice President

724-682-5234
Fax: 724-643-8069

December 16, 2005
L-05-198

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
Supplemental Information for License Amendment Request Nos. 320 (Unit No. 1 TAC No. MC6725) and 302/173 (Unit No. 1 TAC No. MC4645/Unit No. 2 TAC No. MC4646)

On October 4, 2004, FirstEnergy Nuclear Operating Company (FENOC) submitted License Amendment Request (LAR) Nos. 302 and 173 by letter L-04-125 (Reference 1). 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 No. 320 for BVPS Unit No. 1 by letter L-05-069 (Reference 2). This submittal requested the Technical Specification changes necessary for operation of BVPS Unit No. 1 with the replacement steam generators and is known as the RSG LAR.

Enclosure 1 provides supplemental information that pertains to the RSG LAR and the EPU LAR relative to the Probabilistic Risk Assessment (PRA) Auxiliary Feedwater (AFW) System success criteria and AFW Technical Specification Bases changes.

Enclosure 2 provides supplemental information that pertains to the BVPS Unit No. 1 RSG and EPU LARs relative to the BVPS Unit No. 1 Pressurizer Safety Valves (PSVs). The supplemental information is the result of a review of the RSG and EPU submittals as described in the information provided in the enclosure.

The supplemental information provided in this transmittal has no impact on either the proposed Technical Specification changes or the no significant hazards consideration, transmitted by References 1 or 2. The regulatory commitments contained in this letter are listed in Enclosure 3.

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If you have questions or require additional information, please contact Mr. Gregory A. Dunn, Manager - Licensing, at 330-315-7243.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 16, 2005.

Sincerely,

JHLash

James H. Lash

Enclosures:
1. Probabilistic Risk Assessment (PRA) Auxiliary Feedwater (AFW) System Success Criteria and AFW Technical Specification Bases Changes
2. Pressurizer Safety Valve (PSV) Flow Capacity
3. List of Commitments

References:

1. FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.
2. FENOC Letter L-05-069, License Amendment Request 320, dated April 13, 2005.

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

Enclosure 1 of L-05-198

Probabilistic Risk Assessment (PRA) Auxiliary Feedwater (AFW) System Success Criteria and AFW Technical Specification Bases Changes

Reason for the contained supplemental information:

During teleconferences on November 29, 2005, and December 8, 2005, the NRC staff requested additional clarification concerning the Probabilistic Risk Assessment (PRA) success criteria for the Auxiliary Feedwater (AFW) System. In addition, the NRC requested FENOC modify the AFW Technical Specification Bases to include a justification of the 72 hour allowed outage time (AOT) and the discussion of the realistic assessment that demonstrates that only one motor-driven AFW pump is required to mitigate the Loss of Normal Feedwater event.

Supplemental Information:

Realistic assessments for a Loss of Normal Feedwater event were performed for Beaver Valley Power Station Unit No. 1 (BVPS-1) and Beaver Valley Power Station Unit No. 2 (BVPS-2) in support of Emergency Operating Procedures (EOP) setpoint development for Extended Power Uprate (EPU) and Replacement Steam Generators (RSG) for conditions related to the minimum AFW flow required to maintain a secondary heat sink. This assessment was performed using the Westinghouse LOFTRAN non-LOCA code. The results showed that the minimum AFW flow required was less than the capacity of one motor-driven pump assuming realistic conditions with either the condenser steam dump valves or the atmospheric steam dump valves available. In this assessment, flow was assumed to be delivered to all three steam generators.

Additionally, a best estimate analysis was performed using MAAP for both BVPS-1 and BVPS-2 to determine the Probabilistic Risk Assessment (PRA) success criteria for the post-EPU Loss of Normal Feedwater. The BVPS-1 analysis also included the RSG, since the post-EPU steam generator low-low level reactor trip setpoint would result in less secondary water inventory. Two cases were run for each unit. The first case used the EPU Technical Specification steam generator water level low-low reactor trip setpoint allowable value. These values are 19.1% of the narrow range instrument span at BVPS-1, and 20.0% of the narrow range instrument span at BVPS-2. These are considered the best estimate cases. The second case involved a sensitivity case, which used a steam generator water level low-low reactor trip setpoint corresponding to 0% of the narrow range instrument span for both BVPS-1 and BVPS-2. For all cases, the Reactor Coolant Pumps (RCPs) were not tripped, and one motor-driven AFW pump was used to deliver a maximum flow of 310 gpm to the steam generators based on the installed cavitating venturis.

The results of these best estimate MAAP analyses show that the pre-EPU and post-EPU PRA transient and the Small Break Loss of Coolant Accident (SBLOCA) success criteria of one AFW pump to one steam generator at BVPS-1 and one AFW pump to two steam generators at BVPS-2 remain valid for the Loss of Normal Feedwater transients. It should be noted that the success criteria requirement for two steam generators at BVPS-2 is due to the smaller capacity of the atmospheric steam dump valves and is based on a SBLOCA with failure of High Head Safety Injection (HHSI), which requires a maximum cooldown of the RCS for accumulator and Low Head Safety Injection (LHSI) pump injection. For all cases, the minimum wide range steam generator level remained above the EOP setpoint for initiating feed and bleed cooling (14% of the wide range instrument span at BVPS-1 and 13% of the wide range instrument span at BVPS-2). A summary of the best estimate MAAP analyses results is presented in Table 1-1.

Table 1-1: PRA Best Estimate MAAP Results for Loss of Main Feedwater AFW Success Criteria							
	SG Low-Low Level Reactor Trip Setpoint (% Narrow Range)	Time of SG Low-Low Level Reactor Trip (seconds)	Number of Motor-Driven AFW Pumps	Number of Steam Generators	Minimum SG Level (% Wide Range)	Time that SG Narrow Range Level Comes Back on Scale (hrs)	Time to Recover SG Nominal Level (hrs)
BVPS-1 Case 1	19.1	46.2	1	1	19.1	4.1	6.2
BVPS-1 Case 2	0	47.4	1	1	18.0	4.2	6.4
BVPS-2 Case 1	20	23.5	1	2	39.0	2.8	5.2
BVPS-2 Case 2	0	36.3	1	2	26.4	3.7	5.9

Conclusion:

As per the NRC request, FENOC will modify the AFW Technical Specification Bases to include a justification of the 72 hour AOT and the discussion of the realistic assessment that demonstrates that only one motor-driven AFW pump is required. The additional wording for the AFW Technical Specification Bases, to be incorporated when the amendments are implemented, is provided below:

"With one inoperable AFW pump, the remaining two AFW pumps will be aligned to separate redundant headers capable of supplying flow to each steam generator.

A realistic analyses of a loss of normal feedwater event demonstrates that one motor-driven AFW pump will maintain sufficient steam generator inventory to provide a secondary heat sink and prevent the RCS from exceeding applicable pressure and temperature limits.

For BVPS-1, the licensing basis has changed to a requirement for two of three AFW pumps to meet the flow requirements for the limiting DBAs. This change was necessitated by the installation of cavitating venturis in the AFW injection paths. The venturis protect the AFW pumps from runout conditions and allow for flow to be directed to the intact steam generators during a FWLB. Cavitating venturis in each individual injection path to the steam generators ensure that sufficient flow will be delivered to the two intact steam generators during a FWLB. Since no single failures are assumed to occur while in an AOT, adequate flow can be supplied by the two operable AFW pumps. Based on this, the AOT of 72 hours continues to remain applicable. This change to the BVPS-1 licensing basis is consistent with the original licensing basis for BVPS-2."

Enclosure 2 of L-05-198

Pressurizer Safety Valve (PSV) Flow Capacity

Reason for the contained supplemental information:

In support of a maintenance initiative program to upgrade the BVPS-1 pressurizer safety valves due to consideration for parts availability and obsolescence, a review of replacement options for the BVPS-1 PSVs was performed. As part of this review, a comparison was made between the BVPS-1 and BVPS-2 PSVs, and a discrepancy was identified for the BVPS-1 PSVs that affects assumed valve performance within selected safety analyses. The discrepancy was in the minimum valve flow capacity at rated pressure. For the EPU LAR, a calculated PSV flow capacity was used in selected plant safety analyses based on the valve flow orifice diameter. This capacity was greater than the rated PSV flow capacity. It was determined that the BVPS-1 PSV design uses a more limiting flow area than what is calculated based on the valve orifice diameter. The discrepancy results in a lower PSV flow capacity than assumed in selected EPU BVPS-1 safety analyses.

As a result, selected EPU non-LOCA transients were re-analyzed to demonstrate continued acceptable reactor coolant and main steam system overpressure protection. Specifically, the Loss of External Load and/or Turbine Trip event and the Single Reactor Coolant Pump Locked Rotor event were re-analyzed. The re-analyses results are applicable to the BVPS-1 RSG and EPU LARs.

The subject re-analyses and associated calculations were completed and available at the time of the NRC safety analysis calculation note audit that was held in November 2005.

Supplemental Information:

A review of the BVPS-1 RSG and EPU Licensing Reports and FENOC responses to NRC's Request for Additional Information (RAIs) relative to the RSG and EPU LARs was conducted to identify necessary changes as a result of the re-analysis. Since the RSG Licensing Report and the EPU Licensing Report are affected, revised pages for the RSG and EPU Licensing Reports are provided in the Attachments to Enclosure 2. Table 2-1 lists the affected pages for the RSG and EPU Licensing Reports along with a discussion pertaining to the changed items. Attachment A of Enclosure 2 provides the revised pages of the RSG Licensing Report, and Attachment B of Enclosure 2 provides the revised pages of the EPU Licensing Report.

Conclusion:

The identified discrepancy was entered into the BVPS Corrective Action Program and evaluated for impact. The identified changes do not impact the conclusions drawn in the applicable EPU safety analysis, do not require a change to the Technical Specifications and do not invalidate the no significant hazards consideration submitted by References 2-1 or 2-2. The proposed changes have been provided to reflect the revised calculations and the corresponding reanalysis.

Table 2-1 Affected RSG and EPU Licensing Report Pages		
RSG Page	**EPU Page**	**Discussion**
RSG & EPU Section 5.3.6, Loss Of External Electrical Load and/or Turbine Trip		
5-79	5-124	Updated peak pressure location and data provided in Table 5.3.6-1A
N/A	5-125	Updated peak pressure location and data provided in Table 5.3.6-1B
5-80	5-126	Replace existing Figure 5.3.6-1A with new figure
5-81	5-128	Replace existing Figure 5.3.6-2A with new figure
5-82	5-130	Replace existing Figure 5.3.6-3A with new figure
5-83	5-132	Replace existing Figure 5.3.6-4A with new figure
5-84	5-134	Replace existing Figure 5.3.6-5A with new figure
5-85	5-136	Replace existing Figure 5.3.6-6A with new figure
5-86	5-138	Replace existing Figure 5.3.6-7A with new figure
5-87	5-140	Replace existing Figure 5.3.6-8A with new figure
RSG & EPU Section 5.3.15, Single Reactor Coolant Pump Locked Rotor		
5-156	5-240	Updated data presented in Tables 5.3.15-1 and 5.3.15-2
5-157	5-241	Replace existing Figure 5.3.15-1A with new figure
5-158	5-243	Replace existing Figure 5.3.15-2A with new figure
5-159	5-245	Replace existing Figure 5.3.15-3A with new figure
5-160	5-247	Replace existing Figure 5.3.15-4A with new figure
RSG & EPU Section 5.3.20, Summary		
5-185	5-307	Updated data presented in Table 5.3.20-1A
5-186	5-309	Updated data presented in Table 5.3.20-2A
EPU Section 9.1.3.6, RCS Design Calculations		
N/A	9-5	Updated statement to reflect that there are several limits used in RCS maximum pressure analyses
N/A	9-6	Updated statement to reflect the applicable safety analyses report sections that address reactor coolant and main steam system overpressure protection

Enclosure 2 References

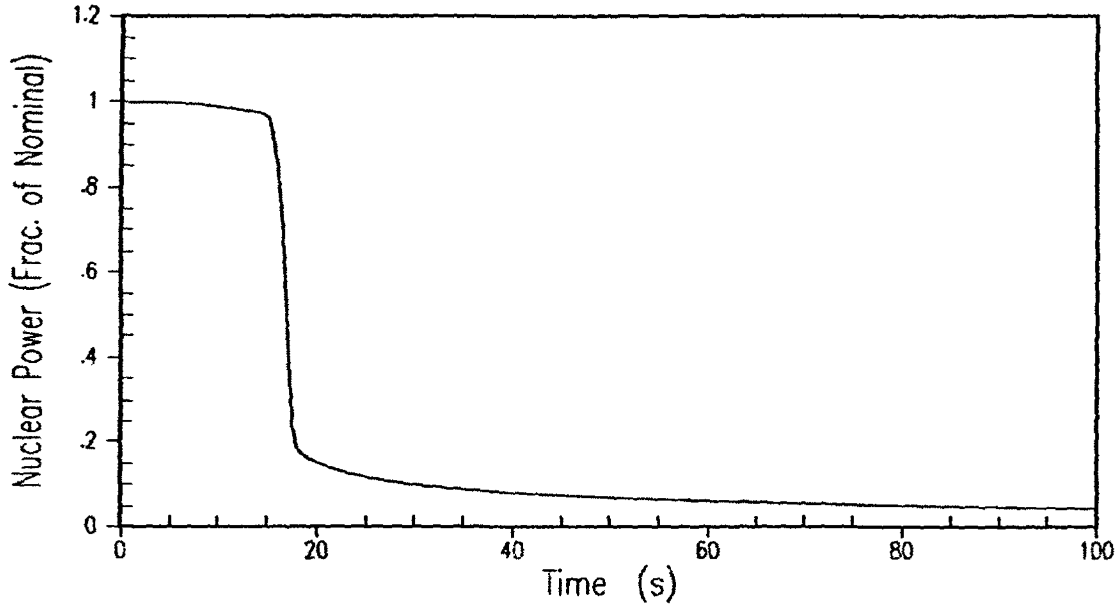
2-1 FENOC Letter L-05-069, License Amendment Request 320, dated April 13, 2005.

2-2 FENOC Letter L-04-125, License Amendment Requests 302 and 173, dated October 4, 2004.

Attachment A of Enclosure 2 of L-05-198

RSG Licensing Report - Revised Pages

Table 5.3.6-1A BVPS-1 Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip		
Case	**Event**	**Time (Sec)**
With pressurizer pressure control (minimum reactivity feedback-DNB Case)	Loss of Electrical Load/Turbine Trip	0.0
	Overtemperature ΔT Reactor Trip Setpoint reached	12.3
	Rods begin to drop	14.3
	Minimum DNBR occurs	15.6
Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.5
	Rods begin to drop	7.5
	Peak ~~pressurizer~~ RCS pressure occurs	~~8.2~~ 8.3



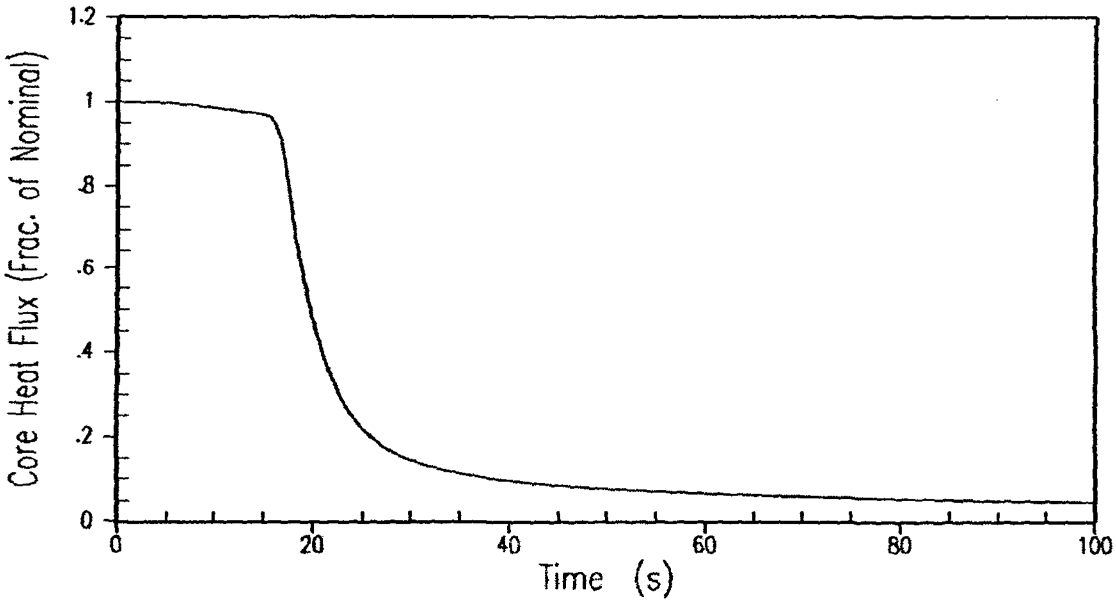
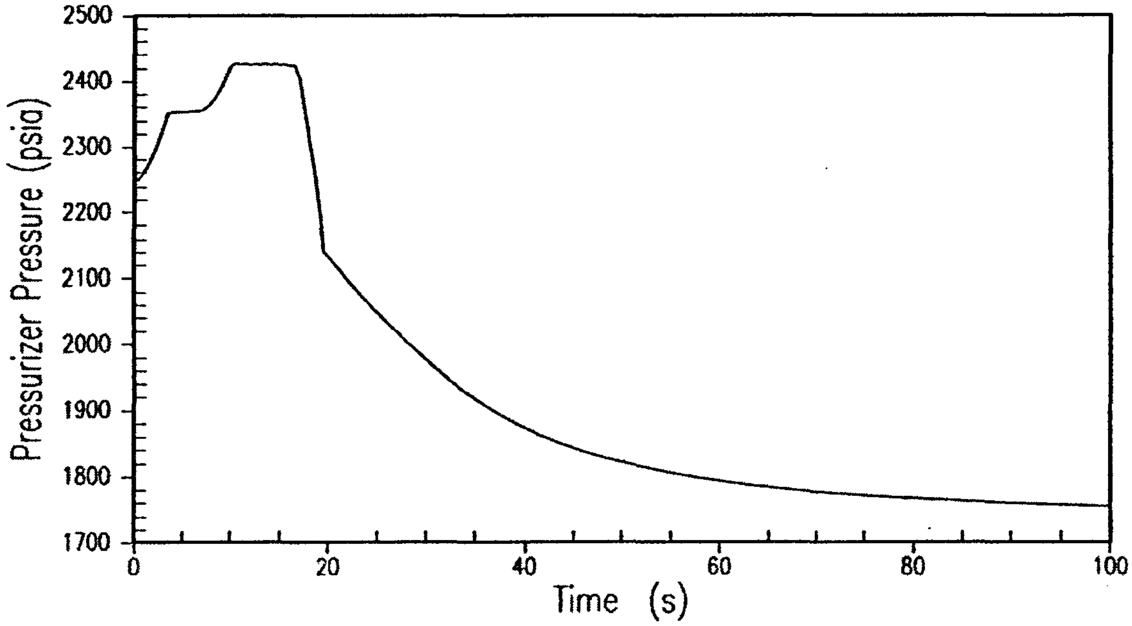


Figure 5.3.6-1A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Nuclear Power and Core Heat Flux versus Time



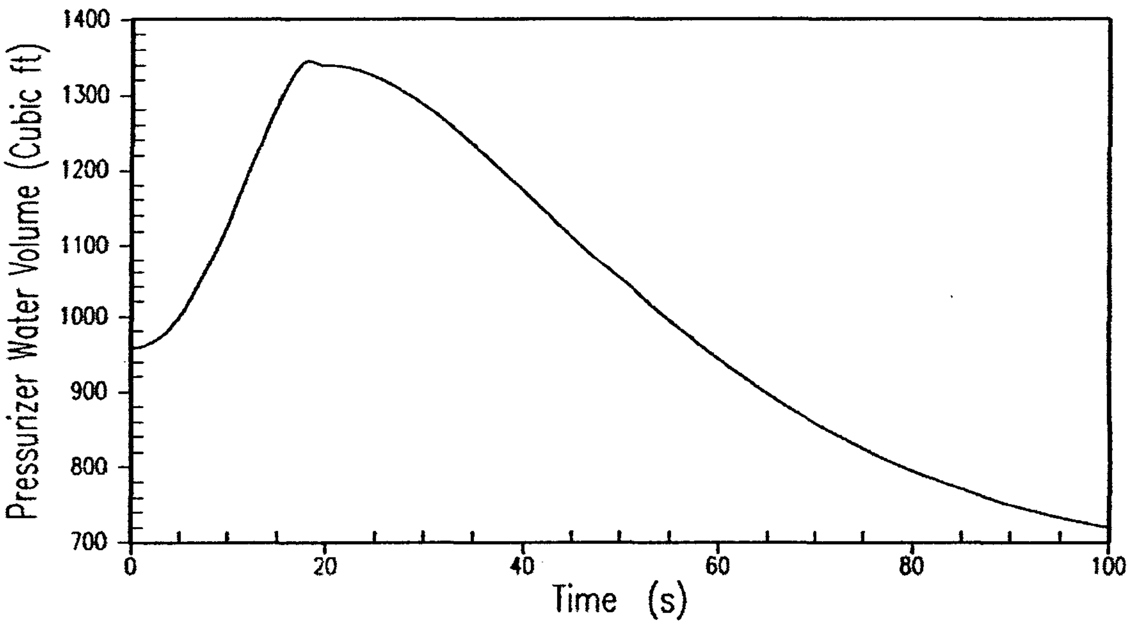
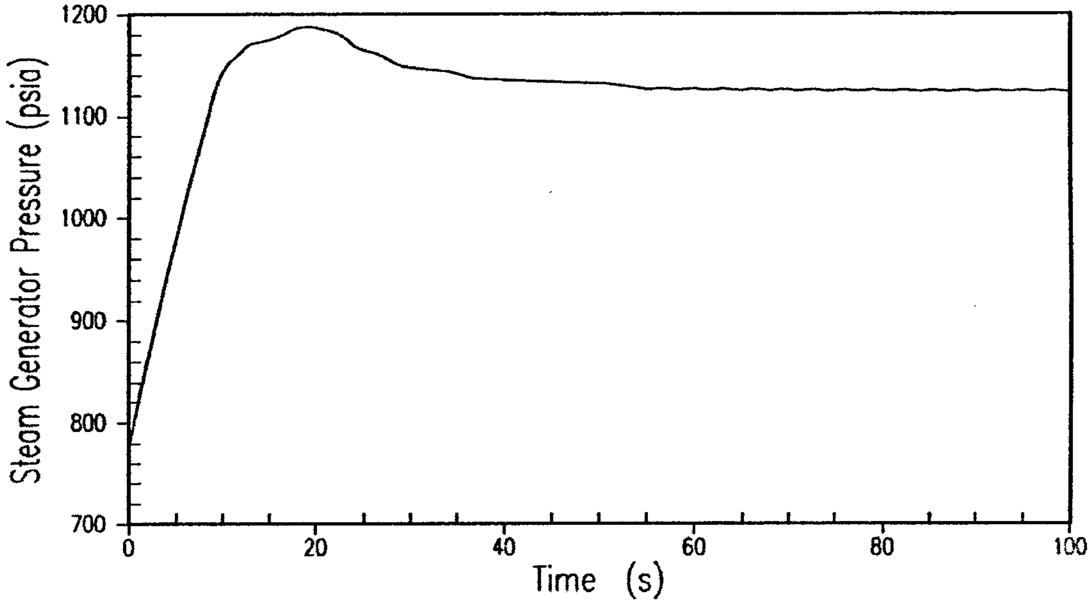


Figure 5.3.6-2A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Pressurizer Pressure and Water Volume versus Time



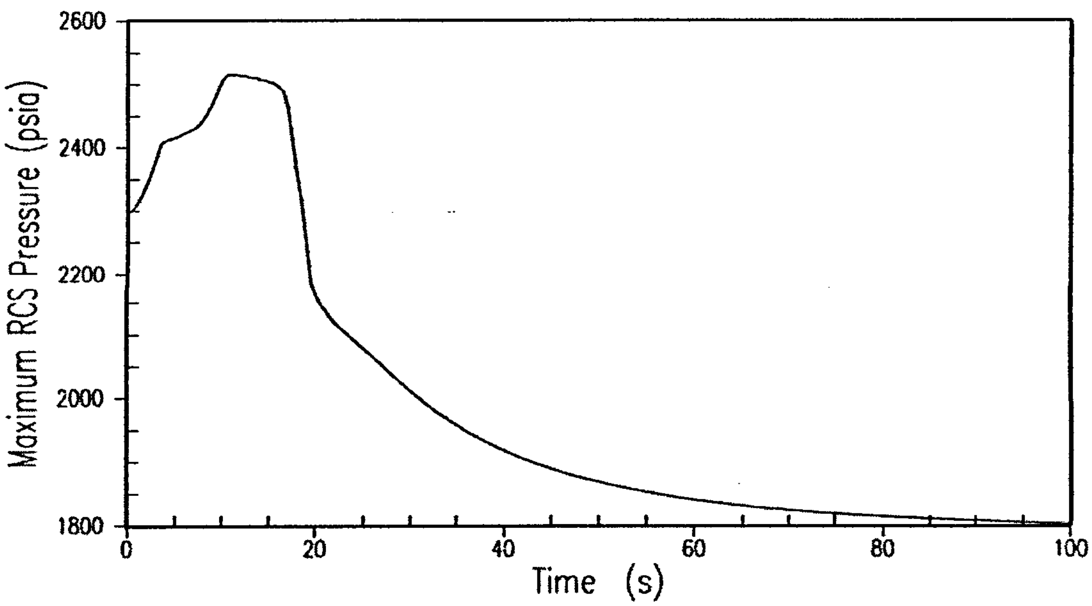
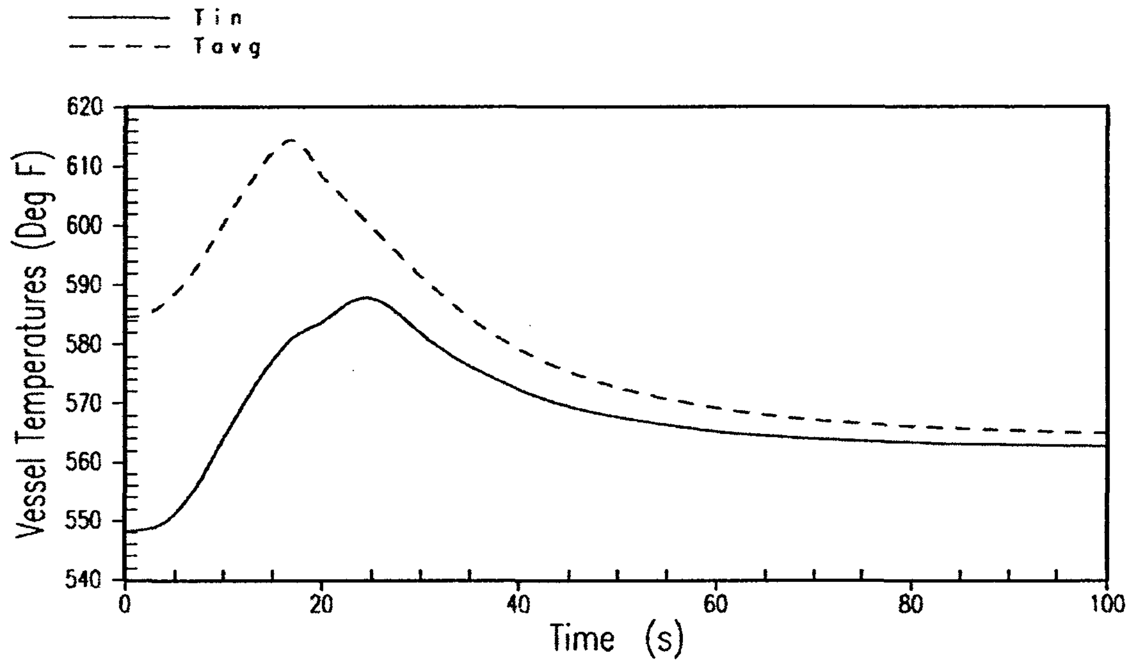


Figure 5.3.6-3A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Steam Generator Pressure and Maximum RCS Pressure versus Time



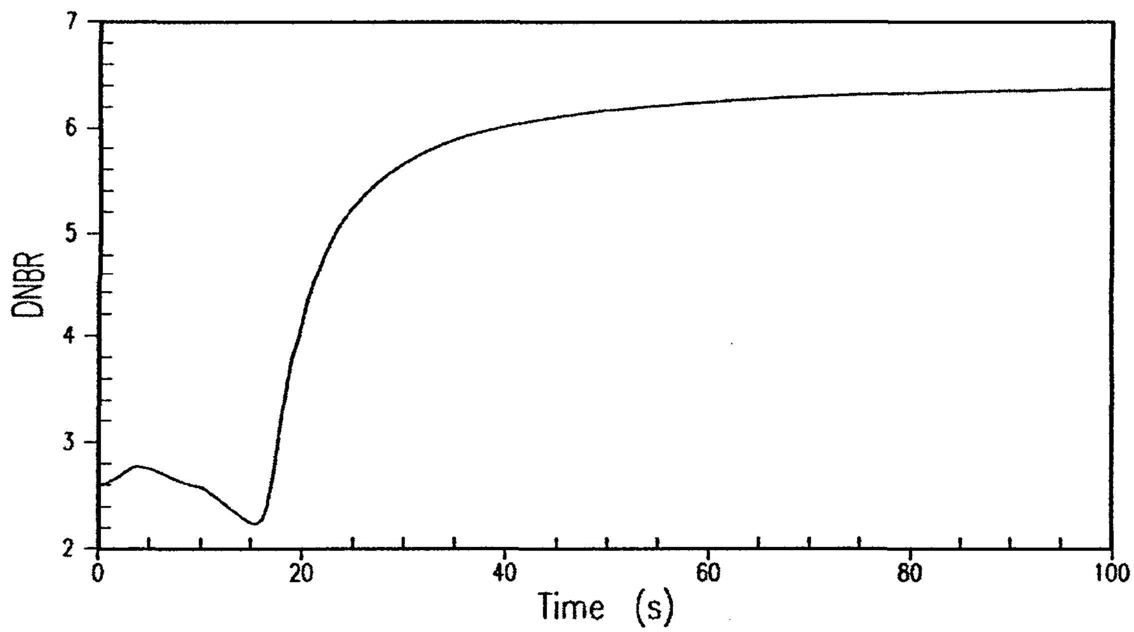


Figure 5.3.6-4A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
RCS Coolant Temperatures and DNBR versus Time

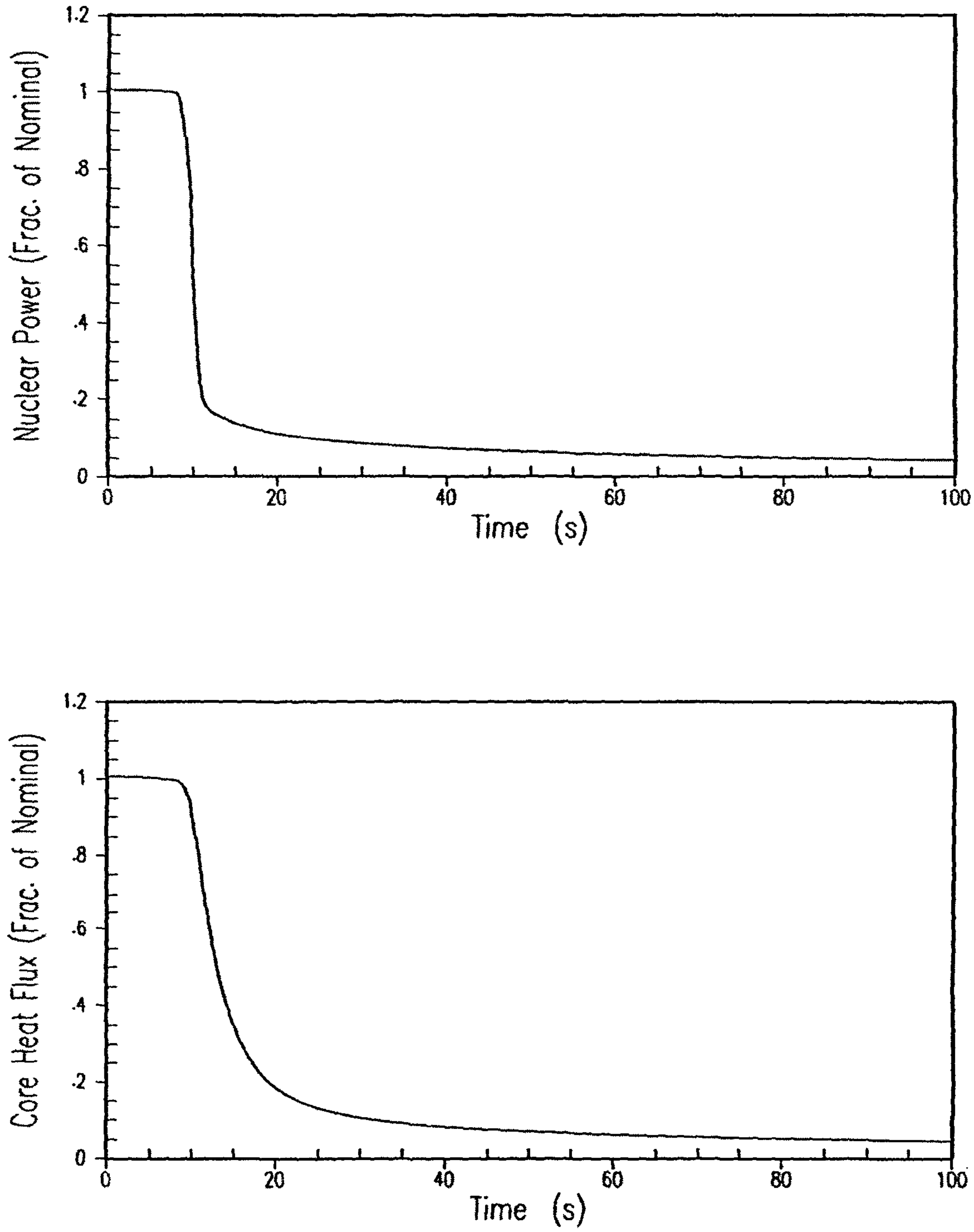


Figure 5.3.6-5A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Nuclear Power and Core Heat Flux versus Time

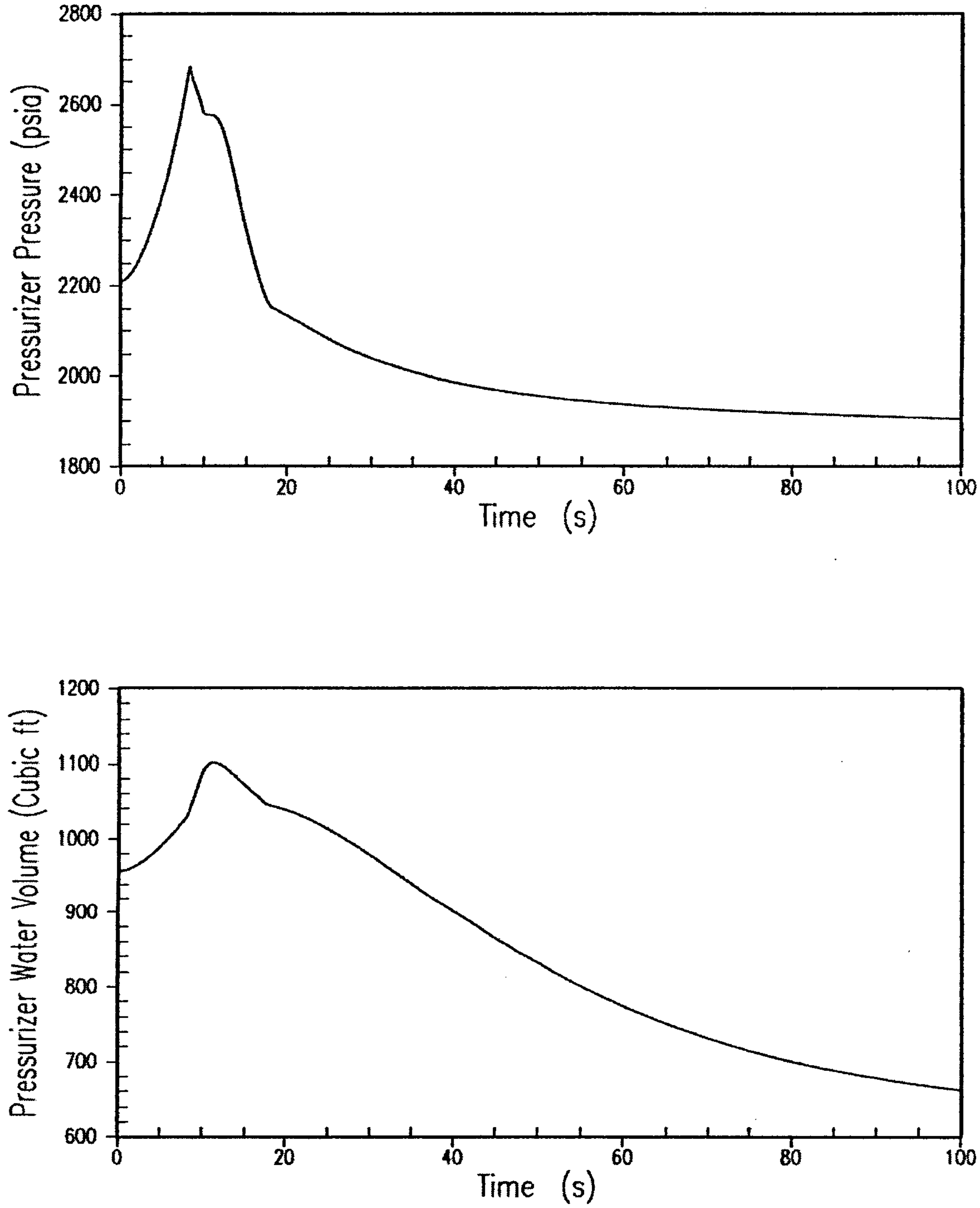


Figure 5.3.6-6A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Pressurizer Pressure and Water Volume versus Time

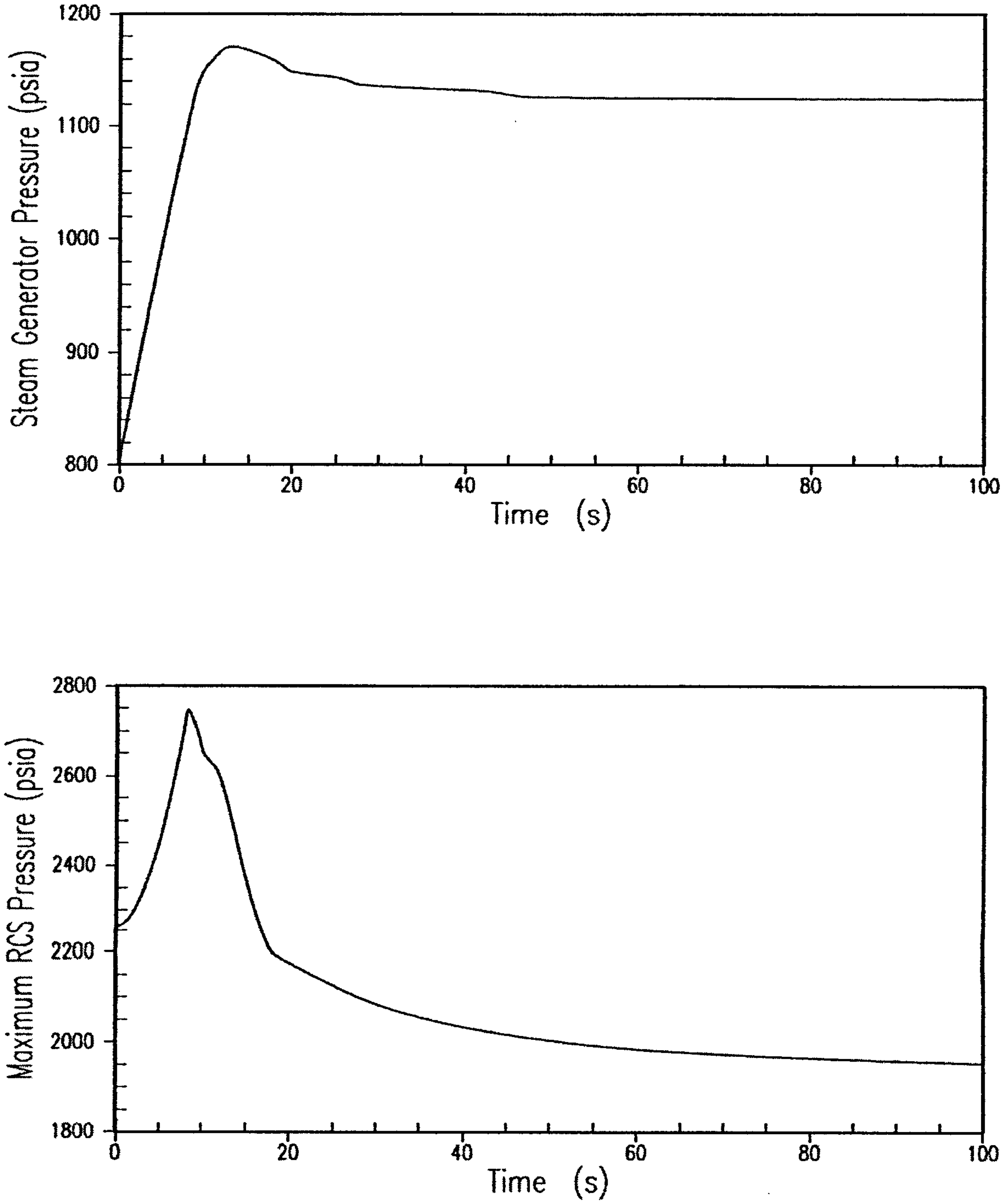


Figure 5.3.6-7A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Steam Generator Pressure and Maximum RCS Pressure versus Time

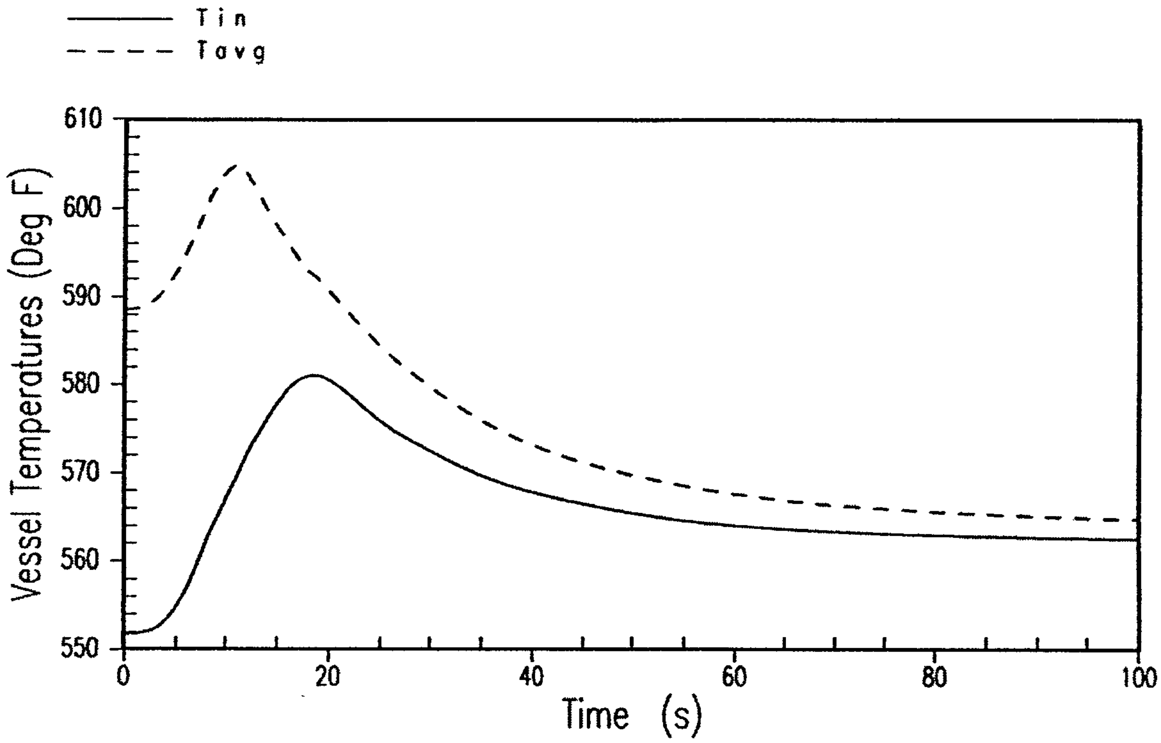
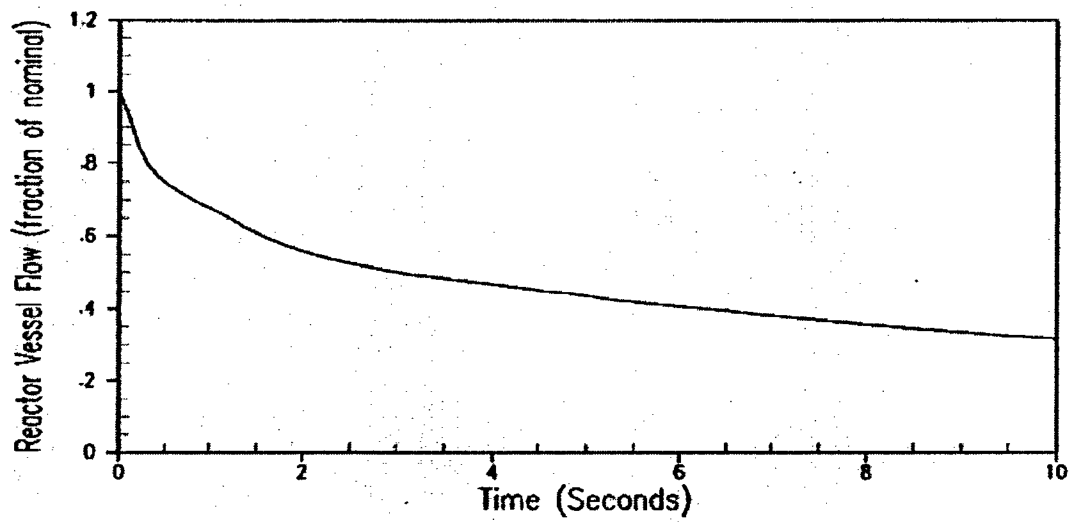


Figure 5.3.6-8A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
RCS Coolant Temperatures versus Time

Table 5.3.15-1 Time Sequence of Events – Single RCP Locked Rotor		
Event	**BVPS-1 Time (sec)**	**BVPS-2 Time (sec)**
Rotor on one pump locked or the shaft breaks	0.0	NA
Low flow reactor trip setpoint reached	0.04	NA
Rods begin to drop	1.04	NA
Remaining pumps lose power and begin to coastdown	1.04	NA
Maximum RCS pressure occurs	~~3.0~~ 3.4	NA
Maximum clad average temperature occurs	3.8	NA
Time of maximum clad oxidation	10.0	NA

Table 5.3.15-2 Summary of Results for Single RCP Locked Rotor			
Criteria	**BVPS-1 3 Loops Initially Operating, One Locked Rotor**	**BVPS-2 3 Loops Initially Operating, One Locked Rotor**	**Limit**
Maximum Clad Temperature at Core Hot Spot, °F	~~1868~~ 1884	NA	2700
Maximum $Zr-H_2O$ Reaction at Core Hot Spot, wt. %	0.41	NA	16.0
Maximum RCS Pressure, psia	~~2716~~ 2747	NA	2997



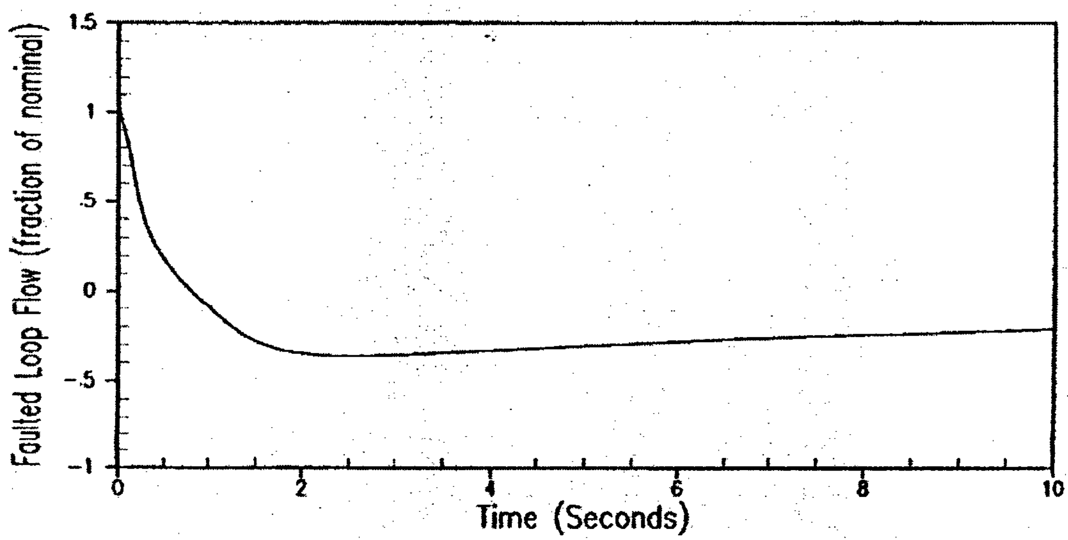


Figure 5.3.15-1A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Reactor Vessel Flow and Faulted Loop Flow versus Time

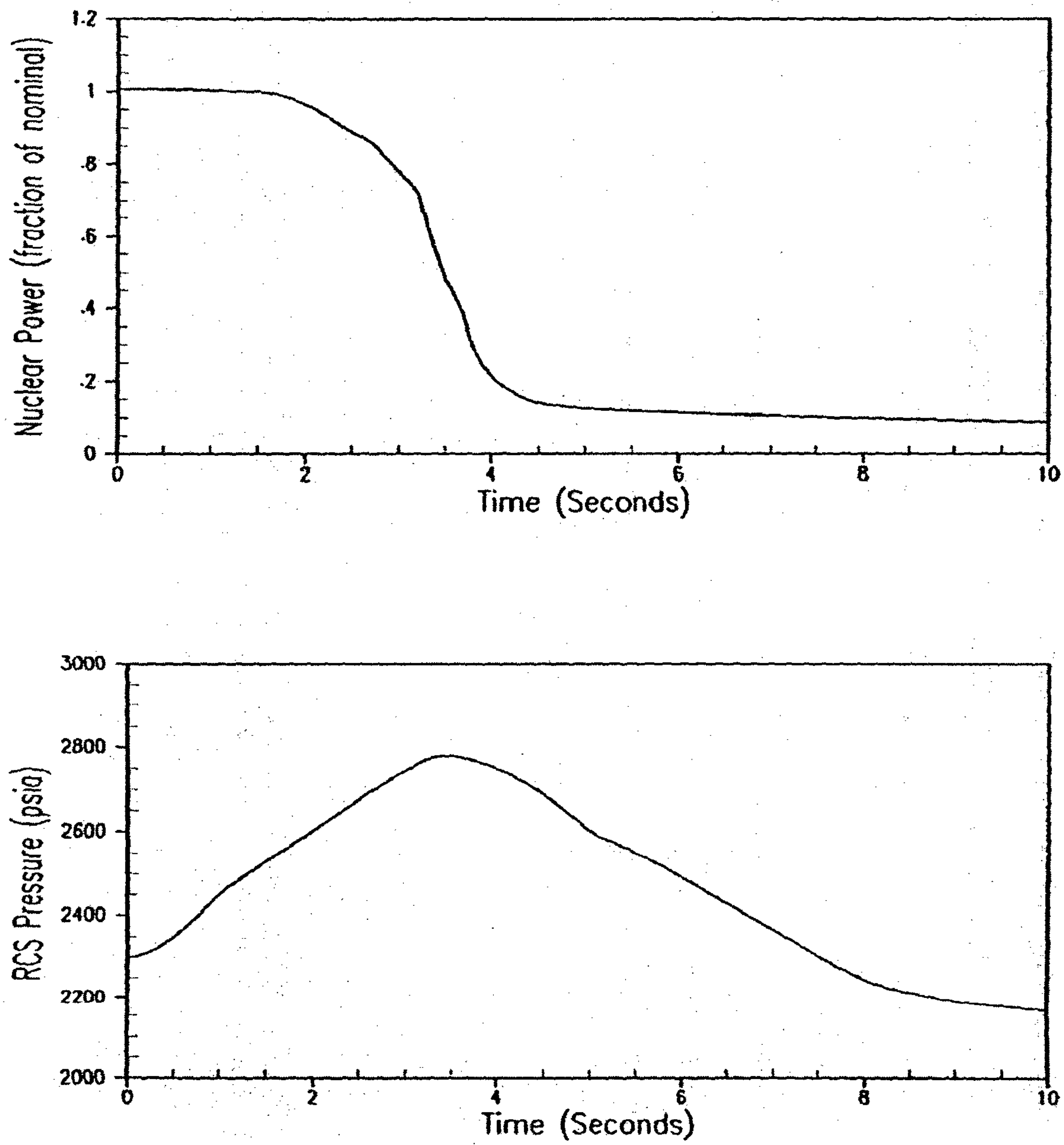


Figure 5.3.15-2A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Nuclear Power and RCS Pressure versus Time

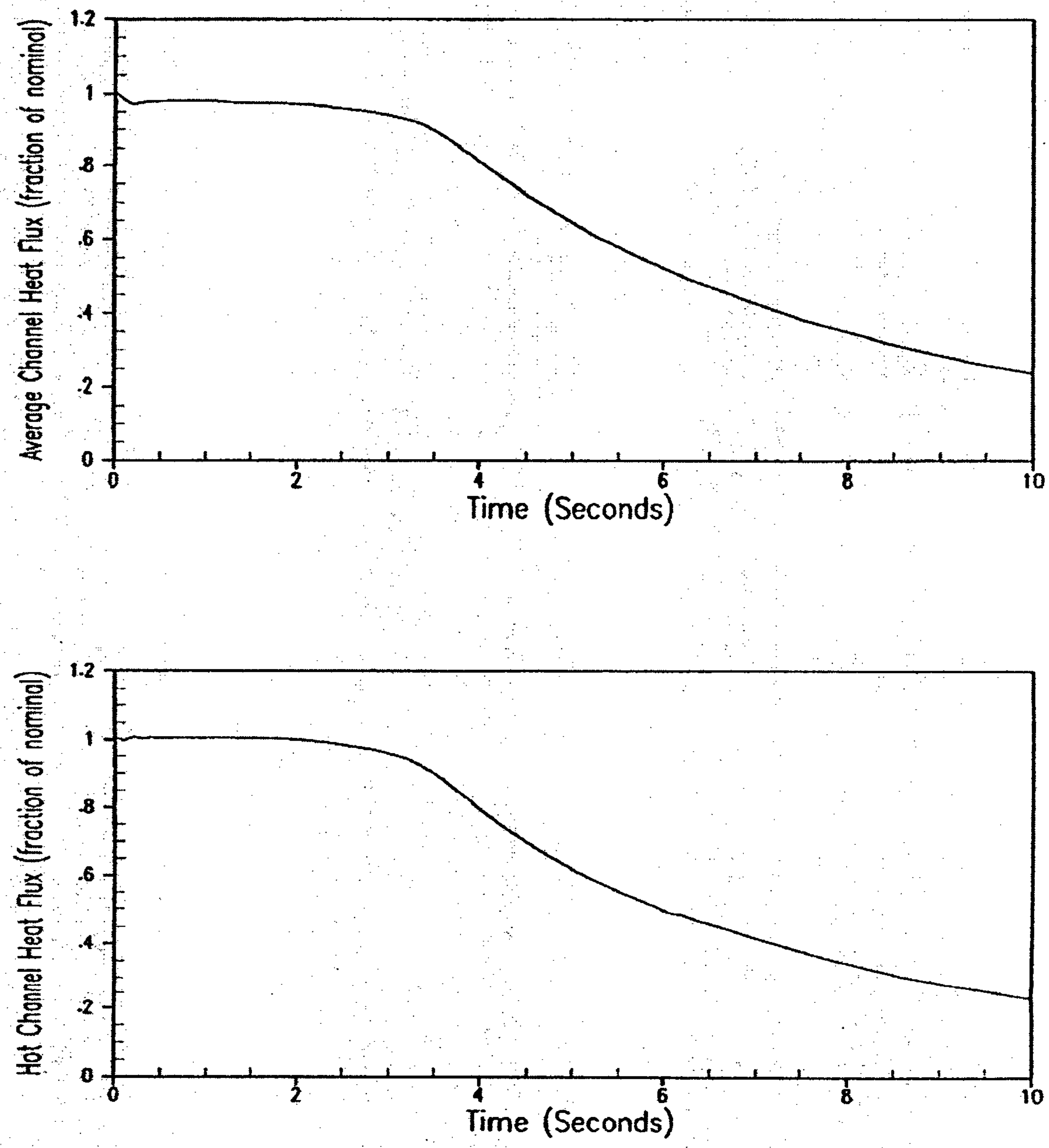
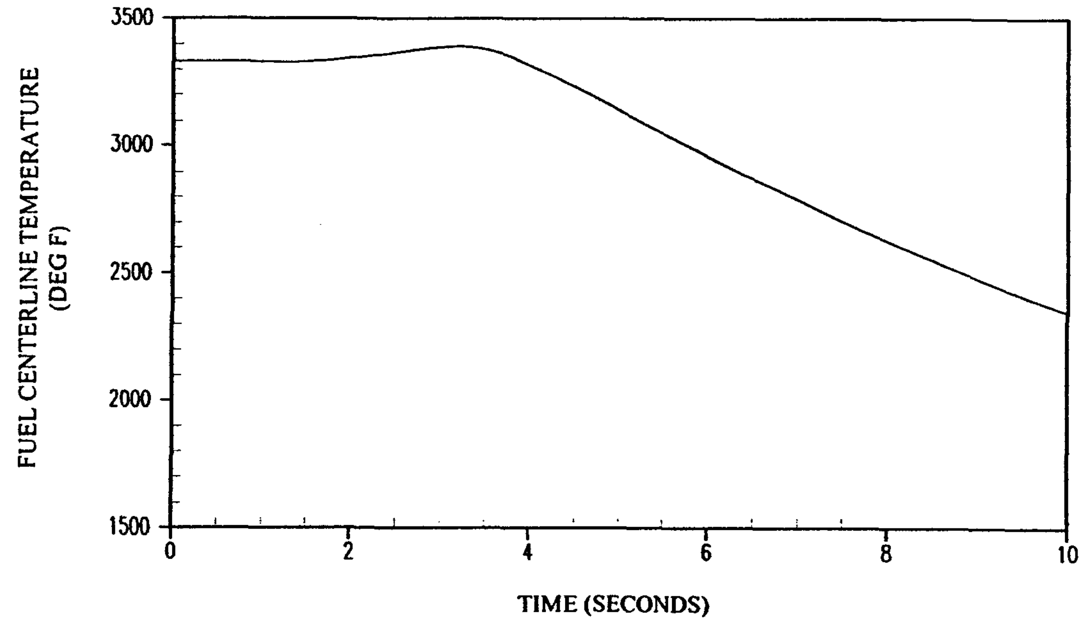


Figure 5.3.15-3A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Average Channel and Hot Channel Heat Flux versus Time



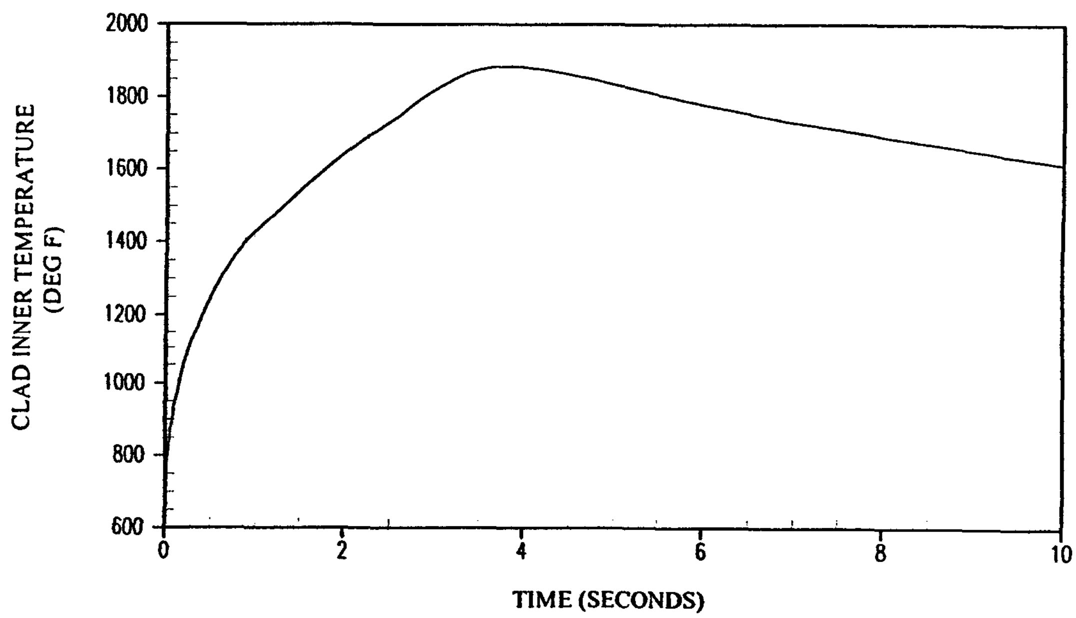


Figure 5.3.15-4A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Fuel Centerline and Clad Inner Temperatures versus Time

Table 5.3.20-1A
BVPS-1 Condition II DNB Event Results

Event Name	UFSAR Section	Report Section	Minimum DNBR	Peak Primary Pressure (psia)	Peak Secondary Pressure (psia)
RCCA Bank Withdrawal from Subcritical	14.1.1	5.3.2	Limit met(5,6)	N/A	N/A
RCCA Bank Withdrawal at Power	14.1.2	5.3.3	1.57	N/A(1)	1170.1
RCCA Misalignment	14.1.3	5.3.4	Limit met(5)	N/A	N/A
Loss of Load	14.1.7	5.3.6	2.23	~~2744.6~~(4) 2747.5(4)	~~1187.7~~ 1191.6
Feedwater System Malfunctions a. Feedwater Flow Increase b. Feedwater Enthalpy Decrease	 14.1.9 14.1.9	 5.3.9 5.3.9	 1.75(7) 1.67	 2357.0 2300.0	 1124.0 914.0
Excessive Load Increase(2)	14.1.10	5.3.10	Limit met	Limit met	Limit met
RCS Depressurization	14.1.15	5.3.11	1.62	N/A	N/A
Main Steam Pipe Rupture (HZP)(3)	14.2.5.1	5.3.12	Limit met(5,6)	N/A	N/A
Partial Loss of Flow	14.1.5	5.3.13	2.25(8)	2373.8	989.0
Complete Loss of Flow(3)	14.2.9	5.3.14	1.64(8)	2504.1	992.8
Limits	---	---	1.55	2748.5	1208.5

Notes:

(1) A generic Westinghouse evaluation addresses peak pressures for Rod Withdrawal at Power analyses.

(2) Current methodology for evaluating this event involves a comparison of conservative generic statepoints to the plant specific core thermal limits. In all cases, the generic statepoints are bounded by the core thermal limits.

(3) These events are not Condition II events but are analyzed to the more restrictive Condition II acceptance criteria.

(4) The analysis supports a pressurizer safety valve setpoint tolerance of +/-3.0%

(5) DNB statepoints are evaluated and the conclusion is that the limits are met.

(6) The 1.55 DNBR limit listed above is not applicable for these events. See Table 6.1-3 for the applicable DNB correlations and limits.

(7) The results reported are for the HFP case. An additional case was analyzed at HZP conditions. It was concluded that this case is bounded by the HZP steamline break analysis (UFSAR 14.2.5.1).

(8) These values are applicable for the RFA fuel. For the V5H fuel, the Partial Loss of Flow minimum DNBR is 1.90 compared to a limit of 1.32 (thimble cell) and the Complete Loss of Flow minimum DNBR is 1.39 compared to a limit of 1.33 (typical cell).

Table 5.3.20-2A BVPS-1 Locked Rotor Analysis Results				
Event Name	**UFSAR Section**	**Report Section**	**Percentage of Rods-in-DNB (%)**	**Peak Primary Pressure (psia)**
Locked Rotor	14.2.7	5.3.15	< 20	~~2716 (1)~~ 2797 (1)
Limits	---	---	20	2997

Note:

(1) The peak Reactor Coolant System pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits.

Table 5.3.20-3A BVPS-1 Pressurizer Filling Event Results			
Event Name	**UFSAR Section**	**Report Section**	**Peak Pressurizer Volume (ft^3)**
Loss of Normal Feedwater	14.1.8	5.3.7	1384.0
Loss of Non-Emergency AC Power	14.1.11	5.3.8	1224.0
Spurious Safety Injection at Power	14.1.16	5.3.18	NA
Limits	---	---	1458.1

Note:

NA

Attachment B of Enclosure 2 of L-05-198

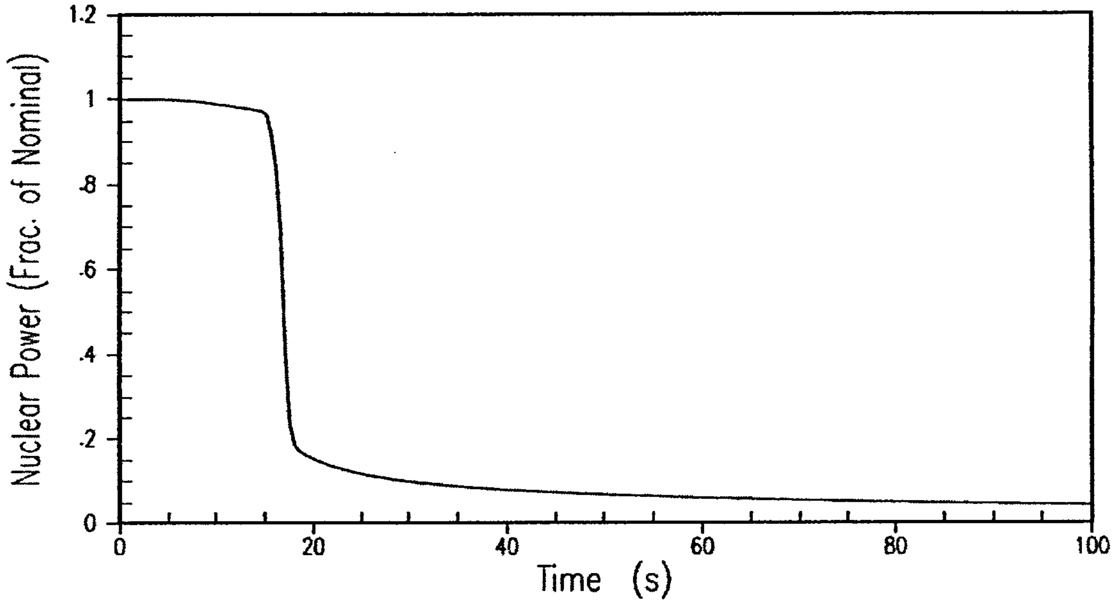
EPU Licensing Report - Revised Pages

Table 5.3.6-1A BVPS-1 Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip		
Case	**Event**	**Time (Sec)**
With pressurizer pressure control (minimum reactivity feedback-DNB Case)	Loss of Electrical Load/Turbine Trip	0.0
	Overtemperature ΔT Reactor Trip Setpoint reached	12.3
	Rods begin to drop	14.3
	Minimum DNBR occurs	15.6
Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.5
	Rods begin to drop	7.5
	Peak ~~pressurizer~~ RCS pressure occurs	~~8.2~~ 8.3

Table 5.3.6-1B
BVPS-2 Time Sequence of Events – Loss of External Electrical Load and/or Turbine Trip

Case	Event	Time (Sec)
With pressurizer pressure control (minimum reactivity feedback-DNB Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	11.2
	Rods begin to drop	13.2
	Minimum DNBR occurs	14.6
Without pressurizer pressure control (minimum reactivity feedback-Pressure Case)	Loss of Electrical Load/Turbine Trip	0.0
	High Pressurizer Pressure Reactor Trip Setpoint reached	5.4
	Rods begin to drop	7.4
	Peak ~~pressurizer~~ pressure occurs	8.4

RCS



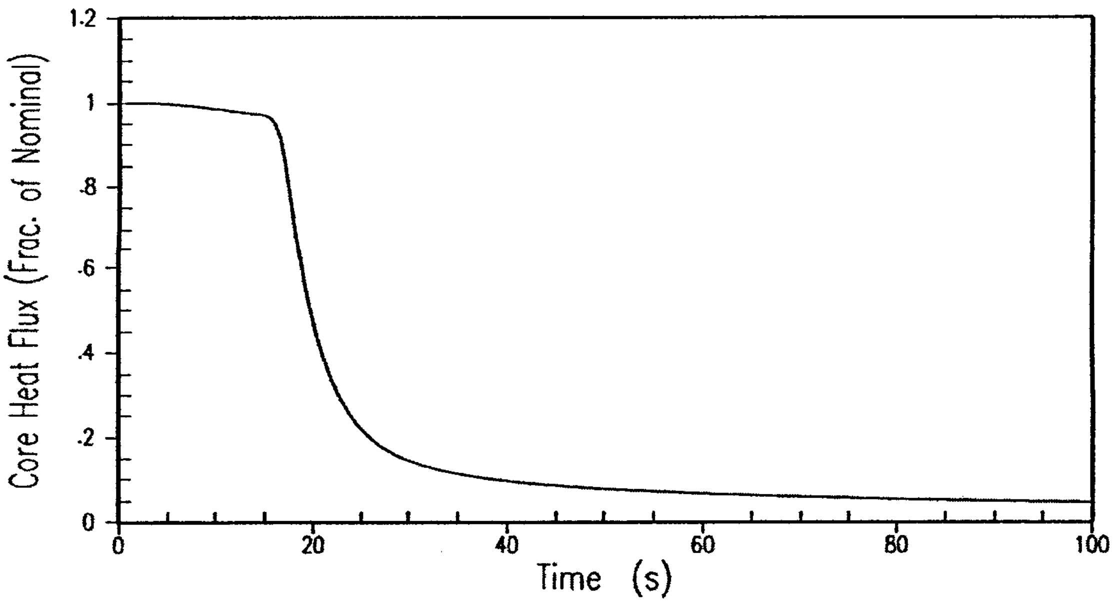
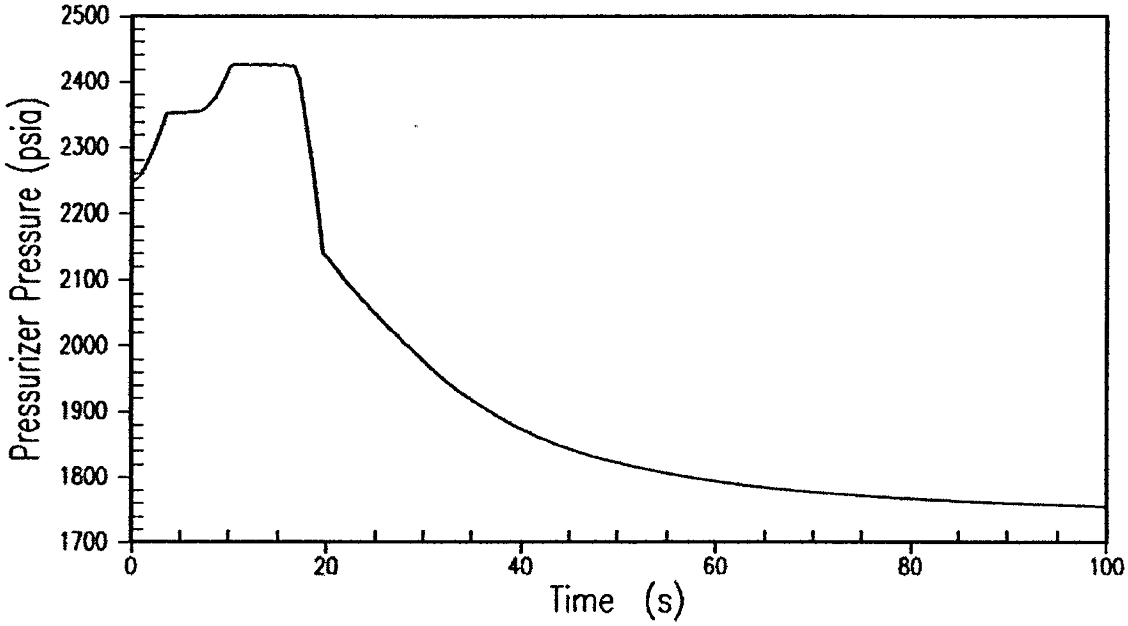


Figure 5.3.6-1A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Nuclear Power and Core Heat Flux versus Time



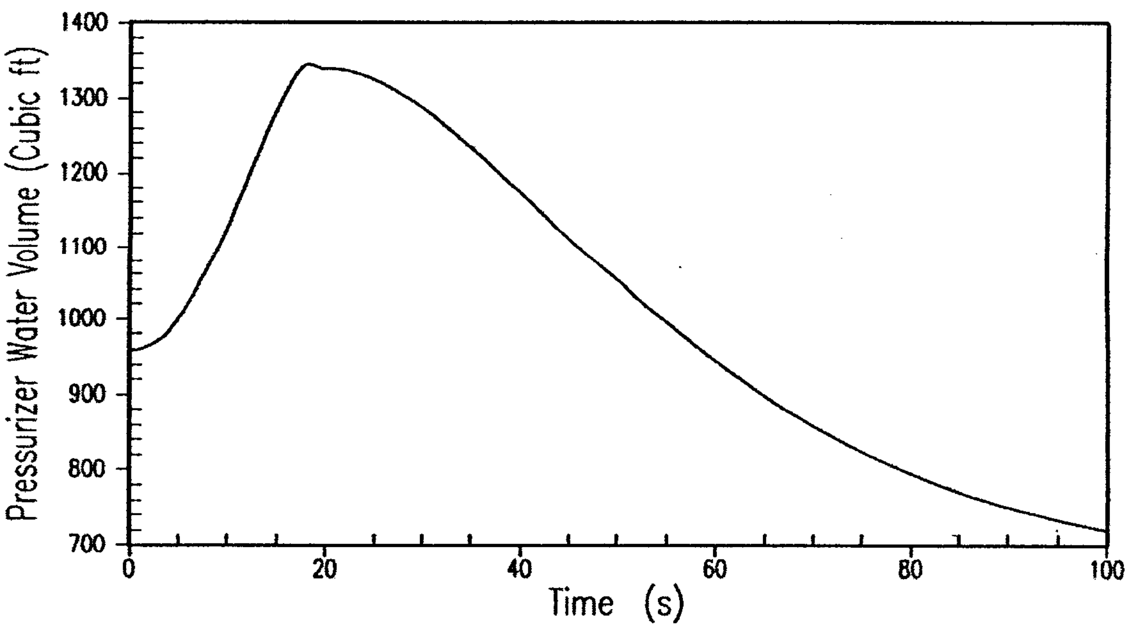


Figure 5.3.6-2A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Pressurizer Pressure and Water Volume versus Time

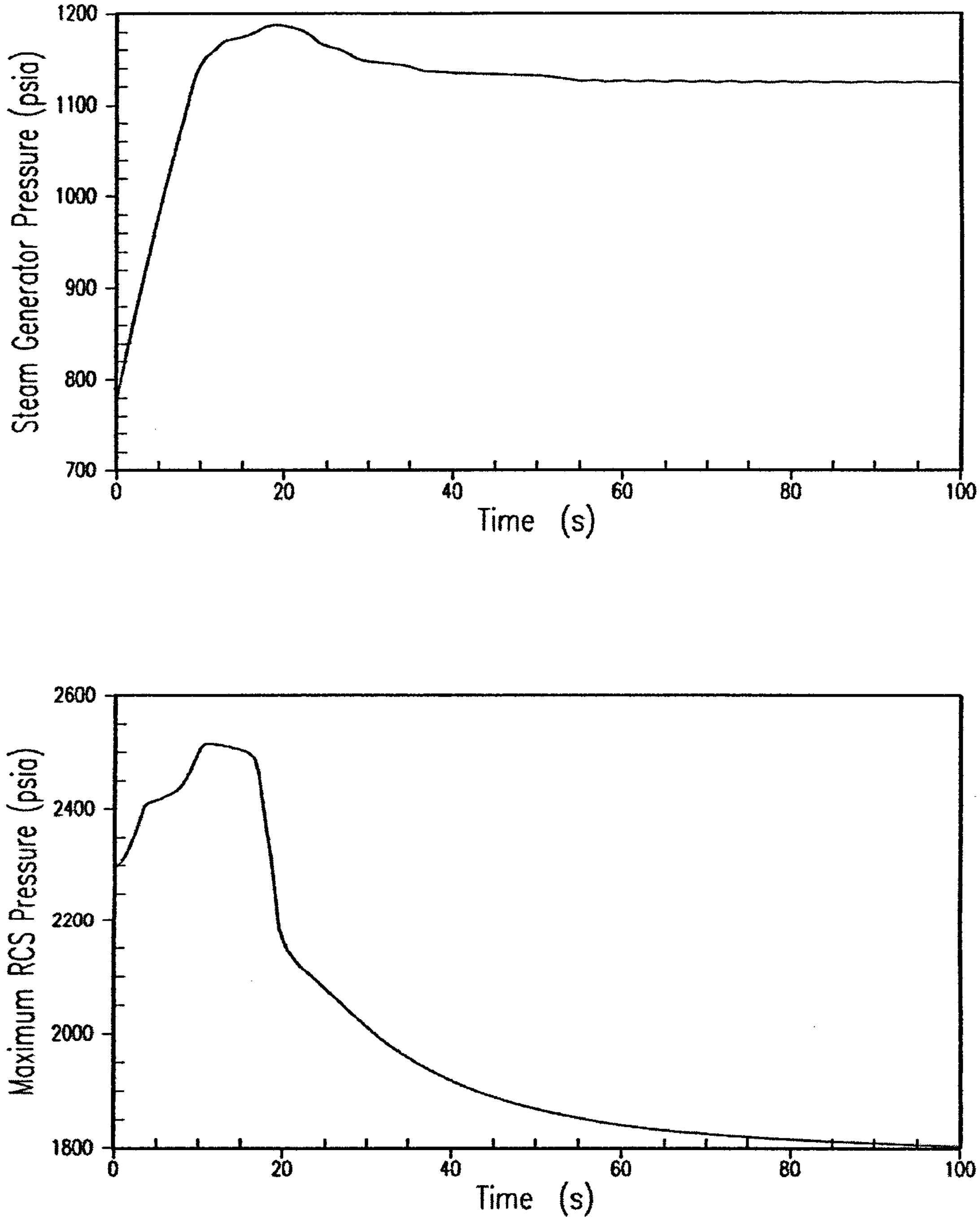


Figure 5.3.6-3A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
Steam Generator Pressure and Maximum RCS Pressure versus Time

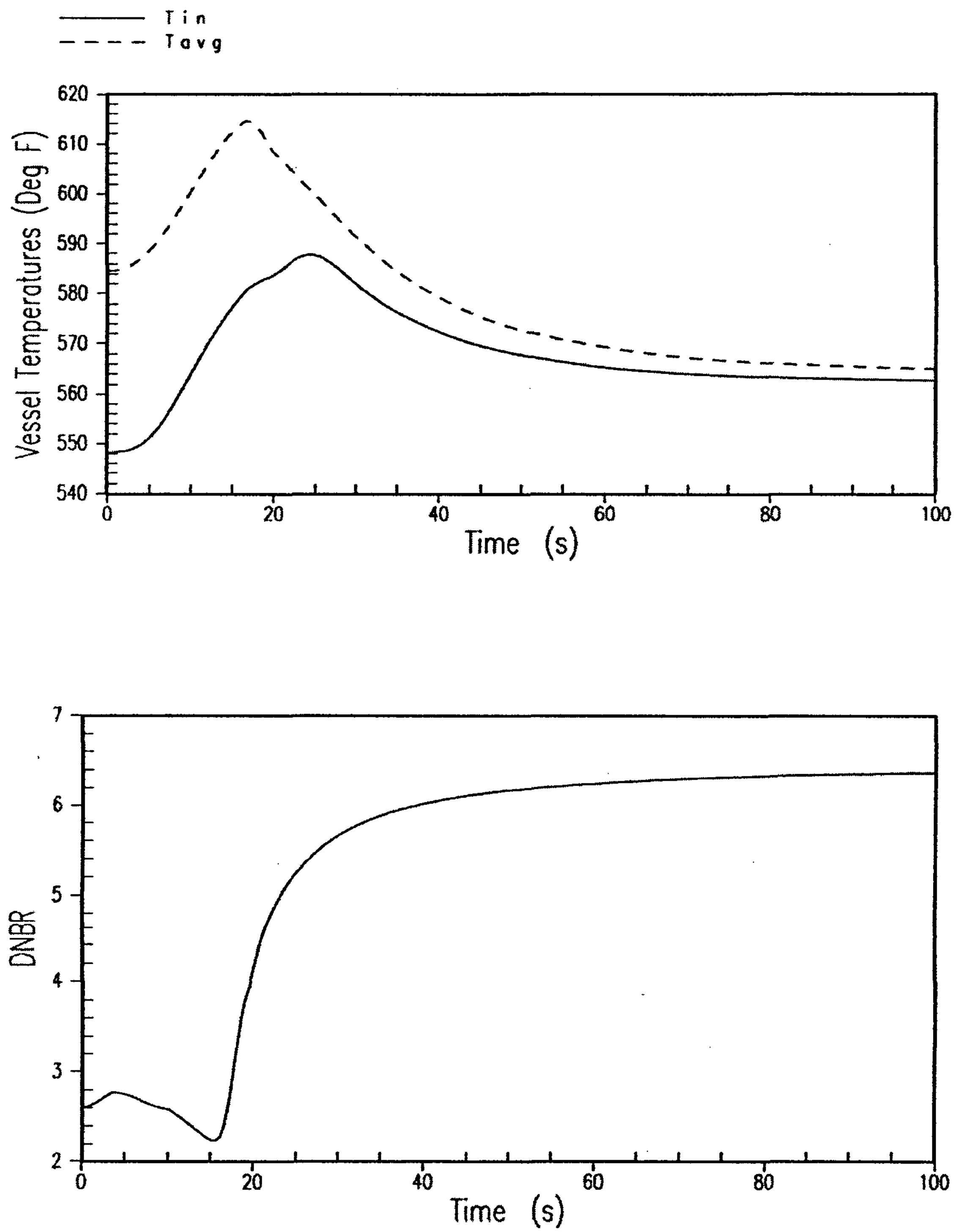


Figure 5.3.6-4A
BVPS-1 Loss of Load / Turbine Trip with Pressure Control
RCS Coolant Temperatures and DNBR versus Time

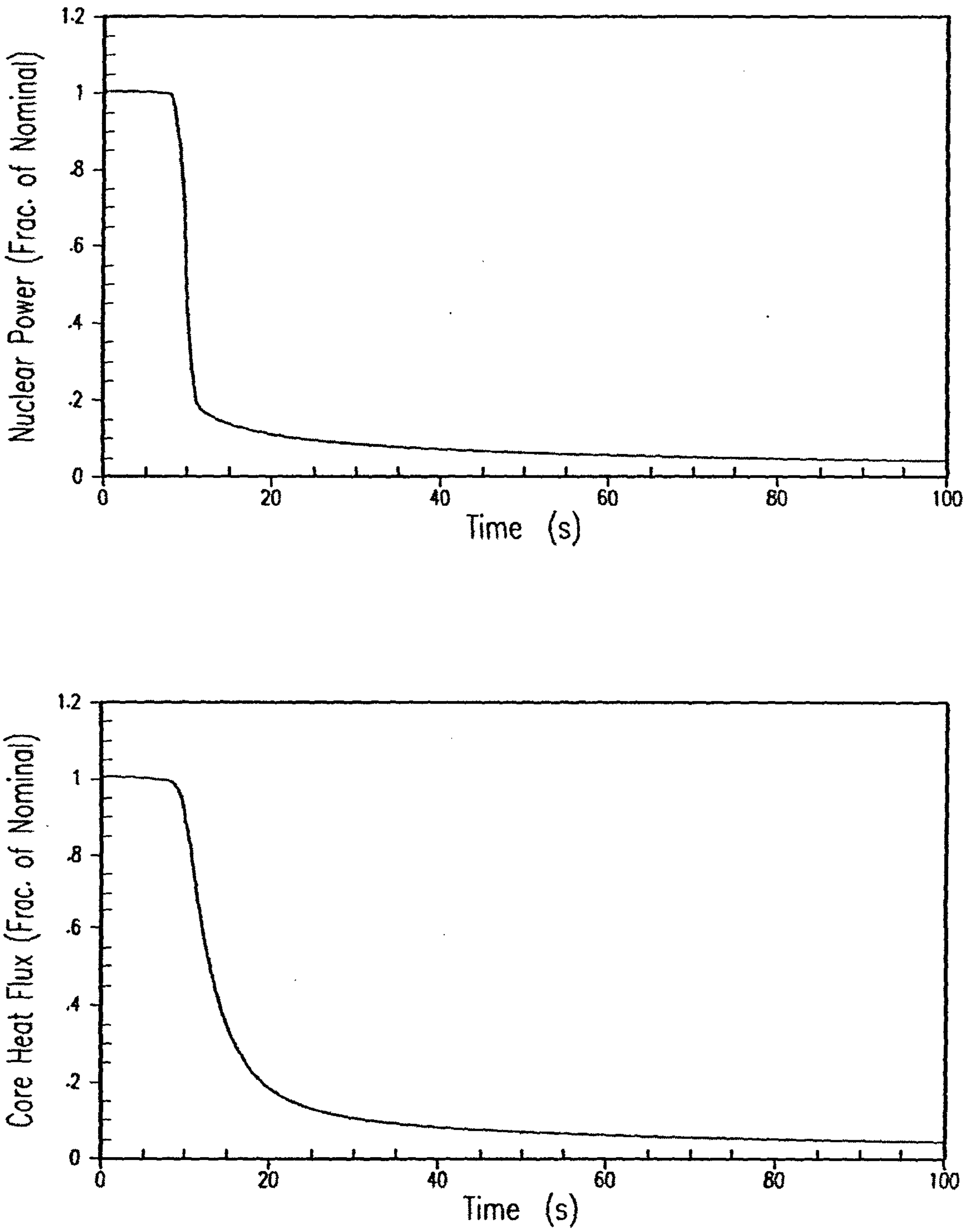


Figure 5.3.6-5A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Nuclear Power and Core Heat Flux versus Time

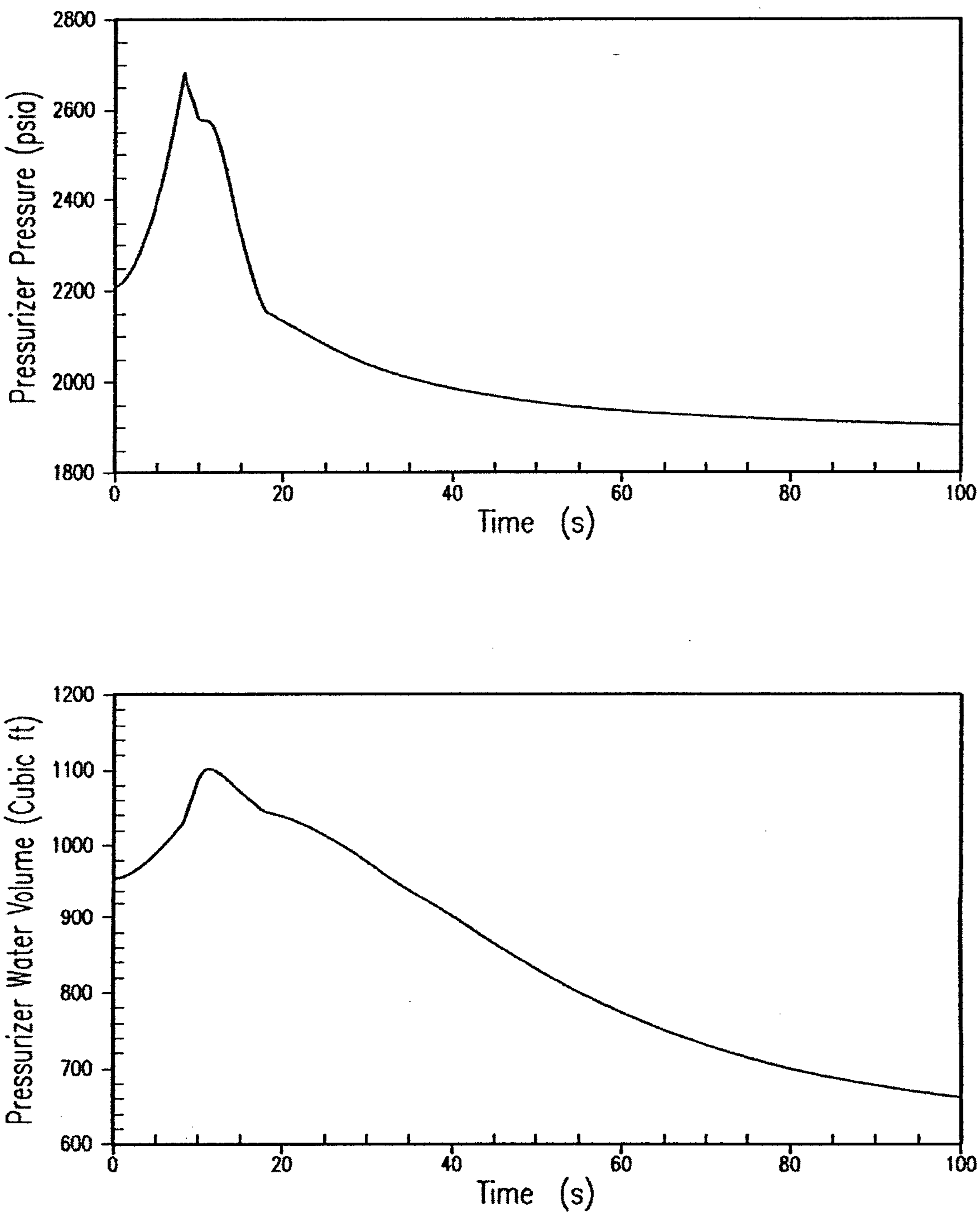
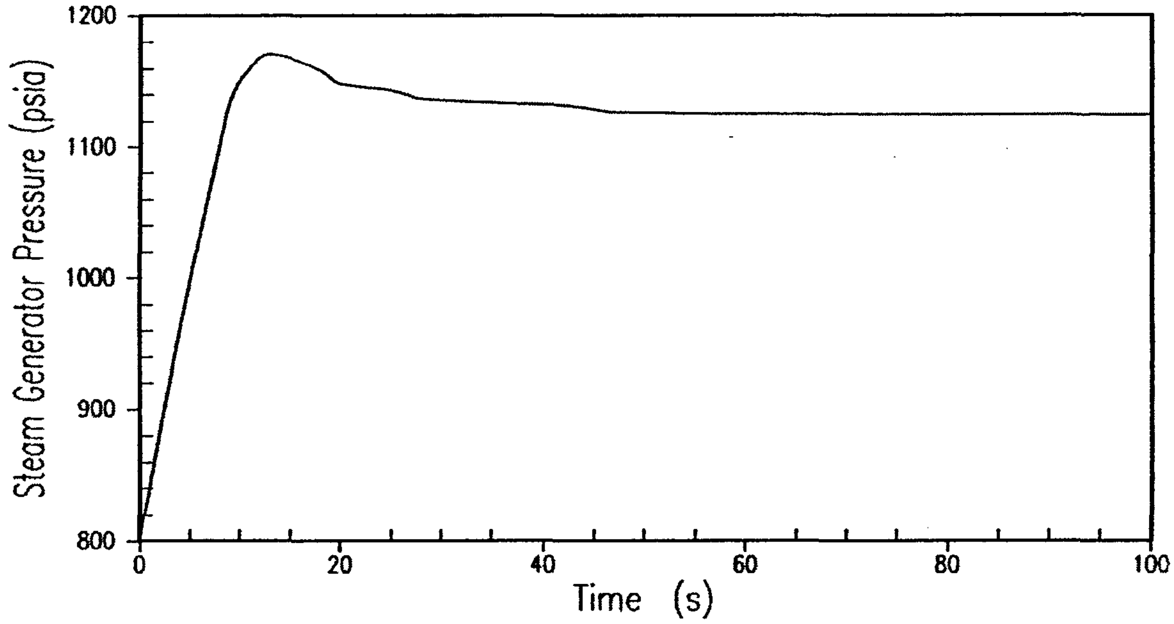


Figure 5.3.6-6A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Pressurizer Pressure and Water Volume versus Time



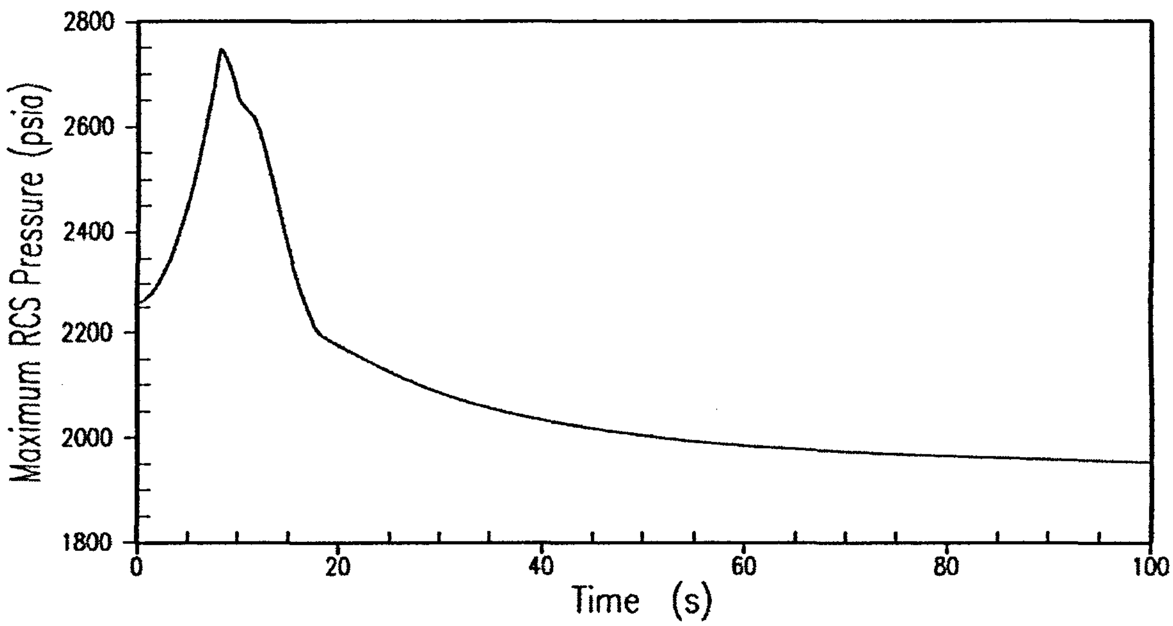


Figure 5.3.6-7A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
Steam Generator Pressure and Maximum RCS Pressure versus Time

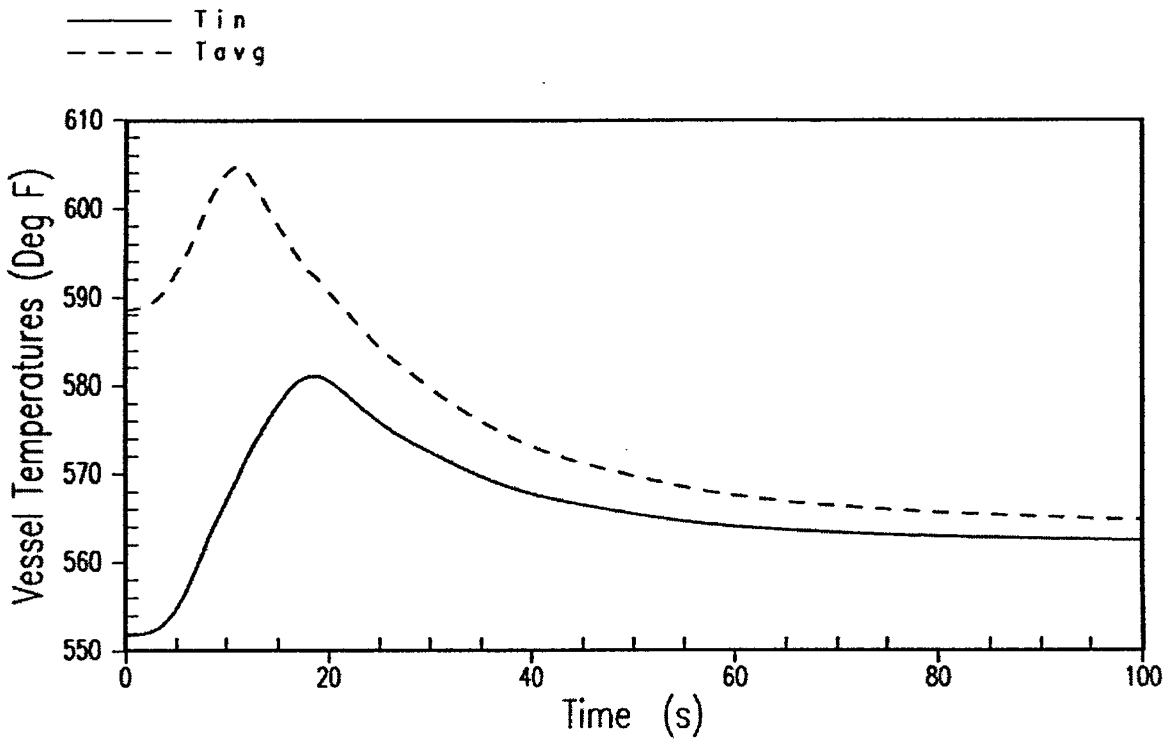


Figure 5.3.6-8A
BVPS-1 Loss of Load / Turbine Trip without Pressure Control
RCS Coolant Temperatures versus Time

Table 5.3.15-1 Time Sequence of Events – Single RCP Locked Rotor		
Event	**BVPS-1 Time (sec)**	**BVPS-2 Time (sec)**
Rotor on one pump locked or the shaft breaks	0.0	0.0
Low flow reactor trip setpoint reached	0.04	0.04
Rods begin to drop	1.04	1.04
Remaining pumps lose power and begin to coastdown	1.04	1.04
Maximum RCS pressure occurs	~~3.0~~ 3.4	3.6
Maximum clad average temperature occurs	3.8	3.9
Time of maximum clad oxidation	10.0	10.0

Table 5.3.15-2 Summary of Results for Single RCP Locked Rotor			
Criteria	**BVPS-1 3 Loops Initially Operating, One Locked Rotor**	**BVPS-2 3 Loops Initially Operating, One Locked Rotor**	**Limit**
Maximum Clad Temperature at Core Hot Spot, °F	~~1868~~ 1884	1824	2700
Maximum Zr-H_2O Reaction at Core Hot Spot, wt. %	0.41	0.35	16.0
Maximum RCS Pressure, psia	~~2716~~ 2797	2825	2997

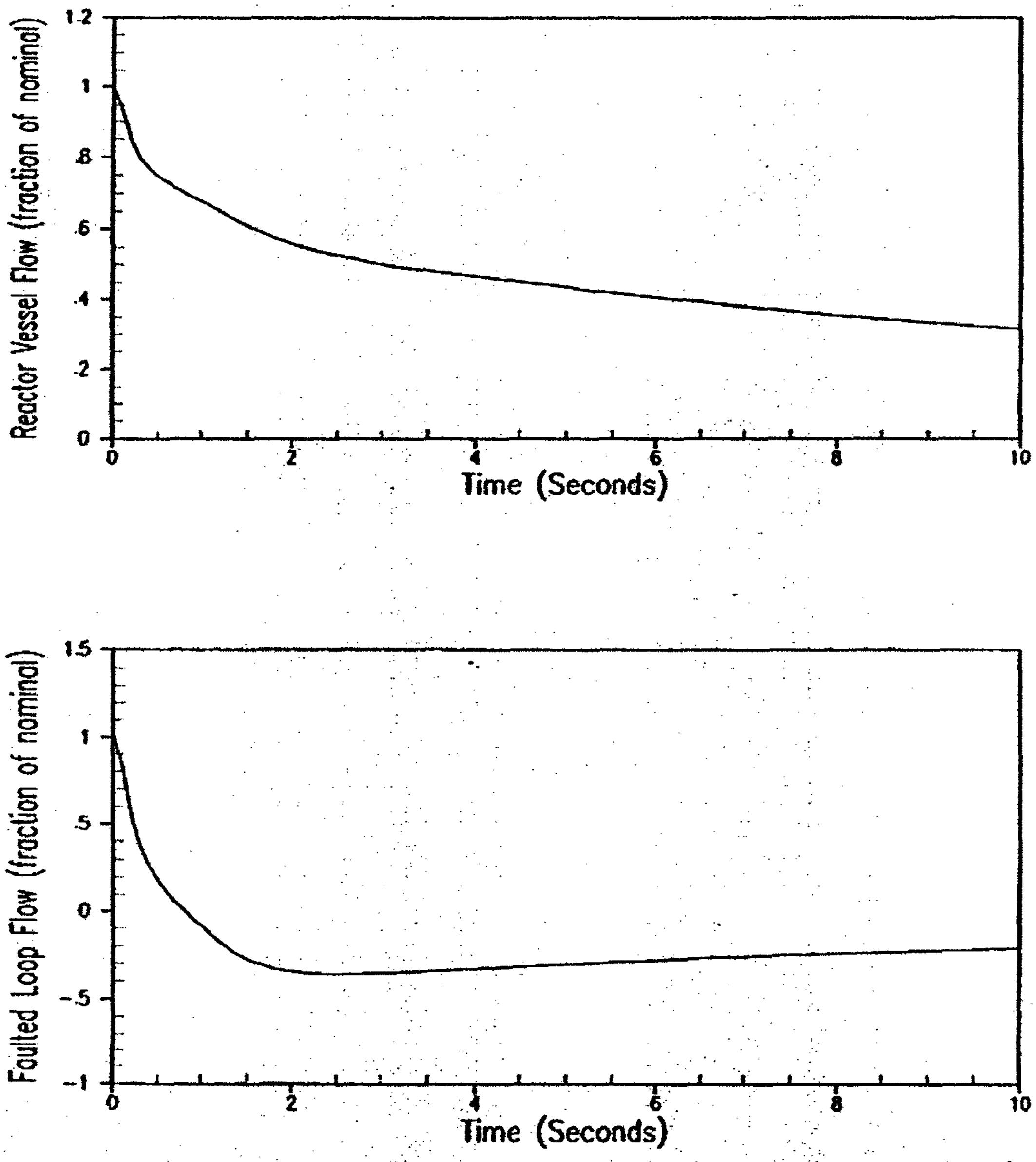
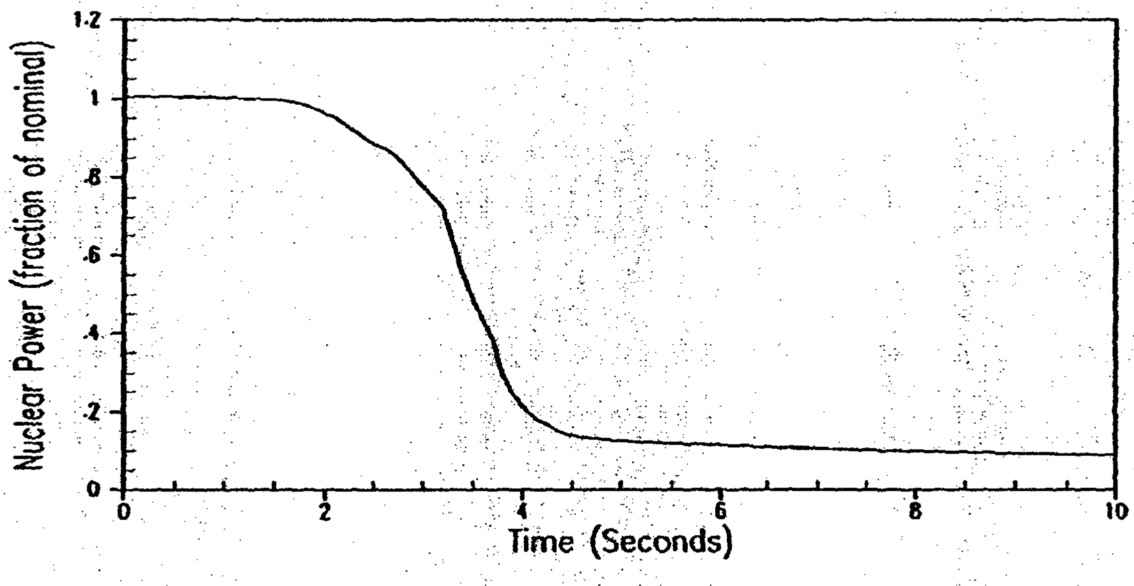


Figure 5.3.15-1A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Reactor Vessel Flow and Faulted Loop Flow versus Time



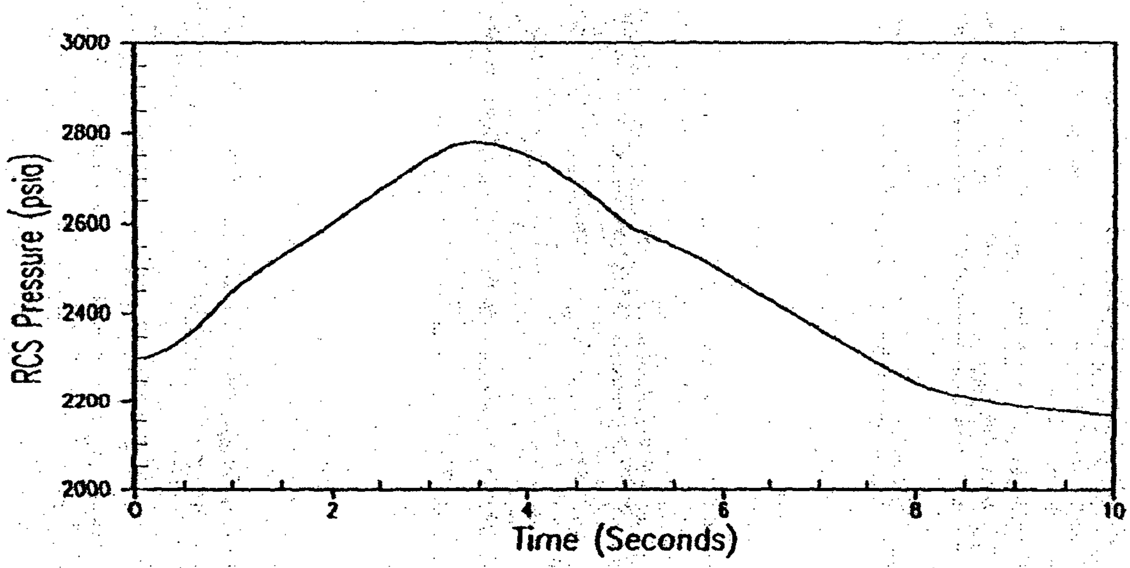
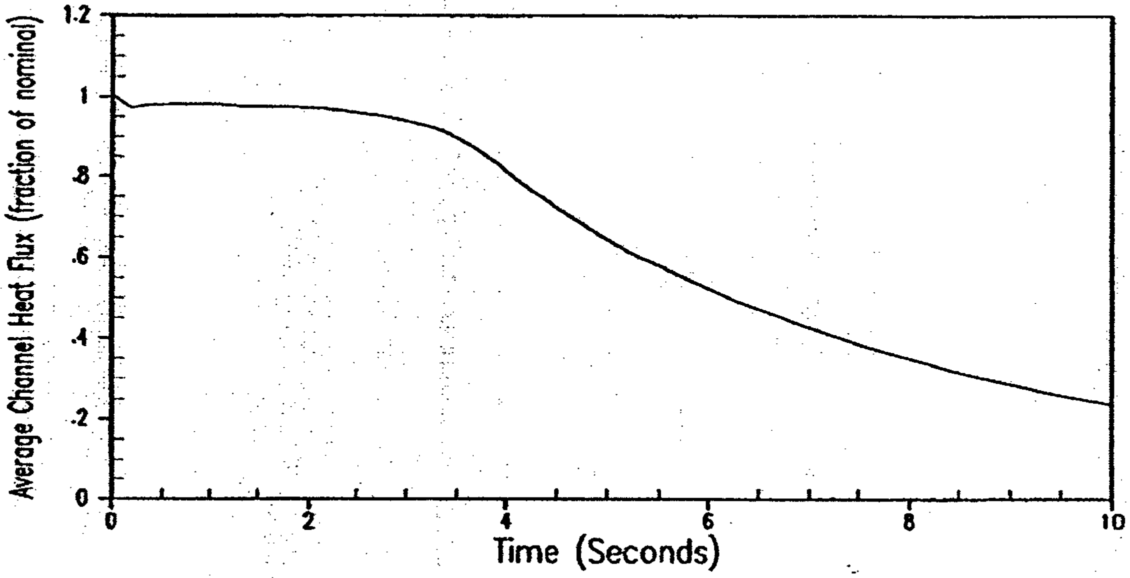


Figure 5.3.15-2A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Nuclear Power and RCS Pressure versus Time



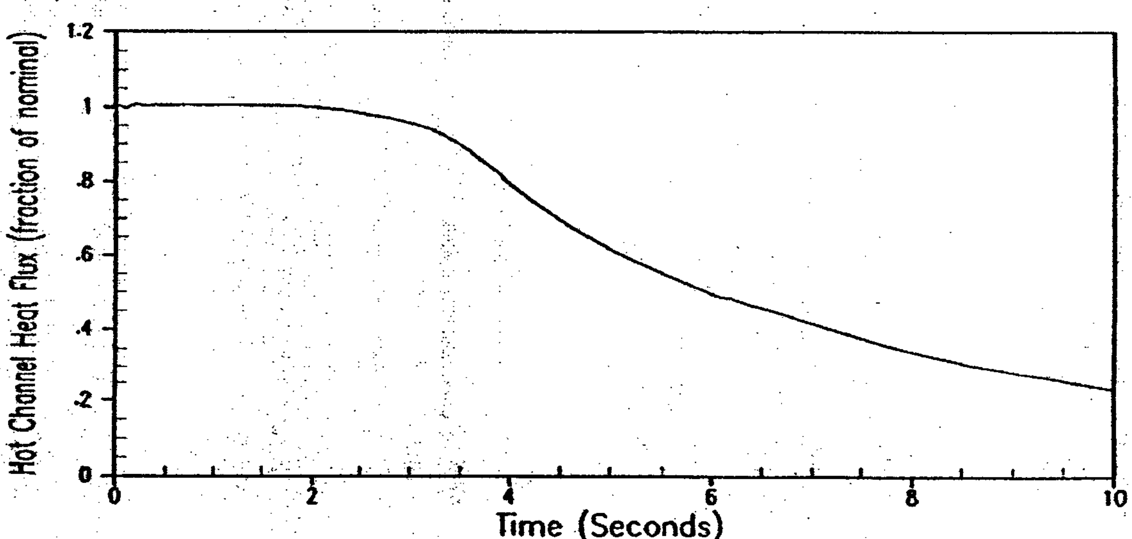


Figure 5.3.15-3A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Average Channel and Hot Channel Heat Flux versus Time

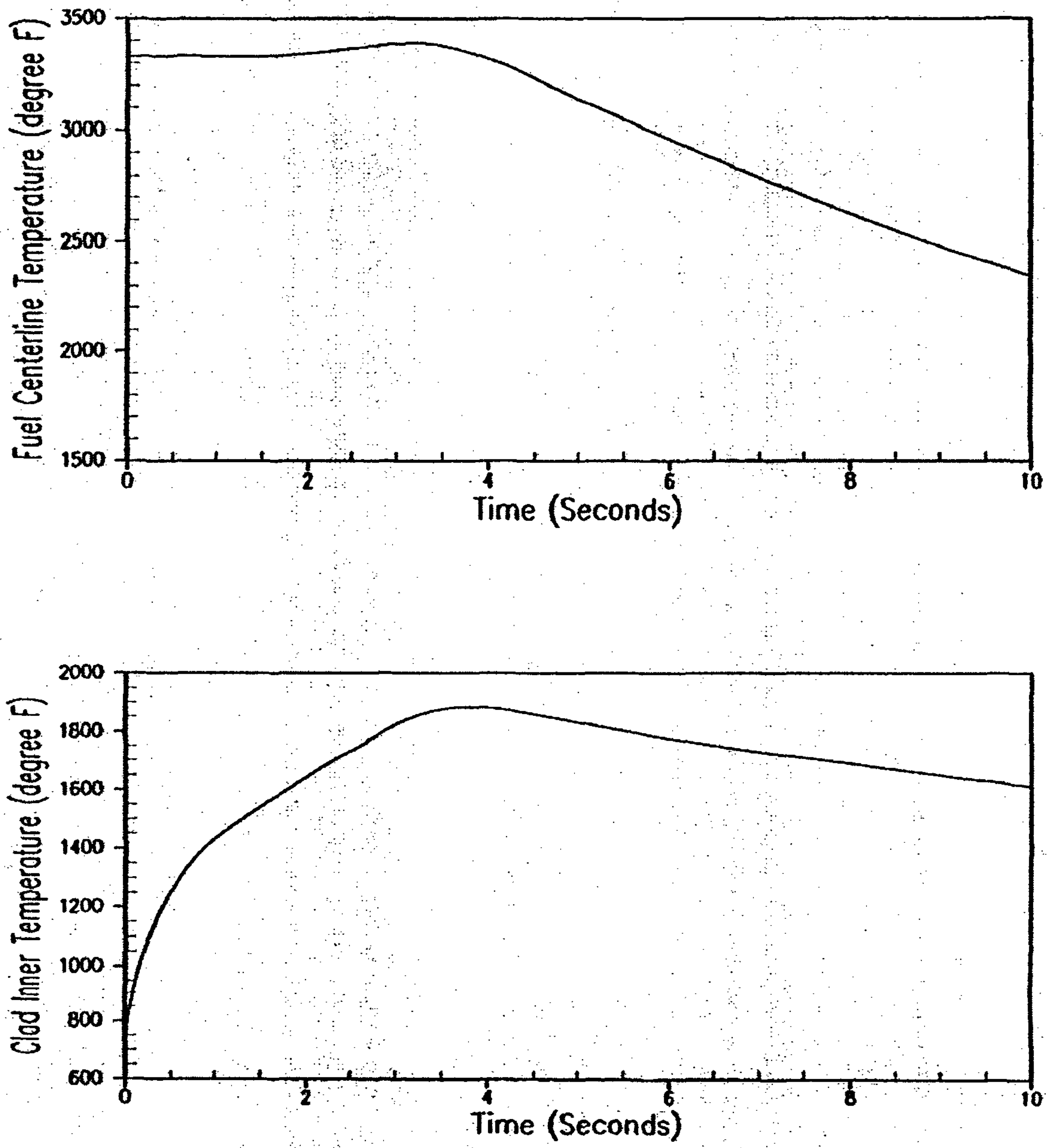


Figure 5.3.15-4A
BVPS-1 Single Reactor Coolant Pump Locked Rotor
Fuel Centerline and Clad Inner Temperatures versus Time

Table 5.3.20-1A BVPS-1 Condition II DNB Event Results					
Event Name	**UFSAR Section**	**Report Section**	**Minimum DNBR**	**Peak Primary Pressure (psia)**	**Peak Secondary Pressure (psia)**
RCCA Bank Withdrawal from Subcritical	14.1.1	5.3.2	Limit met(5,6)	N/A	N/A
RCCA Bank Withdrawal at Power	14.1.2	5.3.3	1.57	N/A(1)	1170.1
RCCA Misalignment	14.1.3	5.3.4	Limit met(5)	N/A	N/A
Loss of Load	14.1.7	5.3.6	2.23	~~2744.4(4)~~ 2747.3(4)	~~1187.7~~ 1191.6
Feedwater System Malfunctions a. Feedwater Flow Increase b. Feedwater Enthalpy Decrease	 14.1.9 14.1.9	 5.3.9 5.3.9	 1.75(7) 1.67	 2357.0 2300.0	 1124.0 914.0
Excessive Load Increase(2)	14.1.10	5.3.10	Limit met	Limit met	Limit met
RCS Depressurization	14.1.15	5.3.11	1.62	N/A	N/A
Main Steam Pipe Rupture (HZP)(3)	14.2.5.1	5.3.12	Limit met(5,6)	N/A	N/A
Partial Loss of Flow	14.1.5	5.3.13	2.25(8)	2373.8	989.0
Complete Loss of Flow(3)	14.2.9	5.3.14	1.64(8)	2504.1	966.5
Limits	---	---	1.55	2748.5	1208.5

Notes:

(1) A generic Westinghouse evaluation addresses peak pressures for Rod Withdrawal at Power analyses.

(2) Current methodology for evaluating this event involves a comparison of conservative generic statepoints to the plant specific core thermal limits. In all cases, the generic statepoints are bounded by the core thermal limits.

(3) These events are not Condition II events but are analyzed to the more restrictive Condition II acceptance criteria.

(4) The analysis supports a pressurizer safety valve setpoint tolerance of +/-3.0%

(5) DNB statepoints are evaluated and the conclusion is that the limits are met.

(6) The 1.55 DNBR limit listed above is not applicable for these events. See Table 6.1-3 for the applicable DNB correlations and limits.

(7) The results reported are for the HFP case. An additional case was analyzed at HZP conditions. It was concluded that this case is bounded by the HZP SLB analysis (UFSAR 14.2.5.1).

(8) These values are applicable for the RFA fuel. For the V5H fuel, the Partial Loss of Flow minimum DNBR is 1.90 compared to a limit of 1.32 (thimble cell) and the Complete Loss of Flow minimum DNBR is 1.39 compared to a limit of 1.33 (typical cell).

Table 5.3.20-2A BVPS-1 Locked Rotor Analysis Results				
Event Name	**UFSAR Section**	**Report Section**	**Percentage of Rods-in-DNB (%)**	**Peak Primary Pressure (psia)**
Locked Rotor	14.2.7	5.3.15	< 20	2797 (1) ~~2716 (1)~~
Limits	---	---	20	2997

Note:

(1) The peak Reactor Coolant System pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits.

Table 5.3.20-2B BVPS-2 Locked Rotor Analysis Results				
Event Name	**UFSAR Section**	**Report Section**	**Percentage of Rods-in-DNB (%)**	**Peak Primary Pressure (psia)**
Locked Rotor	15.3.3	5.3.15	< 20	2825 (1)
Limits	---	---	20	2997

Note:

(1) The peak Reactor Coolant System pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits.

new calculation was performed to determine both the maximum and minimum pressurizer spray flow capabilities.

9.1.3.2 Pressurizer Spray Line Temperature

In the assessment of system operation, the minimum RCS T_{cold} temperature (provided in Table 9.1-1) for the EPU conditions was compared to the existing pressurizer spray line low temperature alarm setpoint. The available temperature difference between RCS T_{cold} and the low temperature alarm was evaluated to determine acceptability of the alarm setpoint.

9.1.3.3 RCS Temperatures

In the assessment of system operation, the maximum expected RCS T_{hot} temperature (provided in Table 9.1-1) was compared to RCS design temperatures.

9.1.3.4 Pressurizer Relief Tank Sizing and Level Alarm Setpoints

In the assessment of the pressurizer level conditions, the maximum steam space volume discharged from the pressurizer during a loss of normal feedwater event was compared to the volume assumed in the original PRT design basis calculation to determine acceptability of the PRT sizing and level alarm setpoints at EPU conditions.

9.1.3.5 RCS Net Heat Input

The net heat input calculation is a detailed heat balance on the RCS. The purpose is to determine the net heat input to the RCS considering all heat inputs and losses. The calculation considers the primary source of heat input which is the RCPs, but it also considers other relatively smaller heat inputs and losses such as letdown and charging flow. The original value used for net heat input is 8 MWt. For the EPU Project, a value of 10 MWt is used. The net heat input calculation was performed to verify that a minimum net heat input of 10 MWt is available to support the PCWG parameters for EPU conditions. The calculation considered an SG tube plugging range of 0% to 22% consistent with the PCWG parameters for EPU.

9.1.3.6 RCS Design Calculations

The following RCS design calculations were evaluated to determine their applicability at 2910 MWt NSSS power considering the revised PCWG parameters that are associated with the EPU conditions:

- Pressurizer Spray Flow Capability
- Pressurizer Relief Tank Sizing
- Pressurizer Relief Tank Setpoints
- Pressurizer Surge Line Data
- Pressurizer Surge Line Pressure Drop
- Pressurizer Relief Line Pressure Drop

Limits.

The pressurizer safety valves operate to prevent the RCS from being pressurized above its Safety ~~Limit of 2735 psig~~. Each safety valve is designed (i.e., rated) to relieve at least 345,000 lb per hour of saturated

5.3.15 and 5.8

steam at the valve set point of 2485 psig. The safety analysis for EPU presented in Sections 5.3.6, confirm that the installed pressurizer safety valves are adequate for at-power overpressure protection.

9.1.4 Acceptance Criteria and Results

9.1.4.1 Pressurizer Spray Flow

The design basis minimum pressurizer spray flow requirement (total) was established at 600 gpm. The minimum calculated flow (considering RCS process conditions and RCS best estimate flow) should be at or above this value. Otherwise, RCS control system transient analyses, which inherently considered this flow, would have to be reanalyzed. The minimum RCS best estimate flow is calculated based on a maximum SG tube plugging level of 22% and the maximum RCS best estimate flow is calculated based on a minimum SG tube plugging level of 0%. The calculated minimum pressurizer spray flow based on minimum RCS best estimate flow is 713 gpm for BVPS-1 and 787 gpm for BVPS-2. The calculated maximum pressurizer spray flow based on maximum RCS best estimate flow is 776 gpm for BVPS-1 and 854 gpm for BVPS-2. These values exceed the minimum flow requirement of 600 gpm (total); thereby supporting RCS control systems transient analyses.

9.1.4.2 Pressurizer Spray Line Temperature

In the assessment of system operation, the minimum RCS T_{cold} must be several degrees higher than the pressurizer spray line low temperature alarm setpoint. The minimum RCS T_{cold} is limited to 530°F, which corresponds to operation near the bottom of the RCS T_{avg} range. Since operation is expected to be in the middle to upper portion of the T_{avg} range, T_{cold} during operation is expected to be at least several degrees above the 530°F minimum value. Thus, the current spray line low temperature alarm setpoints of 515°F for BVPS-1 and 530°F for BVPS-2 are sufficiently below the expected T_{cold} during operation to avoid unnecessary alarms. Thus, changes to the spray line low temperature alarm setpoints are not required.

9.1.4.3 RCS Temperatures

In the assessment of system operation, the maximum expected RCS T_{hot} must be less than or equal to the maximum RCS design temperature of 650°F. The maximum RCS T_{hot} of 617°F is still less than the RCS design temperature.

9.1.4.4 Pressurizer Relief Tank Sizing and Level Alarm Setpoints

In the assessment of the PRT relief capability, the desirable acceptance criteria for the PRT is "successful" operation following a maximum expected pressurizer discharge condition. The PRT nominal liquid and gas volumes specified for the tank for full power operation are based on the following Westinghouse PRT design criteria:

1. The PRT initial water volume was selected to limit the final water temperature (following a steam discharge) to 200°F. This is the maximum allowable temperature for discharge to the Liquid Waste Disposal System without external cooling.