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DCP/NRC1470

Project 711

December 12, 2000

Document Control Desk
U S Nuclear Regulatory Commission
Washington, D. C. 20555

SUBJECT: Westinghouse AP1000 Plant Description and Analysis Report

References:
1. Westinghouse Letter DCP/NRC1465, W. E. Cummins to S. J. Collins, 8/28/2000
2. NRC Letter "AP1000 Pre-Application Review – Phase 2" S. J. Collins to W. E. Cummins, 12/5/2000

Dear Mr. Wilson,

Enclosed is WCAP-15612, "AP1000 Plant Description and Analysis Report." The AP1000 report provides an overview description of a 1000MWe standard nuclear plant that utilizes passive safety systems. The report also includes results of analyses of the plant response to various accident scenarios. This report is submitted for review as part of Phase 2 of the AP1000 pre-application review.

The AP1000 plant is derived from the AP600 standard plant that was granted Design Certification under Title 10, Code of Federal Regulations Part 52. The items to be resolved during Phase 2 of the pre-application review have been outlined in Reference 1 and are as follows:

1. Applicability of AP600 Test Program to AP1000
2. Applicability of AP600 Analysis Codes to AP1000
3. AP1000 Design Acceptance Criteria
4. AP1000 Exemptions

This report is the first submittal of the pre-application review and supports resolution of the four items above. Subsequent submittals for each of the four items above will be submitted prior to initiation of the NRC review in February 2001. Based on Reference 2, the NRC has estimated that the Phase 2 review will take 6 to 9 months to complete. For planning purposes, Westinghouse plans to submit an application for Design Certification under 10 CFR Part 52 for the AP1000 in early 2002, contingent upon successful resolution of the Phase 2 pre-application review within the currently planned time period and contingent on our ability to attract continued support for the design from the Department of Energy and the nuclear industry.

Please direct questions on this submittal to Mike Corletti at (412) 374-5355.

Very truly yours,

W E Cummins

W.E. Cummins

/Enclosure

cc: J. N. Wilson - NRC

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AP1000 RESPONSIBLE MANAGER	SIGNATURE*	APPROVAL DATE
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WESTINGHOUSE NON-PROPRIETARY CLASS 3

WCAP-15612

AP1000
Plant Description and Analysis Report

December 2000

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TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF TABLES (Cont.)

LIST OF FIGURES

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

EXECUTIVE SUMMARY

On December 3, 1999, The United States Nuclear Regulatory Commission issued Design Certification of the AP600 standard nuclear reactor design. This culminated an 8-year review of the AP600 design, safety analysis and probabilistic risk assessment. The AP600 is a 600 MWe reactor that utilizes passive safety features that, once actuated, depend only on natural forces such as gravity and natural circulation to perform all required safety functions. These passive safety systems result in increased plant safety and have also significantly simplified plant systems and equipment, resulting in simplified plant operation and maintenance. The AP600 meets NRC deterministic safety criteria and probabilistic risk criteria with large margins.

The large safety margins of the AP600 can be attributed to the performance of the passive safety systems in response to accidents. An extensive AP600 test program was performed to provide confidence in the ability to adequately predict the performance characteristics of the passive safety systems as required by 10 CFR 50. This test program consisted of separate effects and integral systems tests of the passive safety systems and is well documented in NUREG-1512, Final Safety Evaluation Report Related to Certification of the AP600 Standard Design. Westinghouse used the test programs to develop analytical computer codes that can predict with adequate certainty, the performance of the passive safety systems in response to design basis and beyond design basis accidents. In addition to the extensive test program conducted by Westinghouse, the NRC also performed confirmatory tests and analyses at both the APEX test facility at Oregon State University and the ROSA test facility at the Japan Atomic Energy Research Institute. As a result, the Westinghouse computer codes were validated as sufficient for use in performing accident analyses in accordance with the requirements of 10 CFR Part 50 and Part 52. In addition, the NRC performed independent analyses of the AP600 using different analysis codes to confirm the adequacy of the AP600 design as well as the AP600 safety analysis presented in the AP600 Standard Safety Analysis Report. These independent analyses also confirmed the large safety margins exhibited in the AP600.

Westinghouse is developing a larger version of the AP600 called the AP1000. The AP1000 design is based largely on the AP600. It employs passive systems that operate in the same manner as the AP600 passive systems. The AP1000 is being designed to meet NRC regulatory criteria in a similar manner to that found to be acceptable for the AP600. The AP1000 is being designed to meet NRC deterministic safety criteria and probabilistic risk criteria with large margins.

Westinghouse intends to certify the AP1000 standard plant design under the provisions of 10 CFR Part 52. As discussed in NUREG 1512, 10 CFR 52.47(b)(2)(i)(A) states that "Certification of a standard design which differs significantly from the light water reactor designs described in paragraph (b)(1) of this section or utilizes simplified, inherent, passive, or other innovative means to accomplish its safety functions will be granted only if

1. The performance of each safety feature of the design has been demonstrated through either analysis, appropriate test programs, experience, or a combination thereof;

2. Interdependent effects among the safety features of the design have been found acceptable by analysis, appropriate test programs, experience, or a combination thereof;

3. Sufficient data exist on the safety features of the design to assess the analytical tools used for safety analyses over a sufficient range of normal operating conditions, transient conditions, and specified accident sequences, including equilibrium core conditions;"

In this report the AP1000 plant design is described, with focus on the AP1000 passive safety systems. Comparisons of the AP1000 design features to the AP600 or operating reactors are provided to demonstrate the proven basis for the AP1000 design features selected. Table 1 provides a summary comparison of the key design parameters of the AP1000 with those of the AP600.

Table 1 Comparison of NSSS Design Parameters

	AP600	AP1000
Reactor Power, MWt	1933	3400
Hot Leg Temperature, °F	600	615
Number of Fuel Assemblies	145	157
Type of Fuel Assembly	17x17	17x17
Active Fuel Length, ft	12	14
Linear Heat Rating, kw/ft	4.10	5.707
R/V I.D., inches	157	157
Steam Generator Heat Transfer Area, ft^2	75,180	125,000
Reactor Coolant Pump Flow, gpm	51,000	75,000
Pressurizer Volume, ft^3	1600	2100

A summary comparison of key passive safety system design features are provided in Table 2. These key features are discussed due to their importance in affecting the key thermal-hydraulic phenomenon exhibited by the passive safety systems in critical areas.

Table 2 Comparison of Passive Safety System Design Features

	AP600	AP1000	Comment
Core Makeup Tanks Number Volume, ft^3 Line Resistance, % Design Flow Rate, %	 2 2000 100% 100%	 2 2500 64% 125%	Core makeup tank volume and flow rate is increased to provide additional safety injection flow. CMT elevations are maintained at the AP600 level. The duration of CMT injection is maintained similar to AP600.
Accumulators Number Volume, ft^3 Pressure, psig	 2 2000 700	 2 2000 700	The accumulators are the same as AP600. Accumulator sizing is based on LBLOCA performance and is determined largely on reactor vessel volume. The AP600 employs a 3-loop reactor vessel, while the AP1000 employs a 3XL vessel similar to Doel and Tihange plants. AP1000 LBLOCA performance will be similar to AP600.
IRWST Volume, gallons Water Level, ft Line Resistance Design Flow Rate, %	 557,000 130.00" 100% 100%	 590,000 131.58" 32% 184%	The IRWST level has been increased in the AP1000 by using more accurate level instruments. This permits a higher operating level.
Automatic Depressurization Stages 1-3 Location, Configuration, Vent Area, %	 Top pzr 6 paths 100%	 Top pzr 6 paths 100%	The first three stages of ADS are the same as AP600. Their sizing basis is to reduce pressure to permit adequate injection from the accumulators and to permit transition to 4th stage ADS.
Stage 4 Location, Configuration, Line size, nominal Vent Area, % Line Resistance Capacity	 Hot Leg 4 paths 10-inch 100% 100% 100%	 Hot legs 4 paths 14-inch 176% 28% 189%	The ADS 4th stage vent area is increased more than the ratio of the core power. The 4th stage ADS venting is the most important design feature to allow for stable IRWST/sump injection during long term core cooling.
Passive RHR Heat Exchanger Type Surface Area, % Design Flow Rate, % Design Heat Transfer, %	 C-Tube 100% 100% 100%	 C-Tube 122% 174% 172%	The AP1000 PRHR HX retains the AP600 configuration. The heat transfer surface area is increased by extending the length of the heat exchanger. The inlet and outlet piping has been increased resulting in higher flow rates.

Table 2 Comparison of Passive Safety System Design Features (cont.)

	AP600	AP1000	Comment
Containment Diameter, ft Overall Height, ft Shell Thickness, 1A Design Pressure, psig Net Free Volume, ft^3	 130 189.83 1.625 45 1.73 E06	 130 215.33 1.75 59 2.07 E06	The AP1000 containment volume and design pressure are increased to accommodate higher mass and energy releases.
Passive Containment Cooling System Water Storage Tank Volume (Top of Overflow), gallons	580,000	800,000	The PCS water storage tank was increased to accommodate higher flow rates. The PCS flow rates have been increased based on the increase in core power.

Accident analyses were performed for the AP1000 using the AP600 validated analysis codes and preliminary models of the AP1000 plant. These analyses are not a complete set of analyses as prescribed by 10 CFR 50. They are provided to characterize the expected performance of the AP1000. These analyses were performed using bounding assumptions and are performed in a manner consistent with the approach taken for the AP600, unless otherwise discussed in the report. In addition, the analysis results are provided in comparison to the AP600 analysis results for the same event to better demonstrate similarities to, or contrast differences with the performance of the AP600.

Based on the results of these analysis assessments, it appears that the analysis results for the AP1000 will provide large safety margins for the range of postulated accidents and transient events. The figures presented in this report show that the timing and interactions predicted for the AP1000 are similar to the performance predicted for the AP600. No new phenomenon or significant differences in performance characteristics are observed in the analysis results.

The use of WCOBRA-TRAC for long-term cooling calculations in a "window" mode was approved for AP600 for analysis of long-term cooling following a LOCA. Westinghouse intends to use a similar approach for the same events as was analyzed for the AP600. In this report, the use of WCOBRA-TRAC for an analysis of long-term cooling for DVI line break is provided and compared with WCOBRA-TRAC analysis in "window" mode for the same event. The analysis results demonstrate the validity of the use of the "windows" mode for predicting long-term core cooling.

Westinghouse is preparing a related report for submittal to the U.S. NRC as part of the pre-application review of the AP1000. That report – WCAP-15613, AP1000 Scaling Assessment and Analysis Plan, provides scaling studies of the AP600 tests, and assesses their scalability to the AP1000. The purposes of WCAP-15613, when considered with the information provided in this report, are to demonstrate that for the AP1000:

- The design features and operating characteristics have been selected such that the performance of each safety feature and their interdependent effects can be judged to be sufficiently similar to the AP600 such that the NRC could determine that the AP600 test data satisfy the requirements of 10 CFR 52.47(b)(2)(I)(A) Items 1, 2, and 3 discussed above,

- The Westinghouse analysis codes validated for AP600, and modified and/or employed as described in WCAP-15612 and WCAP-15613 will be sufficient to perform the prescribed accident analyses for a Design Certification for the AP1000.

In conclusion, this report summarizes the scope of the design changes to the AP600 that are most important in evaluating the passive plant design features embodied in the certified AP600 standard plant design. These design changes are being incorporated into the AP1000 standard plant design that Westinghouse intends to certify under 10 CFR Part 52. The safety analysis results presented demonstrate that the passive safety concepts can be successfully applied to a plant of a higher power rating, and that the benefits of passive plant technology can be realized in the AP1000.

1 INTRODUCTION

Westinghouse Electric Company has designed an advanced 600 MWe (1933 MWt) nuclear power plant called the AP600. The AP600 uses passive safety systems to enhance plant safety and to satisfy US licensing requirements. The use of passive safety systems provides significant and measurable improvements in plant simplification, safety, reliability, investment protection and plant costs. These systems use only natural forces such as gravity, natural circulation, and compressed gas to provide the driving forces for the systems to adequately cool the reactor core following an accident. The AP600 received Design Certification by the Nuclear Regulatory Commission in December 1999.

Westinghouse has initiated development of the AP1000 standard nuclear reactor design based closely on the AP600 design. The AP1000, with a power output of approximately 1000 MWe (3400 MWt), maintains the AP600 design configuration, use of proven components and licensing basis by limiting the changes to the AP600 design to as few as possible.

The AP1000 reactor and passive safety features retain the same configuration as the AP600. The capacities of the major reactor components have been increased to support the increased power rating. The approach to designing the passive safety features (core cooling and containment cooling) is to evaluate each feature to determine if changes are necessary to provide proper safety margins at the higher power rating. Preliminary safety evaluations have shown that the AP1000 passive safety systems provide adequate performance during limiting design basis accidents.

This report contains a description of the AP1000 plant design and a summary of the preliminary safety evaluations which confirm the feasibility of the uprating concept. The AP1000 plant description focuses on the major components and systems on the nuclear island. Major differences between the AP1000 and AP600 are highlighted at the end of each system/component section. Documentation of the preliminary safety evaluations includes descriptions of the events, analysis input assumptions, and evaluation results.

2 AP1000 DESIGN DESCRIPTION

2.1 PLANT OVERVIEW

2.1.1 Design Origin and Overall Plant Description

The AP1000 is a two-loop, 1000 MWe pressurized water reactor (PWR) with passive safety features and extensive plant simplifications to enhance the construction, operation, and maintenance. The AP1000 design is derived directly from the AP600, a two-loop, 600 MWe PWR. The AP600 uses proven technology which builds on over 30 years of operating PWR experience. The AP600 design received Final Design Approval from the U.S. NRC in September 1998 and Design Certification in December 1999. The AP1000 retains the AP600 approach of using proven PWR technology and safety features that rely on natural forces.

The AP1000 passive safety systems are the same as those for the AP600, except for some changes in component capacities. The safety systems maximize the use of natural driving forces such as pressurized gas, gravity flow, and natural circulation flow. Safety systems do not use active components (such as pumps, fans, or diesel generators) and are designed to function without safety-grade support systems (such as alternating current [ac] power, component cooling water, service water, or heating, ventilation, and air-conditioning [HVAC]). The number and complexity of operator actions required to control the safety systems are minimized; the approach is to eliminate required operator action rather than to automate it. The net result is a design with reduced complexity and improved operability.

The approach in uprating the AP600 to the AP1000 was to increase the power capability of the plant within the space constraints of the AP600, while retaining the credibility of proven components and substantial safety margins. Therefore, the AP1000 retains the AP600 licensing basis.

Some of the high-level design characteristics of the AP1000 are as follows:

- Net electrical power is approximately 1090 MWe, and nuclear steam supply system (NSSS) thermal power is 3415 MWt.

- Rated performance is achieved with up to 10 percent of the steam generator tubes plugged and with a maximum hot leg temperature of 617°F.

- Major safety systems are passive; they require no operator action for 72 hours after an accident, and maintain core and containment cooling for a protracted time without ac power.

- Predicted core damage frequency will be similar to AP600 (1.7E-07/yr) and will be well below the 1E-04/yr requirement. The frequency of significant release will be similar to AP600 (1.8E-08/yr) which is well below the 1E-06/yr requirement.

- Standard design is applicable to anticipated U.S. sites.
- Occupational radiation exposure is expected to be below 0.7 man-Sv/yr (70 man-rem/yr).
- The core is designed for an 18-month fuel cycle.
- Overall plant availability is greater than 93 percent, including forced and planned outages; the goal for unplanned reactor trips is less than one per year.
- The plant is designed to accept a 100-percent load rejection from full power to house loads without reactor trip or operation of the pressurizer or steam generator safety valves. The design provides for a turbine capable of continued stable operation at house loads.
- The plant is designed with significantly fewer components and significantly fewer safety-related components than a current pressurized water reactor of a comparable size.
- The plant design objective is 60 years without the planned replacement of the reactor vessel, which itself has a 60-year design objective based on conservative assumptions. The design provides for the replaceability of other major components, including the steam generators.
- The design of the major components required for power generation – such as the steam generators, reactor coolant pumps, fuel, internals, turbine, and generator – is based on equipment that has successfully operated in power plants. Modifications to these proven designs were based on similar equipment that had successful operating experience in similar or more severe conditions.

2.1.2 Plant Comparisons

2.1.2.1 Overall Plant Parameters

A comparison of the major AP1000 design features and nominal parameters with the AP600 and conventional pressurized water plants with a similar power rating as the AP1000 is provided in Table 2.1-1. The values provided are nominal and provided for comparison and not for design certification. The V. C. Summer plant was chosen for comparison because it has a core power density similar to that of the AP1000. The San Onofre Unit 2 and 3 parameters provide a comparison to a two-loop plant of similar thermal power rating.

2.1.2.2 Plant Design Features

The design approach for the AP1000 was to utilize design features and components that have been proven in currently operating plants or are based on such proven components. The AP1000 incorporates both design features that are the same as in current operating plants, and those that are based heavily on proven technology. The major design features which are based

on proven designs in current plants are discussed here. They include the core design, steam generator design, reactor coolant pump motors.

CORE DESIGN

The AP1000 core design incorporates 157 fuel assemblies. This core design is the same as in V. C. Summer, Doel 3, and Tihange 4. The active fuel region in the Doel and Tihange plants is 14 feet, just as in the AP1000. However, the linear power density of the AP1000 core is approximately the same as the V. C. Summer core, although the active length of the V. C. Summer core is only 12 feet. Thus, the Doel and Tihange plants provide operating experience with the 157 assembly core and the longer fuel assembly mechanical design. The V. C. Summer plant provides operating experience with this core arrangement at the higher AP1000 linear power density compared to Doel and Tihange.

STEAM GENERATOR DESIGN

Design Features and Power Rating

The AP1000 steam generator is a vertical U-tube design with a triangular pitch tube arrangement. Many of the design features of the Delta 125 units have been incorporated from the operating replacement Delta 75 and Delta 94 steam generators. Operating experience with these generators has been obtained in the V. C. Summer and Shearon Harris plants (Delta 75) and the South Texas plant (Delta 94). These generators operate at a lower power rating than those of the AP1000. However, the replacement steam generators for the Arkansas #1 unit, provide experience in the power range of the AP1000. The steam generators for the San Onofre and Waterford units are also rated at the same 1700 MWt as the AP1000.

Inconel Tubes

In the past, steam generator tube integrity has been linked with tube material and the reactor coolant system hot leg temperature. The AP1000 steam generator design utilizes Inconel-690 tubes and has a hot leg temperature of 615°F. Table 2.1-2 lists the current operating plants which have steam generators with Inconel-690 tubes along with their reactor coolant hot leg temperature. As can be seen from the table, three plants have hot leg operating temperatures higher than the temperature proposed for the AP1000.

REACTOR COOLANT PUMP

The AP1000 reactor coolant pump utilizes a hermetically sealed canned motor of proven design. The addition of a uranium alloy flywheel to provide the rotating inertia needed for flow coast-down is based on the design of the AP600 reactor coolant pumps. The AP1000 pump incorporates the hydraulics scaled down from the hydraulics developed for the Tsuruga 3/4 reactor coolant pumps. Thus, the AP1000 reactor coolant pumps are based on components with extensive operating history and previous design work.

Table 2.1-1 AP1000 Plant Comparison With Other Facilities				
Systems/Components	**AP1000**	**AP600**	**San Onofre 2&3**	**V. C. Summer**
Overall Plant				
Plant Life Design Objective	60 Years	60 Years	40 Years	40 Years
NSSS Power	3,415 MWt	1,940 MWt	3,410 MWt	2,912 MWt
Core Power	3,400 MWt	1,933 MWt	3,390 MWt	2,900 MWt
Net Electrical Output	1,090 MWe	600 MWe	~1,100 MWe	~950 MWe
Reactor Operating Pressure	2,250 psia	2,250 psia	2,250 psia	2,250 psia
Hot Leg Temperature	615°F	600°F	611°F	622°F
SG Design Pressure	1200 psia	1200 psia[1]	1100 psia	1200 psia
Main Feedwater Temperature	440°F	435°F	445°F	440°F
Core				
Number of Fuel Assemblies	157	145	217	157
Active Fuel Length	168 in	144 in	150 in	144
Fuel Assembly Array	17 x 17	17 x 17	16 x 16	17 x 17
Number of Control Assemblies	53	45	83 Full Length 8 Part Length	48
- Absorber Material	Ag-In-Cd	Ag-In-Cd	Ag-In-Cd	Ag-In-Cd
Number of Gray Rod Assemblies	16	16	None	None
- Absorber Material	SS-304/ Ag-In-Cd	SS-304/ Ag-In-Cd	-----	-----
Average Linear Power	5.707 kw/ft	4.10 kw/ft	5.34 kw/ft	5.69 kw/ft (Engineered Safety Design Rating)
Heat Flux Hot Channel Factor, F_Q	2.60	2.60	2.35	2.45

[1] Actual design pressure for the Delta-75 SG is 1200 psia. A design pressure of 1100 psia was retained for the AP600.

Table 2.1-1 AP1000 Plant Comparison With Other Facilities (cont.)

Systems/Components	AP1000	AP600	San Onofre 2&3	V. C. Summer
Reactor Vessel				
Vessel ID	157 in	157 in	172 in	157 in
Number Hot Leg Nozzles	2	2	2	3
- ID	31.0 in	31.0 in	42 in	29 in
Number Cold Leg Nozzles	4	4	4	3
- ID	22.0 in	22.0 in	30 in	27.5 in
Number Safety Injection Nozzles	2	2	None	None
Steam Generators				
Type	Vertical U-Tube, Recirc Design	Vertical U-Tube, Recirc Design	Vertical U-Tube Design	Vertical U-Tube Design
Model	Delta-125	Delta-75	C-E	Delta-75
Number	2	2	2	3
Heat Transfer Area/SG	125,000 ft^2	75,180 ft^2	103,574 ft^2	75,180 ft^2
Number Tubes/SG	10,000	6,307	9,300	6,307
Tube Material	I 690 TT	I 690 TT	I 600	I 690 TT
Separate Startup Feedwater Nozzle	Yes	Yes	No	No
Reactor Coolant Pumps				
Type	Canned	Canned	Shaft Seal	Shaft Seal-Model 93A
Number	4	4	4	3
Rated HP[2]	6,000 hp/pump	≤ 3,500 hp/pump	7,200 hp/pump	7,000 hp/pump (cold)
Estimated Flow/Loop (Best Estimate)	150,000 gpm	102,000 gpm	198,000 gpm	103,400 gpm
Pressurizer				
Total Volume	2,100 ft^3	1,600 ft^3	1,514 ft^3	1,400 ft^3
Volume/MWt	0.615 ft^3/MWt	0.825 ft^3/MWt	0.45 ft^3/MWt	0.481 ft^3/MWt

[2] Rated at Hot Conditions

Table 2.1-1 AP1000 Plant Comparison With Other Facilities (cont.)

Systems/Components	AP1000	AP600	San Onofre 2&3	V. C. Summer
Safety Valves #/Size	2 – 6 x 8	2 – 6 x 6	2 – 6 x 8	3 – 6 x 6
PORV #/Size	No	No	No	3-3 in
PRT Volume	No	No	320 ft^3	1300 ft^3
Automatic Depressurization	Yes	Yes	No	No
Turbine Island				
Turbine - # HP Cylinder	1	1	1	1
# LP Cylinder	2 or 3	2	3	2
Number Reheat Stages	1	1	2	1
Feedwater Heating Stages				
- # LP Stages	4	4	5	4
- # HP Stages	2	2	1	2
Deaerator	Yes	Yes	No	Yes
Main Feedwater Pumps	2 – Motor Driven	2 – Motor Driven	2 – Turbine Driven	3 – Turbine Driven
Containment				
Type	Steel	Steel	Reinforced Concrete	Reinforced Concrete
Inside Diameter	130 ft	130 ft	150 ft	126 ft
Free Volume	2.07+06 ft^3	1.73E+06 ft^3	2.34E+06 ft^3	1.84E+06 ft^3
Volume/MWt	605 ft^3/MWt	910 ft^3/MWt	690 ft^3/MWt	635 ft^3/MWt
Post Accident Cooling	Air & Water on Outside of Containment Vessel	Air & Water on Outside of Containment Vessel	Containment Spray/Safety Grade Bldg Cooling	Containment Spray/Safety Grade Bldg Cooling
Safety Injection				
Accumulator - #/Volume	2/2,000 ft^3	2/2,000 ft^3	4/2,250 ft^3	3/1,450 ft^3
Core Makeup Tank - #/Volume	2/2,500 ft^3	2/2,000 ft^3	None	None
High Head Pumps - #	None	None	3	3
- Runout Flow	—	—	1,000 gpm	690 gpm
- Shutoff Head	—	—	3,410 ft	6,200 ft

Table 2.1-1 AP1000 Plant Comparison With Other Facilities (cont.)

Systems/Components	AP1000	AP600	San Onofre 2&3	V. C. Summer
Low Head Pumps - #	None	None	2 (RHR)	2 (RHR)
Refueling Water Storage Tank - #	1	1	2	1
- Location	In-Containment	In-Containment	Outside Containment	Outside Containment
- Water Volume	590,000 gal	557,000 gal	490,000 gal (Nominal-Total)	491,000 gal
Normal RHR				
Design Pressure	900 psig	900 psig	650 psig (discharge), 435 psig (suction)	600 psig (discharge), 450 psig (suction)
NRHR Pumps - #/Design Flow	2/1,000 gpm per pump	2/1,000 gpm per pump	2/4,150 gpm per pump	2/3,750 gpm per pump
Cooling Water Systems				
Safety-Related	No	No	Yes	Yes
Component Cooling Water Pumps	2	2	3	3
Service Water Pumps	2	2	4	3
Heat Sink	Separate Mechanical Draft Cooling Tower	Separate Mechanical Draft Cooling Tower	Ocean	Lake
Startup/Aux Feedwater				
Motor Pumps - #/Flow per Pump/Safety Related	2/675 gpm/no	2/380 gpm/no	2 EFW/ 860 gpm/Yes	2 EFW/ 400 gpm/Yes
Turbine Pumps - #/Flow	None/—	None/—	1 EFW/ 860 gpm/Yes	1 EFW/ 800 gpm/Yes
Passive RHR HX - #/Safety Related	1/Yes	1/Yes	None	None
Chemical & Volume Control				
Purification/Letdown Flow				
- Normal	100 gpm	100 gpm	40 gpm	60 gpm
- Maximum	100 gpm	100 gpm	128 gpm	120 gpm

Table 2.1-1 AP1000 Plant Comparison With Other Facilities (cont.)

Systems/Components	AP1000	AP600	San Onofre 2&3	V. C. Summer
Purification Location	Inside Containment	Inside Containment	Outside Containment	Outside Containment
RCP Seal Injection/Pump	None	None	None	8 gpm/pump
Charging Pumps	2 @ 100 gpm	2 @ 100 gpm	3 @ 44 gpm	3 @ 180 gpm
- SI Use	No	No	No	Yes
- Safe Shutdown Use	No	No	Yes	Yes
- Continuous Operation	No	No	Yes	Yes
Boron Thermal Regeneration	No	No	No	Yes
Boron Recycle Evaporator	No	No	Exists, but not used	Yes
Electrical				
Diesels - #	2	2	2	2
- Safety Related	No	No	Yes	Yes
- Capacity	4,000 kw	4,000 kw	4,700 kw	4,400 kw
1E Batteries – Total Capacity	28,000 Amp-Hr	28,000 Amp-Hr	9,200 Amp-Hr	4,350 Amp-Hr

Table 2.1-2 Current Plants With Inconel 690 Steam Generator Tubing				
Plant	**# of SGs**	**Total # of Tubes**	**Service Date**	**Hot Leg Operating Temp (°F)**
South Texas 1	4	30,340	3/00	624
V. C. Summer	3	17,217	12/94	619
Sizewell B	4	22,504	2/95	617
AP1000	*2*	*20,000*	–	*615*
North Anna 1	3	10,776	4/93	613
North Anna 2	3	10,776	6/95	613
Ko-Ri 1	2	9,868	6/98	607
Farley 1	3	10,776	3/00	607
D. C. Cook 2	4	14,364	3/89	606
Indian Point 3	4	12,856	6/89	602
Point Beach 2	2	6,998	9/96	597

2.2 REACTOR SYSTEM DESIGN

The reactor system consists of those major items of equipment constituting the operating nuclear reactor. The system is defined to include the reactor vessel, core, reactor internals, control rod drive mechanisms (CRDM) and the integrated head package. These components are described below.

2.2.1 Core Design

The AP1000 core design consists of 157 17 x 17 fuel assemblies with a 14 foot active fuel length. The preliminary overall core parameters are given in Table 2.2.1-1.

2.2.1.1 Fuel Assemblies

Each fuel assembly consists of 264 fuel rods, 24 guide thimbles, and 1 instrumentation tube arranged within a supporting structure. The instrumentation thimble is located in the center position and provides a channel for insertion of an in-core neutron detector, if the fuel assembly is located in an instrumented core position. The guide thimbles provide channels for insertion of either a rod cluster control assembly, a gray rod cluster assembly, a neutron source assembly, or burnable absorber assembly, depending on the position of the particular fuel assembly in the core. The AP1000 incorporates the Westinghouse ROBUST fuel assembly design that includes guide thimbles with increased wall thickness and an improved grid design. Figure 2.2.1-1 shows a cross-section of the fuel assemblies in the reactor vessel, and Figure 2.2.1-2 shows a preliminary fuel assembly full-length view.

The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles. The fuel rods are supported within the fuel assembly structure by ten grids. The top and bottom grids are fabricated from nickel-chromium-iron Alloy 718, while the intermediate grids are fabricated from Zircaloy-4. Top, bottom, and intermediate grids provide axial and lateral support to the fuel rods. In addition, four intermediate flow mixer (IFM) grids located near the center of the fuel assembly and between the intermediate grids provide additional fuel rod restraint.

Fuel assemblies are installed vertically in the reactor vessel and stand upright on the lower core plate, which is fitted with alignment pins to locate and orient each assembly. After the fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears down against the hold-down springs on the top nozzle of each fuel assembly to hold the fuel assemblies in place.

Improper orientation of fuel assemblies within the core is prevented by the use of an indexing hole in one corner of the top nozzle top plate. The assembly is oriented with respect to the handling tool and the core by means of a pin inserted into this indexing hole. Visual confirmation of proper orientation is also provided by an engraved identification number on the opposite corner clamp.

The fuel assembly structure consists of a bottom nozzle, top nozzle, fuel rods, guide thimbles, and grids which are discussed below.

FUEL RODS

The fuel rods consist of uranium dioxide ceramic pellets contained in ZIRLO™ tubing, which is plugged and seal-welded at the ends to encapsulate the fuel. The fuel pellets are right circular cylinders consisting of slightly enriched uranium dioxide powder which has been compacted by cold pressing and then sintered to the required density. The ends of each pellet are dished slightly, to allow greater axial expansion at the pellet centerline and to increase the void volume for fission gas release. The ends of each pellet also have a small chamfer at the outer cylindrical surface which improves manufacturability, and mitigates potential pellet damage due to fuel rod handling.

Void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the clad and the fuel, and fuel density changes during irradiation. To facilitate the extended burnup capability necessitated by longer operating cycles, the fuel rod is designed with two plenums (upper and lower) to accommodate the additional fission gas release. The upper plenum volume is maintained by a fuel pellet hold-down spring. The lower plenum volume is maintained by a standoff assembly.

The AP1000 fuel rod design may also include axial blankets. The axial blankets consist of fuel pellets of a reduced enrichment at each end of the fuel rod pellet stack. Axial blankets reduce neutron leakage axially and improve fuel utilization.

The AP1000 fuel rods include integral fuel burnable absorbers. The integral fuel burnable absorber coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boride coating less than 0.001 inch in thickness on the pellet cylindrical surface. Coated pellets occupy the central portion of the fuel column.

BOTTOM NOZZLE

The bottom nozzle serves as the bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The nozzle is fabricated from Type 304 stainless steel and consists of a perforated plate, and casting which incorporates a skirt and four angle legs with bearing pads. The legs and skirt form a plenum to direct the inlet coolant flow to the fuel assembly. The perforated plate also prevents accidental downward ejection of the fuel rods from the fuel assembly. The bottom nozzle is fastened to the fuel assembly guide thimbles by locked thimble screws, which penetrate through the nozzle and engage with a threaded plug in each guide thimble.

Coolant flows from the plenum in the bottom nozzle, upward through the penetrations in the plate, to the channels between the fuel rods. The penetrations in the plate are positioned between the rows of the fuel rods.

In addition to serving as the bottom structural element of the fuel assembly, the bottom nozzle also functions as a debris filter.

Axial loads (from top nozzle hold-down springs) imposed on the fuel assembly and the weight of the fuel assembly are transmitted through the bottom nozzle to the lower core plate.

TOP NOZZLE

The reconstitutable top nozzle functions as the upper structural component of the fuel assembly and, in addition, provides a partial protective housing for the rod cluster control assembly, wet annular burnable absorber, or other core components. The basic components of the welded top nozzle include the adapter plate, enclosure, and top plate. The top nozzle assembly includes four sets of hold-down springs and associated spring screws and clamps, which are secured to the top nozzle top plate. The springs are made of nickel-chromium-iron Alloy 718. The other top nozzle components are made of Type 304 stainless steel.

GUIDE THIMBLES

The guide thimbles are structural members that provide channels for the neutron absorber rods, burnable absorber rods, neutron source rods, or other assemblies. Each guide thimble is fabricated from Zircaloy-4 or ZIRLO™ tubing having two different diameters. The larger tube diameter at the top section provides a relatively large annular area necessary to permit rapid control rod insertion during a reactor trip, as well as to accommodate the flow of coolant during normal operation. Holes are provided on the guide thimble above the dashpot to reduce the rod drop time. The lower portion of the guide thimble is swaged to a smaller diameter, which results in a dashpot action near the end of the control rod travel during normal trip operation. The dashpot is closed at the bottom by means of an end plug, which is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation.

GRIDS

The fuel rods are supported at intervals along their lengths by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. Each fuel rod is given support at six contact points within each grid by the combination of support dimples and springs. The grid assembly consists of individual slotted straps assembled and interlocked into an egg-crate type arrangement with the straps permanently joined at their points of intersection. The straps may contain springs, support dimples, and mixing vanes; or any such combination.

Two types of structural grid assemblies are used on the AP1000 fuel assembly. One type, with mixing vanes projecting from the edges of the straps into the coolant stream, is used in the high heat flux region of the fuel assemblies to promote mixing of the coolant. The other type, located at the top and bottom of the assembly, does not contain mixing vanes on the internal straps. The outside straps on the grids contain mixing vanes that, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or during loading and unloading of the core.

Because of its corrosion resistance and high strength properties, the bottom grid material is nickel-chromium-iron Alloy 718. The top grid is fabricated from nickel-chromium-iron Alloy 718.

The intermediate (mixing vane), or structural grids on the AP1000 fuel assembly are made of ZIRLO™. The intermediate flow mixer grids are located at selected spans between the zirconium alloy mixing vane structural grids and incorporate a similar mixing vane array. Their prime function is mid-span flow mixing in the hotter fuel assembly spans. The intermediate flow mixer grids, like the mixing vane grids, are fabricated from ZIRLO™.

2.2.1.2 In-Core Control Components

Reactivity control is provided by neutron absorbing rods, gray rods, burnable absorber rods, and a soluble chemical neutron absorber (boric acid). The boric acid concentration is varied to control long-term reactivity changes such as fuel and burnable absorber depletion, fission product buildup, and zero power reactivity changes.

A negative power coefficient is maintained at hot, full-power conditions throughout the entire cycle to reduce possible deleterious effects caused by a positive coefficient during pipe rupture or loss-of-flow accidents.

ROD CLUSTER CONTROL ASSEMBLIES

The rod cluster control assemblies are divided into two categories: control and shutdown. The control groups compensate for reactivity changes due to variations in operating conditions of the reactor, that is, power and temperature variations.

The absorber material used in the control rods is silver-indium-cadmium alloy, which is essentially "black" to thermal neutrons and has sufficient additional resonance absorption to significantly increase worth. The absorber material is in the form of solid bars sealed in cold-worked stainless steel tubes. The material used in the absorber rod end plugs is Type 308 stainless steel.

GRAY ROD CLUSTER ASSEMBLIES

The mechanical design of the gray rod cluster assemblies plus the control rod drive mechanism and the interface with the fuel assemblies and guide thimbles are identical to the rod cluster control assembly.

The gray rod cluster assemblies consist of 24 rodlets fastened at the top end to a common hub or spider. Geometrically, the gray rod cluster assembly is the same as a rod cluster control assembly except that 20 of the 24 rodlets are stainless steel while the remaining four contain the same silver-indium-cadmium absorber material clad with stainless steel as the rod cluster control assemblies.

The gray rod cluster assemblies are used in load follow maneuvering and provide a mechanical shim to replace the use of changes in the concentration of soluble boron, that is, a chemical shim, normally used for this purpose. The AP1000 uses 53 rod cluster control assemblies and 16 gray rod cluster assemblies.

BURNABLE ABSORBER ASSEMBLY

Each burnable absorber assembly consists of wet annular burnable absorber rods attached to a hold-down assembly. When needed for nuclear considerations, burnable absorber assemblies are inserted into selected thimbles within fuel assemblies.

The wet annular burnable absorber rods consist of annular pellets of alumina-boron carbide material contained within two concentric zirconium alloy tubes. These zirconium alloy tubes, which form the inner and the outer clad for the wet annular burnable absorber rod, are plugged, pressurized with helium, and seal-welded at each end to encapsulate the annular stack of absorber material. The absorber stack length is positioned axially within the wet annular burnable absorber rod by the use of a zirconium alloy bottom-end spacer. An annular plenum is provided within the rod to accommodate and retain the helium gas released from the absorber material as it depletes during irradiation. The reactor coolant flows inside the inner tube and outside the outer tube of the annular rod.

NEUTRON SOURCE ASSEMBLIES

The purpose of a neutron source assembly is to provide a base neutron level to give confidence that the detectors are operational and responding to core multiplication neutrons. For the first core, a neutron source is placed in the reactor to provide a positive neutron count of at least two counts per second on the source range detectors attributable to core neutrons. The detectors, called source range detectors, are used primarily during subcritical modes of core operation.

The source assembly also permits detection of changes in the core multiplication factor during core loading, refueling, and approach to criticality. This can be done since the multiplication factor is related to an inverse function of the detector count rate. Changes in the multiplication factor can be detected during addition of fuel assemblies while loading the core, changes in control rod positions, and changes in boron concentration.

Four source assemblies are typically installed in the reactor core: two primary source assemblies and two secondary source assemblies. Each primary source assembly contains one primary source rod and a number of burnable absorber rods. Each secondary source assembly contains a symmetrical grouping of four to six secondary source rods.

2.2.1.3 Differences Between AP1000 and AP600

The major differences in the AP1000 core design compared to the AP600 core design are the addition of 12 fuel assemblies, an increase in the length of the fuel assemblies, and additional control assemblies. The extra assemblies and increase in length along with an increase in the linear power density in the core enabled the core power rating to be increased from 1,933 MWt

to 3,400 MWt within the same diameter reactor vessel. The number of rod control cluster was increased to 53 in the AP1000 compared to 45 in the AP600. The AP1000 core also incorporates the Westinghouse ROBUST fuel assembly design compared to the Vantage 5-H design of the AP600. The ROBUST design includes guide tubes with increased wall thickness. These differences are highlighted in the table below. More differences between the AP100 and AP600 Fuel assembly design may be identified as the detailed design of the AP1000 fuel assembly proceeds.

Core Design Differences – AP1000 and AP600		
Parameter	**AP600**	**AP1000**
Core Power MWt	1,933	3,400
Number of Fuel Assemblies	145	157
Fuel Assembly Active Length, ft	12	14
Average Linear Power, kw/ft	4.10	5.707
Number of Rod Control Clusters	45	53
Guide Thimble Outer Diameter, in.	0.474	0.482
Guide Thimble Thickness, in.	0.016	0.020
Instrument Tube Outer Diameter, in.	0.474	0.482
Instrument Tube Thickness, in.	0.016	0.020

Table 2.2.1-1 AP1000 Overall Core Parameters	
Parameter	**Value**
Core Power, MWt	3,400
Number of Fuel Assemblies	157
Number of Fuel Rods	41,448
Fuel Assembly Pitch, in.	8.466
Inter-Assembly Gap, in. (At Inconel top and bottom grids)	0.040
Active Core Length, in.	168
Core Loading, MTU	84.5
Average Linear Power, kw/ft	5.707
Average Power Density, kw/liter	109.7
Average Specific Power, kw/kg	40.2
Fuel Rod Heat Transfer Area, ft^2	56,816
Average Heat Flux, Btu/hr-ft^2	198,930
Fraction of Heat Generated in Fuel	0.974
Design Value of F_Q	2.60
Design Value of $F_{\text{delta H}}$	1.65
Number of Rod Control Clusters	53
Number of Gray Rod Clusters	16

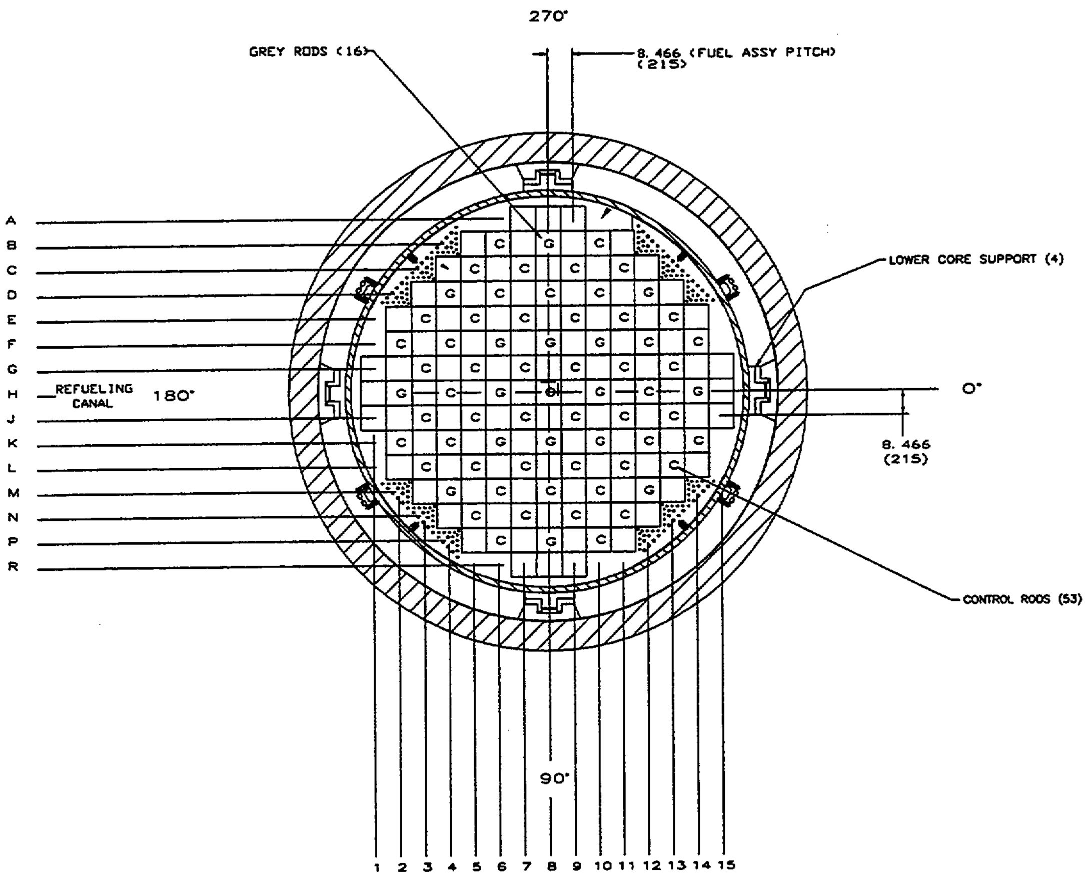


Figure 2.2.1-1 Cross Section of Fuel Assembly Arrangement

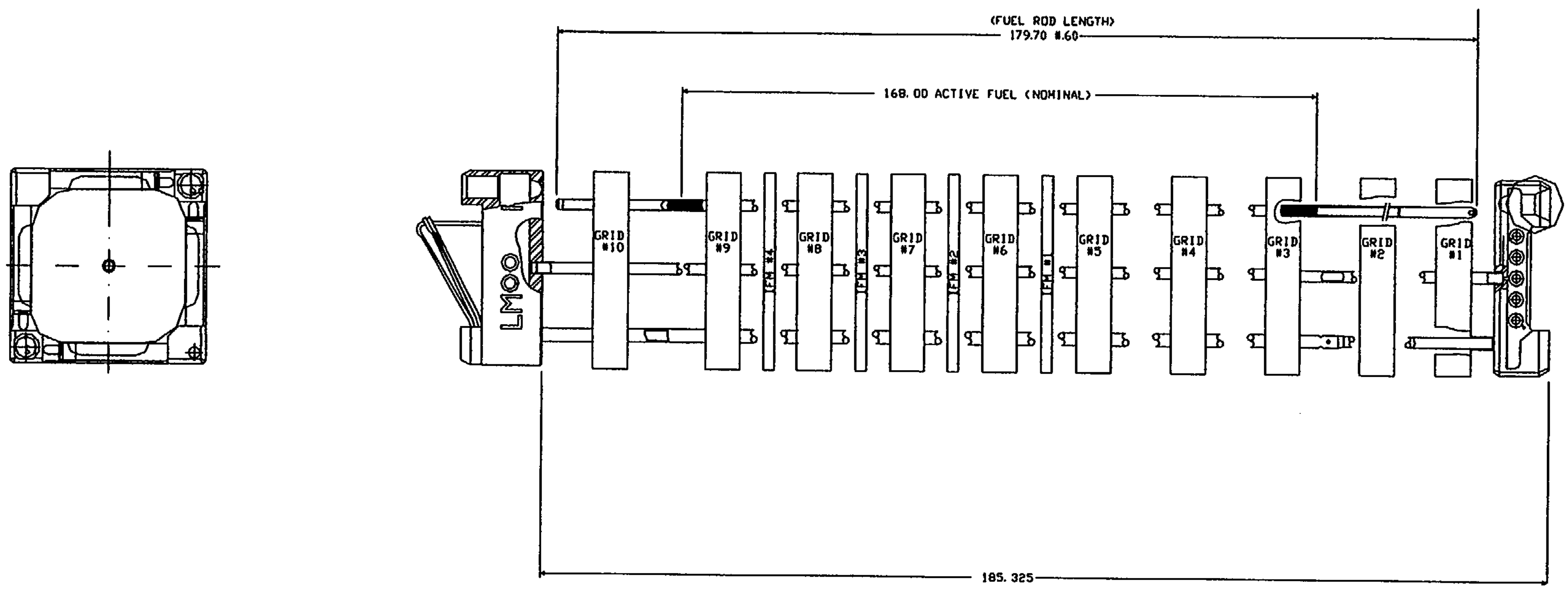


Figure 2.2.1-2 Fuel Assembly Full Length View

2.2.2 Reactor Vessel and Internals Design

2.2.2.1 Reactor Vessel

The reactor vessel is the high pressure containment boundary used to support and enclose the reactor core. It provides flow direction with the reactor internals through the core and maintains a volume of coolant around the core. The vessel is cylindrical, with a hemispherical bottom head and removable flanged hemispherical upper head. The vessel inside diameter at the core region is 157 inches and overall length as shown in the outline drawing of Figure 2.2.2-1. The vessel is fabricated by welding together the lower head, the lower shell and the upper shell. The upper shell contains the penetrations from the inlet and outlet nozzles and direct vessel injection nozzles. The closure head is fabricated with a head dome and bolting flange. The upper head has penetrations for the control rod drive mechanisms, the incore instrumentation, head vent, and support lugs for the integrated head package. The removable flanged hemispherical closure head is attached to the vessel (consisting of the upper shell-lower shell-bottom hemispherical head) by studs. Two metal o-rings are used for sealing the two assemblies. Inner and outer monitor tubes are provided through the upper shell to collect any leakage past the o-rings.

Surfaces which can become wetted during operation and refueling are clad to a nominal 0.22 inches of thickness with stainless steel welded overlay which includes the upper shell top surface but not the stud holes. The AP1000 reactor vessel's design objective is to withstand the design environment of 2500 psi and 650°F for 60 years. An evaluation of the reactor vessel fluence indicates that the increase in fluence from the AP600 to the AP1000 will not have a major impact on the AP1000 reactor vessel.

The reactor vessel supports the internals. An internal ledge is machined into the top of the upper shell section. The core barrel flange rests on the ledge. A large circumferential spring is positioned on the top surface of the core barrel flange. The upper support plate rests on the top surface of the spring. The spring is compressed by installation of the reactor vessel closure head and the upper and lower core support assemblies are restrained from any axial movements.

Four core support pads are welded to the bottom hemispherical head just below the bottom hemispherical head-to-lower shell circumferential weld. The core support pads function as a clevis. At assembly, as the lower internals are lowered into the vessel, the keys at the bottom of the lower internals engage the clevis in the axial direction. With this design, the internals are provided with a lateral support at the furthest extremity and may be viewed as a beam supported at the top and bottom.

The interfaces between the reactor vessel and the lower internals core barrel are such that the main coolant flow enters through the inlet nozzle and is directed down through the annulus between the reactor vessel and core barrel and flows up through the core. The annulus is designed such that the core remains in a coolable configuration for all design conditions.

The closure head has a 77.5-inch inner spherical radius and a 188.0-inch O.D. outer flange. Cladding is extended across the bottom of the flange for refueling purposes. Forty-five,

seven-inch diameter studs attach the head to the lower vessel and two metal o-rings are used for sealing. There are 69 penetrations in the removable flanged hemispherical head (closure head) that are used to provide access for the control rod drive mechanisms. Each control rod drive mechanism is positioned in its opening and welded to the closure head penetration. In addition there are penetrations in the closure head used to provide access for in-core and core exit instrumentation. A tube is inserted into each of the penetrations and is welded to the closure head penetration.

Lugs are welded to the outside surface of the closure head along the outer periphery of the dome section. The purpose of these lugs is to provide support and alignment for the integrated head package.

Attached to the top surface and along the outer periphery of the upper shell is a ring section. During field assembly the ring is welded to the refueling cavity seal liner. This ring provides an effective water seal between the refueling cavity and sump during refueling operations.

A support pad is integral to each of the four inlet nozzles. The pads support the reactor vessel. The pads rest on steel base pads atop a support structure, which is attached to a concrete foundation wall. Thermal expansion and contraction of the vessel are accommodated by sliding surfaces between the support pads and the base plates. Side stops on these plates keep the vessel centered and resist lateral loads.

The vessel upper shell is a large ring forging. Included in this forging are four 22-inch inner diameter inlet nozzles, two 31-inch inner diameter outlet nozzles and two 6.81-inch inner diameter direct vessel injection nozzles (8-inch schedule 160 pipe connections). These nozzles are forged into the ring or are fabricated by "set in" construction. The inlet and outlet nozzles are offset axially in different planes by 17.5 inches. This offset allows pump maintenance without discharging the core. The injection nozzles are 100 inches down from the main flange and the outlet nozzles are 80 inches down and the inlet nozzles are 62.5 inches below the mating surface. The primary coolant nozzles support one end of the primary coolant system. Reaction loads are transferred into the nozzles and eventually into the support pads.

There are no penetrations in the reactor vessel below the core. This eliminates the possibility of a loss-of-coolant accident by leakage from the reactor vessel that would allow the core to be uncovered.

2.2.2.2 Reactor Vessel Internals Design

The reactor internals are the structural assemblies that support the core within the reactor vessel and provide the proper flow path for the circulation of the coolant through the core. Included with the internals are those structures which guide and enable movement of the control rods.

When assembled in the reactor vessel the reactor internals provide the appropriate guidance, protection, alignment and support for the core and control rods to enable safe and reliable reactor operation. The internals consist of two major assemblies: the lower internals and the upper internals. The upper internals and core barrel are supported by the reactor vessel ledge

and are restrained against upward movement by the vessel head. The lower end of the internals is restrained against horizontal movement by barrel radial support keys located at the bottom of the core barrel.

The lower internals consists of the core barrel, lower support plate, vortex suppression plate, radial reflector, radial support and the related attachment hardware. Figure 2.2.2-2 illustrates the preliminary reactor lower internals design concept. During reactor operation the core barrel serves to direct the coolant flow from the reactor vessel inlet nozzles through the downcomer annulus, and into the lower plenum below the lower support plate. The flow then turns and passes upward through the lower core support plate into the core region.

The upper internals assembly which is located above the core, consists of the upper support plate, upper support columns, upper core plate, guide tubes and the related attachment hardware. Figure 2.2.2-3 illustrates the reactor upper internals assembly design concept. During operation coolant flows up from the core through the upper core plate and out through the outlet nozzles.

2.2.2.3 Integrated Head Package Design

The purpose of the integrated head package is to help reduce the outage time and minimize personnel radiation exposure by combining operations associated with movement of the reactor vessel head during the refueling outage. The integrated head package also helps to reduce the laydown space required in the containment.

The integrated head package consists of the following components:

- Shroud Assembly and Cooling System
- Lifting System
- Mechanism Seismic Support Structure
- Messenger Tray and Cable Support Structure
- Cable Bridge
- Cables
- Incore Instrumentation Conduits

With the integrated head package concept, the control rod drive mechanisms (CRDMs), and rod position indicators (RPI) remain with the reactor vessel head within the cooling shroud assembly at all times. The shroud assembly is a carbon steel structure which encloses the CRDMs above the reactor head. During normal operation it provides for flow of cooling air for the CRDMs and RPI coil stacks.

The overall height of the integrated head package is illustrated in Figure 2.2.2-1.

2.2.2.4 Differences Between AP1000 and AP600

The AP1000 reactor vessel has the same overall diameter and number and size of nozzles as the AP600 vessel. The overall length of the AP1000 vessel has been increased to accommodate the increase in core length to 14 feet. The AP1000 reactor vessel internals are of the same design as the AP600 vessel internals except that the length of the lower internals has increased because of the longer core design. Also, the thickness of the lower support plate has increased to accommodate the heavier AP1000 core which has both additional fuel assemblies (12) and heavier assemblies due to the longer length.

Although the preliminary AP1000 reactor vessel internals design includes a radial reflector concept similar to that of the AP600, the use of a reflector for the AP1000 is the subject of an ongoing engineering study. It is clear that a reflector is not required to achieve a 60 year reactor vessel life.

The AP1000 integrated head package design is the same as that of the AP600 except that the overall height has increased to accommodate the longer control rod drives and incore components required for the 14-foot AP1000 core. Internally, the AP1000 integrated head package also accommodates an additional eight control rod assemblies.

Figure 2.2.2-1 illustrates the overall height differences between the AP1000 and AP600 reactor vessels and integrated head packages. The table below summarizes the major differences between the AP1000 and AP600 reactor vessel internals designs.

Reactor Vessel and Internals Design Differences – AP1000 and AP600		
Parameter	**AP1000**	**AP600**
Reactor Vessel Overall Length (From Closure Head Flange to Bottom of Lower Head), ft-in	33 – 7.8	32 – 0.3
Lower Internals Overall Length, ft-in	32 – 3	30 – 7
Lower Support Plate Thickness, in	15	14
Radial Reflector	Currently Under Review	Yes
Rod Control Clusters	53	45

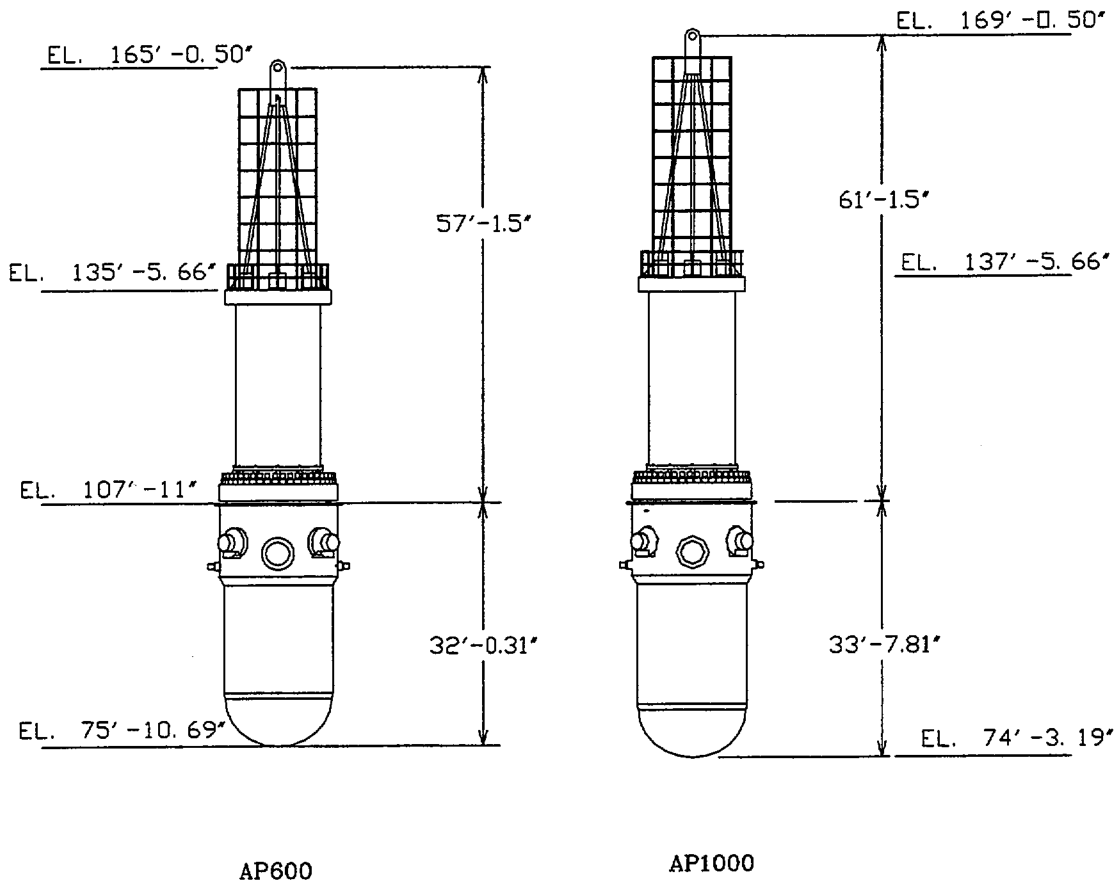


Figure 2.2.2-1 AP1000 and AP600 Reactor Vessel Outline Drawings

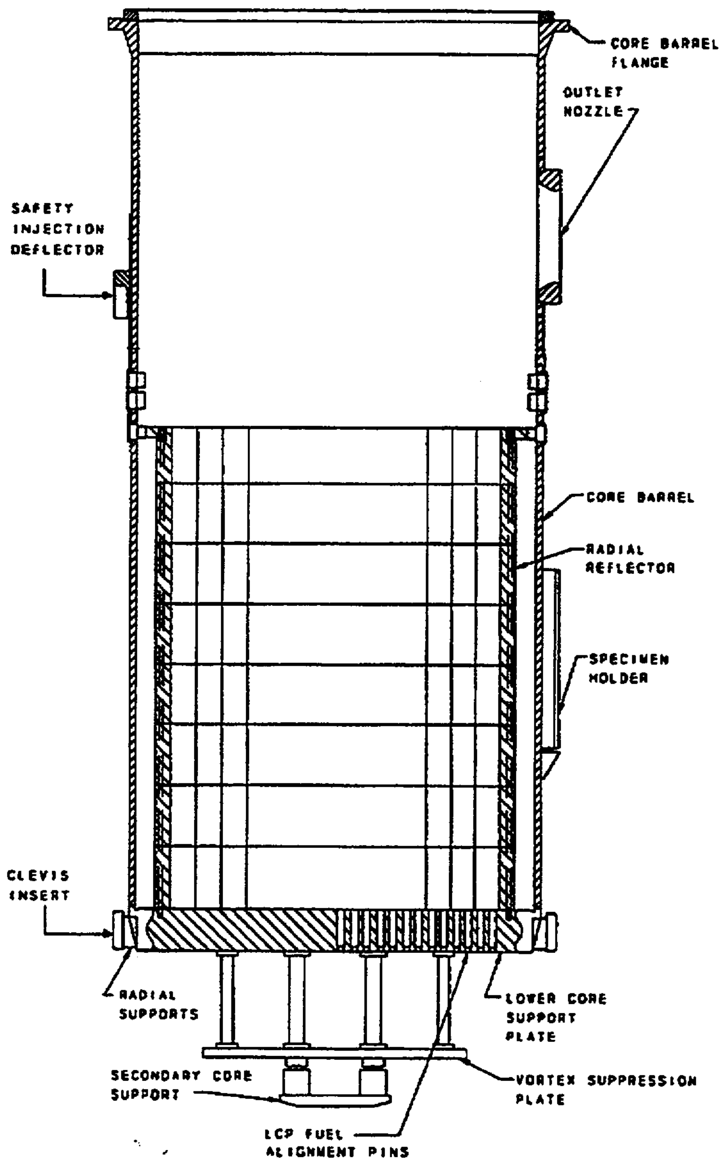


Figure 2.2.2-2 Reactor Vessel Lower Internals

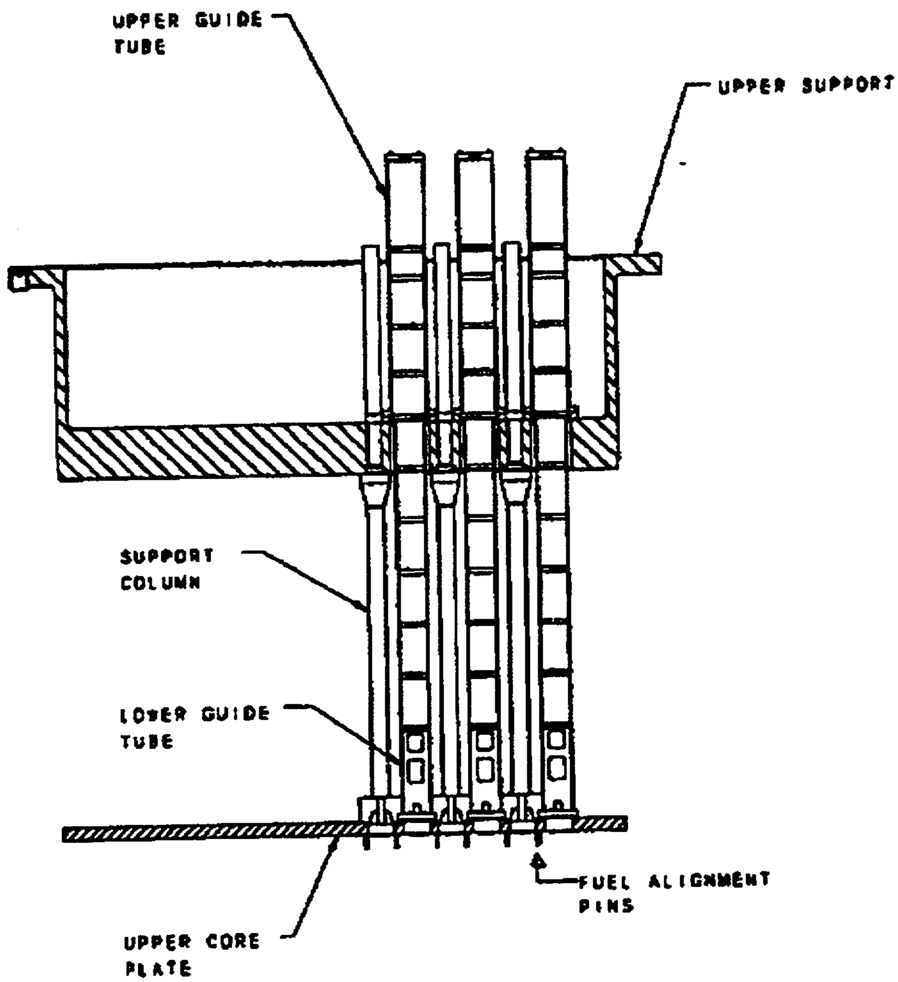


Figure 2.2.2-3 Reactor Vessel Upper Internals

2.3 REACTOR COOLANT SYSTEM DESIGN

2.3.1 Overall System Design

The reactor coolant system consists of two heat transfer circuits, each with a steam generator, two reactor coolant pumps, a single hot leg and two cold legs, for circulating reactor coolant between the reactor and the steam generators. In addition, the system includes a pressurizer, automatic depressurization system, interconnecting piping, valves, and instrumentation necessary for operational control and safeguards actuation. All system equipment is located in the reactor containment. Figure 2.3.1-1 shows a schematic of the reactor coolant system.

During operation, the reactor coolant pumps circulate pressurized water through the reactor vessel and the steam generators. The water, which serves as coolant, moderator, and solvent for boric acid (used for chemical shim control), is heated as it passes through the core. It next flows to the steam generators where the heat is transferred to the feedwater to make steam for the turbine/generator, and then is returned to the reactor by the reactor coolant pumps to repeat the process. The steam generators have a vertical shell and u-tube configuration with integral moisture separating equipment. The reactor coolant pumps are high-inertia, high-reliability, low-maintenance, canned-motor pumps and are integrated into the steam generator channel heads in the inverted position. The pressurizer controls reactor coolant system pressure by maintaining a single major water-steam interface in equilibrium under saturated conditions by electrical heaters and/or a water spray. Spring-loaded safety valves are installed above and connected to the pressurizer to provide overpressure protection for the reactor coolant system. The automatic depressurization system consists of four different valve stages that open sequentially to reduce reactor coolant system pressure so that long term cooling can be provided from the passive core cooling system.

Table 2.3.1-1 lists the nominal thermal hydraulic parameters of the reactor coolant system. The system performance parameters are also determined for an assumed 10 percent uniform steam generator tube plugging condition.

The reactor coolant system includes the following:

- The reactor vessel, including control rod drive mechanism housings.
- The reactor coolant pumps, consisting of four canned motor pumps that pump fluid through the entire reactor coolant and reactor systems and two pumps that are coupled with each steam generator.
- The portion of the steam generators containing reactor coolant, including the channel head, tubesheet, and tubes.
- The pressurizer which is attached by the surge line to one of the reactor coolant hot legs. With a combined steam and water volume, the pressurizer maintains the reactor system within a narrow pressure range.

- The safety and automatic depressurization system valves.
- The reactor vessel head vent isolation valves.
- The interconnecting piping and fittings between the preceding principal components.
- The piping, fittings, and valves leading to connecting auxiliary or support systems.

Table 2.3.1-1 AP1000 Reactor Coolant System Thermal-Hydraulic Parameters		
Flow Conditions	**Without SG Tube Plugging**	**With 10% SG Tube Plugging**
Best-Estimate Flow (1)		
Flow Rate, gpm/loop	150,000	(5)
RV Outlet Temperature, °F	614.9	(5)
RV Inlet Temperature, °F	539.1	(5)
Thermal Design Flow (2)		
Flow Rate, gpm/loop	142,800	141,100
RV Outlet Temperature, °F	616.7	617.2
RV Inlet Temperature, °F	537.3	536.8
Minimum Measured Flow (3)		
Flow Rate, gpm/loop	145,500	143,750
Mechanical Design Flow (4)		
Flow Rate, gpm/loop	156,000	—

(1) The best-estimate flow is the most likely value for the normal full-power operating condition. The best-estimate flow provides the basis for the other design flows required for the system and component design.

(2) The thermal design flow is the conservatively low value used for thermal-hydraulic analyses where the design and measurement uncertainties are not combined statistically, and additional flow margin must therefore be explicitly included. The thermal design flow is derived by subtracting the plant flow measurement uncertainty from the minimum measured flow. The thermal design flow is approximately 4.5 percent less than the best-estimate flow.

(3) The minimum measured flow is specified in the technical specifications as the flow that must be confirmed or exceeded by the flow measurements obtained during plant startup. The measured flow is expected to fall within a range around the best-estimate flow. The magnitude of the expected range is established by statistically combining the system hydraulics uncertainty with the total flow rate within the expected range, less any excess flow margin that may be provided to account for future changes in the hydraulics of the reactor coolant system.

(4) Mechanical design flow is the conservatively high flow used as the basis for the mechanical design of the reactor vessel internals, fuel assemblies, and other system components. Mechanical design flow is established at 104 percent of best-estimate flow.

(5) The parameters for this condition will be determined in the design work to support Design Certification for the AP1000.

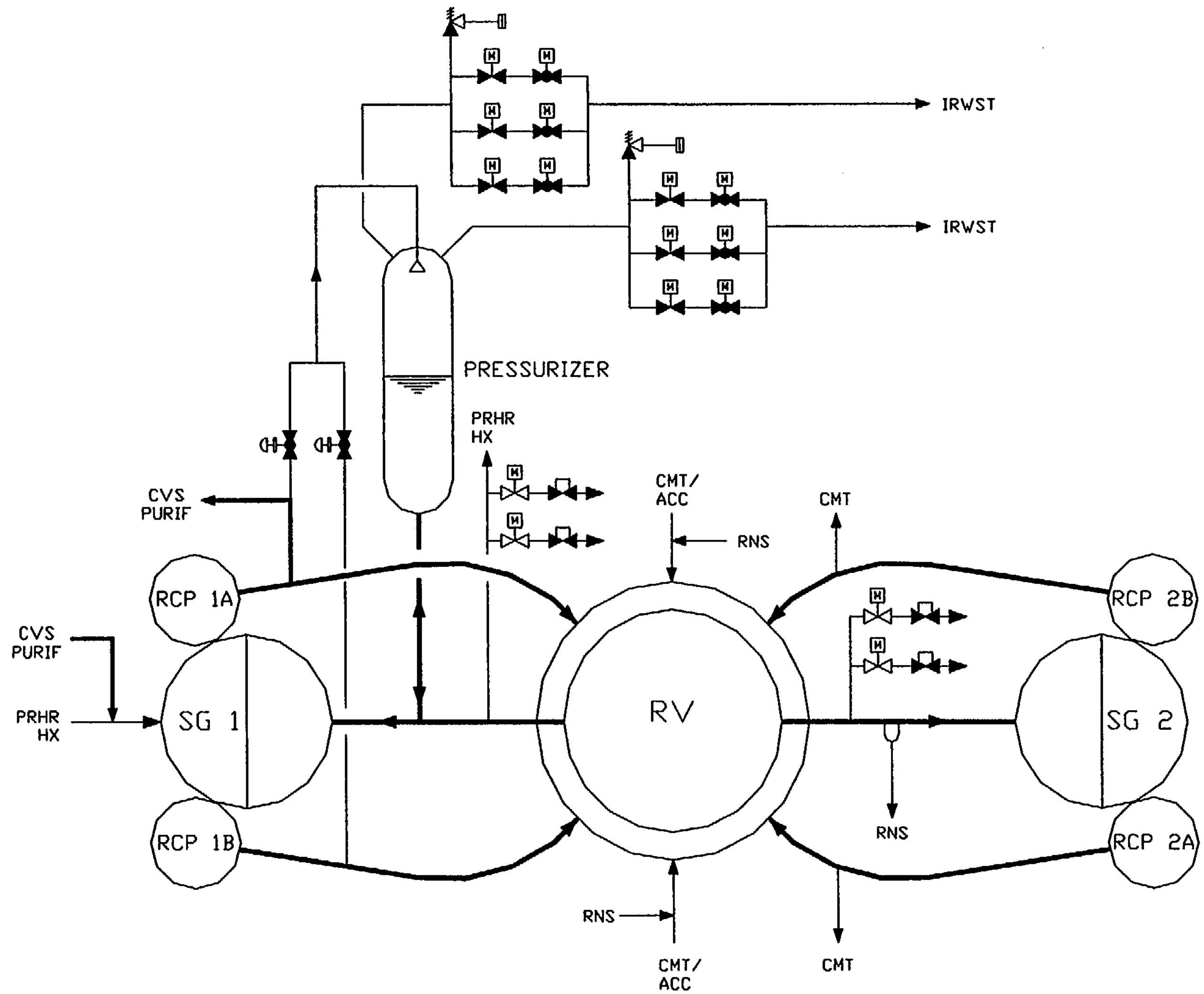


Figure 2.3.1-1 AP1000 Reactor Coolant System Flow Schematic

The major components are described in more detail below.

2.3.2 Steam Generator Design

2.3.2.1 Design Bases

The steam generator channel head, tubesheet, and tubes are a portion of the reactor coolant pressure boundary. The tubes transfer heat to the steam system while retaining radioactive contaminants in the primary system. The steam generator removes heat from the reactor coolant system during power operation and anticipated transients and under natural circulation conditions.

The steam generator secondary shell functions as containment boundary during operation and during shutdown when access opening closures are in place.

The AP1000 utilizes a Model Delta-125 steam generator. This generator design is based on the following proven designs:

- Delta 75 – Replacement steam generator for V. C. Summer plant and other plants
- Delta 94 – Replacement steam generator for South Texas plant
- ANO (Arkansas) – Replacement steam generator (1500 MWt per steam generator)
- San Onofre and Waterford – Steam generator capacities similar to the 1700 MWt capacity of the AP1000 generators

The overall Delta-125 parameters are given in Table 2.3.2-1.

2.3.2.2 Design Description

The AP1000 steam generator is a vertical-shell U-tube evaporator with a triangular pitch tube bundle and integral moisture separating equipment. Figure 2.3.2-1 shows the overall steam generator outline.

On the primary side, the reactor coolant flow enters the primary chamber via the hot leg nozzle. The lower portion of the primary chamber is spherical and merges into a cylindrical portion, which mates to the tubesheet. This arrangement provides enhanced access to all tubes, including those at the periphery of the bundle, with robotics equipment. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the apex of the head to the tubesheet.

The reactor coolant flow enters the inverted U-tubes, transferring heat to the secondary side during its traverse, and returns to the cold leg side of the primary chamber. The flow exits the steam generator via two cold leg nozzles to which the canned-motor reactor coolant pumps are directly attached.

A passive residual heat removal (PRHR) nozzle attaches to the bottom of the channel head of the loop 1 steam generator on the cold leg portion of the head. This nozzle provides recirculated flow from the passive residual heat removal heat exchanger to cool the primary side under emergency conditions.

The steam generator channel head has provisions to drain the head. To minimize deposits of radioactive corrosion products on the channel head surfaces and to enhance the decontamination of these surfaces, the channel head cladding is machined or electropolished for a smooth surface.

The tubes are fabricated of nickel-chromium-iron Alloy 690. The tubes undergo thermal treatment following tube-forming operations. The tubes are tack-rolled, welded, and hydraulically expanded essentially over the full depth of the tubesheet. Westinghouse has used this practice in F-type steam generators. The process was selected because of its capability to control secondary water ingress to the tube-to-tube-sheet crevice. Residual stresses smaller than from other expansion methods result from this process and are minimized by tight control of the pre-expansion clearance between the tube and tubesheet hole.

Support of the tubes is provided by ferritic stainless steel tube support plates. The holes in the tube support plates are broached with a hole geometry to promote high-velocity flow along the tube and to provide an appropriate interface between the tube support plate and the tube. Anti-vibration bars installed in the U-bend portion of the tube bundle minimize the potential for excessive vibration.

Steam is generated on the shell side, flows upward, and exits through the outlet nozzle at the top of the vessel. Feedwater enters the steam generator at an elevation above the top of the U-tubes through a feedwater nozzle. The feedwater enters a feedring via a welded thermal sleeve connection and leaves it through nozzles attached to the top of the feedring. The nozzles are fabricated of an alloy that is very resistant to erosion and corrosion with the expected secondary water chemistry and flow rate through the nozzles. After exiting the nozzles, the feedwater flow mixes with saturated water removed by the moisture separators. The flow then enters the downcomer annulus between the wrapper and the shell.

At the bottom of the wrapper, the water is directed toward the center of the tube bundle by a flow distribution baffle. This baffle arrangement serves to minimize the low-velocity zones having the potential for sludge deposition. Flow-blocking devices restrict water streaming into the tubelane region, maintaining a substantially radial flow pattern at the tube bundle inlet.

As the water passes the tube bundle, it is converted to a steam-water mixture. Subsequently, the steam-water mixture from the tube bundle rises into the steam drum section, where centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators, or dryers, for further moisture removal, increasing its quality to a designed minimum of 99.9 percent (0.1 percent by weight maximum moisture). Water separated from the steam combines with entering feedwater and recirculates through the steam generator. A sludge collector located amidst the inner primary separator risers provides a benign region for sludge settling away from the tubesheet and tube support plates. The dry,

saturated steam exits the steam generator through the outlet nozzle, which has a steam-flow restrictor.

The Delta-125 steam generator incorporates a separate startup feedwater nozzle. The startup feedwater nozzle is located at an elevation that is just below the main feedwater nozzle and is circumferentially rotated 60 degrees clockwise with respect to the main feedwater nozzle. A spray system independent of the main feedwater feedring is used to introduce startup feedwater into the steam generator.

2.3.2.3 Differences Between AP1000 and AP600

There are differences between the Delta-75 steam generators used in the AP600 and the Delta-125 steam generators used in the AP1000 both in number of tubes and size of the steam generator shell. Both units are vertical-shell U-tube evaporators with a triangular pitch tube bundle and integral moisture separating equipment. To accommodate the higher thermal output of the AP1000 more heat transfer surface is required, thus increasing the shell diameter and height to enclose the larger tube bundle and larger moisture separation equipment required for the higher steam flow.

The secondary side volume of the Delta-125 steam generator is also larger than that of the Delta-75. This increased water mass results in a greater heat transfer capability from the reactor coolant system and is credited at the time of a design basis accident.

Figure 2.3.2-1 shows the overall steam generator dimensions for both the AP600 and AP1000. The following table provides a comparison of the major parameters of the AP1000 and AP600 steam generators.

Steam Generator Design Differences – AP1000 and AP600		
Parameter	**AP1000**	**AP600**
Model	Delta 125	Delta 75
Number of Units	2	2
Power, MWt/unit	1707.5	970
Number of Tubes Per Unit	10,000	6,307
Surface Area, ft^2/Unit	125,000	75,180
Overall Length, in. (SG Outlet Nozzle to RCP Casing Weld)	887	830
Upper Shell I.D./O.D., in.	221/230	168.5/176.3
Lower Shell I.D./O.D., in.	166.3/173.8	129.4/135.5
Tubesheet Thickness, in.	31.13	26.17
Zero Load Temperature, °F	440	435
Exit Steam Pressure, psia	855	833
Steam Flow, lb/hr per unit	7.47×10^6	4.2×10^6
Total Primary Water Volume, ft^3 per unit	2164.5	1355.9
Water Volume in Tubes, ft^3	1503.4	895.8
Water Volume in Plenums (Including Nozzles), ft^3	661.1	460.1
Secondary Water Mass, lb_m per unit	187,634	107,449

Table 2.3.2-1 AP1000 Steam Generator Parameters	
Parameter	**Value**
Model	Delta 125
Number of Units	2
Power, MWt/unit	1707.5
Number of Tubes Per Unit	10,000
Surface Area, ft^2/Unit	125,000
Tube Material	Nickel-Chromium-Iron Alloy 690 TT
Tube Outer Diameter, in.	0.688
Tube Wall Thickness, in.	0.04
Tube Inner Diameter, in.	0.607
Tube Pitch, in.	0.98 (triangular)
Overall Length, in.	887
Upper Shell I.D./O.D., in.	221/230
Lower Shell I.D./O.D., in.	166.3/173.8
Tubesheet Thickness, in.	31.13
Zero Load Temperature, °F	440
Exit Steam Pressure, psia	855
Steam Flow, lb/hr per unit	7.47×10^6
Total Primary Water Volume, ft^3 per unit	2164.5
Water Volume in Tubes, ft^3	1503.4
Water Volume in Plenums (Including Nozzles), ft^3	661.1
Secondary Water Mass, lb_m per unit	187,634

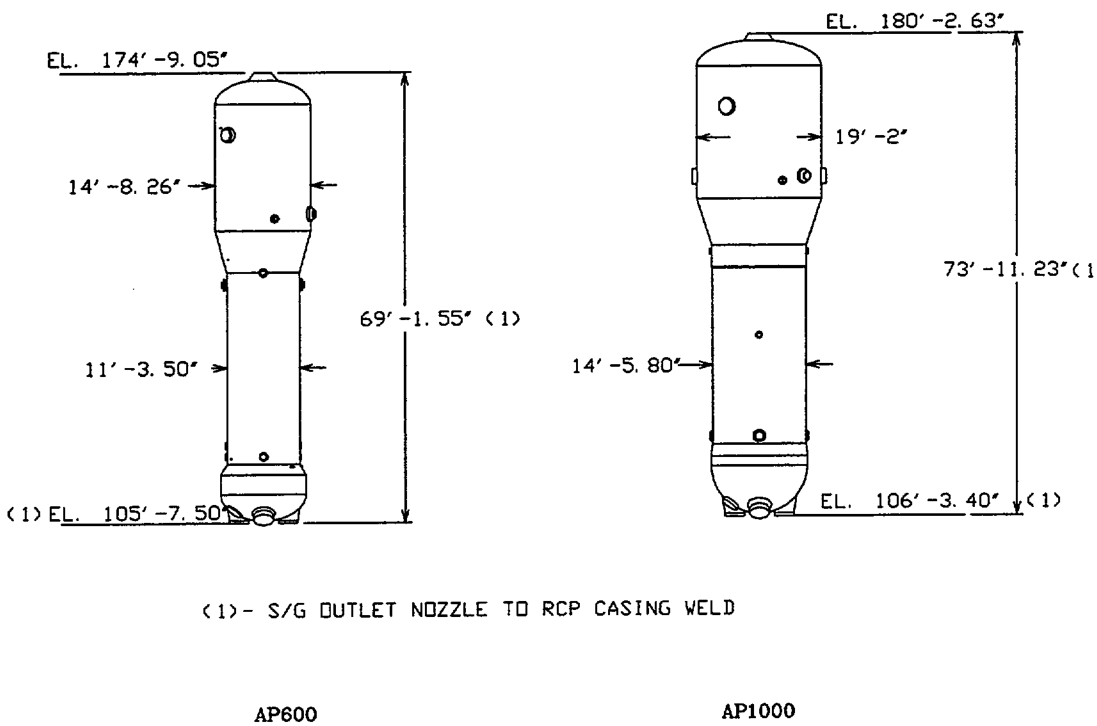


Figure 2.3.2-1 AP1000 and AP600 Steam Generator Outline Drawings

2.3.3 Reactor Coolant Pump Design

2.3.3.1 Design Description

The AP1000 reactor coolant pump is a single stage, hermetically sealed, high-inertia, centrifugal canned-motor pump. The AP1000 pump is based on the AP600 canned-motor pump design with provisions to provide more flow and a longer flow coast down. The motor size is minimized through the use of a variable speed controller to reduce motor power requirements during cold coolant conditions. The variable speed controller is not used during power operations. The pump hydraulics are based on the high-efficiency hydraulics developed and tested for the Tsuruga 3/4 reactor coolant pumps. Figure 2.3.3-1 shows the reactor coolant pump outline.

A reactor coolant pump is directly connected to each of two outlet nozzles on the steam generator channel head as illustrated in Figure 2.3.3-2.

A canned motor pump contains the motor and all rotating components inside a pressure vessel. The pressure vessel consists of the pump casing, thermal barrier, stator shell, and stator cap, which are designed for full reactor coolant system pressure. The stator and rotor are encased in corrosion-resistant cans that prevent contact of the rotor bars and stator windings by the reactor coolant. Because the shaft for the impeller and rotor is contained within the pressure boundary, seals are not required to restrict leakage out of the pump into containment. A gasket and canopy seal type connection between the pump casing, the stator flange, and the thermal barrier is provided. This design provides definitive leak protection for the pump closure. To access the internals of the pump and motor, the canopy seal weld is severed. When the pump is reassembled a canopy seal is rewelded. Canned-motor reactor coolant pumps have a long history of safe, reliable performance in military and commercial nuclear plant service.

The reactor coolant pump driving motor is a vertical, water-cooled, squirrel-cage induction motor with a canned rotor and a canned stator. It is designed for removal from the casing for inspection, maintenance and replacement, if required. The stator can protects the stator (windings and insulation) from the controlled portion of the reactor coolant circulating inside the motor and bearing cavity. The can on the rotor isolates the copper rotor bars from the system.

The motor is cooled by component cooling water circulating through a cooling jacket on the outside of the motor housing and through a thermal barrier between the pump casing and the rest of the motor internals. Inside the cooling jacket are coils filled with circulating rotor cavity coolant. This rotor cavity coolant is a controlled volume of reactor coolant that circulates inside the rotor cavity. After the rotor cavity coolant is cooled in the cooling jacket, it enters the lower end of the rotor and passes axially between the rotor and stator cans to remove heat from the rotor and stator.

A flywheel assembly between the motor and pump impeller provides rotating inertia that increases the coastdown time for the pump. The flywheel assembly is a composite of a uranium alloy flywheel casting or forging contained within a welded nickel-chromium-iron alloy

enclosure. Surrounding the flywheel assembly is the thick cylindrical motor end closure and the heavy wall of the stator shell and main flange.

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

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

2.3.3.2 Description of Operation

Reactor coolant is pumped by the main impeller. It is drawn through the eye of the impeller and discharged via the diffuser out through the radial discharge nozzle in the side of the casing. Once the motor housing is filled with coolant, the labyrinth seals around the shaft between the impeller and the thermal barrier minimize the flow of coolant into the motor during operation.

An auxiliary impeller at the lower part of the rotor shaft circulates a controlled volume of the coolant through the motor cooling coils. The coolant is cooled to about 150°F by component cooling water circulating around the cooling coils in the cooling jacket outside the stator shell. The cooled reactor coolant then passes through the annulus between the rotor and stator cans, where it removes heat from the rotor and stator and lubricates the motor's hydrodynamic bearings.

2.3.3.3 Differences Between AP1000 and AP600

The same basic canned-motor pump design is employed in the AP1000 as in the AP600. However, the higher thermal power and core power density of the AP1000 requires higher flow and longer coastdown from the AP1000 pumps compared to the AP600 pumps. A variable speed controller was added to the AP1000 pumps to reduce the motor power required when pumping cold reactor coolant. To provide the larger flow rates, the AP1000 pumps include high efficiency hydraulics which were scaled down from the Tsuruga 3/4 reactor coolant pump design. A longer coastdown is obtained in the AP1000 pumps through increased inertia in the flywheel.

The table below summarizes the major differences in design parameters between the AP1000 and the AP600 reactor coolant pumps. Figure 2.3.3-1 illustrates the dimensional differences between the two pumps.

Reactor Coolant Pump Design Differences – AP1000 and AP600		
Parameter	**AP1000**	**AP600**
Variable Speed	Yes	No
BHP @ T_{hot}	6,000	2,797
BHP @ T_{cold}	6,000	3,723
Effective Power to Coolant, MWt	15	7
Rated Flow, gpm	75,000	51,000
Rated Head, ft	350	240
Required Coastdown Beta	0.20	0.31
Required Inertia for Beta (lb-ft^2)	15,750	4,956

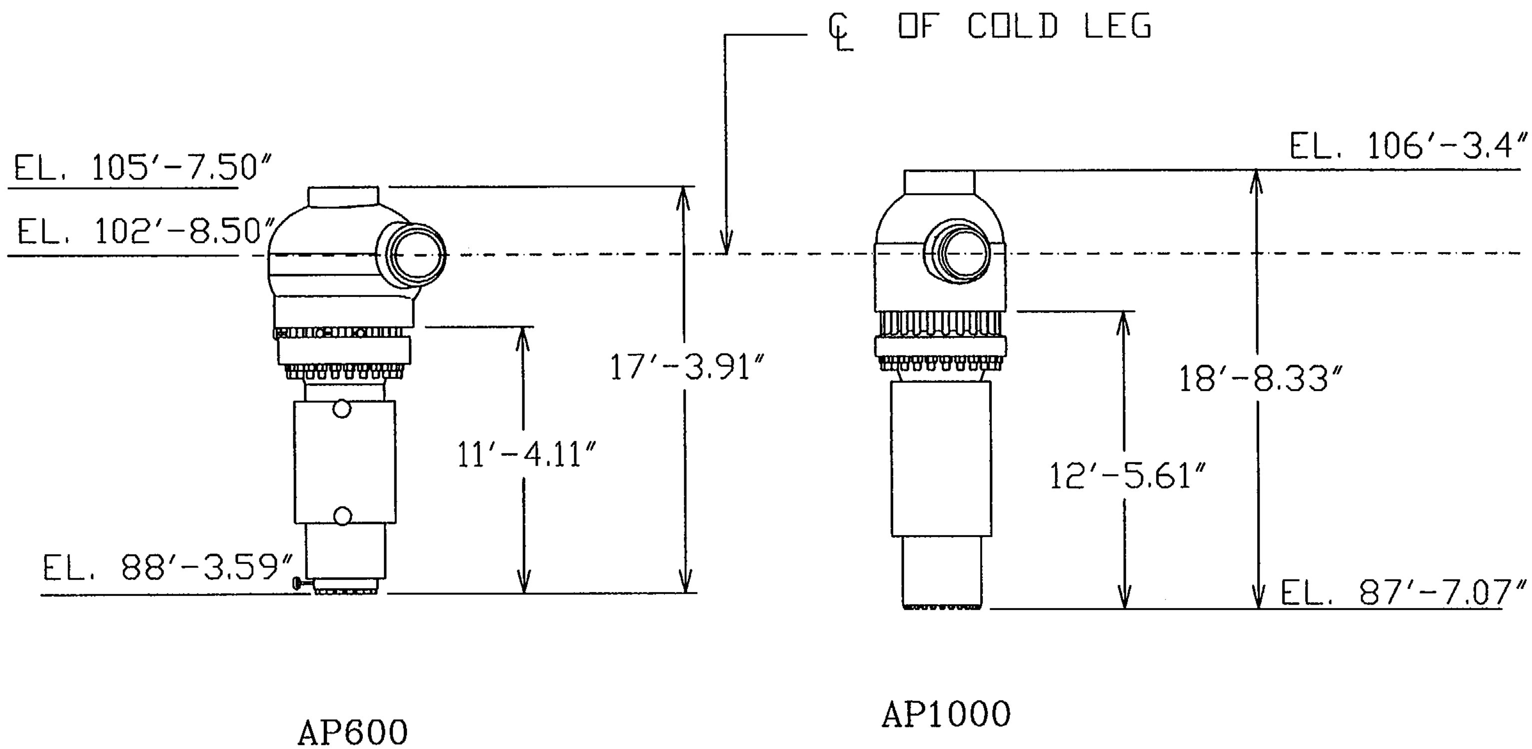


Figure 2.3.3-1 AP1000 and AP600 Reactor Coolant Pumps

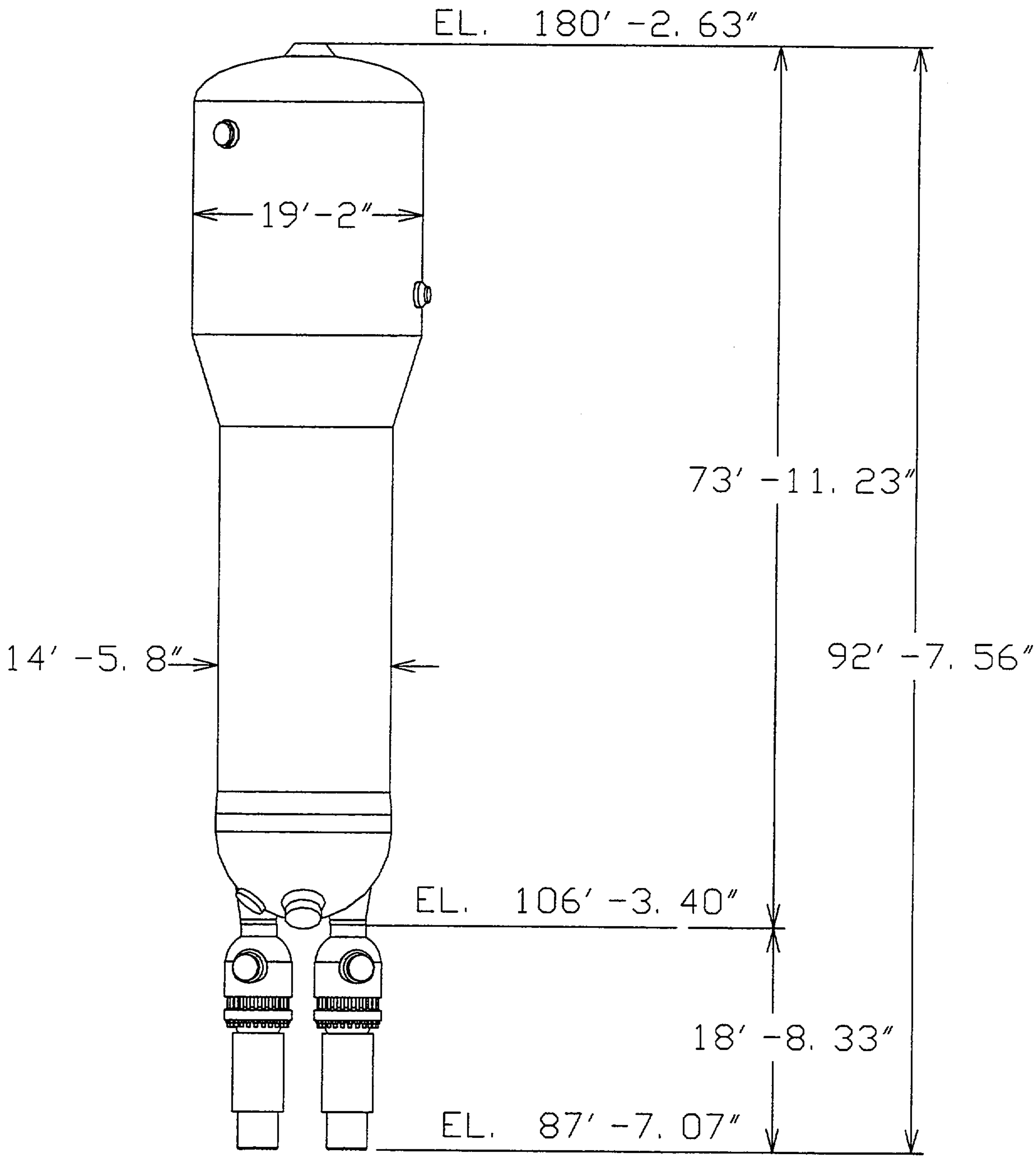


Figure 2.3.3-2 AP1000 Steam Generator and Reactor Coolant Pump

2.3.4 Pressurizer and Reactor Coolant System Piping Loop Arrangement

2.3.4.1 Pressurizer Design

The pressurizer provides a point in the reactor coolant system where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control of the reactor coolant system during steady-state operations and transients. The pressurizer provides a controlled volume from which level can be measured. The pressurizer contains the water inventory used to maintain reactor coolant system volume in the event of a minor system leak for a reasonable period without replenishment. The pressurizer surge line connects the pressurizer to one reactor coolant hot leg. This allows continuous coolant volume and pressure adjustments between the reactor coolant system and the pressurizer.

The pressurizer is a vertical, cylindrical vessel having hemispherical top and bottom heads constructed of low alloy steel. Internal surfaces exposed to the reactor coolant are clad austenitic stainless steel. An outline drawing of the pressurizer is shown in Figure 2.3.4-1. Pressurizer parameters are provided in Table 2.3.4-1.

The spray line nozzles and the automatic depressurization and safety valve connections are located in the top head of the pressurizer vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually from the control room. In the bottom head at the connection of the surge line to the surge nozzle a thermal sleeve protects the nozzle from thermal transients. The pressurizer surge nozzle and the surge line between the pressurizer and one hot leg are sized to maintain the pressure drop between the reactor coolant system and the safety valves within allowable limits during a design discharge flow from the safety valves or the valves of the automatic depressurization system.

A retaining screen above the surge nozzle prevents passage of any foreign matter from the pressurizer to the reactor coolant system. Baffles in the lower section of the pressurizer prevent an in-surge of cold water from flowing directly to the steam/water interface. The baffles also assist in mixing the incoming water with the water in the pressurizer. The retaining screen and baffles also act as a diffuser. The baffles also support the heaters to limit vibration.

Electric direct-immersion heaters are installed in vertically oriented heater wells located in the pressurizer bottom head. The heater wells are welded to the bottom head and form part of the pressure boundary. The heaters can be removed for maintenance or replacement.

The heaters are grouped into a control group and backup groups. The heaters in the control group are proportional heaters which are supplied with continuously variable power to match heating needs. The heaters in the backup group are either off or at full power.

Safety valves are installed above and connected to the pressurizer to provide overpressure protection for the reactor coolant system. The pressurizer safety valves are spring loaded, self-actuated with back-pressure compensation. Their set pressure and combined capacity is based

on not exceeding the reactor coolant system maximum pressure limit during the level B service condition loss of load transient.

Brackets on the upper shell attach the structure (a ring girder) of the pressurizer safety and relief valve (PSARV) module. The pressurizer safety and relief valve module includes the safety valves and the first three stages of automatic depressurization system valves. The support brackets on the pressurizer represent the primary vertical load path to the building structure. Sway struts between the ring girder and pressurizer compartment walls also provide lateral support to the upper portion of the pressurizer.

Four steel columns attach to pads on the lower head to provide vertical support for the vessel. Lateral support for the lower portion of the vessel is provided by sway struts between the columns and compartment walls.

2.3.4.2 Reactor Coolant System Loop Piping

The main reactor coolant system loop piping connects the reactor vessel to the steam generators, reactor coolant pumps, and pressurizer. There are two hot legs, four cold legs, and one pressurizer surge line. The size of each pipe is:

- Hot Leg (Inside Diameter) – 31 inches
- Cold Leg (Inside Diameter) – 22 inches
- Surge Line (Outside Diameter) – 18 inches

Reactor coolant system piping is fabricated of austenitic stainless steel. The piping is forged seamless without longitudinal or electroslag welds.

2.3.4.3 Differences Between AP1000 and AP600

The AP1000 pressurizer volume was increased compared to the AP600 to accommodate the larger reactor coolant system volume in the AP1000. This was accomplished by making the AP1000 pressurizer taller while maintaining the same diameter pressurizer as in the AP600. The difference in the pressurizer height is shown in Figure 2.3.4-1. The total volume of the AP1000 pressurizer is 2,100 ft^3 compared to 1,600 ft^3 for the AP600.

The sizes of the AP1000 reactor coolant loop piping are the same as those for the AP600. The elevations of the AP1000 hot and cold legs are also maintained the same as those in the AP600.

Table 2.3.4-1 AP1000 Pressurizer Parameters	
Parameter	**Value**
Number of Units	1
Total Volume, ft^3	2,100
Spray Capacity, gpm	500
Inside Diameter, inches	90
Surge Line Volume, ft^3	99.7
Rated Pressurizer Heater Capacity, kw	1,600

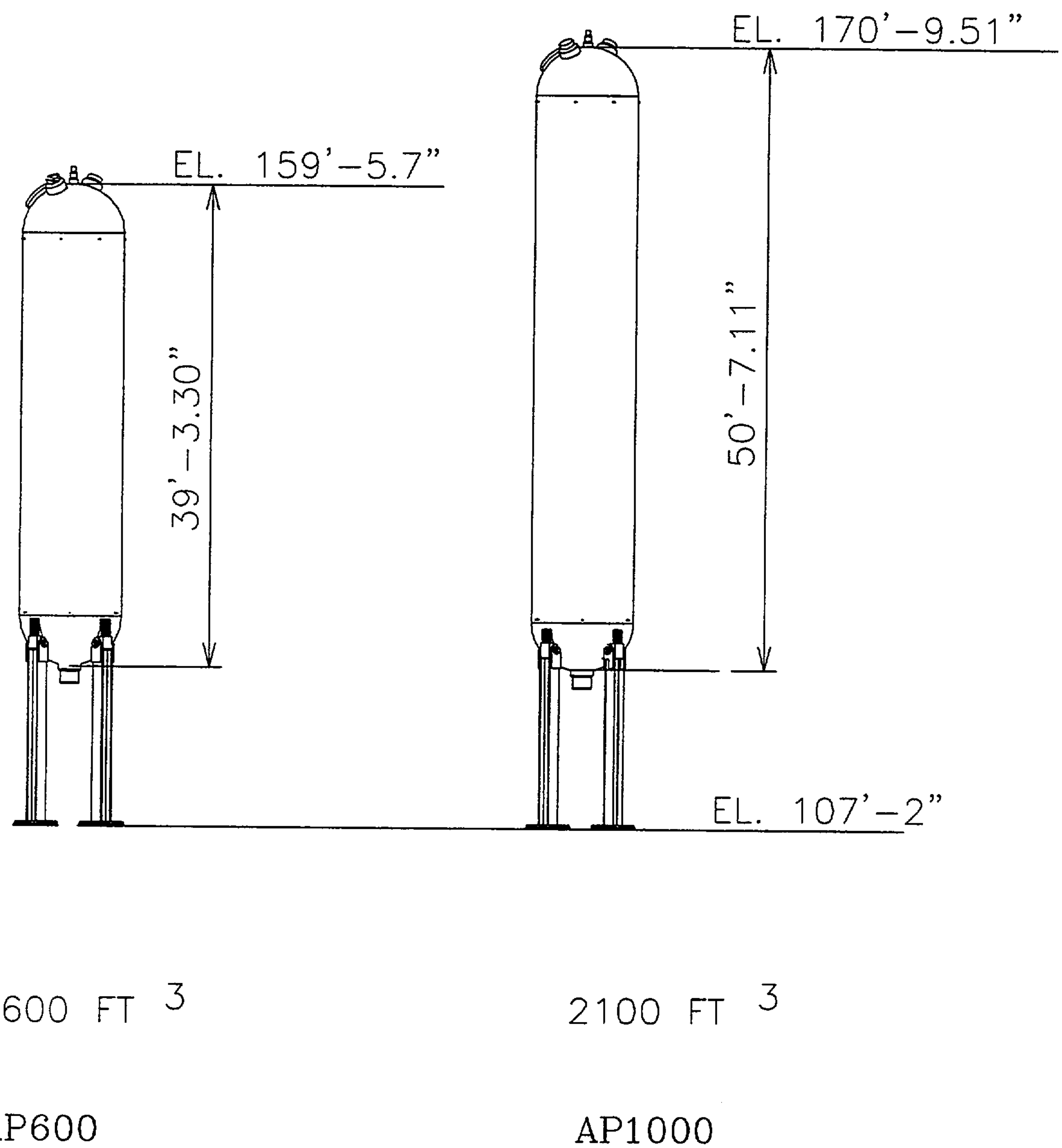


Figure 2.3.4-1 AP1000 and AP600 Pressurizer Outline Drawings

2.3.5 Automatic Depressurization System Design

The automatic depressurization system is part of the reactor coolant system and consists of four different stages of valves. The first three stages each have two lines and each line has two valves in series; both normally closed. The fourth stage has four lines with each line having two valves in series; one normally open and one normally closed. The four stages, therefore, include a total of 20 valves. The four valve stages open sequentially. Opening of the automatic depressurization system valves is required for the passive core cooling system to function as required to provide emergency core cooling following postulated accident conditions.

The valves sizes for the first three stage of the automatic depressurization system are 4-inch, 8-inch, and 8-inch, respectively. The first stage, second-stage and third-stage valves have dc motor operators. The stage 1/2/3 control valves are normally closed globe valves; the isolation valves are normally closed gate valves. The fourth stage control valves are 14-inch squib valves. There is a normally open motor-operated gate valve in series with each squib valve.

The automatic depressurization system first, second, and third stage valves are included as part of the pressurizer safety and relief valve (PSARV) module. The first three stages have a common inlet header connected to the top of the pressurizer. The outlet of the first to third stages then combine to a common discharge line to one of the spargers in the in-containment refueling water storage tank. There is a second identical group of first- to third-stage valves with its own inlet and outlet line and sparger.

The fourth-stage valves connect directly to the top of the reactor coolant hot leg and vent directly to the steam generator compartment. There are also two groups of fourth stage valves, with one group in each steam generator compartment. The fourth stage valves are interlocked so that they can not be opened until reactor coolant system pressure has been substantially reduced.

The automatic depressurization valves are designed to automatically open when actuated and to remain open for the duration of an automatic depressurization event. Valve stages 1 and 4 actuate at discrete core makeup tank levels, as either tank's level decreases during injection or from spilling out a broken injection line. Valve stages 2 and 3 actuate based upon a timed delay after actuation of the preceding stage. This opening sequence provides a controlled depressurization of the reactor coolant system. The valve opening sequence prevents simultaneous opening of more than one stage, to allow the valves to sequentially open. The valve actuation logic is based on two-of-four level detectors, in either core makeup tank for automatic depressurization system stages 1 and 4.

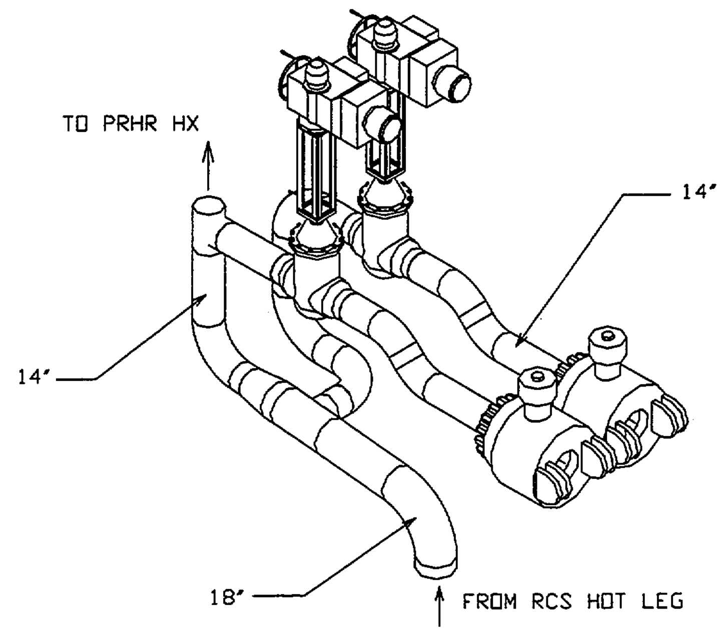
The stage 1/2/3 automatic depressurization control valves are designed to open relatively slowly. During the actuation of each stage, the isolation valve is sequenced open before the control valve. Therefore, there is some time delay between stage actuation and control valve actuation.

The operators can manually open the first-stage valves to a partially open position to perform a controlled depressurization of the reactor coolant system.

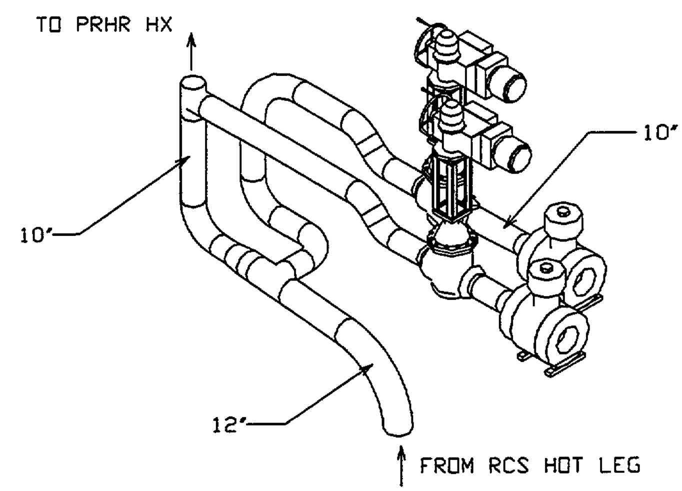
DIFFERENCES BETWEEN AP1000 AND AP600

The first three stages of the AP1000 automatic depressurization system are the same as in the AP600 design. The fourth stage squib valves located on the reactor coolant system hot legs have been increased to 14-inch valves in the AP1000 compared to 10-inch in the AP600. The header from each hot leg which connects to the two automatic depressurization system fourth stage flow paths was increased to 18 inches in the AP1000 compared to 12 inches in the AP600. A comparison of the layout of the fourth stage valves connected to one of the hot legs is shown in Figure 2.3.5-1.

ADS 4 STAGE WEST COMP. PIPING



AP1000



AP600

Figure 2.3.5-1 Automatic Depressurization System Fourth Stage Valve Comparison

2.4 PASSIVE CORE COOLING SYSTEM DESIGN

The passive core cooling system is a seismic Category I, safety-related system. It consists of two core makeup tanks, two accumulators, the in-containment refueling water storage tank, the passive residual heat removal heat exchanger, pH adjustment baskets, and associated piping, valves, instrumentation, and other related equipment. The automatic depressurization system valves and spargers, which are part of the reactor coolant system, also provide important passive core cooling functions by lowering the reactor coolant system pressure to enable passive injection from the passive core cooling system water sources.

The passive core cooling system is designed to provide adequate core cooling in the event of design basis events. The redundant onsite safety-related class 1E dc and UPS system provides power such that protection is provided for a loss of ac power sources, coincident with an event, assuming a single failure has occurred.

The four passive core cooling system functions are:

- Emergency decay heat removal
- Emergency reactor makeup/boration
- Safety injection
- Containment pH control

The overall system and component parameters are given in Table 2.4-1.

2.4.1 Passive Residual Heat Removal

For events not involving a loss of coolant, the emergency core decay heat removal is provided by the passive core cooling system via the passive residual heat removal heat exchanger. The heat exchanger consists of a bank of C-tubes, connected to a tubesheet and channel head arrangement at the top (inlet) and bottom (outlet). The passive residual heat removal heat exchanger connects to the reactor coolant system through an inlet line from one reactor coolant system hot leg (through a tee from one of the fourth stage automatic depressurization lines) and an outlet line to the associated steam generator cold leg plenum (reactor coolant pump suction). The passive decay heat removal flow schematic is shown in Figure 2.4-1.

The inlet line is normally open and connects to the upper passive residual heat removal heat exchanger channel head. The inlet line is connected to the top of the hot leg and is routed continuously upward to the high point near the heat exchanger inlet. The normal water temperature in the inlet line will be hotter than the discharge line.

The outlet line contains normally closed air-operated valves that open on loss of air pressure or on control signal actuation. The alignment of the passive residual heat removal heat exchanger (with a normally open inlet motor-operated valve and normally closed outlet air-operated valves) maintains the heat exchanger full of reactor coolant at reactor coolant system pressure. The water temperature in the heat exchanger is about the same as the water in the

in-containment refueling water storage tank, so that a thermal driving head is established and maintained during plant operation.

The heat exchanger is elevated above the reactor coolant system loops to induce natural circulation flow through the heat exchanger when the reactor coolant pumps are not available. The passive residual heat removal heat exchanger piping arrangement also allows actuation of the heat exchanger with reactor coolant pumps operating. When the reactor coolant pumps are operating, they provide forced flow in the same direction as natural circulation flow through the heat exchanger. If the pumps are operating and subsequently trip, then natural circulation continues to provide the driving head for heat exchanger flow.

The heat exchanger is located in the in-containment refueling water storage tank, which provides the heat sink for the heat exchanger.

The passive residual heat removal heat exchanger, in conjunction with the passive containment cooling system, can provide core cooling for an indefinite period of time. After the in-containment refueling water storage tank water reaches its saturation, the process of steaming to the containment initiates.

Condensation occurs on the steel containment vessel, which is cooled by the passive containment cooling system (subsection 2.5.2). The condensate is collected in a safety-related gutter arrangement located at the operating deck level which returns the condensate to the in-containment refueling water storage tank. The gutter normally drains to the containment sump, but when the passive residual heat removal heat exchanger actuates, safety-related isolation valves in the gutter drain line shut and the gutter overflow returns directly to the in-containment refueling water storage tank. Recovery of the condensate maintains the passive residual heat removal heat exchanger heat sink for an indefinite period of time.

2.4.2 Reactor Coolant System Emergency Makeup and Boration

The core makeup tanks provide reactor coolant system makeup and boration during events not involving loss of coolant when the normal makeup system is unavailable or insufficient. There are two core makeup tanks located inside the containment at an elevation slightly above the reactor coolant loops. During normal operation, the core makeup tanks are completely full of cold, borated water. The boration capability of these tanks provides adequate core shutdown margin following a steam line break.

The core makeup tanks are connected to the reactor coolant system through a discharge injection line and an inlet pressure balance line connected to a cold leg. The discharge line is blocked by two normally closed, parallel air-operated isolation valves that open on a loss of air pressure or electrical power, or on control signal actuation. The core makeup tank discharge isolation valves are diverse from the passive residual heat removal heat exchanger outlet isolation valves discussed above. They use different globe valve body styles and different air operator types. The connection of the core makeup tanks to the reactor coolant system is shown schematically in Figure 2.4-2.

The pressure balance line from the cold leg is normally open to maintain the core makeup tanks at reactor coolant system pressure, which prevents water hammer upon initiation of core makeup tank injection.

The cold leg pressure balance line is connected to the top of the cold leg and is routed continuously upward to the high point near the core makeup tank inlet. The normal water temperature in this line will be hotter than the discharge line.

The outlet line from the bottom of each core makeup tank provides an injection path to one of the two direct vessel injection lines, which are connected to the reactor vessel downcomer annulus. Upon receipt of a safeguards actuation signal, the two parallel valves in each discharge line open to align the associated core makeup tank to the reactor coolant system.

There are two operating processes for the core makeup tanks, steam-compensated injection and water recirculation. During steam-compensated injection, steam is supplied to the core makeup tanks to displace the water that is injected into the reactor coolant system. This steam is provided to the core makeup tanks through the cold leg pressure balance line. The cold leg line only has steam flow if the cold legs are voided.

During water recirculation, hot water from the cold leg enters the core makeup tanks, and the cold water in the tank is discharged to the reactor coolant system. This results in reactor coolant system boration and a net increase in reactor coolant system mass.

The operating process for the core makeup tanks depends on conditions in the reactor coolant system, primarily voiding in the cold leg. When the cold leg is full of water, the cold leg pressure balance line remains full of water and the injection occurs via water recirculation. If reactor coolant system inventory decreases sufficiently to cause cold leg voiding, then steam flows through the cold leg balance lines to the core makeup tanks.

2.4.3 Safety Injection During Loss of Coolant Accidents

The passive core cooling system uses four different sources of passive injection during loss of coolant accidents.

- Accumulators provide a very high flow for a limited duration of several minutes.
- The core makeup tanks provide a relatively high flow for a longer duration.
- The in-containment refueling water storage tank provides a lower flow, but for a much longer time.
- The containment is the final long-term source of water. It becomes available following the injection of the other three sources and floodup of containment.

The simplified flow schematic for passive core cooling safety injection is shown in Figure 2.4-2.

The core makeup tanks provide injection rates commensurate with the severity of the loss of coolant accident. For a larger loss of coolant accident, and after the automatic depressurization system has been actuated, the cold legs are expected to be voided. In this situation, the core makeup tanks operate at their maximum injection rate with steam entering the core makeup tanks through the cold leg pressure balance lines.

Downstream of the parallel discharge isolation valves, the core makeup tank discharge line contains two check valves in series, that normally remain open with or without flow in the line. These valves prevent reverse flow through this line, from the accumulator, that would bypass the reactor vessel in the event of a larger loss of coolant accident in the cold leg or the cold leg pressure balance line.

For smaller loss of coolant accidents the core makeup tanks initially operate in the water recirculation mode since the cold legs are water filled. During this water recirculation, the core makeup tanks remain full, but the cold, borated water is purged with hot, less borated cold leg water. The water recirculation provides reactor coolant system makeup and also effectively borates the reactor coolant system. As the accident progresses, when the cold legs void, the core makeup tanks switch to the steam displacement mode which provides higher flow rates.

The two accumulators contain borated water and a compressed nitrogen cover gas to provide rapid injection. They are located inside the reactor containment and the discharge from each tank is connected to one of the direct vessel injection lines. These lines connect to the reactor vessel downcomer. A deflector in the annulus directs the water flow downward to minimize core bypass flow. The water and gas volumes and the discharge line resistance provide several minutes of injection in a large loss of coolant accident.

The in-containment refueling water storage tank is located in the containment at an elevation slightly above the reactor coolant system loop piping. Reactor coolant system injection is possible only after the reactor coolant system has been depressurized by the automatic depressurization system or by a loss of coolant accident. Squib valves in the in-containment refueling water storage tank injection lines open automatically on a 4th stage automatic depressurization signal. Check valves, arranged in series with the squib valves, open when the reactor pressure decreases to below the in-containment refueling water storage tank injection head.

After the accumulators, core makeup tanks, and the in-containment refueling water storage tank inject, the containment is flooded up to a level sufficient to provide recirculation flow through the gravity injection lines back into the reactor coolant system.

The time that it takes until the initiation of containment recirculation flow varies greatly, depending on the specific event. With a break in a direct vessel injection line, the in-containment refueling water storage tank spills out through the break and floods the containment, along with reactor coolant system leakage, and recirculation can occur in several hours. In the event of automatic depressurization without a reactor coolant system break and with condensate return, the in-containment refueling water storage tank level decreases very slowly. Recirculation may not initiate for several days.

Containment recirculation initiates when the recirculation line valves are open and the containment flood-up level is sufficiently high. When the in-containment refueling water storage tank level decreases to a low level, the containment recirculation motor-operated valve and squib valves automatically open to provide redundant flow paths from the containment to the reactor.

These recirculation flow paths can also provide a suction flow path from the containment to the normal residual heat removal pumps, when they are operating after containment flood up. In addition, the motor-operated valve path can be manually opened to intentionally drain the in-containment refueling water storage tank to the reactor cavity during severe accidents.

In larger loss of coolant accidents, including double ended ruptures in reactor coolant system piping, the passive core cooling system can provide a large flow rate, from the accumulators, to quickly refill the reactor vessel lower plenum and downcomer. The accumulators provide the required injection flow during the first part of the event including refilling the downcomer and lower plenum and partially reflooding the core. After the accumulators empty, the core makeup tanks complete the reflooding of the core. The subsequent in-containment refueling water storage tank injection and containment recirculation provide long-term cooling. Both injection lines are available since the injection lines are not the source of a large pipe break.

2.4.4 Containment pH Control

Control of the pH in the containment sump water post-accident is achieved through the use of pH adjustment baskets containing granulated trisodium phosphate (TSP). The baskets are located below the minimum post-accident floodup level, and chemical addition is initiated passively when the water reaches the baskets. The baskets are placed at least a foot above the floor to reduce the chance that water spills in containment will dissolve the TSP.

The TSP is designed to maintain the pH of the containment sump water in a range from 7.0 to 9.5. This chemistry reduces radiolytic formation of elemental iodine in the containment sump, consequently reducing the aqueous production of organic iodine, and ultimately reducing the airborne iodine in containment and offsite doses.

The chemical addition also helps to reduce the potential for stress corrosion cracking of stainless steel components in a post flood-up condition, where chlorides can leach out of the containment concrete and potentially affect these components during a long-term flood-up event.

2.4.5 Differences Between AP1000 and AP600

The basic design of the AP1000 passive core cooling system is the same as that of the AP600. The AP1000 passive core cooling system design incorporates the same components as in the AP600 design. Due to the increased power rating of the AP1000, however, some of these components have increased in size.

The higher core thermal power of the AP1000 requires the passive residual heat removal heat exchanger to remove more heat from the reactor coolant system than in the AP600. To improve

the heat transfer capability of the AP1000 passive residual heat removal heat exchanger, both the heat transfer surface area and the reactor coolant flow through the heat exchanger have been increased. The surface area was increased by adding two rows of tubes (18 tubes total) and lengthening the heat exchanger frame by approximately three feet in the horizontal direction. Both the inlet and outlet pipe diameters have been enlarged to increase the reactor coolant flow through the AP1000 heat exchanger. Figure 2.4-3 illustrates the increase in the AP1000 heat exchanger frame size. Figures 2.4-4 and 2.4-5 show a comparison of AP600 PRHR heat exchanger supply and return piping size and routing.

To increase the safety injection flow rate capability of the AP1000 passive core cooling system, the AP1000 direct vessel injection (DVI) line routing was modified slightly to minimize the line resistance. Also, the injection line size from the IRWST and the recirculation line size from the containment sump were increased. The differences in these two lines between the AP600 and AP1000 are illustrated in Figure 2.4-6.

To provide more water for safety injection, the AP1000 core makeup tank volume was also increased. In conjunction with this increase in volume the flow restricting orifice was resized such that the injection flow from the core makeup tank is increased in proportion to the tank volume increase. Thus the duration of injection flow from the core makeup tank is about the same in the AP1000 as in the AP600.

Although the surface area of the IRWST is the same for both the AP600 and AP1000, the minimum water height was increased in the AP1000 through the addition of more accurate narrow range IRWST level instruments. This higher water level increases the amount of water available for injection and also provides a higher driving pressure.

The containment flood-up level has been increased in the AP1000 as a result of the increased water available in the IRWST and by providing a drain from the bottom of the refueling cavity to the loop compartment. Check valves in the refueling cavity drain line are provided. The check valves in the AP1000 prevent water from flooding back into the cavity as the IRWST injects and results in the availability of more water to increase the containment recirculation water level compared to the AP600.

Although the fourth stage automatic depressurization valves are part of the reactor coolant system (and are discussed in subsection 2.3.5) they are included here also because they are integral to the operation of the passive core cooling system. The size of these valves was increased in the AP1000 to provide greater venting capability to accommodate the AP1000 higher core power and decay heat.

The table below summarizes the major differences between the AP1000 and AP600 passive core cooling system components.

Passive Core Cooling System Design Differences – AP1000 and AP600		
Parameter	**AP1000**	**AP600**
PRHR HX Number of Tubes	689	671
PRHR HX Heat Transfer Area, ft^2	5,278	4,326
PRHR HX Inlet Pipe Size, in	14	10
PRHR HX Outlet Pipe Size, in	14	10
IRWST Injection Line Size, in	10 to sump tee 8 - remainder of line to DVI	6
IRWST Minimum Water Height, ft	28.58	27
IRWST Minimum Water Volume, ft^3	78,900	74,500
Minimum Containment Flood-Up Level Above DVI Nozzle, ft	8.7	7.2
Containment Recirculation Line Size, in	8	6
Core Makeup Tank Volume, ft^3	2,500	2,000
Fourth Stage ADS Valve Size, in	14	10
pH Adjustment Basket Volume, ft^3	135	107

2.4.6 Design Margin Assessment

The design approach for the AP1000 passive safety features is to selectively increase their capacity using insights from the AP600 design, testing, analysis and licensing activities. Two key factors in these insights are the uncertainty in the computer analysis tools and the margin between the calculated results and the licensing limits. These insights indicate that some features (like IRWST injection, containment recirculation and ADS stage 4) should be increased at least as much as the change in core power. These insights also indicate that other features (like CMT and Accumulators) may not need to be increased as much as the change in power.

The following provides an assessment of the margins provided in the AP1000 passive core cooling system (PXS) as compared with the AP600 PXS. This margin assessment is intended to provide a simple quantitative comparison between the AP600 and the AP1000 PXS features. It is intended to supplement other analysis/evaluation activities such as preliminary safety analysis and scaling evaluations. Preliminary AP1000 safety evaluation are provided in Section 3.0 of this report. A scaling assessment will be provided in a subsequent report. Later during the Design Certification licensing review of the AP1000, computer codes verified for use on AP1000 will be used to determine that the AP1000 passive safety features are capable of meeting the licensing requirements.

A comparison of the following PXS features is provided in this section:

- Passive Residual Heat Removal Heat Exchanger (PRHR heat exchanger)
- Accumulator
- Core Makeup Tank (CMT)
- Incontainment Refueling Water Storage Tank (IRWST)
- Containment recirculation
- Automatic Depressurization System (ADS)

These margin assessments are based on simple physical models that are independent of detailed safety and scaling analyses. The assessments compare AP1000 and AP600 safety system capacities under conditions where minimum margins occur. Consideration is also given to uncertainties due to the analysis models and the supporting tests. Appropriate plant conditions (RCS pressure/temperature, containment pressure, etc.) are applied to both the AP600 and the AP1000 features. The performance of the feature is calculated by hand using simple equations, such as the Darcy formula for liquid flow:

Water Flow = (Pressure Drop/Resistance) ^ 0.5

Generally, conservative simplifying assumptions have been made as described. The resulting performance difference is compared to the difference in core power to determine margin.

The assessments are based on simple, easily understood, physically based hand calculation methods and are not dependent upon test results, scaling, or safety analysis codes. They should provide useful input to the review of the AP1000 PXS design during this pre-application review.

2.4.6.1 Passive Residual Heat Removal Heat Exchanger

The primary parameter of interest for the PRHR heat exchanger is heat removal during natural circulation conditions. The PRHR heat exchanger removes less heat during natural circulation conditions than when the reactor coolant pumps are operating and forcing flow through the PRHR heat exchanger. The PRHR heat exchanger operates in the natural circulation mode after a loss of offsite power or other events in which the reactor coolant pumps are not operating.

The natural circulation heat removal capability is affected by the flow resistance of the PRHR heat exchanger flow path, the heat transfer surface area of the PRHR heat exchanger, and the elevation of the heat exchanger. For the AP1000, although the heat exchanger elevation is unchanged, the thermal center of the core has moved down one foot thus increasing the driving head during natural circulation conditions. This change was conservatively ignored in the assessment below. The AP1000 uses the same basic PRHR heat exchanger design, although the surface area has been increased to increase heat transfer. This increase has been accomplished by increasing the horizontal tube length and by adding a few additional tubes; the heat transfer

area has been increased by 22%. In addition, the PRHR heat exchanger lines have been increased in size from 10" to 14" in order to reduce the flow resistance. This change results in the flow resistance being reduced to about 33% of the AP600 flow resistance.

If the heat exchanger saw the same inlet temperature and was able to produce the same outlet temperature, the driving head would be the same and the reduced flow resistance would allow a 74% increase in flow and heat removal. This increase in flow is calculated by using the Darcy formula that in this case reduces to:

Flow ratio = (1/resistance ratio) ^ 0.5 = (1/33%) ^ 0.5 = 174%

The table below summarizes the results of a calculation of the PRHR heat exchanger heat transfer rate that accounts for both the change in flow resistance and the heat transfer area. In this calculation, the reactor coolant pumps are not assumed to operate, so the heat exchanger performance is based on natural circulation. The CMTs are also not assumed to operate to simplify the calculation and to separate the effects of the two features.

The PRHR inlet temperature (RCS hot leg temperature) is assumed to be the saturated temperature at the steam generator safety valve setpoint. This temperature was selected because without RCP and CMT operation the RCS tends to remain at this temperature for some time until the PRHR heat exchanger matches decay heat and then the PRHR heat exchanger starts to cool down the RCS. This steam generator (SG) safety valve pressure setpoint is 1100 psig for AP600 and 1200 psig for AP1000.

The time to match decay heat is calculated based on the above PRHR heat exchanger performance as discussed above, and assuming core operation at 102% power prior to trip and decay heat based on ANS 1979 plus 2 sigma.

The initial SG secondary side water mass is based on the SG narrow range low level reactor trip setpoint. The preliminary initial SG secondary side water mass at the reactor trip setpoint for the AP1000 (105,000 lbm) is approximately 139% more than the water mass for the AP600 (44,000 lbm). The final SG water mass is calculated using the PRHR and plant operating conditions discussed above, and assuming that the decay heat in excess of the PRHR heat exchanger capacity is removed by boiling off some of the SG secondary side water. The SG water mass continues to decrease until the PRHR heat exchanger capacity matches decay heat.

	AP600	AP1000
PRHR HX Surface Area	100%	122%
PRHR HX Line Sizes, HL to PRHR tee	12", 10"	18", 14"
PRHR Inlet/Outlet	10"	14"
PRHR Flow Path Resistance	100%	33%
Calculated PRHR Heat Transfer		
HL temperature	556°F	567°F
HX outlet temperature	178°F	197°F
HX flow rate	100%	174%
Heat transfer	100%	172%
Time to Match Decay Heat (min.)	38	44
SG Secondary Side Water		
Initial Water Mass per MW	100%	136%
Final Water Mass per MW	100%	212%

As shown in the above table, the AP1000 PRHR heat exchanger capacity has been increased substantially, almost as much as the increase in core power. In addition, the AP1000 SG secondary side inventory has been increased more than the ratio of core powers. The above table shows that the AP1000 initial SG water mass at the time of trip is 36% greater (per MW of core power) than the AP600. At the end of the transient, the AP1000 SG mass is more than twice as large as the AP600 SG mass, even though the AP1000 PRHR heat exchanger matches decay heat a few minutes later.

Based on this evaluation, the substantial increase in PRHR heat exchanger capacity resulting from the increase in PRHR heat exchanger heat transfer area and from the reduced flow resistance, together with the increased SG secondary side water mass should provide greater margin in non-LOCA decay heat removal transients than the AP600. Preliminary AP1000 non-LOCA safety analysis, in Section 3.0, supports this conclusion.

2.4.6.2 Accumulator

The primary parameter of interest with the accumulator is the time it takes to refill the reactor vessel lower plenum in a large LOCA and the effect on the fuel peak clad temperature (PCT) occurring during reflood. The larger LOCA is limiting because it requires the highest injection rate.

For the AP1000, the accumulator tank, water level, gas pressure, discharge line resistance, and reactor vessel lower plenum volume are unchanged from the AP600.

In the AP600, the large LOCA PCT is much lower than it is in operating plants and occurs during blowdown. This blowdown PCT is 1676°F with uncertainties, which is significantly less than the licensing limit of 2200°F. The reflood PCT is only 1504°F with uncertainties. AP1000 has the same lower plenum volume such that with the same accumulator injection capability, the time to refill the lower plenum will be about the same. However because of the higher core power density, higher PCTs are expected.

Simplified calculations have been performed to estimate the large LOCA PCT for the AP1000. The assumptions and results for the two cases calculated are given below.

Case 1 shows an approximation of the AP1000 reflood PCT made with the following assumptions:

- Same end of blowdown PCT
- Same time for core heatup, from the end of blowdown PCT to the reflood PCT
- Higher PCT heatup rate during this time based on the ratio of higher linear power

Case 2 shows the results using more conservative/bounding assumptions:

- 100°F higher end of blowdown PCT
- 7 second longer time for core heatup, from the end of blowdown PCT to the reflood PCT
- Higher PCT heatup rate during this time based on the ratio of higher linear power and the longer heatup time

Case 2 considers that the end of blowdown peak may be higher because of the higher linear power. It also considers that the time for core heatup, from end of blowdown PCT to the reflood PCT, may be longer because of the longer downcomer and fuel. Note that the lower plenum is not larger because the reactor vessel is the same diameter and the fuel is located at the same elevation relative to the bottom of the reactor vessel.

		AP1000	
	AP600	**Case 1**	**Case 2**
End of blowdown PCT (°F)	1100	~1100	~1200
Reflood heatup duration (sec)	43	~43	~50
Full power linear power (kw/ft)	4.10	5.707	5.707
Reflood PCT temperature rise (°F)	290	~410	~470
Reflood PCT without uncertainty	1390	~1510	~1670
Reflood PCT with uncertainty	1504	~1630	~1800

The Case 1 temperature rise is calculated:

= AP600 temp rise * AP1000 linear power/AP600 linear power

= 290°F * 5.707 kw/ft/4.10 kw/ft = ~410°F

The Case 2 temperature rise is calculated:

= AP600 temp rise * AP1000 linear power/AP600 linear power * AP1000 time/ AP600 time

= 290°F * 5.707 kw/ft/4.10 kw/ft * 50 sec/43 sec = ~470°F

It is possible to increase the accumulator flow by changing the flow limiting orifice in the discharge line. However this would shorten the duration of the accumulator injection which can cause negative side effects.

Shortening the accumulator injection duration could impact multiple failure accident sequences considered in the PRA, including a DVI LOCA with failure of the intact CMT. During this accident the accumulator provides more than enough flow while it is injecting since the break flow with ADS operation is smaller than a large LOCA. The more limiting factor is its duration of injection. The challenge to core cooling comes after the accumulator empties and before IRWST injection starts. MAAP analysis was used to show that the AP600 provided adequate core cooling during this beyond design basis event. Preliminary AP1000 MAAP analysis shows that the AP1000 also provides adequate core cooling for this event with the proposed delivery rate.

Based on this evaluation, the AP1000 accumulators should refill the lower plenum and downcomer fast enough following a large LOCA to limit the reflood PCT to well below the licensing limit of 2200°F. The AP1000 PCTs are expected to be higher than the AP600 PCTs. In addition, maintaining the current AP600 accumulator delivery time helps during DVI LOCAs with multiple failures (PRA sequences). Large break LOCA analyses will be provided as part of the AP1000 DCD.

2.4.6.3 Core Makeup Tank

The primary parameter of interest with the CMTs is its injection capability during a LOCA. The limiting design basis event is a DVI LOCA because it causes the complete spill of one of the two CMTs and results in a quick actuation of ADS because of the rapid draining of the faulted CMT.

The AP1000 CMT volume and its injection capability have been increased by about 25%. Because of building layout constraints the tank volume increase is accomplished by increasing the CMT diameter. The injection capability increase has been accomplished by changing the flow limiting orifice in the CMT discharge line. Increasing the CMT volume and its injection

capability maintains the same injection duration which maintains the same (or similar) time when the ADS stages are actuated and the IRWST begins to provide safety injection.

The following table shows the flow capability margins available in the CMTs during a design basis DVI line break accident. Note that in such an accident the intact accumulator provides the RCS injection during the majority of the RCS depressurization activity which occurs during the first 500 seconds. When the accumulators empty at 600 seconds the RCS pressure is already relatively low and the main function of the CMTs is to provide enough injection to remove core decay heat and sensible heat from the reactor vessel and its internals.

	AP600	AP1000
CMT line resistance (outlet CMT to DVI)	100%	64%
CMT flow capability	100%	125%
Time accumulators empty in a DVI LOCA (sec)	600	600
Required CMT flow for DVI at above time to remove decay and sensible heat	100%	155%
Actual CMT flow capability vs. required flow	161%	129%

Note that the time when the accumulators empty in the AP1000 is expected to be later because the DVI lines are the same size for both plants and the AP1000 has a larger RCS volume and greater decay heat. As a result, the blowdown of the RCS is expected to be slower. Assuming the same time is conservative in the above evaluation because it requires more CMT flow due to the greater decay and sensible heat that occur at the earlier time.

The flow capability shown above is calculated in the same manner as for the PRHR heat exchanger using the Darcy formula assuming that the differential pressures are the same for the AP1000 and AP600. The differential pressures are expected to be the same since the DVI nozzle and the CMT top/bottom elevations are the same. Note that the line resistance of interest is between the CMT outlet and the DVI nozzle. The line resistance for the pressure balance line between the CL and the CMT top inlet is not important because of the low density of steam in the line when the accumulators empty at less than 100 psig.

Flow ratio = (1/resistance ratio) ^ 0.5 = (1/64%) ^ 0.5 = 125%

Note that the required CMT flow for the AP1000 is less than the ratio of core power because of differences in sensible heat in the reactor vessel. The AP1000 sensible heat per MW is lower than the AP600 because the reactor vessel diameter is the same diameter, although it is somewhat longer. Also note that the AP600 CMTs provide large margin to the required flow (61%). As a result, increasing the AP1000 CMT flow capability by 25% over that of the AP600 is sufficient to maintain a comfortable margin of 29% versus the AP1000 required flow.

Another potentially limiting event is a multiple failure accident sequence considered in the PRA, a DVI LOCA with failure of the intact accumulator. During this accident the CMT

provides injection for a sufficient time because of its injection characteristics. The more limiting factor is the magnitude of the CMT injection since failure of the accumulator significantly reduces the peak injection available. MAAP analysis was used to show that the AP600 provided adequate core cooling during this beyond design basis event. Preliminary AP1000 MAAP analysis have been performed and results demonstrate that the AP1000 also provides adequate core cooling for this event.

Based on this evaluation, the AP1000 CMTs should provide sufficient injection to adequately cool the core during LOCAs. Preliminary AP1000 small LOCA safety analyses presented in Section 3.0 support this conclusion.

2.4.6.4 IRWST Injection

The primary parameter of interest with the IRWST is its gravity injection capability to the RCS. The limiting condition is the initiation of IRWST injection following a DVI LOCA. This event is limiting because the break location causes one IRWST line to spill and the rapid blowdown of one CMT results in an early actuation of ADS which requires earlier injection from the IRWST. The initiation of IRWST flow to the core in a DVI LOCA also has more uncertainty in the supporting test results and safety analysis computer code models than other phenomenon during the accident sequence.

The nominal size of the injection lines have been increased from 6" to 8" in order to reduce the flow resistance. This change results in the flow resistance being reduced to about 32% of the AP600's. In addition, the initial water level in the IRWST has been increased from 27' to 28.58' to increase the initial injection pressure. More accurate narrow range IRWST level instruments have been added to decrease the instrument uncertainty and allow similar operating margins.

The following table shows the effect of these changes on the IRWST injection capability. The assumed RCS pressure (versus containment) is typical of the initial IRWST cut-in conditions.

	AP600	AP1000
IRWST initial water level (ft)	130.00'	131.58'
DVI nozzle centerline elevation (ft)	99.6'	99.6'
RCS pressure – containment pressure (psi)	4.0	4.0
Available driving pressure (psi)	9.04	9.72
	100%	108%
IRWST injection line resistance	100%	32%
IRWST injection flow	100%	184%

The flow capability shown above has been is calculated using the Darcy formula. In this case, the differential pressure is not the same because of the difference in IRWST water levels.

Flow ratio = (DP ratio/resistance ratio) ^ 0.5 = (1.08%/32%) ^ 0.5 = 184%

Based on this evaluation, the AP1000 IRWST gravity injection capability has been increased by more than the AP1000/AP600 core power increase (3400/1933 or 176%). As a result, this feature should provide increased margins for the AP1000. Preliminary AP1000 small LOCA and long term cooling safety analyses presented in Section 3.0 support this conclusion.

2.4.6.5 Containment Recirculation

The primary feature of interest is the containment recirculation flow capability. The limiting condition is a DVI LOCA because it results in the lowest containment water level and an earlier time for the initiation of containment recirculation. The lower water level reduces the available driving head for containment recirculation. For the AP600, the worst DVI case was with RNS injection because it increased the spill of IRWST water to the containment by pumping water from the IRWST to the break. This results in the earliest time for initiation of containment recirculation. However as discussed below, improvements have been made to the AP1000 such that operation of the RNS during a DVI LOCA is no longer the limiting case. For the AP1000, the limiting case is a DVI LOCA with gravity injection of the IRWST and no RNS pumped injection.

The nominal line size for the containment recirculation lines has been increased from 6" to 8" in order to reduce the flow resistance. This change results in the flow resistance being reduced to about 32% of the AP600's. In addition, several changes have been made to increase the containment water level at the time of recirculation as well as to delay the time when recirculation is initiated. All of these changes improve containment recirculation capability and are summarized below.

- The IRWST initial water level has been increased.

- The drain from the refueling cavity has been revised. The drain is now connected to the bottom of the pit. In addition, check valves have been added to prevent backflow from the loop compartments to the refueling cavity during the initial containment flooding. The revised refueling cavity drain arrangement makes the cavity similar to the design used in the two PXS valve rooms and in the CVS equipment room. It allows water that may initially overflow into this cavity from the IRWST due to ADS operation to drain out of the refueling cavity into the loop compartments. Later on as the IRWST injects and the containment water level rises, check valves prevent water from flooding back into the refueling cavity. As a result, more water is available in the loop compartments which results in a higher containment recirculation water level.

- The normal RNS pump suction has been changed so that it will normally take suction from the spent fuel cask loading pit instead of the IRWST. In the longer term it will be

re-aligned by the operators to the IRWST/containment so that it can provide a continuous water supply by recirculating water from the containment.

The limiting long term cooling event for the AP600 is a DVI line break where the RNS pumps are started by the operators in accordance with the emergency procedures. Their operation during IRWST injection results in a faster drain down of the IRWST and a quicker initiation of recirculation. In addition, it is assumed that the RNS pumps fail just as recirculation begins and gravity driven recirculation is required to provide injection flow. By changing the RNS water supply to outside containment, its potential adverse interaction can be prevented. In the AP1000, RNS operation will result in a less limiting condition than no RNS operation because the drain down of the IRWST will not be enhanced by the RNS pump and the recirculation water level will be higher because of the additional water injected from outside containment. The PXS/CVS room curbs have been increased to allow for the higher recirculation levels and to prevent flooding of the PXS valves before the recirculation valves actuate.

The following table compares the AP600 and the AP1000 containment recirculation conditions. The assumed RCS pressure (versus containment) is typical of the containment recirculation start conditions.

	AP600	**AP1000**
Containment Recirc Line Resistance	100%	39%
DVI LOCA with RNS Operation		
- Time recirc occurs (hr)	2.10	~2.67
- RCS pressure – containment pres (psi)	2.2	2.2
- Containment water level (ft)	106.2′	108.4′
- DVI nozzle centerline elev (ft)	99.6′	99.6′
- Available driving pressure (psi)	0.59	1.51
- Available driving pressure	100%	256%
- Recirc flow (%)	100%	256%
- Desired flow (core power, recirc time)	100%	~159%
- Available recirculation flow as percentage of desired flow	100%	161%
DVI LOCA without RNS Operation		
- Time recirc occurs (hr)	4.76	2.67
- RCS pressure – containment pres (psi)	2.2	2.2
- Containment water level (ft)	106.2	107.7′

	AP600	AP1000
- DVI nozzle centerline elev (ft)	99.6′	99.6′
- Available driving pressure (psi)	0.59	1.24
- Available driving pressure	100%	209%
- Recirc flow (%)	100%	231%
- Desired flow (core power, recirc time)	79%	159%
- Available recirculation flow as percentage of desired flow	127%	145%

Note that the "desired" flow is adjusted from the AP600 DVI LOCA case with RNS operation. This flow is ratioed based on the difference in decay heat levels accounting for both rated core power and recirculation initiation times. As seen the AP1000 case without RNS operation has a longer time to recirculation than the AP600 (2.67 vs. 2.10 hr) which reduces the decay heat fraction so that the "desired" flow is shown as 159%, where-as the core power ratio is 176%.

The AP1000 case with RNS operation shown above is less limiting than the case without RNS operation. The reason is that the RNS takes water from outside containment instead of from the IRWST. As a result the IRWST drains about the same with or without RNS operation and RNS operation adds water to the containment which increases the recirculation level above the case without RNS operation.

The AP1000 case without RNS operation in the above table shows longer time until recirculation than the limiting AP600 case with RNS operation (2.67 hr without AP1000 RNS operation versus 2.10 hr with AP600 RNS operation), although this time is faster than the comparable AP600 case (without RNS operation). The reason for this is that the AP1000 has incorporated larger IRWST injection lines that result in greater spill of water to the containment during a DVI LOCA. Note that the AP1000 has incorporated features (discussed above) to raise the water level at the time of recirculation by 1.5′. This results in an increase in net recirculation driving pressure of 109% (0.59 to 1.24 psi). The following shows the calculation of the increased recirculation flow capabilities:

With RNS operation:

Flow ratio = (DP ratio/resistance ratio) ^ 0.5

= (256%/39%) ^ 0.5 = 256%

Without RNS operation:

Flow ratio = (DP ratio/resistance ratio) ^ 0.5

= (209%/39%) ^ 0.5 = 231%

As shown above the flow ratio with RNS operation is greater than the flow ratio without RNS operation. Since the desired flow ratio is about the same (159%), the case without RNS operation is the limiting case.

Based on this evaluation, the AP1000 containment recirculation capability should provide increased margin relative to the AP600 design. Preliminary AP1000 long term cooling safety analyses presented in Section 3.0 support this conclusion.

2.4.6.6 Automatic Depressurization System

The primary parameter of interest in the ADS feature is the non-choked flow capability of the ADS 4 lines. The reason for this is that these lines provide essentially all of the ADS vent flow at the time of IRWST injection cut-in and afterwards during long term cooling (IRWST injection and containment recirculation). The reasons the ADS stage 1, 2, 3 are ineffective at these low pressure conditions are:

- Their flow resistance is much greater.
- They discharge through the ADS spargers which are located ~10′ under water, increasing their backpressure.
- Venting through these ADS valves tends to drag water from the hot legs up into the pressurizer where it gets trapped, increasing their backpressure.

The nominal line size for the ADS stage 4 lines has been increased from 10" to 14" in order to reduce the flow resistance. In addition, the line size common to each pair of ADS 4 lines has been increased from 12" to 18". This change results in the flow resistance being reduced to about 28% of the AP600 system resistance. This change also increases the ADS 4 vent flow area 76%, which is the same increase as the core power increase.

The following table shows the effect of this reduction in flow resistance on the ADS stage 4 vent capacity.

	AP600	AP1000
ADS 4 valve vent flow area	100%	176%
ADS 4 flow resistance	100%	28%
RCS pressure vs. containment pressure	100%	100%
ADS 4 vent flow capability	100%	189%

The flow ratio shown above was calculated in the same manor as previously using the Darcy formula. In this case it is assumed that the differential pressure between the core and the containment is the same. This is conservative because the elevation of the hot leg and ADS stage 4 discharge are the same, the IRWST injection/recirc capability are greater (tends to

support a greater DP), and the ADS 4 vent flow ratio is greater than the core power ratio (tends to support a greater DP).

Flow ratio = (1/resistance ratio) ^ 0.5 = (1/28%) ^ 0.5 = 189%

Note that this calculation does not include velocity head, which is important in this line because of the large change in steam velocity from the hot leg to the discharge. Since the AP1000 valve vent area ratio is equal to the core power ratio, the velocity head loss will be the same if the vent flow is the same per MW. In the case shown above, the vent flow is calculated to be somewhat greater which would increase the velocity head and reduce the increase in flow ratio. The reduction in the flow ratio from this effect is not expected to be significant.

This evaluation shows that the ADS stage 4 low pressure, non-choked, vent flow capability has been increased greater than the core power increase of 176%. As a result, this feature should provide increased margins relative to the AP600 design. Preliminary AP1000 small LOCA safety analyses presented in Section 3.0 support this conclusion.

Table 2.4-1 AP1000 Passive Core Cooling System Parameters	
Parameter	**Value**
Passive RHR Heat Exchanger	
Type of Heat Exchanger	"C" Tube
Number of Heat Exchanger Tubes	689
Tube ID/OD, in	0.62/0.75
Core Makeup Tanks	
Number	2
Volume (Minimum), ft^3	2500
Boron Concentration (Minimum), ppm	3400
Accumulators	
Number	2
Total Volume (Minimum), ft^3	2000
Water Volume (Min Flow Case), ft^3	1732
Gas Volume (Min Flow Case), ft^3	268
Initial Gas Pressure (Min Flow Case), psig	637
Boron Concentration (Minimum), ppm	2600
In-Containment Refueling Water Storage Tank	
Water Volume (Min Flow Case), ft^3	78,900
Water Height (Min Flow Case), ft	28.58
Boron Concentration (Minimum), ppm	2600
Spargers	
Number	2
Type	Cruciform
Flow Area of Holes per Sparger, in^2	274
pH Adjustment Baskets	
Number	2
Type	Rectangular
Volume, ft^3	135
Fourth Stage Automatic Depressurization Valves	
Number of Flow Paths	2 Off of Single Header Per Hot Leg
Valve Size, in	14
Isolation Valve Type (Operator)	Gate (MOV, Normally Open)
Control Valve Type	Squib

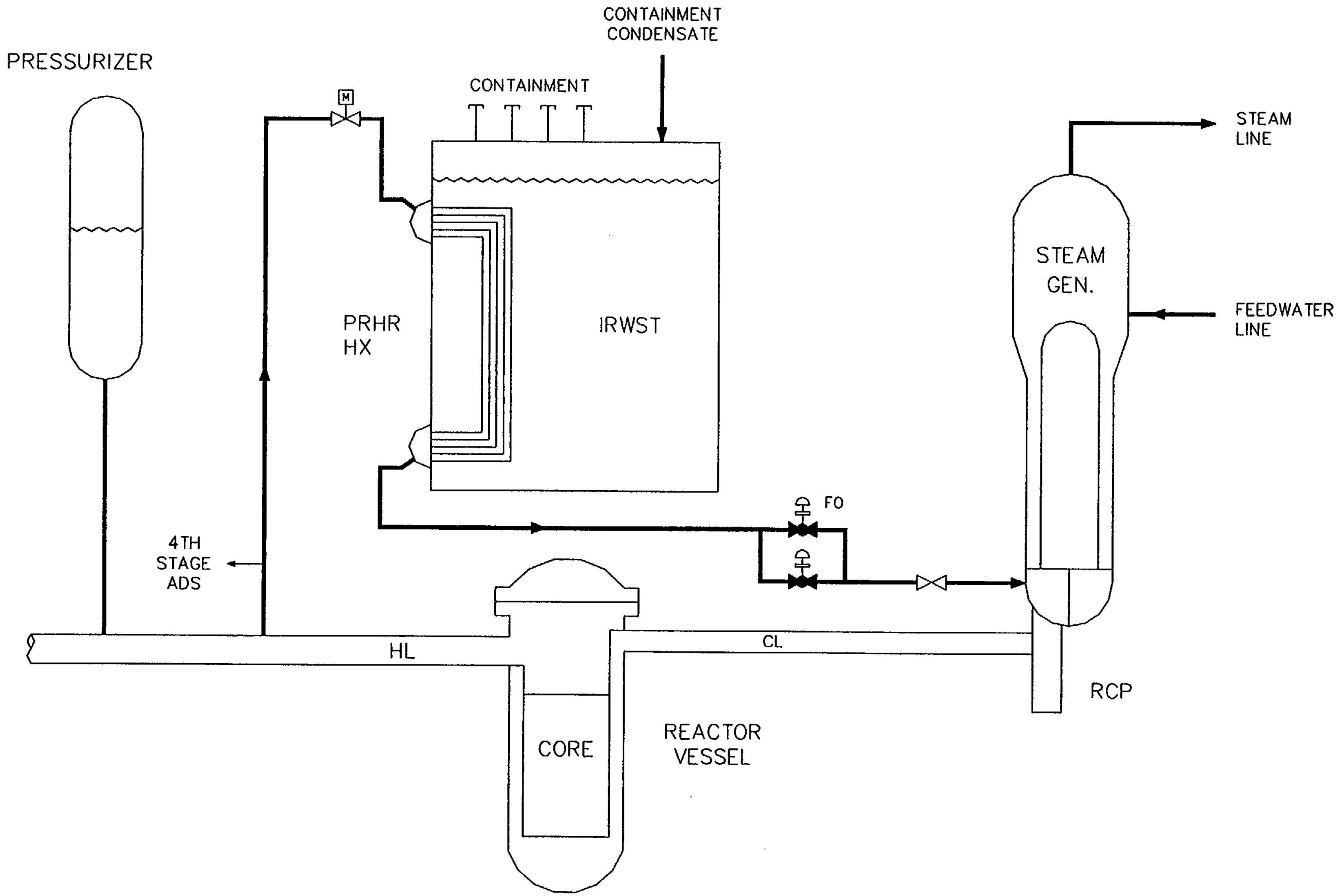


Figure 2.4-1 AP1000 Passive Decay Heat Removal Flow Schematic

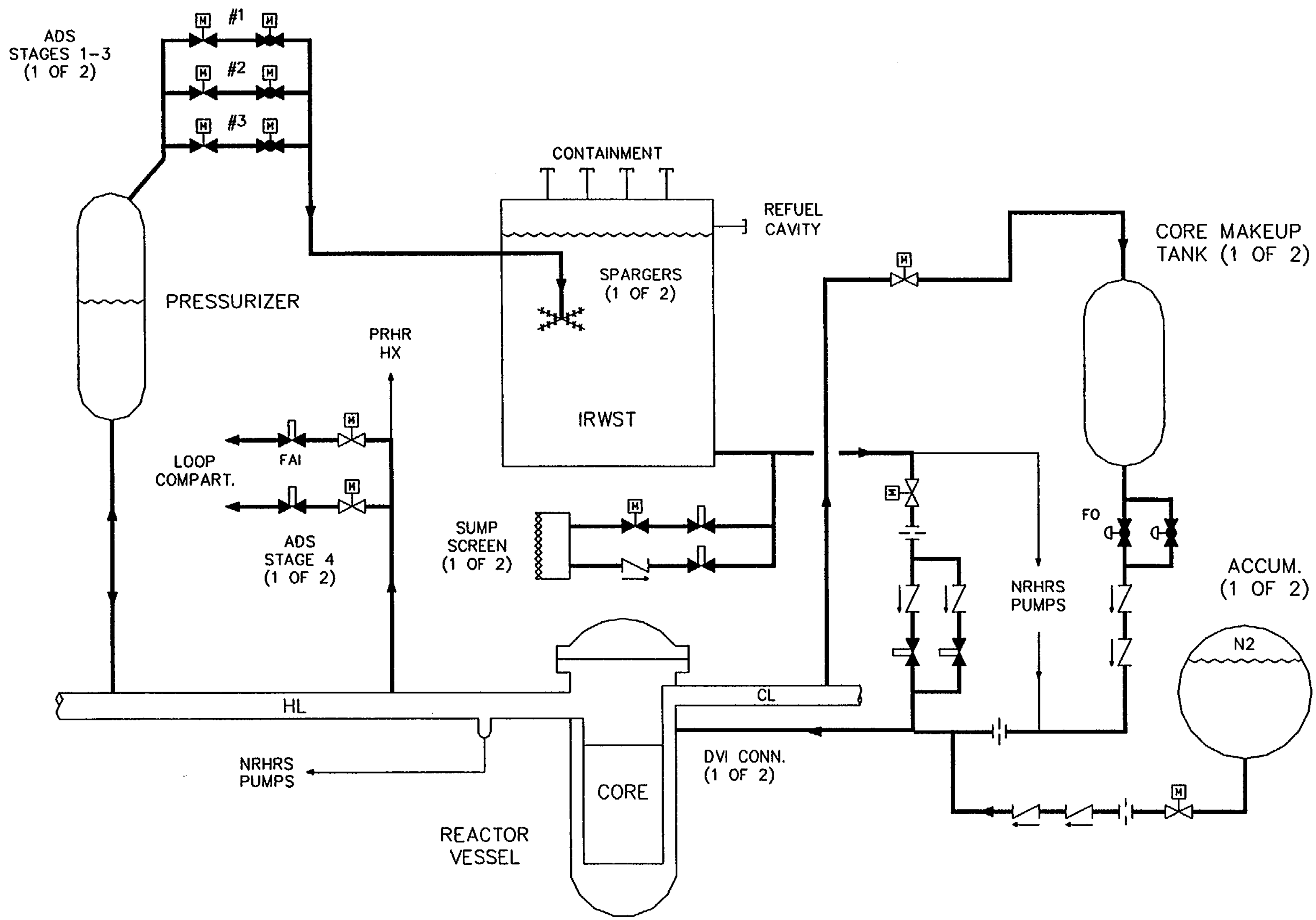
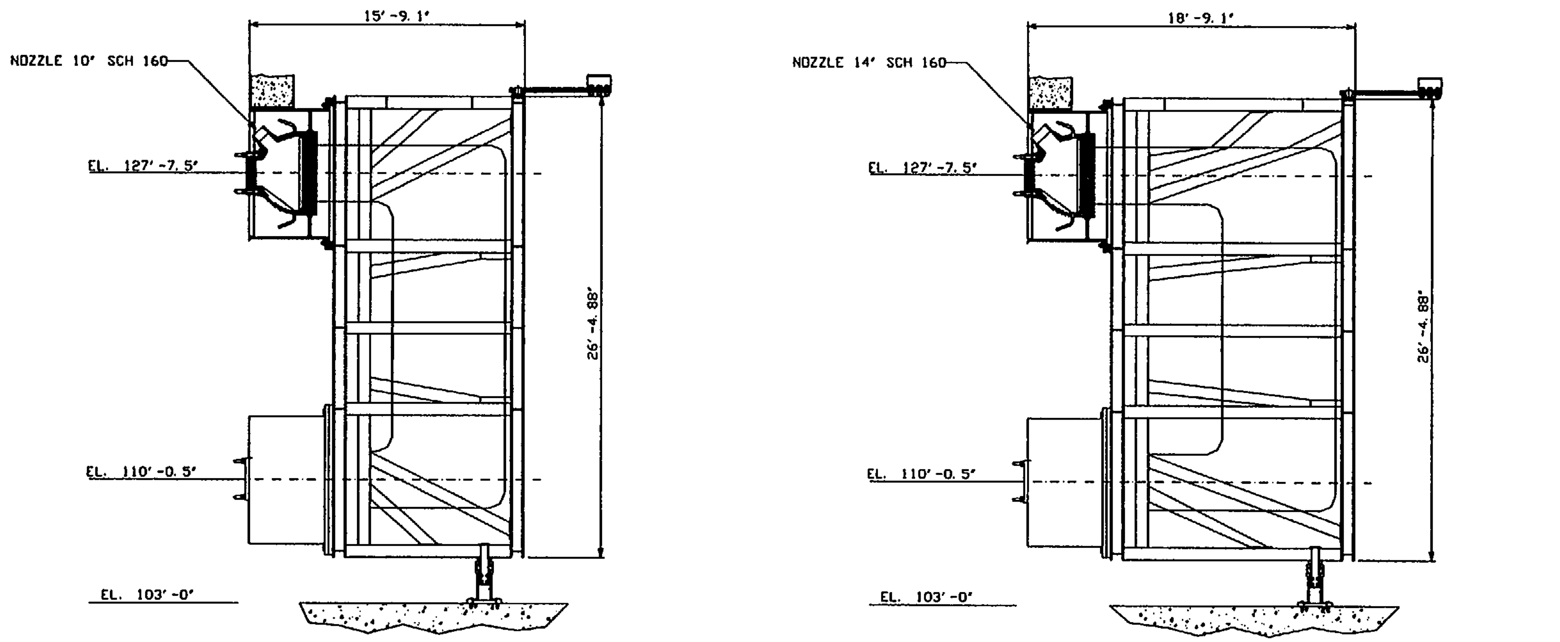


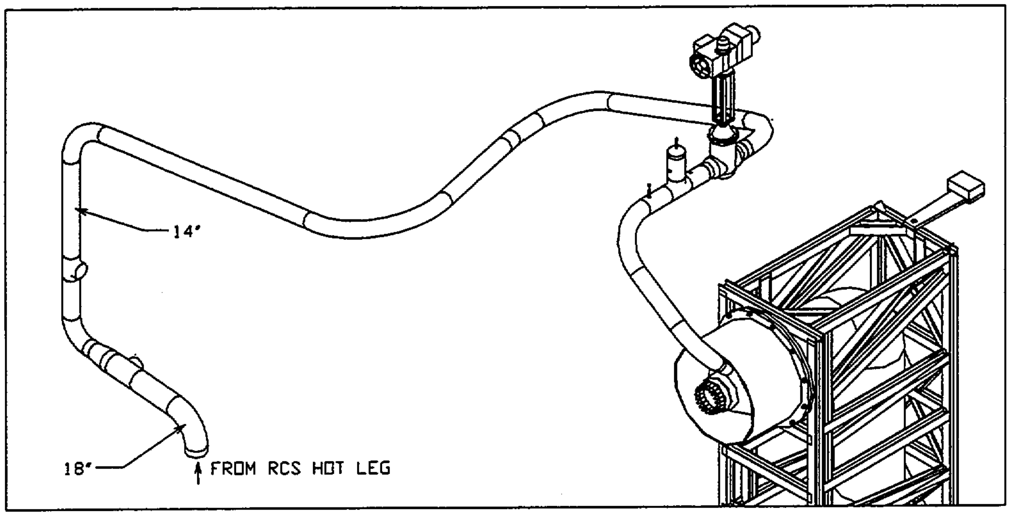
Figure 2.4-2 AP1000 Passive Safety Injection Flow Schematic



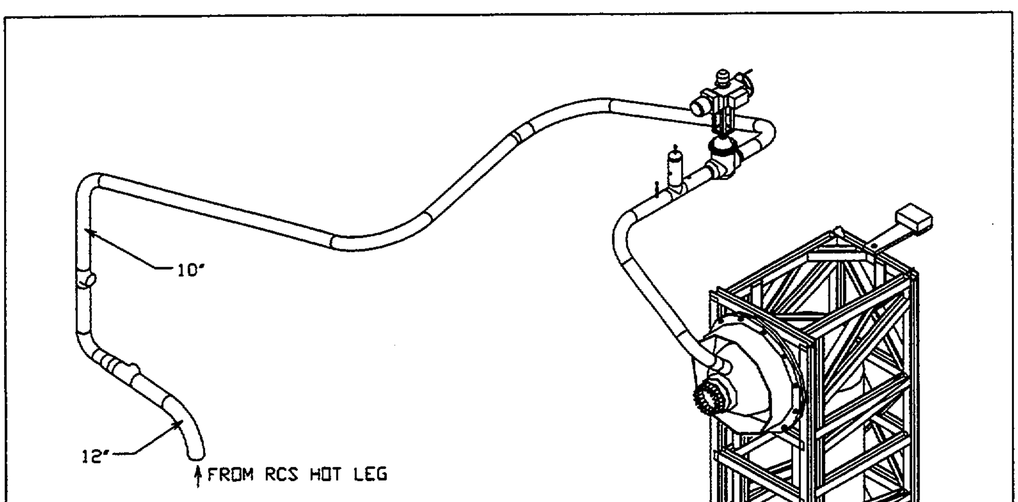
AP600 AP1000

Figure 2.4-3 AP1000 and AP600 Passive RHR Heat Exchanger Outline Drawings

PRHR SUPPLY PIPING



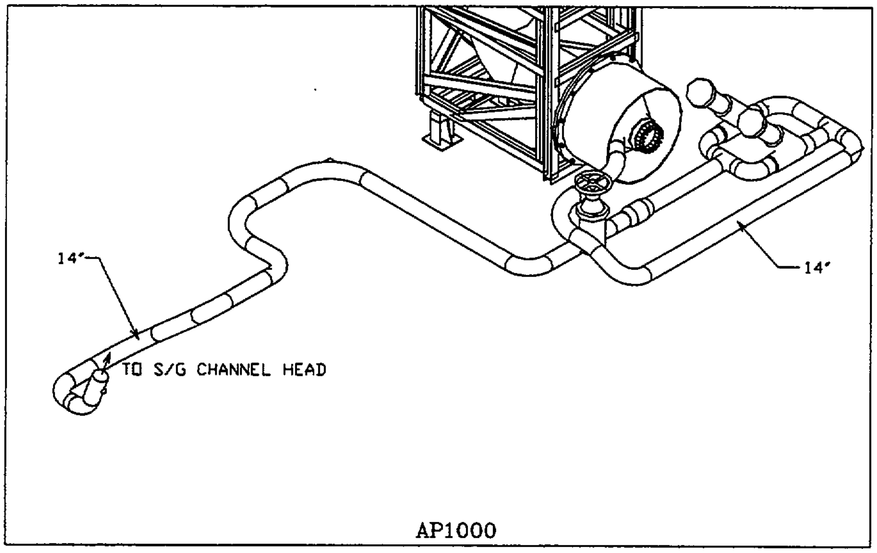
AP1000



AP600

Figure 2.4-4 Comparison of AP1000 and AP600 PRHR Heat Exchanger Supply Piping

PRHR RETURN PIPING



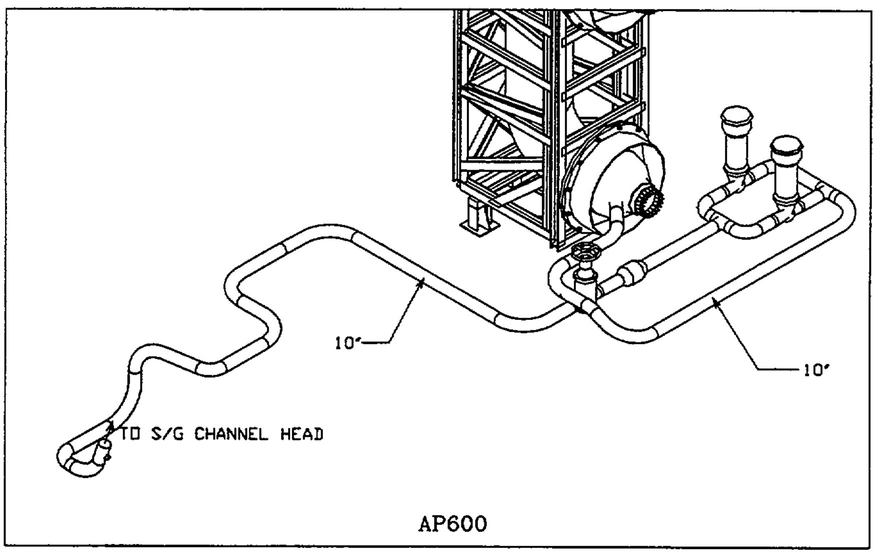
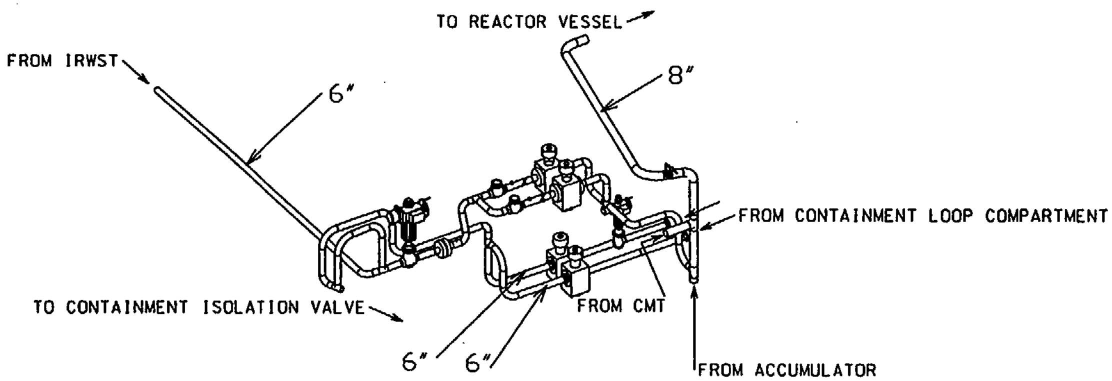
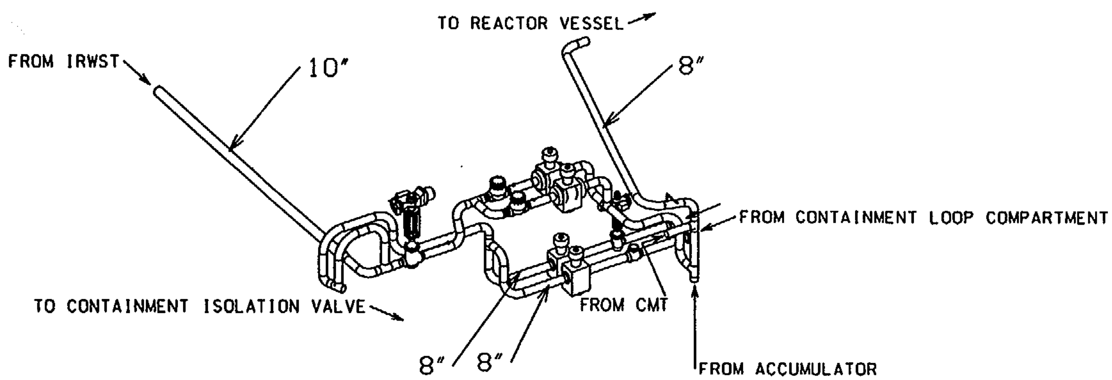


Figure 2.4-5 Comparison of AP1000 and AP600 PRHR Heat Exchanger Return Piping



DVIA-AP600



DVIA-1000

Figure 2.4-6 Comparison of AP1000 and AP600 IRWST and Containment Sump Injection Piping

2.5 CONTAINMENT AND CONTAINMENT COOLING SYSTEM DESIGN

2.5.1 Containment Vessel Design

2.5.1.1 Vessel Description

The containment vessel is an ASME metal containment. It serves both to limit releases in the event of an accident and to provide the safety-related ultimate heat sink.

The containment arrangement is indicated in the general arrangement figures in Section 2.8. The portion of the vessel above elevation 132 ft-3 in is surrounded by the shield building but is exposed to ambient conditions as part of the passive containment cooling flow path. A flexible watertight and airtight seal is provided at elevation 132 ft-3 in between the containment vessel and the shield building. The portion of the vessel below elevation 132 ft-3 in is fully enclosed within the shield building.

Figure 2.5.1-1 shows the containment vessel outline. It is a free-standing, cylindrical steel vessel with ellipsoidal upper and lower heads. The containment vessel has the following design characteristics:

Diameter: 130 feet

Height: 215 feet 4 inches

Design Code: ASME III, Div. 1

Material: SA738 Grade B

Design Pressure: 59 psig

Design Temperature: 280°F

Design External Pressure: 3.0 psid

The wall thickness of the cylinder and the heads is 1.75 inches. The heads are ellipsoidal with a major diameter of 130 feet and a height of 37 feet 7.5 inches.

The containment vessel includes the shell, hoop stiffeners and crane girder, equipment hatches, personnel airlocks, penetration assemblies, and miscellaneous appurtenances and attachments.

The polar crane is designed for handling the reactor vessel head during normal refueling. The crane girder and wheel assemblies are designed to support a special trolley to be installed in the event of steam generator replacement.

The containment vessel supports most of the containment air baffle. The air baffle is arranged to permit inspection of the exterior surface of the containment vessel. Flow distribution weirs are welded to the dome as part of the water distribution system of the passive containment cooling system, described in subsection 2.5.2.

The containment vessel is designed and constructed according to the 1998 edition of the ASME Code (with 1999 addenda), Section III, Subsection NE, Metal Containment. A Code Case is being prepared for submittal for use of SA738 Grade B material for a metal containment.

2.5.1.2 Containment Vessel Support

The bottom head is embedded in concrete, with concrete up to elevation 100 ft on the outside and approximately elevation 108 ft on the inside. The containment vessel is assumed as an independent, free-standing structure above elevation 100 ft. The thickness of the lower head is the same as that of the upper head. There is no reduction in shell thickness even though credit could be taken for the concrete encasement of the lower head.

Vertical and lateral loads on the containment vessel and internal structures are transferred to the basemat below the vessel by friction and bearing. Seals are provided at the top of the concrete on the inside and outside of the vessel to prevent moisture between the vessel and concrete.

2.5.1.3 Coatings

The containment vessel is coated with an inorganic zinc coating, except for those portions fully embedded in concrete. The inside of the vessel below the operating floor and up to 8 feet above the operating floor also has a phenolic top coat. Below elevation 100 ft the vessel is fully embedded in concrete with the exception of the few penetrations at low elevations. Embedding the steel vessel in concrete protects the steel from corrosion.

The exterior of the vessel is embedded at elevation 100 ft and concrete is placed against the inside of the vessel up to elevation 107 ft-2 in. Above this elevation the inside and outside of the containment vessel are accessible for inspection of the coating. The vessel is coated with an inorganic zinc primer to a level just below the concrete. Seals are provided at the surface of the concrete inside and outside the vessel so that moisture is not trapped next to the steel vessel just below the top of the concrete. The seal on the inside accommodates radial growth of the vessel due to pressurization and heatup.

2.5.1.4 Differences Between AP1000 and AP600

Although there are several differences between the AP1000 and AP600 containment vessels, the diameter of the vessel remains unchanged. The containment free volume was increased in the AP1000 by increasing the containment vessel height.

The vessel pressure capability was increased by changing the vessel material and increasing the wall thickness of the vessel.

The table below summarizes the major differences between the AP1000 and AP600 containment vessel designs.

Containment Vessel Design Differences – AP1000 and AP600		
Parameter	**AP1000**	**AP600**
Material	SA738 Grade B	SA537 Class 2
Overall Height, ft-in	215 - 4	189 - 10
Free Volume, ft^3	2.07×10^6	1.73×10^6
Shell Thickness, in	1.75	1.625
Design Pressure, psig	59	45
Design Code	ASME Section III, Div 1 (1998 with 1999 addenda)	ASME Section III, Div 1 (1992)

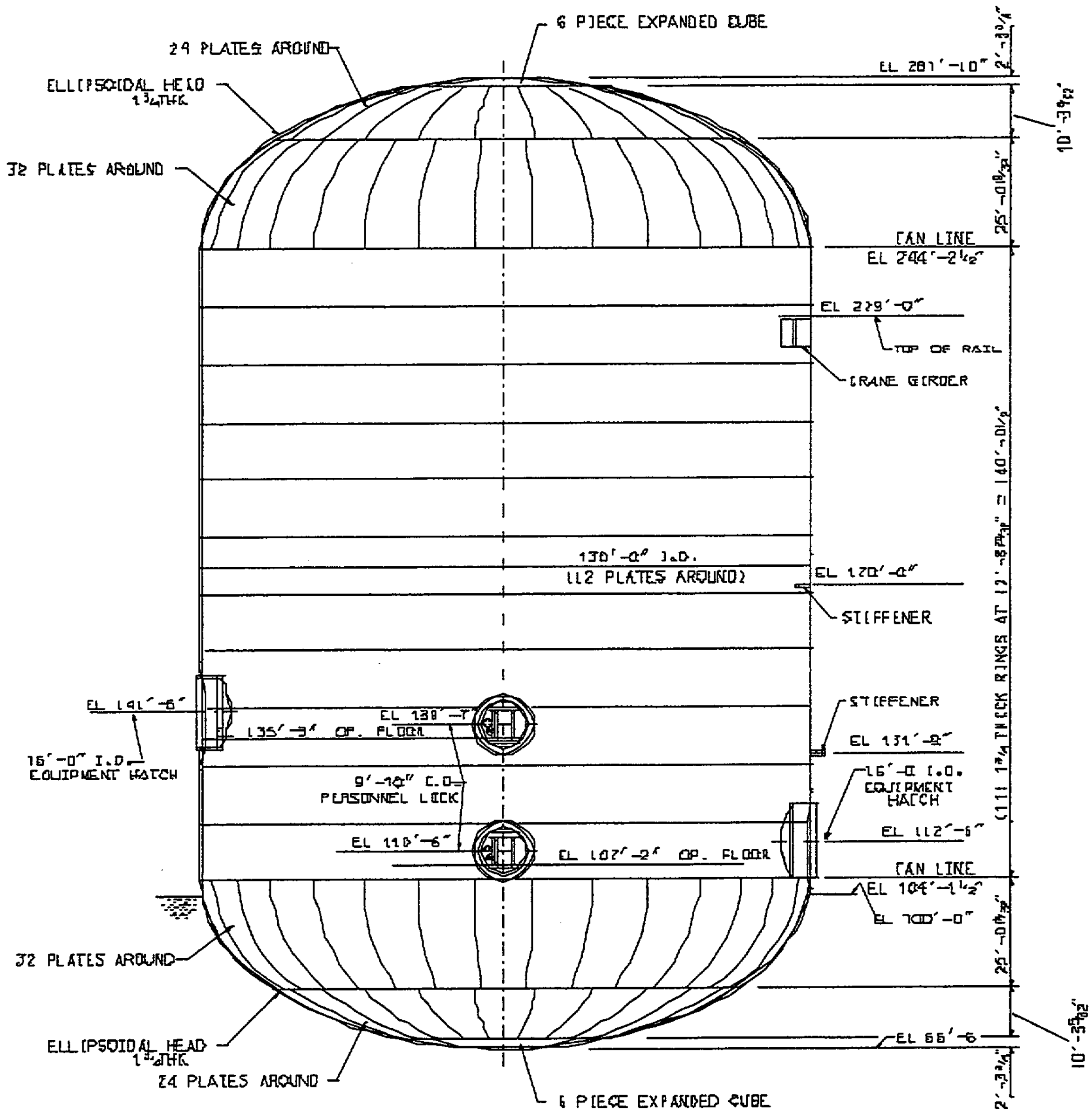


Figure 2.5.1-1 AP1000 Containment Vessel Outline

2.5.2 Passive Containment Cooling System Design

2.5.2.1 System Functions

The passive containment cooling system (PCS) is an engineered safety features system. Its functional objective is to reduce the containment temperature and pressure following a loss of coolant accident (LOCA) or main steam line break (MSLB) accident inside the containment by removing thermal energy from the containment atmosphere. The passive containment cooling system also serves as the means of transferring heat to the safety-related ultimate heat sink for other events resulting in a significant increase in containment pressure and temperature.

The passive containment cooling system limits releases of radioactivity (post-accident) by reducing the pressure differential between the containment atmosphere and the external environment, thereby diminishing the driving force for leakage of fission products from the containment to the atmosphere.

The passive containment cooling system also provides a source of makeup water to the spent fuel pool in the event of a prolonged loss of normal spent fuel pool cooling.

2.5.2.2 System Description

The passive containment cooling system is a safety-related system which is capable of transferring heat directly from the steel containment vessel to the environment. This transfer of heat prevents the containment from exceeding the design pressure and temperature following a postulated design basis accident. The passive containment cooling system makes use of the steel containment vessel and the concrete shield building surrounding the containment. The major components of the passive containment cooling system are: the passive containment cooling water storage tank (PCCWST) which is incorporated into the shield building structure above the containment; an air baffle, located between the steel containment vessel and the concrete shield building, which defines the cooling air flowpath; air inlets and an air exhaust, also incorporated into the shield building structure; and a water distribution system, mounted on the outside surface of the steel containment vessel, which functions to distribute water flow on the containment. A passive containment cooling ancillary water storage tank and two recirculation pumps are provided for onsite storage of additional passive containment cooling system cooling water (for post-72 hour operation), to transfer the inventory to the passive containment cooling water storage tank, and to provide a back-up supply to the fire protection system (FPS) seismic standpipe system.

A recirculation path is provided to control the passive containment cooling water storage tank water chemistry and to provide heating for freeze protection. Passive containment cooling water storage tank filling operations and normal makeup needs are provided by the demineralized water transfer and storage system.

A normally isolated, manually-opened flow path is also available between the passive containment cooling system water storage tank and the spent fuel pool.

Overall system parameters are shown in Table 2.5.2-1. A simplified system sketch is included as Figure 2.5.2-1.

Heat removal by the PCS is initiated automatically by the protection and safety monitoring system in response to a Hi-Hi containment pressure signal. Actuation of the PCS initiates water flow by gravity from the PCS water storage tank contained in the shield building structure above the containment onto the containment dome outer surface, forming a water film over the structure. The water flow is automatically established by the opening of either of two parallel air operated isolation valves.

A path for natural circulation of air upward along the outside walls of the containment shell is always open with no moving components and with specific features to assure its availability. The natural circulation air flow path begins at the shield building inlet, where atmospheric air enters horizontally through openings in the concrete structure. The air inlets are located high in the shield building to limit the effects of ground and nearby building interference and turbulences. Air flows through the inlets and past a set of fixed louvers. The air flows down an outer annulus enclosed by the concrete shield building on the outside and a removable baffle wall on the inside. At the bottom of the baffle wall a curved vane aids in turning the flow upward 180 degrees into the inner containment annulus. This inner annulus is enclosed by the baffle wall on the outside and the steel containment vessel on the inside. Air flows up through the inner annulus to the top of the containment vessel and then exhausts through the shield building chimney.

As the containment structure heats up in response to steam release from a design basis event, heat is transferred from the containment atmosphere through the containment wall to the cooling air. Heat from the containment atmosphere is transferred to the containment shell via conduction, convection, radiation and steam condensation on the vessel inner wall. Heat is transferred via conduction through the steel shell. The heat is then transferred from the shell via convection and evaporation from the water film and shell to the air, and radiation from the water film and the dry portions of the shell to the air baffle. As heat and water vapor are transferred to the air space between the containment structure and air baffle, the air becomes less dense than the air in the inlet annulus. This density difference causes an increase in the natural circulation of the air upward between the containment structure and the air baffle, with the air finally exiting at the top center of the shield building.

2.5.2.3 Component Descriptions

PASSIVE CONTAINMENT COOLING WATER STORAGE TANK

The passive containment cooling water storage tank is incorporated into the shield building structure above the containment vessel. The inside wetted walls of the tank are lined with stainless steel plate. It is filled with demineralized water and functions as the safety-related ultimate heat sink. The passive containment cooling water storage tank is seismically designed and missile protected.

In addition to its containment heat removal function, the passive containment cooling water storage tank also serves as a source of makeup water to the spent fuel pool and a seismic Category I water storage reservoir for fire protection following a safe shutdown earthquake.

The PCCWST suction pipe for the fire protection system is configured so that actuation of the fire protection system will not infringe on the volume allocated to the passive containment cooling function.

PASSIVE CONTAINMENT COOLING WATER STORAGE TANK ISOLATION VALVES

The passive containment cooling system water storage tank outlet piping is equipped with two sets of redundant isolation valves. The air-operated butterfly valves are normally closed and open upon receipt of a Hi-2 containment pressure signal. These valves fail-open, providing a fail-safe position, on the loss of air or loss of 1E dc power. The normally-open motor-operated gate valves are located upstream of the butterfly valves. They are provided to allow for testing or maintenance of the butterfly valves.

FLOW CONTROL ORIFICES

Orifices are installed in each of the four passive containment cooling water storage tank outlet pipes. They are used, along with the different elevations of the outlet pipes, to control the flow of water from the passive containment cooling water storage tank as a function of water level.

WATER DISTRIBUTION BUCKET

A water distribution bucket is provided to deliver water to the outer surface of the containment dome. The redundant passive containment cooling water delivery pipes and auxiliary water source piping discharge into the bucket, below its operational water level, to prevent excessive splashing. A set of circumferentially spaced distribution slots are included around the top of the bucket. The bucket is hung from the shield building roof and suspended just above the containment dome for optimum water delivery.

WATER DISTRIBUTION WEIR SYSTEM

A weir-type water delivery system is provided to optimize the wetted coverage of the containment shell during passive containment cooling system operation. The water delivered to the center of the containment dome by the water distribution bucket flows over the containment dome, being distributed evenly by slots in the distribution bucket. Vertical divider plates are attached to the containment dome and originate at the distribution bucket extending radially along the surface of the dome to the first distribution weir. The divider plates limit maldistribution of flow which might otherwise occur due to variations in the slope of the containment dome. At the first distribution weir set, the water in that sector is collected and then redistributed onto the containment utilizing channeling walls and collection troughs equipped with distribution weirs. A second set of weirs are installed on the containment dome at a greater radius to again collect and then redistribute the cooling water to enhance shell

coverage. The system includes channeling walls and collection troughs, equipped with distribution weirs.

AIR FLOW PATH

An air flow path is provided to direct air along the outside of the containment shell to provide containment cooling. The air flow path includes a screened shield building inlet, an air baffle that divides the outer and inner flow annuli, and a chimney to increase buoyancy.

PASSIVE CONTAINMENT COOLING ANCILLARY WATER STORAGE TANK

The passive containment cooling ancillary water storage tank is a cylindrical steel tank located at ground level near the auxiliary building. It is filled with demineralized water for makeup to the passive containment cooling water storage tank. The tank is analyzed, designed and constructed using the method and criteria for Seismic Category II building structures. The tank is designed and analyzed for Category 5 hurricanes including the effects of sustained winds, maximum gusts, and associated wind-borne missiles.

CHEMICAL ADDITION TANK

The chemical addition tank is a small, vertical, cylindrical tank that is sized to inject a solution of hydrogen peroxide to maintain a passive containment cooling water storage tank concentration for control of algae growth.

RECIRCULATION PUMPS

Each recirculation pump is a 100 percent capacity centrifugal pump with wetted components made of austenitic stainless steel. The pump is sized to recirculate the entire volume of PCCWST water once every week. Both pumps are operated in parallel to meet fire protection system requirements.

RECIRCULATION HEATER

The recirculation heater is provided for freeze protection. The heater is sized based on heat losses from the passive containment cooling water storage tank and recirculation piping at the minimum site temperature.

2.5.2.4 Differences Between AP1000 and AP600

To accommodate the larger power output of the AP1000 the passive containment cooling system (PCS) water storage tank capacity was increased to be able to provide more flow over the containment during the first 72 hours of the design basis accident.

The sizing of the initial flow rate of water over the containment for both the AP600 and AP1000 is based on providing a large flow to ensure that the containment surface is wetted. This flow is maintained for approximately three hours, which is beyond the time when the containment

peak pressure occurs. The initial flow rate for both the AP600 and AP1000 is larger than that required for decay heat removal. Note that the initial PCS flow has very little impact on the containment pressure during a design basis event since the initial blowdown peak pressure is mainly a function of the containment free volume. After the uncovery of the first standpipe at approximately three hours, the sizing of the cooling water flow rate over the containment is based on decay heat removal.

For the period beyond 72 hours additional water flow is also required compared to the AP600 and thus the ancillary PCS water storage tank capacity will also increase. The required tank capacity will be determined during the detailed design work supporting the application for Design Certification for the AP1000.

The table below summarizes the major differences in tank capacities and flow rates between the AP1000 and the AP600.

Passive Containment Cooling System (PCS) Design Differences – AP1000 and AP600		
Parameter	**AP1000**	**AP600**
PCS Water Storage Tank Capacity for Cooling (Top of Overflow), gal	800,000	580,000
Cooling Water Flow Rate Over Containment – Initial, gpm	469	442
Cooling Water Flow Rate Over Containment – at 72 Hours, gpm	100.7	62.7

Table 2.5.2-1 AP1000 Passive Containment Cooling System (PCS) Parameters	
Parameter	**Value**
Minimum PCS Water Storage Tank Capacity for Containment Cooling (Top of Overflow), gal	800,000
Minimum PCS Water Storage Tank Capacity for Fire Protection, gal	18,000
Minimum Initial Inventory Duration, Hours	72
Minimum Cooling Water Flow Rate Over Containment – Initial, gpm	469
Minimum Cooling Water Flow Rate Over Containment – at 72 Hours, gpm	100.7

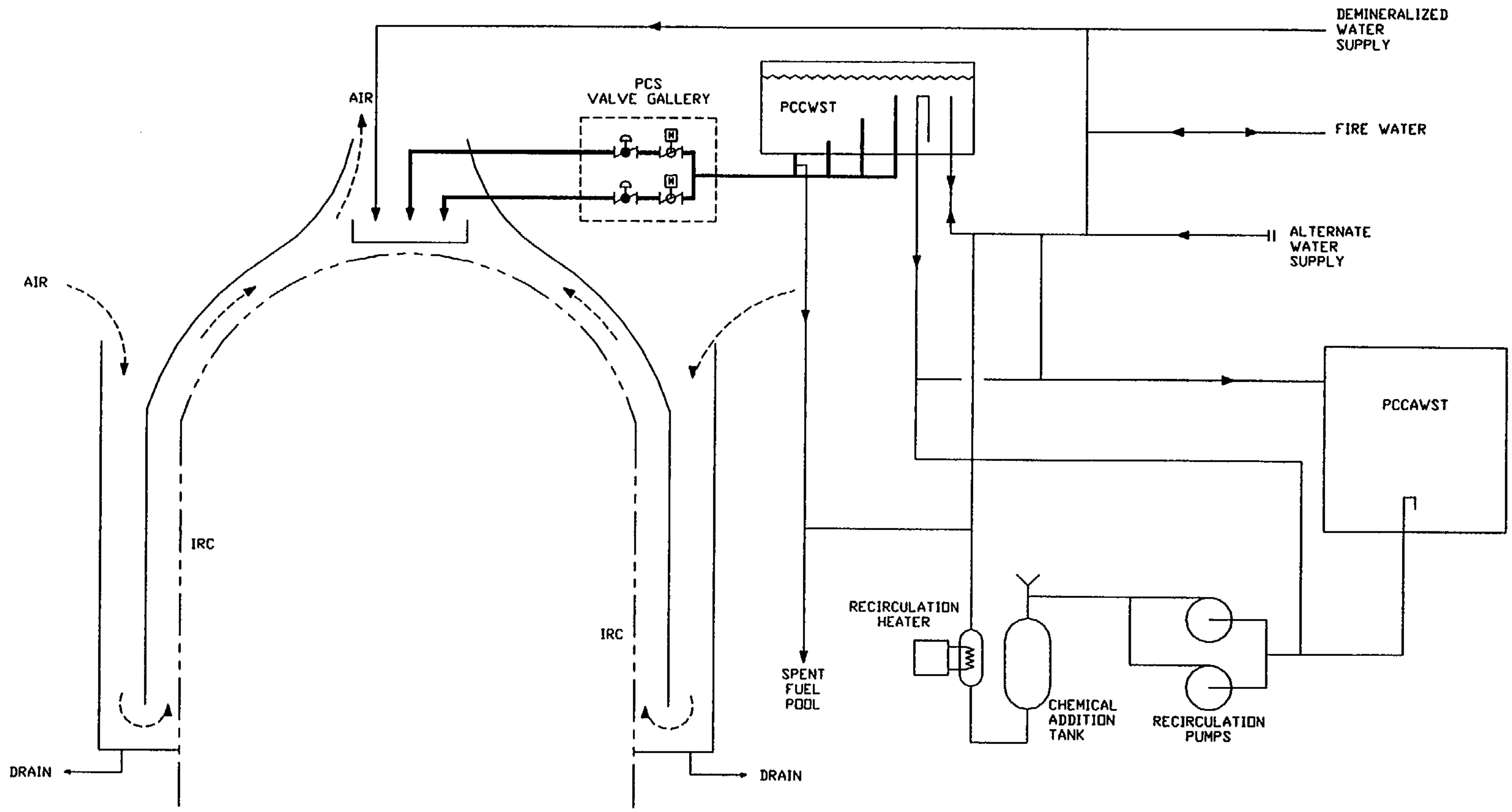


Figure 2.5.2-1 AP1000 Passive Containment Cooling System Flow Schematic

2.5.3 Containment Design Margin and Vessel Pressure Capability Assessment

The primary purpose of the containment is to preclude release of radioactive materials to the environment. Although the peak pressure may result from a main steam line break event, the highest potential for radioactive releases occur for LOCA events. The AP1000 containment is designed for the peak containment pressure resulting from the break of a high-energy pipe inside containment. The design limit for the AP1000 steel containment is 59 psig, compared to 45 psig for AP600. The AP1000 containment design pressure is higher than that of the AP600 due to an increase in the containment wall thickness and change of material to SA738 Grade B. The higher power reactor requires a larger containment volume and a higher capacity passive containment cooling system (PCS). Two types of design basis events are considered: main steam line break (MSLB) and large break LOCA.

Due to the higher power and inventory, it is expected that the mass and energy releases into containment will be higher for AP1000. For the steam line break, the higher volume of steam released to containment is countered by the increased containment free volume and the increased heat capacity of the containment shell. These factors, coupled with the increased design pressure, are expected to result in even greater margins for AP1000.

The WGOTHIC computer code was used to evaluate these events and to determine a preliminary peak containment pressure. The model includes compartment volumes, heat sinks, inter-compartmental flow paths inside the containment vessel, and the air flow path and evaporative surface outside the containment vessel. An Evaluation Model (EM) with conservative assumptions for heat and mass transfer, mass and energy release rates, and other parameters is used to address the uncertainties in WGOTHIC.

The limiting event for the AP600 containment is the MSLB where the maximum pressure is 44.1 psig. The margin to the design pressure for this event is 0.9 psi. For the AP1000, the limiting event is also the MSLB where the maximum pressure is 56 psig. The margin to the design pressure for this event is 3 psi.

For AP600, the peak pressure for the double-ended cold leg break is 43.4 psig. The margin to the design pressure for this event is 1.6 psi. It was determined during the licensing review process that the mass and energy release rate assumptions for the DECL were overly conservative because the secondary side steam generator energy is released in an arbitrarily short period of time. Subsequent calculations by the NRC showed that the release is much more gradual, and the resulting peak containment pressure is much lower.

For the AP1000 double-ended cold leg break evaluation, more mechanistic mass and energy release assumptions were made; namely, the steam generator energy is released more slowly into the containment. This assumption is supported by AP600 test results and independent calculations performed by the NRC during the AP600 licensing process. The resulting peak pressure occurs after the RCS blowdown, at a value of 46 psig. The margin to the design pressure for this event is 13 psi. See Section 3.0 for the detailed description of the containment analyses performed for AP1000.

The preliminary containment pressure integrity results, summarized in Table 2.5.3-1 show that there is significantly more margin for the AP1000 for these limiting design basis events.

A detailed assessment of the ultimate pressure capability made for the AP600 containment vessel showed that the ultimate pressure capacity for the containment function is expected to be limited by leakage caused by excessive radial deflection of the containment cylindrical shell. This radial deflection causes distress to the mechanical penetrations, and leakage would be expected at the expansion bellows for the main steam and feedwater piping. There is high confidence that this failure would not occur before stresses in the shell reach the minimum specified material yield.

For the AP600 containment vessel, stresses in the shell reach the minimum specified material yield at a pressure of 144 psig at ambient temperature and 120 psig at 400°F. Failure would be more likely to occur at a pressure about 15 percent higher based on expected actual material properties.

For the AP1000 containment vessel, the shell thickness is 1.75 inches (7.7% greater than AP600) and the minimum specified material yield is the same as for the AP600. Stresses in the shell reach the minimum specified material yield at a pressure of 155 psig at ambient temperature and 129 psig at 400°F. This provides a margin greater than a factor of 2 above the design pressure of 59 psig. Table 2.5.3.1 summarizes the containment design and ultimate pressures for the two containment vessel designs.

Table 2.5.3-1 Summary of Containment Pressures for AP1000 and AP600

	AP1000		AP600	
Break	**Pressure (psig)**	**Margin (psi)**	**Pressure (psig)**	**Margin (psi)**
Containment Vessel Design Pressure	59	–	45	-
Peak Pressure During Double-ended Cold Leg Break	46	13	43.4	1.6
Peak Pressure During Main Steam Line Break	56	3	44.1	0.9
Estimated Pressure at which containment Function is lost (assumes 400°F)	129	-	120	-

2.6 NSSS AUXILIARY SYSTEMS

In the AP1000 the main auxiliary systems supporting the NSSS systems are:

- Normal Residual Heat Removal System (RNS)
- Component Cooling Water System (CCS)
- Spent Fuel Pool Cooling System (SFS)
- Service Water System (SWS)
- Chemical and Volume Control System (CVS)

All of these systems are non-safety systems whose functions and designs are the same as in the AP600. Due to the increase in thermal power in the AP1000, the size of some components may increase.

2.6.1 Normal Residual Heat Removal System

The AP1000 normal residual heat removal system removes heat from the core and reactor coolant system during normal plant cooldown and continues to remove heat during refueling operations. The normal residual heat removal system also provides low pressure makeup to the reactor coolant system following automatic depressurization system (ADS) actuation to prevent actuation of the 4th stage ADS valves and to provide non-safety related low head injection.

The normal residual heat removal system consists of two mechanical trains of equipment. Each train includes one residual heat removal pump and one residual heat removal heat exchanger located in the Auxiliary Building. The two trains of equipment share a common suction line from the reactor coolant system and a common discharge header. The normal residual heat removal system includes the piping, valves and instrumentation necessary for system operation.

2.6.2 Component Cooling Water System

The AP1000 component cooling water system is a closed loop cooling system that transfers heat from various plant components to the service water system cooling tower. It operates during normal phases of plant operation including power operation, normal cooldown, and refueling. The system includes two component cooling water pumps, two component cooling water heat exchangers, one component cooling water surge tank and associated valves, piping, and instrumentation.

The system components are arranged into two mechanical trains. Each train includes one component cooling water pump and one component cooling water heat exchanger. The two trains of equipment take suction from a single return header. The surge tank is connected to the return header. Each pump discharges directly to its respective heat exchanger. A bypass line

around each heat exchanger containing a throttle valve prevents overcooling the component cooling water. The discharge of each heat exchanger is to the common supply header.

2.6.3 Spent Fuel Pool Cooling System

The AP1000 spent fuel pool cooling system is a non-safety-related system designed to remove decay heat from the fuel pool and to circulate water through demineralizers to maintain fuel pool water purity. The safety-related function of cooling and shielding the fuel in the spent fuel pool is performed by the water in the pool.

The spent fuel pool cooling system consists of two mechanical trains of equipment. Each train includes one spent fuel pool pump, one spent fuel pool heat exchanger, one spent fuel pool demineralizer and one spent fuel pool filter. The two trains of equipment share common suction and discharge headers. In addition, the spent fuel pool cooling system includes the piping, valves, and instrumentation necessary for system operation.

The spent fuel pool cooling system is designed such that either train of equipment can be operated to perform any of the functions required of the spent fuel pool cooling system independently of the other train. One train is continuously cooling and purifying the spent fuel pool while the other train is available for water transfers, in-containment refueling water storage tank purification, or aligned as a backup to the operating train of equipment.

2.6.4 Service Water System

The AP1000 service water system is a non-safety system that rejects heat from the component cooling water heat exchangers to the atmosphere through a mechanical draft cooling tower.

The service water system is arranged into two trains of components and piping. Each train includes one service water pump, one strainer, and one cooling tower cell. Each train provides 100-percent-capacity cooling for normal power operation. Cross-connections between the trains upstream and downstream of the component cooling water system heat exchangers allows either service water pump to supply either heat exchanger, and allows either heat exchanger to discharge to either cooling tower cell.

The service water pumps, located in the turbine building, take suction from piping which connects to the basin of the service water cooling tower. Service water is pumped through strainers to the component cooling water heat exchangers for removal of heat. Heated service water from the heat exchangers then returns through piping to a mechanical draft cooling tower where the system heat is rejected to the atmosphere. Cool water, collected in the tower basin, flows through fixed screens to the pump suction piping for recirculation through the system.

2.6.5 Chemical and Volume Control System

The principal functions of the AP1000 chemical and volume control system include controlling reactor coolant system chemistry, purity, and inventory. The system provides some functions necessary for the continued normal operation of the plant such as the means to vary the boron

concentration in the reactor coolant system and inventory control to accommodate startup, shutdown, step load changes, and ramp load changes.

The chemical and volume control system consists of regenerative and letdown heat exchangers, demineralizers and filters, makeup pumps, tanks, and associated valves, piping, and instrumentation.

The normal chemical and volume control system purification loop is inside containment and operates at reactor coolant system pressure, utilizing the developed head of the reactor coolant pumps as the motive force for the purification flow. During power operations, fluid is continuously circulated through the chemical and volume control system from the discharge of one of the reactor coolant pumps. It passes through the regenerative heat exchanger where it is cooled by the returning chemical and volume control system flow, and is further cooled by component cooling water in the letdown heat exchanger to a temperature compatible with the demineralizer resins. The letdown fluid flows through a mixed bed demineralizer, optionally through a cation bed demineralizer, and through a filter. It returns to the suction of a reactor coolant pump after being heated in the regenerative heat exchanger. The purification loop is at reactor coolant system pressure.

Since the motive force for the purification loop is the reactor coolant pump head in a closed loop with the reactor coolant system, continuous purification is provided without operating the chemical and volume control system makeup pumps.

Changes in reactor coolant volume are accommodated by the pressurizer level program for normal power changes, including transition from hot standby to full-power operation and returning to hot standby. In addition, the pressurizer has sufficient volume, within the deadband of the level control program, to accommodate minor reactor coolant system leakage for some time. The chemical and volume control system provides inventory control to accommodate minor leakage from the reactor coolant system, expansion during heatup from cold shutdown, and contraction during cooldown. This inventory control is provided by letdown to the liquid radwaste system and makeup via operation of the makeup pumps.

2.6.6 Differences Between AP600 and AP1000

The design bases and system configurations for the AP1000 auxiliary systems are similar to those of the AP600. System capacities have been increased to accommodate the higher core power where necessary. These systems will be described in detail in the AP1000 Design Certification Document (DCD) to be prepared in support of Design Certification, as they are generally not important factors in the current pre-application review of the AP1000. However, a possible change to the design basis of the Normal Residual Heat Removal System (RNS) has a secondary importance to the considerations currently under review, and therefore a discussion of this proposed change is provided below.

The function of the RNS is to provide core cooling during shutdown operations. In addition, the system can also provide defense-in-depth to the passive safety systems following an accident. Their role is discussed in the AP600 DCD and is explicitly modeled in the AP600 PRA.

As part of the AP600 Design Certification, the issue of potential adverse system interactions was raised. Westinghouse performed a systematic assessment of potential adverse system interactions that could exist due to the use of both passive safety-related systems, and active, nonsafety-related defense-in-depth systems such as the RNS. One of the potential adverse system interactions that was identified for the AP600 was the use of the RNS pumps to inject refueling water from the IRWST into the core following actuation of the ADS stages 1-3. Although the use of the RNS pumps by the operator to provide makeup to the RCS following ADS actuation has several benefits, it does cause the IRWST to drain faster than it otherwise would. This interaction was discussed in detail in "The AP600 Adverse System Interactions Evaluation Report" (WCAP-14477, Revision 1, April 1997).

As a result of this potential interaction, the AP600 analysis to demonstrate long-term cooling of the core following a LOCA considered this potential interaction. The long-term cooling safety analysis presented in Chapter 15 of the AP600 DCD is an analysis of the ability of the passive systems to provide core cooling during the sump recirculation phase. To conservatively bound the initial conditions to be evaluated, the earliest possible time that sump recirculation would be required post-LOCA was determined. The potential adverse interaction of the RNS pumps was considered for this analysis. The most challenging (i.e., earliest time) that the sump recirculation phase could be required is for double-ended rupture of a direct vessel injection line. Not only does this event disable one-half of the passive core cooling system injection sources (CMT, accumulator, IRWST line), but it also causes the IRWST to spill directly to containment via the broken DVI line. In addition, if the RNS pumps were to be considered operable, then the IRWST would be drained even faster. For the AP600 long-term cooling analysis, the IRWST was assumed to gravity drain to the containment and the RNS pumps were also assumed to pump down the IRWST water level. Furthermore, the RNS pumps were considered to fail once the IRWST water level was reduced to the level where containment recirculation would be actuated. In this way, the earliest possible time when containment recirculation would be required was determined.

For the AP1000, this interaction could be made worse if the capacity of the RNS pumps was increased, or if the resistance in the DVI lines was reduced. To alleviate this potential adverse interaction, the AP1000 RNS configuration has been modified. The AP1000 RNS pump suction line has a connection to the cask loading pit. The AP1000 procedures for post-accident operation of the RNS pumps will be such that the operators must align the pumps to the cask loading pit. When the water in this pit nears empty, the RNS suction would be re-aligned to the IRWST/containment recirculation connection so that the RNS pumps can continue to provide RCS injection. The additional refueling water from the cask loading pit that would be injected via the RNS pumps would actually provide extra water (and thus additional driving head) for the post-accident, containment recirculation. In this way, the potential adverse interaction associated with the RNS pumps draining the IRWST is eliminated.

2.7 STEAM AND POWER CONVERSION SYSTEM

The steam and power conversion system is designed to remove heat energy from the reactor coolant system via the two steam generators and to convert it to electrical power in the turbine-generator.

The steam generated in the two steam generators is supplied to the high-pressure turbine by the main steam system. After expansion through the high-pressure turbine, the steam passes through the moisture separator/reheaters and is then admitted to the low-pressure turbines. A portion of the steam is extracted from the high- and low-pressure turbines for feedwater heating.

Exhaust steam from the low-pressure turbines is condensed and deaerated in the main condenser. The heat rejected in the main condenser is removed by the circulating water system (CWS). The condensate pumps take suction from the condenser hotwell and deliver the condensate through the feedwater heaters. The condensate flows to the suction of the main feedwater pump. The steam generator feedwater pumps discharge the feedwater through high-pressure feedwater heaters to the two steam generators.

Preliminary descriptions of the main steam and condensate/feedwater systems are provided below. Although these systems are non-safety systems, a preliminary system definition is included in this report because they contain safety-grade components, and the systems have an impact on the plant response to design basis accidents. Definition of the remaining steam and power conversion systems will be developed during the design work in support of Design Certification for the AP1000.

2.7.1 Condensate and Feedwater System

2.7.1.1 Overall System Description

The condensate and feedwater system provides feedwater at the required temperature, pressure, and flow rate to the steam generators. Condensate is pumped from the main condenser hotwell by the condensate pumps, passes through the low-pressure feedwater heaters to the feedwater pumps, and is then pumped through the high-pressure feedwater heaters to the steam generators. The major system parameters are given in Table 2.7-1.

The condensate and feedwater system supplies the steam generators with heated feedwater in a closed steam cycle using regenerative feedwater heating. The condensate and feedwater system is composed of the condensate system, the main feedwater system, and portions of the steam generator system. The condensate system collects condensed steam from the condenser and pumps condensate forward to the deaerator. The feedwater system takes suction from the deaerator and pumps feedwater forward to the steam generator system utilizing high-pressure main feedwater pumps. The steam generator system contains the safety-related piping and valves that deliver feedwater to the steam generators. The condensate and feedwater systems are located within the turbine building, and the steam generator system is located within the auxiliary building and containment.

Feedwater is supplied to each of the two steam generators by a main feedwater line during normal operation. Each of the lines is anchored at the auxiliary building/turbine building interface, and has sufficient flexibility to accommodate relative movement of the steam generators resulting from thermal expansion.

2.7.1.2 Major Valves

FEEDWATER ISOLATION VALVES

One main feedwater isolation valve (MFIV) is installed in each of the two main feedwater lines outside the containment and downstream of the feedwater control valve. The MFIVs are installed to prevent uncontrolled blowdown from the steam generators in the event of a feedwater pipe rupture. The main feedwater check valve provides backup isolation. In the event of a secondary side pipe rupture inside the containment, the MFIVs limit the quantity of high energy fluid that enters the containment through the broken loop and limit cooldown. The main feedwater control valve provides backup isolation to limit cooldown and high energy fluid addition.

FEEDWATER CONTROL VALVES

The main feedwater control valves are air-operated control valves with the dual purpose of controlling feedwater flow rate as well as providing backup isolation of the feedwater system. The valve body is a globe design. Seats and trim are of an erosion resistant material.

FEEDWATER CHECK VALVES

Each main feedwater line includes a check valve installed outside containment. During normal and upset conditions, the check valve prevents reverse flow from the steam generator whenever the feedwater pumps are tripped. In addition, the closure of the valves prevents more than one steam generator from blowing down in the event of feedwater pipe rupture.

2.7.2 Main Steam Supply System

The main steam supply system as described in this section includes components of the AP1000 steam generator system (SGS), main steam system (MSS), and main turbine system (MTS).

The function of the main steam supply system is to supply steam from the steam generators to the high-pressure turbine over a range of flows and pressures covering the entire operating range from system warmup to maximum calculated turbine conditions.

The system provides steam to the moisture separator/reheaters and the gland seal system for the main turbine. The system dissipates heat generated by the nuclear steam supply system (NSSS) by means of steam dump valves to the condenser or to the atmosphere through power-operated atmospheric relief valves or spring-loaded main steam safety valves when either the turbine-generator or condenser is unavailable.

The main steam supply system includes the following major components:

- Main steam piping from the steam generator outlet steam nozzles to the main turbine stop valves
- One main steam isolation valve and one main steam isolation valve bypass valve per main steam line
- Main steam safety valves
- Power-operated atmospheric relief valves and upstream isolation valves

Table 2.7-2 lists the design data for the main steam supply system.

2.7.2.1 Main Steam Piping

The main steam lines deliver a steamflow from the secondary side of the two steam generators. A portion of the main steamflow is directed to the reheater and steam seals, with the turbine receiving the remaining steamflow. Each of the main steam lines from the steam generators is anchored at the auxiliary building wall and has sufficient flexibility to accommodate thermal expansion. The main steam lines between the steam generator and the containment penetration are designed to meet the leak-before-break criteria. The portion of the main steam lines between the containment penetration and the anchor downstream of the main steam isolation valves is part of the break exclusion zone.

Each steam generator outlet nozzle contains an internal flow restrictor arrangement to limit flow in the unlikely event of a main steam line break. A large increase in steam flow results in choked flow in the restrictor which limits further increase in flow. In a steam line qualified for mechanistic pipe break, a sudden rupture resulting in a large increase in steam flow is not expected. The flow restrictor performs the following functions:

- Limits rapid rise in containment pressure
- Limits the rate of heat removal from the reactor to keep the cooldown rate within acceptable limits
- Reduces thrust forces on the main steam line piping
- Limits pressure differentials on internal steam generator components, particularly the tube support plates

The flow restrictor consists of seven nickel-chromium-iron Alloy 600 (ASME SB-163) venturi inserts which are installed in holes in an integral steam outlet nozzle forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle, and the other six are equally spaced around it. After insertion into the nozzle forging holes, the venturi inserts are welded to the nickel-chromium-iron alloy cladding on the inner surface of the forging.

2.7.2.3 Major Valves

MAIN STEAM SAFETY VALVES

Main steam safety valves with sufficient rated capacity are provided to prevent the steam pressure from exceeding 110 percent of the main steam system design pressure following:
1) a turbine trip without a reactor trip and with main feedwater flow maintained, and
2) a turbine trip with a delayed reactor trip and with the loss of main feedwater flow.

The individual safety valves are limited to the maximum allowable steam relief valve capacity as indicated in Table 2.7-2 for a system pressure equal to main steam design pressure plus 10 percent overpressure. This value sufficiently limits potential uncontrolled blowdown flow and the ensuing reactor transient should a single safety valve inadvertently fail or stick in the open position.

POWER-OPERATED ATMOSPHERIC RELIEF VALVES

A power-operated atmospheric relief valve is installed on the outlet piping from each steam generator to provide for controlled removal of reactor decay heat during normal reactor cooldown when the main steam isolation valves are closed or the turbine bypass system is not available. The valves are sized to provide a flow as indicated in Table 2.7-2. The maximum capacity of the relief valve at design pressure is limited to reduce the magnitude of a reactor transient if one valve would inadvertently open and remain open.

The operation of the power-operated relief valves is automatically controlled by steam line pressure during plant operations. The power-operated relief valves automatically modulate open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined setpoint. As steam line pressure decreases, the relief valves modulate closed, reseating at a pressure at least 10 psi below the opening pressure. The setpoint is selected between no-load steam pressure and the set pressure of the lowest set safety valves.

The power-operated atmospheric relief valves also help to avoid actuation of the safety valves during certain transients and, following safety valve actuation, act to assist the safety valves to positively reseat by automatically reducing and regulating steam pressure to a value below the safety valve reseating pressure.

An isolation valve with remote controls is provided upstream of each power operated relief valve providing isolation of a leaking or stuck-open valve. The upstream location allows for maintenance on the power-operated relief valve operator at power. The motor-operated isolation valve employs a safety-related operator and closes automatically on low steam line pressure to terminate steam line depressurization transients.

MAIN STEAM ISOLATION VALVES

The function of the main steam isolation is to limit blowdown to one steam generator in the event of a steam line break to limit: 1) the effect upon the reactor core to within specified fuel design limits, and 2) containment pressure to a value less than design pressure.

Main steam isolation consists of one quick-acting gate valve in each main steam line and one associated globe main steam isolation bypass valve with associated actuators and instrumentation. The isolation valves provide positive shutoff with minimum leakage during postulated line severance conditions either upstream or downstream of the valves.

2.7.3 Differences Between AP1000 and AP600

The basic designs of the AP1000 condensate, feedwater, and main steam systems are similar to the corresponding AP600 systems. As a result of the increased power rating of the AP1000, the feedwater and steam flows have increased. These increased flows result in larger components in the AP1000 compared to the AP600. The table below illustrates the differences in the design parameters and some major component sizes between the AP1000 and AP600.

Condensate, Feedwater, and Main Steam Systems Design Differences – AP1000 and AP600		
Parameter	**AP1000**	**AP600**
Steam Flow per SG, lb/hr	7.49×10^6	4.22×10^6
Main Steam Pipe Diameter, in.	38	32
Power Operated Relief Valve		
Number per Main Steam Line	1	1
Design Capacity, lb/hr	1.5×10^6 (@ 1165 psia Inlet)	930,000 (@ 1100 psia Inlet)
Safety Valves		
Number per Main Steam Line	6	3
Valve Size	8 x 12	8 x 12
Minimum Relieving Capacity per Valve at 110% of Design Pressure, lb/hr	1.4×10^6	1.54×10^6

Table 2.7-1 AP1000 Condensate and Feedwater System Parameters (Parameters Per Preliminary Heat Balance, Detailed Engineering Could Result in Modifications)	
Parameter	**Value**
Condensate Design Flow, lb/hr	105×10^6
Number of Condensate Pumps	3
Number of Low Pressure Feedwater Heaters	4
Feedwater Design Flow, lb/hr (gpm @ 440°F)	14.98×10^6 (35,800)
Number of Main Feedwater Pumps/Driver	2/Variable Speed Motor
Number of High Pressure Feedwater Heaters	2

Table 2.7-2 AP1000 Main Steam System Parameters	
Parameter	**Value**
Steam Flow Per Steam Generator, lb/hr	7.49×10^6
Main Steam Line Outside Diameter, in	38
Steam Generator Flow Restrictor	
Number Per SG Outlet Nozzle	7
Throat Size, ft^2	0.2
Total Area, ft^2	1.4
Power-Operated Relief Valve	
Number Per Main Steam Line	1
Maximum Design Capacity, lb/hr @ 1165 psia inlet	1.5×10^6
Main Steam Safety Valve	
Number Per Main Steam Line	6
Valve Size	8 x 12
Minimum Relieving Capacity Per Valve @ 110% Design Pressure, lb/hr	1.4×10^6
Maximum Flow Per Valve at 10% Overpressure, lb/hr	1.8×10^6

2.8 NUCLEAR ISLAND

The AP1000 consists of the following five principal structures. Each of these buildings is constructed on an individual basemat:

- Nuclear island – containment, shield, and auxiliary buildings
- Turbine building
- Annex building
- Diesel generator building
- Radwaste building

The safety-related equipment designed to perform accident mitigation functions is located in the nuclear island.

2.8.1 Containment Building

The containment building, a seismic Category I structure, is a freestanding cylindrical steel containment vessel with elliptical upper and lower heads. It is surrounded by a seismic Category I reinforced concrete shield building.

Figures 2.8-1 and 2.8-2 provide a plan view of the nuclear island at the operating deck elevation and a section view showing the containment and shield buildings.

There are two floor elevations (grade access maintenance floor and operating deck) and four lower equipment compartments within the containment building.

The principal system located within the containment building is the reactor coolant system that consists of two main coolant loops, a reactor vessel, two steam generators, four canned motor reactor coolant pumps, and a pressurizer. Figures 2.8-1 and 2.8-2 show the reactor coolant system equipment locations and elevations.

The main steam and feedwater lines are routed from the steam generators to a horizontal run below the operating deck. The steam and feedwater lines penetrate the north side of the containment vessel and are routed through the main steam isolation valve area in the auxiliary building to the turbine island.

The primary components of the passive core cooling system – two core makeup tanks, two accumulators, the refueling water storage tank, the passive residual heat removal heat exchanger, and two spargers – are also located in the containment building. The first three stages of the automatic depressurization valves are located above the pressurizer and consist of a two-tier valve module.

The passive residual heat removal heat exchanger and the spargers are located within the refueling water storage tank. The core makeup tanks are located on floor elevation 107′2″ level.

The chemical and volume control system equipment module is located in the containment below the maintenance floor level. This module represents the high pressure purification loop of the chemical and volume control system.

The reactor coolant drain tank, the reactor coolant drain tank heat exchanger and the containment sump pumps are located in the compartment adjacent to the reactor vessel cavity. Access to the reactor vessel cavity is via a stairwell that descends from the maintenance floor.

2.8.2 Shield Building

The shield building is the structure that surrounds the containment vessel. During normal operation the shield building, in conjunction with the internal structures of the containment building, provides the required shielding for the reactor coolant system and the other radioactive systems and components housed in the containment. Another function of the shield building is to protect the containment building from external events. The shield building protects the containment vessel and the reactor coolant system from the effects of tornadoes and tornado produced missiles.

During accident conditions, the shield building provides the required shielding for radioactive airborne materials that may be dispersed in the containment as well as radioactive particles in the water distributed throughout the containment.

The shield building is a seismic Category I reinforced concrete structure. It shares a common basemat with the containment building and the auxiliary building. It is an integral part of the passive containment cooling system.

Figure 2.8-2 provides a sectional view of the shield building which shows the basic configuration of the shield building and the annulus area between the containment vessel and the shield building.

The following items represent the significant features of the shield building and the annulus area:

- Shield building cylindrical structure
- Shield building roof structure
- Lower annulus area
- Middle annulus area
- Upper annulus area
- Passive containment cooling system air inlet
- Passive containment cooling system air inlet plenum
- Passive containment cooling system water storage tank

- Passive containment cooling system air diffuser
- Passive containment cooling system air baffle

The cylindrical section of the shield building structurally supports the roof and is a major structural member for the entire nuclear island. Floor slabs and structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

A watertight seal is provided between the upper and middle annulus areas to provide an environmental barrier. The middle annulus area contains the majority of containment penetrations and radioactive piping. This environmental barrier is provided to protect against the following:

- In the event of an accident or spurious actuation, the passive containment cooling system drains the system water storage tank. The water, which runs down the outside of the containment vessel, is prevented from draining into the middle annulus area by the watertight seal. Drains are provided to direct the passive containment cooling system runoff water out of the shield building.

- The passive containment cooling system is designed to perform with the upper annulus permanently open to the environment to permit sufficient air flow through the shield building in the event of an accident. The watertight seal protects the middle annulus area from ambient environmental conditions.

The shield building roof is a reinforced concrete conical shell supporting the passive containment cooling system water storage tank and air diffuser. Air intakes are located at the top of the cylindrical portion of the shield building. The conical roof supports the passive containment cooling system water storage tank which is constructed with a stainless steel liner attached to reinforced concrete walls. The air diffuser in the center of the roof discharges containment cooling air directly upwards.

The passive containment cooling system air baffle is located in the upper annulus area. It is attached to the cylindrical section of the containment vessel. The function of the passive containment cooling system air baffle is to provide a pathway for natural circulation of cooling air in the event that a design basis accident results in a large release of energy into the containment. In this event the outer surface of the containment vessel transfers heat to the air between the baffle and the containment shell. This heated and thus, lower density air flows up through the air baffle to the air diffuser and cooler and higher density air is drawn into the shield building through the air inlets at the top cylindrical portion of the shield building.

2.8.3 Changes to the AP600 Containment Vessel, Shield Building, and Auxiliary Building

The following paragraphs describe several key areas where changes have been made to the existing AP600 structures specifically to accommodate the requirements established for the AP1000 plant. The structures identified in this paragraph are those which are encompassed by

the shield building, the containment vessel, and the auxiliary building. A justification on why the change was made is provided and the following table identifies the specific changes that were made.

CONTAINMENT VESSEL

The diameters for AP1000 and AP600 containment vessel are identical. However to accommodate the increase in the mass/energy release to the containment the height of the containment was increased 25′-6″. This increase in the containment height resulted in an increase in the free volume of the containment of 338,467 cubic feet. The design pressure for the containment has also been increased from 45 psig to 59 psig.

The thickness of the circumferential vertical plates (cylindrical ring sections) and the ellipsoidal head plates has increased from 1 5/8″ to 1 ¾″ and the material has changed from SA537 Class 2 to SA738 Grade B. The AP1000 containment vessel design is based on the 1998 edition of the ASME Code plus the 1999 addenda. The AP600 containment vessel design was based on the 1992 edition of the ASME Code.

CONTAINMENT AIR BAFFLE

As a result of the 25′-6″ height increase in the containment vessel, two additional rows of circumferential containment air baffle panels have been added. The change in the main equipment hatch from 22′-0″ diameter to 16′-0″ diameter also resulted in additional panels.

MAIN EQUIPMENT HATCH

The size of the main equipment hatch, which is located at the operating deck level of the containment (El.135′-3″), has been changed from 22′-0″ diameter (AP600) to 16′-0″ diameter (AP1000).

The 22′-0″ inside diameter of the AP600 main equipment hatch was sized for the removal/replacement of the Delta 75 steam generator. The hatch diameter was dictated by the diameter of the Delta 75 steam drum. The steam drum for AP1000 Delta 125 steam generator has an outside diameter of 230″, therefore due to the size and weight of the Delta 125 steam generator an alternate removal path will be provided.

Since the size of the AP1000 main equipment hatch is not based on the removal of the Delta 125 steam generator, the main equipment hatch has been changed so that it is identical to the 16′-0′ diameter maintenance hatch that is located in the southeastern quadrant of the containment at El. 107′-2″.

POLAR CRANE

The AP600 bridge girder capacity is 400 Tons and it was based on the removal/replacement of the Delta 75 steam generator. The AP1000 bridge girder capacity is 800 Tons and it is based on

the removal/replacement of the Delta 125 steam generator. The trolley capacity, which is based on the weight of the integrated head package, remains unchanged at 275 Tons.

SHIELD BUILDING ROOF/PCS TANK

The AP1000 Shield Building is 25'-6" higher than the AP600 Shield Building. This corresponds to the 25'-6" increase in the height of the containment vessel. The roof of the Shield Building is actually the roof of the Passive Containment Cooling Water Tank. In the AP1000 design this roof is at El. 334'-0", which is 234'-0" above grade elevation (El.100'-0").

The maximum water volume of the AP1000 Passive Containment Cooling Water Tank (PCS-MT-01) is 800,000 gallons as compared to 580,000 gallons for the AP600 tank. These volumes are based on the elevation at the top of the overflow piping. The outside diameter of the AP1000 PCS water storage tank is 89'-0" as compared to 80'-0" for the AP600 tank.

The width of the 14 concrete columns that support the roof has been increased. These columns are located between the 15 air inlets that are located at the top of the Shield Building. The width of the AP1000 concrete columns are approximately 16'-0" as compared to the approximately 12'-0" width of the AP600 columns.

As a result of the increase in the width of the concrete columns, the width of the air inlets has been reduced. To obtain the same total air intake area as AP600 the height of the AP1000 air inlets has been increased. The AP1000 air inlets are 6'-6" high by 12'-0" wide as compared to the AP600 air inlets which are 5'-0" high by 16'-0" wide.

STEAM GENERATOR COMPARTMENT WALLS

The height of the steam generator compartment walls, that extend above the El. 135'-3" operating deck, has been increased from 12'-9" for AP600 to 19'-9" for AP1000. This 7'-0" increase in wall height is required to provide shielding for the longer tube bundle that is associated with the larger AP1000 Delta 125 steam generators.

PRESSURIZER COMPARTMENT WALLS

The height of the pressurizer compartment walls has been increased from 22'-9" for the AP600 pressurizer to 33'-9" for the AP1000 pressurizer. This 11'-0" increase in wall height is required to provide shielding for the larger AP1000 pressurizer. The 2100 cubic foot AP1000 pressurizer is 11'-3.81" longer than the 1600 cubic foot AP600 pressurizer.

FUEL TRANSFER SYSTEM

The AP1000 fuel assemblies are 18.5" longer than the AP600 fuel assemblies. The longer AP1000 fuel assemblies impose changes to the size, location, and depth of the upender pits that are located in the fuel transfer canal and the refueling canal. The length of both of the upender pits has increased by 6 inches and the depth has increased by 5 inches. The distance between the pivot centerlines of the two upenders remains unchanged.

SPENT FUEL POOL

The AP1000 spent fuel storage racks are 18.5 inches longer than the AP600 racks. The height of the water above the active fuel for the AP1000 fuel assemblies is identical to the height of the water level above the active fuel for the AP600 fuel assemblies. The increased length required for the AP1000 storage racks has been accommodated by lowering the floor of the spent fuel pit by 18.5 inches.

NEW FUEL STORAGE AREA

The AP1000 new fuel storage racks are identical to the AP1000 spent fuel storage racks. The increased length required for the AP1000 new fuel storage racks has been accommodated by lowering the floor of the compartment by 18.5 inches.

CASK LOADING PIT

The AP1000 spent fuel shipping cask is 26.78" longer and 7.90" larger in diameter than the AP600 cask. The increase in the length of the cask has been accommodated by lowering the floor of the cask loading pit by 27.0 inches.

	AP600	AP1000	Delta
Containment Vessel			
Containment vessel diameter	130'-0"	130'-0"	N/C
Containment design pressure	45 psig	59 psig	14 psig
Containment free volume (cu.ft.)	1,730,000	2,068,467	338,467
Height of containment vessel	189'-10"	215'-4"	25'-6"
Elevation at top of containment (inside containment shell elevation)	El. 256'-4"	El. 281'-10"	25'-6"
ASME Code	1992	1998 with 1999Addenda	
Material	SA537Class 2	SA738 GradeB	
Cylindrical ring section plate thickness	1 5/8" (first course-1¾")	1 ¾"	+1/8"
Ellipsoidal head plate thickness	1 5/8"	1 ¾"	+1/8"
Elevation of vessel stiffener inside containment	El. 170'-0"	El. 170'-0"	N/C
Elevation of vessel stiffener outside containment	El. 131'-9"	El. 131'-9"	N/C
Main Equipment Hatch			
Inside diameter	22'- 0"	16'- 0"	-6'- 0"
Center line elevation	144'- 6"	141'- 6"	-3'-0"
Center line azimuth	67o	67o	N/C
Polar Crane			
Bridge girder capacity (See Note 1 below)	400 Tons	800 Tons	400 Tons
Trolley capacity (maximum critical load) See Note 2	275 Tons	275 Tons	N/C
Top of girder rail elevation	El. 209'-0"	El. 229'-0"	+20'-0"
Radius to centerline of bridge girder crane rail	62'-0"	62'-0"	N/C
Top of trolley rail elevation	El. 218'-0"	El. 240'-0"	+22'-0"
Distance between trolley rails (top of bridge girders)	26'-0"	29'-0"	+3'-0"

Note 1: The bridge girder capacity is based on the total weight of a steam generator, two reactor coolant pump casings, a temporary trolley, a lift beam, and the rigging that would be supported by the two bridge girders during a steam generator replacement operation. During the replacement operation the permanent trolley would be position at the far end of the bridge girders, therefore the weight of the permanent trolley is not included in the total weight.

Note 2: The maximum critical load for the permanent trolley is based on the weight of the integrated head package.

	AP600	AP1000	Delta
Shield Building Roof/ PCS TANK			
Maximum elevation at top of roof	El. 308′-6″	El. 334′-0″	+25′-6″
Minimum elevation at top of roof	El. 308′-3″	El. 333′-9″	+25′-6″
Maximum water volume of PCS-MT-01 at top of overflow piping. (gallons)	580,000	800,000	220,000
Elevation at top of overflow pipe	El. 303′-0″	El. 327′-3″	+24′-3″
Elevation of PCS floor	El. 276′-4″	El. 298′-9″	+22′-5″
Height of water from floor to top of overflow	26′-8″	28′-6″	+1′-10″
Outside diameter of PCS-MT-01	80′-0″	89′-0″	+9′-0″
Diameter of air cooling diffuser	32′-0″	32′-0″	N/C
Elevation at top of shield slab	El. 266′-0″	El. 291′-6″	+25′-6″
Bottom of air inlet elevation	El. 241′-0″	El. 265′-0″	+24′-0″
Top of air inlet elevation	El. 246′-0″	El. 271′-6″	+25′-6″
Height of air inlets	5′-0″	6′-6″	+1′-6″
Width of air inlets	16′-0″	12′-0″	-4′-0″
Elevation at top of cylinder	El. 250′-4 1/16″	El. 275′-10 1/16″	+25′-6″
Elevation of PCS valve room floor	El. 261′-0″	El. 286′-6″	+25′-6″
Steam Generator and Pressurizer Compartment Structural Walls			
Elevation at Top of S/G Shield Wall	El. 148′-0″	El. 155′-0″	+7′-0″
Height of S/G wall above the operating deck	12′-9″	19′-9″	+7′-0″
Top of PRZ Wall Elevation	El. 158′-0″	El. 169′-0″	+11′-0″
Height of PRZ wall above the operating deck	22′-9″	33′-9″	+11′-0″

	AP600	AP1000	Delta
Fuel Transfer System			
Refueling canal upender pit width	4′-0″	4′-0″	N/C
Refueling canal upender pit length	104″	110″	+6.00″
Refueling canal upender pit depth	5′-7″	6′-0″	+5.00″
Elevation of bottom of pit	El.92′-6″	El.92′-1″	-5.00″
Fuel transfer canal upender pit width	5′-6″	5′-6″	N/C
Fuel transfer canal upender pit length	104″	110″	+6.00″
Fuel transfer canal upender pit depth	5′-7″	6′-0″	+5.00″
Elevation of bottom of pit	El.92′-6″	El.92′-1″	-5.00″
Thickness of concrete below upender pit	36″	31″	-5.00″
Spent Fuel Pool			
Elevation of floor	El.94′-3″	El.92′-8.5″	-18.5″
Thickness of spent fuel pit concrete floor	4′-9.00″	3′-2.50″	-18.5″
Spent Fuel Storage Racks			
Number of storage racks	616	616	N/C
Overall height	180″ (15′-0″)	198.5″ (16′-6.5″)	+18.5″
Elevation at top of fuel container	El.109′-3.0″	El.109′-3.0″	N/C
Elevation at top of fuel assembly in container	El.108′-11.3″	El.108′-11.3″	N/C
Elevation at top of active fuel	El.107′-9.88″	El.107′-9.88″	N/C
Elevation at bottom of storage racks (floor of pit)	El. 94′-3″	El.92′-8.5″	-18.5″
New Fuel Storage Area			
Elevation of floor	El.119′-9″	El.118′-2.5″	-18.5″
Number of storage racks	56	56	N/C
Overall height of new fuel storage racks	180″ (15′-0″)	198.5″ (16′-6.5″)	+18.5″
Cask Loading Pit			
Elevation of floor	El.92′-6″	El.90′-3″	-27″
Thickness of cask loading pit concrete floor	36″	36″	N/C

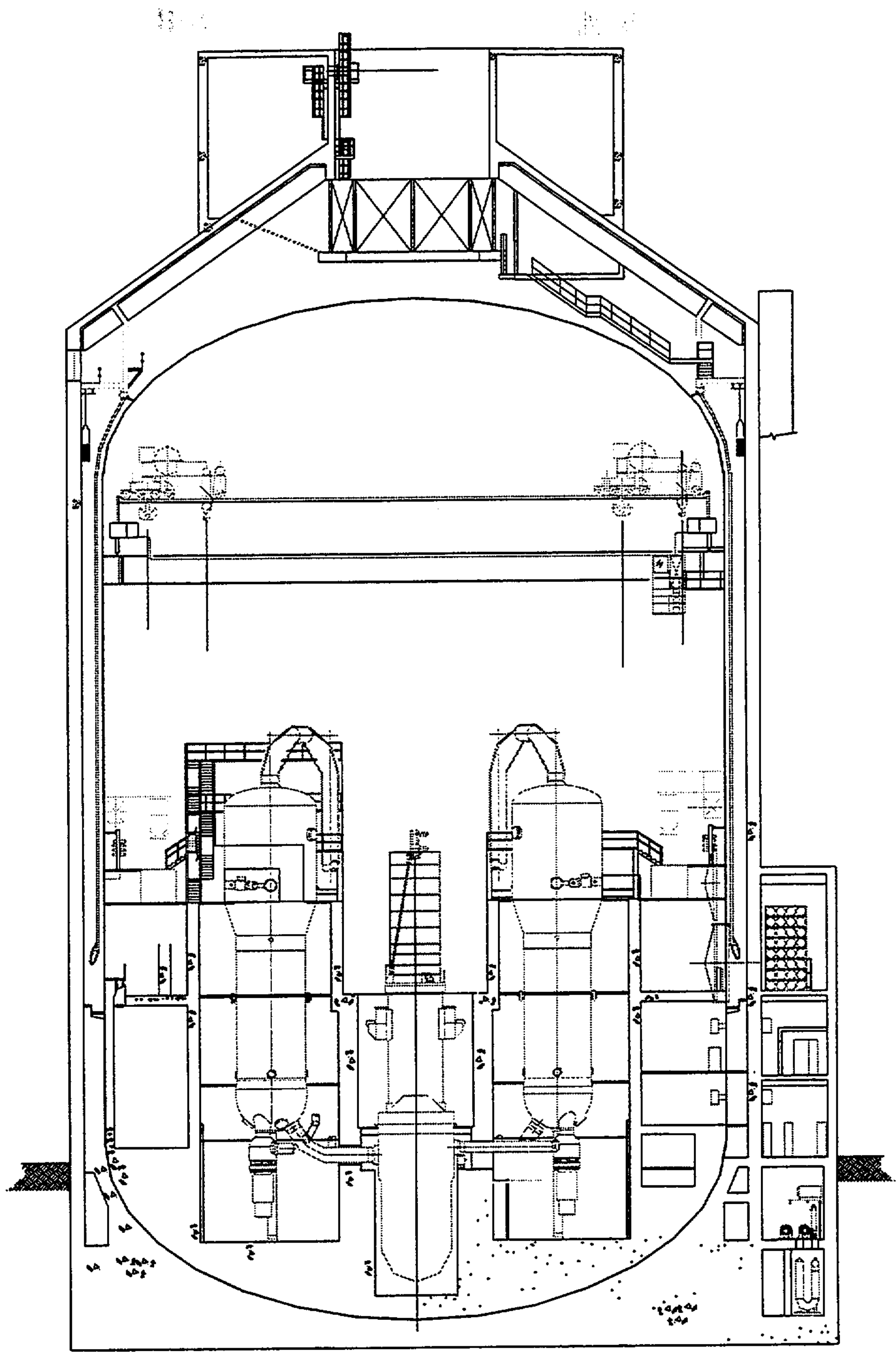


Figure 2.8-2 AP1000 Containment and Shield Building Elevation View

3 AP1000 SAFETY ANALYSIS ASSESSMENTS

Analyses of a spectrum of design basis accidents and events have been performed for the AP600 and are presented in Chapter 15 of the AP600 Design Control Document (DCD). The results of these analyses confirm that the AP600 nuclear plant meets the accident analysis acceptance criterion stipulated by the U.S. Code of Federal Regulations. This section presents analyses for the AP1000 for a subset of the events analyzed in the AP600 DCD, and compares them to the equivalent AP600 analysis results. These AP1000 analyses were generated using the AP600 analysis codes. The input to the analysis is based on the AP1000 design information presented in section 2 of this report. Note that some of the input information used in these analyses is preliminary in nature. Although the analyses results are considered preliminary, Westinghouse believes they are representative of the final safety analysis results that will be generated based on final design information in support of a Design Certification for an AP1000.

The events that are analyzed for the AP1000 are a subset of those analyzed for the AP600, and are particularly useful in making a determination regarding operating characteristics of the AP1000 passive safety systems. The events selected to be analyzed are of special importance for the consideration of the adequacy of the AP600 test database to be used for the AP1000 Design Certification application. Events that were not critical in the determination of the scope of testing performed for AP600 were not selected for analysis at this time. As such, a large break LOCA analysis is not provided because the AP600 licensing basis for LBLOCA was not derived from the AP600 test program. The basis for the selection of the events presented in this report is provided in the following paragraphs.

A loss of normal feedwater and feedwater line break analysis are presented to demonstrate the overall effectiveness of the passive safety systems in mitigating transient events. The loss of normal feedwater is a limiting Condition II event, and demonstrates the ability of the PRHR heat exchanger, in conjunction with the steam generator mass inventory, to remove core decay heat in the event of a loss of the normal RCS heat sink. The feedwater line break is a limiting Condition IV event that also demonstrates the ability of the PRHR and steam generator secondary side mass to remove core decay heat.

An analysis of a complete loss of RCS flow is presented. This event is analyzed to demonstrate that the core DNB limits are within an acceptable range following the simultaneous loss of flow from all four reactor coolant pumps. This analysis demonstrates that the reactor coolant pump inertia is sufficient to prevent unacceptable DNB during pump coast down. The loss of RCS flow event, as well as the loss of normal feedwater and feedwater line break events are analyzed using the LOFTRAN-AP code.

An analysis of the rupture of a steam generator tube is presented. This analysis is useful in demonstrating the ability of the passive safety systems to limit the offsite dose that result from the rupture of a steam generator tube. This event is analyzed using the LOFTTR2 code which is the version of the LOFTRAN-AP code used to evaluate steam generator tube rupture events.

Results of analysis of several AP1000 small break loss of coolant accident (SBLOCA) events using the NOTRUMP computer code are presented. The performance of the AP600 passive

safety systems to mitigate SBLOCA events was demonstrated in the scaled AP600 integral system tests (i.e. SPES, APEX, and ROSA). These scaled test facilities were used to provide integral system performance data for the purposes of validating the Westinghouse computer codes used to predict AP600 passive safety system performance. The events presented are the limiting small break loss of coolant accidents that were presented in the AP600 DCD. The events analyzed include an inadvertent automatic depressurization (no-break) analysis, a 2-inch cold leg break, and a double-ended direct vessel injection (DEDVI) line break. The inadvertent automatic depressurization is the event that most challenges the ability of the automatic depressurization valves to reduce RCS pressure to permit gravity injection from the IRWST. The DEDVI line break is the most challenging small break LOCA because it disables one half of the passive core cooling system injection capability including one CMT, one accumulator, one IRWST injection line, and one containment recirculation line. This event was the most challenging SBLOCA event for the AP600 with respect to RCS inventory. These SBLOCA events demonstrate the prediction of the performance of the AP1000 passive core cooling system using the NOTRUMP computer code that was validated for the AP600. Comparisons of the AP600 and AP1000 performance for these events is presented.

A long-term cooling (LTC) analysis of a DEDVI line break is also presented using the WCOBRA-TRAC model used for LTC analysis of the AP600. In the AP600 DCD, the LTC analyses were presented using a "windows" mode for several portions of the transient. As these events last extraordinarily long (i.e. > 8 hours), it was not practical to provide an analysis of these events as a complete transient from the time of stable IRWST injection (i.e. end of the SBLOCA event analyzed with NOTRUMP) out to the time of stable sump injection using WCOBRA-TRAC. Therefore these events were analyzed in a windows mode, where core cooling was demonstrated at several points in time using a conservative calculation. This approach was found to be acceptable for the AP600. For the AP1000, LTC analyses are presented in this report for the DEDVI line break from the point of stable IRWST injection (i.e. where the NOTRUMP SBLOCA analysis is traditionally ended) out to the point of stable containment sump recirculation flow using WCOBRA-TRAC. This analysis is now possible due to the improvements in computational capabilities. The case presented lasts approximately 9-10 hours, and re-validates the AP600 "windows" approach as a conservative calculation of system performance. The case chosen to analyze is the shortest duration LTC case. Therefore, Westinghouse would still use the "windows" approach for the full spectrum of LTC events in a DCD in support of AP1000 Design Certification, but could provide a validation analysis similar to what is presented in this report to demonstrate the acceptability of the "windows" approach.

Analysis of containment pressure and temperature following limiting events are provided. An analysis of containment pressure and temperature following the rupture of a main steam line is presented. This event represents the limiting event with respect to peak containment pressure. Also presented is the double-ended break of an RCS cold leg. This break was the limiting LOCA event for the AP600. Containment pressure and temperature results are provided. In addition to the limiting analyses, several sensitivity analyses are provided.

3.1 ASSESSMENT OF DECREASE IN HEAT REMOVAL FROM THE SECONDARY SIDE

A number of transients and accidents that could result in a reduction of the capacity of the secondary system to remove heat generated in the reactor coolant system are postulated. Analyses were presented in the AP600 DCD for a complete set of the limiting events of this type. In this section, analyses for a subset of these events is provided. They have been chosen to provide a representative indication of the performance of the AP1000 passive safety systems in mitigating events of this type. The events of this type analyzed in this section are:

- Loss of ac power to the station auxiliaries
- Loss of normal feedwater flow
- Feedwater system pipe break

The above items are considered to be Condition II events, with the exception of a feedwater system pipe break, which is considered to be a Condition IV event. The radiological consequences of these accidents are bounded by the radiological consequences of a main steam line break and are not considered in this report.

3.1.1 Loss of ac Power to the Plant Auxiliaries

3.1.1.1 Identification of Causes and Accident Description

The loss of power to the plant auxiliaries is caused by a complete loss of the offsite grid accompanied by a turbine-generator trip. The onsite standby ac power system remains available but is not credited to mitigate the accident.

The loss of ac power to the plant auxiliaries is characterized by the decrease in heat removal by the secondary system, accompanied by a reactor coolant flow coastdown, which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip:

- Upon reaching one of the trip setpoints in the primary or secondary systems as a result of the flow coastdown and decrease in secondary heat removal.

- Due to the loss of power to the control rod drive mechanisms as a result of the loss of power to the plant.

Following a loss of ac power with turbine and reactor trips, the sequence of events anticipated for the AP1000 is the same as for the AP600. As described below, the following events occur:

- Plant vital instruments are supplied from the Class 1E and uninterruptable power supply.

- As the steam system pressure rises following the trip, the steam generator power-operated relief valves may be automatically opened to the atmosphere. The condenser is assumed not to be available for turbine bypass. If the steam flow rate through the

power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot shutdown condition if the startup feedwater is available to supply water to the steam generators.

- The onsite standby power system, if available, supplies ac power to the selected plant nonsafety loads.

- If startup feedwater is not available, the PRHR heat exchanger is actuated. The PRHR heat exchanger transfers the core decay heat and sensible heat to the in-containment refueling water storage tank (IRWST) and provides an uninterrupted core heat removal capability following loss of normal and startup feedwater.

The startup feedwater system, if available, is started automatically when low levels occur in either steam generator.

During a plant transient, core decay heat removal is normally accomplished by the startup feedwater system. If that system is not available, emergency core decay heat removal is provided by the PRHR heat exchanger. The PRHR heat exchanger provides a passive method for decay heat removal. The AP1000 PRHR is similar in configuration to the AP600 with slightly increased heat transfer surface area as discussed in section 2 of this report. The AP1000 PRHR heat exchanger is a C-tube heat exchanger, located inside the IRWST, connected, through inlet and outlet headers. The inlet to the heat exchanger is from the reactor coolant system hot leg, and the return is to the steam generator outlet plenum. The AP1000 heat exchanger is above the reactor coolant system to provide natural circulation of the reactor coolant. Similar to the AP600, operation of the AP1000 PRHR heat exchanger is initiated by the opening of one of the two parallel power-operated valves at the PRHR heat exchanger cold leg. The IRWST provides the heat sink for the heat exchanger. The PRHR heat exchanger, in conjunction with the passive containment cooling system, keeps the reactor coolant subcooled indefinitely. After the IRWST water reaches saturation (in about 3 hours for the AP1000), steam starts to vent to the containment atmosphere. The condensation that collects on the containment steel shell (cooled by the passive containment cooling system) returns to the IRWST, maintaining fluid level for the PRHR heat exchanger heat sink.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant and PRHR loops.

A loss of ac power to the plant auxiliaries is a Condition II event, a fault of moderate frequency. This event is more limiting with respect to long-term heat removal than the turbine trip initiated decrease in secondary heat removal without loss of ac power, since heat transfer is

accomplished via natural circulation. A loss of offsite power to the plant auxiliaries can also result in a loss of normal feedwater.

Following the reactor coolant pump coastdown caused by the loss of ac power, the natural circulation capability of the reactor coolant system removes residual and decay heat from the core, using the PRHR heat exchanger. The analysis shows that the natural circulation flow in the reactor coolant system following a loss of ac power event is sufficient to remove residual heat from the core.

The AP1000 plant systems and equipment available to mitigate the consequences of a loss of ac power event are the same as the AP600 plant.

3.1.1.2 Analysis of Effects and Consequences

3.1.1.2.1 Method of Analysis

The method of analysis for this event is consistent with the approach discussed in the AP600 DCD. The analysis is performed for the AP1000 loss of ac power to plant auxiliaries, to examine the adequacy of the protection and safety monitoring system, the PRHR heat exchanger, and the reactor coolant system natural circulation capability in removing long-term (approximately 30,000 seconds) decay heat. This analysis also demonstrates the adequacy of these systems in preventing excessive heatup of the reactor coolant system with possible reactor coolant system overpressurization or loss of reactor coolant system water.

An analysis using a modified version of the LOFTRAN code (Reference 2), described in WCAP-14234 (Reference 6), is performed to simulate the system transient following a plant loss of offsite power. The simulation describes the plant neutron kinetics and reactor coolant system, including the natural circulation, pressurizer, and steam generator system responses. The digital program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in this analysis minimize the energy removal capability of the PRHR heat exchanger and maximize the coolant system expansion.

The transient response of the AP1000 plant following a loss of ac power to plant auxiliaries is similar to the loss of normal feedwater flow accident (see subsection 3.1.2), except that power is assumed to be lost to the reactor coolant pumps at the time of the reactor trip.

The assumptions used in the analysis are the same adopted for the AP600 DCD analysis. They are as follows:

- The plant is initially operating at 102 percent of the design power rating with initial reactor coolant temperature 7°F below the nominal value and the pressurizer pressure 50 psi below the nominal value.

- Core residual heat generation is based on ANSI 5.1 (Reference 3). ANSI 5.1 is a conservative representation of the decay energy release rates.

- Reactor trip occurs on steam generator low level (narrow range). Offsite power is assumed to be lost at the time of reactor trip. This is more conservative than the case in which offsite power is lost at time zero because of the lower steam generator water mass at the time of the reactor trip.

- A heat transfer coefficient is assumed in the steam generator associated with reactor coolant system natural circulation flow conditions following the reactor coolant pump coastdown.

- The PRHR heat exchanger is actuated by the low steam generator water level (wide range) or by the low steam generator water level (narrow range) coincident with low feedwater flow rate plus delay.

- Conservative PRHR heat exchanger heat transfer coefficients (low) associated with the low flow rate caused by the reactor coolant pump trip are assumed.

- For the loss of ac power to the station auxiliaries, the only safety function required is core decay heat removal. That is accomplished by the PRHR heat exchanger. One of two parallel valves in the PRHR outlet line is assumed to fail to open. This is the worst single failure.

- Secondary system steam relief is achieved through the steam generator safety valves.

- The pressurizer safety valves are assumed to function.

Plant characteristics and initial conditions follow the same approach defined in subsection 15.0.3 of the AP600 DCD. Initial conditions and assumptions specific for the AP1000 plant are reported in Tables 3.1-1, 3.1-2 and 3.1-3. The protection and safety monitoring system setpoints and limiting delay time for signals are listed in Tables 3.1-4 and 3.1-5.

Plant systems and equipment necessary to mitigate the effects of a loss of ac power to the station auxiliaries are the same as the AP600 and are listed in Table 3.1-6.

Normal reactor control systems are not required to function. The protection and safety monitoring system is required to function following a loss of ac power. The PRHR heat exchanger is required to function with a minimum heat transfer capability. No single active failure prevents operation of any system required to function.

3.1.1.2.2 Results

The transient response of the AP1000 reactor coolant system following a loss of ac power to the plant auxiliaries is shown in Figures 3.1.1-1 through 3.1.1-12 with comparison to the AP600

transient response. The calculated sequences of events for this event, for both AP1000 and AP600, are listed in Table 3.1-7.

The LOFTRAN code results show that the natural circulation flow and the PRHR system are sufficient to provide adequate core decay heat removal following reactor trip and reactor coolant pump coastdown.

Immediately following the reactor trip, the heat transfer capability of the AP1000 PRHR heat exchanger and the steam generator heat extraction rate are sufficient to slowly cool down the plant. The cooldown continues until a low T_{cold} "S" signal is reached at approximately 2,000 seconds for the AP1000 plant. In the AP600 the Low T_{cold} setpoint was reached much earlier in the transient (about 500 seconds). The reason for the delay in T_{cold} setpoint is due to the different pressure setpoint of the steam generator safety valves in the AP1000, and due to the higher initial RCS temperature and stored energy and to the setpoint value (see Table 3.1-4). The "S" signal actuates the core makeup tanks. During this transient, the core makeup tanks operate in water recirculation mode. The cold borated water injected by the core makeup tanks accelerates the cooldown of the plant. The core makeup tank flow slowly decreases as the core makeup tank fluid temperature increases due to water recirculation.

As the plant cools down, the heat removal capacity of the PRHR heat exchanger is lowered. At approximately 4,000 seconds (3,500 for the AP600), the heat removal rate from the reactor coolant system, due to the cooldown induced by the core makeup tank injection and the PRHR heat exchanger, decreases below the core decay heat produced. The reactor coolant system then begins heating up again. As the reactor coolant system temperature is elevated, the heat removal capacity of the PRHR heat exchanger increases. The reactor coolant system temperature slowly increases until the heat removal rate of the PRHR heat exchanger matches the core decay heat produced. This occurs at approximately 16,300 seconds for the AP1000 and 19,800 seconds for the AP600.

Pressurizer safety valves open to discharge steam to containment and reclose later in the transient when the heat removal rate of the PRHR heat exchanger exceeds the decay heat production rate.

The capacity of the AP1000 PRHR heat exchanger is sufficient to avoid water relief through the pressurizer safety valves. In particular, the AP1000 plant, as shown in Figure 3.1.1-4, maintains a larger margin to overfilling both in absolute and relative terms with respect to the AP600. The maximum AP1000 pressurizer water volume (1956 ft^3) is reached at about 19,000 seconds providing a margin of about 150 ft^3 to overfilling.

The calculated sequence of events for this accident is listed in Table 3.1-7. As shown in Figures 3.1.1-5 and 3.1.1-6, in the long-term, both the AP1000 and AP600 plants start a slow cooldown driven by the PRHR heat exchanger. Plant procedures may be followed to further cool down the plants.

3.1.1.3 Conclusions

Results of the analysis of the loss of ac power to plant auxiliaries event for the AP1000 plant, show the PRHR heat exchanger and the reactor coolant system natural circulation capability in removing long-term (approximately 30,000 seconds) decay heat. This analysis also demonstrates the adequacy of these systems in preventing excessive heatup of the reactor coolant system with possible reactor coolant system overpressurization or loss of reactor coolant system water. In conclusion, the AP1000 PRHR heat exchanger capacity is sufficient to prevent water relief through the pressurizer safety valves following a loss of ac power to plant auxiliaries.

The analysis demonstrates that sufficient long-term reactor coolant system heat removal capability exists, via natural circulation and the PRHR heat exchanger, following reactor coolant pump coastdown to prevent fuel or cladding damage and reactor coolant system overpressure.

3.1.2 Loss of Normal Feedwater Flow

3.1.2.1 Identification of Causes and Accident

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of ac power sources) results in a reduction in the capability of the secondary system to remove the heat generated in the reactor core. If startup feedwater is not available, the safety-related PRHR heat exchanger is automatically aligned by the protection and safety monitoring system to remove decay heat.

A small secondary system break can affect normal feedwater flow control, causing low steam generator levels prior to protective actions for the break. This scenario is addressed by the assumptions made for the feedwater system pipe break (see subsection 3.1.3).

AP1000 behavior following a loss of normal feedwater flow is the same as for the AP600. The following occurs upon loss of normal feedwater (assuming main feedwater pump fails or valve malfunctions):

- The steam generator water inventory decreases as a consequence of the continuous steam supply to the turbine. The mismatch between the steam flow to the turbine and the feedwater flow leads to the reactor trip on a low steam generator water level signal. The same signal also actuates the startup feedwater system.

- As the steam system pressure rises following the trip, the steam generator power-operated relief valves are automatically opened to the atmosphere. The condenser is assumed to be unavailable for turbine bypass. If the steam flow path through the power-operated relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

- As the no-load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power-operated relief valves are not available) are used to dissipate the decay heat and to maintain the plant at the hot shutdown condition, if the startup feedwater is used to supply water to the steam generator.

- If startup feedwater is not available, the PRHR heat exchanger is actuated on either a low steam generator water level (narrow range), coincident with a low startup feedwater flow rate signal or a low-low steam generator water level (wide range) signal. The PRHR heat exchanger transfers the core decay heat and sensible heat to the IRWST so that core heat removal is uninterrupted following a loss of normal and startup feedwater.

A loss-of-normal-feedwater event is classified as a Condition II event, a fault of moderate frequency.

The reactor trip on low narrow range water level in either steam generator provides the necessary protection against a loss of normal feedwater.

The startup feedwater system, if available, is started automatically when low levels occur in either steam generator. During a plant transient, core decay heat removal is normally accomplished by the startup feedwater system. If startup feedwater is unavailable, the PRHR heat exchanger is actuated as discussed above.

An analysis of the system transient is presented below to show that, following a loss of normal feedwater, the AP1000 PRHR heat exchanger is capable of removing the stored and decay heat to prevent either overpressurization of the reactor coolant system or loss of water from the reactor coolant system. It will also be shown that the AP1000 PRHR capability and overall AP1000 design are such that the same order of magnitude of the margins to acceptance criteria are maintained with respect to the AP600, for this class of events.

3.1.2.2 Analysis of Effects and Consequences

3.1.2.2.1 Method of Analysis

An analysis using a modified version of the LOFTRAN code (Reference 2), described in WCAP-14234 (Reference 6), is performed to obtain the plant transient following a loss of normal feedwater for the AP1000 plant. The simulation describes the plant neutron kinetics, reactor coolant system (including the natural circulation), pressurizer, and steam generators. The program computes pertinent variables, including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The assumptions used in the analysis of the loss of normal feedwater event, for the AP1000 plant, are the same used for the AP600 DCD:

- The plant is initially operating at 102 percent of the design power rating.

- Reactor trip occurs on steam generator low (narrow range) level.

- The only safety function required is the core decay heat removal that is carried by the PRHR heat exchanger; therefore, the worst single failure is assumed to occur in the PRHR heat exchanger. The actuation of the PRHR heat exchanger requires the opening of one of the two fail-open valves arranged in parallel at the PRHR heat exchanger discharge. Because no single failure can be assumed that impairs the opening of both valves, the failure of a single valve is assumed.

- The PRHR heat exchanger is actuated by the low-low steam generator water level wide range signal or by a low-low steam generator water level narrow range signal coincident with low startup feedwater flow plus delay.

- Secondary system steam relief is achieved through the steam generator safety valves.

- The initial reactor coolant average temperature is 6.5°F higher than the nominal value, and initial pressurizer pressure is 50 psi lower than nominal.

The loss of normal feedwater analysis is performed to demonstrate the adequacy of the protection and safety monitoring system and the PRHR heat exchanger in removing long-term decay heat and preventing excessive heatup of the reactor coolant system with possible resultant reactor coolant system overpressurization or loss of reactor coolant system water.

The assumptions used in this analysis minimize the energy removal capability of the system, and maximize the coolant system expansion.

For the loss of normal feedwater transient, the reactor coolant volumetric flow remains at its normal value and the reactor trips via the low steam generator narrow range level trip. The reactor coolant pumps continue to run until automatically tripped when the core makeup tanks are actuated.

Plant characteristics and initial conditions follow the same approach defined in subsection 15.0.3 of the AP600 DCD. Plant characteristics, initial conditions and assumptions specific for the AP1000 plant are reported in Tables 3.1-1, 3.1-2 and 3.1-3. The protection and safety monitoring system setpoints and limiting delay time for signals are listed in Table 3.1-4 and 3.1-5.

Plant systems and equipment necessary to mitigate the effects of a loss of normal feedwater event are the same as those of the AP600 plant and are listed in Table 3.1-6.

Normal reactor control systems are not required to function. The protection and safety monitoring system is required to function following a loss of normal feedwater. The PRHR heat exchanger is required to function with a minimum heat transfer capability. No single active failure prevents operation of any system to perform its required function

3.1.2.2.2 Results

Figures 3.1.2-1 through 3.1.2-10 show the significant AP1000 plant parameters in comparison to the AP600 parameters following a loss of normal feedwater.

Prior to reactor trip and the insertion of the rods into the core, the loss of normal feedwater transient is the same for the AP1000 and AP600 plants. The steam generator water inventory decreases as a consequence of the continuous steam supply to the turbine. The mismatch between the steam flow to the turbine and the feedwater flow leads to the reactor trip on a low steam generator water level signal (the time at which the setpoint is reached is very close for the two plants). The same signal should also actuate the startup feedwater system but this system has not been considered in the analysis.

Following the reactor and turbine trip from full load, the water level in the steam generators falls due to the reduction of steam generator void fraction. Steam flow through the safety valves continues to dissipate the stored and core decay heat.

The capacity of the PRHR heat exchanger, when the reactor coolant pumps are operating, is much larger than the decay heat both for the AP600 and AP1000 plants (Figure 3.1.2-1 and Figure 3.1.2-9), and in the first part of the transient, the reactor coolant system is cooled down (Figure 3.1.2-3 and Figure 3.1.2-4) and the RCS and steam generators pressure decrease (Figure 3.1.2-5 and Figure 3.1.2-7) and steam generator safety valves reclose.

For both the AP1000 and AP600 plants the cooldown continues until a low T_{cold} "S" signal is eventually reached (at 1020.7 seconds for the AP1000 and at 1,069.7 seconds for the AP600). The "S" signal actuates the core makeup tanks. During this transient, the core makeup tanks operate in water recirculation mode. The cold borated water injected by the core makeup tanks accelerates the cooldown of the plant while PRHR heat transfer capability has been decreased by the loss of forced coolant flow (Figure 3.1.2-9).

As the plant cools down, the heat removal capacity of the passive residual heat exchanger is lowered. Also the core makeup tank flow slowly decreases (Figure 3.1.2-10) as the core makeup tank fluid temperature increases due to water recirculation, decreasing the capability of the CMT flow to further cooldown the plant. At approximately 3,000 seconds for both the AP600 and the AP1000 plant (Figure 3.1.2-3 and 3.1.2-4), the heat removal rate from the reactor coolant system, due to the core makeup tank injection and the PRHR heat exchanger, decreases below the core decay heat produced. The reactor coolant system then begins heating up again. As the reactor coolant system temperature is elevated, the heat removal capacity of the PRHR heat exchanger increases again. The reactor coolant system temperature slowly increases until the heat removal rate of the PRHR heat exchanger matches the core decay heat produced. This occurs at approximately 16,300 seconds for the AP1000 plant and at 22,000 seconds for the AP600 plant.

The capacity of the AP1000 and AP600 PRHR heat exchangers are sufficient to avoid water relief through the pressurizer safety valves. In particular, the AP1000 plant, as shown in Figure 3.1.2-6, maintains a larger margin to overfilling both in absolute and relative terms with

respect to the AP600. The maximum AP1000 pressurizer water volume (1867 ft^3) is reached at about 20,000 seconds providing a margin of more than 200 ft^3 to overfilling.

The calculated sequences of events for this accident, for both the AP600 and AP1000, are listed in Table 3.1-7. As shown in Figures 3.1.2-3 and 3.1.2-4, in the long term, the plants start a slow cooldown driven by the PRHR heat exchanger. AP1000 temperatures in the long term are very close to the AP600 ones and show that the performances of the AP1000 PRHR are properly defined also to cope with the long term heat transfer capability requirements. Plant procedures may be followed to further cool down the plants.

3.1.2.3 Conclusions

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the reactor coolant system, or the steam system of the AP1000 plant. The heat removal capacity of the AP1000 PRHR heat exchanger is such that reactor coolant water is not relieved from the pressurizer safety valves and the margin to overfilling is even larger than in the AP600 plant. Reactor coolant system and steam generator pressures remain below 110 percent of their design values. DNBR is anticipated to always remains above the design limit values.

3.1.3 Feedwater System Pipe Break

3.1.3.1 Identification of Causes and Accident Description

A major feedwater line rupture is a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the steam generators in order to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedwater line between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. (A break upstream of the feedwater line check valve would affect the plant only as a loss of feedwater. This case is covered by the evaluation in subsections 3.1.1 and 3.1.2.)

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system cooldown (by excessive energy discharge through the break) or a reactor coolant system heatup. Potential reactor coolant system cooldown resulting from a secondary pipe rupture is evaluated for the steam line break events. Therefore, only the reactor coolant system heatup effects are evaluated for a feedwater line rupture in this subsection.

The feedwater line rupture reduces the ability to remove heat generated by the core from the reactor coolant system for the following reasons:

- Feedwater flow to the steam generators is reduced. Because feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip.

- Fluid in the steam generator may be discharged through the break and would not be available for decay heat removal after trip.

- The break may be large enough to prevent the addition of main feedwater after trip.

The PRHR heat exchanger functions to:

- Prevent substantial overpressurization of the reactor coolant system (less than 110 percent of design pressures).

- Maintain sufficient liquid in the reactor coolant system so that the core remains in place, and geometrically intact, with no loss of core cooling capability.

A major feedwater line rupture is classified as a Condition IV event.

The severity of the feedwater line rupture transient depends on a number of system parameters, including the break size, initial reactor power, and the functioning of various control and safety-related systems. Sensitivity studies presented in WCAP-9320 (Reference 4) illustrate that the most limiting feedwater line rupture is a double-ended rupture of the largest feedwater line. At the beginning of the transient, the main feedwater control system is assumed to malfunction due to an adverse environment. Interactions between the break and the main feedwater control system result in no feedwater flow being injected or lost through the steam generator feedwater nozzles. This assumption causes the water levels in both steam generators to decrease equally until the low steam generator level (narrow range) reactor trip setpoint is reached. After reactor trip, a full double-ended rupture of the feedwater line is assumed such that the faulted steam generator blows down through the break and no main feedwater is delivered to the intact steam generator. These assumptions conservatively bound the most limiting feedwater line rupture that can occur. Analysis is performed at full power assuming the loss of offsite power at the time of the reactor trip. This is more conservative than the case where power is lost at the initiation of the event. The case with offsite power available is not presented because, due to the fast core makeup tanks actuation (on an "S" signal generated by the low steam line pressure), the reactor coolant pumps are tripped by the protection and safety monitoring system a few seconds after the reactor trip. The only difference between the cases with and without offsite power available is the operating status of the reactor coolant pumps.

The AP1000 plant protection for a main feedwater line rupture is provided by the same signals and systems/equipment as for the AP600 plant, and in particular:

- A reactor trip on any of the following four conditions:
  - High pressurizer pressure
  - Overtemperature ΔT
  - Low steam generator water level in either steam generator
  - "S" signals from either of the following:
    - Two out of four low steam line pressure in either steam generator
    - Two out of four high containment pressure (high-2)

- The PRHR heat exchanger provides a passive method for decay heat removal. The AP1000 PRHR is similar in configuration to the AP600 with slightly increased heat transfer surface area as discussed in section 2 of this report. The AP1000 PRHR heat

exchanger is a C-tube heat exchanger, located inside the IRWST, connected, through inlet and outlet headers. The inlet to the heat exchanger is from the reactor coolant system hot leg, and the return is to the steam generator outlet plenum. The AP1000 heat exchanger is above the reactor coolant system to provide natural circulation of the reactor coolant. Similar to the AP600, operation of the AP1000 PRHR heat exchanger is initiated by the opening of one of the two parallel power-operated valves at the PRHR heat exchanger cold leg.

3.1.3.2 Analysis of Effects and Consequences

3.1.3.2.1 Method of Analysis

An analysis using a modified version, described in WCAP-14234 (Reference 6), of the LOFTRAN code (Reference 2) is performed to determine the plant transient following a feedwater line rupture. The code describes the plant thermal kinetics, reactor coolant system (including natural circulation), pressurizer, steam generators, and feedwater system responses and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

In order to allow an easier comparison, the AP1000 analysis has been performed with the same assumption and initial conditions of the AP600 analysis presented in the SSAR.

The case analyzed assumes a double-ended rupture of the largest AP1000 feedwater pipe at full power. Major assumptions used in the analysis are as follows:

- The plant is initially operating at 102 percent of the design plant rating.
- Initial reactor coolant average temperature is 6.5°F above the nominal value, and the initial pressurizer pressure is 50 psi below its nominal value.
- The pressurizer spray is turned on.
- Initial pressurizer level is at a conservative maximum value and a conservative initial steam generator water level is assumed in both steam generators.
- No credit is taken for the high pressurizer pressure reactor trip.
- At the start of the transient, interaction between the break in the feedline and the main feedwater control system results in a complete loss of feedwater flow to both steam generators. No feedwater flow is delivered to or lost through the steam generator nozzles.
- After reactor trip, the faulted steam generator blows down through a double-ended break area of 1.755 ft^2 (the double ended break area for the AP600 is 1.12 ft^2). A saturated liquid discharge is assumed until all the water inventory is discharged from the faulted steam generator. This minimizes the heat removal capability of the faulted steam

generator and maximizes the resultant heatup of the reactor coolant. No feedwater flow is assumed to be delivered to the intact steam generator.

- Reactor trip is assumed to be initiated when the low steam generator narrow range level setpoint is reached on the ruptured steam generator.

- The PRHR heat exchanger is actuated by the low steam generator water level (wide range) signal. A 20-second delay is assumed following the low level signal to allow time for the alignment of PRHR heat exchanger valves.

- No credit is taken for heat energy deposited in reactor coolant system metal during the reactor coolant system heatup.

- No credit is taken for charging or letdown.

- Pressurizer safety valve setpoint is assumed to be at its minimum value.

- Steam generator heat transfer area is assumed to decrease as the shell-side liquid inventory decreases. The heat transfer remains approximately 100 percent in the faulted steam generator until the liquid mass reaches about 11 percent. The heat transfer is then reduced to 0 percent with the liquid inventory.

- Conservative core residual heat generation is assumed based upon long-term operation at the initial power level preceding the trip (Reference 3).

- No credit is taken for the following four protection and safety monitoring system reactor trip signals to mitigate the consequences of the accident:
  - High pressurizer pressure
  - Overtemperature ΔT
  - High pressurizer level
  - High containment pressure

The PRHR heat exchanger is initiated if the steam generator water level drops to the low steam generator level (wide range). Similarly, receipt of a low steam line pressure signal in at least one steam line initiates a steam line isolation signal that closes all main steam line and feed line isolation valves. This signal also gives an "S" signal that initiates flow of cold borated water from the core makeup tanks to the reactor coolant system.

AP1000 initial conditions for the accident analyses follow the same approach defined in subsection 15.0.3 of the AP600 DCD. Plant characteristics, initial conditions and assumptions specific for the AP1000 plant are reported in Tables 3.1-1, 3.1-2 and 3.1-3. Protection System setpoints and limiting delay time for signals are listed in Table 3.1-4 and 3.1-5.

Plant systems and equipment necessary to mitigate the effects of a feedline rupture event are the same as those of the AP600 plant and are listed in Table 3.1-6.

The plant control system is not assumed to function in order to mitigate the consequences of the event. The protection and safety monitoring system is required to function following a feedwater line rupture as analyzed here. No single active failure prevents operation of this system.

The engineered safety features assumed to function are the PRHR heat exchanger, core makeup tank, and steam line isolation valves. The single failure assumed is the failure of one of the two parallel discharge valves in the PRHR outlet line as for the AP600 analysis.

The analysis presented hereafter assumes that the offsite ac power is lost at the time of reactor trip, hence there is a flow coastdown until flow in the loops reaches the natural circulation value.

The natural circulation capability of the reactor coolant system is shown (see subsection 3.1.1) to be sufficient to remove core decay heat following reactor trip for the loss of ac power transient. Pump coastdown characteristics are demonstrated in subsections 3.1.4 of this report.

3.1.3.2.2 Results

AP1000 behavior following the worst feedline break event is similar to the AP600.

Calculated plant parameters for the AP1000 and AP600 plants following a major feedwater line rupture are shown in Figures 3.1.3-1 through 3.1.3-10 for providing an easy comparison. The calculated sequences of events for the two plants are listed in Table 3.1-1.

The results presented in Figures 3.1.3-5 and 3.1.3-7 show that, both for the AP1000 and AP600, pressures in the reactor coolant system and main steam system remain below 110 percent of the respective design pressure. For the two plants, the pressurizer pressure decreases after reactor trip on the low steam generator water level (66.9 seconds for the AP1000 and 83.1 seconds for the AP600) due to the loss of heat input from the core.

In the first part of the transient, due to the conservative analysis assumptions, the system response following the feedwater line rupture is similar to the loss of normal feedwater (subsection 3.1.2).

After the trip, the core makeup tanks are actuated on low steam line pressure in the ruptured loop (96.9 seconds for the AP1000, 111.3 seconds for the AP600) while the PRHR heat exchanger is actuated on a low steam generator water level wide range (91.5 seconds for the AP1000, 107.1 seconds for the AP600).

For both the plants, the addition of the PRHR heat exchanger and the core makeup tanks flow rates helps to cool down the primary system and to provide sufficient fluid to keep the core covered with water (Figure 3.1.3-3 and Figure 3.1.3-4).

In fact, in the first part of the transient, there is a cooling effect due to the core makeup tanks that inject cold water into the reactor coolant system and receive hot water from the cold leg.

At about 2500 seconds, the AP1000 pressurizer safety valves open again (about 6,300 for the AP600) since the cooling effect of the CMT flow rate is decreasing both due to the decreased flow rate (Figure 3.1.3-10) and to the increased CMT water temperature and due to the mismatch between decay heat and the heat transfer capability of the PRHR heat exchanger.

AP1000 Reactor coolant system temperatures are low, approximately 500°F at 2,500 seconds (475°F at 3,000 seconds for the AP600 plant) and, in this condition, the PRHR heat exchanger cannot remove the entire decay heat load. Reactor coolant system temperatures increase until an equilibrium between decay heat power and heat absorbed by the PRHR heat exchanger is reached. After about 3.5 hours for the AP1000 plant and 5 hours for the AP600 plant, the heat transfer capability of the PRHR heat exchanger exceeds the decay heat power and the reactor coolant system temperatures, pressure, and pressurizer water volumes start to steadily decrease. Core cooling capability is maintained throughout the transient because reactor coolant system inventory is increasing due to core makeup tank injection.

3.1.3.3 Conclusions

Results of the AP1000 analyses show that for the postulated feedwater line rupture, the capacity of the AP1000 PRHR heat exchanger is adequate to remove decay heat, to prevent overpressurizing the reactor coolant system, and to maintain the core cooling capability. Radioactivity doses from ruptures of the postulated feedwater lines are less than those presented for the postulated main steam line break. The Standard Review Plan, subsection 15.2.8, evaluation criteria are therefore met.

3.1.4 References

1. Cooper, L., Miselis, V., and Starek, R. M., "Overpressure Protection for Westinghouse Pressurized Water Reactors," WCAP-7769, Revision 1, June, 1972. (Also letter NS-CE-622, C. Eicheldinger (Westinghouse) to D. B. Vassallo (NRC), additional information on WCAP-7769, Revision 1, April 16, 1975).

2. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

3. "American National Standard for Decay Heat Power in Light Water Reactors," ANSI/ANS-5.1-1979, August 1979.

4. Lang, G. E., and Cunningham, J. P., "Report on the Consequences of a Postulated Main Feedline Rupture," WCAP-9230 (Proprietary) and WCAP-9231 (Nonproprietary), January 1978.

5. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary) and WCAP-11398-A (Nonproprietary), April 1989.

6. Bachrach, U., Carlin, E. L., "LOFTRAN and LOFTTR2 AP600 Code Applicability Document," WCAP-14234, Revision 1 (Proprietary), August 1997.

Table 3.1-1 **Nuclear Steam Supply System Power Ratings**	
Thermal power output (MWt)	3415
Effective thermal power generated by the reactor coolant pumps (MWt)	15
Core thermal power (MWt)	3400

Table 3.1-2 Summary of Initial Conditions and Computer Codes Used

Section	Faults	Computer Codes Used	Reactivity Coefficient Assumed: Moderator Density Reactivity Coeff. ($\Delta k/gm/cm^3$)	Reactivity Coefficient Assumed: Moderator Temperature Reactivity Coeff. (pcm/°F)	Reactivity Coefficient Assumed: Doppler Defect	Initial Thermal Power Output Assumed (MWT)
3.1	Decrease in heat removal by the secondary system					
	Loss of nonemergency ac power to the station auxiliaries	LOFTRAN	0.0	--	Maximum Doppler Defect	3483.3[(a)]
	Loss of normal feedwater flow	LOFTRAN	0.0	--	Maximum Doppler Defect	3483.3[(a)]
	Feedwater System pipe break	LOFTRAN	0.0	--	Maximum Doppler Defect	3483.3[(a)]

(a) 102% of rated thermal power

Table 3.1-3 Nominal Values of Pertinent Plant Parameters Used in Accident Analyses			
		TDF	
	BEF	TDF Without Steam Generator Tube Plugging	TDF With 10 Percent Steam Generator Tube Plugging
Thermal output of NSSS (MW_t)	3415	3415	3415
Core inlet temperature (°F)	539.1	537.3	536.8
Vessel average temperature (°F)	577	577	577
Reactor coolant system pressure (psia)	2250	2250	2250
Reactor coolant flow per loop (gpm)	150,000	142,800	141,000
Steam flow from NSSS, 10^6 lbm/hr total)	14.98	14.97	14.96
Steam pressure at steam generator outlet (psia)	851	829	811
Maximum steam moisture content (percent)	0.10	0.10	0.10
Assumed feedwater temperature at steam generator inlet (°F)	440.0	440.0	440.0
Average core heat flux (Btu/hr-ft^2)	175,118	175,118	175,118

Table 3.1-4 Protection and Safety Monitoring System Setpoints and Time Delay Assumed in Section 3.1 Analyses		
Function	**Limiting Setpoint Assumed in Analyses**	**Time Delays (seconds)**
Reactor trip on low steam generator narrow range level	95,000 lbm	2.0
PRHR actuation on low steam generator wide range level	55,000 lbm	2.0
PRHR actuation on low steam generator narrow range and low STS flow	55,000 lbm and STS Flow < 45 lbm/sec	2.0 (60 with loss of offsite power)
Chemical and volume control system isolation on high-1 pressurizer water level coincident with "S" signal	[a]	2.0
"S" signal and steamline isolation on low T_{cold} (Minimum)	500°F	2.0
"S" signal and steamline isolation on low T_{cold} (Maximum)	520°F	2.0
"S" signal and steamline isolation on low steamline pressure	420 psia (with an adverse environment assumed) 540 psia (without an adverse environment assumed)	2.0
"S" signal on low pressurizer pressure	1700 psia	1.2
Reactor trip on high pressurizer pressure	2450 psia [b]	2.0
Reactor trip on low pressurizer pressure	1800 psia [b]	1.2
Reactor trip on low reactor coolant flow in any cold leg	87% loop flow [b]	1.45
Reactor trip on reactor coolant pump under speed	90% [b]	0.767

(a) Tentative setpoint between 25% and 28% of the span (corresponding to a pressurizer water volume between 700 and 750 ft^3). The AP600 setpoint is set to 30% (corresponding to about 625 ft^3.)

(b) Not credited in the analysis

Table 3.1-5 Limiting Delay Times for Equipment Assumed in Accident Analyses	
Component	Time Delays (seconds)
Feedwater isolation valve closure, feedwater control valve closure, or feedwater pump trip	10 (maximum value for non-LOCA) 5 (maximum value for mass/energy)
Steamline isolation valve closure	5 [(a)]
Core makeup tank discharge valve opening time	20 (maximum) 10 (nominal value for best-estimate LOCA) 40 seconds (small-break LOCA value: follows a 20-second interval of no valve movement)
Chemical and volume control system isolation valve closure	10
PRHR discharge valve opening time	20 (maximum) 10 (nominal value for best-estimate LOCA) 1.0 second (small-break LOCA value: follows a 20-second interval of no valve movement)

[(a)] 10 seconds have been conservatively assumed in the analysis.

Table 3.1-6 Plant Systems and Equipment Available for Transient and Accident Conditions			
Incident	**Reactor Trip Functions**	**ESF Actuation Functions**	**ESF and Other Equipment**
Decrease in heat removal by the secondary system			
Loss of nonemergency ac power to the station auxiliaries	Steam generator low narrow range level, high pressurizer pressure, high pressurizer level, manual	Steam generator low narrow range level coincident with low startup water flow, steam generator low wide range level	PRHR, steam generator safety valves, pressurizer safety valves
Loss of normal feedwater flow	Steam generator low narrow range level, high pressurizer pressure, high pressurizer level, manual	Steam generator low narrow range level coincident with low startup water flow, steam generator low wide range level	PRHR, steam generator safety valves, pressurizer safety valves
Feedwater system pipe break	Steam generator low narrow range level, high pressurizer pressure, manual	Steam generator low wide range level, low steam line pressure, high-1 containment pressure	PRHR, core makeup tank, MSIVs, feedline isolation, pressurizer safety valves, steam generator safety valves

Table 3.1-7 (Sheet 1 of 3) Time Sequence of Events for Incidents Which Result in a Decrease in Heat Removal by the Secondary System			
Accident	**Event**	**AP1000 Time (seconds)**	**AP600 Time (seconds)**
Loss of ac power to the plant auxiliaries (decay heat removal analysis)	Feedwater is lost	10.0	10.0
	Low steam generator water level reactor trip setpoint is reached	76.4	84.1
	Rods begin to drop, ac power is lost, reactor coolant pumps start to coastdown	78.4	86.1
	Pressurizer safety valves open	80.5	89.1
	Maximum pressurizer pressure reached	82.	90.5
	Steam generator safety valves open	90.0	94.0
	Pressurizer safety valves reclose	87.0	95.9
	Maximum pressurizer water volume reached	140.	95.7
	PRHR heat exchanger actuation on low steam generator water level (wide range)	143.4	151.1
	Core makeup tank actuation on low T_{cold} "S" signal	1,973.	483.1
	Steam line isolation on low T_{cold} "S" signal	1,985.	495.1
	Steam generator 1 safety valves close	2,090.	665.1
	Steam generator 2 safety valves close	2,200.	735.1
	Pressurizer safety valves open	9,936.0	2,632.0
	Pressurizer safety valves reclose	16,300.0	19,360.0
	Second pressurizer water volume peak is reached	18,712.0	19,448.0
	PRHR heat exchanger extracted heat matches decay heat	~ 16,350.0	~ 19,800.0

Table 3.1-7 (Sheet 2 of 3) Time Sequence of Events for Incidents Which Result in a Decrease in Heat Removal by the Secondary System			
Accident	**Event**	**AP1000 Time (seconds)**	**AP600 Time (seconds)**
Loss of normal feedwater flow	Feedwater is lost	10.0	10.0
	Low steam generator water level (narrow range) reactor trip reached	76.2	83.9
	Rods begin to drop	78.2	85.9
	Steam generator safety valves open	81.5	87.6
	Pressurizer safety valves open	74.5	88.1
	Maximum pressurizer pressure reached	80.5	88.4
	Pressurizer safety valves reclose	82.5	88.9
	PRHR heat exchanger actuation on low steam generator water level (wide range)	143.2	150.9
	Steam generator safety valves reclose	157.	182.1
	Steam line isolation on low T_{cold} "S" signal	1032.7	1,081.7
	Reactor coolant pump trip on low T_{cold} "S" signal	1,035.7	1,084.7
	Core makeup tanks actuation on low T_{cold} "S" signal	1,042.7	1,091.7
	Pressurizer safety valves open	3,222	3,488
	Pressurizer safety valves reclose	15,200	22,540
	Passive residual heat removal heat exchanger extracted heat matches decay heat	~16,300	~22,000
	Maximum pressurizer water volume reached	19,712	22,409

Table 3.1-7 (Sheet 3 of 3)	Time Sequence of Events for Incidents Which Result in a Decrease in Heat Removal by the Secondary System		
Accident	**Event**	**AP1000 Time (seconds)**	**AP600 Time (seconds)**
Feedwater system pipe break	Main feedwater flow to both steam generators stops due to interaction between the break an the main feedwater control system	10.0	10.0
	Low steam generator water level (narrow range) setpoint reached	66.9	83.1
	Reverse flow from the faulted steam generator through a full double-ended rupture starts	66.9	83.1
	Rods begin to drop	68.9	85.1
	Loss of offsite power occurs	68.9	85.1
	Low steam generator water level (wide range) setpoint reached	69.5	85.1
	Pressurizer safety valves open	71.1	86.0
	Low steam line pressure setpoint reached	74.9	89.3
	Pressurizer safety valves close	77.5	96.0
	All steam and feedline isolation valves	86.9	101.3
	PRHR heat exchanger actuation on low steam generator water level (wide range)	91.5	107.1
	Faulted steam generator empties	97.5	111.0
	Core makeup tank valves fully opened	96.9	111.3
	Intact steam generator safety valves open	154.0	140.0
	Intact steam generator safety valves reclose	482.0	768.0
	Pressurizer safety valves open	2,485.0	6,304.0
	PRHR heat exchanger extracted heat matches decay heat	12,220	18,500

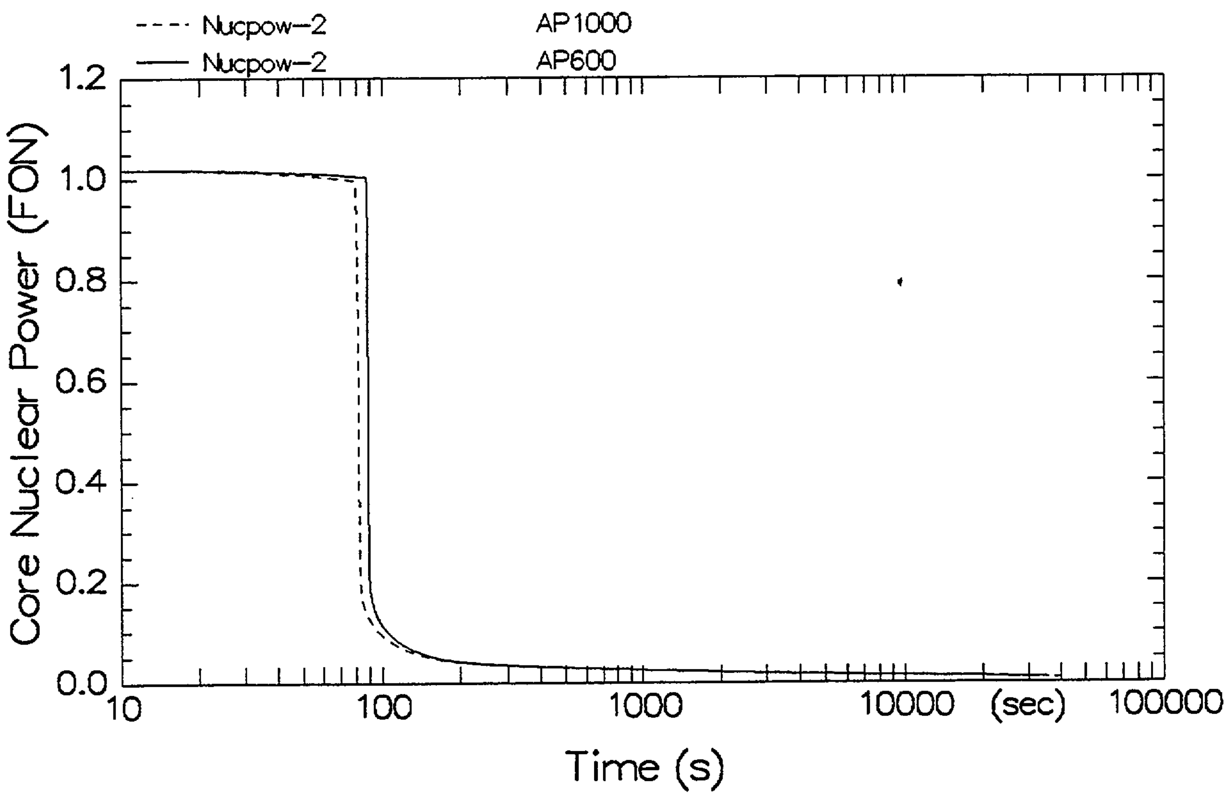


Figure 3.1.1-1 Nuclear Power Transient for Loss of ac Power to the Plant Auxiliaries

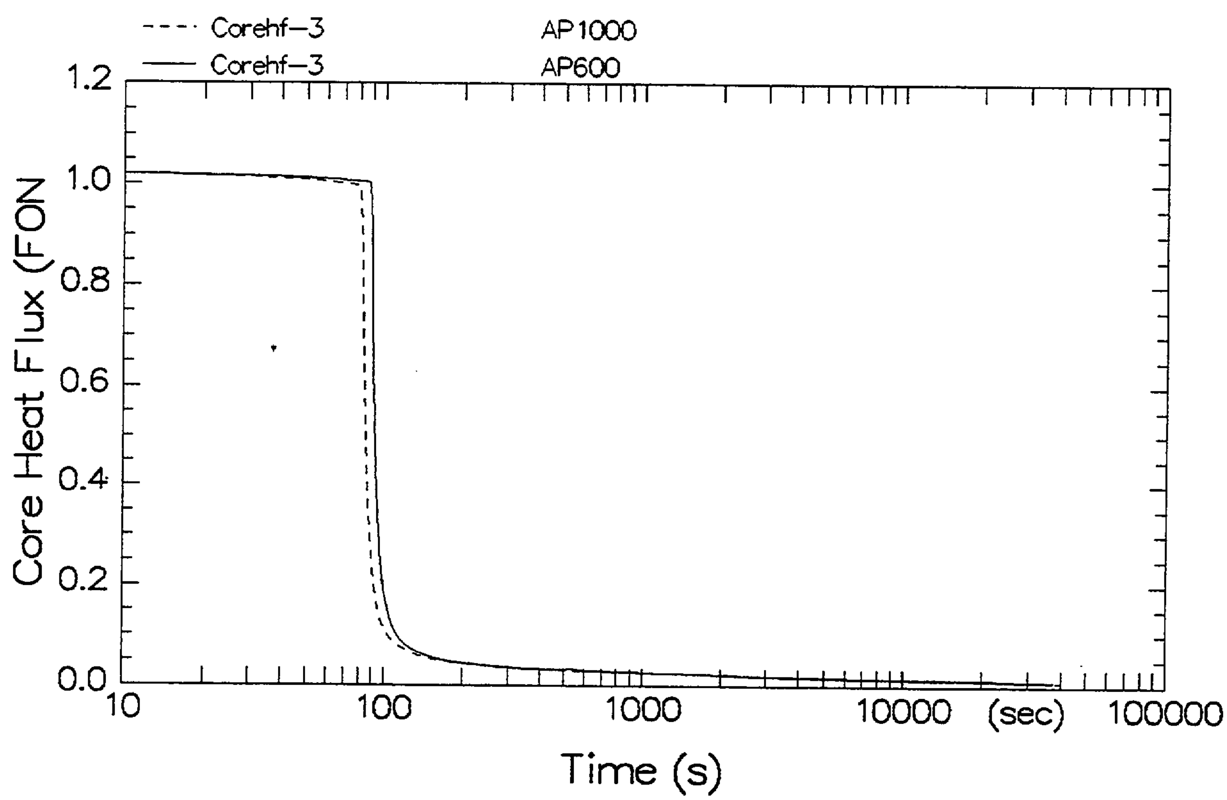


Figure 3.1.1-2 Core Heat Flux Transient for Loss of ac Power to the Plant Auxiliaries

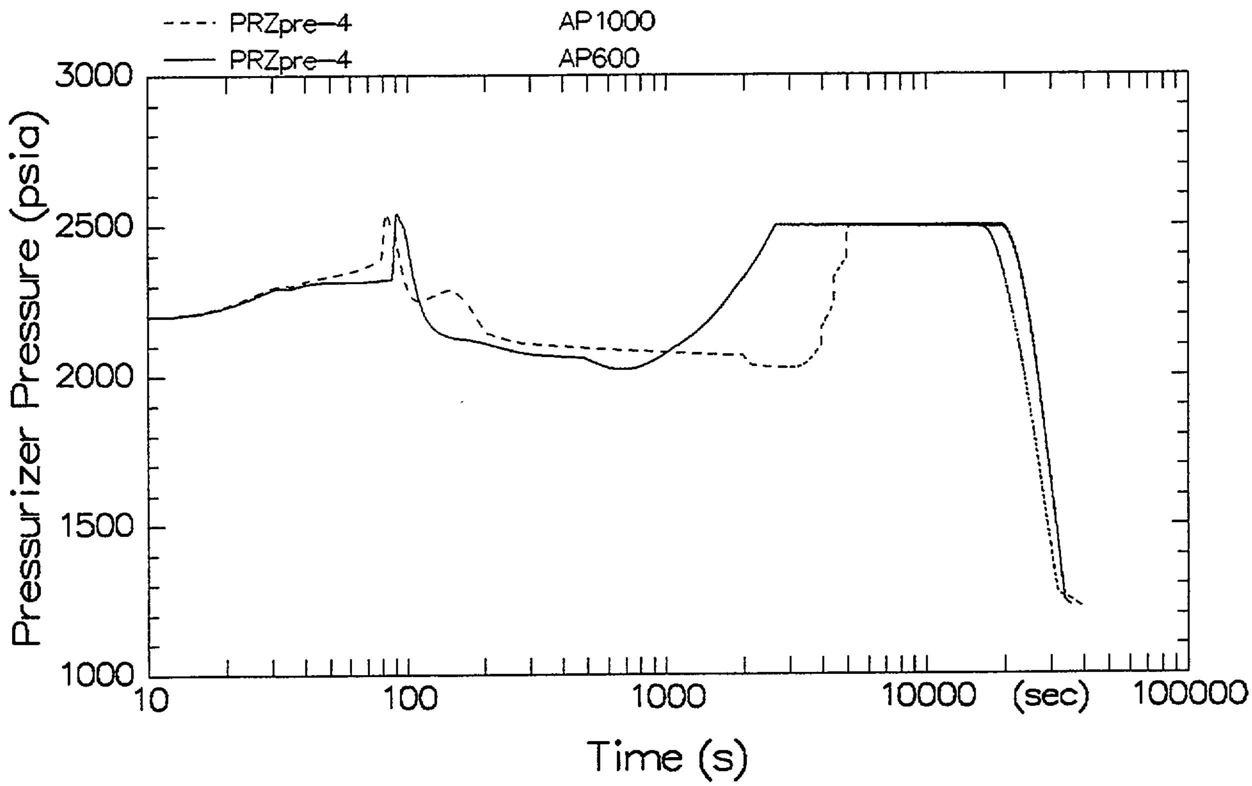


Figure 3.1.1-3 Pressurizer Pressure Transient for Loss of ac Power to the Plant Auxiliaries

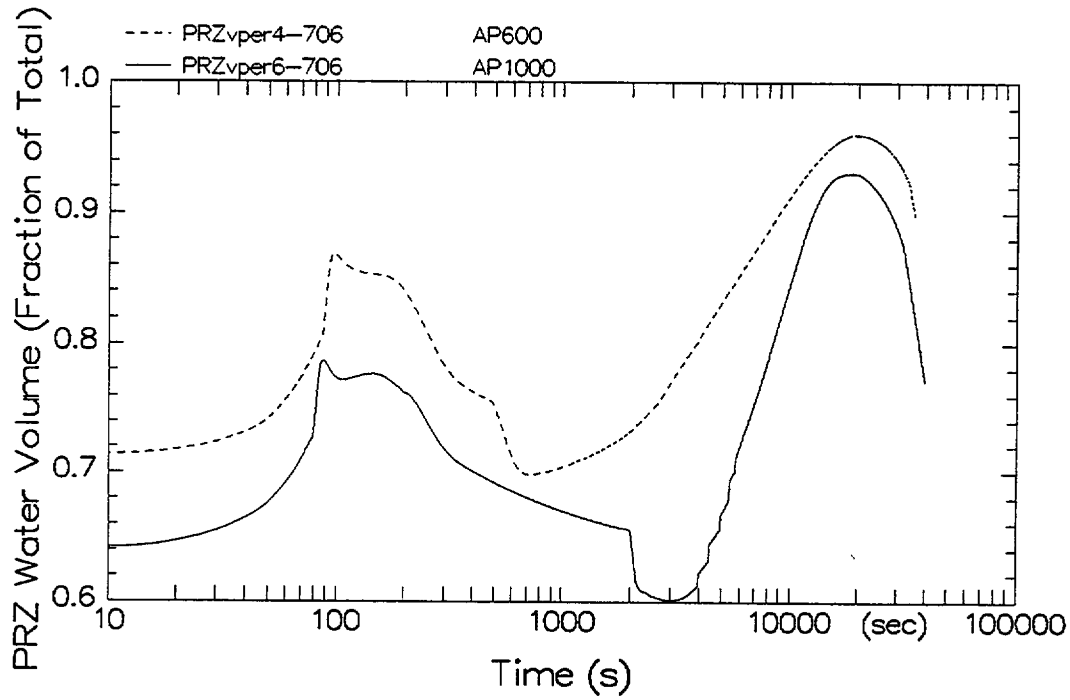


Figure 3.1.1-4 Pressurizer Water Volume Transient for Loss of ac Power to the Plant Auxiliaries

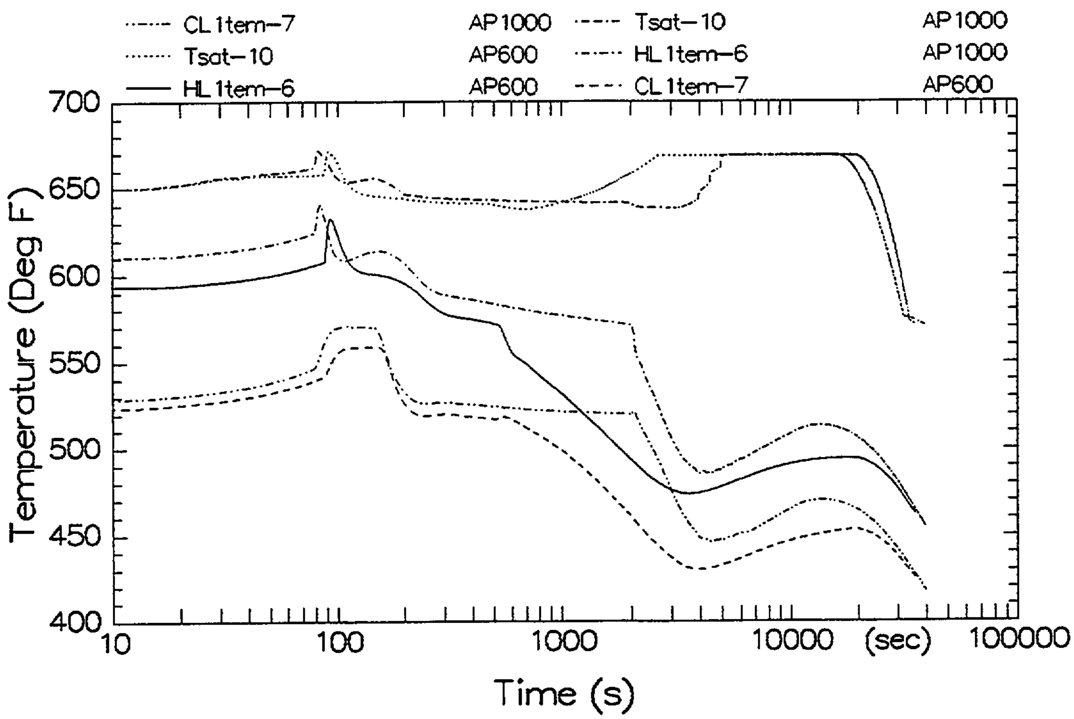


Figure 3.1.1-5 Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss of ac Power to the Plant Auxiliaries

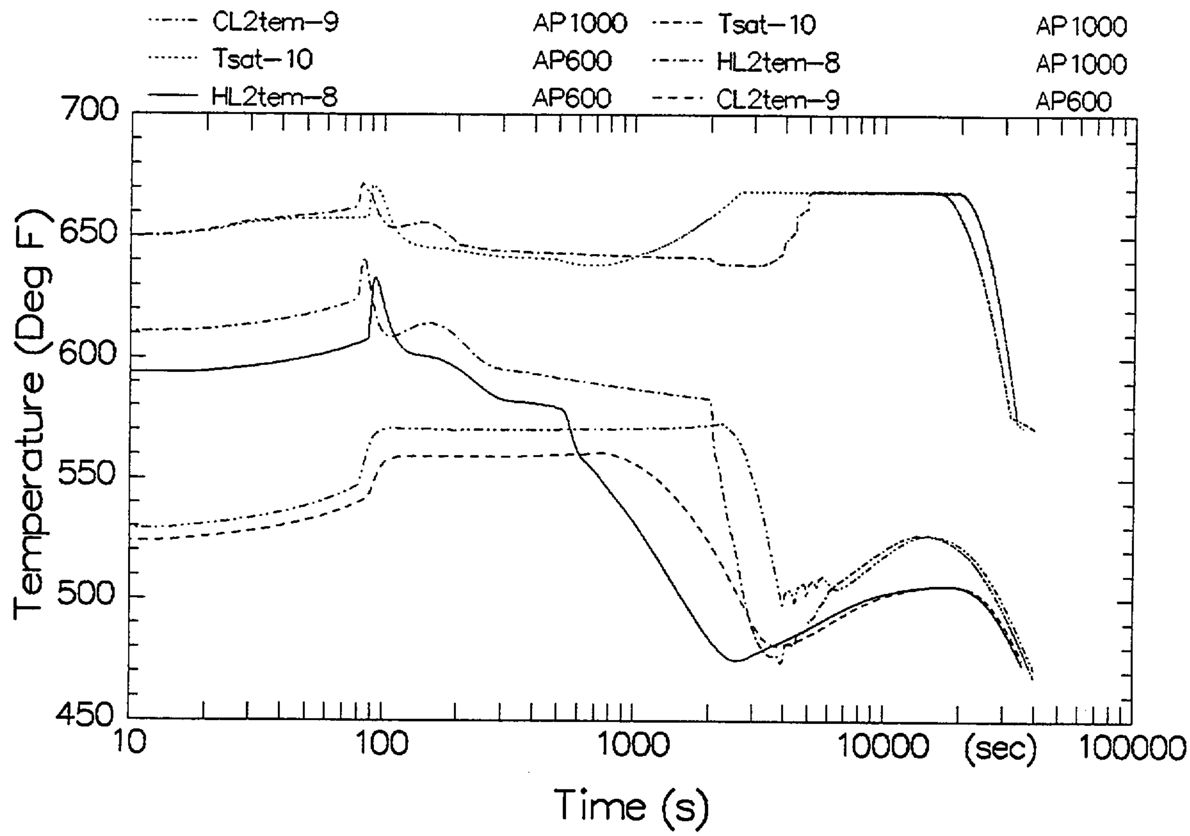


Figure 3.1.1-6 Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of ac Power to the Plant Auxiliaries

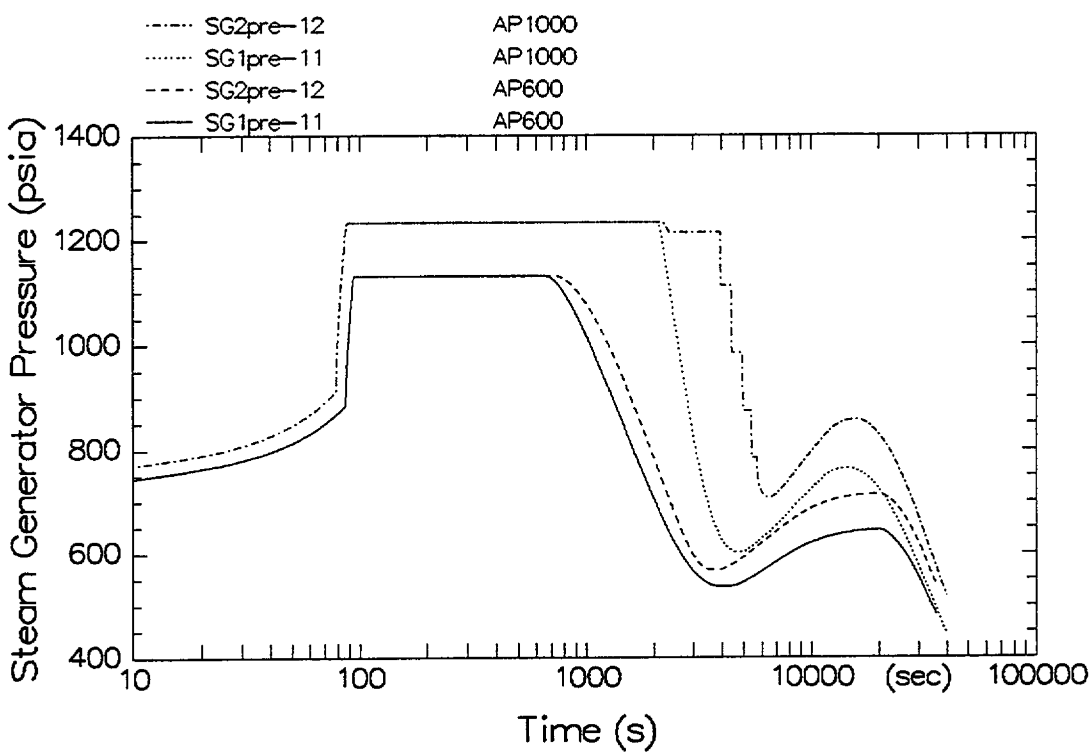


Figure 3.1.1-7 Steam Generator Pressure Transient for Loss of ac Power to the Plant Auxiliaries

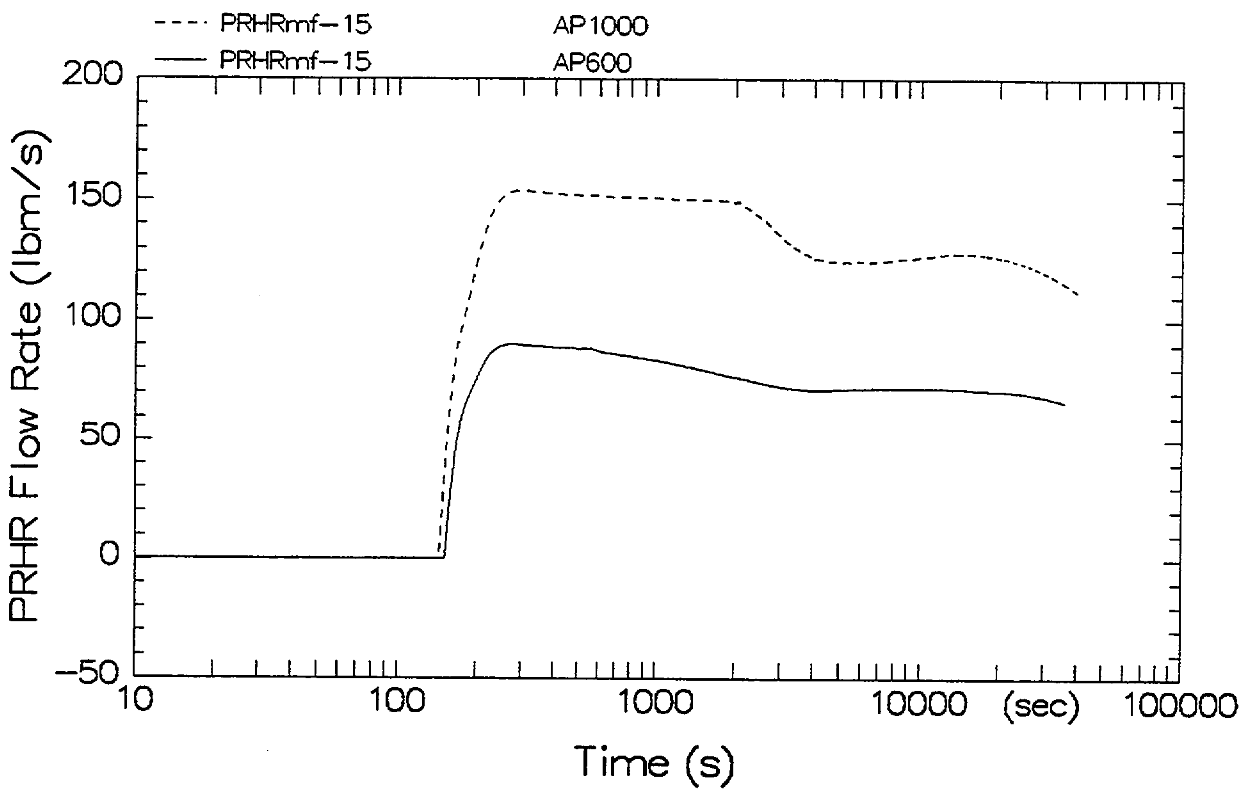


Figure 3.1.1-8 PRHR Flow Rate Transient for Loss of ac Power to the Plant Auxiliaries

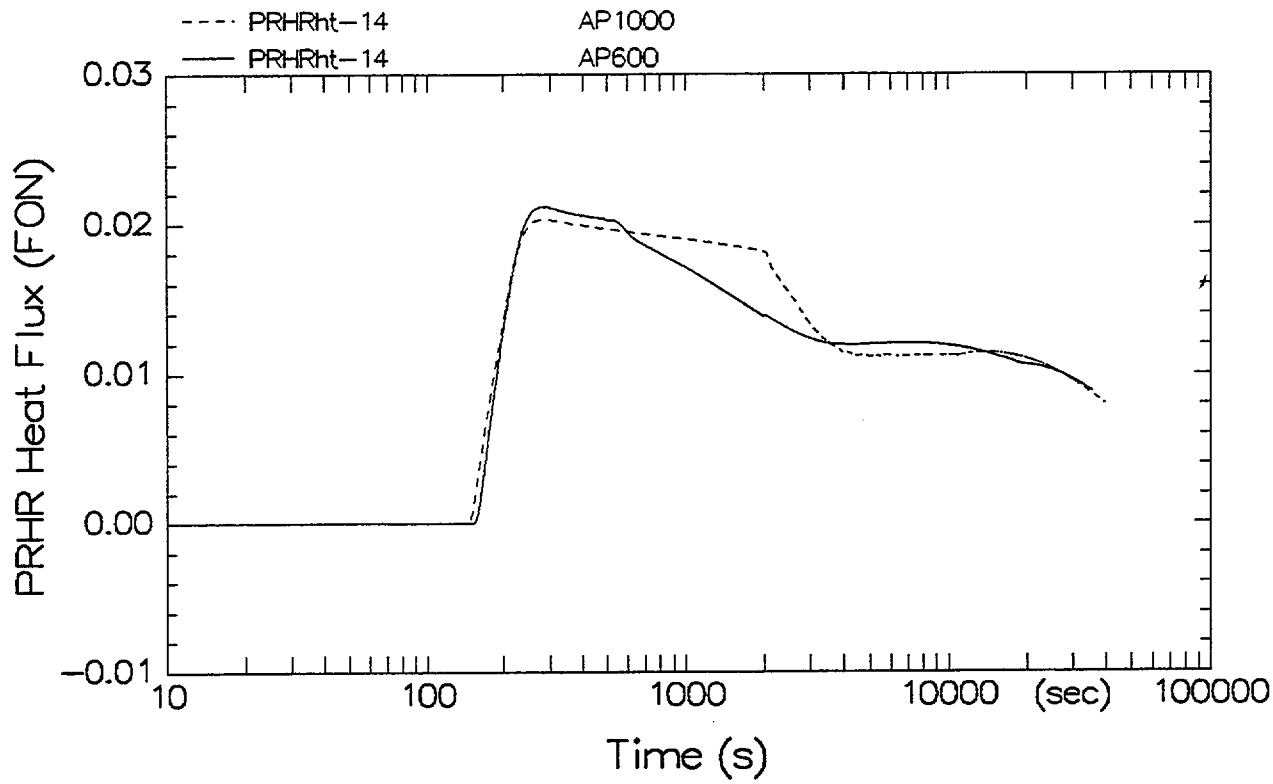


Figure 3.1.1-9 PRHR Heat Flux Transient for Loss of ac Power to the Plant Auxiliaries

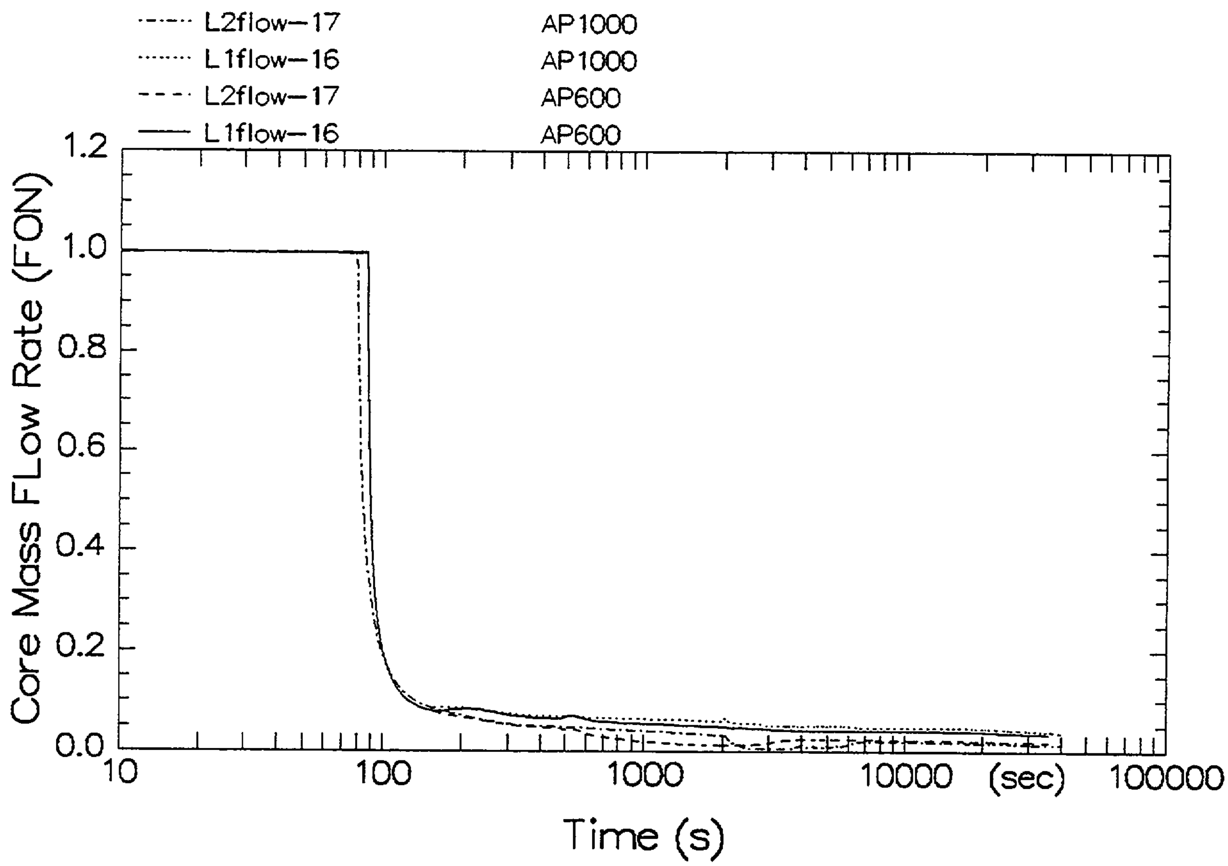


Figure 3.1.1-10 Reactor Coolant Volumetric Flow Rate Transient for Loss of ac Power to the Plant Auxiliaries

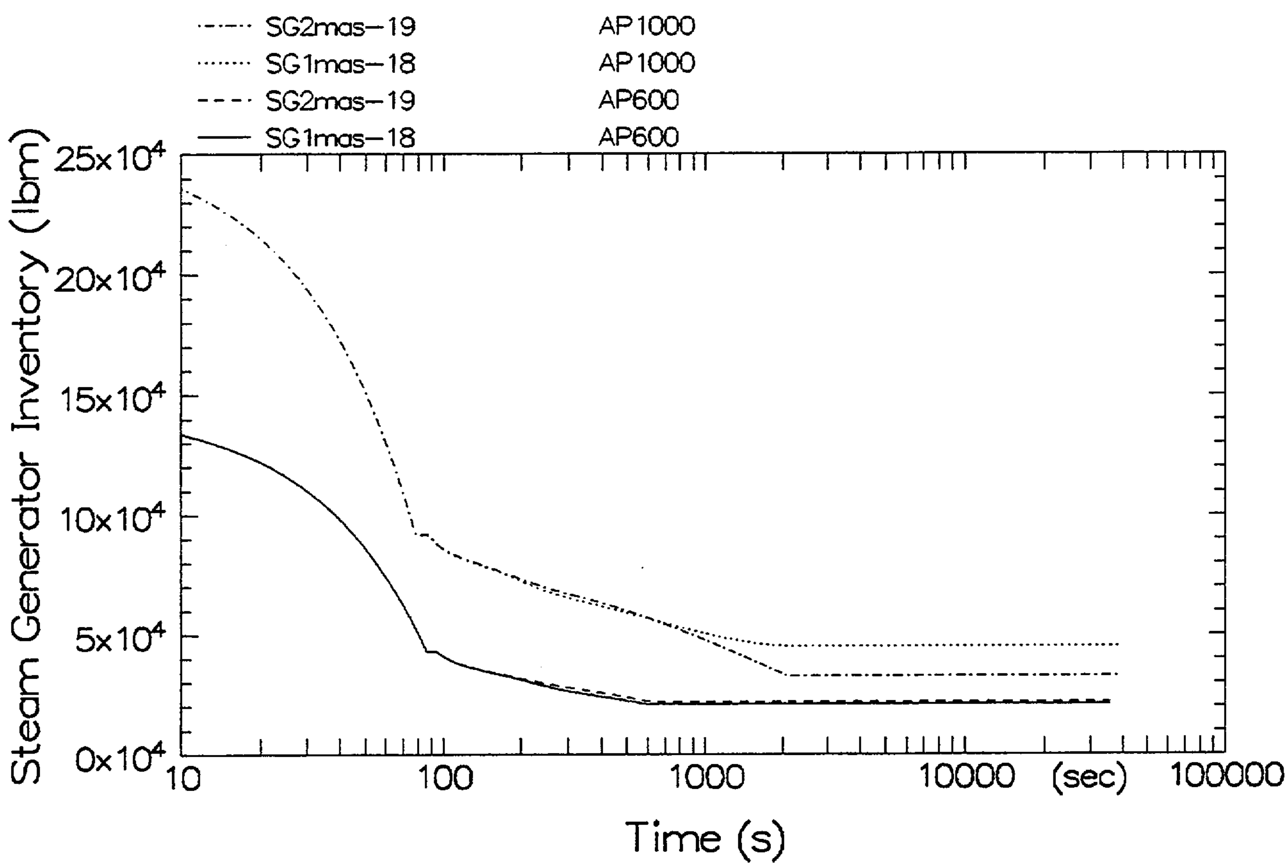


Figure 3.1.1-11 Steam Generator Inventory Transient for Loss of ac Power to the Plant Auxiliaries

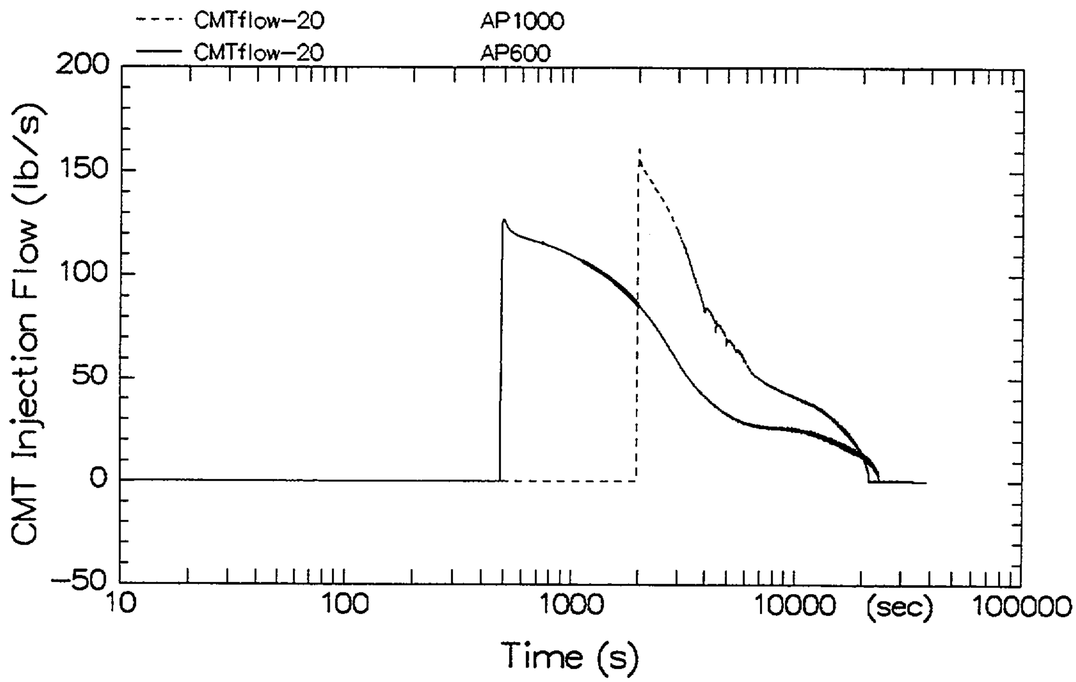


Figure 3.1.1-12 CMT Injection Flow Rate Transient for Loss of ac Power to the Plant Auxiliaries

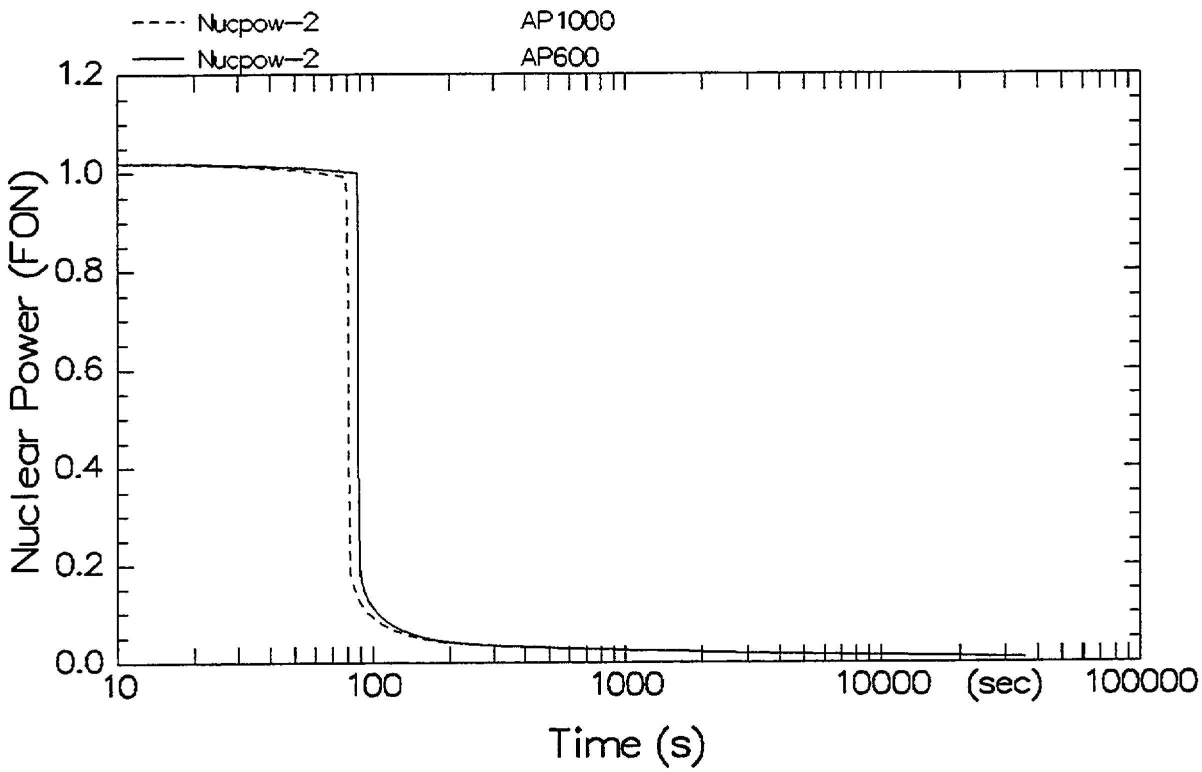


Figure 3.1.2-1 Nuclear Power Transient for Loss of Normal Feedwater Flow

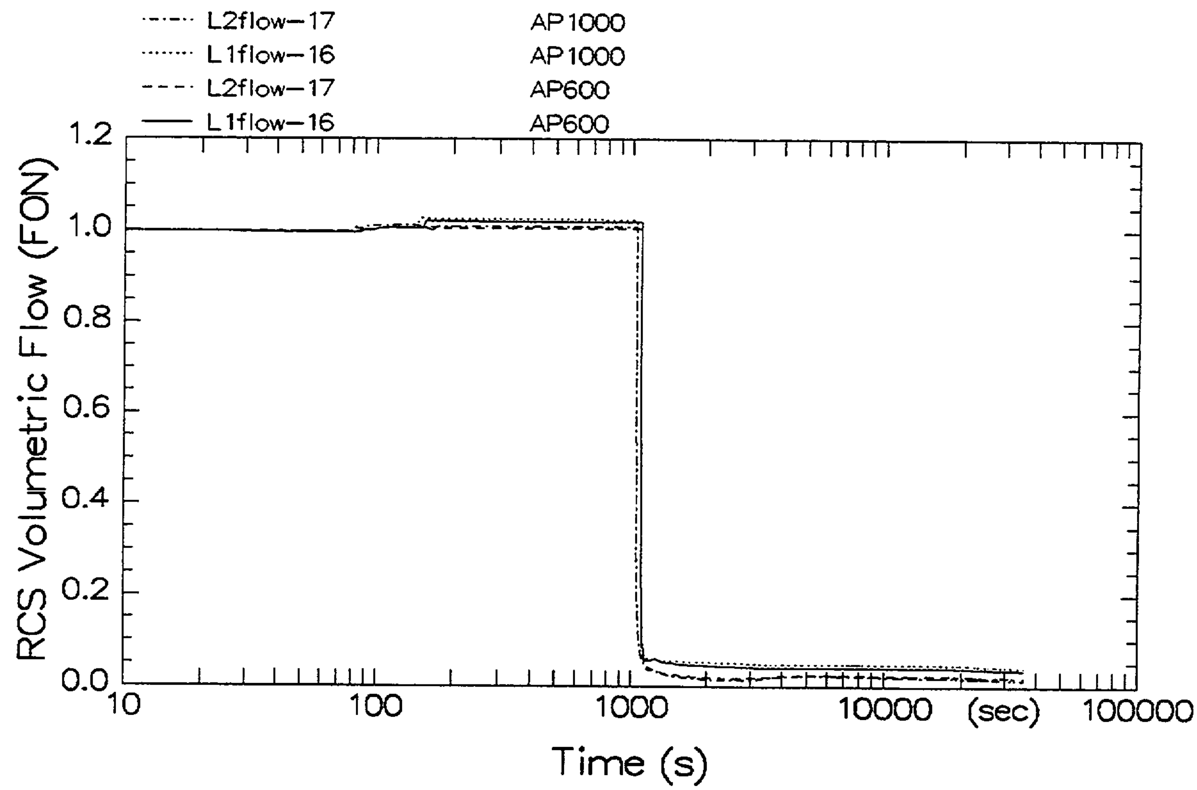


Figure 3.1.2-2 Reactor Coolant System Volumetric Flow Transient for Loss of Normal Feedwater Flow

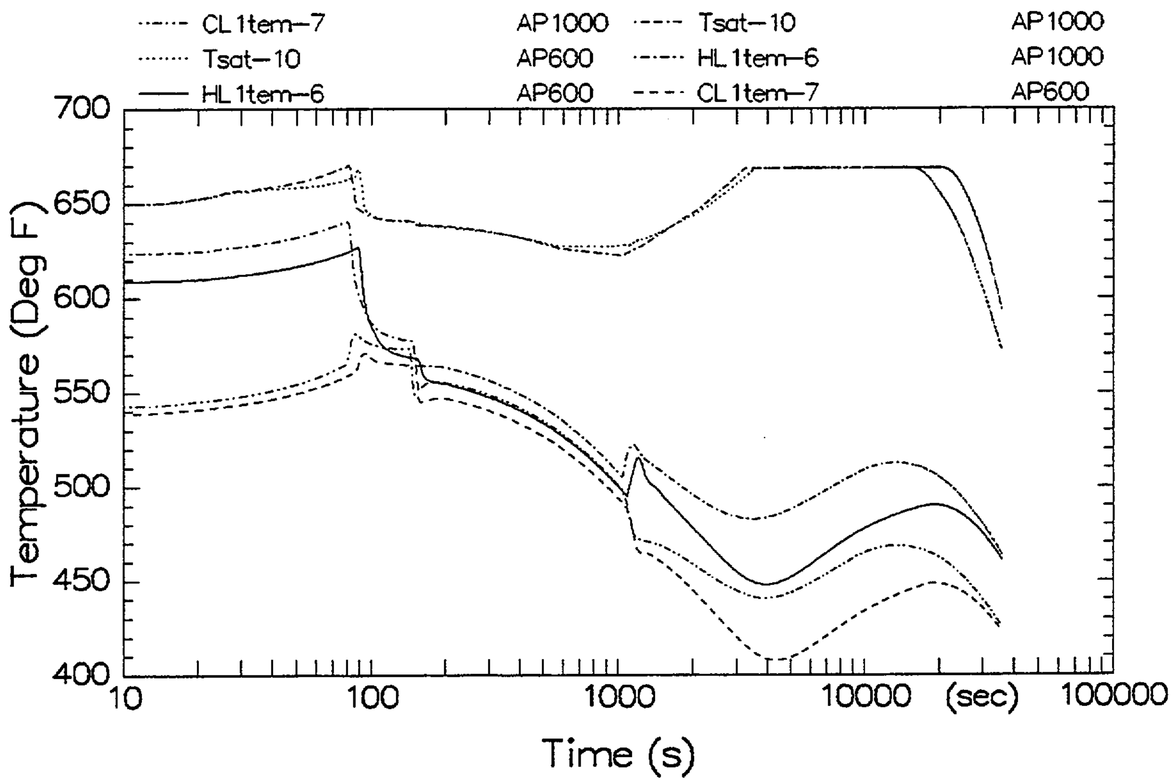


Figure 3.1.2-3 Reactor Coolant System Temperature Transients in Loop Containing the PRHR for Loss Normal Feedwater Flow

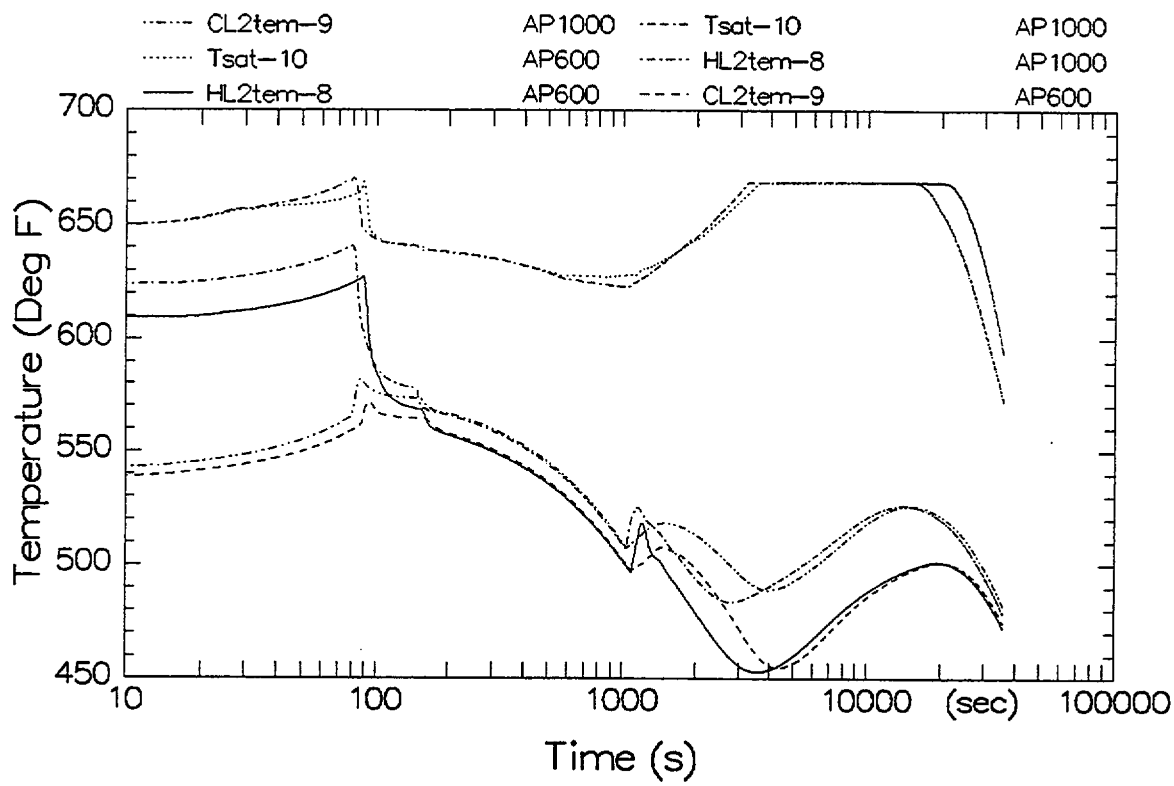


Figure 3.1.2-4 Reactor Coolant System Temperature Transients in Loop Not Containing the PRHR for Loss of Normal Feedwater Flow

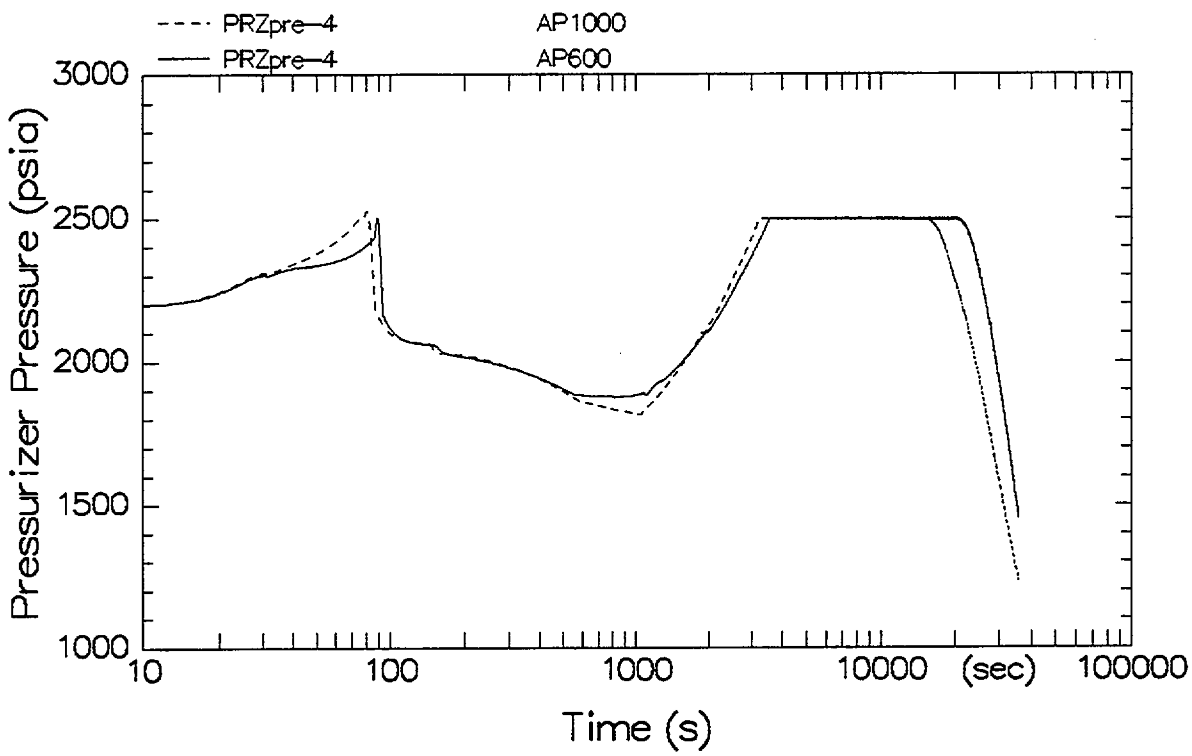


Figure 3.1.2-5 Pressurizer Pressure Transient for Loss of Normal Feedwater Flow

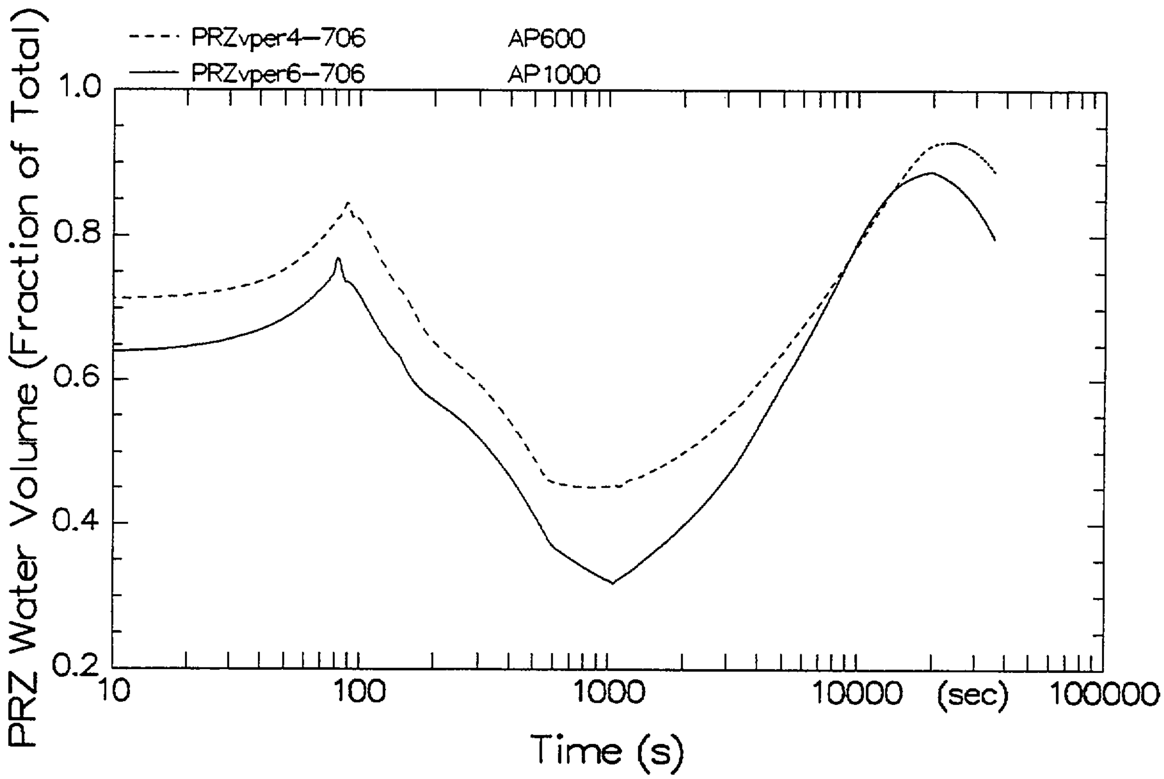


Figure 3.1.2-6 Pressurizer Water Volume Transient for Loss of Normal Feedwater Flow

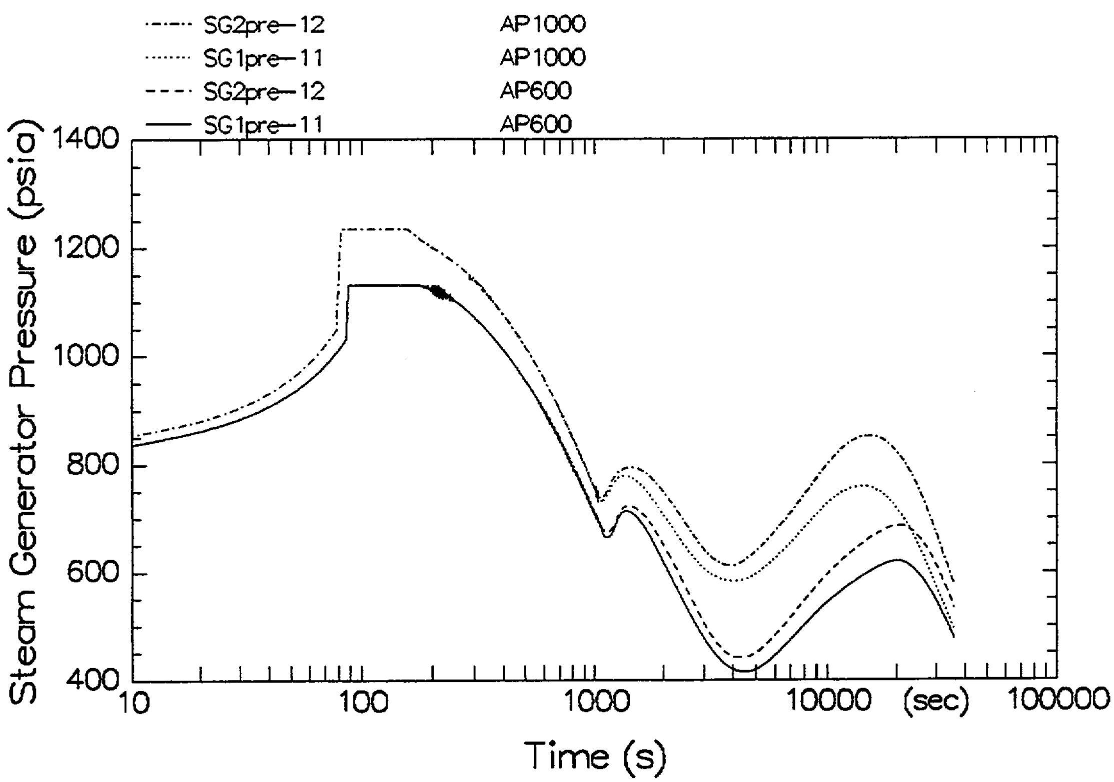


Figure 3.1.2-7 Steam Generator Pressure Transient for Loss of Normal Feedwater Flow

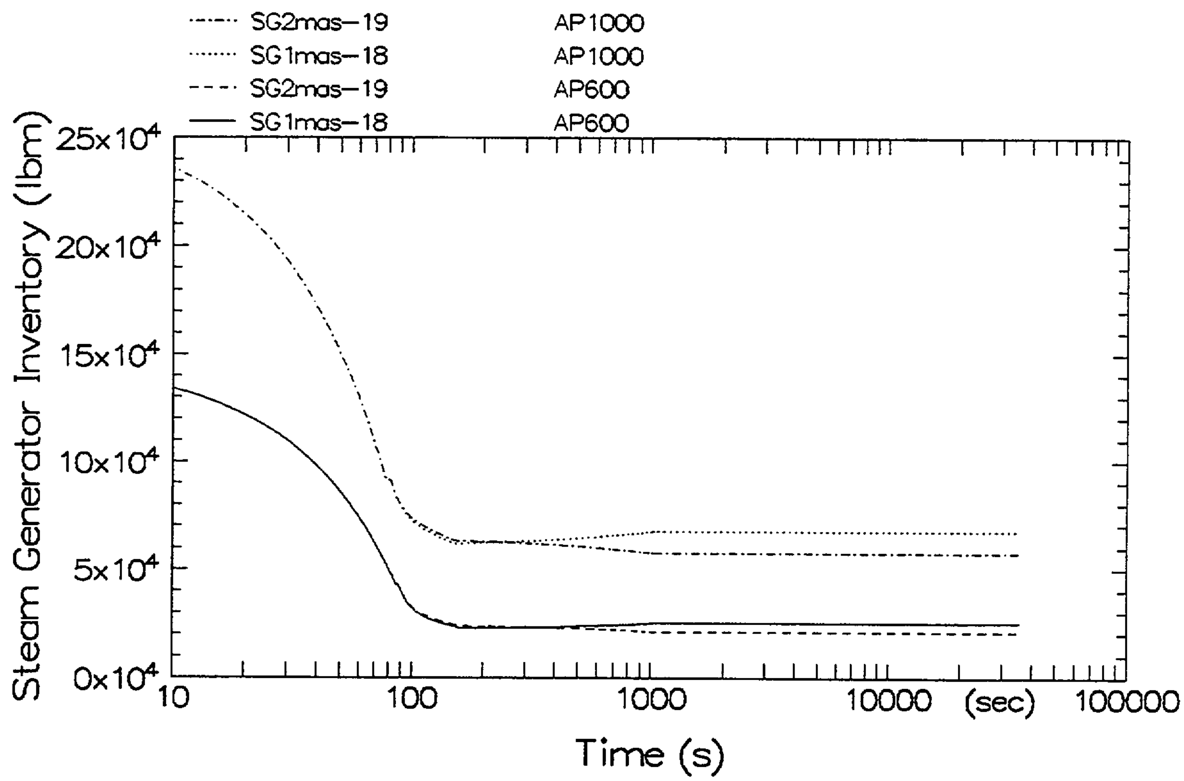


Figure 3.1.2-8 Steam Generator Inventory Transient for Loss of Normal Feedwater Flow

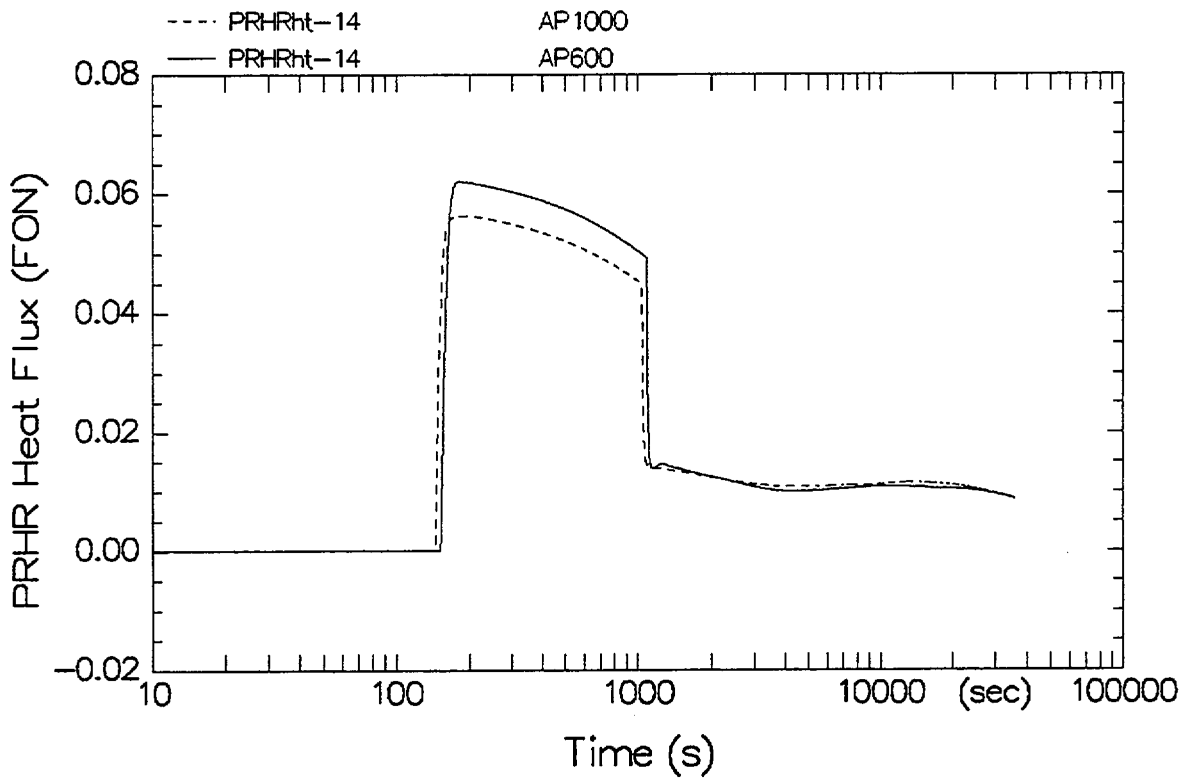


Figure 3.1.2-9 PRHR Heat Flux Transient for Loss of Normal Feedwater Flow

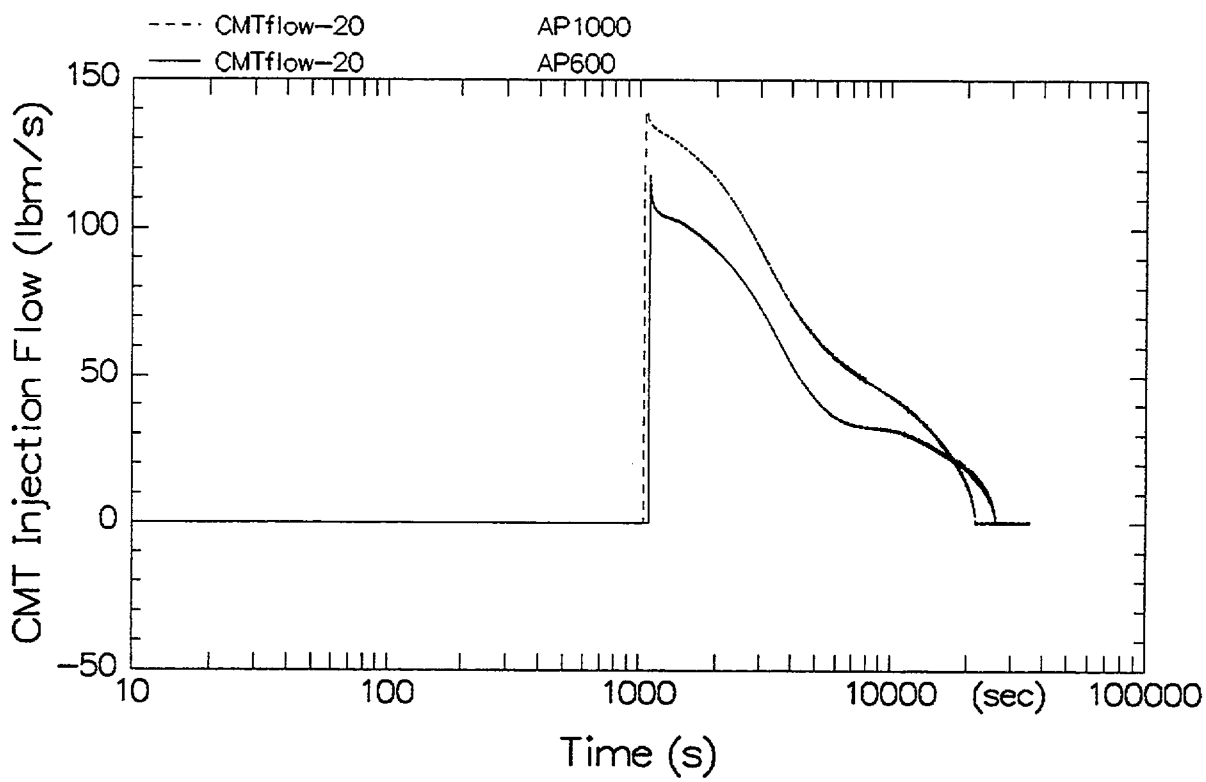


Figure 3.1.2-10 CMT Injection Flow Rate Transient for Loss of Normal Feedwater Flow

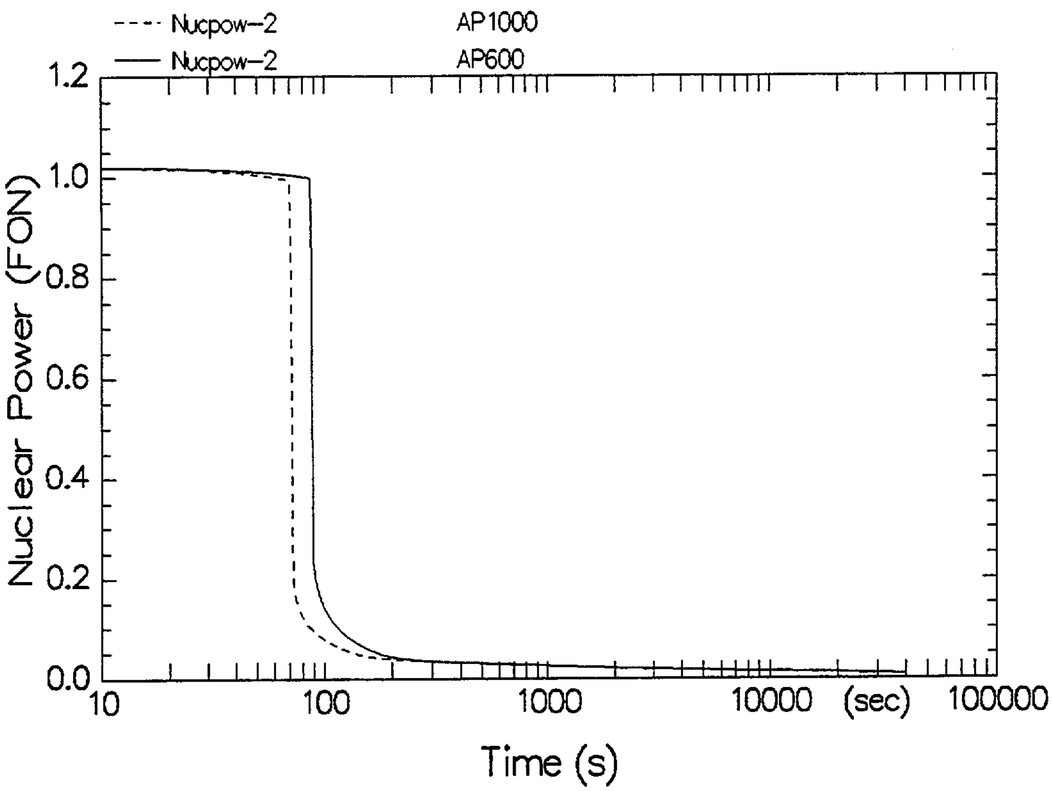


Figure 3.1.3-1 Nuclear Power Transient for Main Feedwater Line Rupture

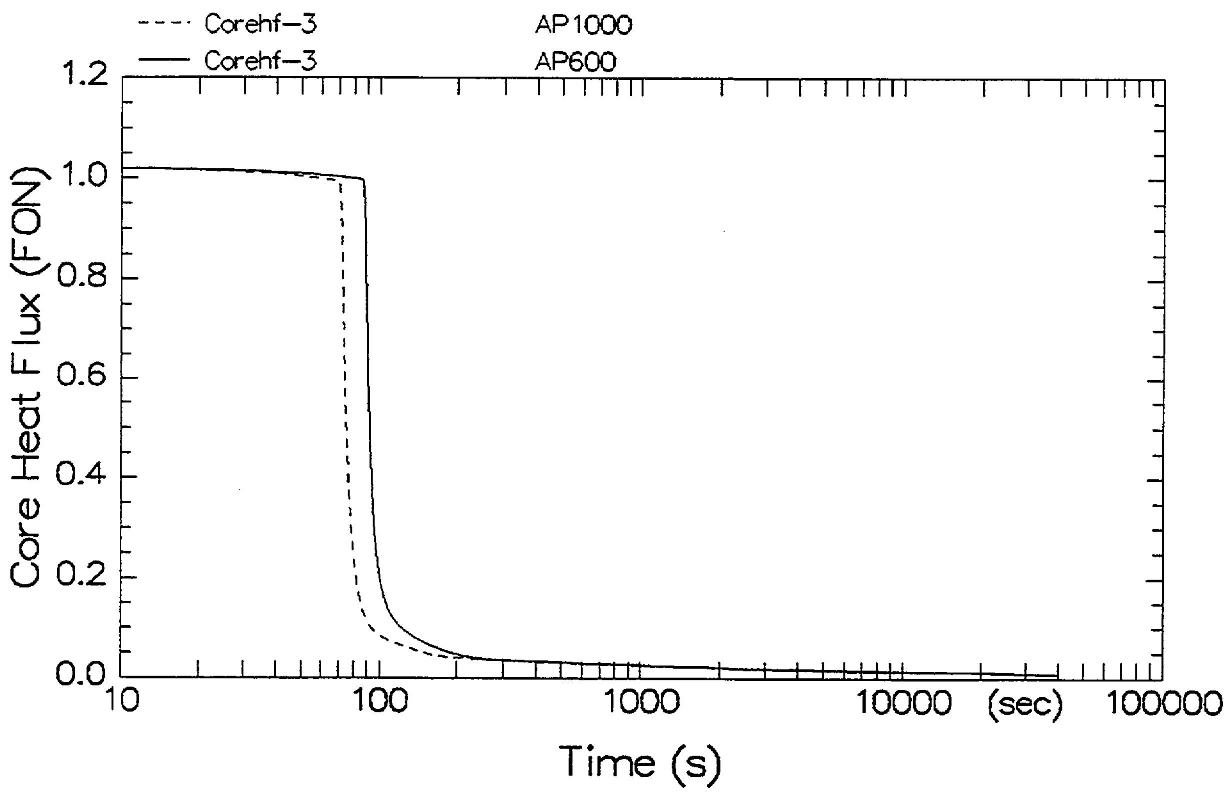


Figure 3.1.3-2 Core Heat Flux Transient for Main Feedwater Line Rupture

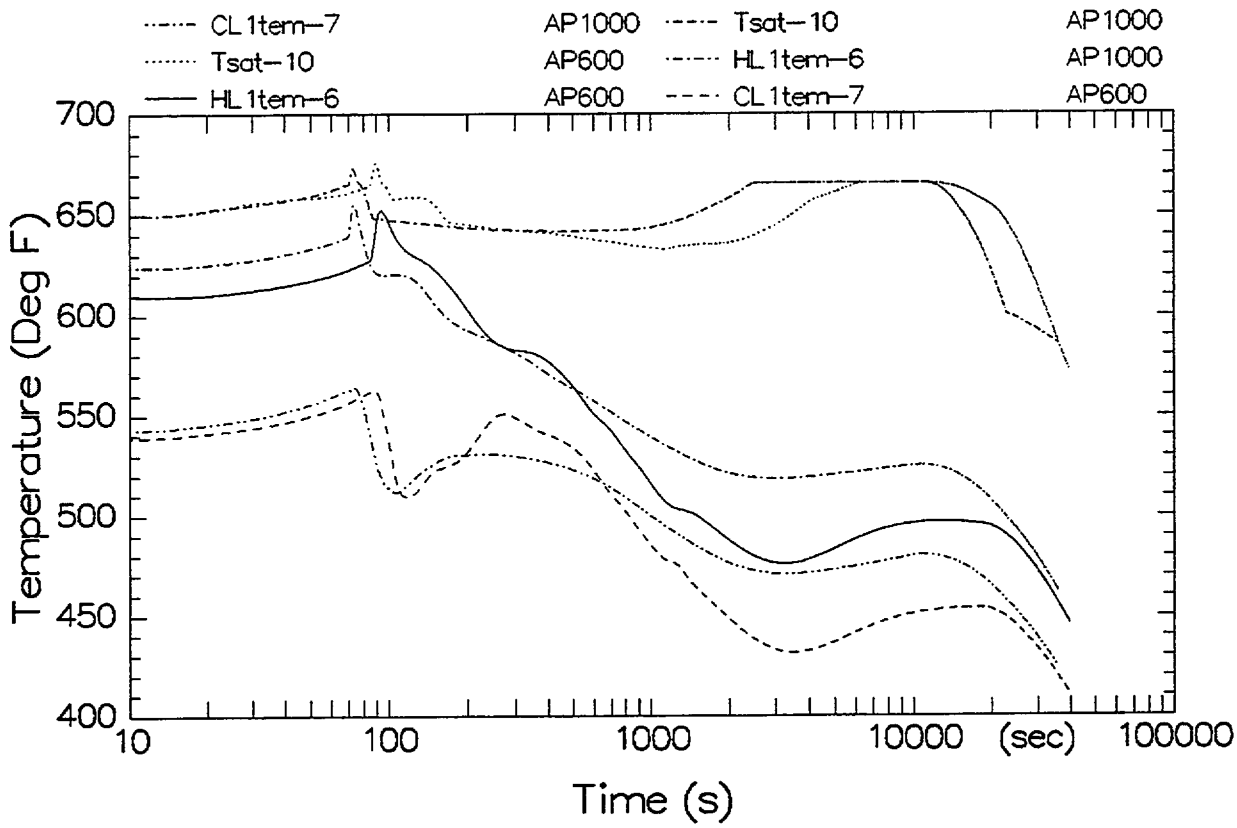


Figure 3.1.3-3 Faulted Loop Reactor Coolant System Temperature Transients for Main Feedwater Line Rupture

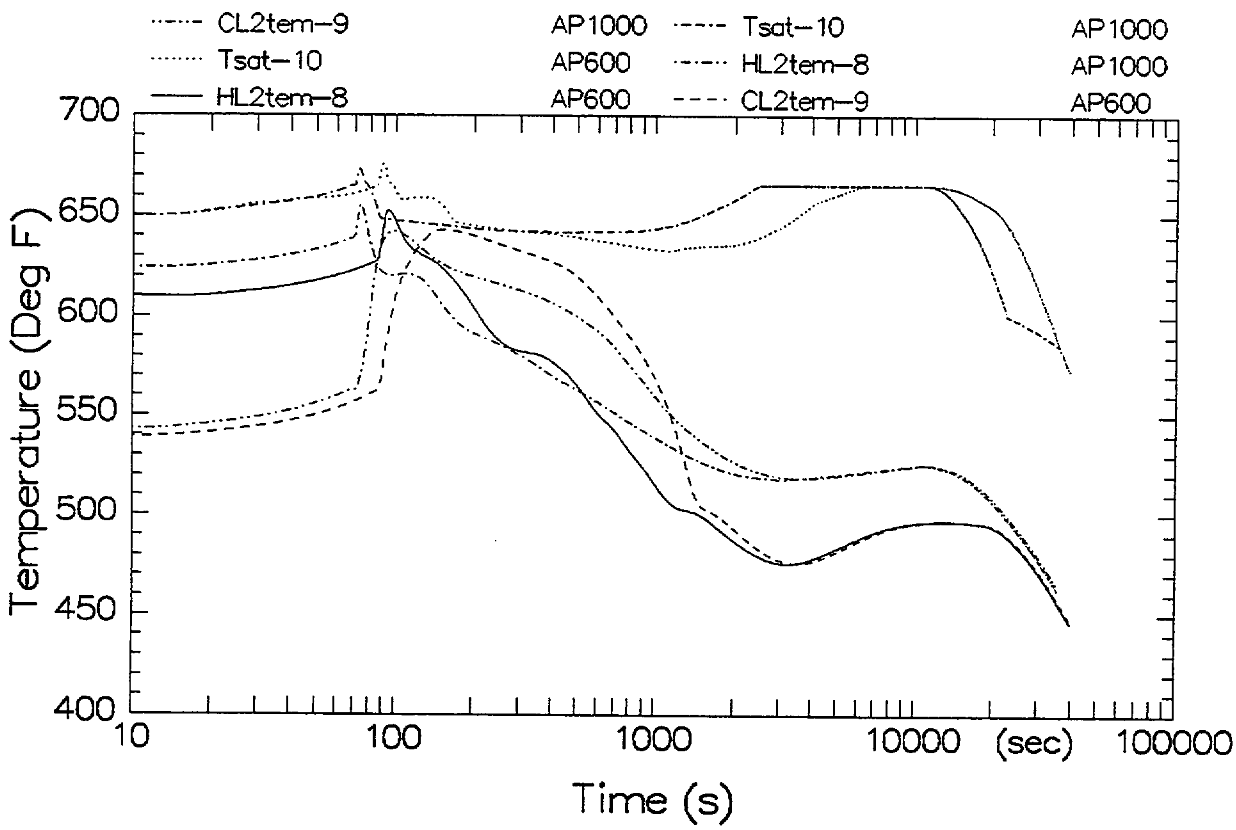


Figure 3.1.3-4 Intact Loop Reactor Coolant System Temperature Transients for Main Feedwater Line Rupture

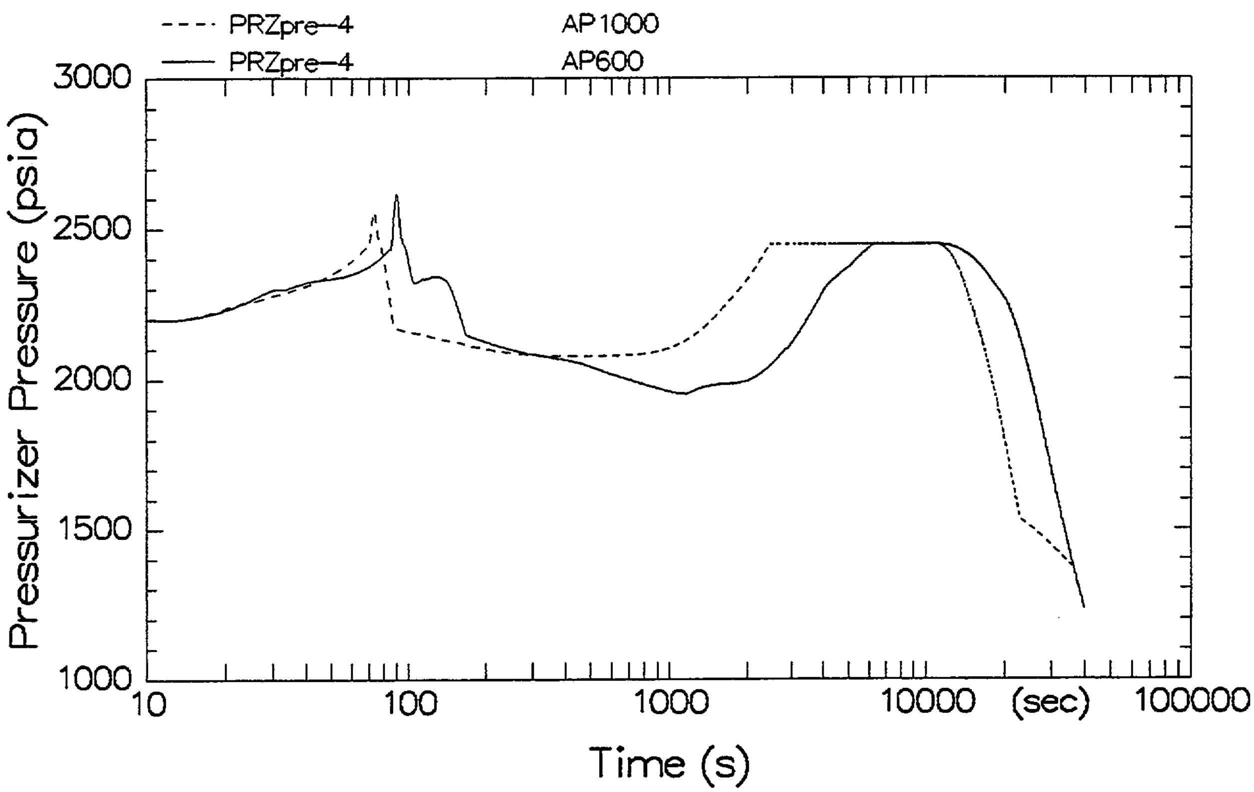


Figure 3.1.3-5 Pressurizer Pressure Transient for Main Feedwater Line Rupture

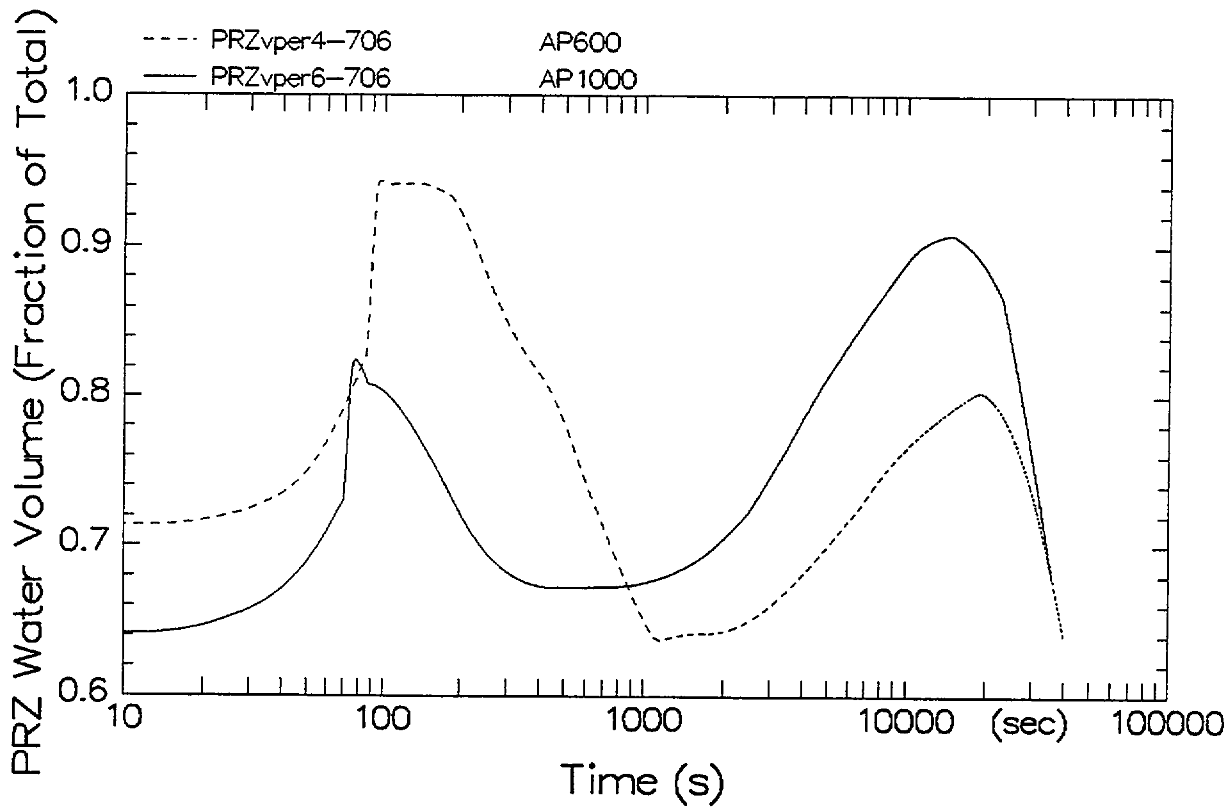


Figure 3.1.3-6 Pressurizer Water Volume Transient for Main Feedwater Line Rupture

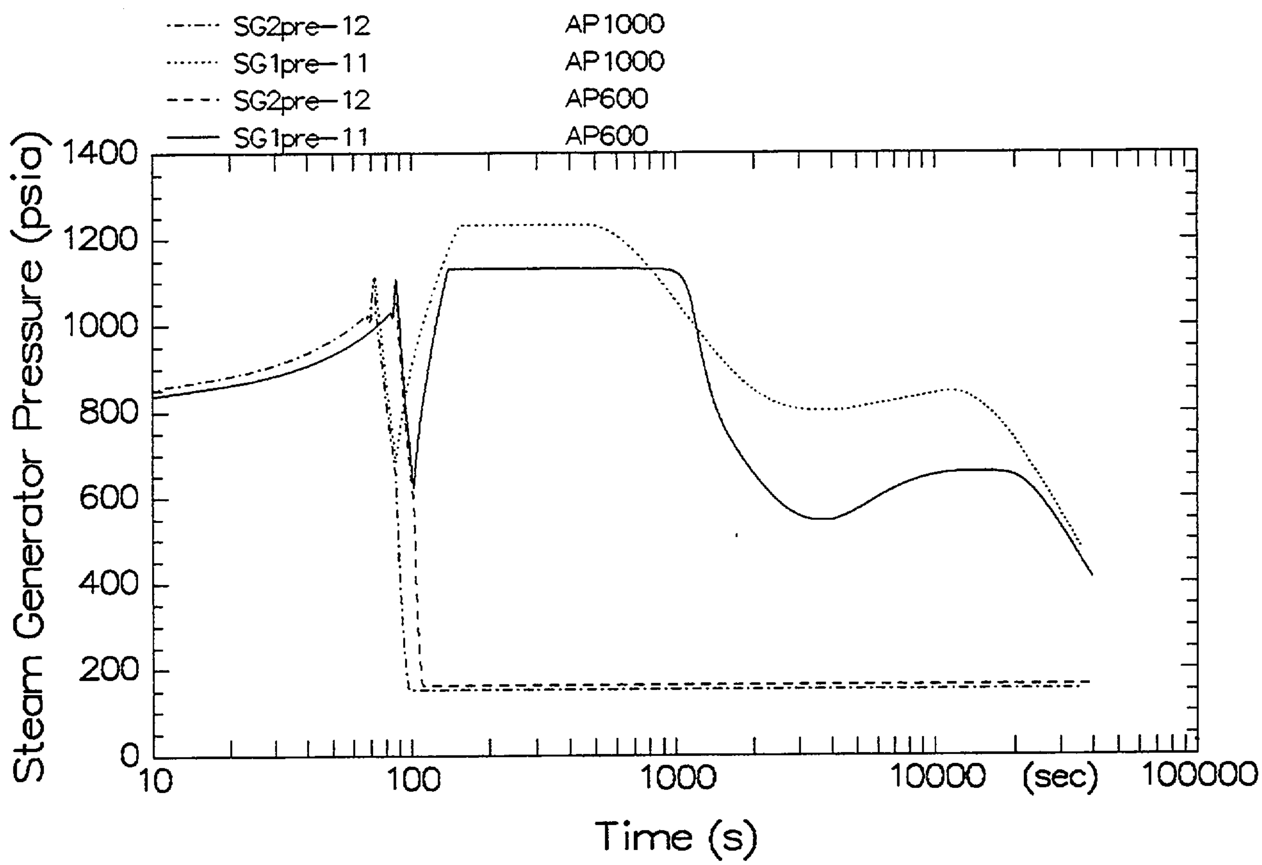


Figure 3.1.3-7 Steam Generator Pressure Transient for Main Feedwater Line Rupture

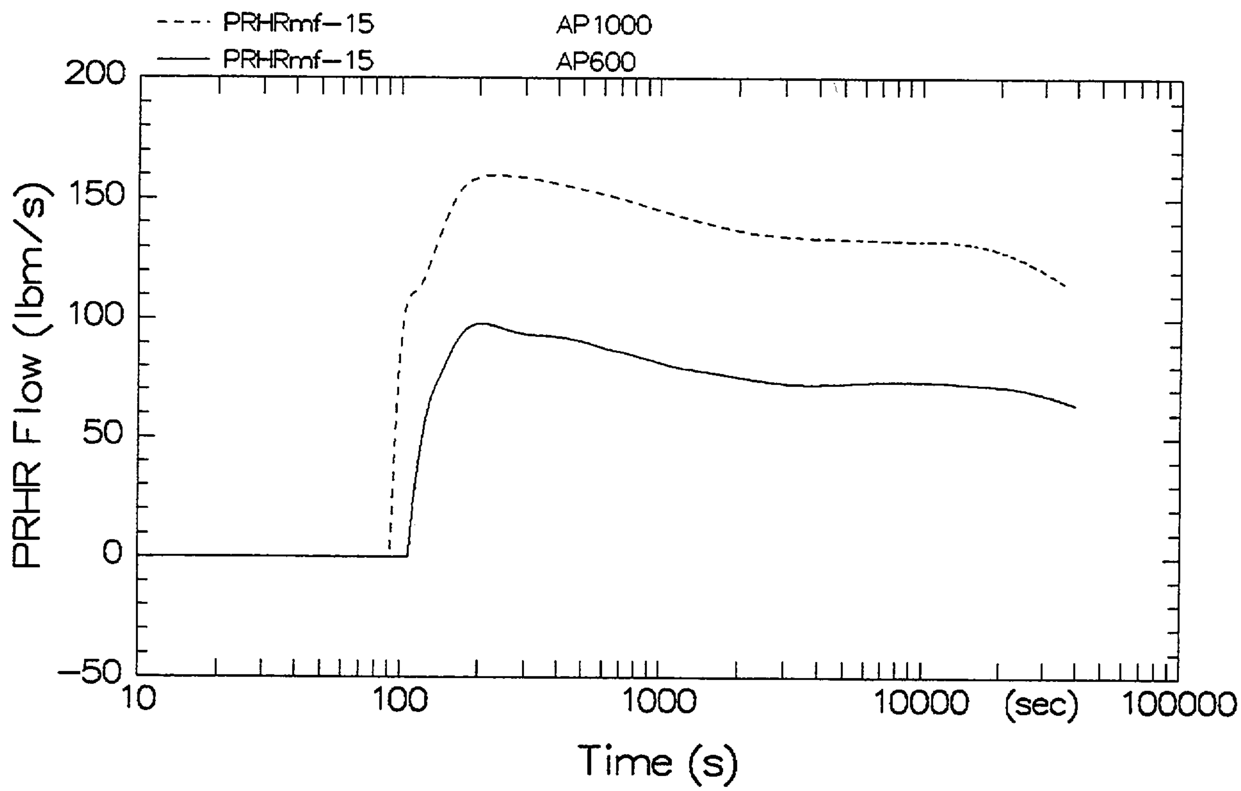


Figure 3.1.3-8 PRHR Flow Rate Transient for Main Feedwater Line Rupture

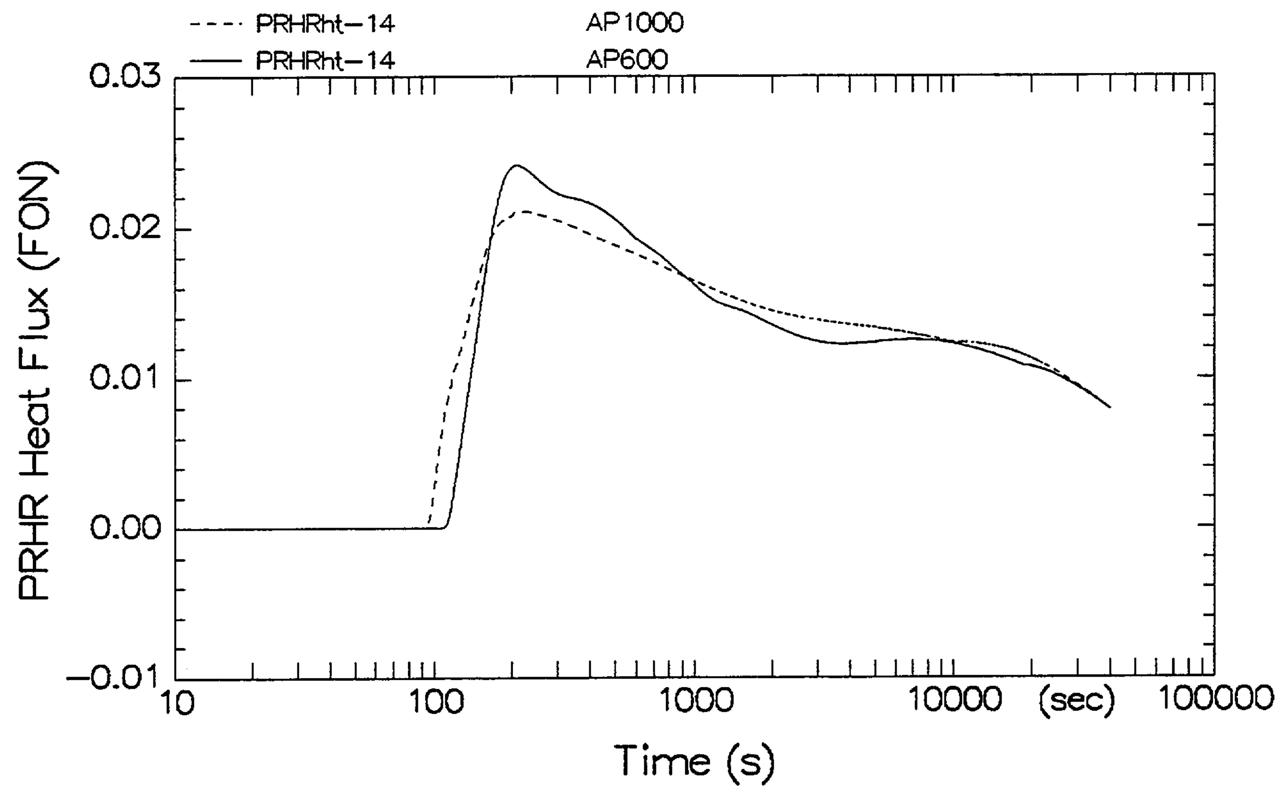


Figure 3.1.3-9 PRHR Heat Flux Transient for Main Feedwater Line Rupture

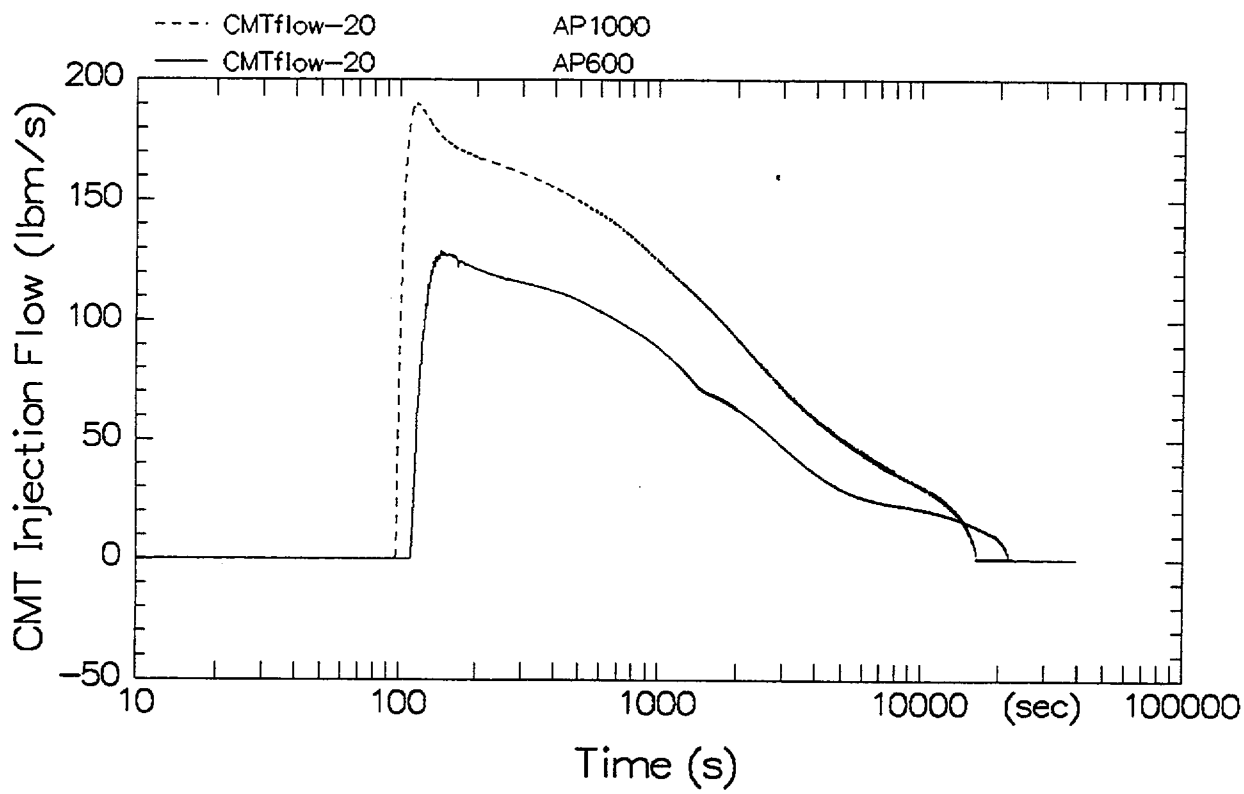


Figure 3.1.3-10 CMT Injection Flow Rate Transient for Main Feedwater Line Rupture

3.2 ASSESSMENT OF DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE EVENTS

A number of faults that could result in a decrease in the reactor coolant system flow rate are postulated. For the AP600, these events are discussed in section 15.3 of the AP600 DCD. In this section, an analysis of one of the limiting Condition II events – a complete loss of forced reactor coolant flow, is presented for the AP1000.

3.2.1 Identification of Causes and Accident Description

A complete loss of flow accident may result from a simultaneous loss of electrical supplies to the reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of a loss of coolant flow is a rapid increase in the coolant temperature.

Electric power for the reactor coolant pumps is supplied through two buses connected to the generator. When a generator trip occurs, the buses receive power from external power lines and the pumps continue to supply coolant flow to the core.

A complete loss of flow accident is a Condition III event (an infrequent fault), as defined in ANSI N18.2. Condition III events are faults that may occur infrequently during the life of the plant. They may result in the failure of only a small fraction of the fuel rods. The release of radioactivity is not sufficient to interrupt or restrict public use of those areas beyond the exclusion area boundary, in accordance with the guidelines of 10 CFR 100. However, to be consistent with Sections 15.3.1-15.3.2 of NUREG-0800 (Reference 4), this event is analyzed to meet the acceptance criteria of a Condition II event (a fault of moderate frequency). Specifically, the following acceptance criteria from NUREG-0800 are used in this analysis:

- "Pressure in the reactor coolant and main steam systems should be maintained below 110% of the design values."
- "Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for PWRs ... based on acceptable correlations ..."
- "An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently."

Mitigation of the complete loss of forced RCS flow is accomplished by tripping the reactor and reducing power before core thermal limits or RCS pressure boundary limits are approached. The following reactor trip signals provide protection against this event:

- Reactor coolant pump underspeed (in 2 out of 4 RCPs when power is above the P-10 permissive)
- Low reactor coolant loop flow (in a single cold leg when power is above the P-8 permissive)

The primary protection function for the complete loss of RCS flow event is the RCP under speed trip. The reactor trip on reactor coolant pump underspeed protects against conditions that can cause a loss of voltage to the reactor coolant pumps. This function is blocked below approximately 10-percent power (permissive P10).

The reactor trip on low primary coolant loop flow is provided to protect against loss of flow conditions that affect only one or two reactor coolant loop cold legs. This function also provides backup protection for the complete loss of flow transient. This function is generated by two-out-of-four low-flow signals per reactor coolant loop cold leg. Above permissive P8 (~48% power), low flow in any cold leg actuates a reactor trip. Between approximately 10-percent power (permissive P10) and the power level corresponding to permissive P8, low flow in any two reactor coolant loop cold legs actuates a reactor trip.

3.2.2 Analysis of Effects and Consequences

3.2.2.1 Method of Analysis

For comparison purposes with the AP1000, the AP600 complete loss of flow analysis from Section 15.3.2 of the AP600 DCD is also presented.

The AP600 complete loss of RCS flow transient is analyzed using three computer codes. First, the LOFTRAN code (Reference 1) is used to calculate the core flow during the transient, the time of reactor trip based on the input loop flows, the nuclear power transient, and the primary system pressure and temperature transients as predicted from the loss of two reactor coolant pumps. The FACTRAN code (Reference 2) is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the WESTAR code (Reference 9) is used to calculate the departure from nucleate boiling ratio (DNBR) during the transient, based on the heat flux from FACTRAN and the flow from LOFTRAN. The DNBR results presented represent the minimum of the typical cell or the thimble cell.

Like the AP600 analysis, the AP1000 complete loss of RCS flow transient is also analyzed using three computer codes. LOFTRAN is used to perform the overall system performance. FACTRAN is used to calculate the core heat flux transient. For this report, THINC-IV (References 10 and 11) was used to calculate the departure from nucleate boiling ratio (DNBR) during the transient, due to the higher core mass flow rates calculated for the AP1000. In the AP600, WESTAR was used due to the AP600 low mass flow during the time of minimum DNBR.

3.2.2.2 Initial Conditions

Initial reactor power, pressure, and reactor coolant system temperature are assumed to be at their nominal values. The Revised Thermal Design Procedure is used for DNBR evaluation and uncertainties in initial conditions are included in the DNBR limit, as described in WCAP-11397-P-A (Reference 5). The plant characteristics and initial conditions assumed in this analysis are summarized in Table 3.2.2-1.

3.2.2.3 Reactivity Coefficients

A conservatively large absolute value of the Doppler-only power coefficient is used in the AP600 and the AP1000 analyses. The AP600 total integrated Doppler reactivity from 0- to 100-percent power of 0.0118 Δk. The AP1000 total integrated Doppler defect is 0.0113 Δk.

A bounding least-negative moderator temperature coefficient (0.0 $\Delta k/gm/cc^3$) is assumed because this results in the maximum core power during the initial part of the transient, when the minimum DNBR is reached.

For these analyses, a curve of trip reactivity versus time based which is calculated based on all the reactor coolant pumps coasting down concurrent with or prior to the insertion of the RCCA. The insertion time for the RCCAs in the AP600 analysis is 1.8 seconds. The insertion time for the AP1000 analysis is 2.1 seconds. The AP1000 RCCA insertion time is longer than that of the AP600 due to higher initial core flow and the longer fuel assembly.

The reactor coolant pump underspeed function is used to trip the reactor. The AP600 and the AP1000 analyses assume the same setpoints. An underspeed reactor trip setpoint of 90% with a delay of 767 milliseconds was used. No single active failure in this trip function adversely affects the consequences of the accident.

3.2.2.4 Analysis Results

Figures 3.2-1 through 3.2-6 show the transient responses of the AP600 and the AP1000 for the complete loss of voltage to all four reactor coolant pumps. A sequence of events is provided in Table 3.2-2. At time=0.0, power to all the reactor coolant pumps is assumed to be lost and a reduction in core flow begins. The core flow is shown in Figure 3.2-1. The AP1000 reactor coolant pumps coast down slower than those of the AP600 due to the higher inertia of the reactor coolant pumps. The AP1000 reactor coolant pumps have an inertia of 15750 lb-ft^2 as compared to 5000 lb-ft^2 for the AP600. The reactor coolant pump under speed reactor trip setpoint is reached at 0.32 seconds for the AP600 case and .556 seconds for AP1000 case. 767 milliseconds after the trip setpoint is reached the RCCAs begin to drop into the core. Because the least negative moderator temperature coefficient is used, the nuclear power (See Figure 3.2-3) stays at the initial full power value prior to reactor trip. As the RCCAs drop into the core, nuclear power is reduced. The use of bounding maximum Doppler-only power coefficient tends to retard the core power reduction. The characteristics of the power transients for the AP600 and the AP1000 are similar with the only significant difference due the differences in the time when the trip setpoint is reached.

The pressurizer pressure is shown in Figure 3.2-4. The pressurization transient for the AP1000 plant is higher than that observed for the AP600 plant. However, the primary pressure increase is limited to a value such that the pressurizer safety valves are not opened during the transient for either the AP1000 or the AP600.

The DNBR for the AP600 and the AP1000 was calculated to be always greater than the design limit value. Table 3.2-4 summarizes the minimum DNB ratios and other related quantities at

the time of minimum DNBR. Table 3.2-3 lists DNBR correlation range limits. The AP600 mass velocity was below the mass velocity limit of the WRB-2 correlation. For the AP600 program, DNB testing was conducted to provide data to extend the WRB-2 correlation to lower flows. A multiplier to the WRB-2 correlation was developed based on this data (Reference 8). The DNBR for the AP600 analysis was calculated using the WRB-2 with the AP600 low flow multiplier. The mass velocity at the time of minimum DNBR for the AP1000 analysis was above the WRB-2 correlation limit of $G=0.9x10^6$ lbm/ft^2-hr. Therefore the AP600 low flow correlation multiplier need not be used. The improved performance of the AP1000 is due to higher initial reactor coolant flow and an increase in the inertia of the reactor coolant pumps.

The fluid quality at the exit of the hot channel for the AP1000 analysis is 29% which is within the limit of the WRB-2 correlation (≤ 30%). The Revised Thermal Design Procedure (RTDP) as described in Reference 5 was used in conjunction with the WRB-2 DNBR correlation to calculate DNBR for the AP1000. In RTDP, uncertainties such as those on initial core power and reactor coolant temperature are statistically combined and included in the DNBR limit value. RTDP also considers the uncertainty on the local core fluid quality. The WRB-2 correlation was validated for a local quality range up to 30%. When this correlation is used in conjunction with RTDP, a quality uncertainty is applied and the RTDP method has an upper bound quality limit of ~25%. The AP1000 analysis value of 29% is beyond the RTDP quality limit of 25%.

To resolve the problem of exceeding the RTDP quality limit for the AP1000 additional analytical work for the WRB-2 correlation can be performed. The existing DNB tests run for development of the WRB-2 correlation were performed for fluid quality up to 35%. However, test results for cases beyond a quality of 30% were not used in formulating WRB-2 correlation. By incorporating the unused test results, the correlation fluid quality range can be increased such that it covers the range observed in AP1000 complete loss of RCS flow analyses and further new DNB tests need not be performed. Extension of the WRB-2 correlation beyond a quality of 25% is planned prior to Design Certification of AP1000.

3.2.3 Conclusions

The analysis shows that, for the complete loss of reactor coolant flow, the DNBR does not decrease below the design basis value at any time during the transient. The core mass flow at the time of the AP1000 minimum DNBR is above the minimum value for the WRB-2 correlation limit. No new DNB testing is needed for the AP1000 and the AP600 low flow correlation multiplier need not be used.

3.2.4 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), April 1984.

2. Hargrove, H. G., "FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908 (Proprietary) and WCAP-7337 (Nonproprietary), June 1975.

3. Baldwin, M. S., et al., "An Evaluation of Loss of Flow Accidents Caused by Power System Frequency Transients in Westinghouse PWRs," WCAP-8424, Revision 1, May 1975.

4. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, July 1981.

5. Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," WCAP-11397-P-A (Proprietary) and WCAP-11398-A (Nonproprietary), April 1989.

6. Soffer, L., et al., "Accident Source Terms for Light-Water Nuclear Power Plants," NUREG-1465, February 1995.

7. American National Standards Institute N18.2, "Nuclear Safety Criteria for the Design of Stationary PWR Plants," 1973.

8. "AP600 Low Flow Critical Heat Flux (CHF) Test Data Analysis," WCAP-14371, May 1995.

9. Ho, S. A., Olson, C. A. and Paik, I. K., "WESTAR: An Advanced Three Dimensional Program for Thermal-Hydraulic Analysis of Light Water Reactors," WCAP-10951-P-A, June 1988.

10. Friedland, A. J., Ray, S., "Improved THINC-IV Modeling for PWR Core Design," WCAP-12330-P-A, September 1991.

11. Stolz, J. F., (NRC), Letter to C. Eicheldinger (Westinghouse) Regarding Staff Evaluation of WCAP-7956, WCAP-8054, WCAP-8567, and WCAP-8762, April 1978.

Table 3.2-1 Initial Conditions		
	AP600 Analysis	**AP1000 Analysis**
Thermal Output of the NSSS (MWt)	1940.	3415.
Tube Plugging Level	10%	10%
Vessel Average Temperature (°F)	567.6	577.0
Reactor coolant flow per loop (gpm)	96600	143500.
Reactor coolant system pressure (psia)	2250.	2250.

Table 3.2-2 Time Sequence of Events For Complete Loss of Reactor Coolant Flow		
	Time, seconds	
Event	**AP600**	**AP1000**
Operating pumps lose power and begin coasting down	0.00	0.0
Reactor coolant pump underspeed trip point reached	0.32	0.556
Rods begin to drop	1.09	1.323
Minimum DNBR occurs	2.80	3.10

Table 3.2-3 DNBR Correlation Limits			
	Correlation Limits		
Parameter	**WRB-2 Correlation**	**WRB-2M Correlation**	**WRB-2 with AP600 Low Flow Multiplier**
Mass Velocity ($lbm/hr\text{-}ft^2$)	≥ 0.9E6	≥ 0.97E6	$0.48 \times 10^6 \leq G \leq 1.04 \times 10^6$
Local Quality	≤ 30%	≤ 29%	≤ 81%

Table 3.2-4 AP600 & AP1000 Values at Point of Minimum DNBR During Complete Loss of Forced RCS Flow Transient

Quantity	AP600	AP1000
DNBR Limit (thimble cell/typical cell)	1.24 / 1.25	1.24 (estimated)
Minimum DNBR (thimble cell/typical cell)	1.394 / 1.484	1.457/1.447
DNBR Margin (thimble cell/typical cell)	11.0% / 15.8%	14.2%/13.6%
Mass Flow (lbm/hr-ft^2) (thimble cell/typical cell)	0.63×10^6 / 0.78×10^6	1.11×10^6/1.23×10^6
Core Exit Quality (thimble cell/typical cell)	26% / 26%	29.0%/28.9%

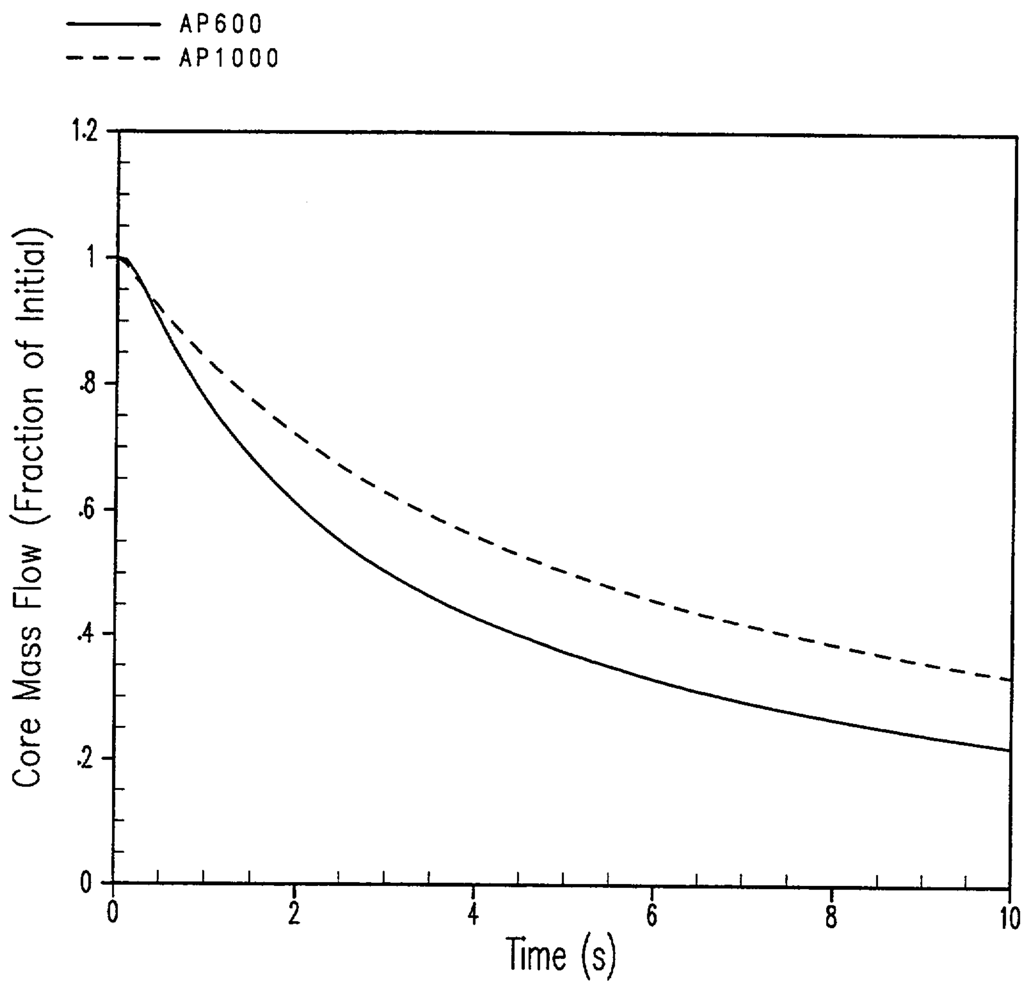


Figure 3.2-1 Core Flow Transient for Four Pumps in Operation, Four Pumps Coasting Down

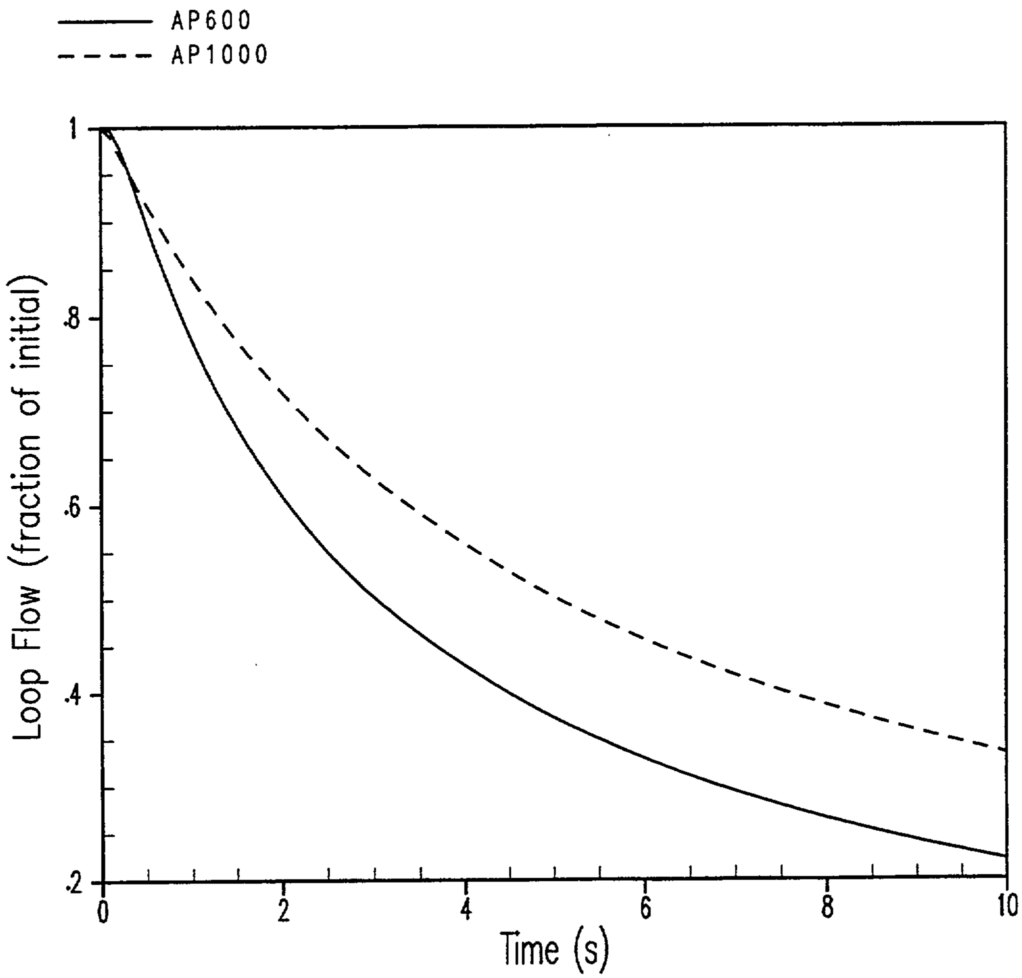


Figure 3.2-2 Loop Flow Transient for Four Pumps in Operation, Four Pumps Coasting Down

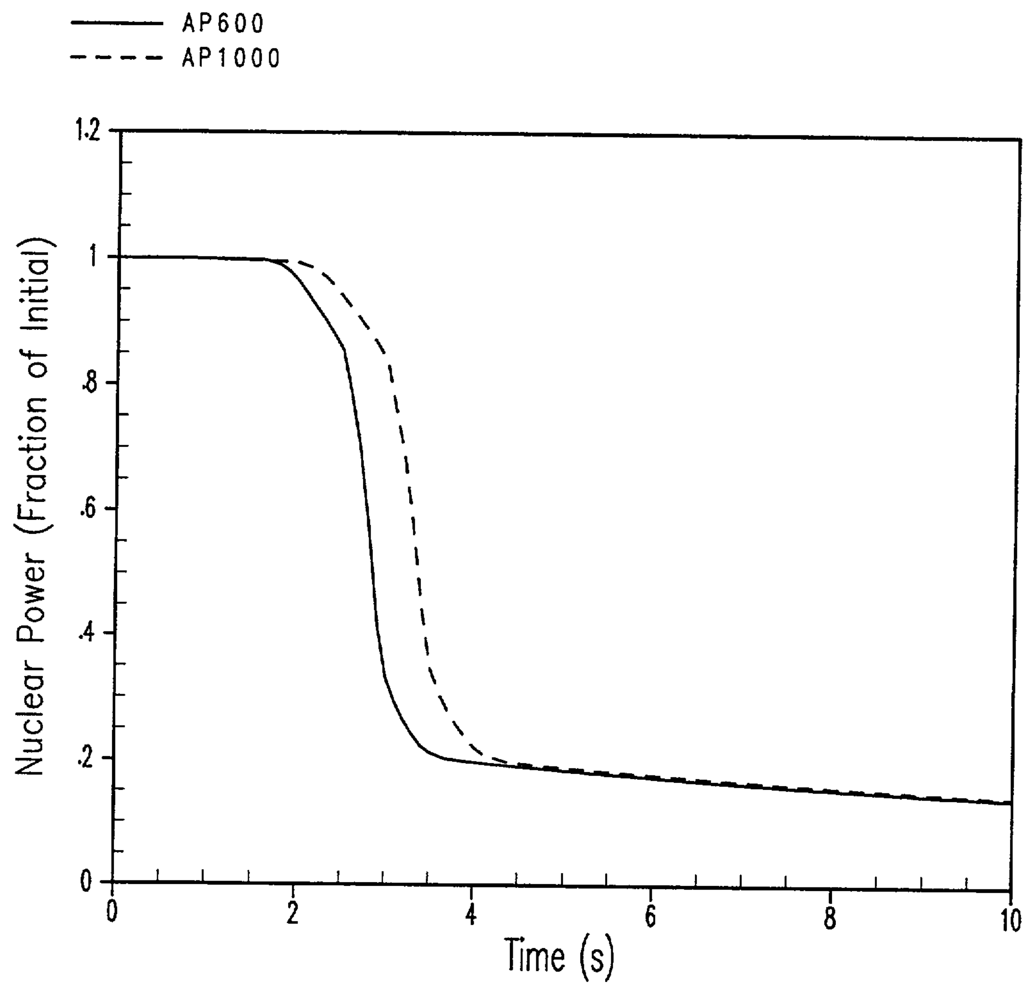


Figure 3.2-3 Nuclear Power Transient for Four Pumps in Operation, Four Pumps Coasting Down

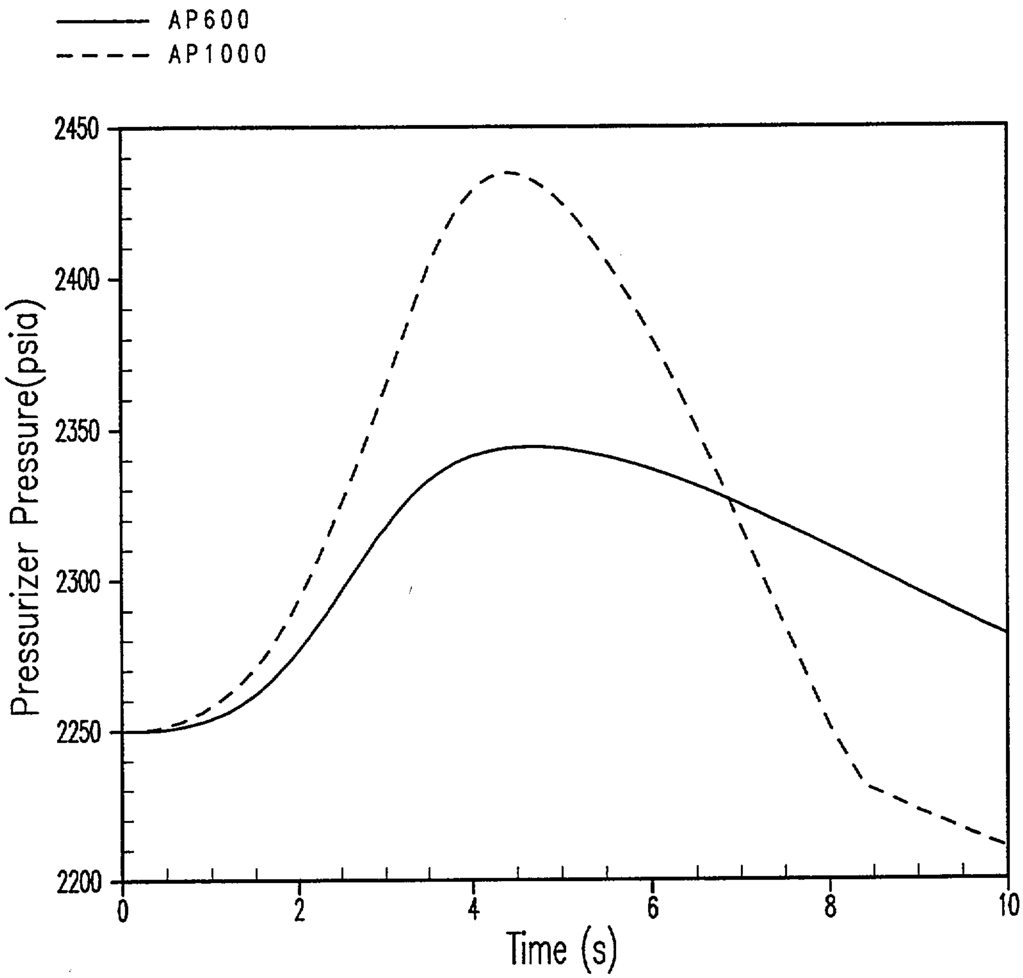


Figure 3.2-4 Pressurizer Pressure Transient for Four Pumps in Operation, Four Pumps Coasting Down

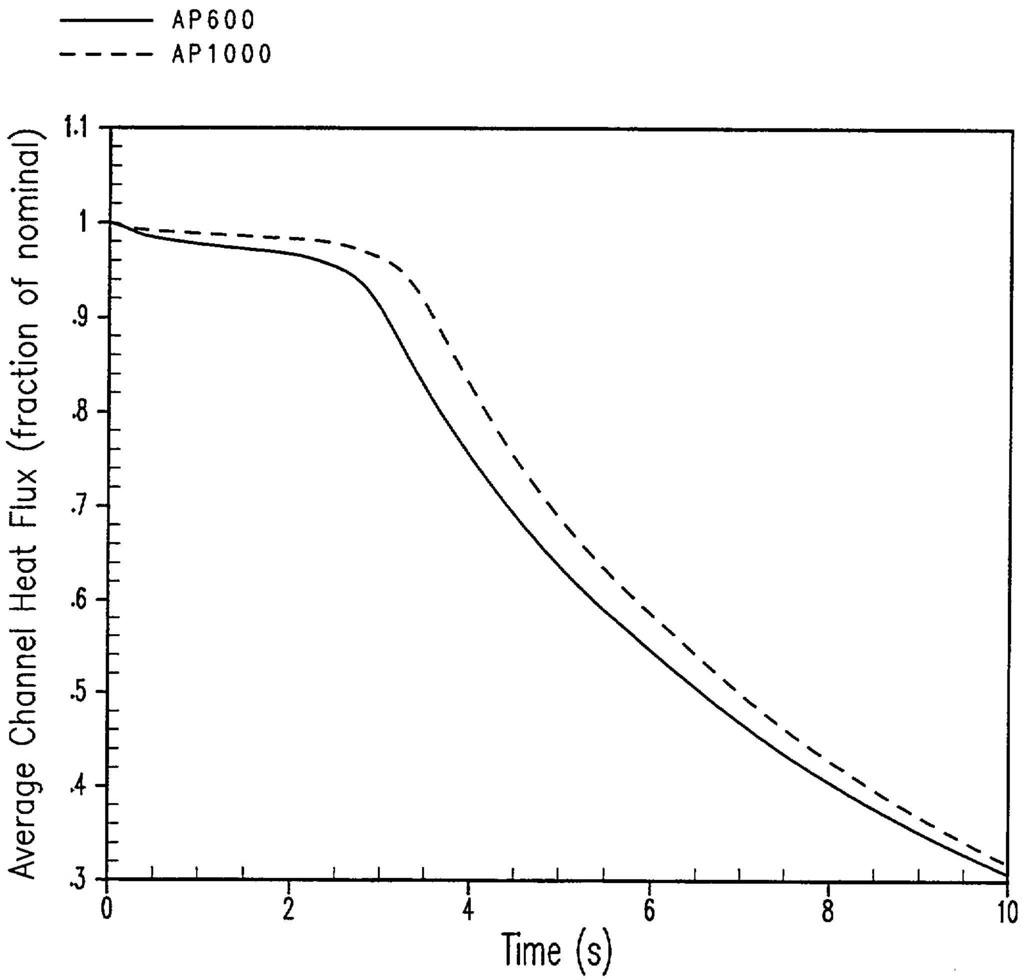


Figure 3.2-5 Average Channel Heat Flux Transient for Four Pumps in Operation, Four Pumps Coasting Down

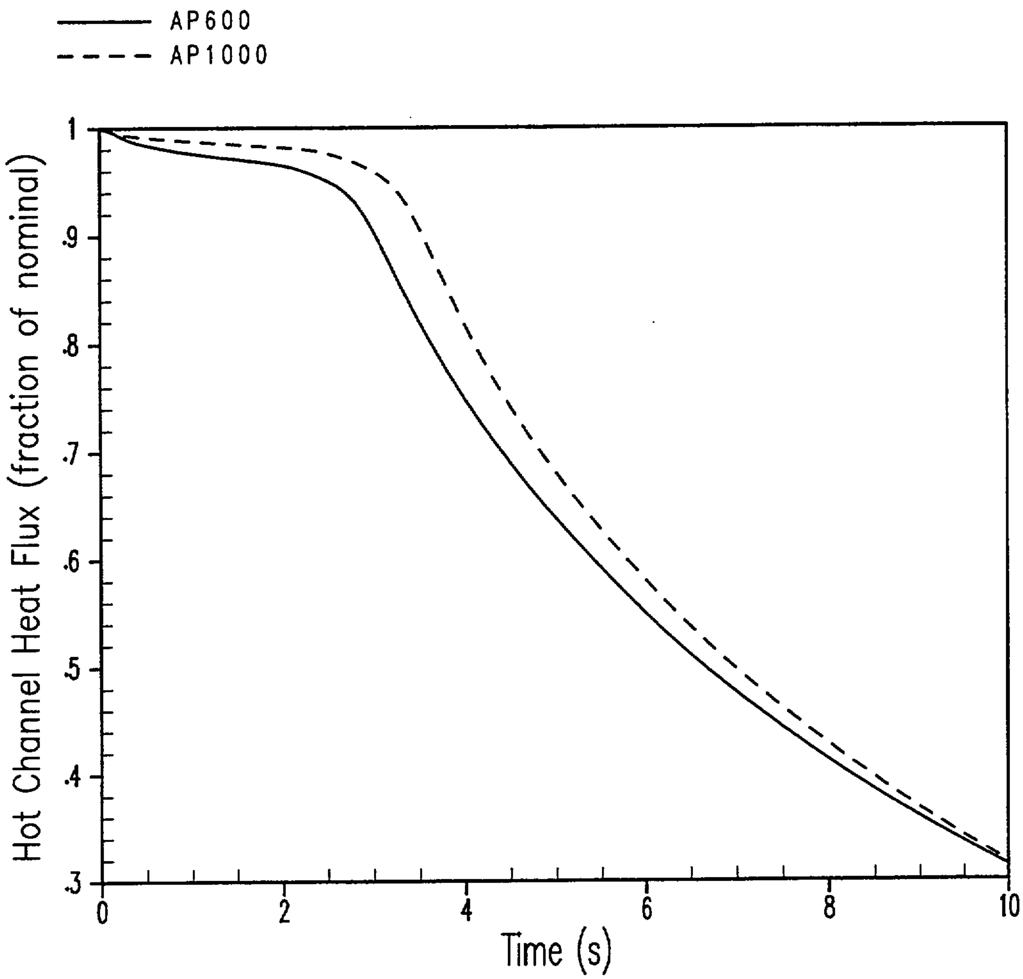


Figure 3.2-6 Hot Channel Heat Flux Transient for Four Pumps in Operation, Four Pumps Coasting Down

3.3 ASSESSMENT OF DECREASE IN REACTOR COOLANT SYSTEM INVENTORY EVENTS

Analyses were presented in the AP600 DCD for a complete set of the limiting events of this type. In this section, analyses for a subset of these events is provided. They have been chosen to provide a representative indication of the performance of the AP1000 passive safety systems in mitigating small break loss of coolant accidents. The events of this type analyzed in this section are:

- A loss-of-coolant accident (LOCA) resulting from a spectrum of postulated piping breaks within the reactor coolant pressure boundary

- A steam generator tube failure

A description of these events and analysis results as well as the method of analysis is discussed below.

3.3.1 Small Break LOCA Analyses

Should a major break occur, depressurization of the reactor coolant system results in a pressure decrease in the pressurizer. The reactor trip signal occurs when the pressurizer low-pressure trip setpoint is reached. An "S" signal is generated when the appropriate setpoint is reached. These measures limit the consequences of the accident in two ways:

- Reactor trip and borated water injection complement void formation in causing rapid reduction of power to a residual level corresponding to fission product decay heat. Insertion of control rods to shut down the reactor is neglected in the large-break analysis.

- Injection of borated water provides core cooling and prevents excessive cladding temperatures.

3.3.1.1 Description of Small-break LOCA Transient

The AP600/AP1000 plant designs include passive safety features to prevent or minimize core uncovery during small-break LOCAs. The passive safety design approaches of the AP600/AP1000 are to depressurize the reactor coolant system if the break or leak is greater than the makeup capability of the makeup system or if the nonsafety makeup system fails to perform. By depressurizing the reactor system, large volumes of borated water in the accumulators and in the IRWST become available for cooling the core. This analysis demonstrates that, with a single failure, the passive systems are capable of depressurizing the reactor coolant system while maintaining acceptable core conditions and establishing stable delivery of cooling water from the IRWST.

During a small-break LOCA, the AP600/AP1000 reactor coolant system depressurizes to the pressurizer low-pressure setpoint, actuating a reactor trip signal. The passive core cooling

system is aligned for delivery following the generation of an "S" signal when the pressurizer low-pressure setpoint is reached. The passive core cooling system includes two core makeup tanks, two accumulators, a large IRWST, and the PRHR heat exchanger.

The core makeup tanks operate at reactor coolant system pressure. They provide high-pressure safety injection in the event of a small-break LOCA. The core makeup tanks share a common discharge line with the accumulators and IRWST; they are filled with borated water to provide core shutdown margin. Gravity head of the colder water in the core makeup tanks provides the injection of the core makeup tanks. The core makeup tanks are located above the reactor coolant loops, and each is equipped with a pressure balancing line from a cold leg to the top of the tank.

The pressurized accumulators provide additional borated water to the reactor coolant system in the event of a LOCA. Nominally, these 2000-ft^3 tanks are filled with 1700 ft^3 of water and 300 ft^3 of nitrogen at an initial pressure of 700 psig. Once sufficient reactor coolant system depressurization occurs, either as a result of a LOCA or the actuation of the ADS, accumulator injection commences.

The IRWST at a minimum provides an additional 590,215 gallons (522,000 for AP600) of water for long-term core cooling. To attain injection from the IRWST, the reactor coolant system pressure must be lowered to approximately 12 psi above containment pressure. For this pressure to be achieved during a small-break LOCA, the ADS system is initiated.

The ADS consists of a series of valves, connected to the pressurizer and hot legs, which provide a phased depressurization of the reactor coolant system. As the reactor system loses inventory through the break, the core makeup tanks provide flow to the reactor vessel. When the level in the core makeup tank drops to the 67.5-percent level, the ADS valves open to accelerate the reactor coolant system depressurization rate. The ADS Stage 1 4-inch valves open at the 67.5-percent level; the 8-inch Stage 2 and the 8-inch Stage 3 valves open in a timed sequence thereafter. The flow from the first three stages of the ADS is discharged into the IRWST through a sparger system. The fourth stages of the ADS are connected to the reactor coolant system hot legs and discharge to containment atmosphere. The ADS Stage 4 valves are activated when the core makeup tank level reaches the 20-percent level.

As the reactor system depressurizes and mass is lost out the break, mass is added to the reactor vessel from the core makeup tanks and the accumulators. When the system is depressurized below the IRWST delivery pressure, flow from the IRWST continues to maintain the core in a coolable state. Calculations described in subsection 3.3.1.4 indicate that acceptable core cooling is provided for the small-break LOCA transients.

3.3.1.2 Small-break LOCA Analysis Methodology

The NOTRUMP computer code is used in the analysis of LOCAs due to small-breaks in the reactor coolant system. The NOTRUMP computer code is a one-dimensional, general network code, which includes a number of advanced features. Among these features are the 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, and regime-dependent heat transfer correlations. The version of NOTRUMP used in AP600/AP1000 small-break LOCA calculations has been validated against applicable passive plant test data (Reference 6).

In NOTRUMP, the reactor coolant system is nodalized into volumes interconnected by flow paths. The transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum applied throughout the system. A description of NOTRUMP is given in WCAP-10079-P-A, WCAP-10080, WCAP-10054-P-A, and WCAP-10081-A (References 3 and 4). The AP600 model is described in WCAP-14601, Revision 1 (Reference 5), and NOTRUMP's applicability to AP600 is documented in WCAP-14206 (Reference 7) and WCAP-14807 (Reference 6). The same methodology will be used for AP1000 except as described later.

The use of NOTRUMP in the analysis involves the representation of the reactor core as heated control volumes with an associated bubble rise model to permit a transient mixture height calculation. The multi-node capability of the program enables an explicit and detailed spatial representation of various system components. Table 3.3.1-1 lists important input parameters and initial conditions of the analysis.

A steady-state input deck for the AP1000 was set up to comply, where appropriate, with the standard small-break LOCA Evaluation Model methodology. Major features of the modeling of the AP600 and AP1000 follow:

- Accumulators are modeled at an initial pressure of 700 psia.
- The flow through the ADS links is modeled using the Henry-Fauske, the homogeneous equilibrium (HEM), and the Murdock/Baumann critical flow models.
- Isolation and check valves used in the passive safety systems are modeled.
- The IRWST is modeled as two connected fluid nodes. The lower node is connected to the direct vessel injection line and is the source of injection water to the DVI lines driven by gravity head. The upper node acts as a sink for the ADS flow from the pressurizer and as a heat sink for the PRHR heat exchanger. These nodes are modeled as having an initial temperature of 120°F, a pressure of 14.7 psia, and the minimum full-power operation level of 28.8 feet (27 feet for AP600). Therefore, the minimum head for IRWST injection is assumed.
- The PRHR system is modeled. The PRHR isolation valve is modeled as opening with the maximum delay of 21.2 seconds after the generation of an "S" signal to conservatively deny the cooling capability of the heat exchanger to the reactor coolant system for an extended period.
- The core power is initially set to 102 percent of the nominal core power. The reactor trip signal occurs when the pressurizer pressure falls below 1800 psia. A conservative delay of 2.4 seconds is modeled between the reactor trip signal and reactor trip. Decay heat is

modeled according to the ANS-1971 (Reference 2) standard, with 20-percent uncertainty added.

- The "S" signal is generated when the pressurizer pressure falls below 1700 psia. The isolation valves on the core makeup tank injection lines begin to open 21.2 seconds after the signal setpoint is reached. The valves are then assumed to open linearly. Core makeup tank injection is conservatively delayed for the maximum time to minimize its contribution to reactor coolant system inventory in the initial stage of larger small-break LOCA. The main feedwater isolation valves are ramped closed between 5 and 10 seconds after the "S" signal. The reactor coolant pumps are tripped 13.3 seconds after the "S" signal.

- The ADS actuation signals are generated on low core makeup tank levels. A list of the ADS parameters is given in Table 3.3.1-2A and B for AP600 and AP1000 respectively. ADS Stages 1, 2, and 3 are modeled as discharging through spargers submerged in the IRWST at the appropriate depth.

- The pressure in the boundary node modeling of the containment is 14.7 psia in all base NOTRUMP cases.

- The steam generator secondary is isolated 1 second after the reactor trip signal, due to closure of the turbine stop valves. This conservatively maximizes steam generator secondary energy. The main steam safety valves actuate and remove energy from the steam generator secondary when pressure reaches 1200 psia (1100 psia for AP600).

Active single failures of the passive safeguards systems are considered. The limiting failure is judged to be one out of four ADS Stage 4 valves failing to open on demand, the failure that most severely impacts depressurization capability. The safety design approach of the AP600 and AP1000 are to depressurize the reactor coolant system to the containment pressure in an orderly fashion such that the large reservoir of water stored in the IRWST is available for core cooling. The mass inventory plots provided for the breaks show the minimum inventory condition generally occurs at the start of IRWST injection. Penalizing the depressurization is the most conservative approach in postulating the single failure for such breaks.

The small-break LOCA spectrum analyzed for AP1000 includes a break that exhibits a minimum reactor vessel inventory early in the transient, before the accumulators become active: the double-ended direct vessel injection (DEDVI) line break. In this transient, the early mass inventory decrease is terminated by injection flow from the intact accumulator, and depressurization through the break enables accumulator injection to begin with no contribution from the actuation of ADS Stages 1, 2, and 3. Therefore, postulated failures among the ADS Stages 1, 2, and 3 valves have no effect on the calculated minimum mass inventory for this case. Assuming that the single failure to occur in the ADS Stage 1 through 3 valves would not cause a change in inventory at the time of accumulator injection for the case analyzed. Therefore, for consistency, the failure of one of the ADS Stage 4 valves located off the PRHR inlet pipe, which adversely affects the depressurization necessary to achieve IRWST injection in small-break LOCAs, is assumed in all cases.

3.3.1.3 AP600/AP1000 Model-Detailed Noding

Refer to WCAP-14601, Revision 1 (Reference 5) for details of the AP600 NOTRUMP modeling. The AP1000 model was developed in the same fashion with modifications to the AP600 methodology being taken where necessary. A modification performed for AP1000 was the addition of two core nodes to reflect the added active fuel length of this design. As opposed to utilizing the IRWST level penalty, which is applied in the latter stages of each NOTRUMP calculation, the ADS-4 flow path resistances were increased to accommodate shortcomings in NOTRUMP identified during the integral test facility simulations, namely, the lack of a detailed momentum flux model in the ADS-4 discharge paths. By increasing the ADS-4 resistances, based on the detailed analysis of the AP600, the onset of IRWST injection is more appropriately calculated. This methodology was demonstrated to be comparable to the SAR document IRWST level penalty modeling and more directly addresses the effect of momentum flux in ADS-4. The assumed ADS-4 resistance increase utilized is identical to that of the AP600 analyses in this study (i.e., 60 percent ADS-4 flow path resistance increase). This value was used for expediency at this time since the ADS-4 flow paths in the AP1000 design have been modified to lessen the effect of momentum flux and the lack of this modeling capability in the NOTRUMP computer code. This value was shown to bound the detailed momentum flux calculation for the AP600 ADS-4 flow paths.

3.3.1.3.1 Plant Initial Conditions/Steady-State

A steady-state calculation is performed prior to initiating the transient portion of the calculation.

Table 3.3.1-1 contains the most important initial conditions for the transient calculations. The behaviors of the primary pressure and pressurizer level, steam generator pressures, and the core flow rate are stable at the end of the 100-second steady-state calculation.

3.3.1.4 Small-break LOCA Analysis Results

Several small-break LOCA transients are analyzed using NOTRUMP, and the results of these calculations are presented. The results demonstrate that the minimum reactor coolant system mass inventory condition occurs for the relatively large system pipe breaks. Smaller breaks exhibit a greater margin-to-core uncovery.

3.3.1.4.1 Introduction

The small-break LOCA safety design approaches for the AP600 and AP1000 are to provide for a controlled depressurization of the primary system if the break cannot be terminated, or if the nonsafety-related charging system is postulated to be lost or cannot maintain acceptable plant conditions. The core makeup tank level activates primary system depressurization. The core makeup tank provides makeup to help compensate for the postulated break in the reactor coolant system. Nonsafety-related systems are not modeled in this design basis analysis; the testing conducted in the SPES-2 facility has indicated that the AP600/AP1000 mass inventory condition during small LOCAs is significantly improved when these nonsafety-related systems

operate. As the core makeup tank level drops, Stages 1 through 4 of the ADS valves are ramped open in sequence. The ADS valve descriptions for the AP600 and AP1000 plant designs are presented in Tables 3.3.1-2A and 3.3.1-2B respectively. The reactor coolant system depressurizes due to the break and the ADS valves, while subcooled water from the core makeup tanks and accumulators enters the reactor vessel downcomer to maintain system inventory and keep the core covered. Design basis maximum values of passive core cooling system resistances are applied to obtain a conservative prediction of system behavior during the small LOCA events.

During depressurization via the ADS, the accumulators and core makeup tanks maintain system inventory for small-break LOCAs. Once the reactor coolant system depressurizes, injection from the IRWST maintains long-term core cooling. For continued injection from the IRWST, the reactor coolant system must remain depressurized. To conservatively model this condition, design maximum resistance values are specified for the IRWST delivery lines.

A controlled depressurization, which occurs while the reactor vessel receives accumulator and core makeup tank injection, occurs during small-break LOCAs. A series of small-break LOCA calculations are performed to assess the AP1000 passive safety system design performance. In these calculations, the decay heat used is the ANS-1971 (Reference 2) plus 20 percent for uncertainty as specified in 10 CFR 50, Appendix K (Reference 1). Its use maximizes the core steam generation to be vented. The breaks analyzed in this document include the following:

Inadvertent ADS Actuation

A "no-break" small-break LOCA calculation that uses an inadvertent opening of the 4-inch nominal size ADS Stage 1 valves is a situation that minimizes the venting capability of the reactor coolant system. Only the ADS valve vent area is available; no additional vent area exists due to a break. This case examines whether sufficient vent area is available to completely depressurize the reactor coolant system and achieve injection from the IRWST without core uncovery. The worst single failure for this situation is a failure of one of four ADS Stage 4 valves connected to either of the two hot legs. The ADS Stage 4 valve is the largest ADS valve, and it vents directly to the containment with no additional backpressure (as in the first three stages of the ADS).

2-inch Break in a Cold Leg with Core Makeup Tank Balance Line Connections

The small size of the break leads to a long period of recirculatory flow from the cold leg into the core makeup tank. This delays the formation of a vapor space in the core makeup tank and therefore the actuation of the ADS.

Double-ended Rupture of the Direct Vessel Injection Line

The injection line break evaluates the ability of the plant to recover from a moderately large-break with only half of the total emergency core cooling system capacity available. The vessel side of the break of the DEDVI line break is 4 inches in equivalent diameter. The double-ended nature of this break means that there are effectively two breaks modeled:

- Downcomer to containment. The direct vessel injection nozzle includes a venturi, which limits the available break area.

- Cold leg to containment via the cold leg balance line and the broken loop core makeup tank.

To assess the effect of containment pressurization during this transient, a sensitivity study was performed in which the containment pressure was conservatively assumed to pressurize to 25 psia. This pressure was selected based on iterative execution of the NOTRUMP and WGOTHIC codes. The NOTRUMP code provides the mass and energy releases from the AP1000 DEDVI break to the AP1000 WGOTHIC containment model while the WGOTHIC code calculates the containment pressure response. The containment pressure assumed in the NOTRUMP simulations was conservatively selected from the generated pressure history curves obtained from the WGOTHIC runs.

3.3.1.4.2 Transient Results

The transient results will compare the AP1000 and AP600 plant responses. The generated tables and figures will be in the form of comparisons of the key AP600/AP1000 parameters of interest. The following sections detail the responses observed for each transient performed. Note that the mixture level comparison plots presented (AP600 vs. AP1000) are offset by the difference in vessel height between the two designs such that the top of the core for both designs are aligned. Note that due to the physical plant size and power level differences between the two designs, it is expected that a given AP600 break performed will respond like a smaller break for the AP1000 design. As such, it is expected that event timings will be shifted (i.e., delayed) relative to AP600. Should a comparable response be desired, it would be necessary to increase the AP1000 break size to achieve this result.

3.3.1.4.2.1 Inadvertent Actuation of Automatic Depressurization System

An inadvertent ADS signal is spuriously generated and the 4-inch ADS valves open. The plant, which is operating at 102-percent power, is depressurized via the ADS alone. Only safety-related systems are assumed to operate in this and other small-break LOCA cases. Additional ADS valves open; after a 70-second delay, the ADS Stage 2 8-inch valves open, and after an additional 120 seconds, the ADS Stage 3 valves open. At the 20-percent core makeup tank level, the ADS Stage 4 valves, which connect to the hot legs, receive signals to open. Two ADS Stage 4 paths are assumed to open in one of the two loops. The path that fails to open as the assumed single active failure is the Stage 4A valve off the PRHR inlet pipe. The reactor steady-state initial conditions assumed can be found in Table 3.3.1-1. The sequence of events for the transient is given in Table 3.3.1-3.

The transient is initiated by the opening of the two ADS Stage 1 paths. The total throat area of the valves is 9.2 in^2. Reactor trip, reactor coolant pump trip, and safety injection signals are generated via a pressurizer low-pressure signal with appropriate delays. After generation of the reactor trip signal, the turbine stop valves begin to close. The main feedwater isolation valves begin to close 5 seconds after the "S" signal pressure setpoint is reached. The opening of

the ADS valves and the reduction in core power due to reactor trip causes the primary pressure to fall rapidly (Figure 3.3.1.4-1). Flow of fluid toward the open ADS paths causes the pressurizer to fill rapidly (Figure 3.3.1.4-2), and the ADS flow becomes two-phase (Figures 3.3.1.4-3 and -4). The safety injection signal opens the valves isolating the core makeup tanks and injection of cold water begins (Figures 3.3.1.4-5 and -6). The mixture level in the core makeup tanks is relatively constant until the accumulators inject (Figures 3.3.1.4-7 and -8). The reactor coolant pumps begin to coast down due to an automatic trip signal following a 13.3-second delay.

Continued mass flow through the ADS Stage 1, 2, and 3 valves drains the upper parts of the circuit. The steam generator tube cold leg sides start to drain at about 110 seconds (90 seconds for AP600), followed by the mixture levels in the hot leg sides. As the ADS Stage 2 and 3 paths (21 in^2 throat area each) begin to open, increased ADS flow causes the primary pressure to fall rapidly (Figure 3.3.1.4-1). At about 160 seconds (140 seconds for AP600), following the emptying of the steam generator tube cold leg sides, the cold legs have drained and a mixture level forms in the downcomer (Figure 3.3.1.4-9).

At about 285 seconds (225 seconds for AP600), the primary pressure falls below the pressure in the accumulators, causing the accumulator check valves to open and accumulator delivery to begin (Figures 3.3.1.4-10 and -11). The accumulators continue to inject until ~900 seconds (584 seconds for AP600). Each core makeup tank injects until it empties. The ADS flow falls off as the primary pressure decreases. The flow from the accumulators raises the mixture levels in the upper plenum and downcomer (Figures 3.3.1.4-16 and 3.3.1.4-9).

At 1680 seconds (1818 seconds for AP600), the levels in the core makeup tanks reach the ADS Stage 4 setpoint. One out of two paths are opened from the top of the hot leg (loop 1) and begin discharging fluid. This path has an area of 67 in^2 (38 in^2 for AP600); 30 seconds later, the second path in loop one opens, as does a loop 2 Stage 4 path. Activating the Stage 4 paths leads to reduced flow from ADS Stages 1, 2, and 3. The reduced flow allows the pressurizer level to fall, and these stages begin to discharge only steam. By 2300 seconds (2271 seconds for AP600), both core makeup tanks are empty and delivery ceases (Figures 3.3.1.4-7 and -8). By 2620 seconds (3900 seconds for AP600), the reactor coolant system pressure has fallen sufficiently due to the total flow through the ADS Stage 4 flow paths (Figure 3.3.1.4-12) to allow gravity drain from the IRWST to begin (Figures 3.3.1.4-13 and -14). The time duration between CMT empty and IRWST injection start has been reduced in the AP1000 design due to changes in the initial IRWST water level and the increased capacity of the ADS-4 valves themselves. At 5000 seconds, the calculation was considered complete; IRWST delivery exceeds the ADS flows (which are removing the decay heat), and the reactor coolant system inventory is slowly rising (Figure 3.3.1.4-15). Core uncovery does not occur and the upper plenum mixture level remains well above the core elevation throughout (Figure 3.3.1.4-16).

The inadvertent opening of the ADS Stage 1 transient confirms the minimum venting area capability to depressurize the reactor coolant system to the IRWST pressure. The analysis indicates that the ADS sizing is sufficient to depressurize the reactor coolant system even assuming the worst single failure of a Stage 4 ADS path failing to open and decay heat equal to the 10 CFR 50 Appendix K (Reference 1) value of the ANS-1971 Standard (Reference 2) plus

20 percent, which over estimates the core steam generation rate. Even under these limiting conditions, IRWST injection is obtained, and the core remains covered such that no cladding heatup occurs.

3.3.1.4.2.2 2-inch Cold Leg Break in the Core Makeup Tank Loop

This case models a 2-inch break occurring in the balance line loop leg at the bottom of the pipe. The reactor steady-state conditions initial conditions assumed for this transient can be found in Table 3.3.1-1. The event times for this transient are given in Table 3.3.1-4.

The break opens at time zero, and the pressurizer pressure begins to fall as shown in Figure 3.3.1.4-17 as mass is lost out the break. The pressurizer mixture level initially decreases as given in Figure 3.3.1.4-18. The break fluid flow is shown in Figures 3.3.1.4-32 and -33. The pressurizer pressure falls below the safeguards set point, causing the reactor to trip and closing the steam generator isolation valves. The core makeup tank isolation valves on both delivery lines and the PRHR delivery line open after an "S" signal occurs; the reactor coolant pumps trip after an "S" with a 13.3-second delay. The reactor coolant system is cooled by natural circulation with the steam generators removing the energy through their safety valves (as well as by the break) and via the PRHR. Differences in the lift setpoints of the main steam-line safety valves result in an increase in the equilibrium pressure obtained for the AP1000 design relative to the AP600. Once the core makeup tank isolation valves open, the core makeup tanks begin to inject borated water into the reactor coolant system as shown in Figures 3.3.1.4-22 and -23. As observed, the AP1000 drain behavior is significantly delayed relative to the AP600 due to the increased size of the AP1000 plant. As such, the 2-inch cold leg break behaves like a smaller break in the AP600 resulting in decreased CMT drain and subsequently delayed ADS actuation. Note that reduced re-circulation rates are observed in the AP1000 simulation results. The observed behavior is driven by pressure fluctuations in the DVI line which cause intermittent closure of the CMT check valves. The closure of these check valves induces pressure oscillations in the system, which impede the ability of the CMTs to continuously re-circulate and delays the onset of CMT draining. Such behavior was exhibited in the AP600 0.5-inch cold leg break presented in the DCD.

As time proceeds, the loops drain to the reactor vessel. The hot leg sides of the steam generator tubes drain through about 1300 seconds (800 seconds for AP600), while the cold leg sides drain completely by 900 seconds (600 seconds for AP600). The mixture level in the downcomer begins to drop rapidly at about 420 seconds (350 seconds for AP600) as seen in Figure 3.3.1.4-30, and the core remains completely covered. The core makeup tank reaches the 67.5-percent level at ~2640 seconds (1080 seconds for AP600), and after an appropriate delay, the ADS Stage 1 valves open. When the ADS is actuated, the mixture level increases in the pressurizer (Figure 3.3.1.4-18) because an opening has been created at the top of the pressurizer. After these valves open, a more rapid depressurization occurs as seen in Figure 3.3.1.4-17; the accumulator setpoint is reached at 2760 seconds (1200 seconds for AP600) and the accumulators begin to inject. The injection flow from the core makeup tank is shown in Figures 3.3.1.4-22 and -23, and from the accumulator, in Figures 3.3.1.4-24 and -25.

As Figures 3.3.1.4-22 and -23 indicate, when the accumulators begin to inject the flow from the intact loop core makeup tank is reduced, and the flow is stopped due to the pressurization of the core makeup tank injection line by the accumulator.

The ADS Stage 2 valves open at 2720 seconds (1208 seconds for AP600), maintaining the depressurization rate as shown in Figure 3.3.1.4-17. At 2910 seconds (1328 seconds for AP600), ADS Stage 3 valves open, thereby increasing the system venting capability. The first ADS Stage 4 valve opens at 3941 seconds (2522 seconds for AP600). The additional ADS Stage 4 valves open 30 seconds later. Figures 3.3.1.4-28 and -31 indicate the instantaneous liquid and integrated total mass discharged from the ADS Stage 4 valves. After the ADS Stage 4 path opens, the pressurizer begins to drain mixture into the hot legs as seen in Figure 3.3.1.4-18. The Figure 3.3.1.4-29 mass inventory plot considers the primary inventory to be the reactor coolant system proper, including the pressurizer; the mass present in the passive safety system components is not included at time zero. At 4500 seconds (3560 seconds for AP600), the downcomer pressure drops below the IRWST injection pressure such that flow enters the reactor vessel from the IRWST. The mixture level in the reactor vessel is approximately at the hot leg elevation as shown in Figure 3.3.1.4-30 throughout this transient; the core never uncovers, and the peak cladding temperature occurs for this transient at the inception of the event. The 2-inch break cases exhibit large margin-to-core uncovery.

3.3.1.4.2.3 Direct Vessel Injection Line Break (Nominal Containment Pressure)

This case models the double-ended rupture of the DVI line at the nozzle into the downcomer. The broken loop injection system (consisting of an accumulator, a core makeup tank, and an IRWST delivery line) is modeled to spill completely out the DVI side of the break. The steady-state reactor coolant system conditions for this transient are shown in Table 3.3.1-1. Design maximum resistances are applied to the inlet and outlet lines of that core makeup tank to conservatively minimize intact loop core makeup tank delivery through the time of minimum reactor coolant system mass inventory.

The event times for this transient are shown in Table 3.3.1-3. The break is assumed to open instantaneously at 0 seconds. The accumulator on the broken loop starts to discharge via the DVI line to the containment. Figure 3.3.1.4-36 shows the subcooled discharge from the downcomer nozzle, which causes a rapid reactor coolant system (RCS) depressurization (Figure 3.3.1.4-38). A reactor trip signal is generated at 15.3 seconds (8.5 seconds for AP600). The delay in achieving the trip signal is due to the differences in initial operating conditions between the AP600 and the AP1000 designs. With a conservative delay of 2.4 seconds, reactor trip occurs at 17.7 seconds (10.9 seconds for AP600). The "S" signal is generated at 20.6 seconds (10.3 seconds for AP600) and following a delay, the isolation valves on the core makeup tank and PRHR delivery lines begin to open. The "S" signal also causes closure of the main feedwater isolation valves after a 5-second delay and trips the reactor coolant pumps after a 16.2-second delay. The opening of the core makeup tank isolation valves allows the broken loop core makeup tank to discharge directly to the containment (Figure 3.3.1.4-39), and a small circulatory flow develops through the intact loop core makeup tank (Figure 3.3.1.4-40).

As the pressure falls, the reactor coolant system fluid saturates, and at about 40 seconds, a mixture level forms in the upper plenum and then falls to the hot leg elevation (Figure 3.3.1.4-41). The upper parts of the reactor coolant system start to drain, and a mixture level forms in the downcomer at about 140 seconds (Figure 3.3.1.4-42) and falls below the elevation of the break. Two-phase discharge, then vapor flow occurs from the downcomer side of the break (Figure 3.3.1.4-37).

At about 100 seconds in the broken loop core makeup tank, a level forms and starts to fall. The ADS Stage 1 setpoint is reached, and the ADS Stage 1 open valves after the signal delay time elapses. The ensuing steam discharge from the top of the pressurizer (Figure 3.3.1.4-43) increases the reactor coolant system depressurization rate. The depressurization rate is also increased due to the steam discharge from the downcomer to the containment (Figure 3.3.1.4-37) as the downcomer mixture level falls below the DVI nozzle (Figure 3.3.1.4-42).

During the initial portion of the DEDVI break, only liquid flows out the top of the core (Figure 3.3.1.4-45). Soon, steam flows out also (Figure 3.3.1.4-46) because the void fraction in the core increases (Figure 3.3.1.4-44). From about 115 seconds, the break in the downcomer draws fluid from the bottom of the core (Figure 3.3.1.4-47) and insufficient liquid remains in the core and upper plenum to sustain the mixture level. The mixture level therefore starts to decrease (Figure 3.3.1.4-41). The mixture level falls to a minimum and then starts to recover, as flow re-enters the core from the downcomer (Figure 3.3.1.4-41 compared to -47). Due to the higher initial RCS inventory of the AP1000 design, the minimum inventory that occurs during the blowdown phase is reduced by approximately 30,000 lb relative to AP600 since the vessel side break size is unaltered. As such, the minimum downcomer mixture level and RCS inventory that occurs for the AP1000 during the blowdown period is reduced relative to the AP600 design.

The ADS Stage 2 valves open at 320.3 seconds (323 seconds for AP600) because of the time delay of 70 seconds between the actuation of the first two stages of the ADS. At about 280 seconds (230 seconds for AP600), the intact loop accumulator starts to inject into the downcomer (Figure 3.3.1.4-50) causing the mixture level in the downcomer to slowly rise (Figure 3.3.1.4-42). The mixture level also increases within the upper plenum.

The ADS Stage 3 valves open upon completion of the time delay of 120 seconds between the actuation of Stages 2 and 3 of the ADS. At ~220 seconds, the broken loop core makeup tank level reaches the ADS Stage 4 setpoint, but the ADS Stage 4 valves do not open until 560 seconds (563 seconds for AP600) because of the minimum time delay between the actuation of ADS Stages 3 and 4. Two-phase discharge ensues through three of the four Stage 4 paths (Figures 3.3.1.4-48 and -49). The broken loop core makeup tank empties continuously, and by 460 seconds (370 seconds for AP600), the broken loop accumulator has emptied.

At about 380 seconds (250 seconds for AP600), the fluid level at the top of the intact loop core makeup tank starts to decrease slowly (Figure 3.3.1.4-52) because injection from the tank has begun (Figure 3.3.1.4-40). By 681 seconds (597 seconds for AP600), the intact loop accumulator has emptied (Figure 3.3.1.4-50) and the reduced pressure in the injection line allows the core makeup tank to inject continuously.

During the period of accumulator injection (280 – 680 seconds), the downcomer mixture level rises slowly (Figure 3.3.1.4-42). Since the AP1000 accumulator design is unaltered relative to the AP600, the RCS inventory/downcomer mixture level recovery that results from accumulator injection is smaller for the AP1000 design (Figure 3.3.1.4-53). With only intact loop core makeup tank injection available after 680 seconds, the downcomer level once again falls, as does the RCS inventory. However, the level in the upper plenum is maintained near the hot leg elevation (Figure 3.3.1.4-41) throughout the remainder of transient. As expected, the higher power output of the AP1000 design results in higher core exit void fractions than experienced by the AP600 design (Figure 3.3.1.4-44).

At about 600 seconds (520 seconds for AP600), the pressure in the broken DVI line falls below that in the IRWST and water from the tank is spilled to the containment.

Stable, but decreasing, injection continues from the intact loop core makeup tank as the reactor coolant system pressure declines slowly. After the intact loop core makeup tank empties (Figure 3.3.1.4-52), the reactor coolant system pressure continues to fall until it drops below that of the IRWST, and injection begins (Figure 3.3.1.4-51). Due to differences in the initial IRWST tank water level and ADS-4 capacities between AP600 and AP1000, the time delay between CMT empty and IRWST injection is shortened for the AP1000 design. The increased power production of the AP1000 results in higher core vapor boil-off rates (Figure 3.3.1.4-46) requiring higher injection flows to maintain RCS inventory at levels comparable to the AP600 design. Once CMT injection terminates, core boil-off increases the rate of RCS inventory depletion until sufficient IRWST injection flow can be introduced. With the reduced initial RCS inventory recovery from the accumulators and only a single intact injection path available for the DEDVI line break, the minimum inventory time is shifted from the pre-accumulator injection to post stable IRWST injection flow period. After 2600 seconds, stable injection flow greater than the sum of the break and ADS flows exists, resulting in a slow rise in the reactor coolant system inventory (Figure 3.3.1.4-53). Since no core uncovery is predicted for this scenario, the PCT for this break occurs at time zero.

3.3.1.4.2.4 Direct Vessel Injection Line Break (25 psia Containment Pressure)

This case is similar to the DEDVI transient performed in Section 3.3.1.4.2.3 except that the containment backpressure is defined to be a constant 25 psia. While not exactly reflecting the containment pressure history that occurs as a result of the DVI line break, it represents a conservatively low estimate of the expected containment pressure response during a DEDVI transient. This case was performed to demonstrate the expected behavior of IRWST injection under containment pressurization scenarios. The containment is expected to pressurize for a DEDVI break as a result of the break mass and energy releases in addition to the ADS-4 discharge paths that vent directly to the containment atmosphere. This scenario also demonstrates that the RCS minimum inventory time would shift back to the initial blowdown phase of the transient as opposed to the long-term boil-off phase as seen in the base AP1000 DEDVI line break.

The containment pressurization was estimated based on iterative calculations between the NOTRUMP small break LOCA code and the WGOTHIC containment model. Mass and energy

releases from both sides of the DVI break (both vessel side and DVI side) and ADS-4 valve discharges were provided in a tabular form to the WGOTHIC AP1000 containment model. These releases were provided for both the nominal containment and 25 psia containment pressurization assumptions. The containment pressurization was determined to equilibrate at approximately 38 psia, which is much higher than the containment pressure assumed for this simulation. As such, it is expected that the behavior observed in this simulation would improve relative to the base case with higher predicted RCS inventories being observed and earlier IRWST injection being predicted.

Table 3.3.1-5 presents the sequence of events comparison between the DEDVI line break assuming a 25-psia containment backpressure vs. the nominal 14.7 psia containment backpressure case. No major changes in transient timing other than the intact CMT empty time and IRWST injection start times are observed. This is as expected since with containment pressurization assumed, IRWST injection can occur at correspondingly higher RCS pressures. As a result, intact loop IRWST injection is predicted co-incident with intact CMT injection thereby delaying the time at which the intact CMT empties. A series of comparison plots are presented in Figures 3.3.1.4-56 through 3.3.1.4-72. A summary of the major changes in predicted transient response is summarized below.

- The RCS pressure response following ADS-4 activation is consistent with the assumed containment pressurization with the pressurizer pressure remaining ~3 psia above the containment pressurization assumed (Figure 15-6.5.4-56).

- The higher containment backpressure affects the ADS 1-3 discharge rates (Figure 3.3.1.4-68) resulting in a more rapid draining of the pressurizer following ADS-4 actuation (Figure 3.3.1.4-57).

- Improved downcomer mixture level relative to the base AP1000 simulation (Figure 3.3.1.4-68) resulting in improved core mixture level behavior (Figure 3.3.1.4-58) and reduced core exit void fractions (Figure 3.3.1.4-59).

- Earlier IRWST injection (Figure 3.3.1.4-71) resulting in a shift in the RCS minimum inventory time from the long-term boil-off phase to the initial blowdown phase (Figure 3.3.1.4-72).

As can be summarized from the above and a review of the selected figures, the response to a double-ended DVI line break can be significantly improved should one model the correct containment pressurization characteristics which occur as a result of a DVI line break.

3.3.1.5 Conclusions

The small break LOCA break simulations continue to exhibit significant margin to core uncovery for the AP1000 design relative to the AP600 model. The minimum reactor coolant system mass inventory condition among the small-break LOCA cases analyzed occurs for the DEDVI line.

The analyses performed show that the passive safeguards systems in the AP1000 are sufficient to mitigate LOCAs. Specifically, it is concluded that:

- The primary side can be depressurized by the ADS to allow stable injection into the core.
- Injection from the core makeup tanks, accumulators, and IRWST prevents any cladding heatup for small-break LOCA, including double-ended ruptures in the passive safeguards system lines.

The analyses performed demonstrate that the 10 CFR 50.46 Acceptance Criteria are met by the AP1000. Summarizing the small-break LOCA spectrum:

Break Location/Diameter	AP600 Minimum RCS Inventory	AP1000 Minimum RCS Inventory
Inadvertent ADS	98,200	107,700
2-inch cold leg cases	127,000	127,150
DEDVI (Nominal Containment pressure)	78,000	102,000
DEDVI (25 psia Containment pressure)	Not analyzed	110,600

The DEDVI breaks exhibit the limiting minimum inventory conditions. The AP1000 design is such that with a nominal containment pressure of 14.7 psia assumed, the minimum inventory time has shifted to the pre IRWST injection period as opposed to the initial blowdown period and is due largely to the DVI flow restricting nozzle being identical to the AP600 design. As such, the resulting DVI line break behaves like a smaller break for the AP1000 design. Accounting for the effects of containment pressurization resulting from the double-ended DVI line break results in the minimum inventory time occurring during the initial blowdown period with a significant improvement in the calculated minimum system inventory. All breaks simulated in the break spectrum produce results that continue to demonstrate large margins to core uncovery.

3.3.1.6 References

1. 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors," and Appendix K to 10 CFR 50, "ECCS Evaluation Models."

2. American Nuclear Society Proposed Standard, ANS 5.1 "Decay Energy Release Rates Following Shutdown of Uranium-Cooled Thermal Reactors," October (1971), Revised October (1973).

3. Meyer, P. E., "NOTRUMP - A Nodal Transient Small-Break and General Network Code," WCAP-10079-P-A, (Proprietary) and WCAP-10080-A (Nonproprietary), August 1985.

4. Lee, N., Rupprecht, S. D., Schwarz, W. R., and Tauche, W. D., "Westinghouse Small-Break ECCS Evaluation Model Using the NOTRUMP Code," WCAP-10054-P-A (Proprietary) and WCAP-10081-A (Nonproprietary), August 1985.

5. Kemper, R. M., "AP600 Accident Analyses – Evaluation Models," WCAP-14601, Revision 2 (Proprietary), June 1998.

6. "NOTRUMP Final Validation Report for AP600," WCAP-14807, Revision 5, (P), August 1998.

7. Kemper, R. M., "Applicability of the NOTRUMP Computer Code to AP600 SSAR Small-Break LOCA Analyses," WCAP-14206 (Proprietary), November 1994.

Table 3.3.1-1 Initial Conditions				
	AP600		AP1000	
Condition	Calculation	Nominal Steady-state	Calculation	Nominal Steady-state
Pressurizer pressure (psia)	2250	2250	2256	2250
Vessel inlet temperature (°F)	528.8	528.7	529.2	529.7
Vessel outlet temperature (°F)	599.9	600	617.6	617.9
Vessel flow rate (lb/sec)	20106	20311	29716	29709
Steam generator pressure (psia)	764	794	717.8	807.5

Table 3.3.1-2A AP600 ADS Parameters					
Actuation Signal (percentage of core makeup tank level)		Earliest Actuation Time (seconds)	Minimum Valve Flow Area (for each path, in^2)	Number of Paths	Valve Opening Time (seconds)
Stage 1 – Control – Isolation	67.5		4.6	2 out of 2	≤ 30 ≤ 20
Stage 2 – Control – Isolation	67.5	70 after Stage 1	21	2 out of 2	≤ 80 ≤ 30
Stage 3 – Control – Isolation	67.5	120 after Stage 2	21	2 out of 2	≤ 80 ≤ 30
Stage 4A	20	120 after Stage 3	38	1 out of 2	≤ 30
Stage 4B	20	30 after Stage 4A	38	2 out of 2	≤ 30

Table 3.3.1-2B AP1000 ADS Parameters					
Actuation Signal (percentage of core makeup tank level)		Earliest Actuation Time (seconds)	Minimum Valve Flow Area (for each path, in^2)	Number of Paths	Valve Opening Time (seconds)
Stage 1 – Control – Isolation	67.5		4.6	2 out of 2	≤ 30 ≤ 20
Stage 2 – Control – Isolation	67.5	70 after Stage 1	21	2 out of 2	≤ 80 ≤ 30
Stage 3 – Control – Isolation	67.5	120 after Stage 2	21	2 out of 2	≤ 80 ≤ 30
Stage 4A	20	120 after Stage 3	67	1 out of 2	≤ 3
Stage 4B	20	30 after Stage 4A	67	2 out of 2	≤ 3

Table 3.3.1-3 Inadvertent ADS Depressurization Sequence of Events		
Event	AP600 Time (seconds)	AP1000 Time (seconds)
Inadvertent opening of the ADS valves	0.0	0.0
Reactor trip signal	28.3	37.7
Steam turbine stop valves close	29.3	38.7
"S" signal	31.9	43.7
Main feed isolation valves begin to close	36.9	48.7
Reactor coolant pumps start to coast down	48.1	59.9
ADS Stage 2	70.0	70.0
ADS Stage 3	190.0	190.0
Accumulator injection starts	225	280
Accumulator empties	584	1700*
ADS Stage 4	1818	1680
Core makeup tank empty	2271	2300
IRWST injection starts	3900	2620

*Although not truly empty until this time, the accumulators are effectively empty at 930 seconds

Table 3.3.1-4 2-Inch Cold Leg Break in CLBL Line Sequence of Events		
	AP600	**AP1000**
Event	**Time (seconds)**	**Time (seconds)**
Break opens	0.0	0.0
Reactor trip signal	33.3	8.3
Steam turbine stop valves close	34.3	59.3
"S" signal	39.5	64.9
Main feed isolation valves begin to close	44.5	69.9
Reactor coolant pumps start to coast down	55.7	81.1
ADS Stage 1	1138	2719.6
Accumulator injection starts	1200	2760
ADS Stage 2	1208	2719.6
ADS Stage 3	1328	2909.6
Accumulator empties	1575	3183
ADS Stage 4	2522	3941.4
Core makeup tank empty	2920	4240
IRWST injection starts	3560	4500

Table 3.3.1-5 Double-Ended Injection Line Break Sequence of Events		
	AP600	AP1000
Event	Time (seconds)	Time (seconds)
Break opens	0.0	0.0
Reactor trip signal	8.5	15.3
Steam turbine stop valves close	9.5	16.3
"S" signal	10.3	20.6
Main feed isolation valves begin to close	15.3	25.6
Reactor coolant pumps start to coast down	26.5	36.8
Accumulator injection starts	230	280
ADS Stage 1	253	250.3
ADS Stage 2	323	320.3
ADS Stage 3	443	440.3
ADS Stage 4	563	560.3
Accumulator empties	597	681
Intact loop core makeup tank empties	2010	2066
IRWST injection starts	2805	2340

Table 3.3.1-6 Double-Ended Injection Line Break Sequence of Events		
	AP1000 Nominal Containment	AP1000 w/25 psi Back-pressure
Event	Time (seconds)	Time (seconds)
Break opens	0.0	0.0
Reactor trip signal	15.3	15.3
Steam turbine stop valves close	16.3	16.3
"S" signal	20.6	20.6
Main feed isolation valves begin to close	25.6	25.6
Reactor coolant pumps start to coast down	36.8	36.8
Accumulator injection starts	280	280
ADS Stage 1	250.3	245.7
ADS Stage 2	320.3	315.7
ADS Stage 3	440.3	435.7
ADS Stage 4	560.3	560.3
Accumulator empties	681	676.7
Intact loop core makeup tank empties	2066	2194
IRWST injection starts	2340	1230

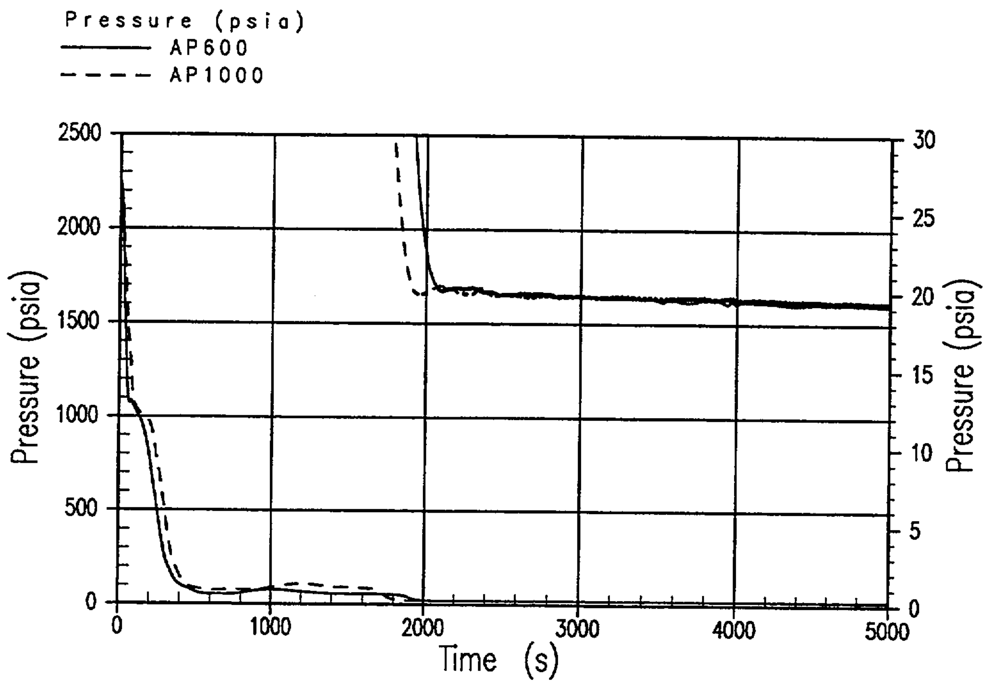


Figure 3.3.1.4-1 Inadvertent ADS RCS Pressure

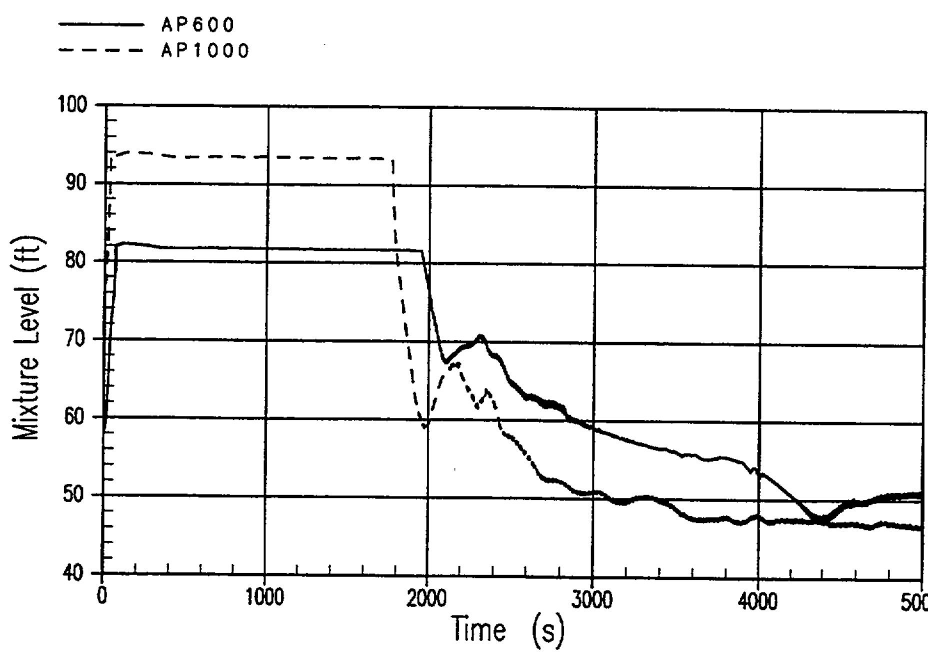


Figure 3.3.1.4-2 Inadvertent ADS Pressurizer Mixture Level

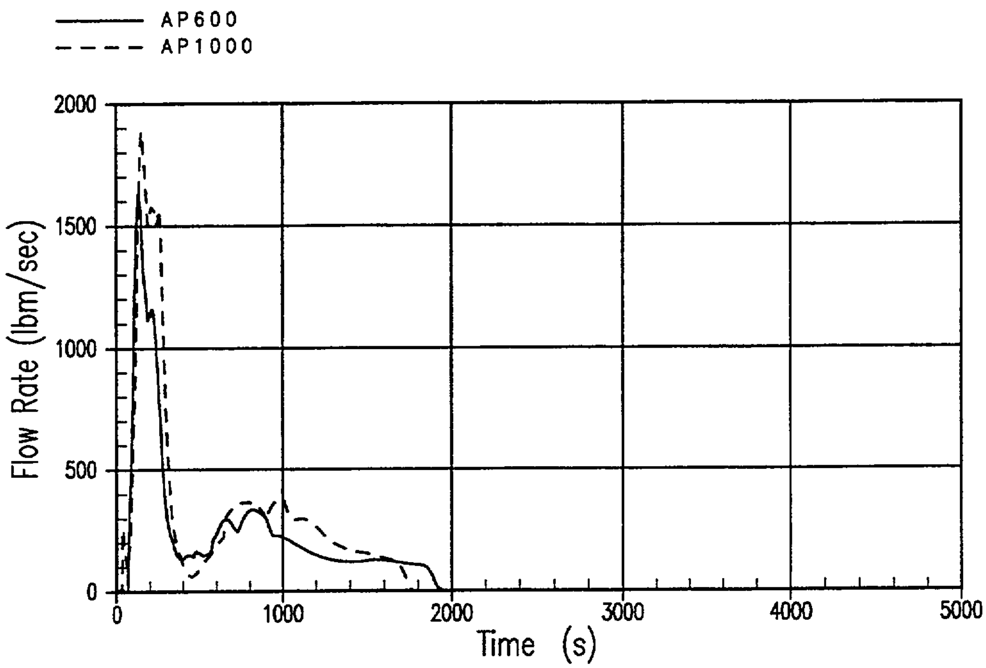


Figure 3.3.1.4-3 Inadvertent ADS ADS 1-3 Liquid Discharge

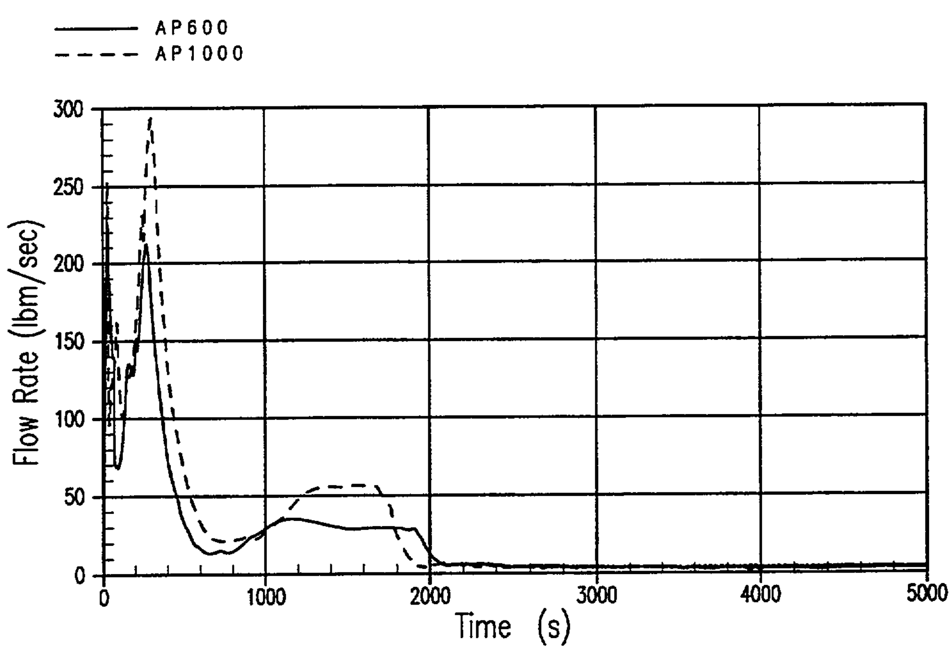


Figure 3.3.1.4-4 Inadvertent ADS ADS 1-3 Vapor Discharge

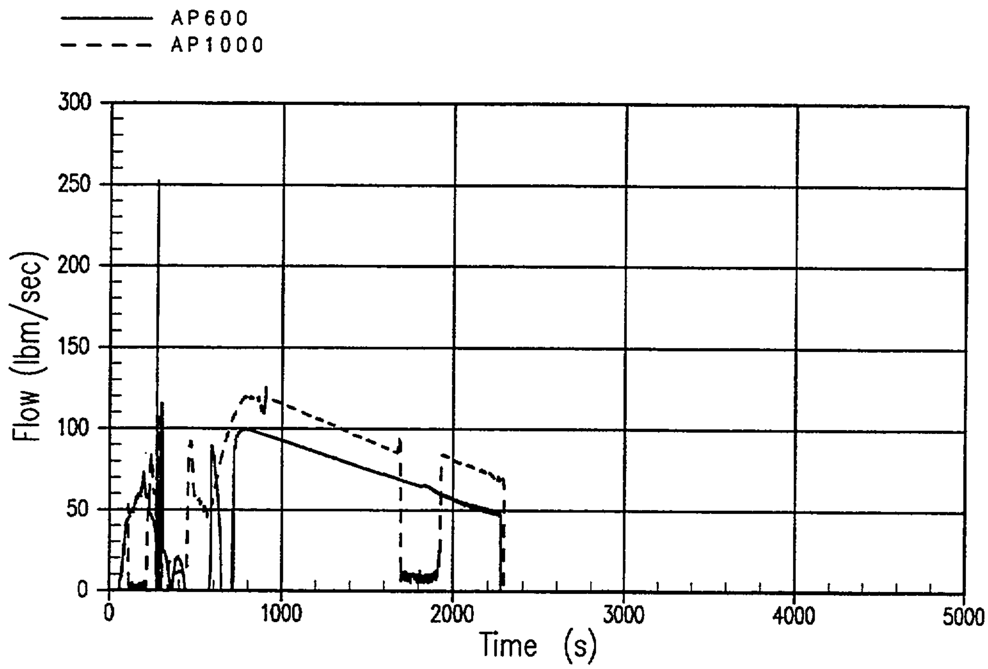


Figure 3.3.1.4-5 Inadvertent ADS CMT-1 Injection Rate

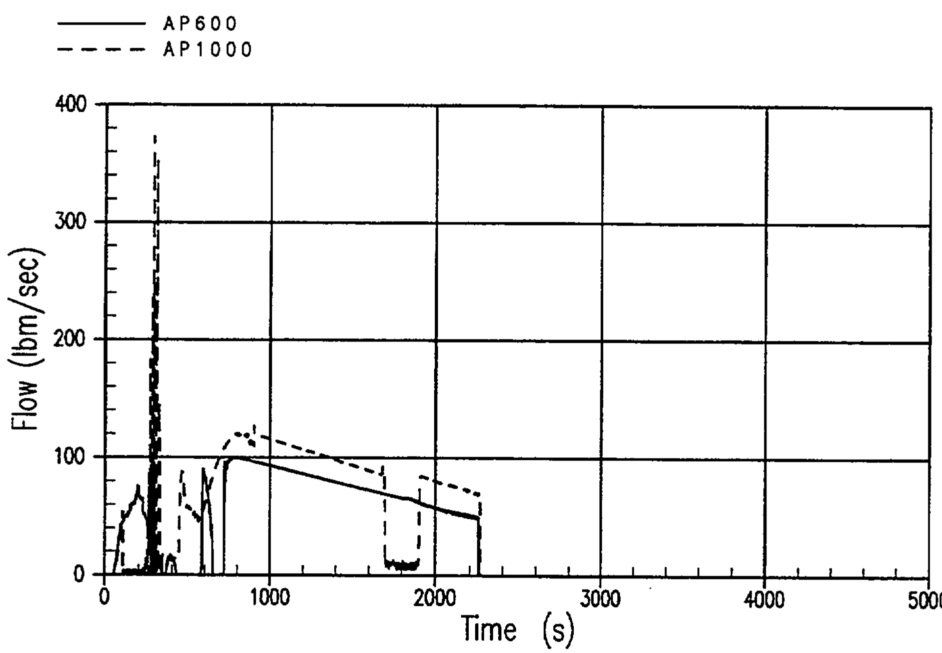


Figure 3.3.1.4-6 Inadvertent ADS CMT-2 Injection Rate

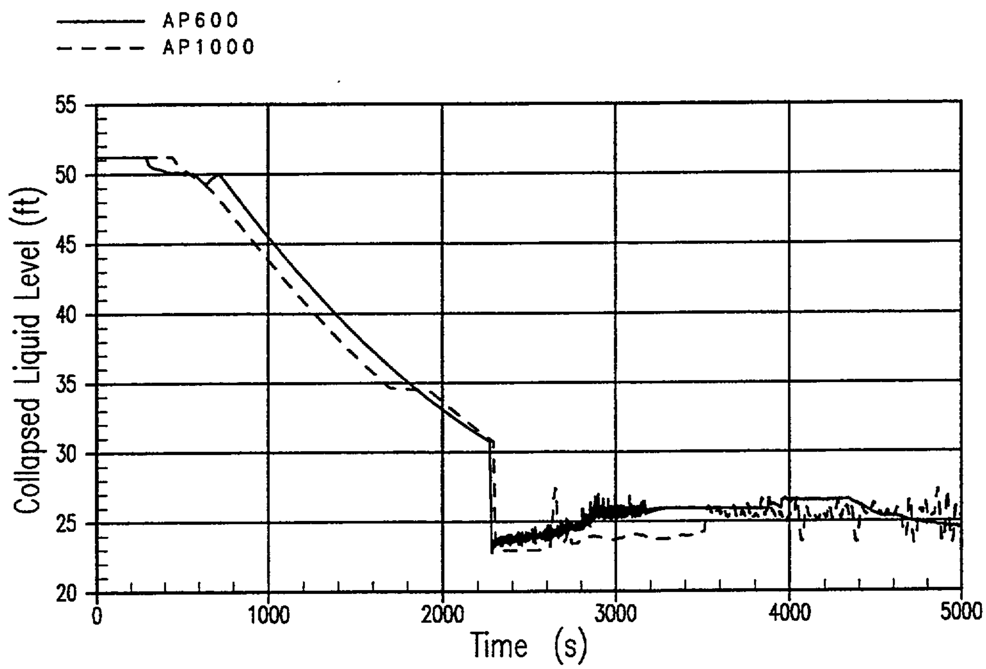


Figure 3.3.1.4-7 Inadvertent ADS CMT-1 Mixture Level

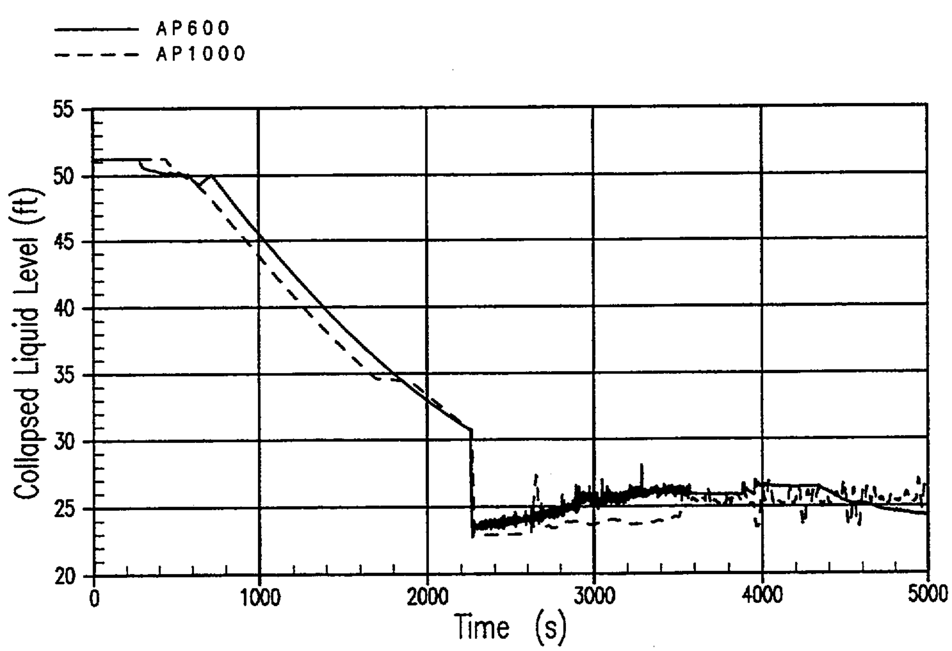


Figure 3.3.1.4-8 Inadvertent ADS CMT-2 Mixture Level

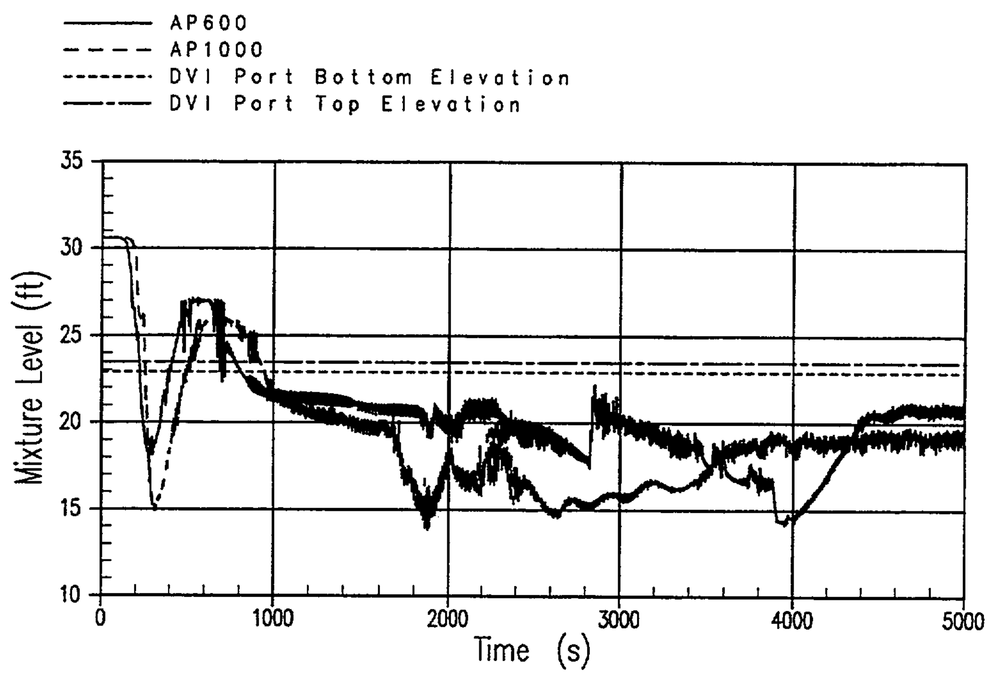


Figure 3.3.1.4-9 Inadvertent ADS Downcomer Mixture Level

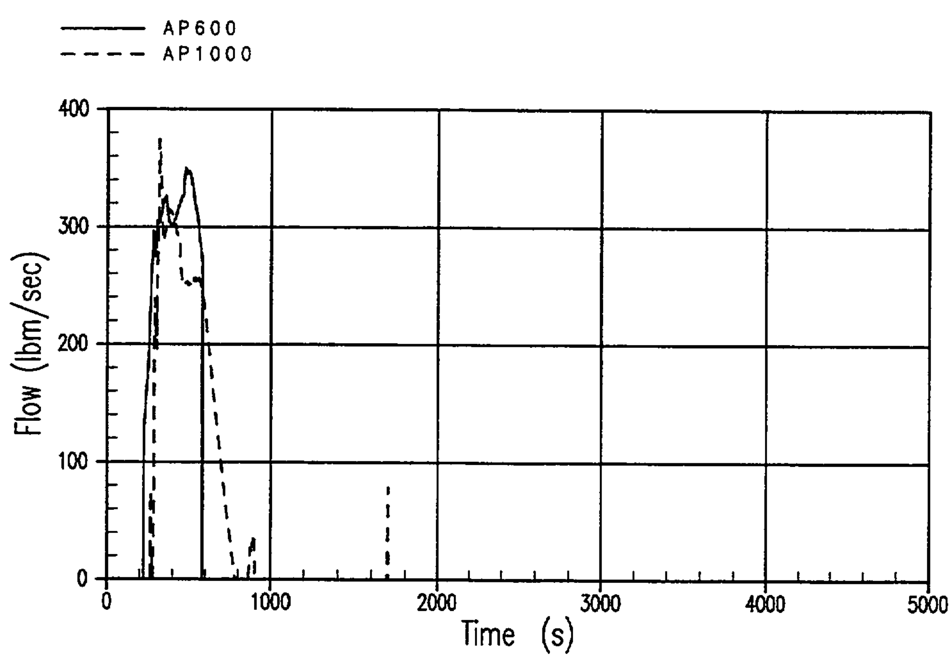


Figure 3.3.1.4-10 Inadvertent ADS Accumulator-1 Injection Rate

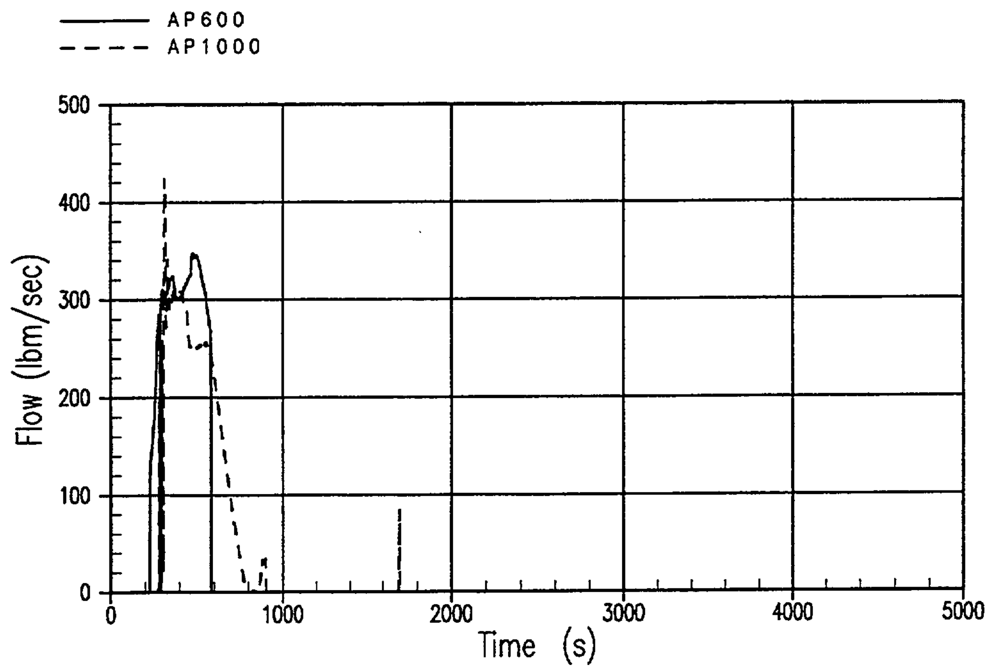


Figure 3.3.1.4-11 Inadvertent ADS Accumulator 2 Injection Rate

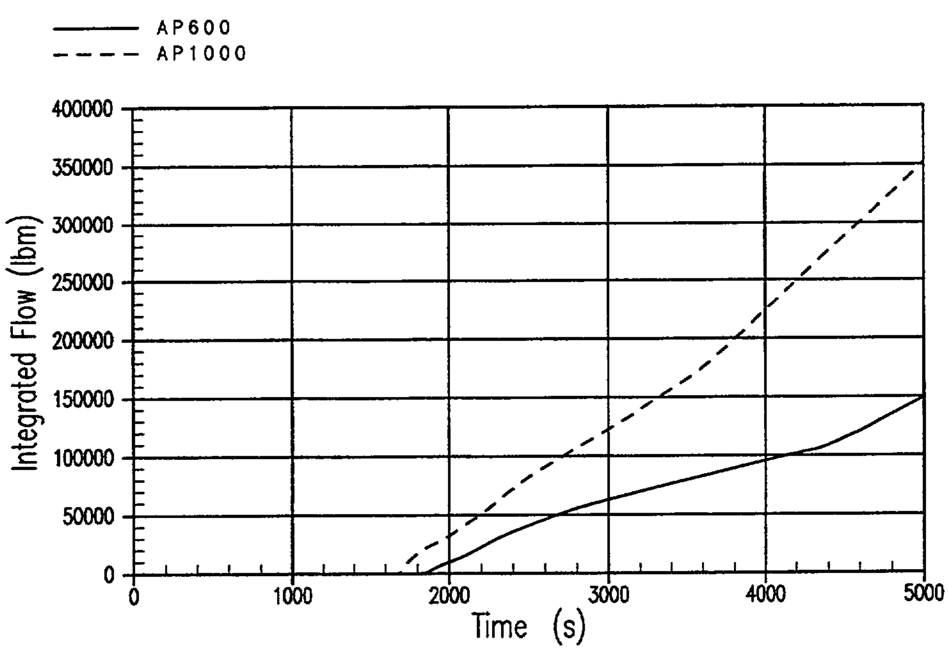


Figure 3.3.1.4-12 Inadvertent ADS ADS 4 Integrated Discharge

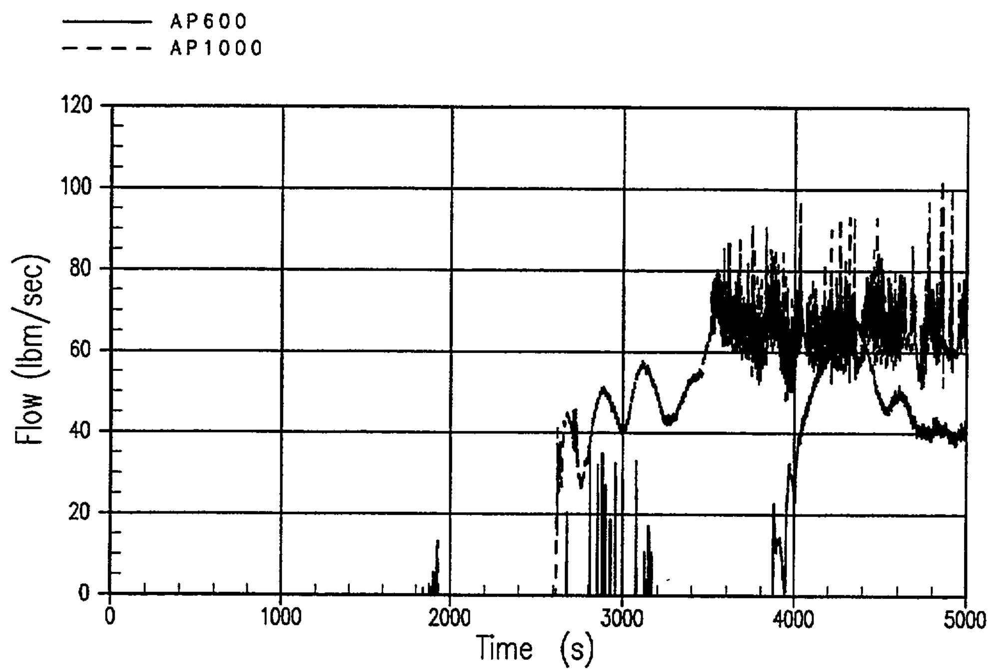


Figure 3.3.1.4-13 Inadvertent ADS IRWST-1 Injection Rate

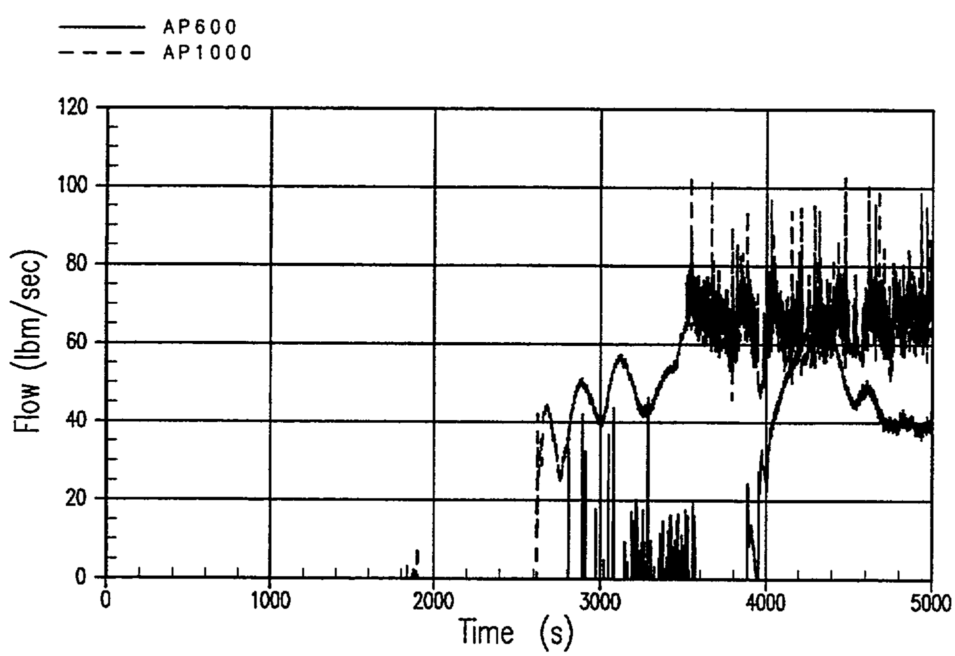


Figure 3.3.1.4-14 Inadvertent ADS IRWST-2 Injection Rate

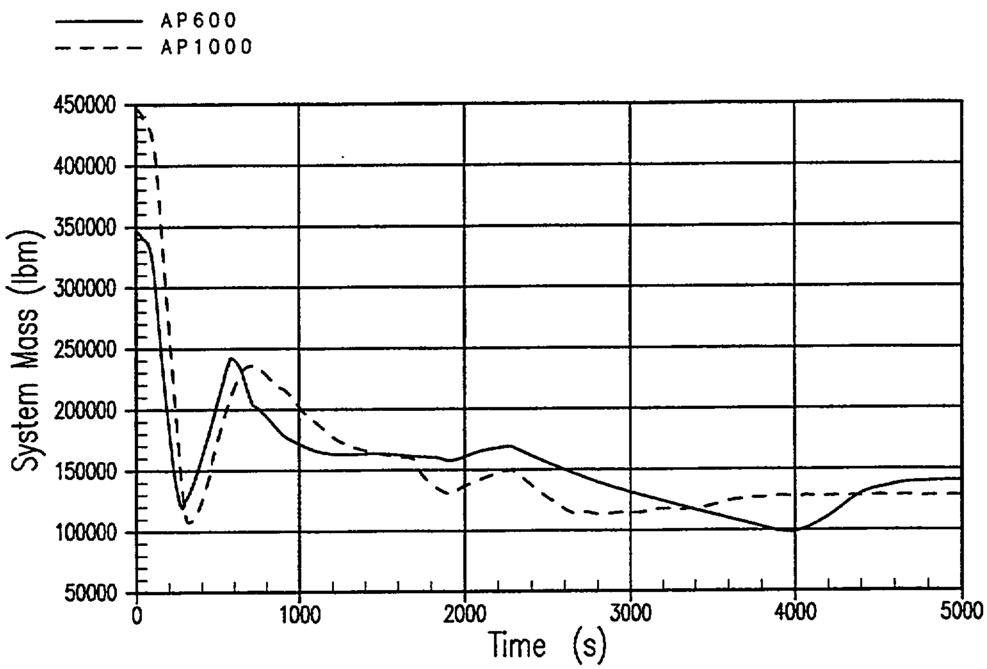


Figure 3.3.1.4-15 Inadvertent ADS RCS System Inventory

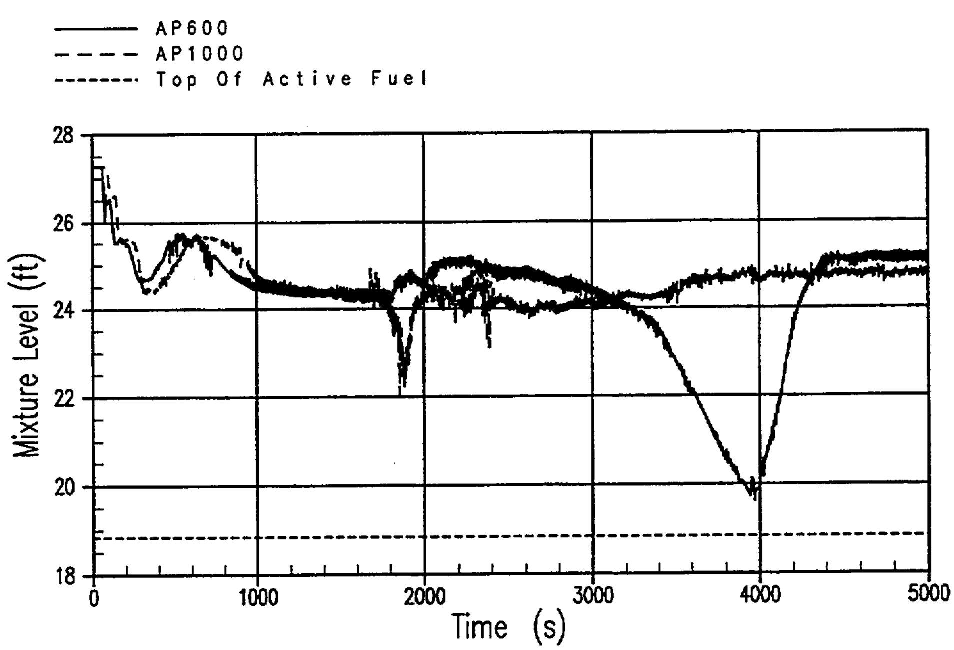


Figure 3.3.1.4-16 Inadvertent ADS Core/Upper Plenum Mixture Level

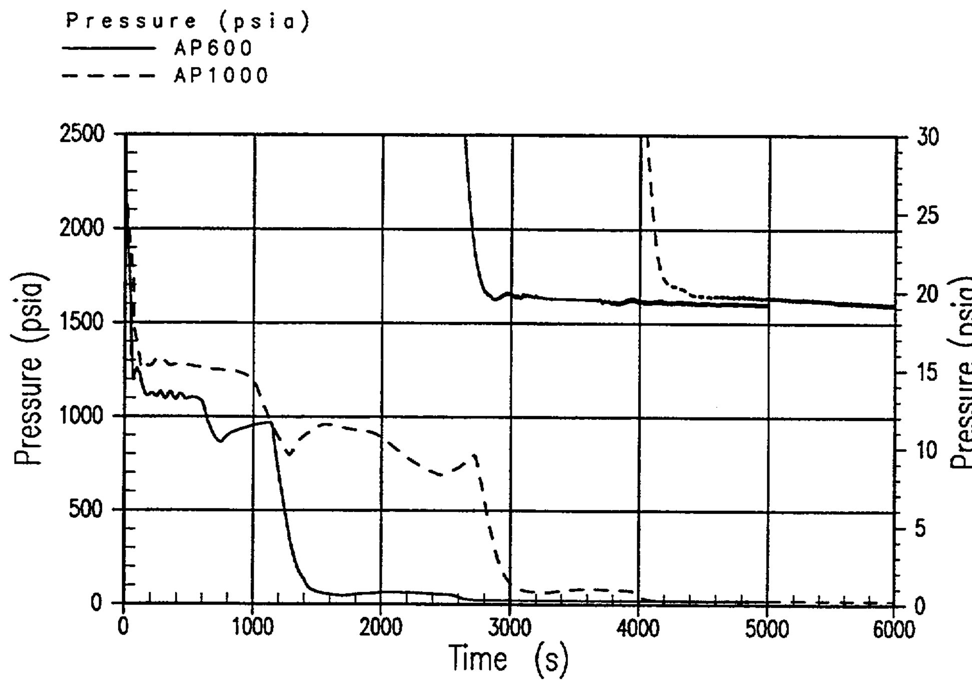


Figure 3.3.1.4-17 2-Inch Cold Leg Break RCS Pressure

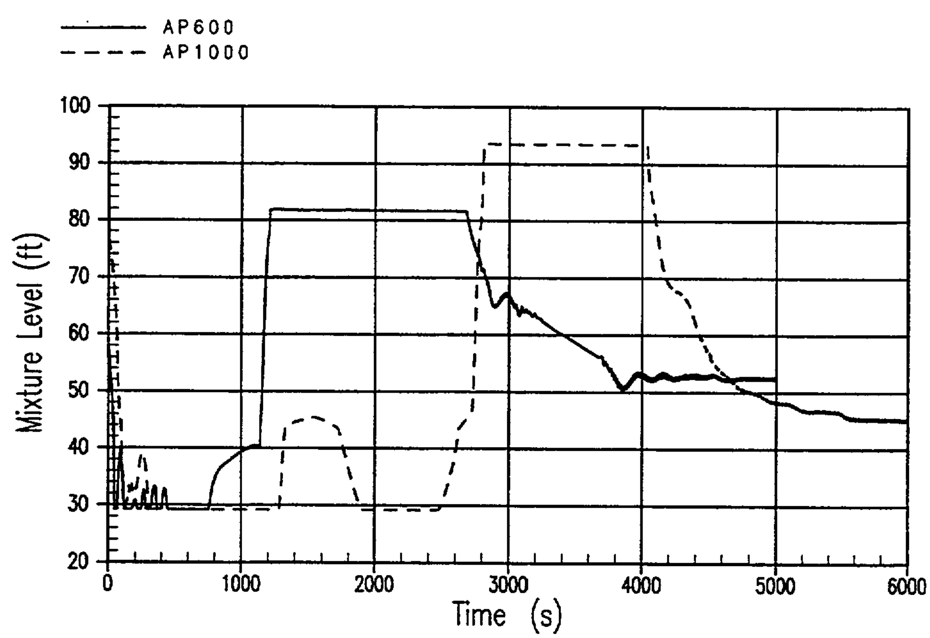


Figure 3.3.1.4-18 2-Inch Cold Leg Break Pressurizer Mixture Level

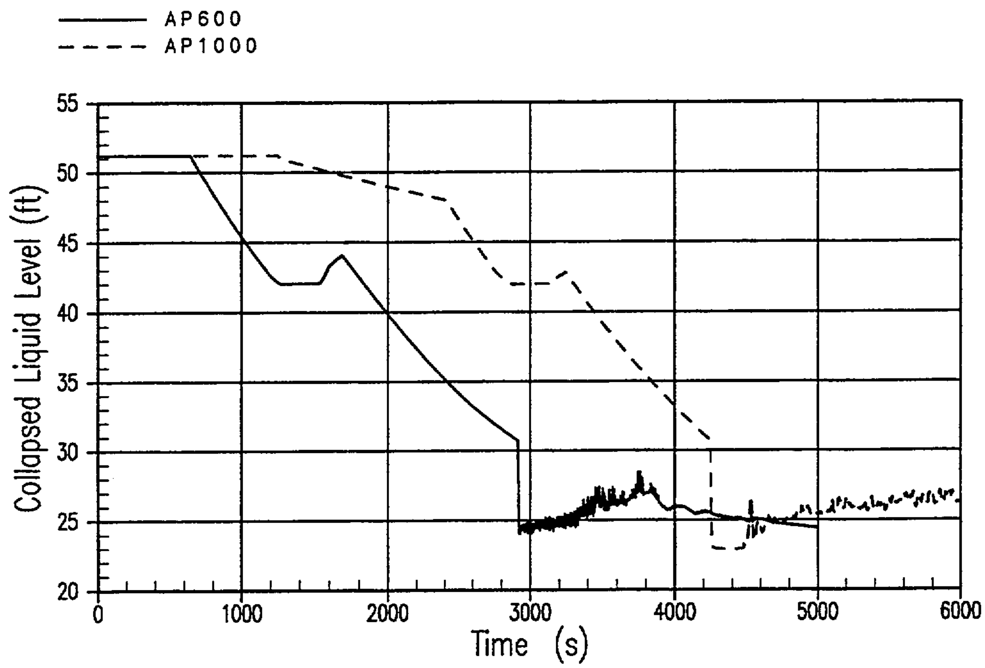


Figure 3.3.1.4-19 2-Inch Cold Leg Break CMT-1 Mixture Level

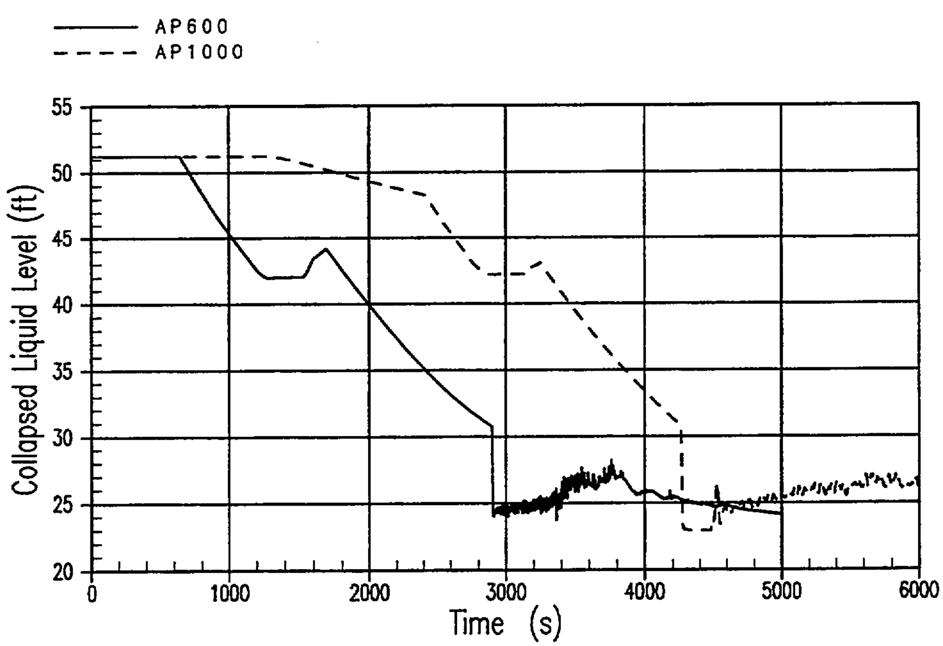


Figure 3.3.1.4-20 2-Inch Cold Leg Break CMT-2 Mixture Level

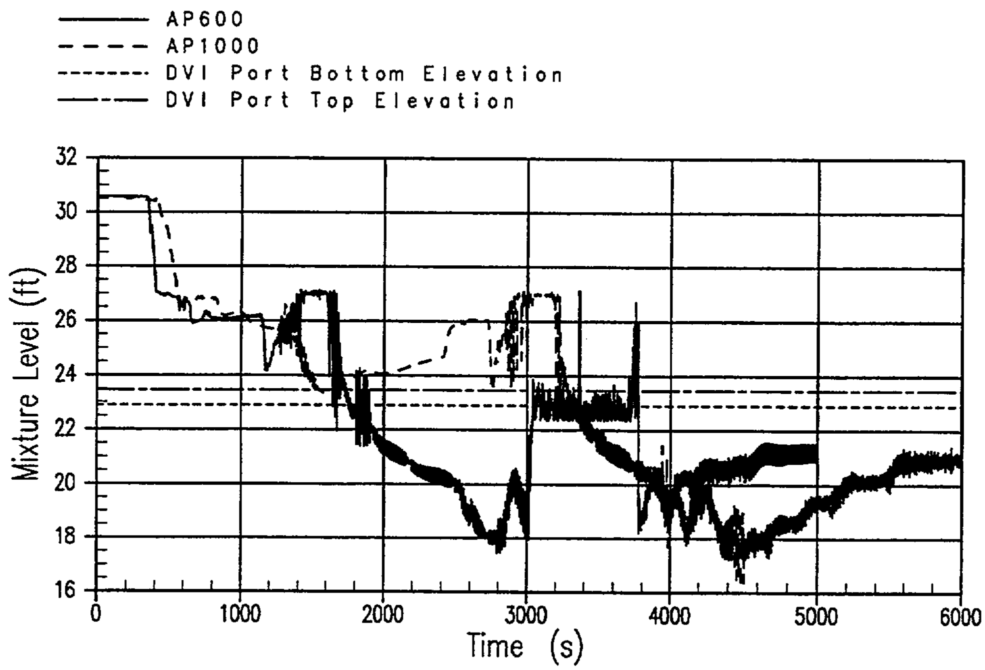


Figure 3.3.1.4-21 2-Inch Cold Leg Break Downcomer Mixture Level

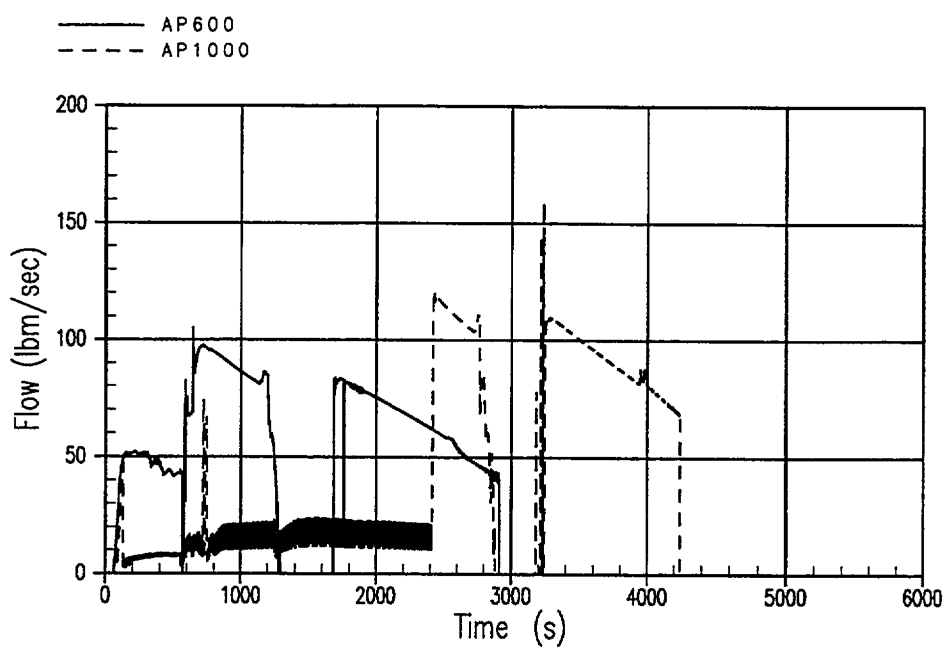


Figure 3.3.1.4-22 2-Inch Cold Leg Break CMT-1 Injection Rate

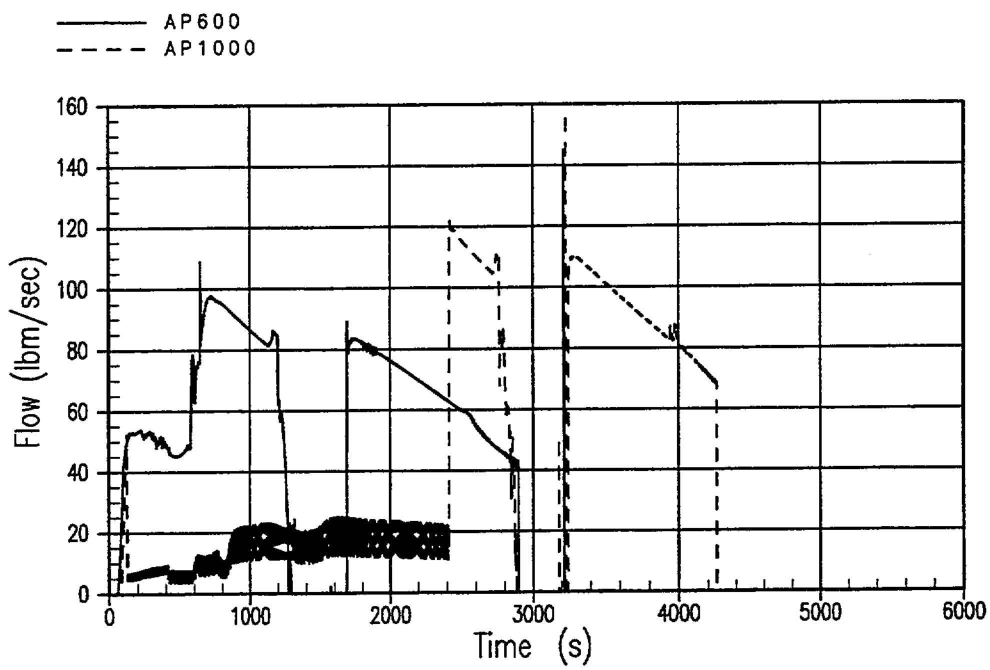


Figure 3.3.1.4-23 2-Inch Cold Leg Break CMT-2 Injection Rate

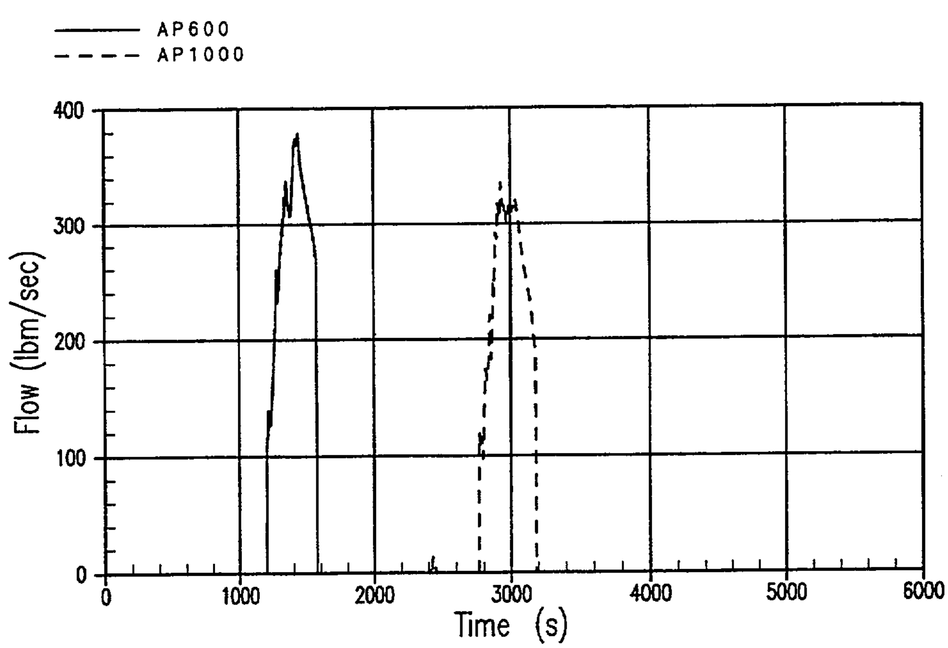


Figure 3.3.1.4-24 2-Inch Cold Leg Break Accumulator-1 Injection Rate

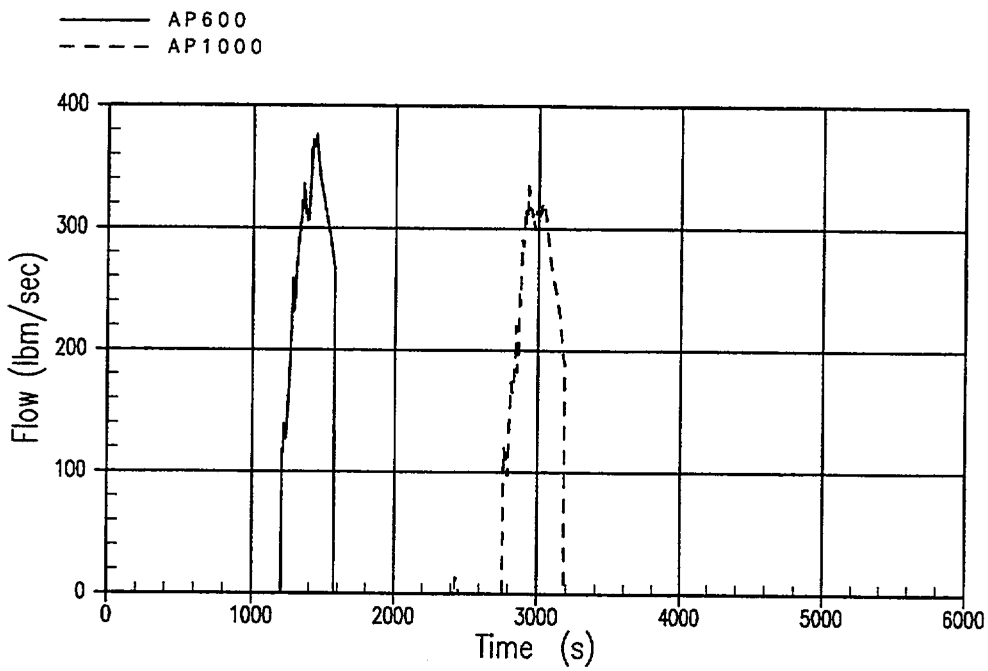


Figure 3.3.1.4-25 2-Inch Cold Leg Break Accumulator-2 Injection Rate

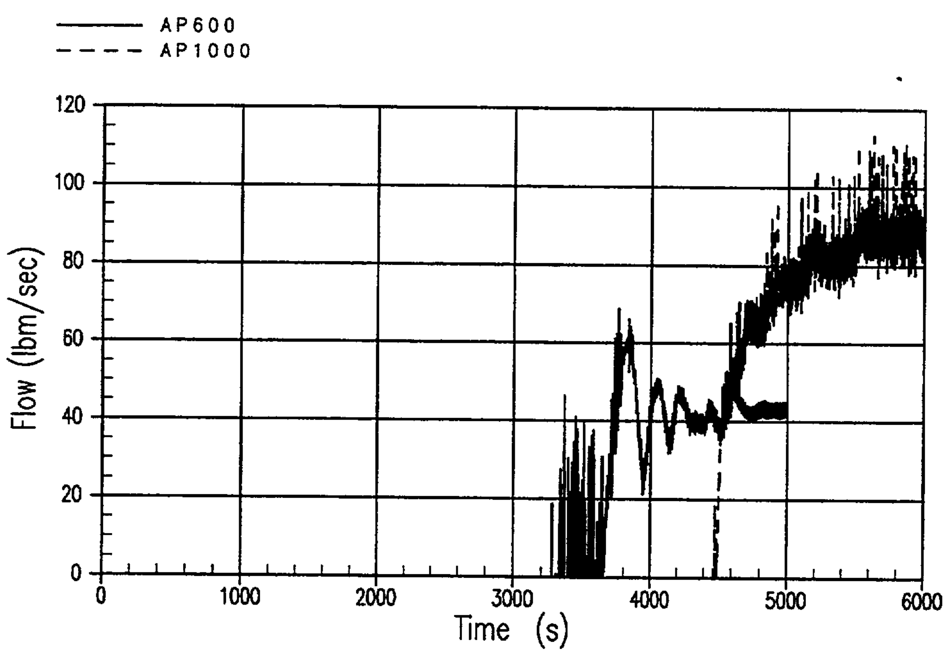


Figure 3.3.1.4-26 2-Inch Cold Leg Break IRWST-1 Injection Rate

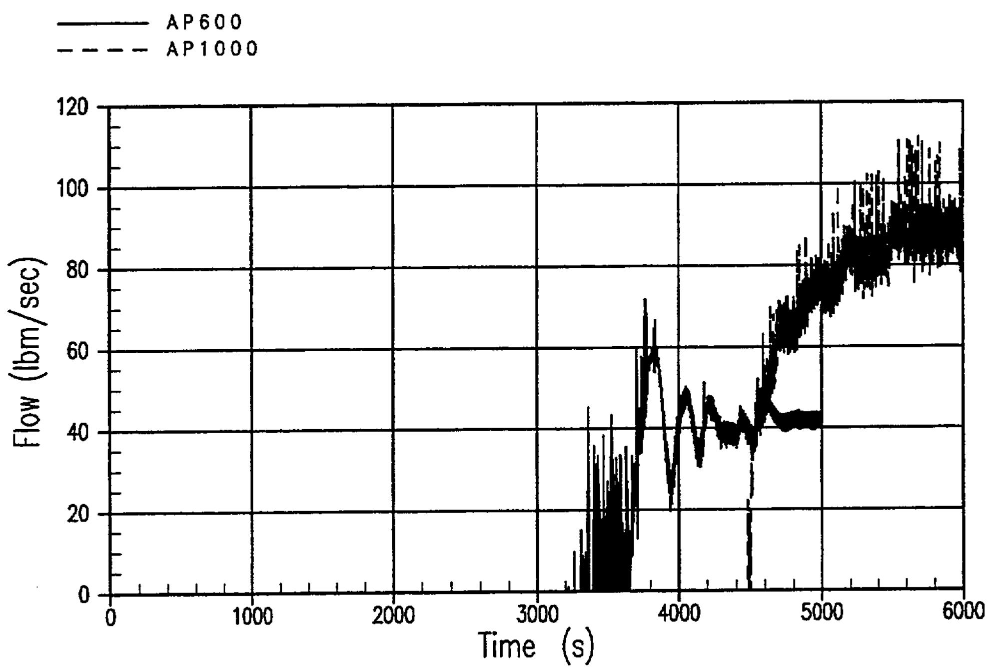


Figure 3.3.1.4-27 2-Inch Cold Leg Break IRWST-2 Injection Rate

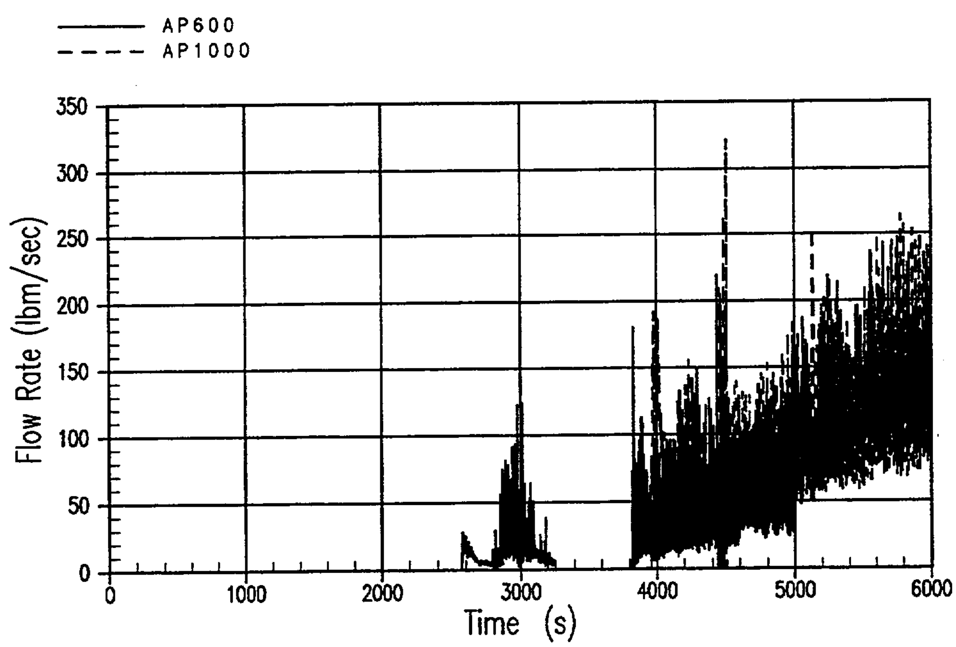


Figure 3.3.1.4-28 2-Inch Cold Leg Break ADS-4 Liquid Discharge

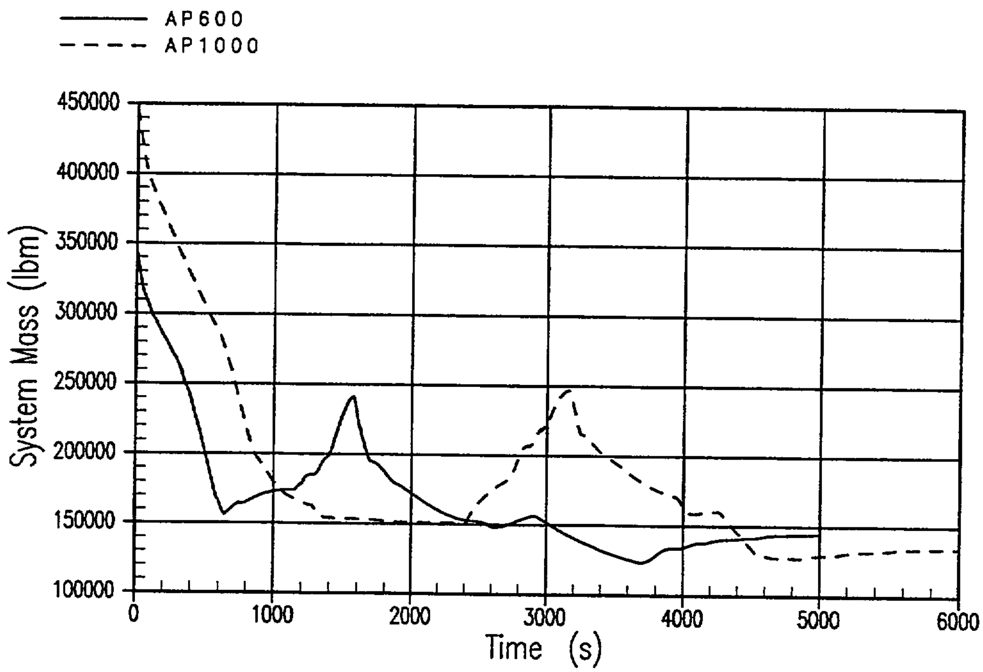


Figure 3.3.1.4-29 2-Inch Cold Leg Break RCS Inventory

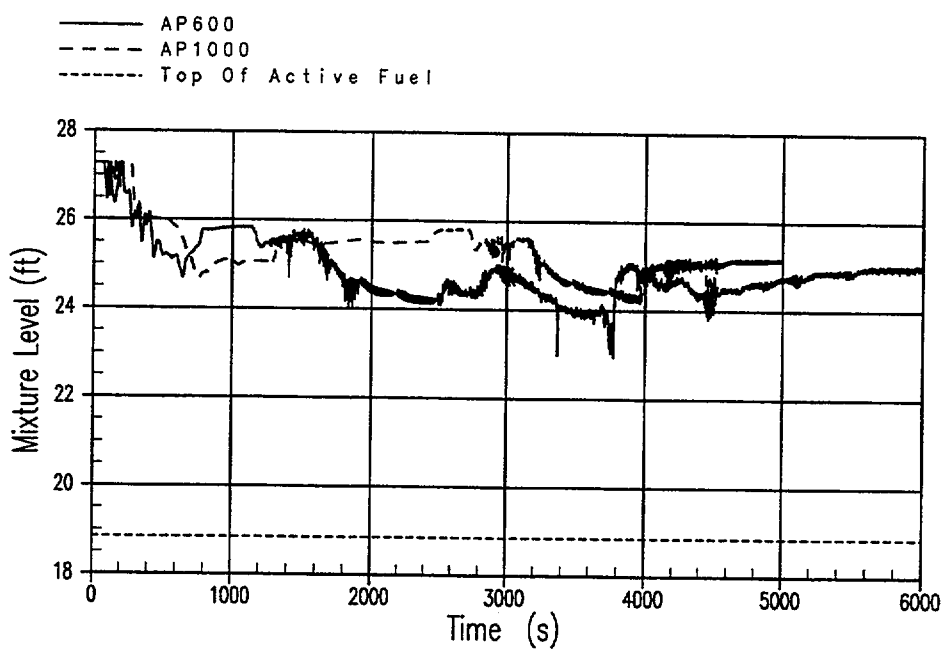


Figure 3.3.1.4-30 2-Inch Cold Leg Break Core/Upper Plenum Mixture Level

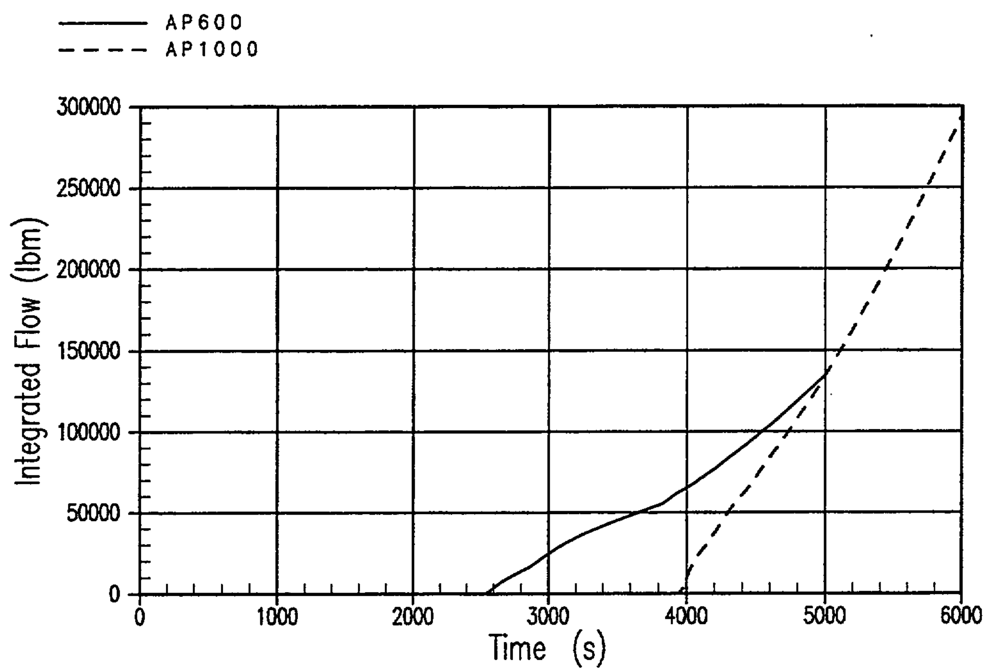


Figure 3.3.1.4-31 2-Inch Cold Leg Break ADS-4 Integrated Discharge

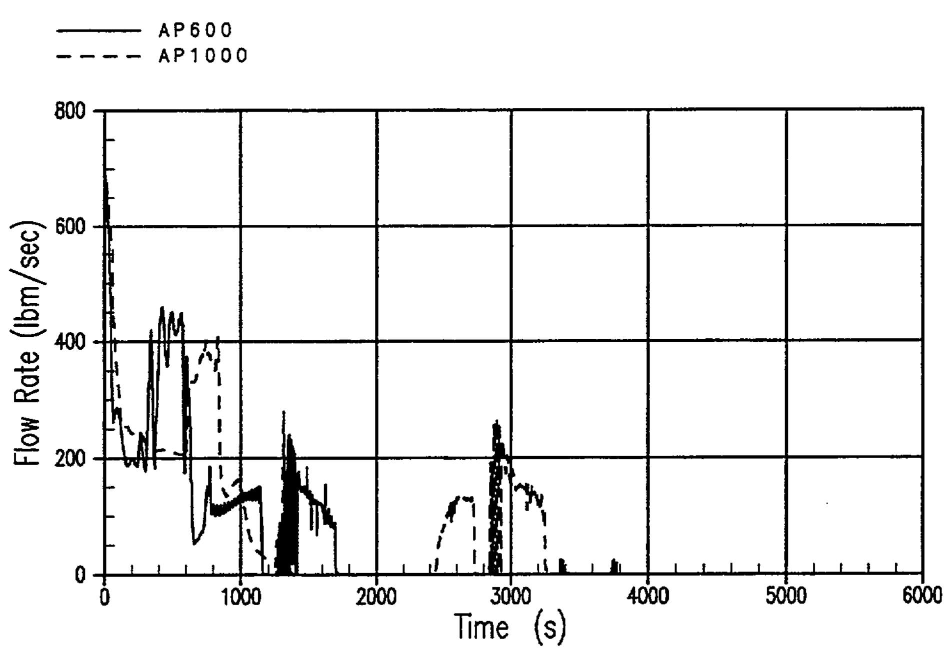


Figure 3.3.1.4-32 2-Inch Cold Leg Break Liquid Break Discharge

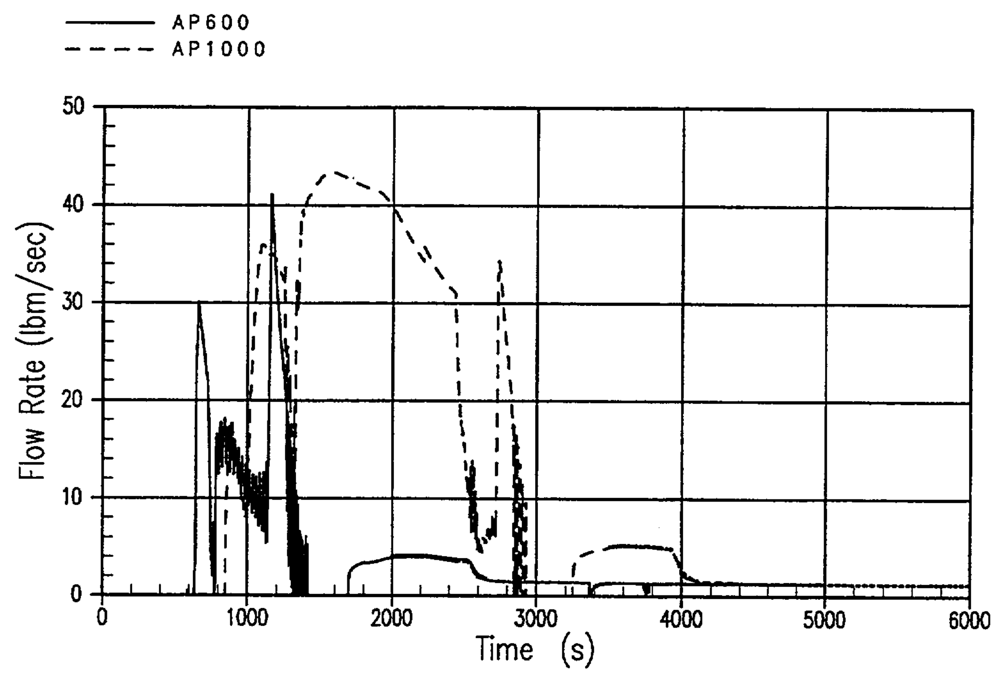


Figure 3.3.1.4-33 2-Inch Cold Leg Break Vapor Break Discharge

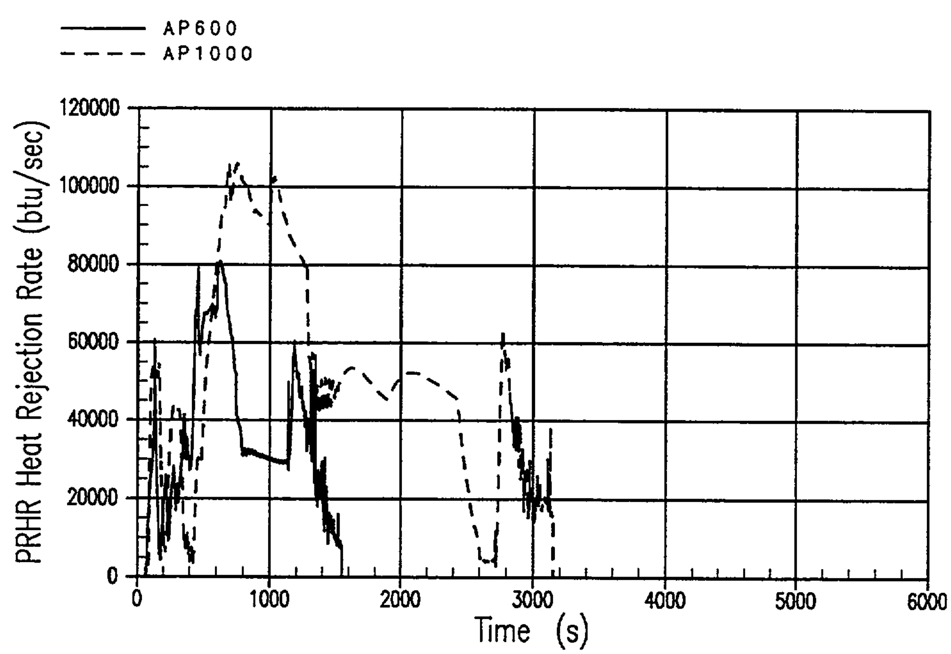


Figure 3.3.1.4-34 2-Inch Cold Leg Break PRHR Heat Removal Rate

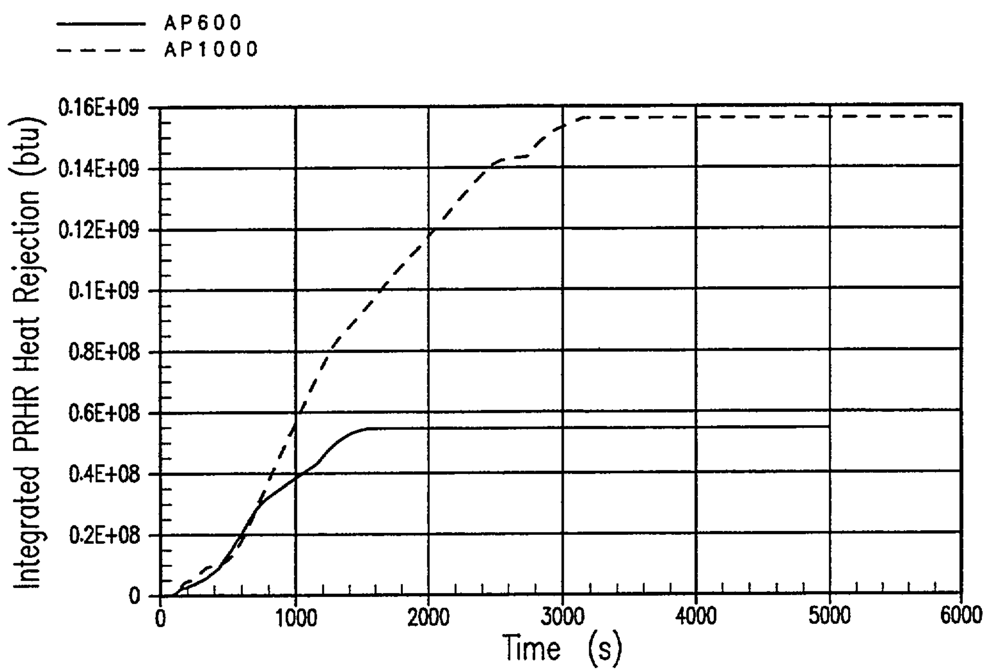


Figure 3.3.1.4-35 2-Inch Cold Leg Break Integrated PRHR Heat Removal

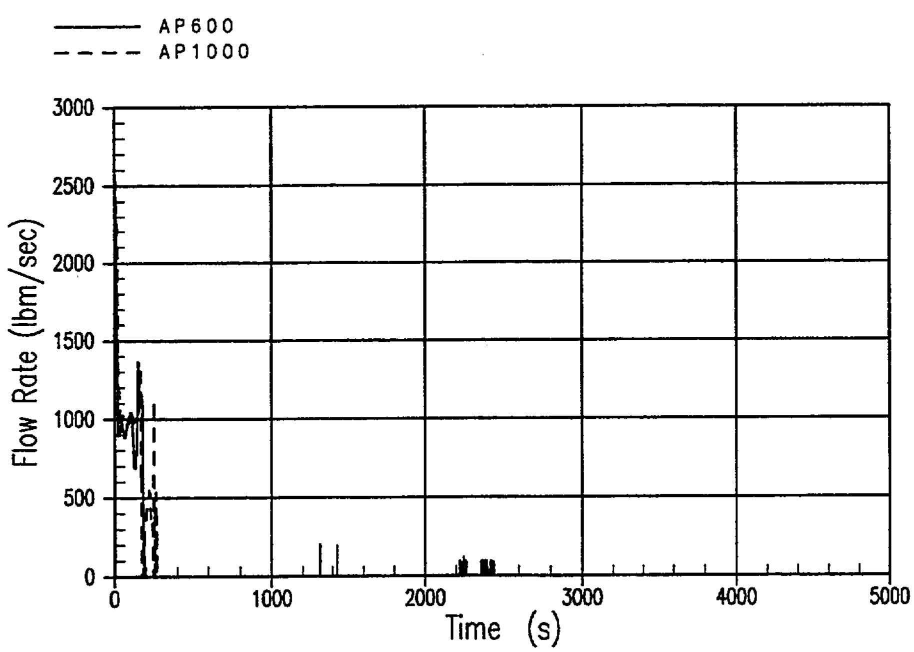


Figure 3.3.1.4-36 DEDVI Vessel Side Liquid Break Discharge

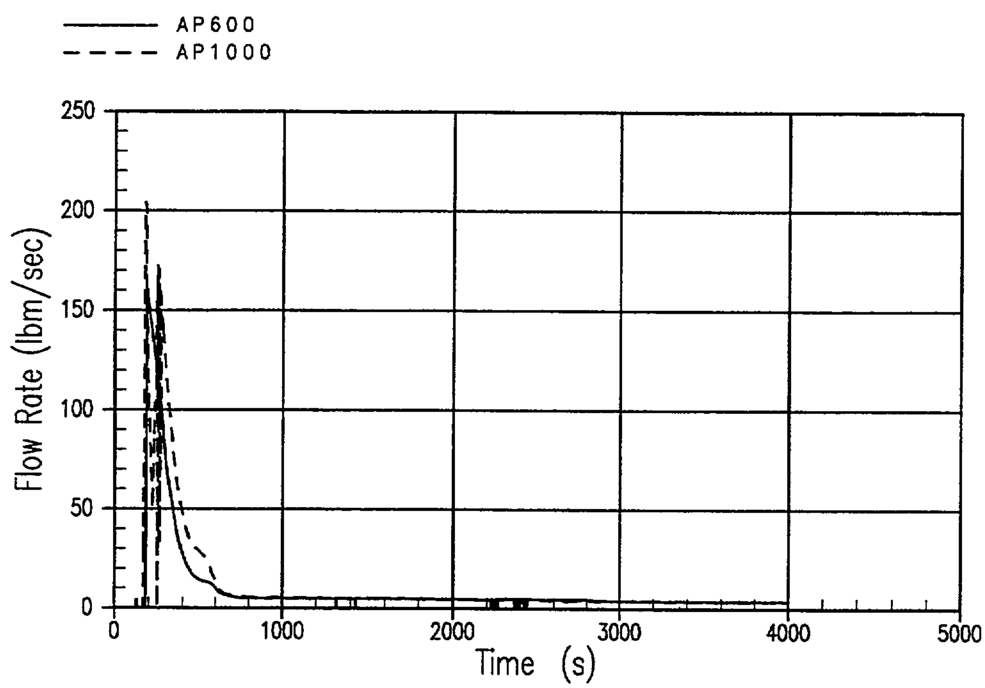


Figure 3.3.1.4-37 DEDVI Vessel Side Vapor Break Discharge

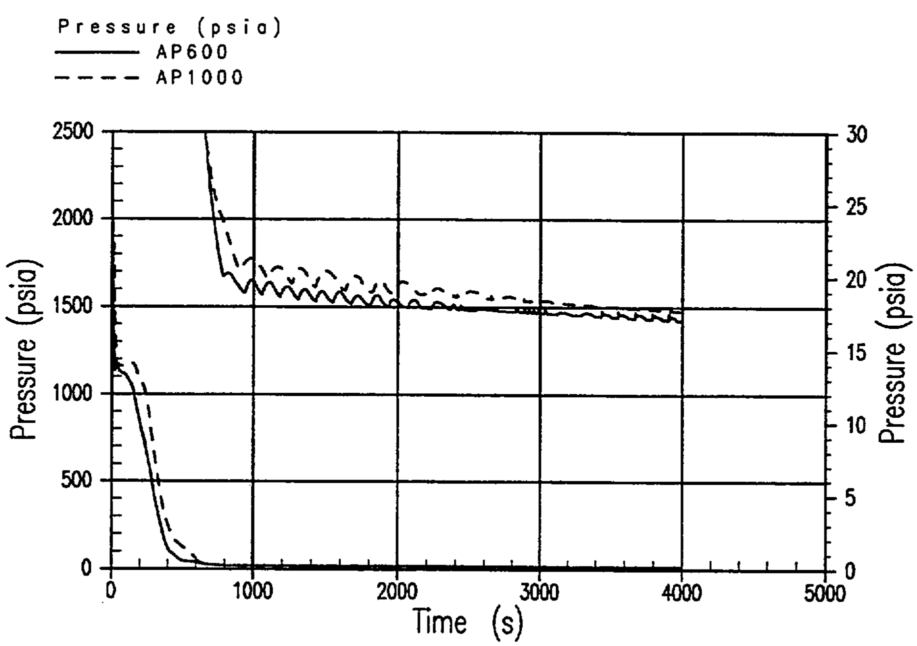


Figure 3.3.1.4-38 DEDVI RCS Pressure

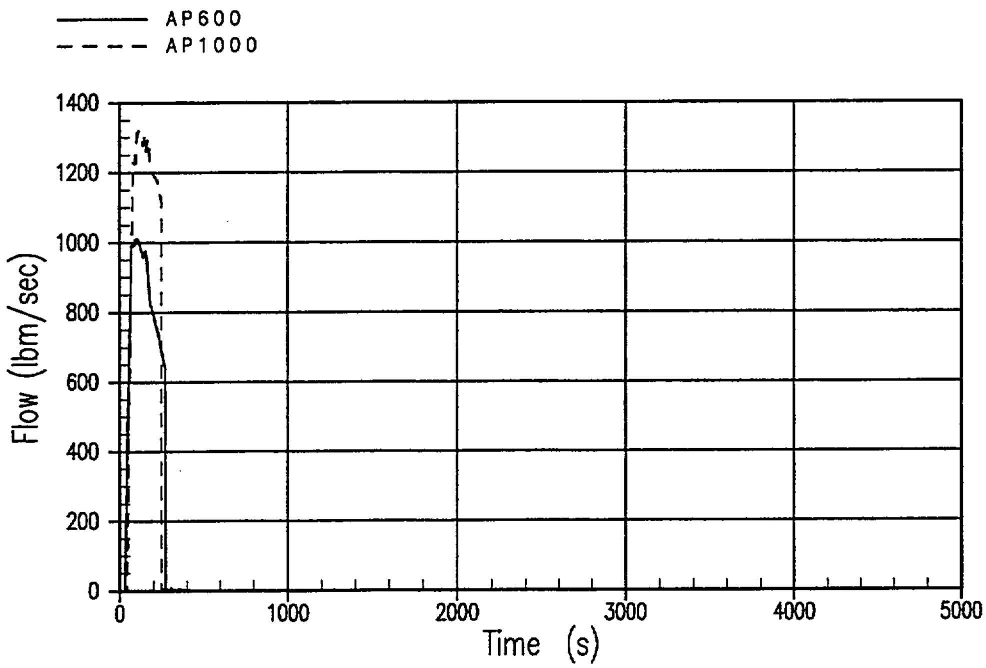


Figure 3.3.1.4-39 DEDVI Broken CMT Injection Rate

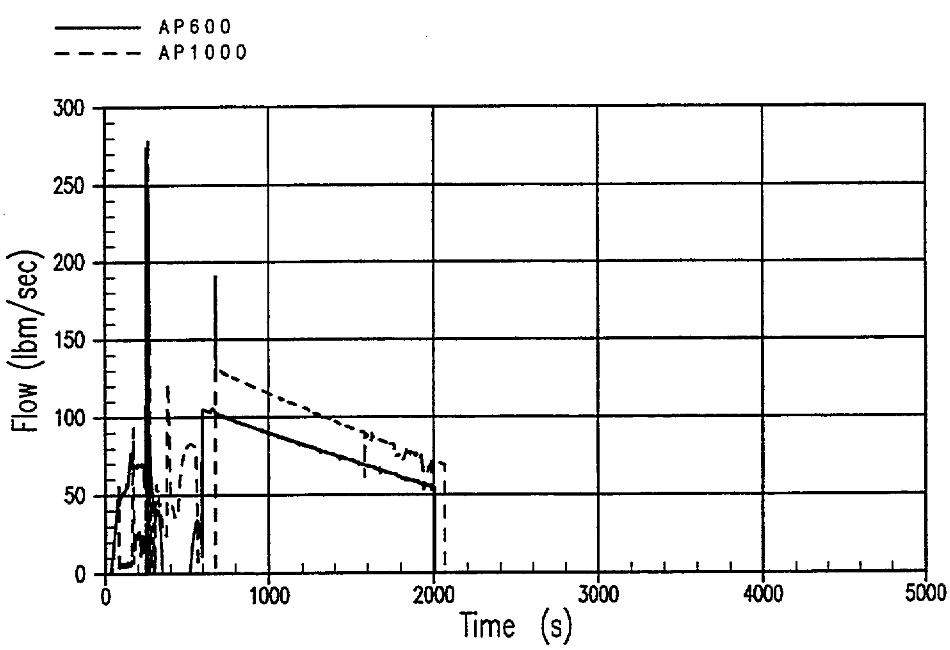


Figure 3.3.1.4-40 DEDVI Intact CMT Injection Rate

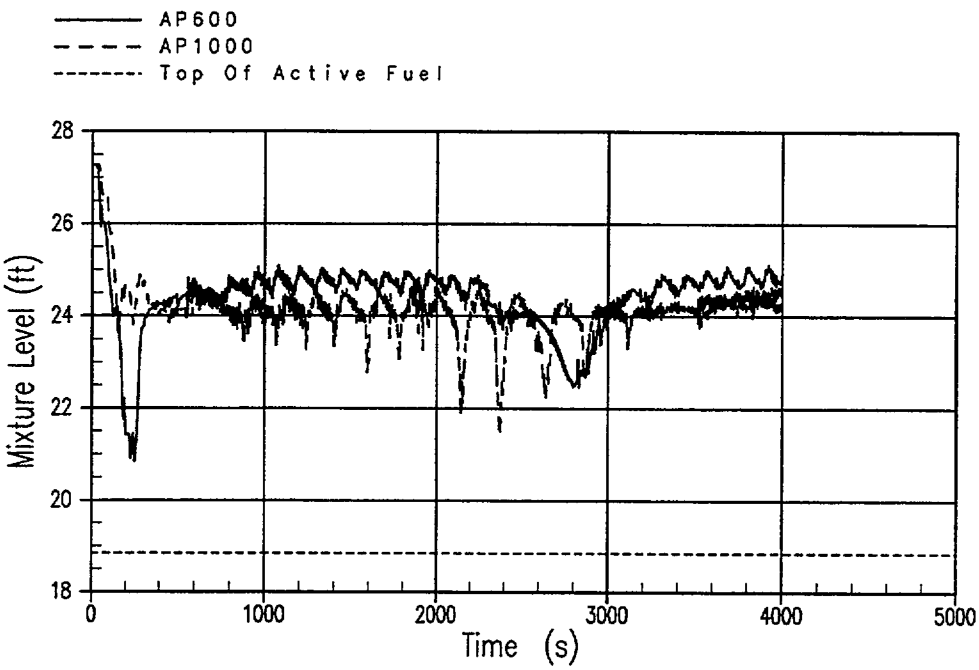


Figure 3.3.1.4-41 DEDVI Core/Upper Plenum Mixture Level

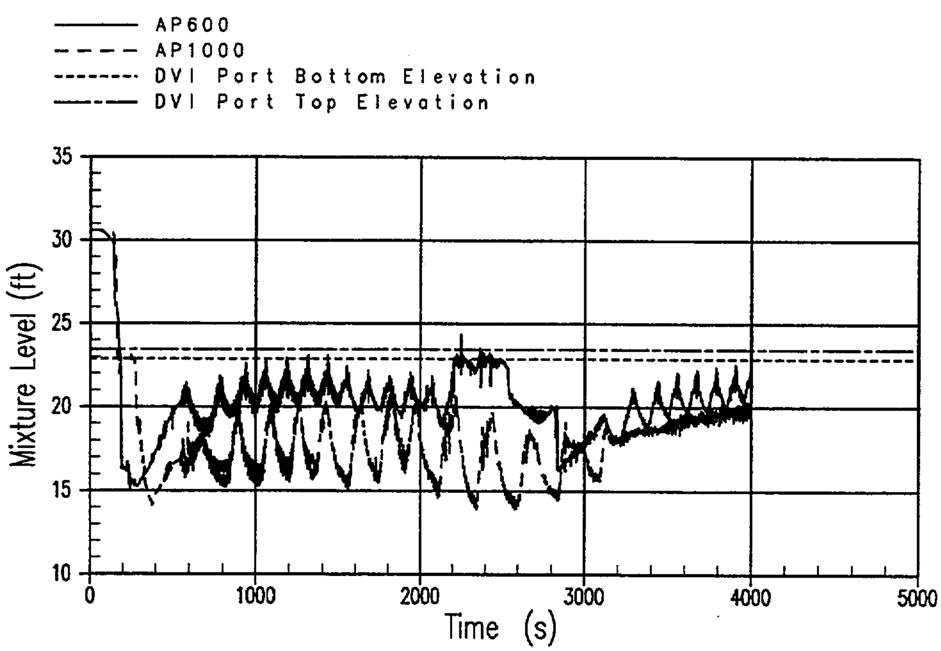


Figure 3.3.1.4-42 DEDVI Downcomer Mixture Level

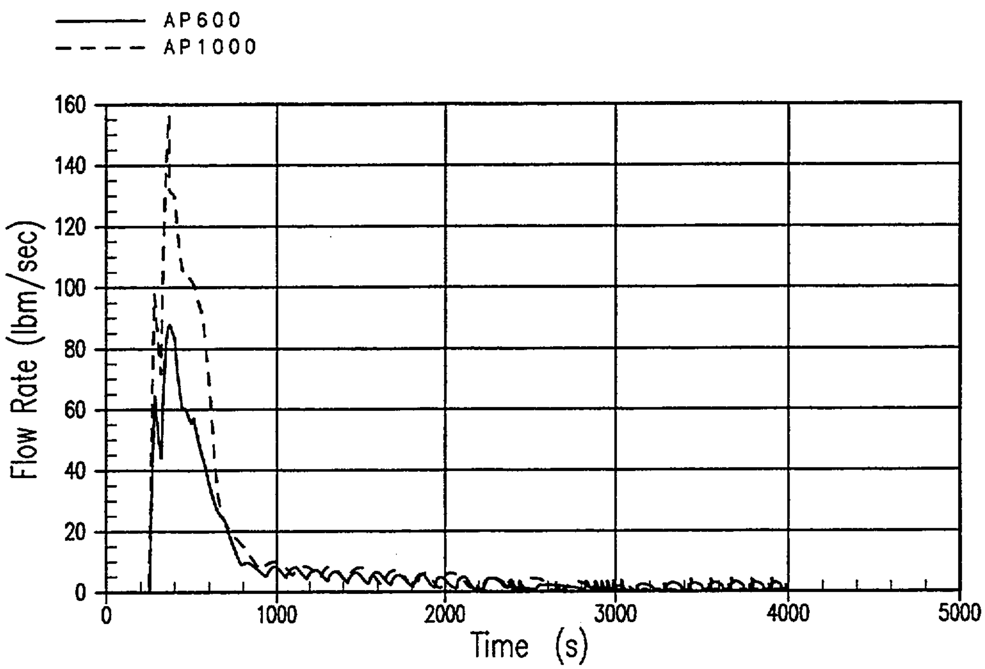


Figure 3.3.1.4-43 DEDVI ADS 1-3 Vapor Discharge Rate

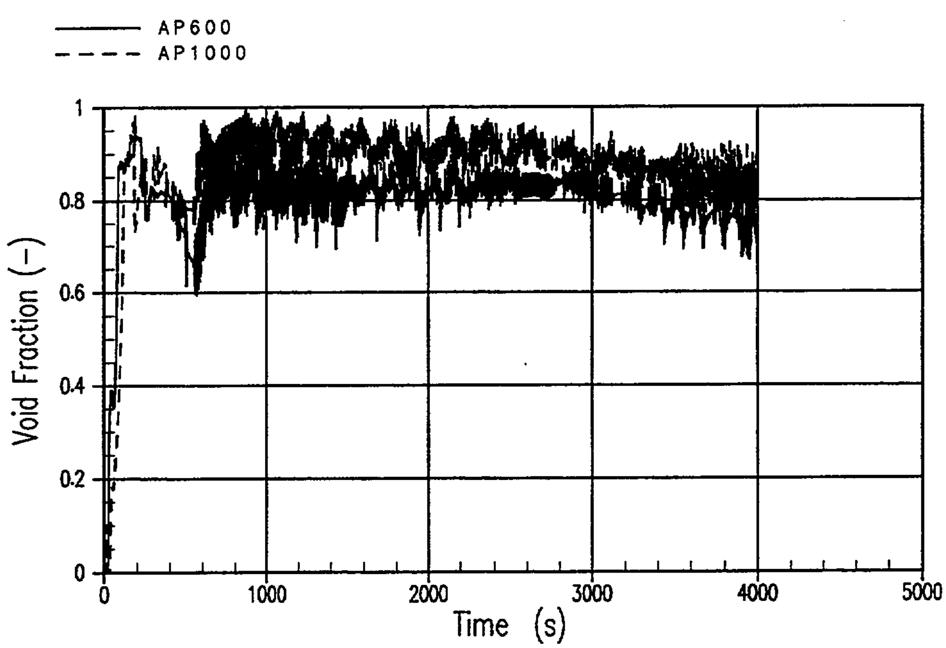


Figure 3.3.1.4-44 DEDVI Core Exit Void Fraction

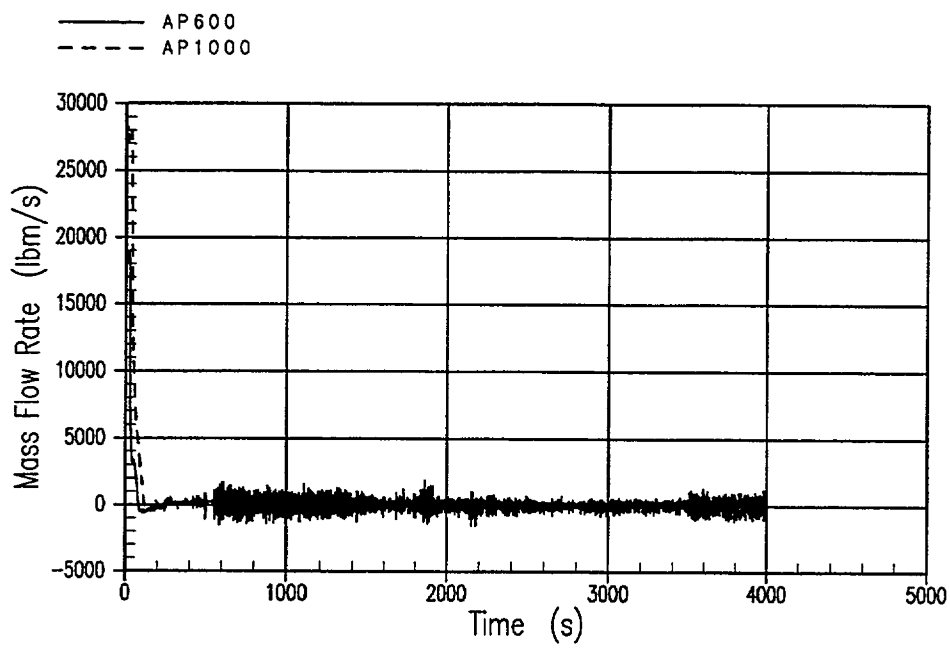


Figure 3.3.1.4-45 DEDVI Core Exit Liquid Flow Rate

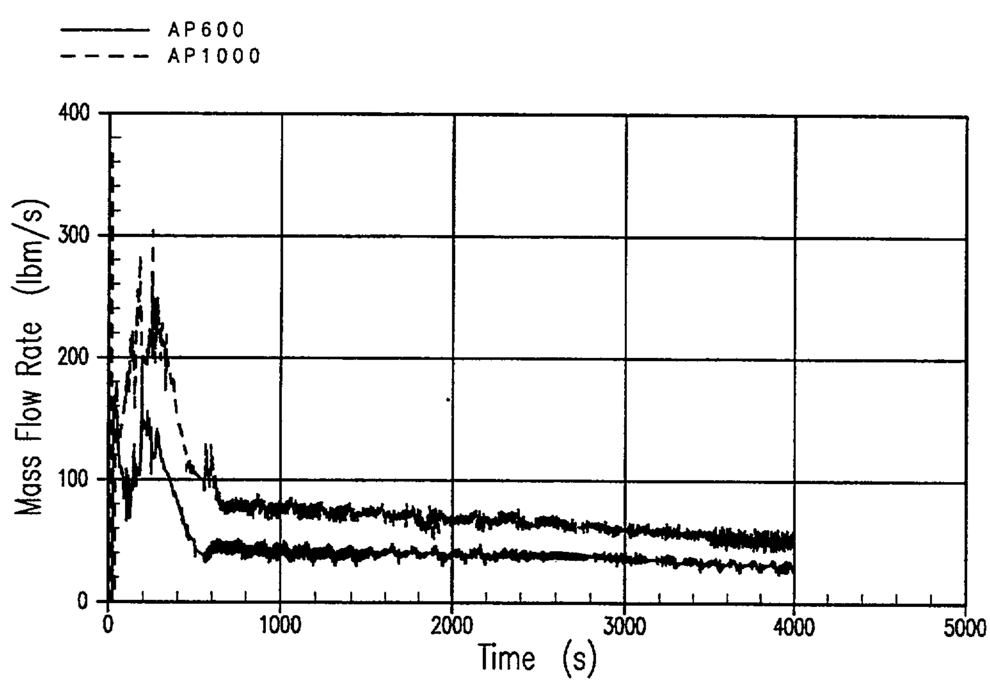


Figure 3.3.1.4-46 DEDVI Core Exit Vapor Flow Rate

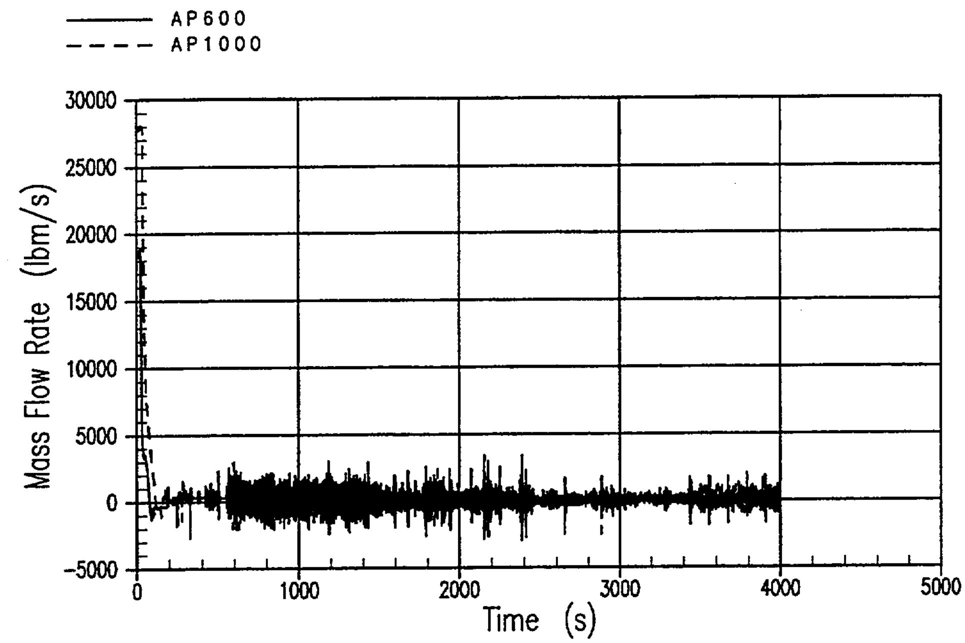


Figure 3.3.1.4-47 DEDVI Lower Plenum to Core Flow Rate

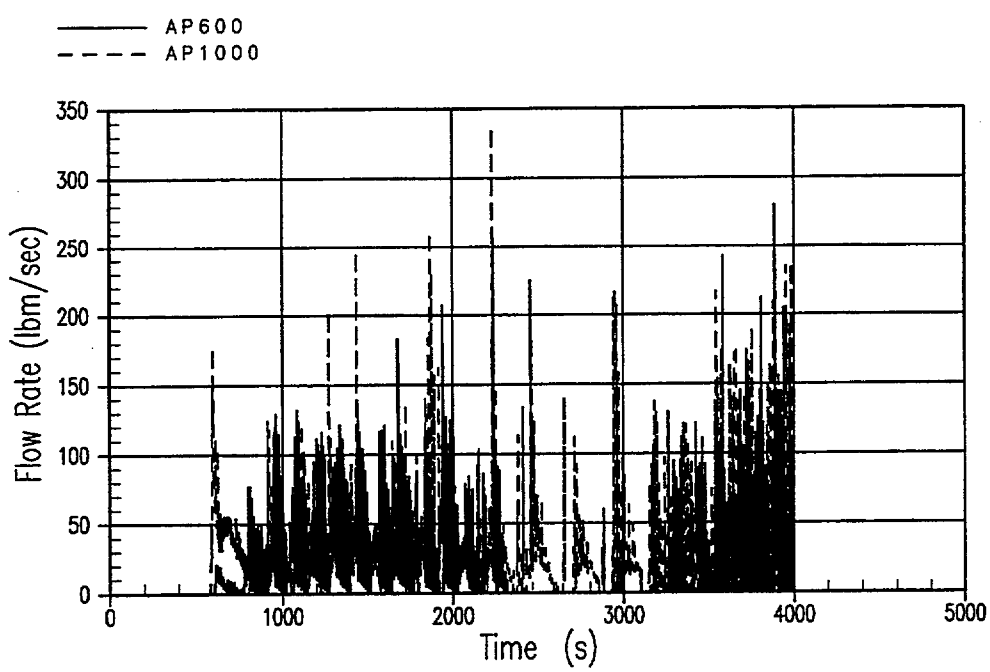


Figure 3.3.1.4-48 DEDVI ADS 4 Liquid Discharge Rate

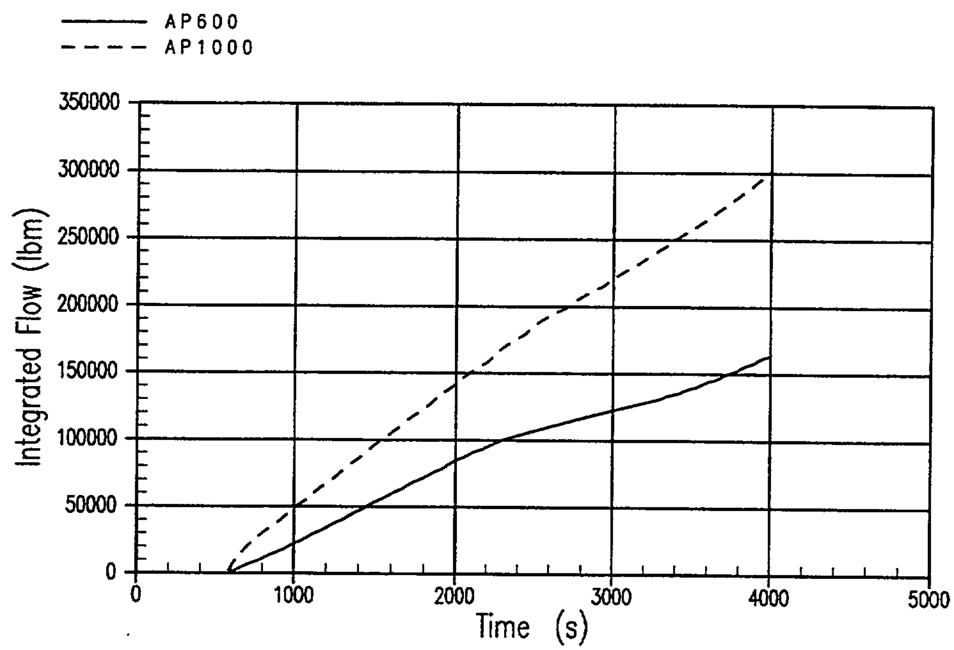


Figure 3.3.1.4-49 DEDVI ADS 4 Integrated Discharge

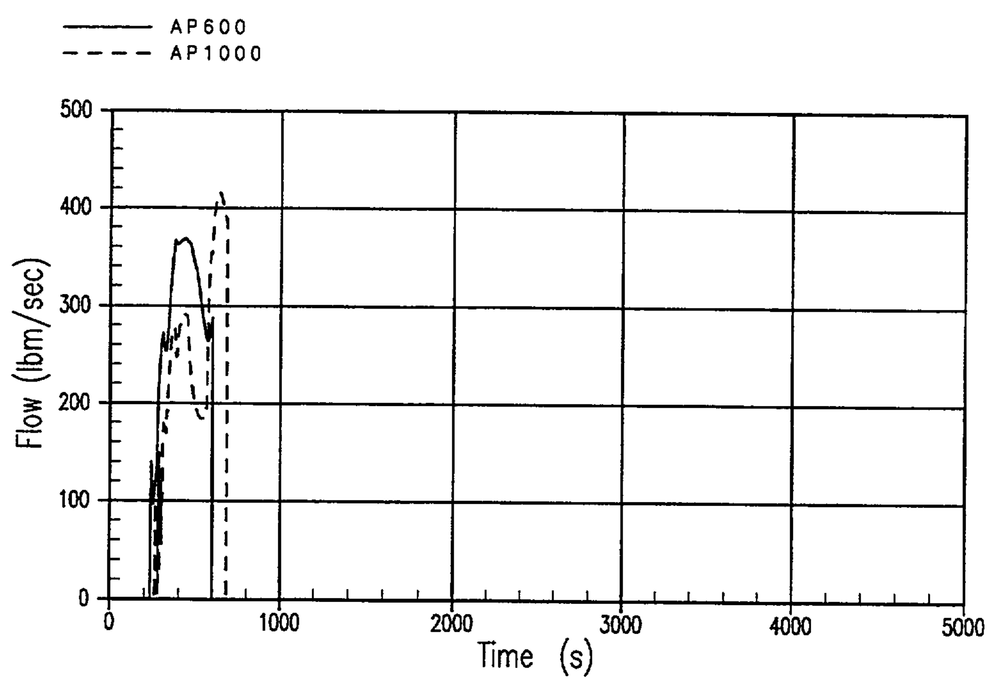


Figure 3.3.1.4-50 DEDVI Intact Accumulator Flow Rate

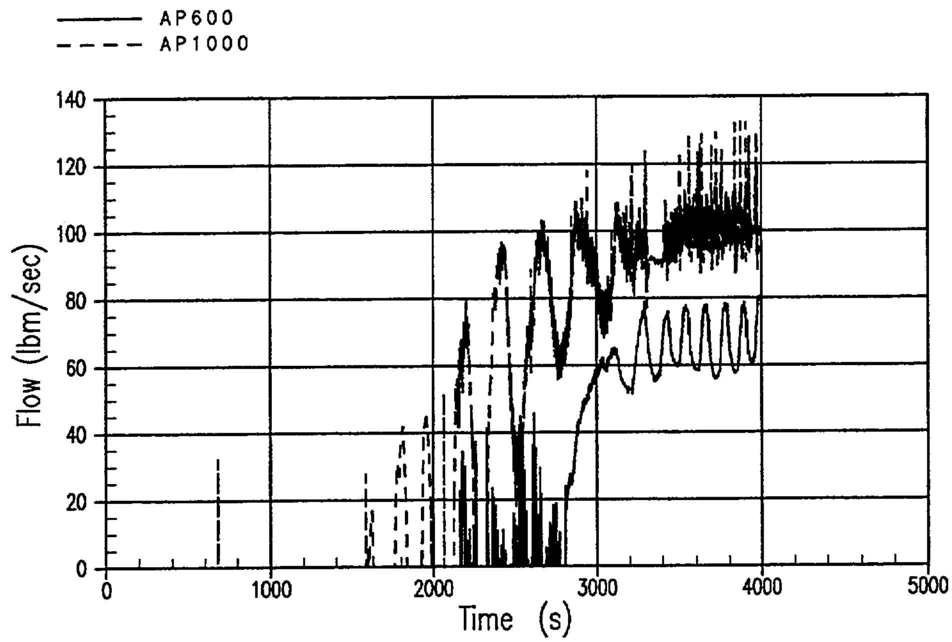


Figure 3.3.1.4-51 DEDVI Intact IRWST Injection Rate

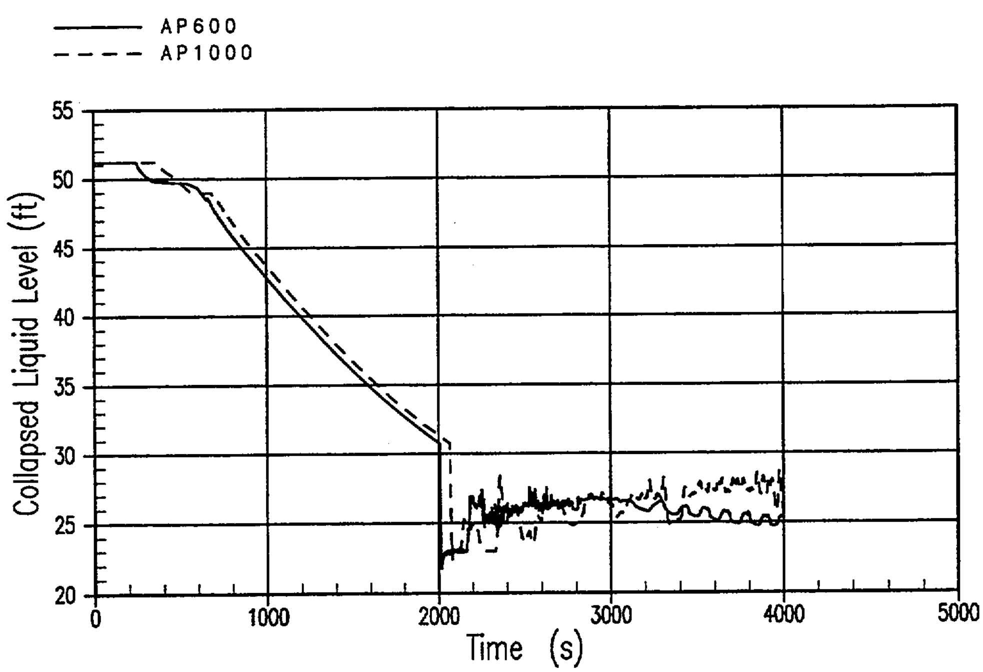


Figure 3.3.1.4-52 DEDVI Intact CMT Mixture Level

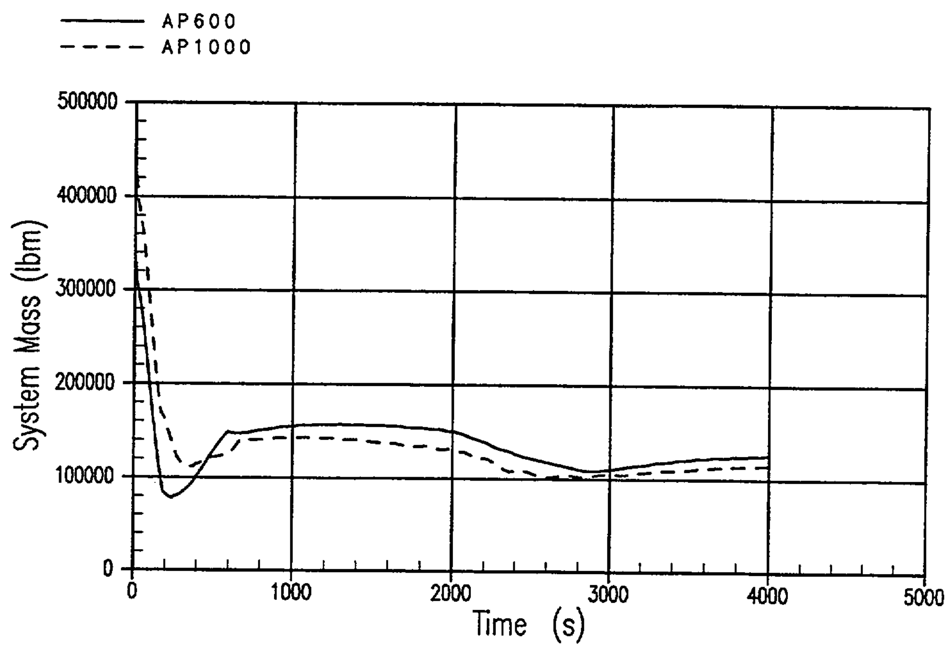


Figure 3.3.1.4-53 DEDVI RCS Inventory

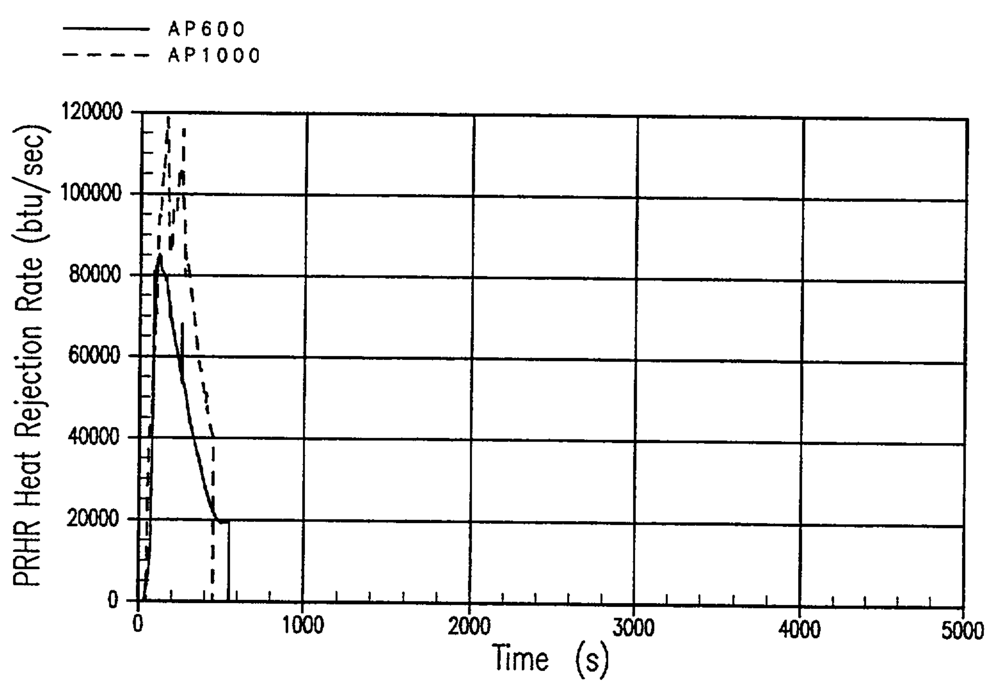


Figure 3.3.1.4-54 DEDVI PRHR Heat Rejection Rate

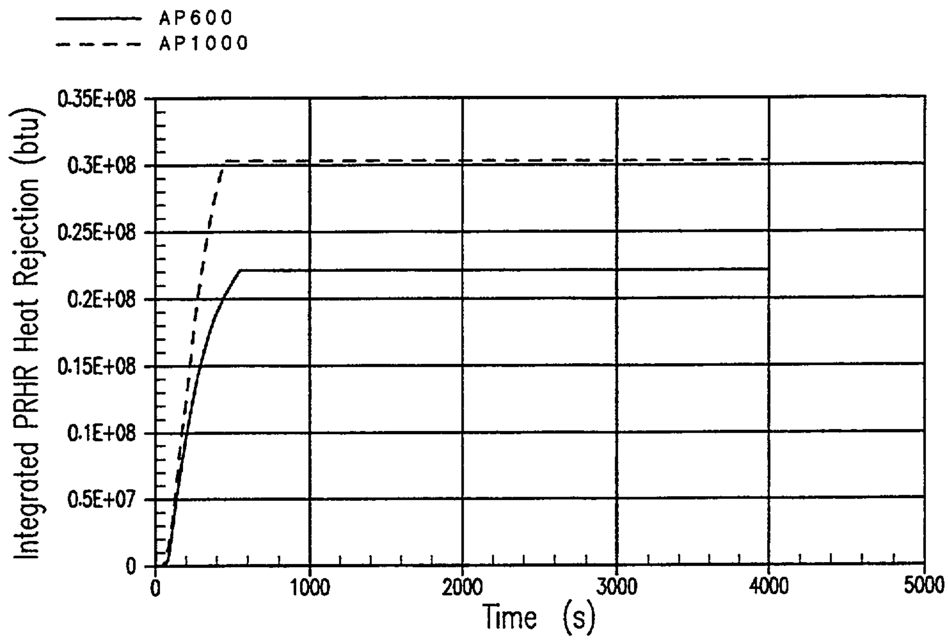


Figure 3.3.1.4-55 DEDVI Integrated PRHR Heat Removal

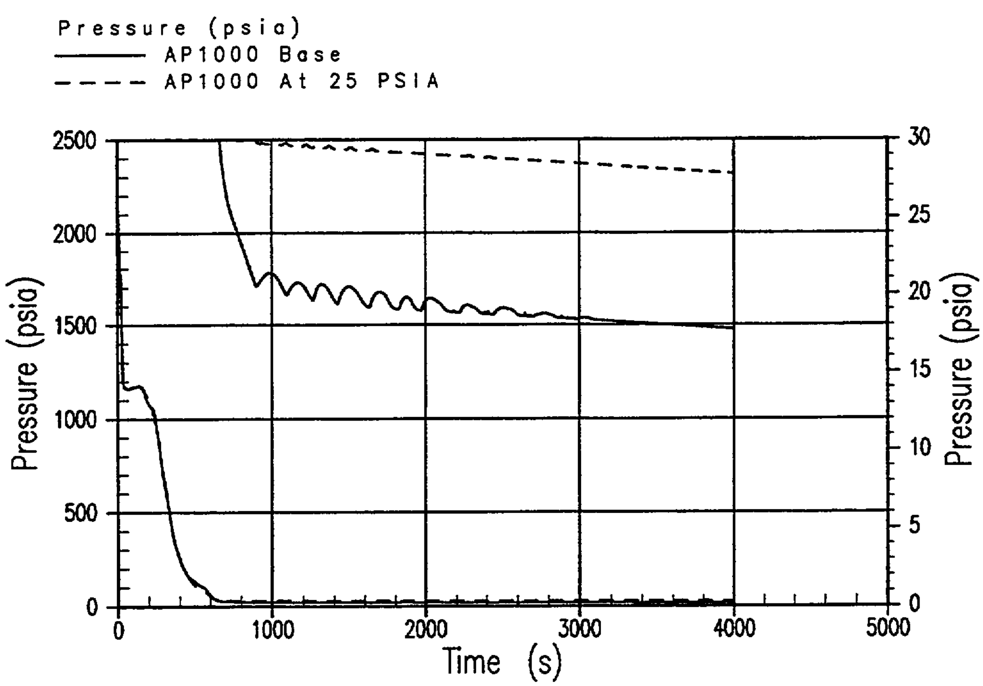


Figure 3.3.1.4-56 DEDVI @ 25 psia RCS Pressure

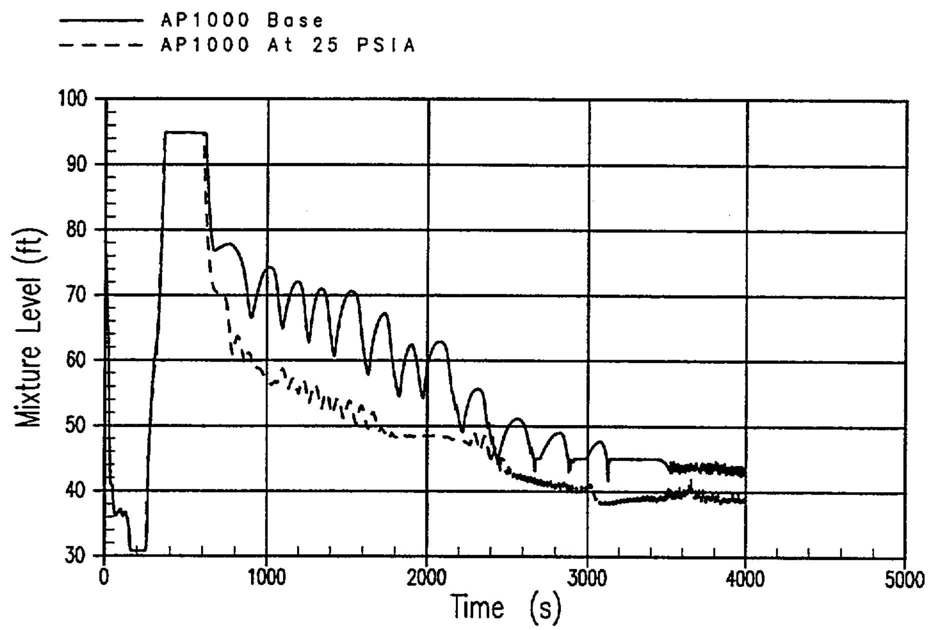


Figure 3.3.1.4-57 DEDVI @ 25 psia Pressurizer Mixture Level

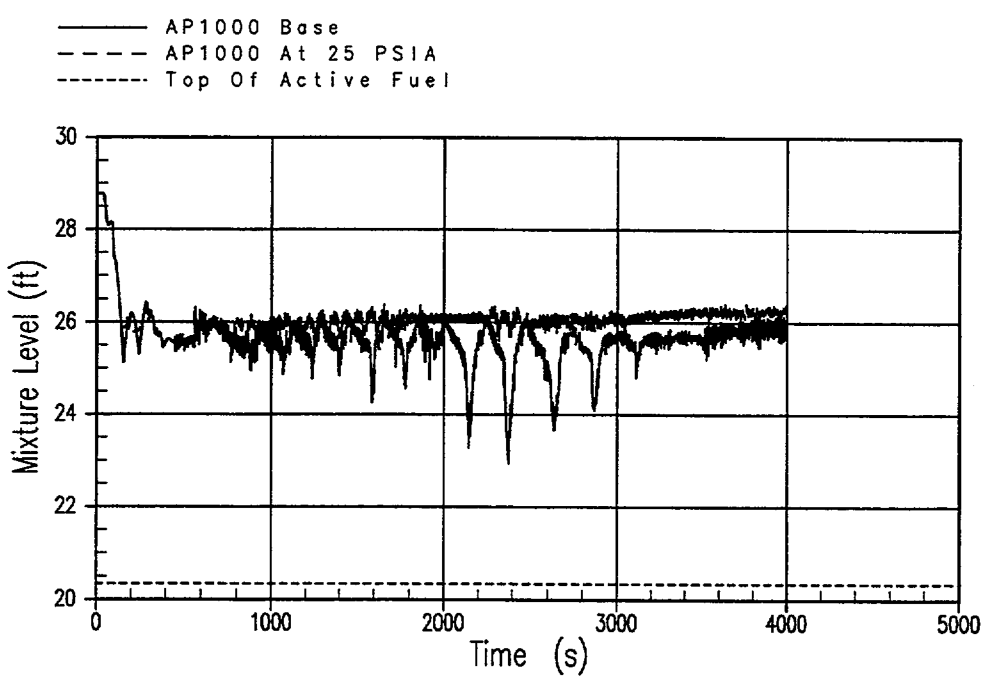


Figure 3.3.1.4-58 DEDVI @ 25 psia Core/Upper Plenum Mixture Level

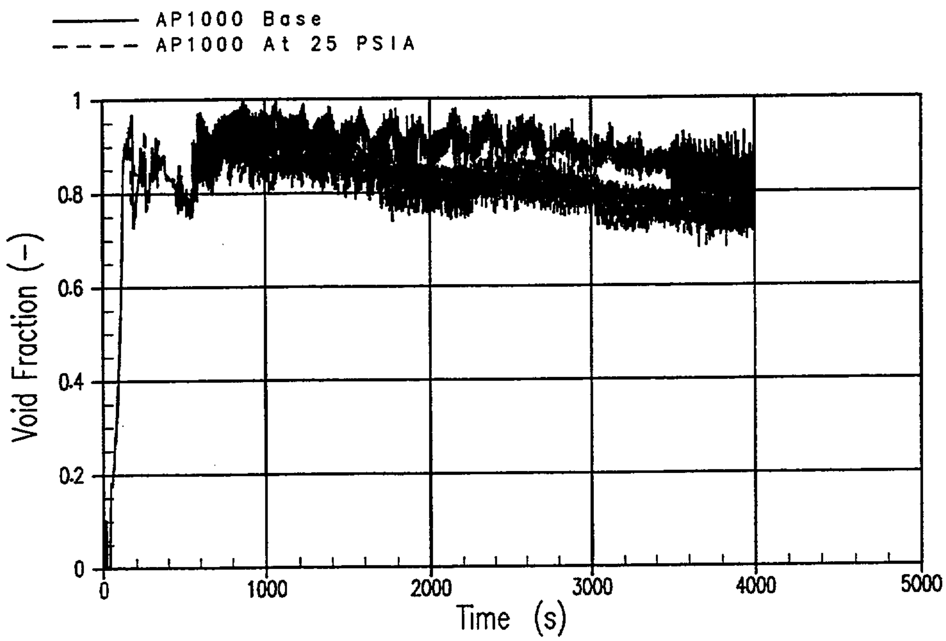


Figure 3.3.1.4-59 DEDVI @ 25 psia Core Exit Void Fraction

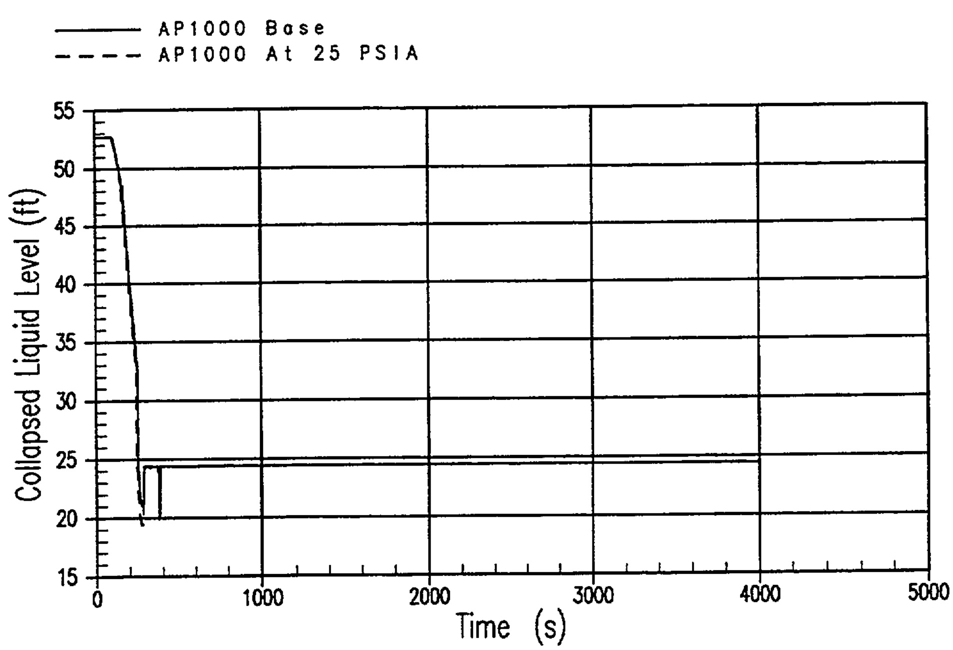


Figure 3.3.1.4-60 DEDVI @ 25 psia Broken CMT Mixture Level

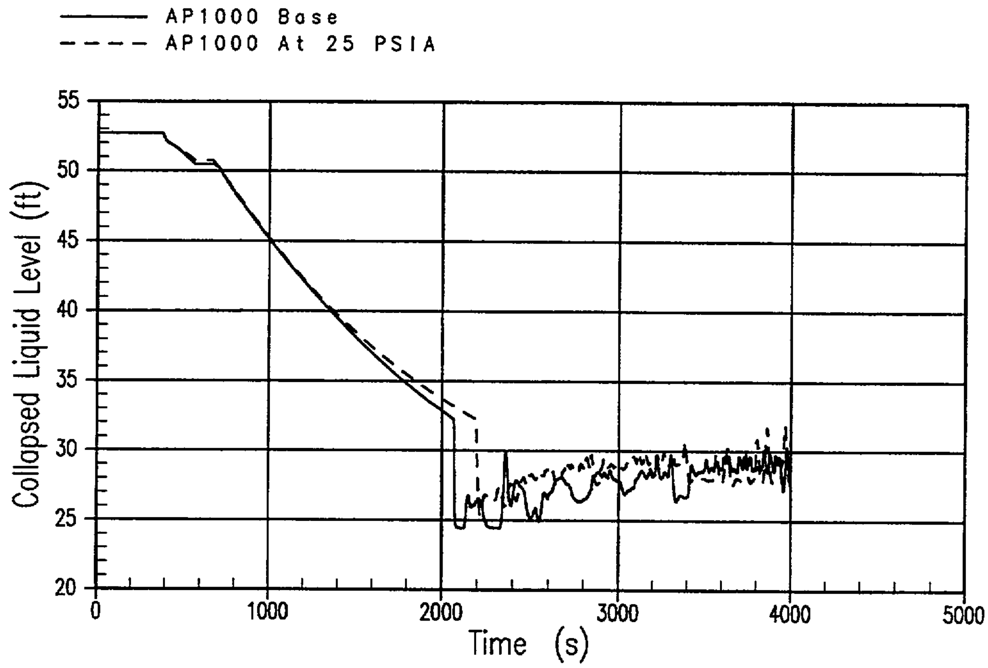


Figure 3.3.1.4-61 DEDVI @ 25 psia Intact CMT Mixture Level

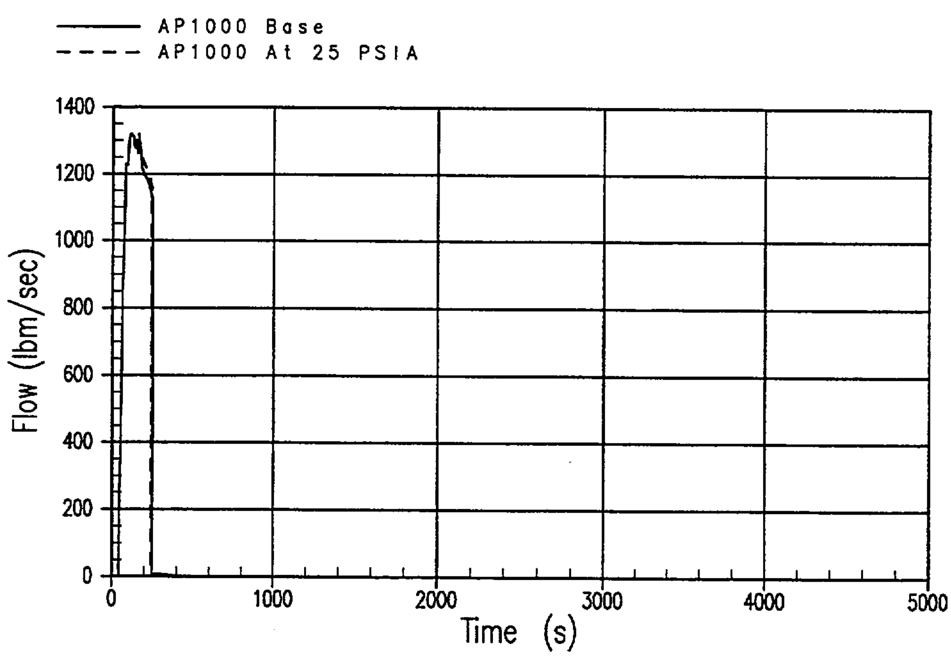


Figure 3.3.1.4-62 DEDVI @ 25 psia Broken CMT Injection Rate

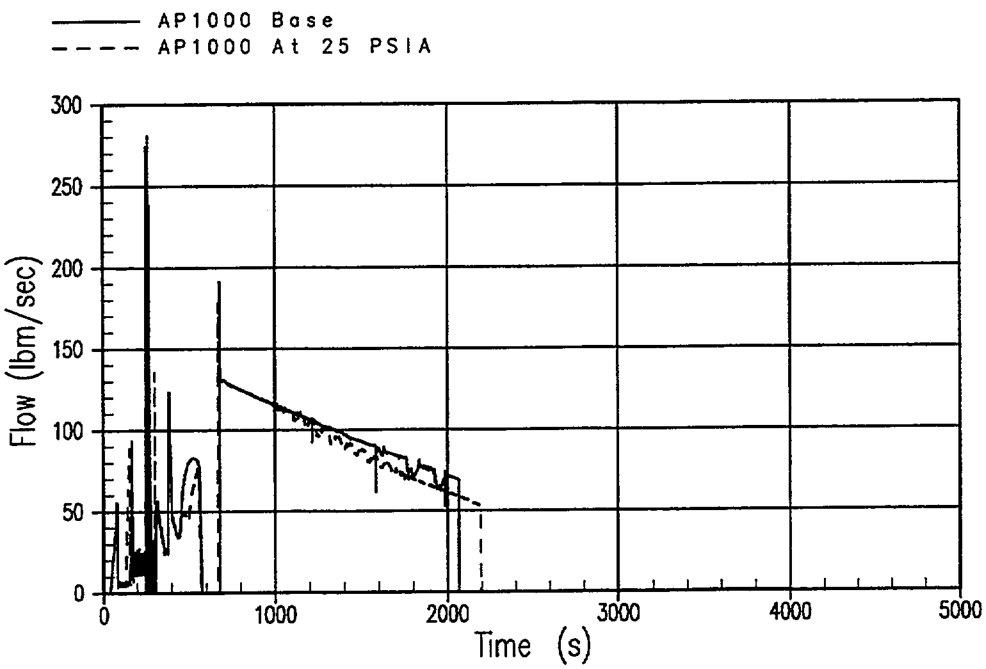


Figure 3.3.1.4-63 DEDVI @ 25 psia Intact CMT Injection Rate

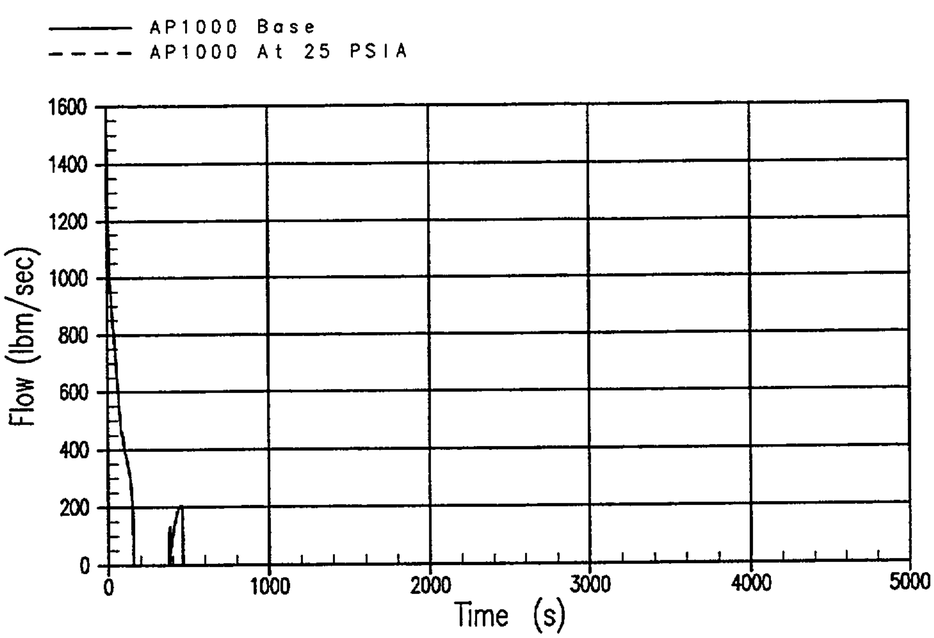


Figure 3.3.1.4-64 DEDVI @ 25 psia Broken Accumulator Injection Rate

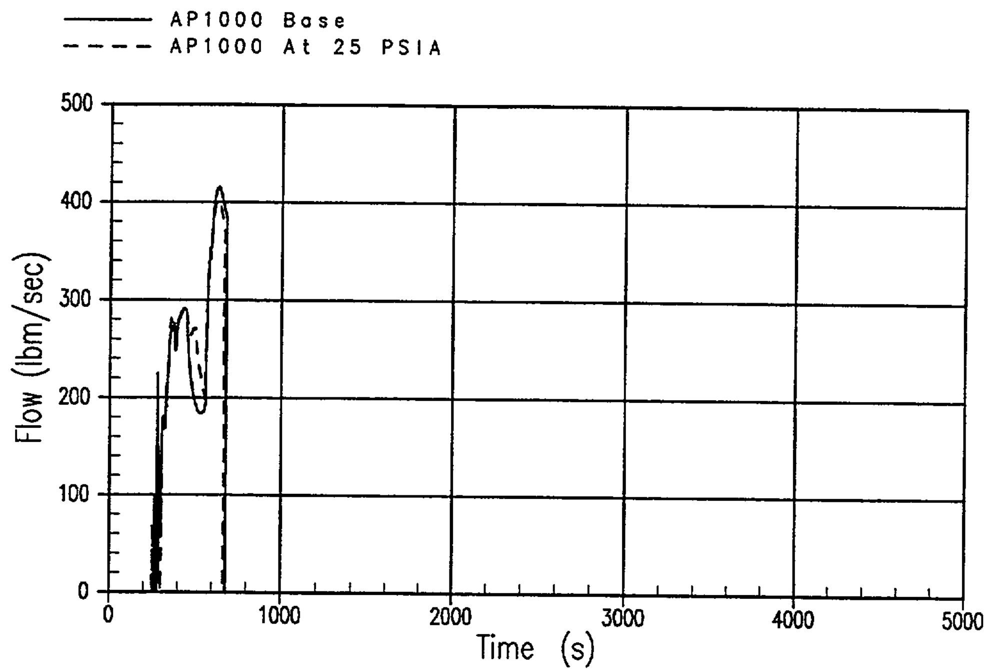


Figure 3.3.1.4-65 DEDVI @ 25 psia Intact Accumulator Injection Rate

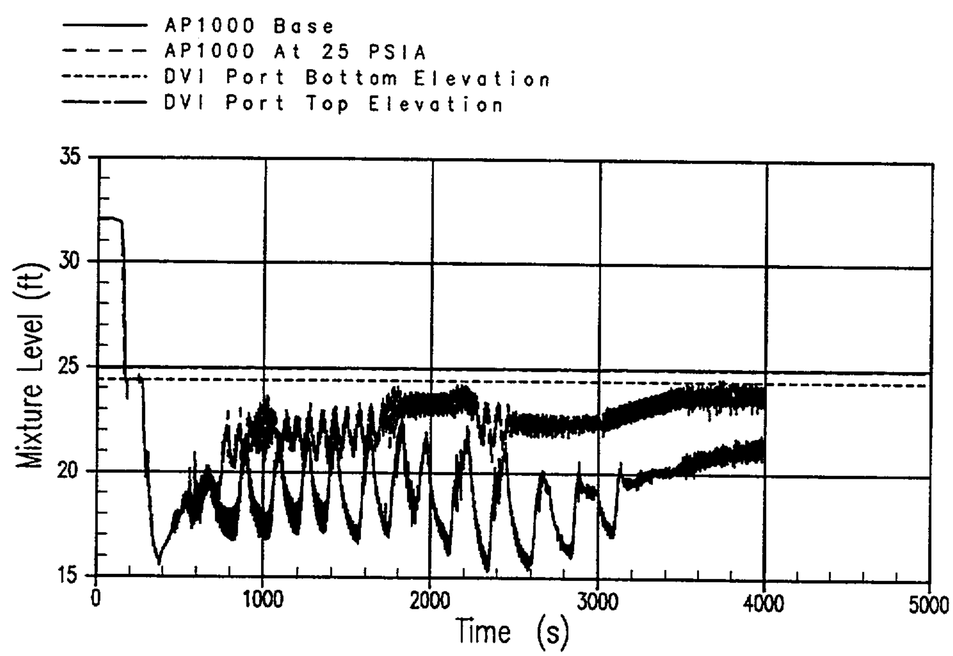


Figure 3.3.1.4-66 DEDVI @ 25 psia Downcomer Mixture Level

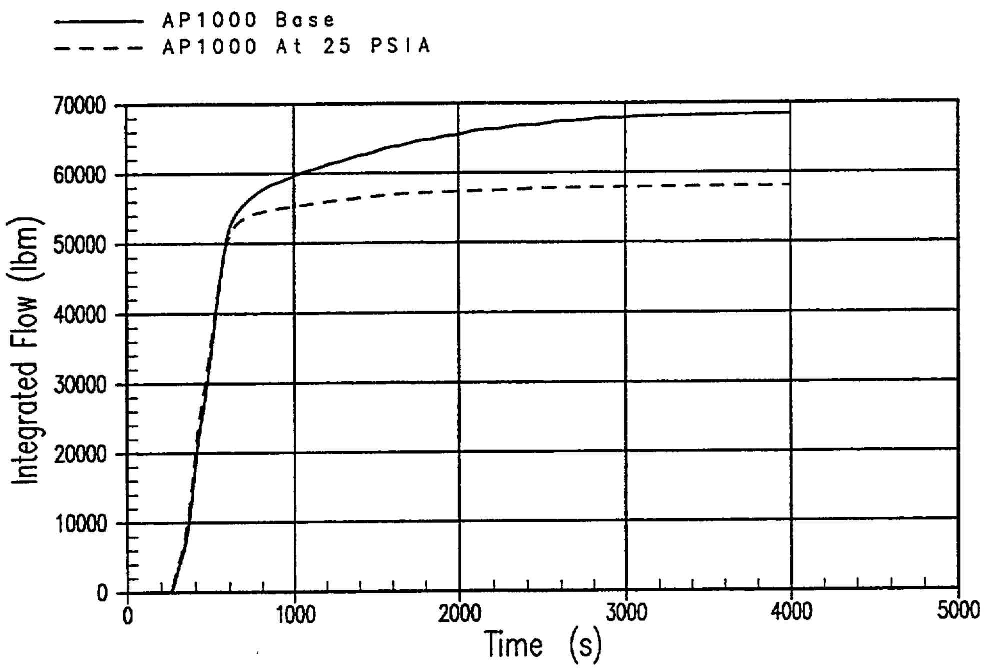


Figure 3.3.1.4-67 DEDVI @ 25 psia ADS 1-3 Integrated Discharge

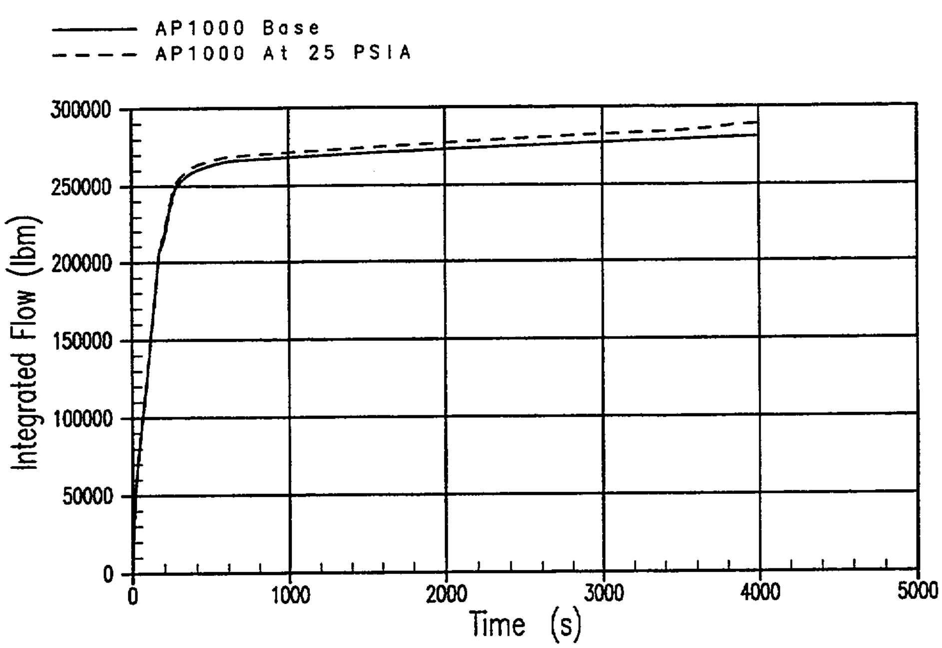


Figure 3.3.1.4-68 DEDVI @ 25 psia Vessel Side Break Integrated Discharge

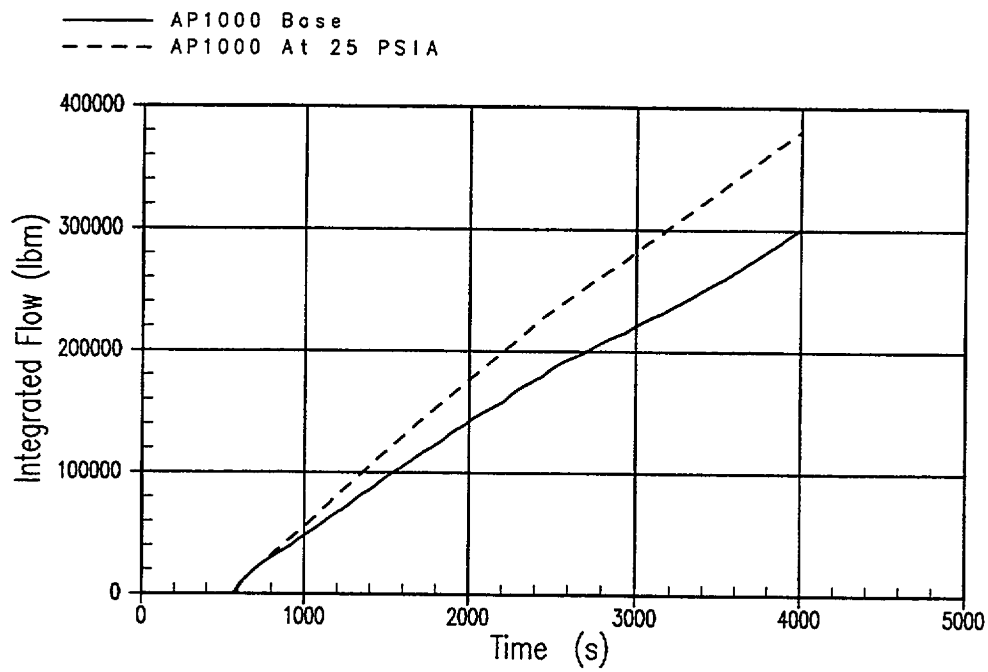


Figure 3.3.1.4-69 DEDVI @ 25 psia ADS-4 Integrated Discharge

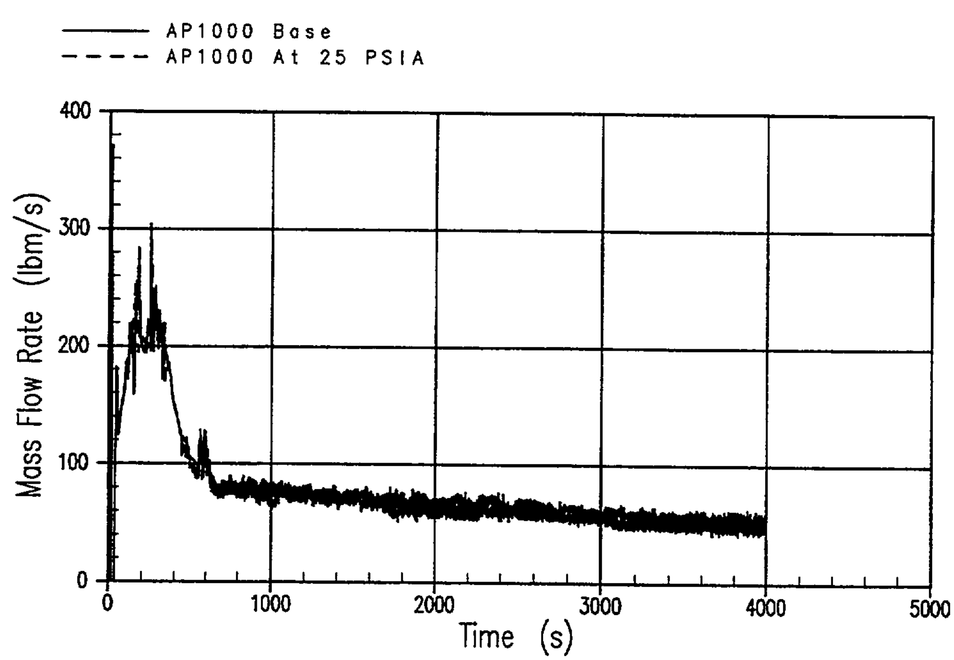


Figure 3.3.1.4-70 DEDVI @ 25 psia Core Exit Vapor Flow Rate

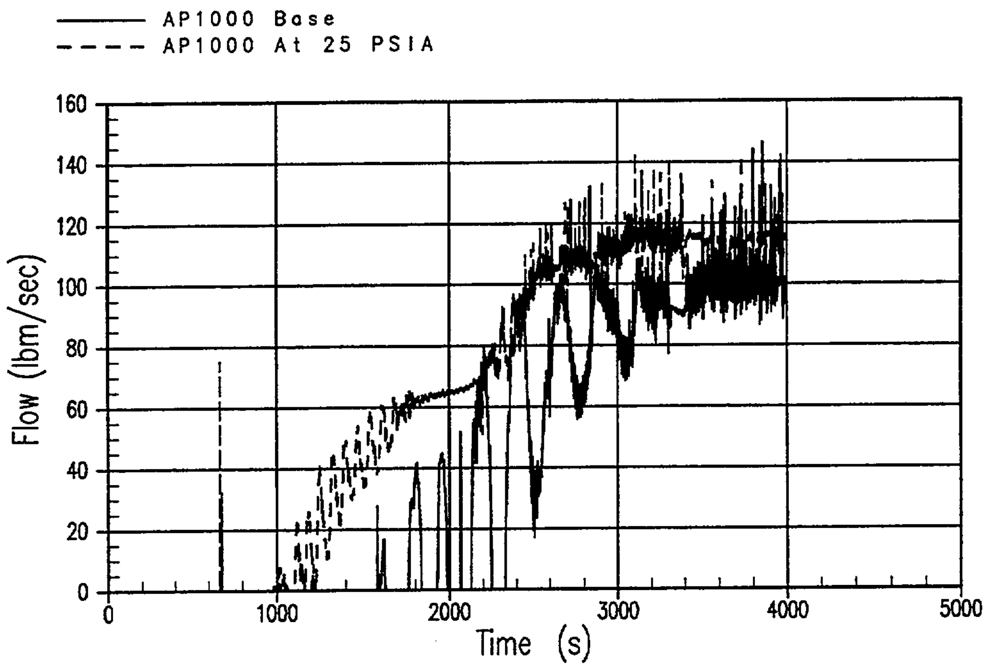


Figure 3.3.1.4-71 DEDVI @ 25 psia Intact IRWST Injection Rate

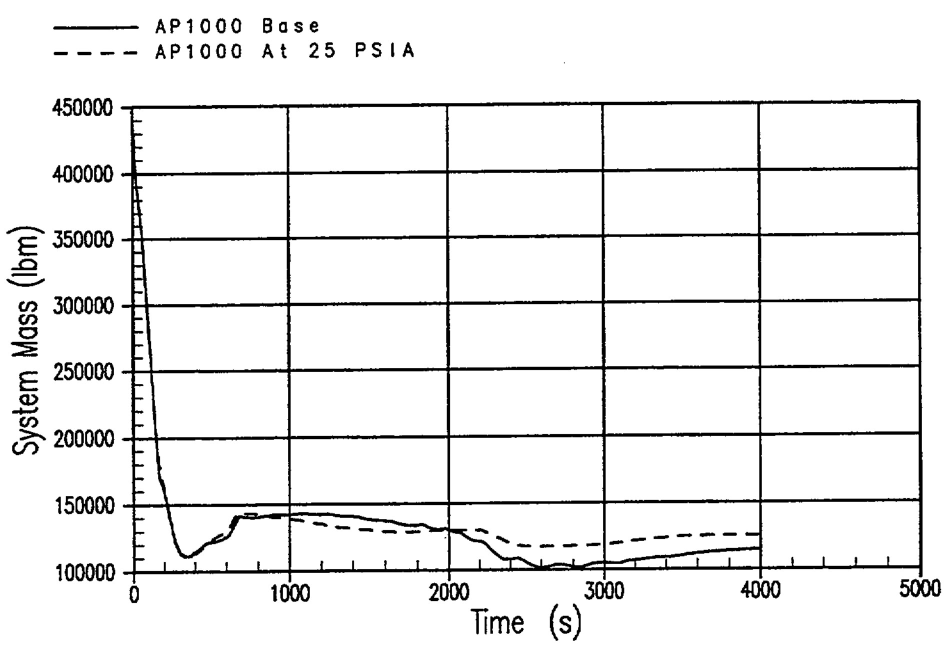


Figure 3.3.1.4-72 DEDVI @ 25 psia RCS Inventory

3.3.2 Steam Generator Tube Rupture Analysis

3.3.2.1 Introduction

The accident examined is the complete severance of a single steam generator tube. The accident is assumed to take place at power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited number of defective fuel rods within the allowance of the Technical Specifications. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system. In the event of a coincident loss of offsite power, or a failure of the condenser steam dump, discharge of radioactivity to the atmosphere takes place via the steam generator power-operated relief valves or the safety valves.

The assumption of a complete tube severance is conservative because the steam generator tube material (Inconel 690) is a corrosion-resistant and ductile material. The more probable mode of tube failure is one or more smaller leaks of undetermined origin. Activity in the secondary side is subject to continual surveillance, and an accumulation of such leaks, which exceeds the limits established in the Technical Specifications, is not permitted during operation.

The AP600 and the AP1000 designs provide automatic protective actions to mitigate the consequences of an SGTR. The automatic actions include reactor trip, actuation of the passive residual heat removal (PRHR) heat exchanger, initiation of core makeup tank flow, termination of pressurizer heater operation, and isolation of chemical and volume control system flow and startup feedwater flow on high steam generator level. These protective actions result in automatic cooldown and depressurization of the reactor coolant system, termination of the break flow and release of steam to the atmosphere, and long-term maintenance of stable conditions in the reactor coolant system. These protection systems serve to prevent steam generator overfill and to maintain offsite radiation doses within the allowable guideline values for a design basis SGTR. The operator may take actions that would provide a more rapid mitigation of the consequences of an SGTR.

Because of the series of alarms described next, the operator can readily determine when an SGTR occurs, identify and isolate the faulted steam generator, and complete the required recovery actions to stabilize the plant and terminate the primary-to-secondary break flow. The recovery procedures are completed on a time scale that terminates break flow to the secondary system before steam generator overfill occurs and limits the offsite doses to acceptable levels without actuation of the ADS. Indications and controls are provided to enable the operator to carry out these functions.

3.3.2.2 Sequence of Events for a Steam Generator Tube Rupture

The following sequence of events occur following an SGTR:

- Pressurizer low pressure and low level alarms are actuated and chemical and volume control system makeup flow and pressurizer heater heat addition starts or increases in an attempt to maintain pressurizer level and pressure. On the secondary side, main

feedwater flow to the affected steam generator is reduced because the primary-to-secondary break flow increases steam generator level.

- The condenser air removal discharge radiation monitor, steam generator blowdown radiation monitor, and/or main steam line radiation monitor alarm indicate an increase in radioactivity in the secondary system.

- Continued loss of reactor coolant inventory leads to a reactor trip generated by a low pressurizer pressure or over-temperature ΔT signal. Following reactor trip, the SGTR leads to a decrease in reactor coolant pressure and pressurizer level, counteracted by chemical and volume control system flow and pressurizer heater operation. A safeguards ("S") signal that provides core makeup tank and PRHR heat exchanger actuation is initiated by low pressurizer pressure or low-2 pressurizer level. The "S" signal automatically terminates the normal feedwater supply and trips the reactor coolant pumps. The power to the pressurizer heaters is also terminated. Startup feedwater flow is initiated on a low steam generator narrow range level signal and controls the steam generator levels to the narrow range low-level setpoint.

- The reactor trip automatically trips the turbine, and if offsite power is available, the steam dump valves open permitting steam dump to the condenser. In the event of a loss of offsite power or loss of the condenser, the steam dump valves automatically close to protect the condenser. The steam generator pressure rapidly increases resulting in steam discharge to the atmosphere through the steam generator power-operated relief valves and/or the safety valves.

- Following reactor trip and core makeup tank and PRHR actuation, the PRHR heat exchanger operation – combined with startup feedwater flow, borated core makeup tank flow, and chemical and volume control system flow – provides a heat sink that absorbs the decay heat. This reduces the amount of steam generated in the steam generators and steam bypass to the condenser. In the case of loss of offsite power, this reduces steam relief to the atmosphere.

- Injection of the chemical and volume control system and core makeup tank flow stabilizes reactor coolant system pressure and pressurizer water level, and the reactor coolant system pressure trends toward an equilibrium value, where the total injected flow rate equals the break flow rate.

3.3.2.3 Steam Generator Tube Rupture Automatic Recovery Actions

The AP600 and AP1000 incorporate several protection system and passive design features that automatically terminate a steam generator tube leak and stabilize the reactor coolant system, in the highly unlikely event that the operators do not perform recovery actions. Following an SGTR, the injecting chemical and volume control system flow (and pressurizer heater heat addition if the pressure control system is operating) maintains the primary-to-secondary break flow and the faulted steam generator secondary level increases as break flow accumulates in the steam generator. Eventually, the faulted steam generator secondary level reaches the high-2

steam generator narrow range level setpoint, which is near the top of the narrow range level span.

The AP600 and AP1000 protection system automatically provides several safety-related actions to cool down and depressurize the reactor coolant system, terminate the break flow and steam release to the atmosphere, and stabilize the reactor coolant system in a safe condition. The safety-related actions include initiation of the PRHR system heat exchanger, isolation of the chemical and volume control system pumps and pressurizer heaters, and isolation of the startup feedwater pumps.

Actuating the PRHR heat exchanger transfers core decay heat to the in-containment reactor water storage tank (IRWST) and initiates a cooldown (and a consequential depressurization) of the reactor coolant system.

Isolation of the chemical and volume control system pumps and pressurizer heaters minimizes the repressurization of the primary system. This allows primary pressure to equilibrate with the secondary pressure, which effectively terminates the primary-to-secondary break flow. Because the core makeup tank continues to inject when needed to provide boration following isolation of the chemical and volume control system pumps, isolating the chemical and volume control system pumps does not present a safety concern.

Isolation of the startup feedwater provides protection against a failure of the startup feedwater control system, which could potentially result in the faulted steam generator being overfilled. With decay heat removal by the PRHR heat exchanger, steam generator steaming through the power-operated relief valves ceases and steam generator secondary level is maintained.

3.3.2.4 Analysis of Effects and Consequences

An SGTR results in the leakage of contaminated reactor coolant into the secondary system and subsequent release of a portion of the activity to the atmosphere. An analysis is performed to demonstrate that the offsite radiological consequences resulting from an SGTR are within the allowable guidelines.

One of the concerns for an SGTR is the possibility of steam generator overfill because this can potentially result in a significant increase in the offsite radiological consequences. Automatic protection and passive design features are incorporated into the AP600 and AP1000 designs to automatically terminate the break flow to prevent overfill during an SGTR. These features include actuation of the PRHR system, isolation of chemical and volume control system flow, and isolation of startup feedwater.

For determining the offsite radiological consequences, an SGTR analysis is performed assuming the limiting single failure and limiting initial conditions relative to offsite doses. Because steam generator overfill is prevented for the AP600 and AP1000, the results of this analysis represent the limiting radiological consequences for an SGTR.

A thermal-hydraulic analysis is performed to determine the plant response for a design basis SGTR, the integrated primary-to-secondary break flow, and the mass releases from the faulted and intact steam generators to the condenser and to the atmosphere. This information is then used to calculate the radioactivity release to the environment and the resulting radiological consequences.

3.3.2.5 Computer Program

The plant response following an SGTR until the primary-to-secondary break flow is terminated is analyzed with the LOFTTR2 program (Reference 1). The LOFTTR2 program is modified to model the PRHR system, core makeup tanks, and protection system actions unique to the AP600 and AP1000. These modifications to LOFTTR2 are described in WCAP-14234, Revision 1 (Reference 2).

3.3.2.6 Analysis Results

The consequences of a postulated steam generator tube rupture (SGTR) were analyzed for the AP600 and presented in Section 15.6.3 of the DCD. The AP1000 has design features similar to those in the AP600. In order to evaluate the impact the differences in the two plant designs the transient analyzed for the AP600 in the DCD was analyzed for the AP1000. The general plant response to the SGTR is similar. The higher power level, larger pressurizer and longer steam generator tubes result in a slower rate of depressurization for the AP1000. Therefore, the low pressurizer level "S" signal was credited in the AP1000 analysis. The AP600 analysis in the DCD waited until the low pressurizer pressure signal was generated.

The sequence of events for the AP1000 SGTR is compared to that of the AP600 DCD case in Table 3.3.2-1.

Overall the transient response of the AP1000 is similar to the AP600. The larger plant takes longer to depressurize and lose pressurizer level, which impacts the time for "S" actuation. Break flow termination is delayed due to the higher power and the larger steam generator which delays CVS isolation by allowing more mass accumulation in the secondary side before the high level signal is generated. The higher decay heat results in increased steam releases. The higher hot leg temperature results in a higher break flow flashing fraction.

Figures comparing key transient parameters are provided at the end of this section.

Table 3.3.2-2 presents the mass transfer results for the AP1000 LOFTTR2-AP analysis compared to the AP600 analysis.

The higher power results in increased releases for the AP1000 relative to the AP600. Experience with operating plant SGTR analyses has shown that uprating provides higher releases for dose analyses.

Offsite total effective dose equivalent (TEDE) doses were calculated for the AP600 and presented in the DCD. The TEDE dose is the combination of the committed effective dose

equivalent (CEDE) and gamma whole body doses from iodines and the gamma whole body doses from noble gases.

The increase in total break flow results in a proportional increase in the contribution from noble gases since no partitioning or holdup is modeled.

The increase in flashed break flow would result in an approximately proportional increase in the thyroid doses, since iodine activity transferred in the flashed break flow is assumed to be released directly to the atmosphere. These releases account for the majority of the doses from iodine. The increase in break flow and steam release does not have as significant an impact since the 0.01 partition coefficient applies to the releases.

Calculations have been performed to conservatively estimate the impact that the higher break flow and steam release will have on the calculated offsite doses. Results of these calculations show that the offsite doses for a steam generator tube rupture are expected to increase by a factor of approximately 1.65 over those calculated for the AP600. Table 3.3.2-3 compares the calculated AP600 offsite doses, the estimated AP1000 offsite doses, and the doses reported in the AP600 DCD.

The estimated AP1000 SGTR doses are well below the applicable limits of 2.5 rem for the accident-initiated iodine spike and 25 rem for the pre-accident iodine spike, and also below the dose results reported for the AP600 in the DCD.

Based on the SGTR transient analyzed and offsite doses assessment presented in this report there is no indication that the AP1000 design would present a problem from an SGTR dose standpoint.

3.3.2.7 References

1. Lewis, R. N., et al., "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill", WCAP-10698-P-A (Proprietary) and WCAP-10750-A (Nonproprietary), August 1987.

2. Carlin, E. L., Bachrach, U., "LOFTRAN & LOFTTR2 AP600 Code Applicability Document," WCAP-14234, Revision 1 (Proprietary), August 1997.

Table 3.3.2-1 Sequence of Events for a Steam Generator Tube Rupture		
Event	AP1000 Time (sec)	AP600 Time (sec)
SGTR occurs	0.0	0.0
Reactor trip	0.0 (actually 0.15)	0.0 (actually 0.15)
RCPs tripped	0.0	0.0
CVS Makeup Pump flow initiated	0.0 (actually 0.2)	0.0 (actually 0.2)
Pzr heaters on	0.0 (actually 0.2)	0.0 (actually 0.2)
SIS low pressurizer level setpoint	2639	1524 (ignored)
SIS low pressurizer pressure setpoint	2768*	2765
Pzr heaters off	2641	2765
Ruptured SG PORV fails open	2641	2765
CMT injection begins	2662	2787
PRHR actuates	2662	2787
Ruptured SG PORV isolated	3009	3013
Charging flow isolated	13025	8393

* Due to depressurization caused by failed open SG PORV

Table 3.3.2-2 Steam Generator Tube Rupture Mass Transfer Results				
Plant	Time Break Flow Flashing Stops	Total Flashed Break Flow After Trip	Total Ruptured SG Steam Releases After Trip	Total Break Flow
AP1000	3407 sec	7351.0 lbm	324600 lbm	427300 lbm
AP600	3216 sec	5052.4 lbm	144800 lbm	264900 lbm

Table 3.3.2-3 Comparison of Radiological Consequences of a Steam Generator Tube Rupture			
	AP600 Calculated TEDE Dose (rem)	**AP1000 Estimated TEDE Dose (rem)**	**AP600 TEDE Dose (As Reported in DCD) (rem)**
Accident-initiated iodine spike			
Site boundary	0.54	0.9	1.5
Low population zone	0.08	0.13	0.3
Pre-accident iodine spike			
Site boundary	0.85	1.4	3.0
Low population zone	0.13	0.21	0.45

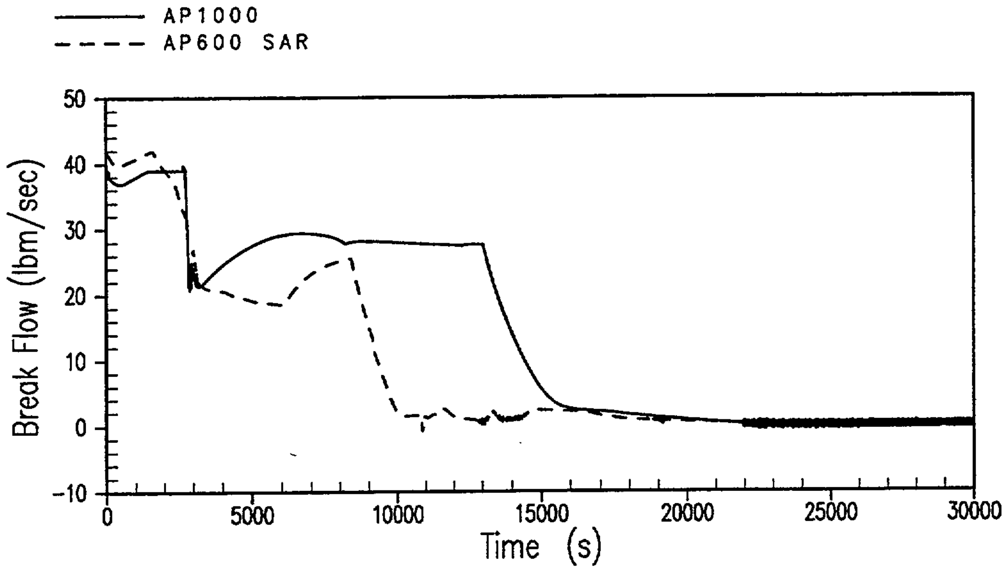


Figure 3.3.2-1 Steam Generator Tube Rupture Break Flow

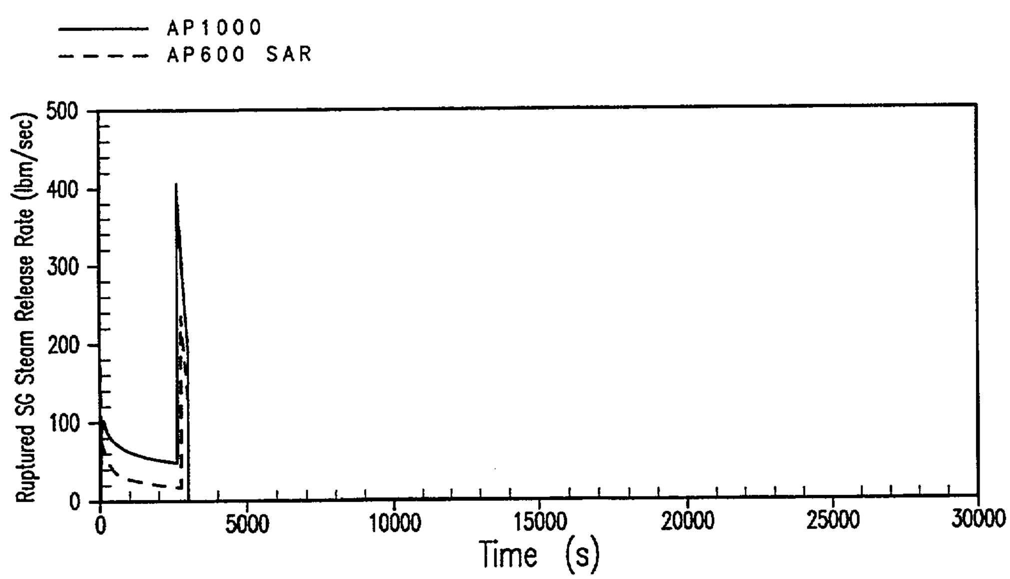


Figure 3.3.2-2 Steam Generator Tube Rupture SG Steam Release

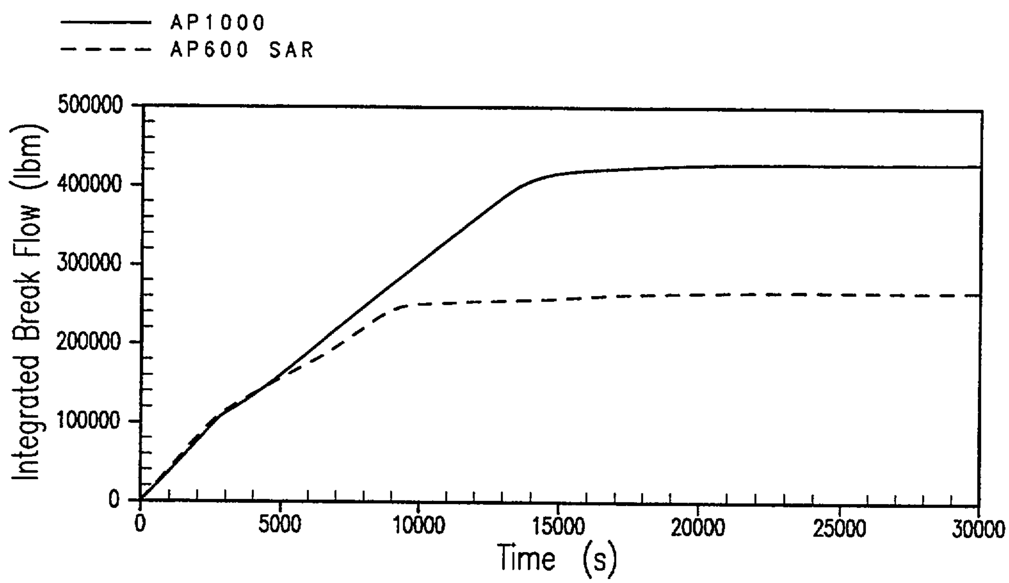


Figure 3.3.2-3 Steam Generator Tube Rupture Integrated Break Flow

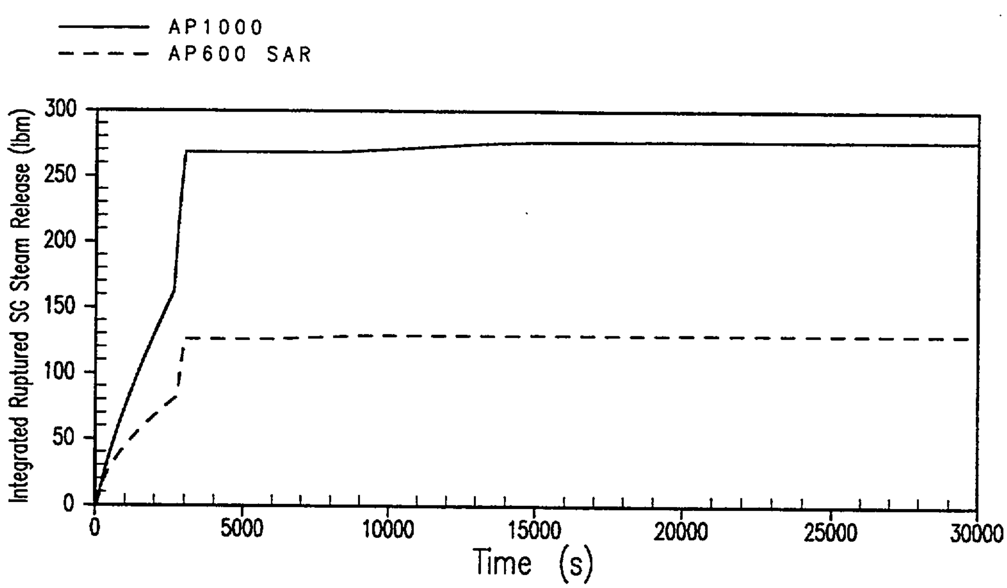


Figure 3.3.2-4 Steam Generator Tube Rupture Integrated SG Steam Release

3.3.3 Post-LOCA Long-Term Cooling

3.3.3.1 Long-Term Cooling Analysis Methodology

The AP1000 safety-related systems are designed to provide adequate cooling of the reactor indefinitely. Initially, this is achieved by discharging water from the IRWST into the vessel. When the low-3 level setpoint is reached in the IRWST, the containment recirculation subsystem isolation valves open and water from the containment reactor coolant system (RCS) compartment can flow into the vessel. The water in containment rises in temperature to near the saturation temperature. Long-term heat removal from the reactor and containment is by heat transfer through the containment shell to atmosphere.

The purpose of the long-term cooling analysis is to demonstrate that the passive systems provide adequate emergency core cooling system performance during the IRWST injection/containment recirculation time scale. The long-term cooling analysis is performed using the WCOBRA/TRAC computer code to verify that the passive injection system is providing sufficient flow to the reactor vessel to cool the core and to preclude boron precipitation.

A DEDVI line break is analyzed because it is the most limiting in the relationship between decay power and available liquid driving head. Because the IRWST spills directly onto the containment floor in a DEDVI break, this event has the highest core decay power when the IRWST empties during long-term cooling. In postulated break cases, before the IRWST becomes empty, the RCS compartment water level exceeds the reactor coolant system loop level, so water can flow from the containment into the reactor coolant system through the passive core cooling system piping once the containment recirculation subsystem isolation valves have opened; this in-flow of water through the DVI lines continues the cycle of heat removal from the core. The steam produced by boiling in the core vents to the containment through the ADS valves and condenses on the inner surface of the steel containment vessel. The condensate is collected and drains to the IRWST to become available for injection into the reactor coolant system. The WCOBRA/TRAC analysis presented analyzes the DEDVI small-break LOCA events from a time near the inception of IRWST injection to the time of containment recirculation. During this time, the head of water to drive the flow into the vessel for IRWST injection decreases from the initial level to its lowest value at the containment recirculation switchover time.

The time from occurrence of a break to the establishment of a steady flow of water from the containment is long. The approach in the AP600 DCD was to perform the calculations in a "window" mode. This means that the WCOBRA/TRAC long-term cooling calculation was initiated at times during the long-term transient with conditions that come from a previous WCOBRA/TRAC large-break LOCA calculation, from a previous NOTRUMP small-break LOCA calculation, or from conservative estimates of the conditions at the time of the calculation. In this report, a continuous analysis of the post-LOCA long term cooling is provided from the time of stable IRWST injection to the time of sump recirculation. Results of that analysis is presented in Section 3.3.3.2. A window mode case long-term cooling calculation is presented in Section 3.3.3.3 for comparison with the continuous analysis result. The AP1000

design resistances are applied in WCOBRA/TRAC for both the ADS Stage 4 flow paths and the IRWST injection and containment recirculation flow paths.

The break modeled is a double-ended guillotine failure in one of the direct vessel injection lines. The long-term cooling phase begins after the simultaneous opening of the isolation valves in the IRWST DVI lines and the opening of ADS Stage 4 squib valves, when flow injection from the IRWST has been activated.

The discharge from the IRWST through the broken line is such that the water level in the valve room compartment is above the broken nozzle at the start of long-term cooling.

In the analysis, one of the two ADS Stage 4 valves in the non-PRHR loop is assumed to have failed. Also, the initial reactor coolant system liquid inventory and temperatures for these cases are determined from the NOTRUMP calculation for the DEDVI break presented in Section 6.2.1. This equates to a full lower plenum and downcomer, a core collapsed liquid level of 8.5 feet (relative to the bottom of the heated length), and a collapsed level of 3 feet in the upper plenum. The core makeup tanks do not contribute to the DVI injection. Steam generator secondary side conditions are taken from the NOTRUMP calculation (at the beginning of long-term cooling). The reactor coolant pumps are tripped and not rotating.

The levels in the IRWST, the broken DVI line valve room, and the containment sump are generated using the MAAP code model of the AP1000 containment. A constant containment pressure of 29.5 psia is assumed based on a WGOTHIC calculation of the conservative minimum pressure.

3.3.3.2 DEDVI Line Break with ADS Stage 4 Single Failure, Passive Core Cooling System Only Case; Continuous Case

This subsection presents the results of a DEDVI line break analysis during IRWST injection phase continuing into sump recirculation. Initial conditions at the start of the case are prescribed based on the NOTRUMP DEDVI break results to allow a calculation to begin shortly after IRWST injection begins in the small break long-term cooling transient. The WCOBRA/TRAC calculation is then allowed to proceed until a quasi-steady-state is achieved. At this time, the predicted results are independent of the assumed initial conditions. This calculation uses boundary conditions taken from a MAAP analysis of IRWST drain; the IRWST level, which at the beginning of the simulation is set to a value of 124 feet, is decreased constantly during the calculation, which is carried out for 10000 seconds until a quasi-steady-state sump recirculation condition has been established for 800 seconds.

In this transient, the IRWST provides a hydraulic head sufficient to drive water into the downcomer through the intact DVI nozzle. Also, water flows into the downcomer from the passive core cooling system valve room through the broken DVI line. The water flows down the downcomer and up through the core, into the upper plenum. Steam produced in the core entrains liquid and flows out of the reactor coolant system via the ADS Stage 4 valves. There is little flow out of ADS Stages 1, 2, and 3 even when the IRWST liquid level falls below the

sparger elevation. The venting provided by the ADS paths enables liquid to flow through the core to maintain core cooling.

Approximately 1000 seconds of WCOBRA/TRAC calculation are required to establish the quasi-steady-state condition associated with IRWST injection at the start of long-term cooling and so are ignored in the following discussion. The hot leg levels are such that during the IRWST injection phase the quality of the ADS Stage 4 mass flows varies as water is entrained from the hot legs. This periodically increases the pressure drop across the ADS Stage 4 valves and the upper plenum pressure. The higher pressure in the upper plenum reduces the injection flow. This cycle of pressure variations due to changing void fractions in the flow through ADS Stage 4 is consistent with test observations and is expected to recur often during long-term cooling.

The head of water in the IRWST and in the passive core cooling system valve room causes a flow of subcooled water into the downcomer at average rates of 40 lbm/sec and 60 lbm/sec through the DVI nozzles, respectively at the start of long-term cooling. The downcomer level at the end of the code initiation, the start of long-term cooling is about 19 feet (Figure 3.3.3.2-1). Note that the time scale of this and other figures in subsection 3.3.3.2 is offset by (-2000) seconds; that is, a time of 1000 seconds on the Figure 3.3.3.1 axis equals 3000 seconds transient time for the DEDVI break. All of the injection water flows down the downcomer and up through the core. The accumulators have been fully discharged before the start of the time window and do not contribute to the DVI flow.

Boiling in the core produces steam and a two-phase mixture, which flows into the upper plenum. The core is 14 feet high, and the core collapsed liquid level (Figure 3.3.3.2-2) is about 7.7 feet at the start of long-term cooling. The boiling process causes a variable rate of steam production and resulting pressure spikes, which in turn causes oscillations in the liquid flow rate at the bottom of the core and also variations in the core collapsed level and the flow rates of liquid, entrained droplets and vapor out of the top of the core. In the WCOBRA/TRAC noding, the core is divided into two axial levels, each of which is 7 feet high. The void fractions in the two levels are shown as Figures 3.3.3.2-3 and -4. The core void fraction is low for the bottom cell and has a mean void fraction of 0.1 or less in the entire long-term cooling transient. The void fraction of the upper core cell exceeds 0.8 at the start of long-term cooling, decreases as the decay heat decreases, then increases at the end of long-term cooling during the containment recirculation period. The final 800 seconds of the Figures models injection only from containment; the average upper core node void fraction is 0.8 over this time. There is a continuous flow of two-phase fluid into the hot legs, and mainly vapor flow toward the ADS Stage 4 valve occurs at the top of the pipe. The collapsed liquid level in the hot leg varies between 1.0 feet to 1.5 feet (Figure 3.3.3.2-5). The hot legs on average are more than 50-percent full. Vapor and liquid flows at the top of the core are shown in Figures 3.3.3.2-6 and 3.3.3.2-7, the upper plenum collapsed liquid level in Figure 3.3.3-8. Figures 3.3.3-9 and 3.3.3.2-10 are ADS stage 4 mass flowrates.

The pressure in the upper plenum is shown in Figure 3.3.3.2-11. The upper plenum pressurization, which occurs in some time periods, is due to the ADS Stage 4 water discharged. The hot rod PCT follows saturation temperature (Figure 3.3.3.2-12). A small pressure drop is

calculated across the vessel, and injection rates through the DVI lines into the vessel are presented in Figures 3.3.3.2-13 and -14. Figure 3.3.3.2-13 shows the flow through the broken DVI line is about 70 lbm/s at both the start and end of the long-term cooling period, and it increases to a maximum average value of 90 lbm/s. In contrast, DVI-B flow falls from 170 lbm/s with a full IRWST to about 75 lbm/s flow from the containment in the final 800 seconds. The recirculation core liquid throughput of 110 lbm/s is more than adequate to preclude any boron buildup on the fuel.

3.3.3.3 DEDVI Line Break Window Mode Analysis; Containment Recirculation Time Window

This subsection presents results of an analysis of AP1000 behavior after a DEDVI break immediately prior to and after the containment recirculation switchover at 9613 seconds using window mode methodology. The initial conditions and boundary conditions at the start of the window are consistent with the end of the IRWST injection phase in the continuous calculation. After a 500 second code initiation, almost 1400 seconds of combined injection is used to establish the conditions at the start of the containment recirculation time period. The IRWST injection is then terminated and the calculation is then carried over another 1000 seconds, which is a time period long enough to establish the recirculation quasi-steady-state condition. The RCS compartment level is simulated constant at 107.65 during the time window, and the liquid temperature there is set to 193°F at containment pressure of 29.5 psia, as computed by WGOTHIC.

In this calculation, there is sufficient liquid head to drive water into the downcomer through the intact DVI nozzles. Also, water with a temperature of 145°F is simulated to flow from the passive core cooling system compartment through the broken DVI line as it is replenished from the RCS compartment. The water introduced into the downcomer flows down the downcomer and up through the core into the upper plenum. Steam produced in the core entrains liquid droplets and flows out of the reactor coolant system via the ADS Stage 4 valves. The DVI flow and the venting provided by the ADS paths provide a sufficient flow to cool the core.

The first 500 seconds of transient required to establish the quasi-steady-state condition are ignored in the following discussion. As in the continuous calculation, venting through ADS Stage 4 paths provides adequate safety injection from the IRWST and/or containment in the window analyzed. The 500-3000 second time interval in the subsection 3.3.3.3 set of figures corresponds to the 7500-10000 second interval on the subsection 3.3.3.2 figures.

The sequence of figures in subsection 3.3.3.3 is the same as in subsection 3.3.3.2. The downcomer and core collapsed liquid levels are the same in the two cases at 18 feet and 8 feet, respectively, for the equivalent time frame which is the final 800 seconds of each case. The core node void fractions are also virtually the same, as are the predicted hot leg liquid levels. In fact, almost all of the plotted parameters closely resemble one another between the two runs in the 800 second final time interval. The one slight exception to this is that the window calculation pressure is a bit more variable in the comparable time interval. As a result, the DVI flowrates in Figures 3.3.3.3-13 and 14 show wider fluctuation than do the DVI flowrates in Figures 3.3.3.2-13

and -14. Still, the average DVI flowrates of the two cases agree well for the comparable time interval.

Figures 3.3.3.3-15 and 3.3.3.3-16 provide a direct comparison of the predicted injection flowrates for the two AP100 long-term cooling cases over the final 1000 seconds of the WCOBRA/TRAC runs; the continuous calculation result is the solid line, the window mode result is the dashed curve in these figures. Figure 3.3.3.3-15 shows the injection flow through the intact DVI line, and Figure 3.3.3.3-16 shows the flow entering the reactor vessel through the severed DVI line. As previously stated, close agreement exists between the two predictions. Figures 3.3.3.3-17 and 3.3.3.3-18 show the comparison of collapsed liquid level predictions in the downcomer and core, respectively; once again the continuous calculation result is the solid line, the window mode result the dashed curve. The level predictions of the two cases are essentially identical.

The upper plenum pressurization is due to the ADS Stage 4 water discharge as previously discussed.

3.3.3.4 Conclusions

Calculations of AP1000 long-term cooling performance have been performed using the WCOBRA/TRAC model approved for AP600. The DEDVI case was chosen because it reaches sump recirculation at the earliest time (and highest decay heat).

The DEDVI small break LOCA exhibits significant margin to core uncovery with a favorable reactor coolant system mass inventory condition during the long-term cooling phase from its initiation into containment recirculation. Adequate flow through the core is provided to maintain a low cladding temperature and to prevent any buildup of boric acid on the fuel rods.

The time interval at the beginning of sump recirculation for AP1000 has also been analyzed using the window mode technique from the AP600 DCD. The results obtained agree very well with those from the continuous calculation for the corresponding time interval. This result further demonstrates the capability of the window mode method to analyze the long-term cooling performance of passive plant designs over selected time intervals.

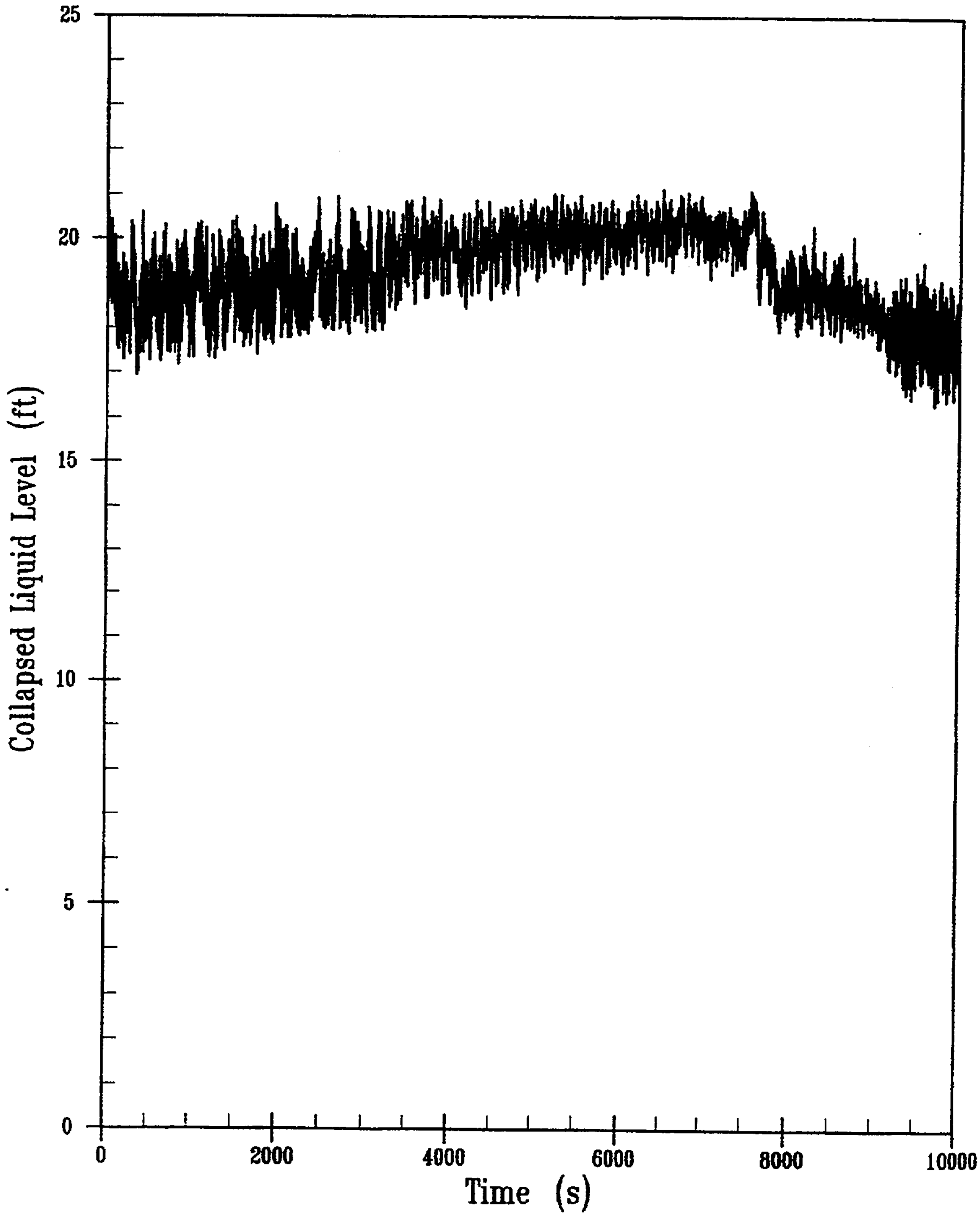


Figure 3.3.3.2-1 Collapsed Level of Liquid in the Downcomer (Continuous Case)

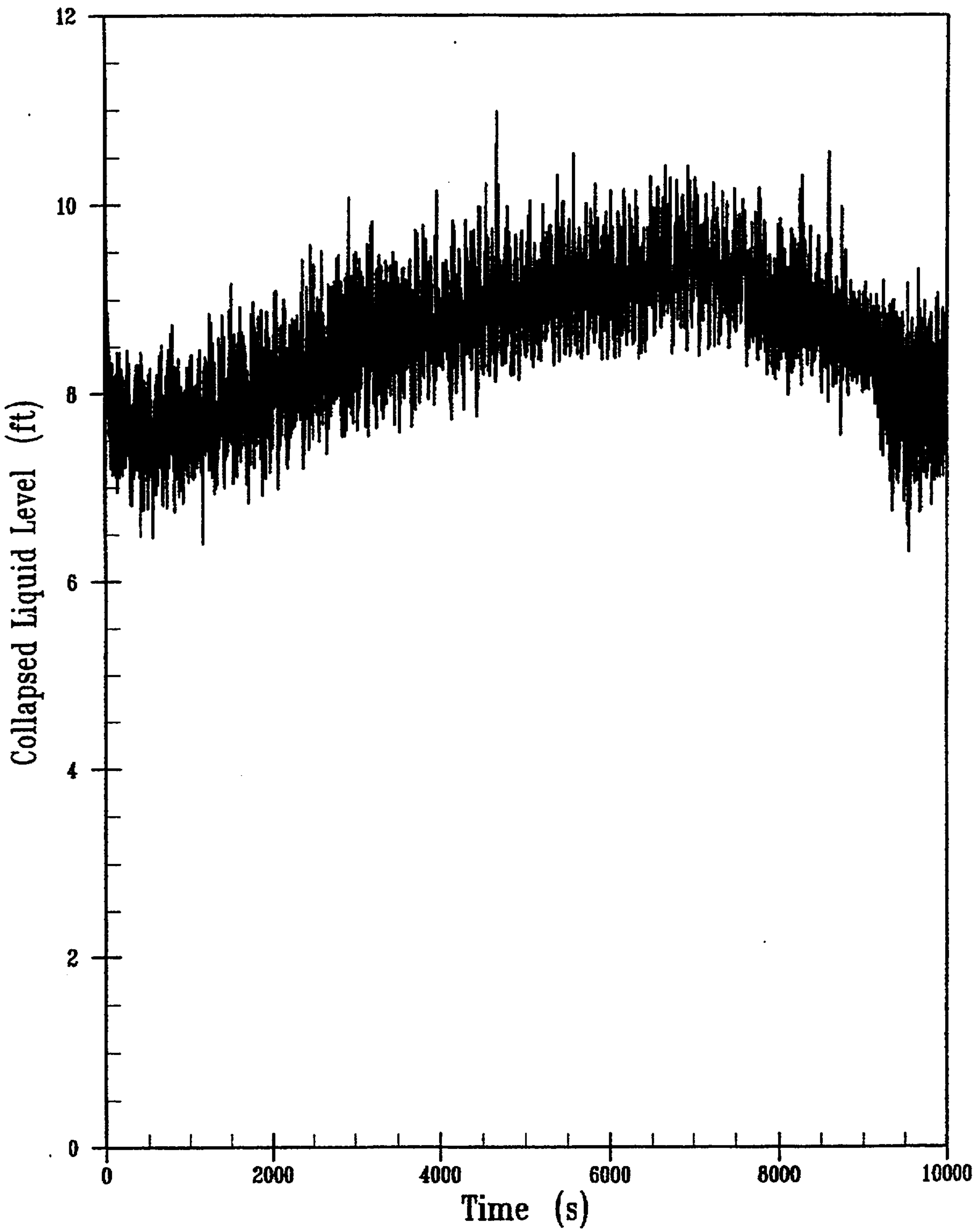


Figure 3.3.3.2-2 Collapsed Level of Liquid over the Heated Length of the Fuel (Continuous Case)

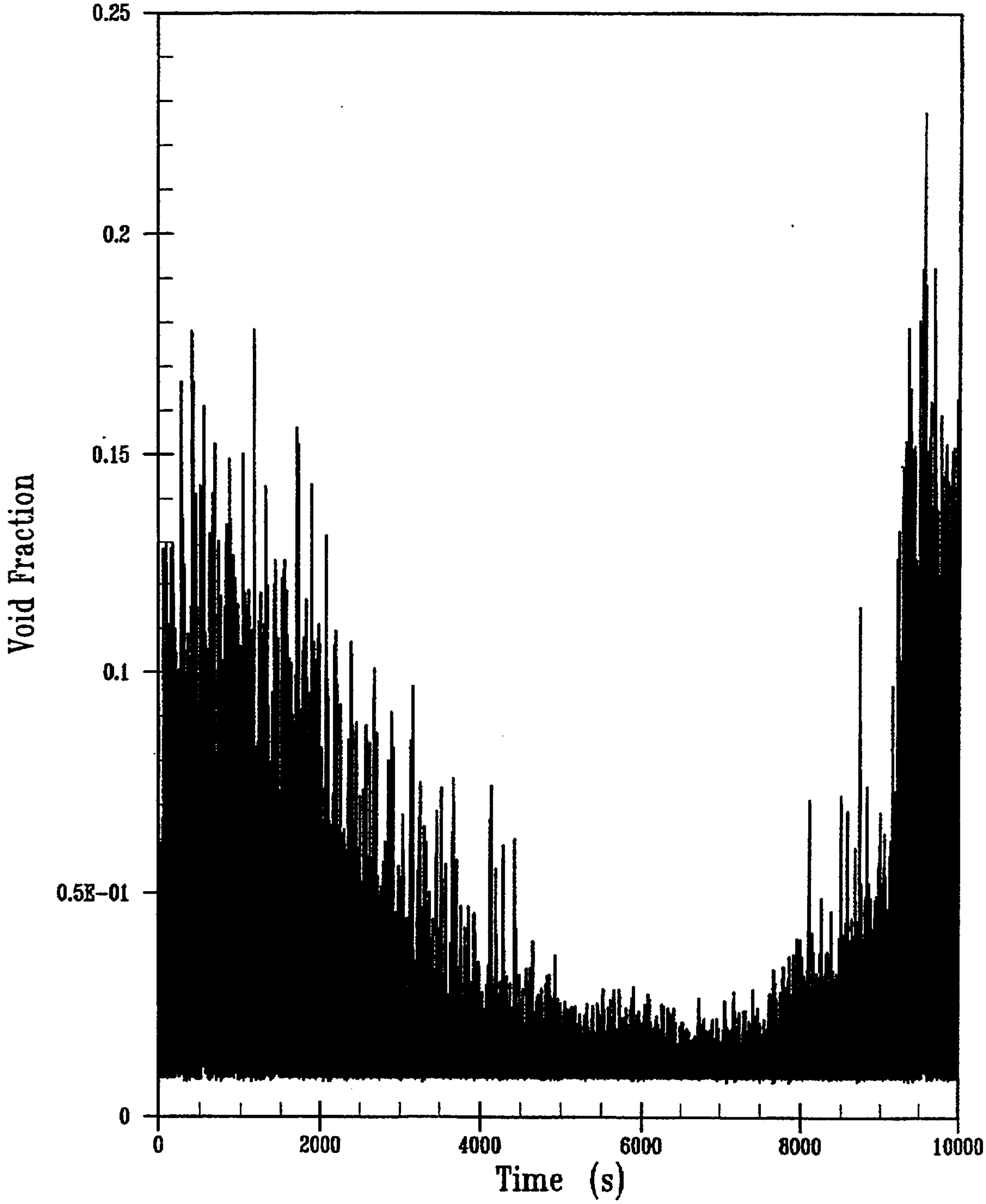


Figure 3.3.3.2-3 Void Fraction in Core Cell Level 1 of 2 (Continuous Case)

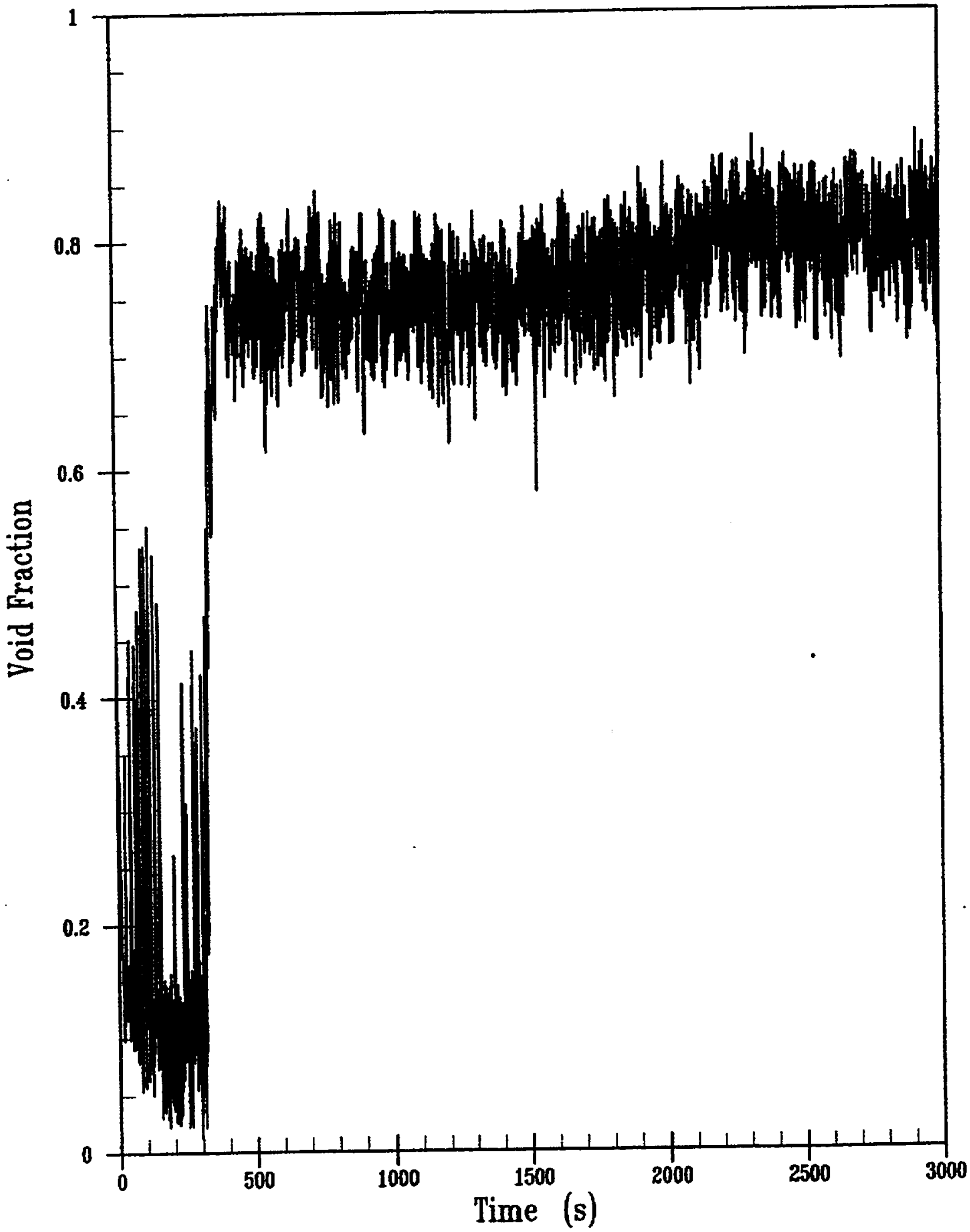


Figure 3.3.3.2-4 Void Fraction in Core Level 2 of 2 (Continuous Case)

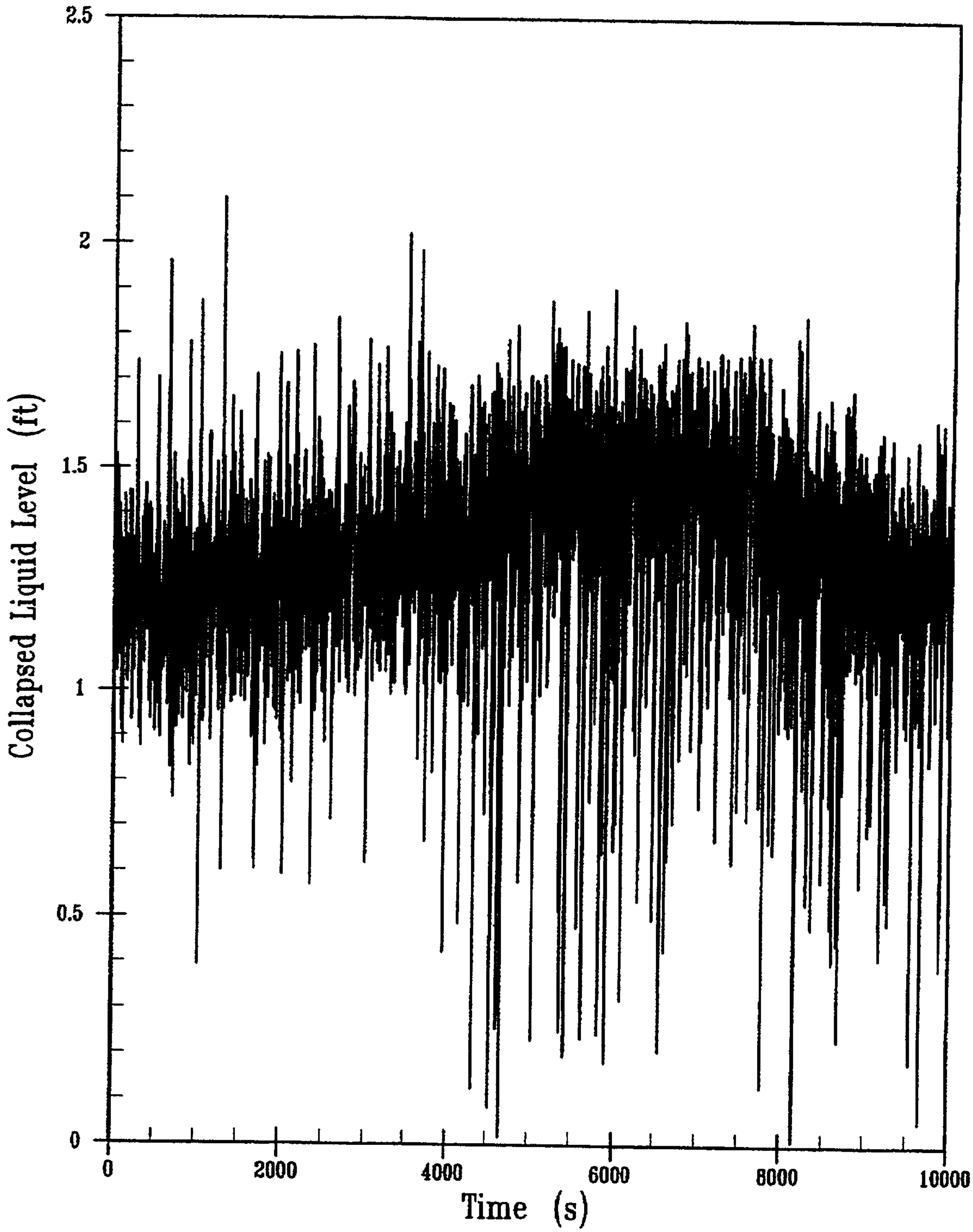


Figure 3.3.3.2-5 Collapsed Liquid Level in the Hot Leg of Intact Loop (Continuous Case)

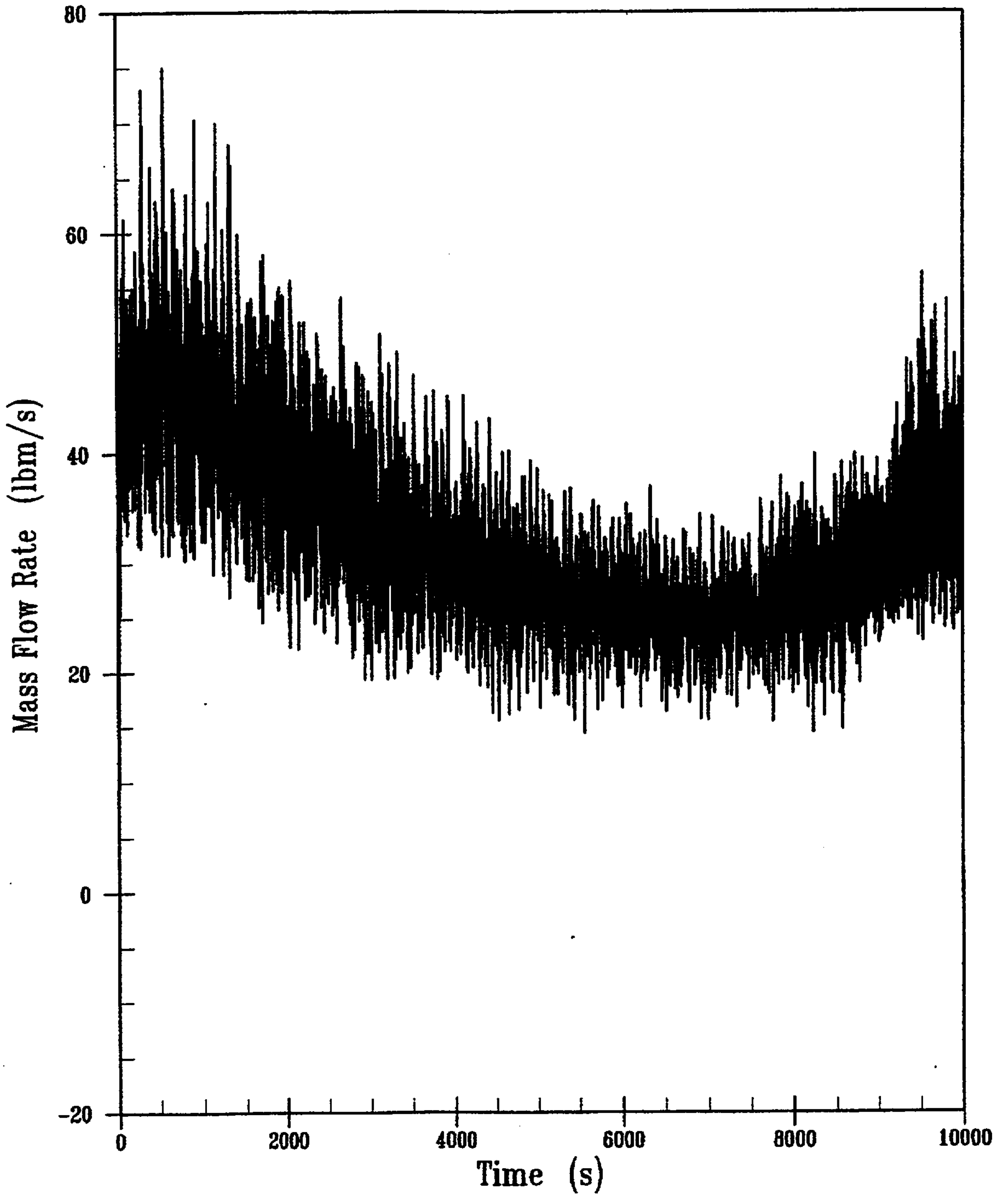


Figure 3.3.3.2-6 Vapor Rate out of the Core (Continuous Case)

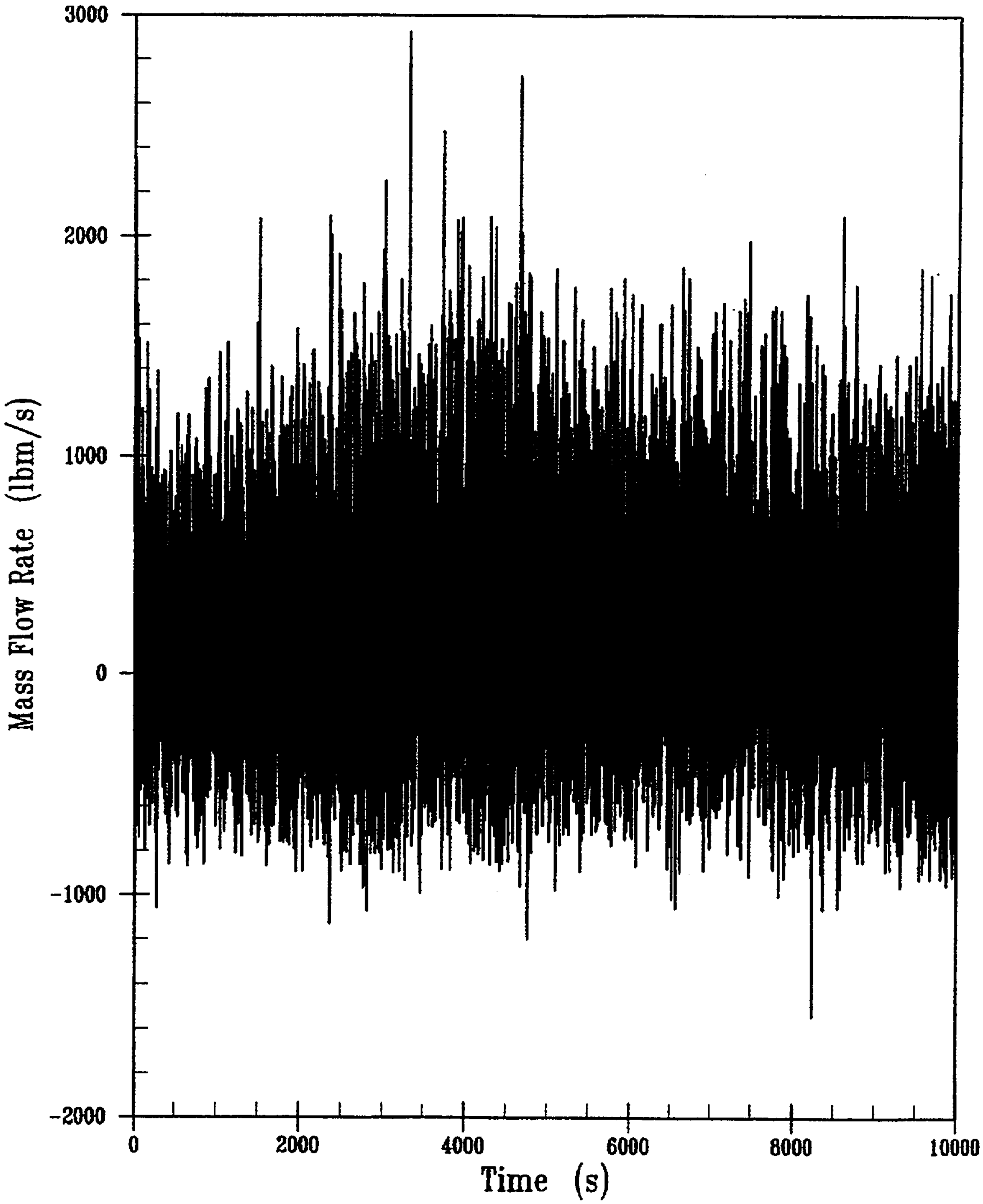


Figure 3.3.3.2-7 Liquid Flow Rate out of the Core (Continuous Case)

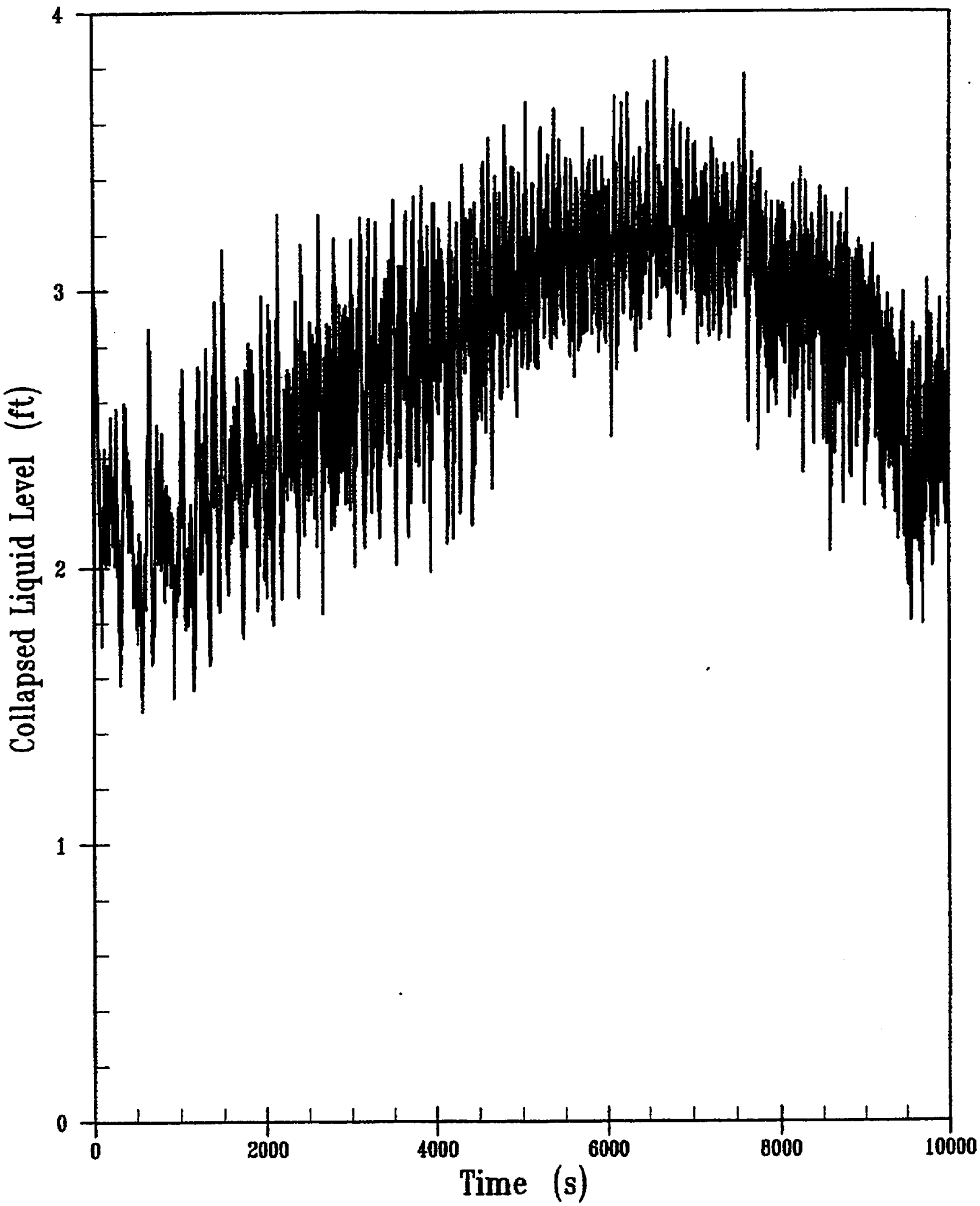


Figure 3.3.3.2-8 Collapsed Liquid Level in the Upper Plenum (Continuous Case)

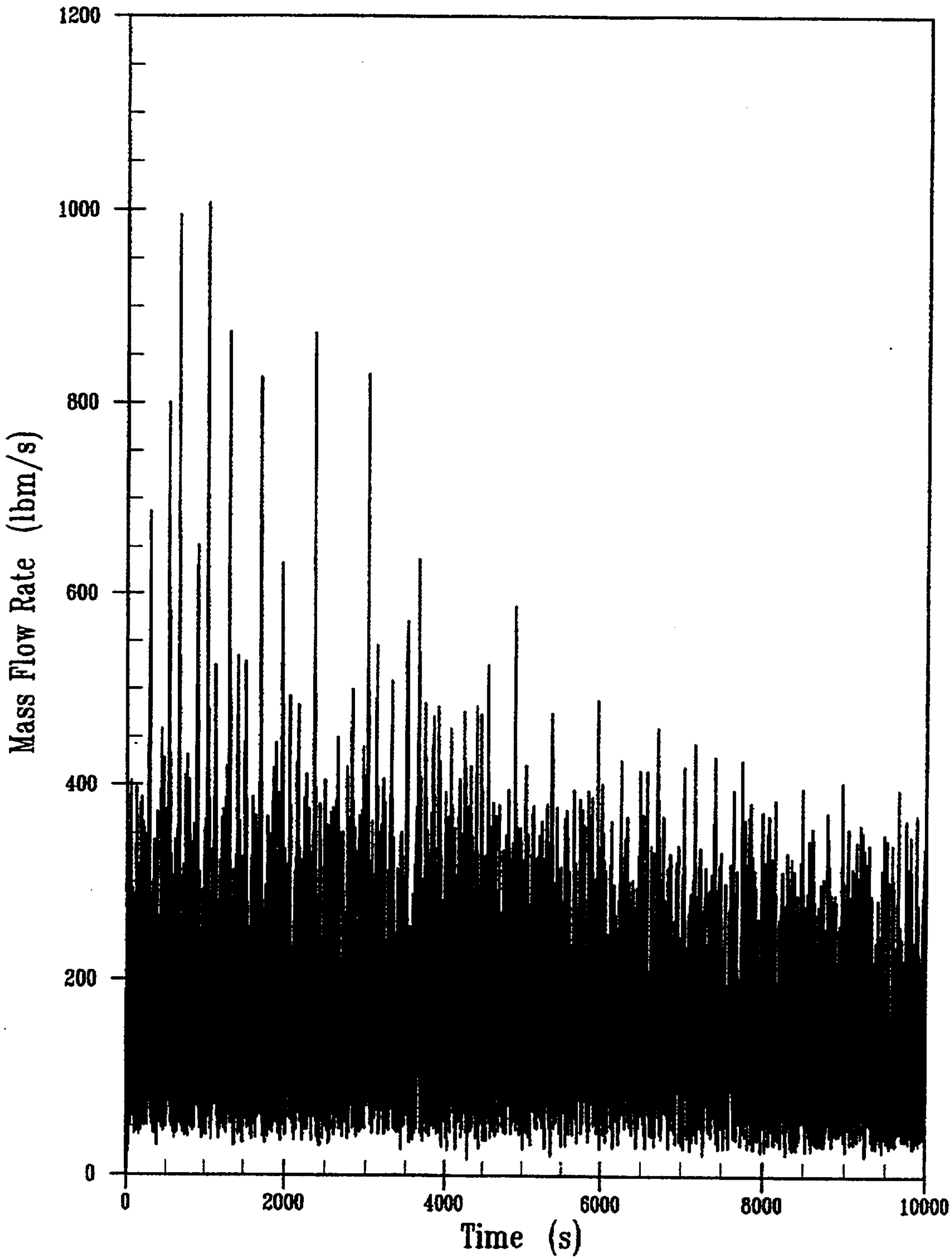


Figure 3.3.3.2-9 Mixture Flow Rate Through ADS Stage 4A Valves (Continuous Case)

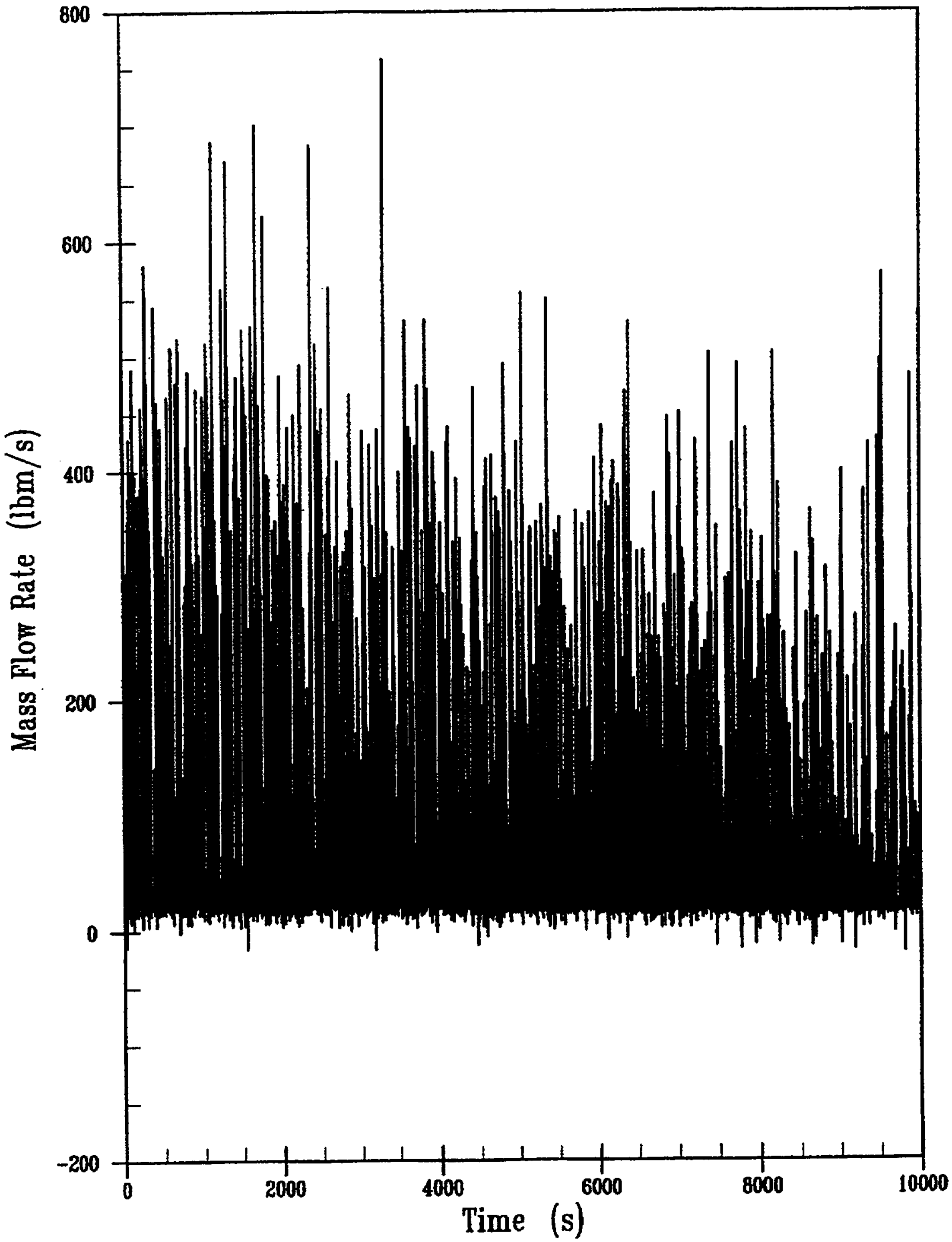


Figure 3.3.3.2-10 Mixture Flow Rate Through ADS Stage 4B Valves (Continuous Case)

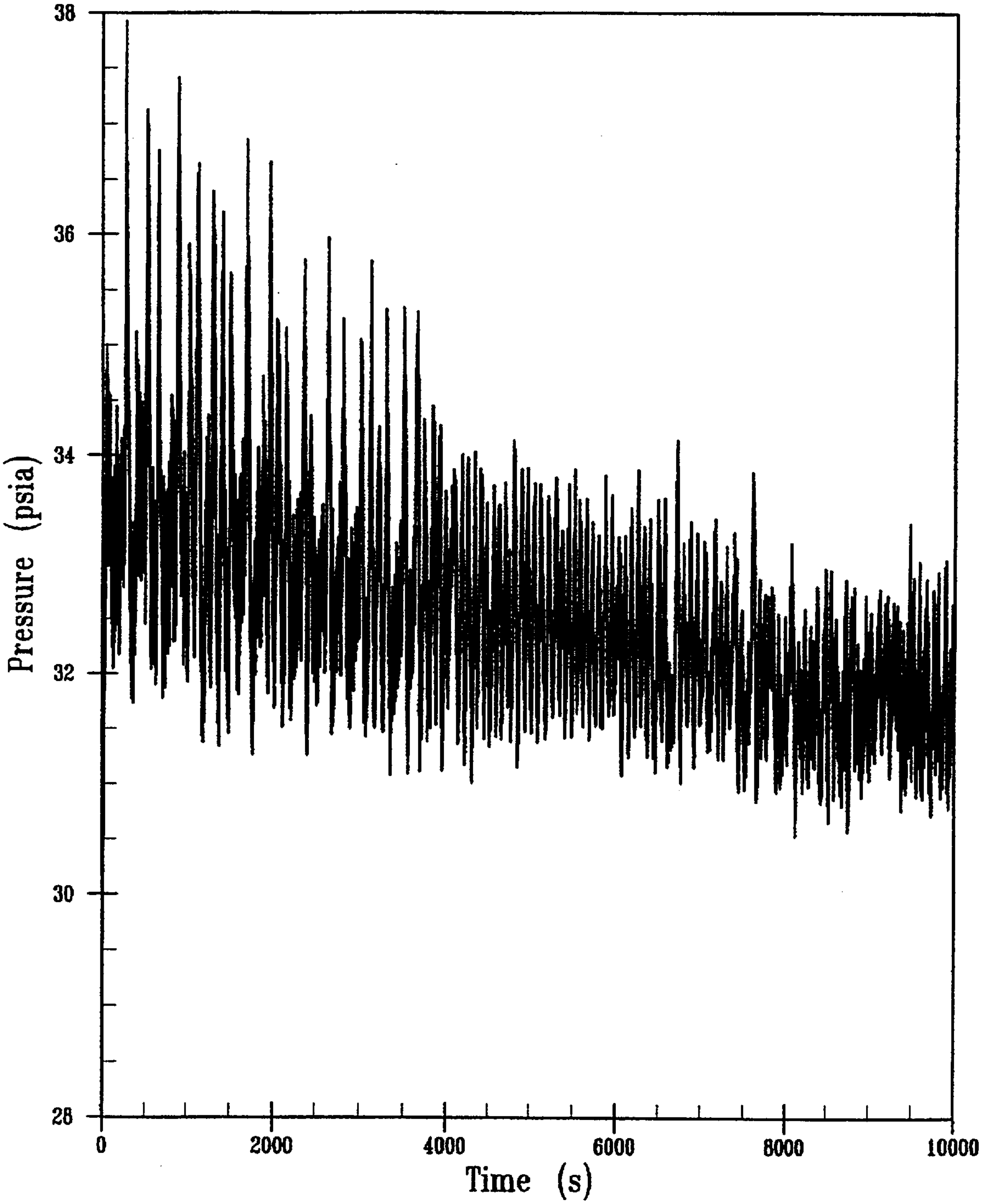


Figure 3.3.3.2-11 Upper Plenum Pressure (Continuous Case)

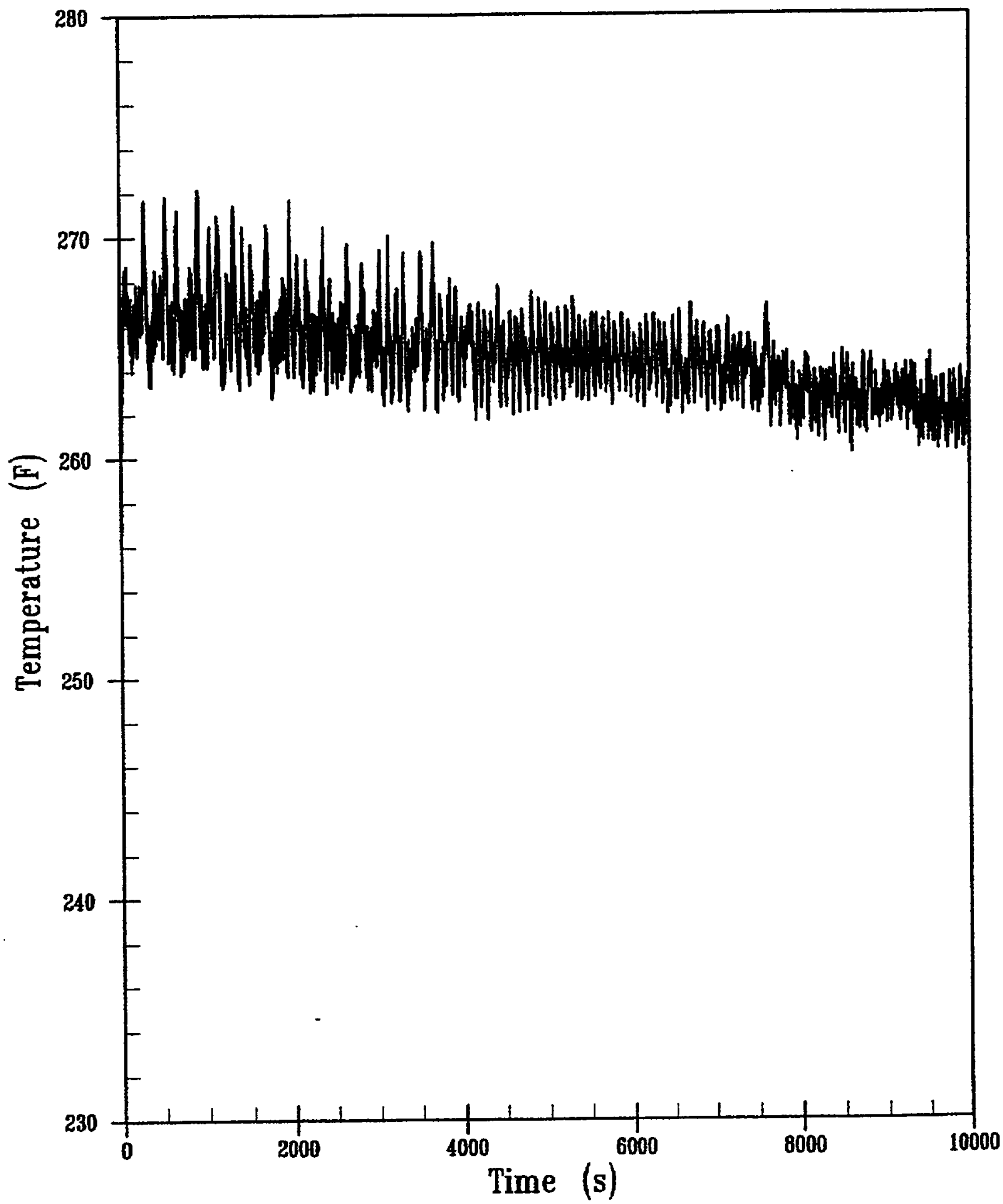


Figure 3.3.3.2-12 PCT of the Hot Rod (Continuous Case)

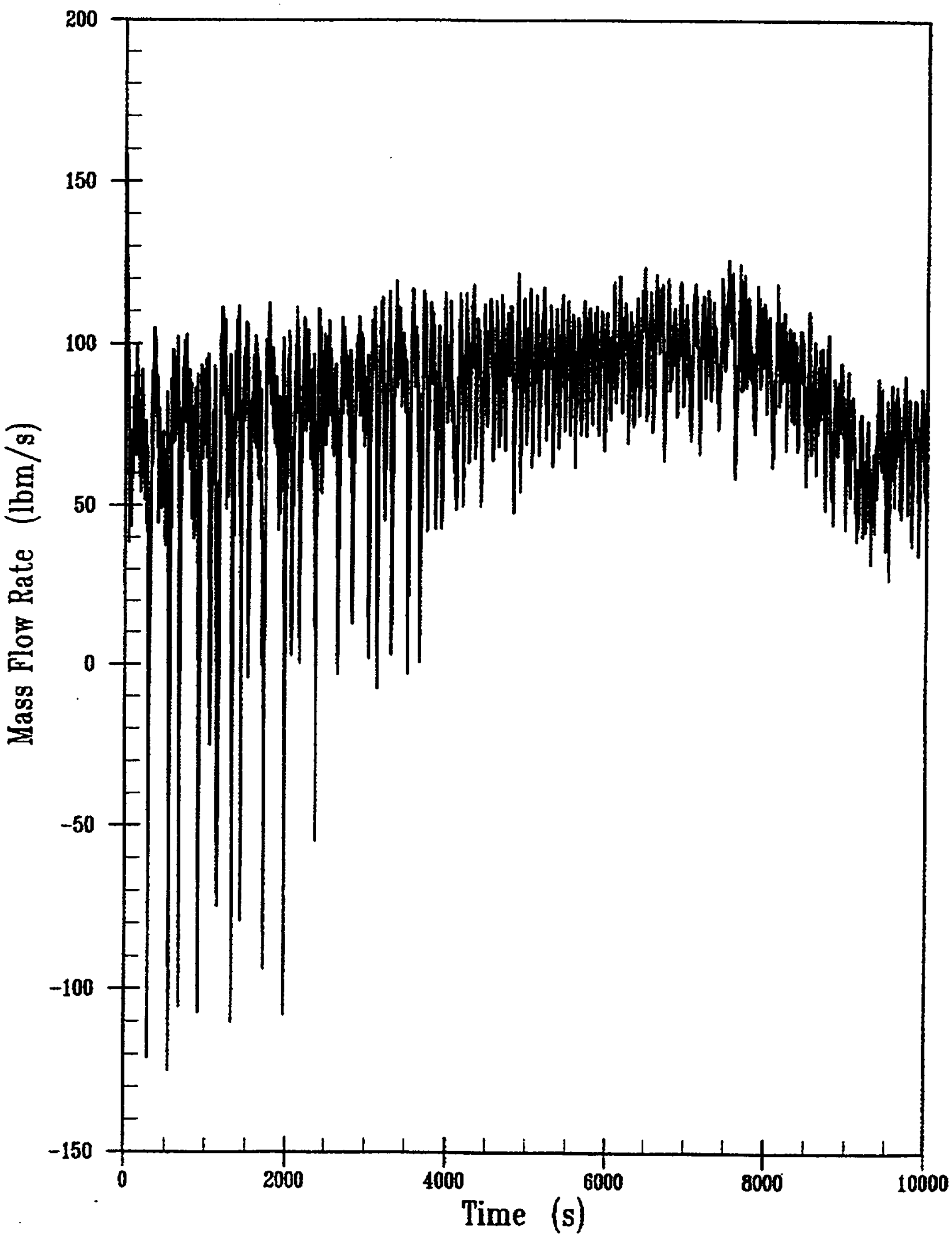


Figure 3.3.3.2-13 DVI–A Mixture Flow Rate (Continuous Case)

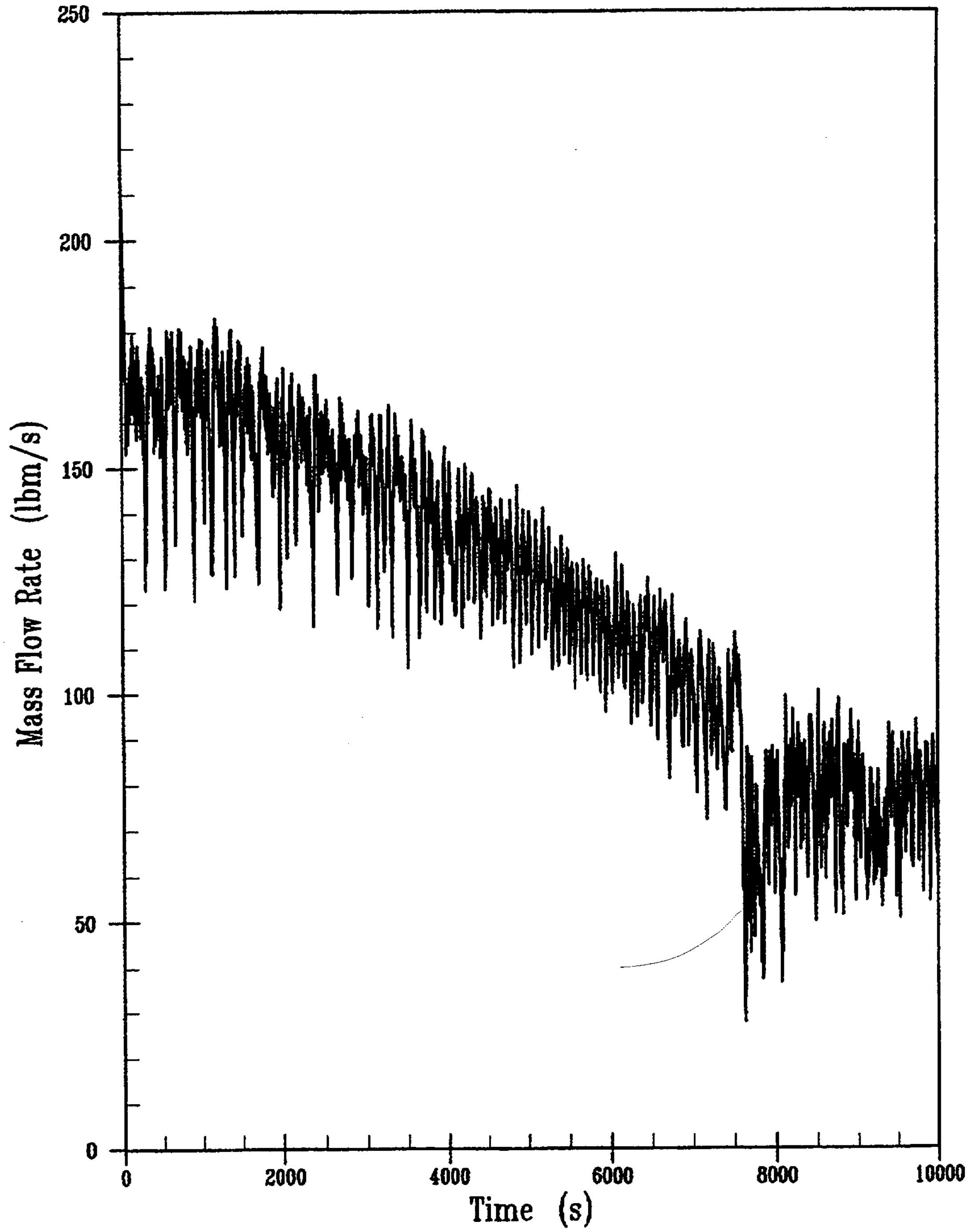


Figure 3.3.3.2-14 DVI–B Mixture Rate (Continuous Case)

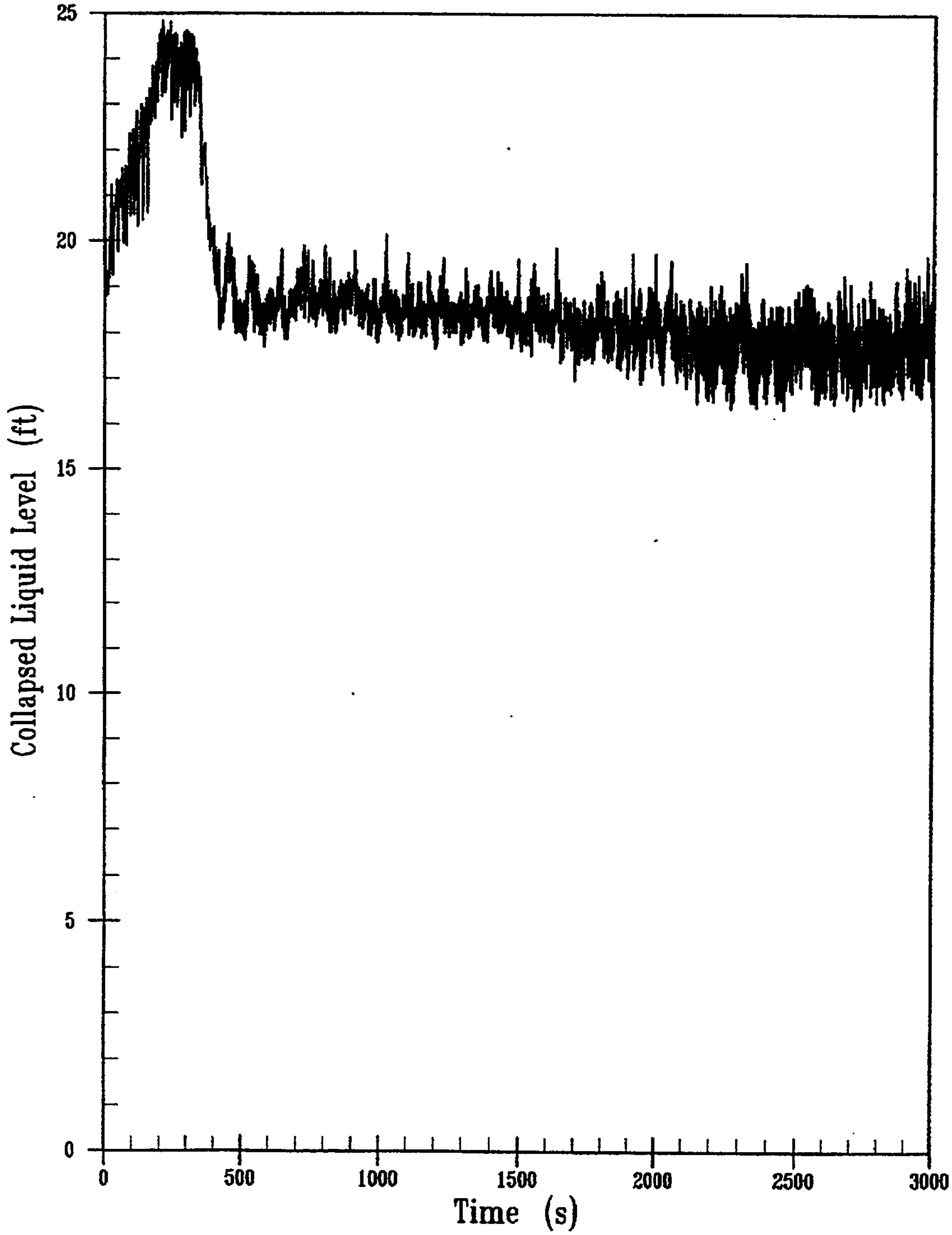


Figure 3.3.3.3-1 Collapsed Level of Liquid in the Downcomer (Window Case)

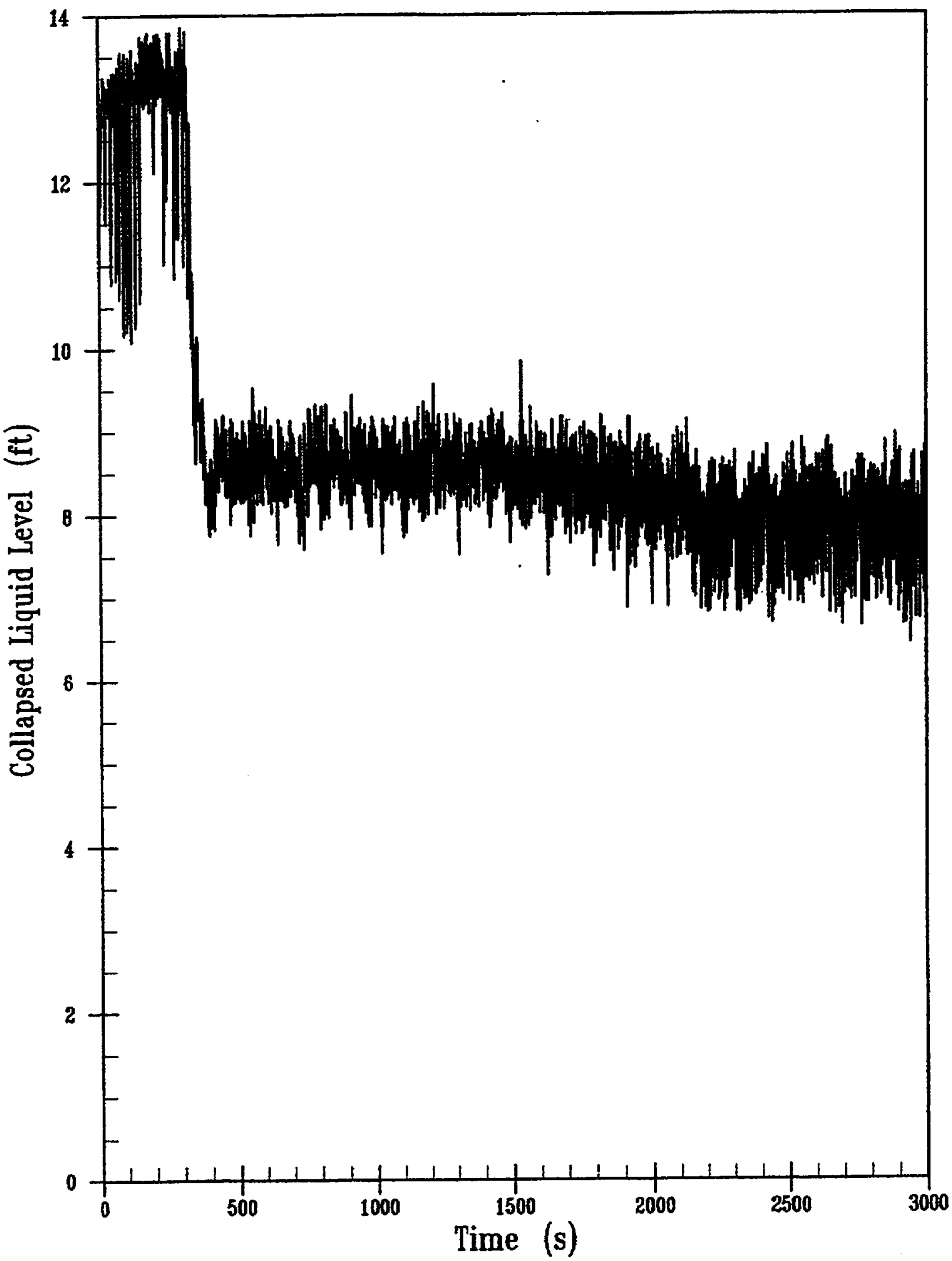


Figure 3.3.3.3-2 Collapsed Level of Liquid over the Heated Length of the Fuel Rod (Window Case)

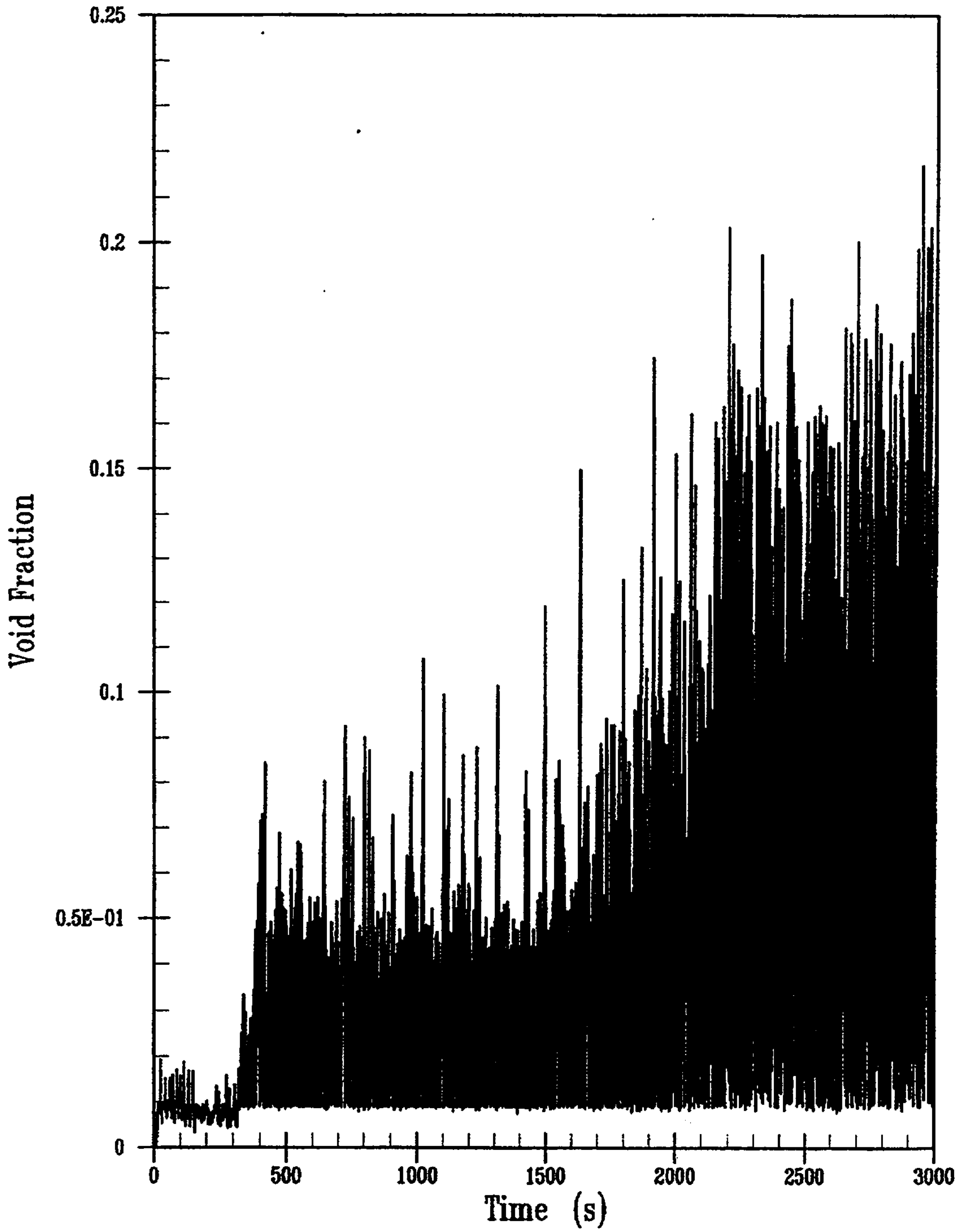


Figure 3.3.3.3-3 Void Fraction in Core Cell Level 1 of 2 (Window Case)

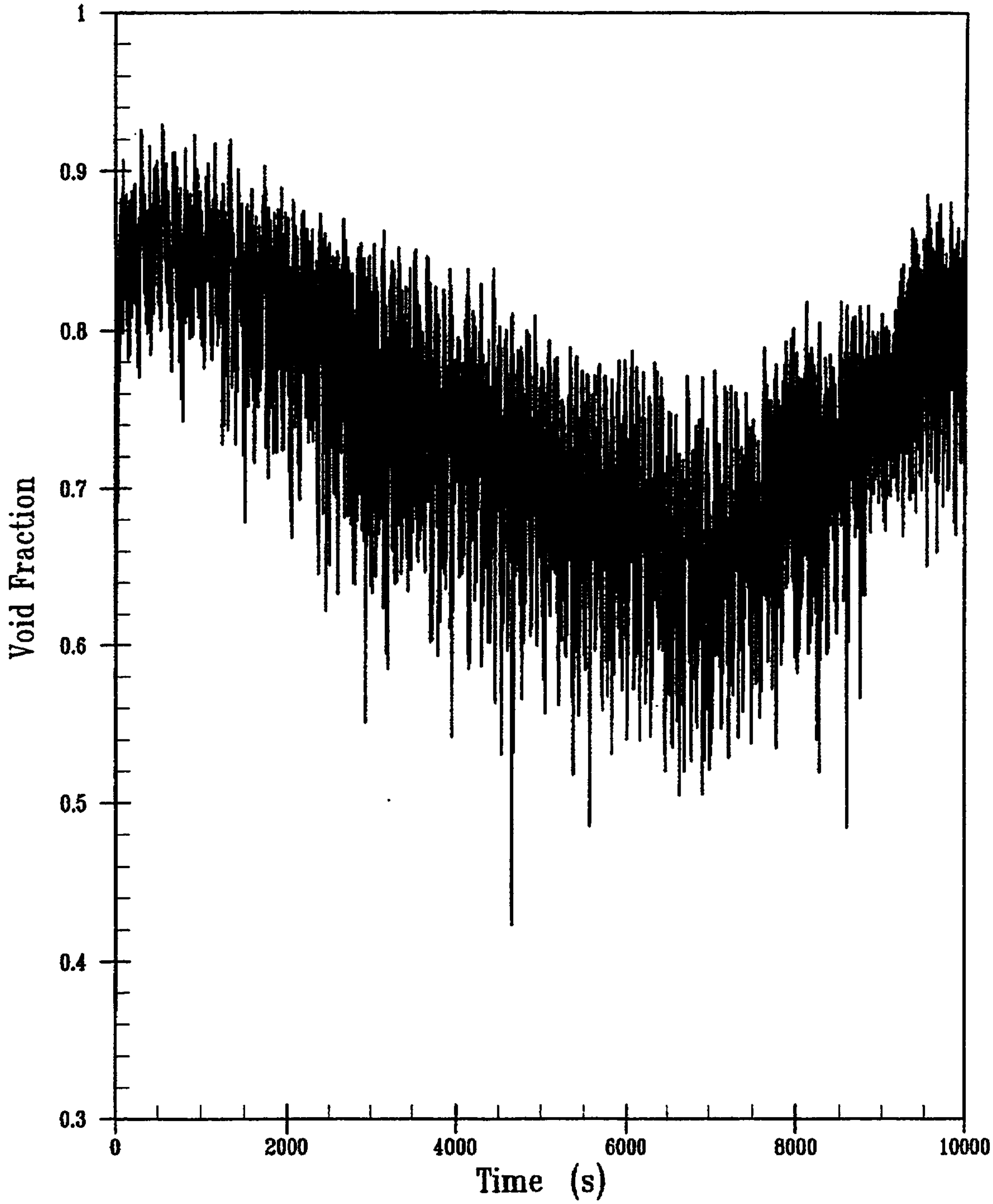


Figure 3.3.3.3-4 Void Fraction in Core Level 2 of 2 (Window Case)

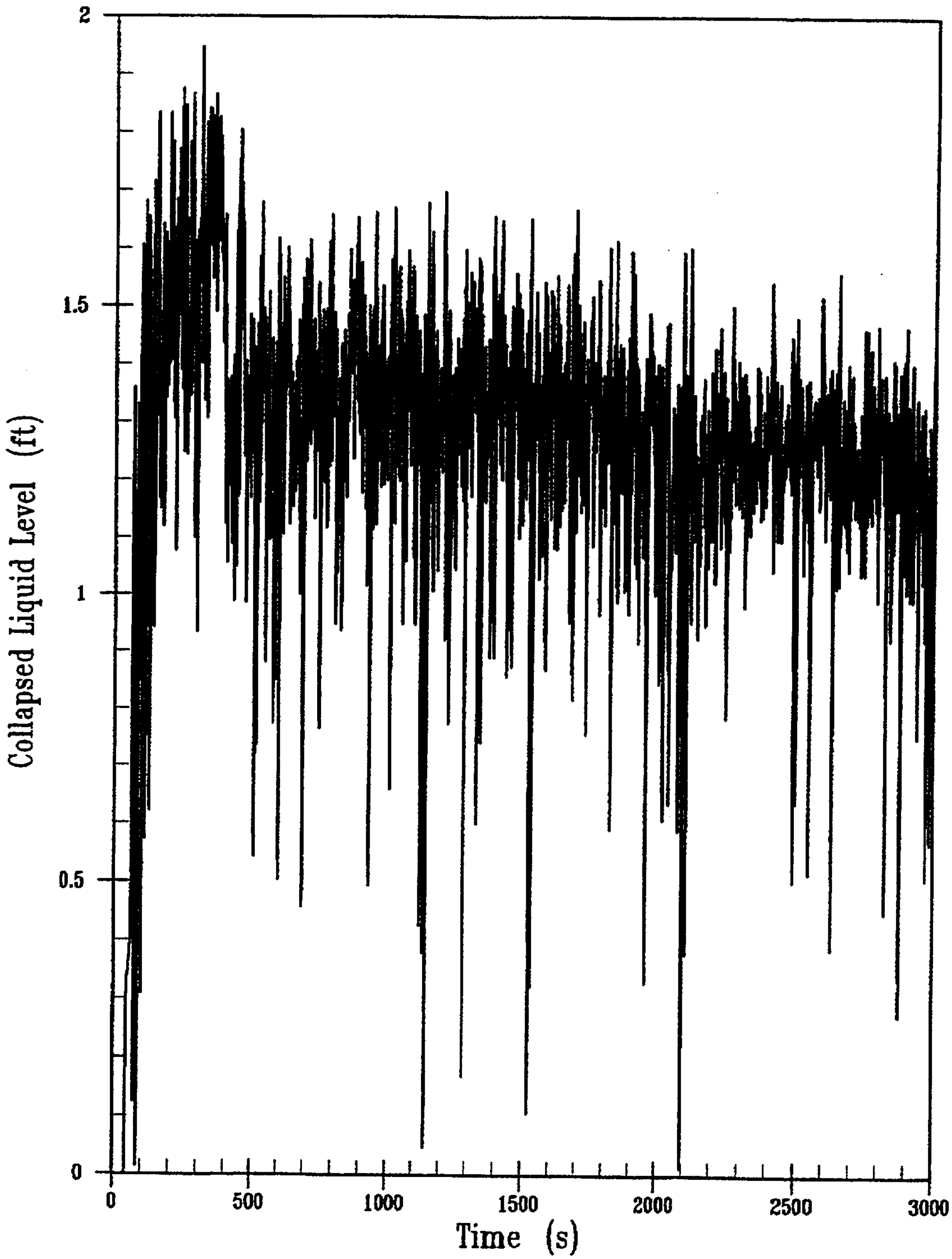


Figure 3.3.3.3-5 Collapsed Liquid Level in the Hot Leg of Intact Loop (Window Case)

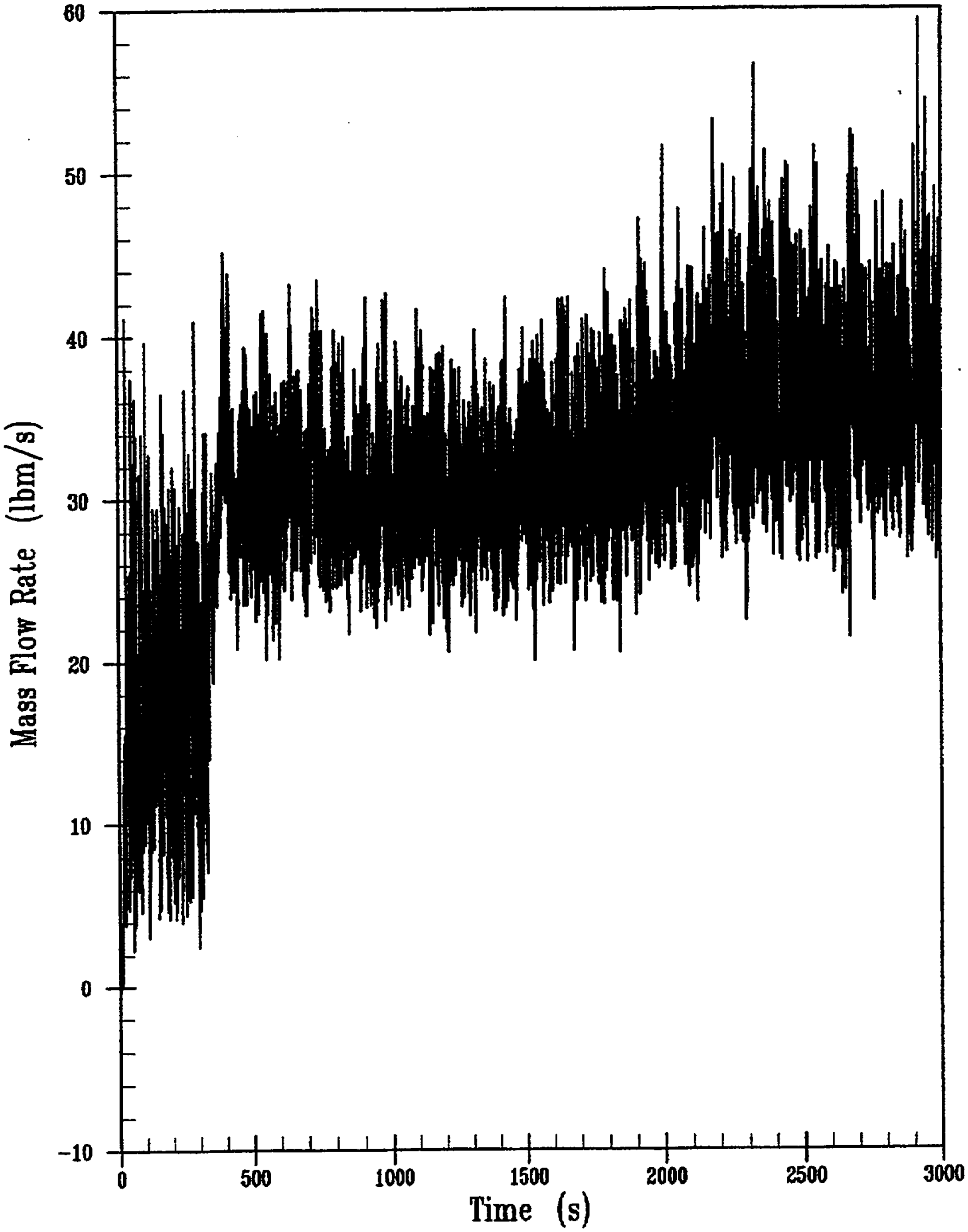


Figure 3.3.3.3-6 Vapor Flow Rate out of the Core (Window Case)

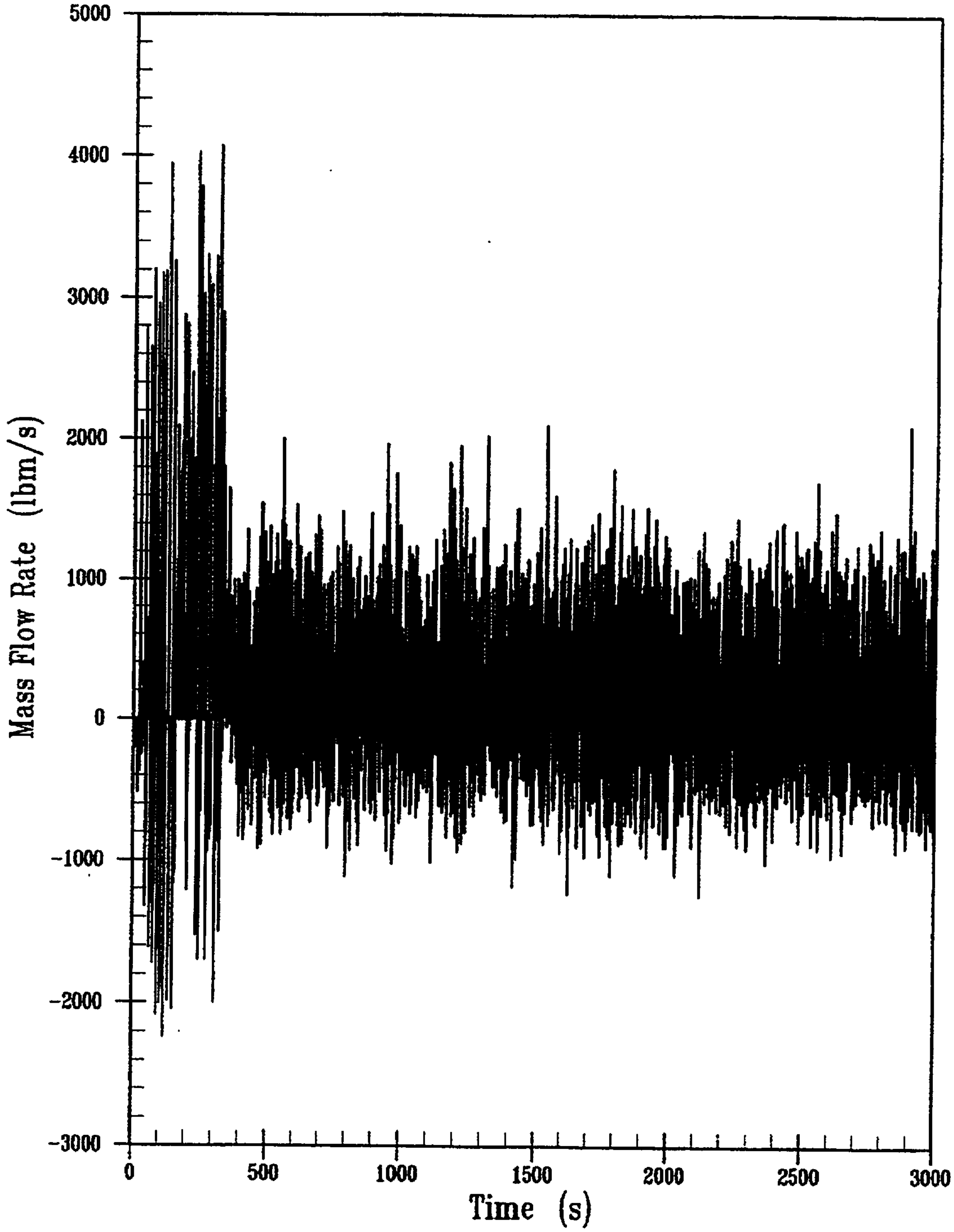


Figure 3.3.3.3-7 Liquid Flow Rate out of the Core (Window Case)

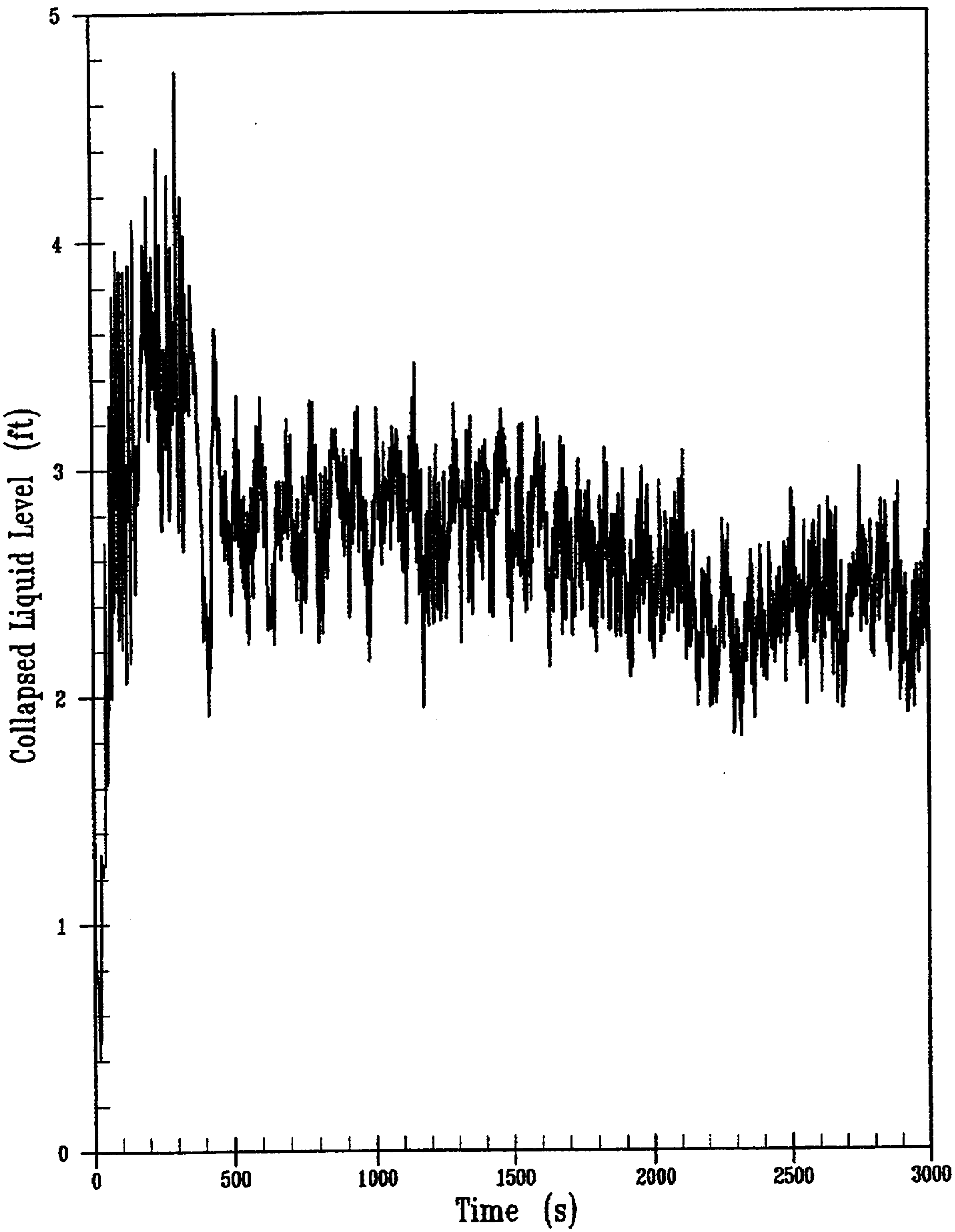


Figure 3.3.3.3-8 Collapsed Liquid Level in the Upper Plenum (Window Case)

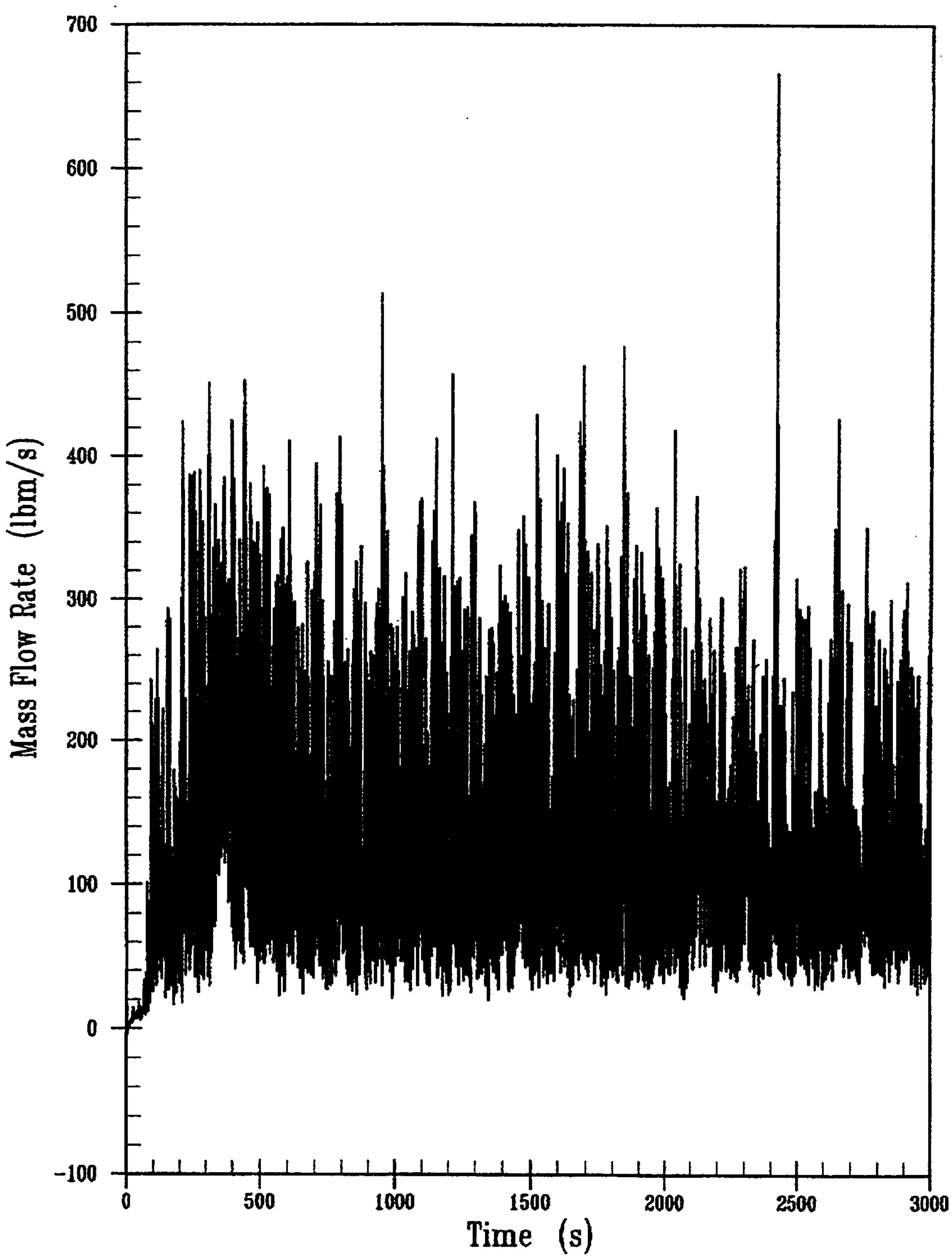


Figure 3.3.3.3-9 Mixture Flow Rate Through ADS State 4A Valves (Window Case)

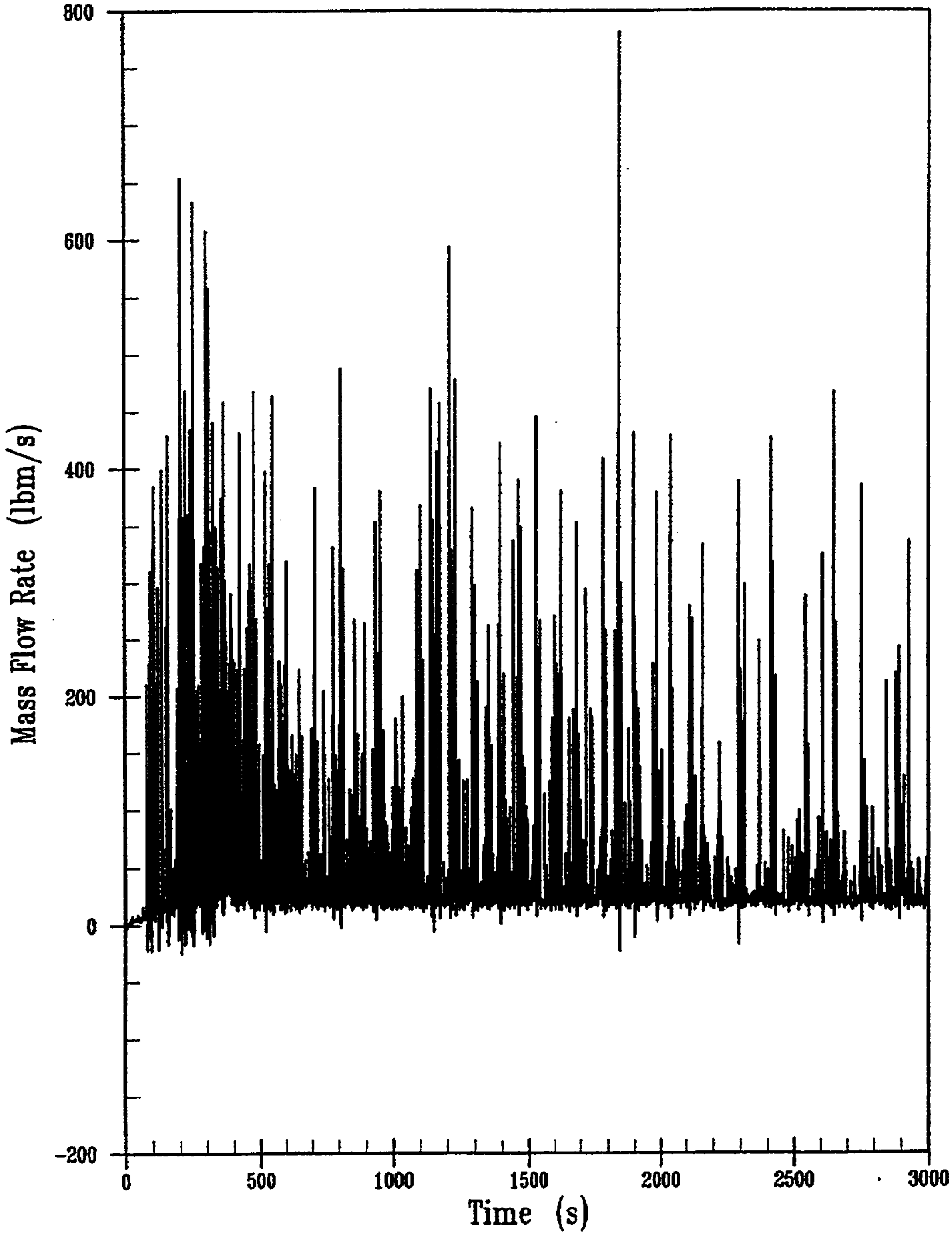


Figure 3.3.3.3-10 Mixture Flow Rate Through ADS Stage 4B Valves (Window Case)

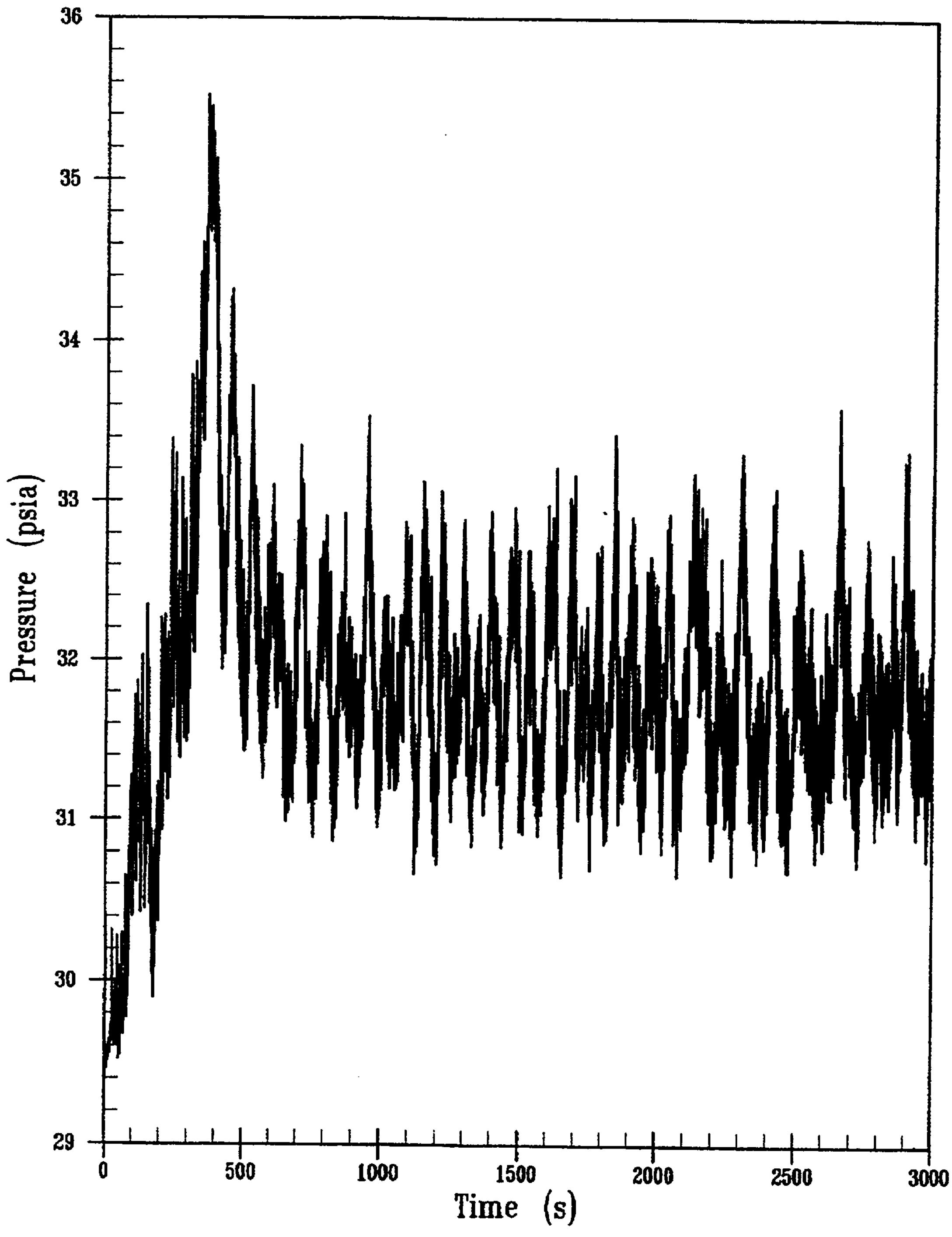


Figure 3.3.3.3-11 Upper Plenum Pressure (Window Case)

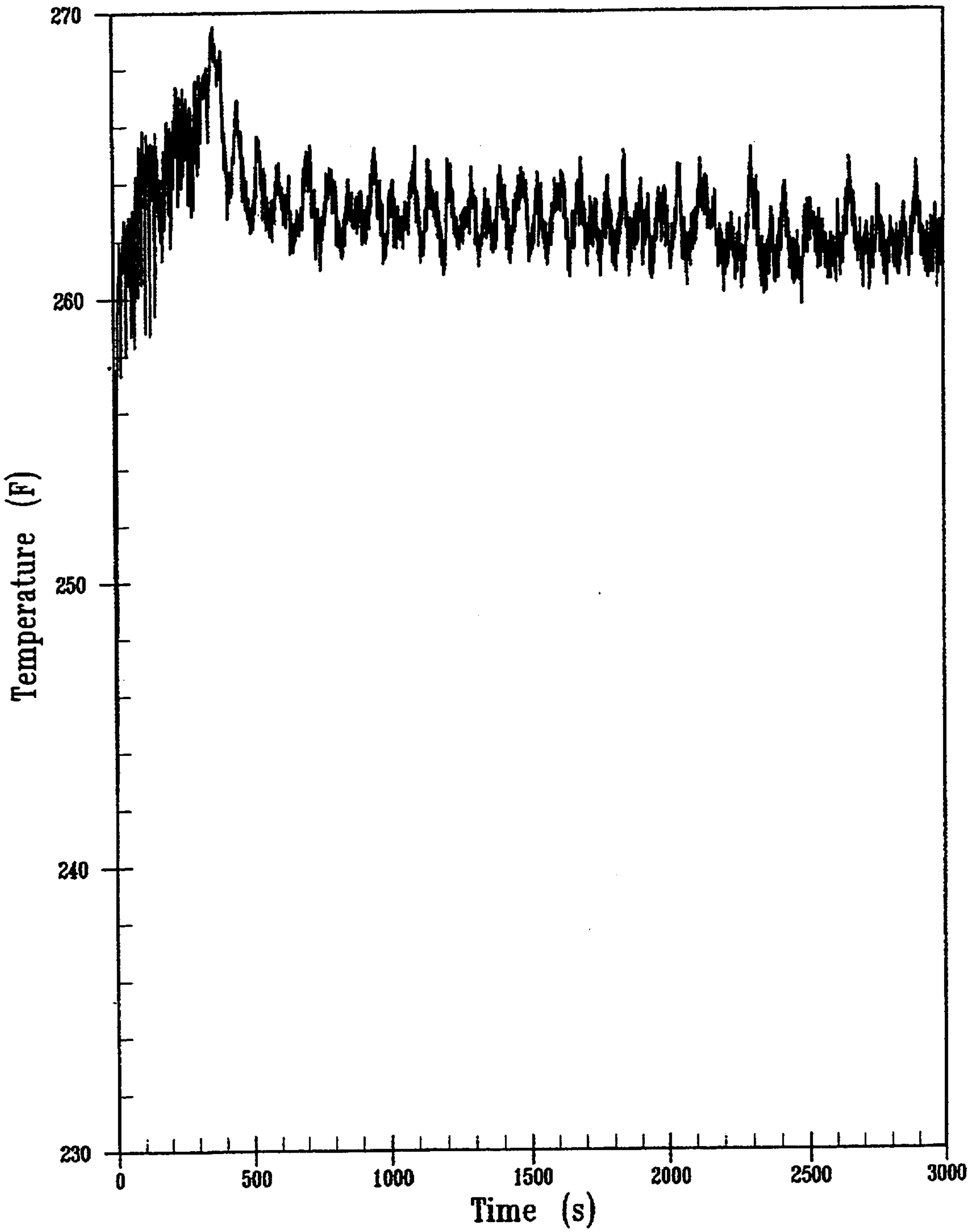


Figure 3.3.3.3-12 PCT of the Hot Rod (Window Case)

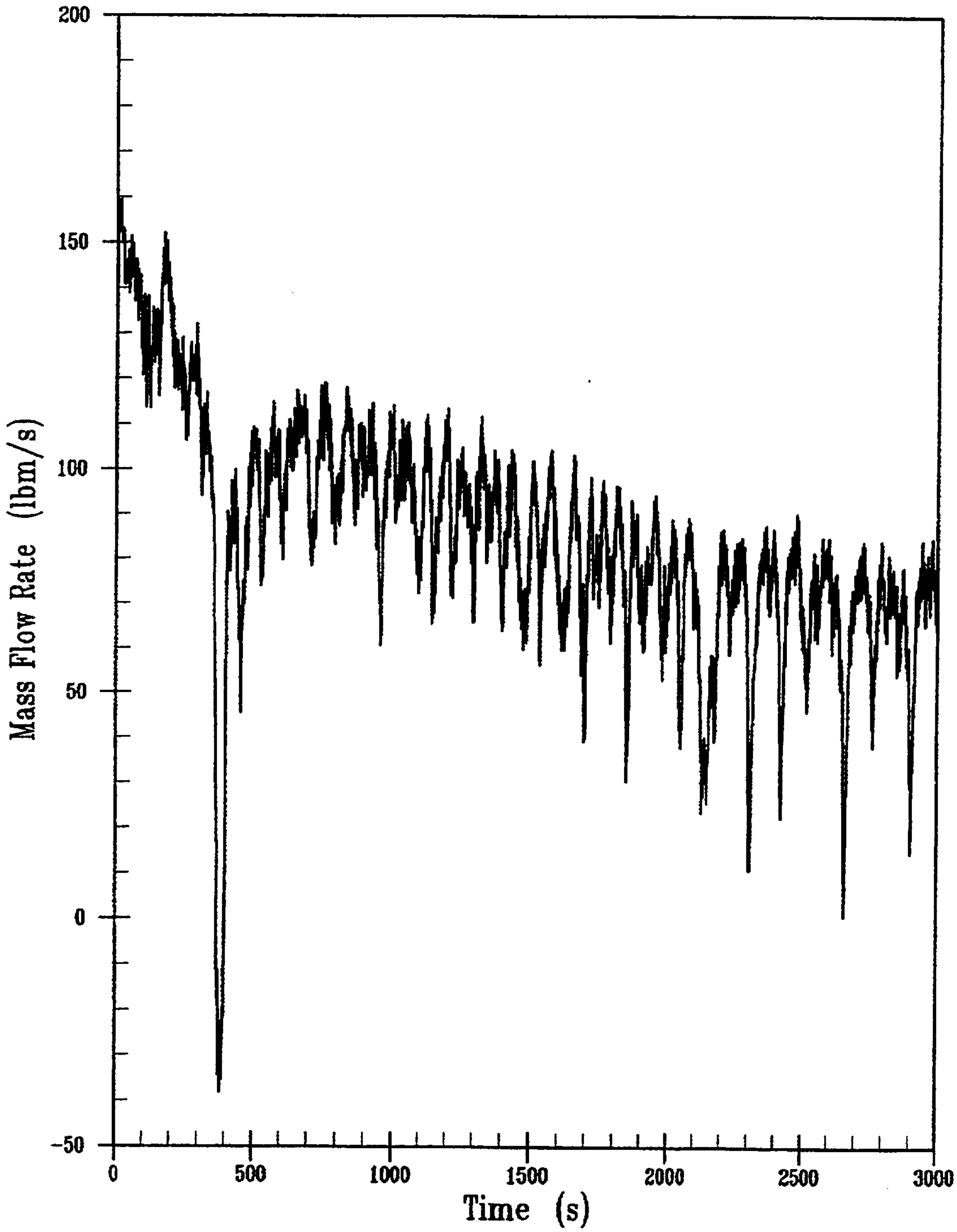


Figure 3.3.3.3-13 DVI–A Mixture Flow Rate (Window Case)

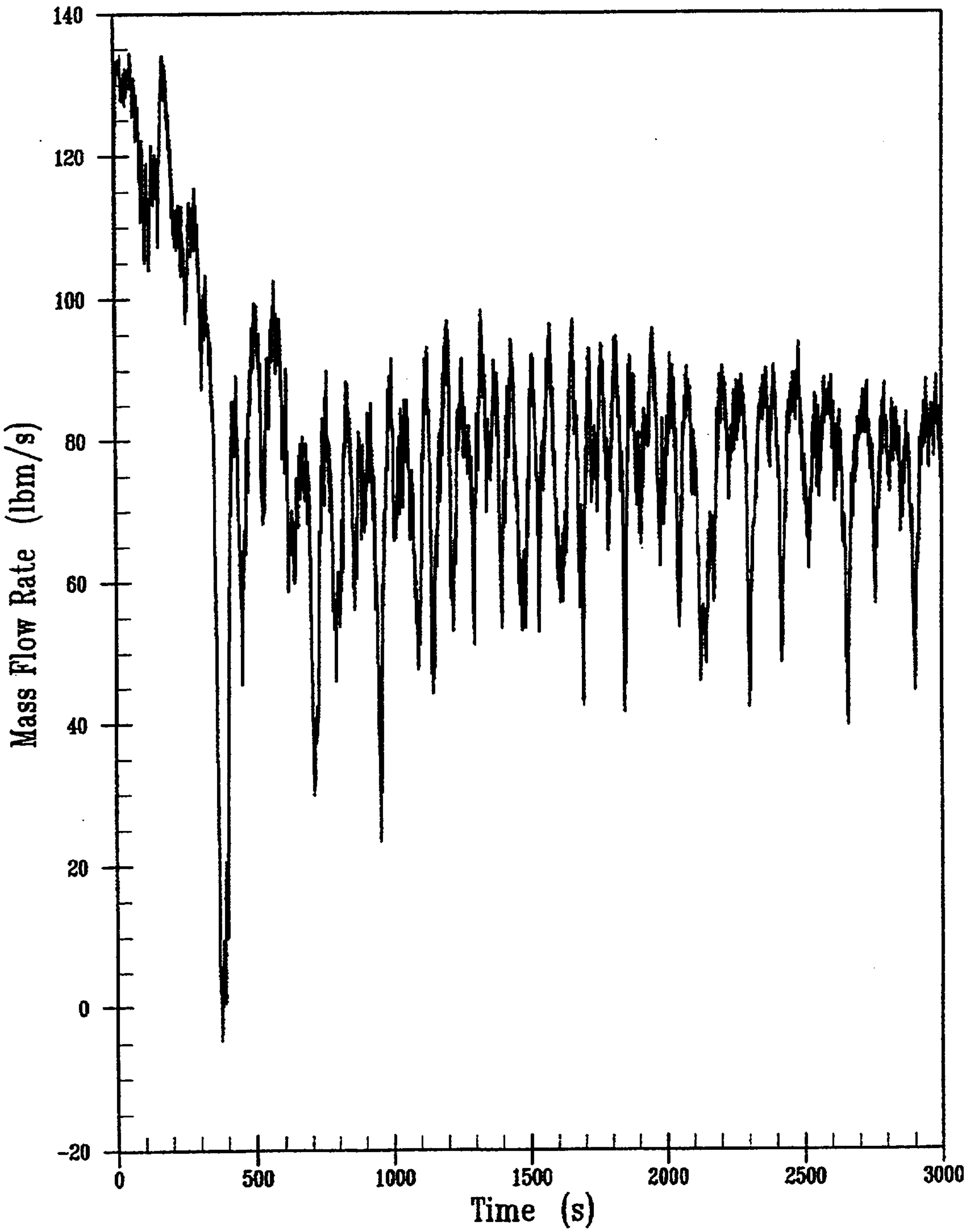


Figure 3.3.3.3-14 DVI–B Mixture Flow Rate (Window Case)

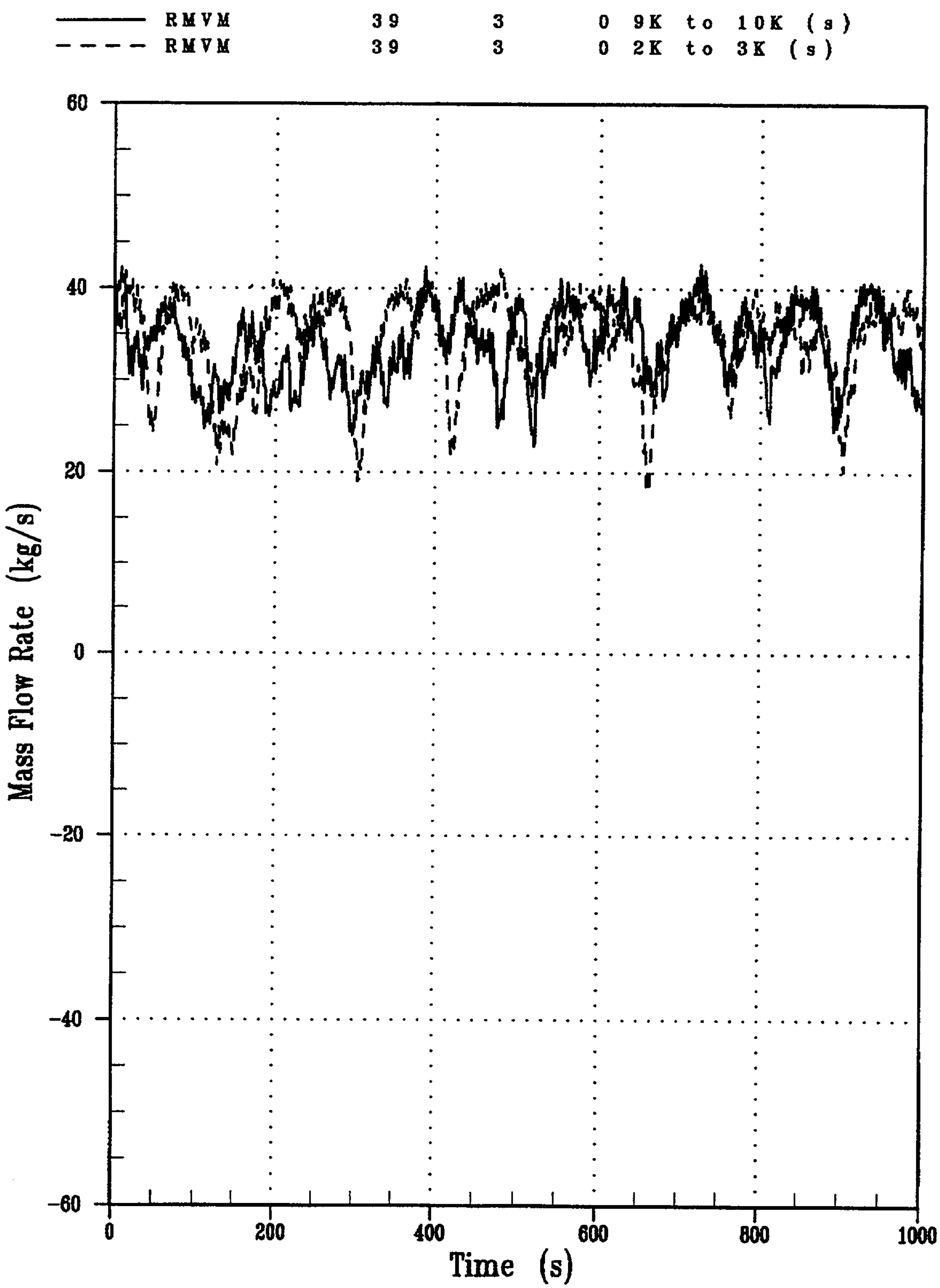


Figure 3.3.3.3-15 Comparison of DVI-B Flowrates, Continuous (9K to 10K) and Window-Mode (2K to 3K) Calculations

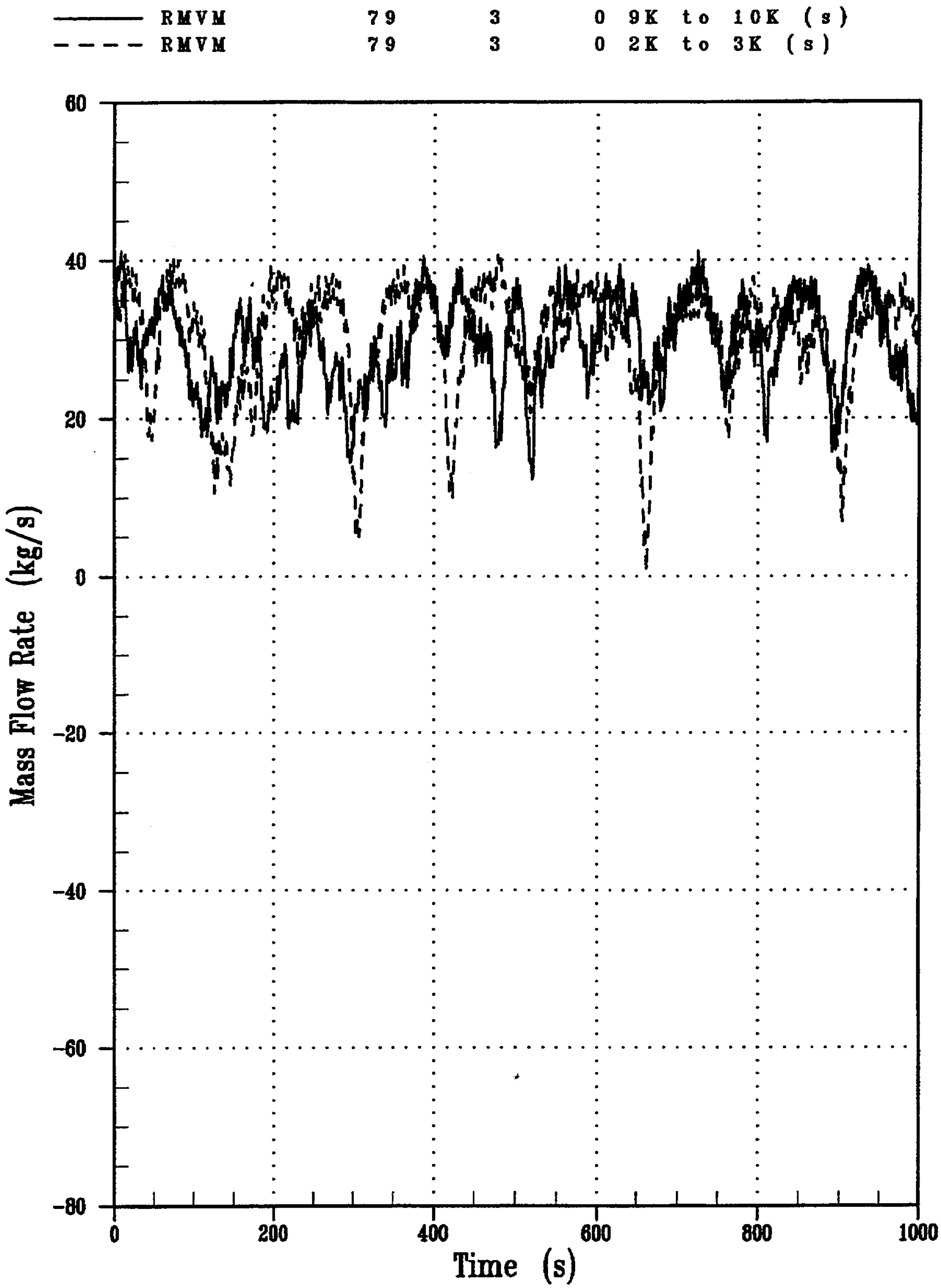


Figure 3.3.3.3-16 Comparison of DVI–A Flowrates, Continuous (9K to 10K) and Window-Mode (2K to 3K) Calculations

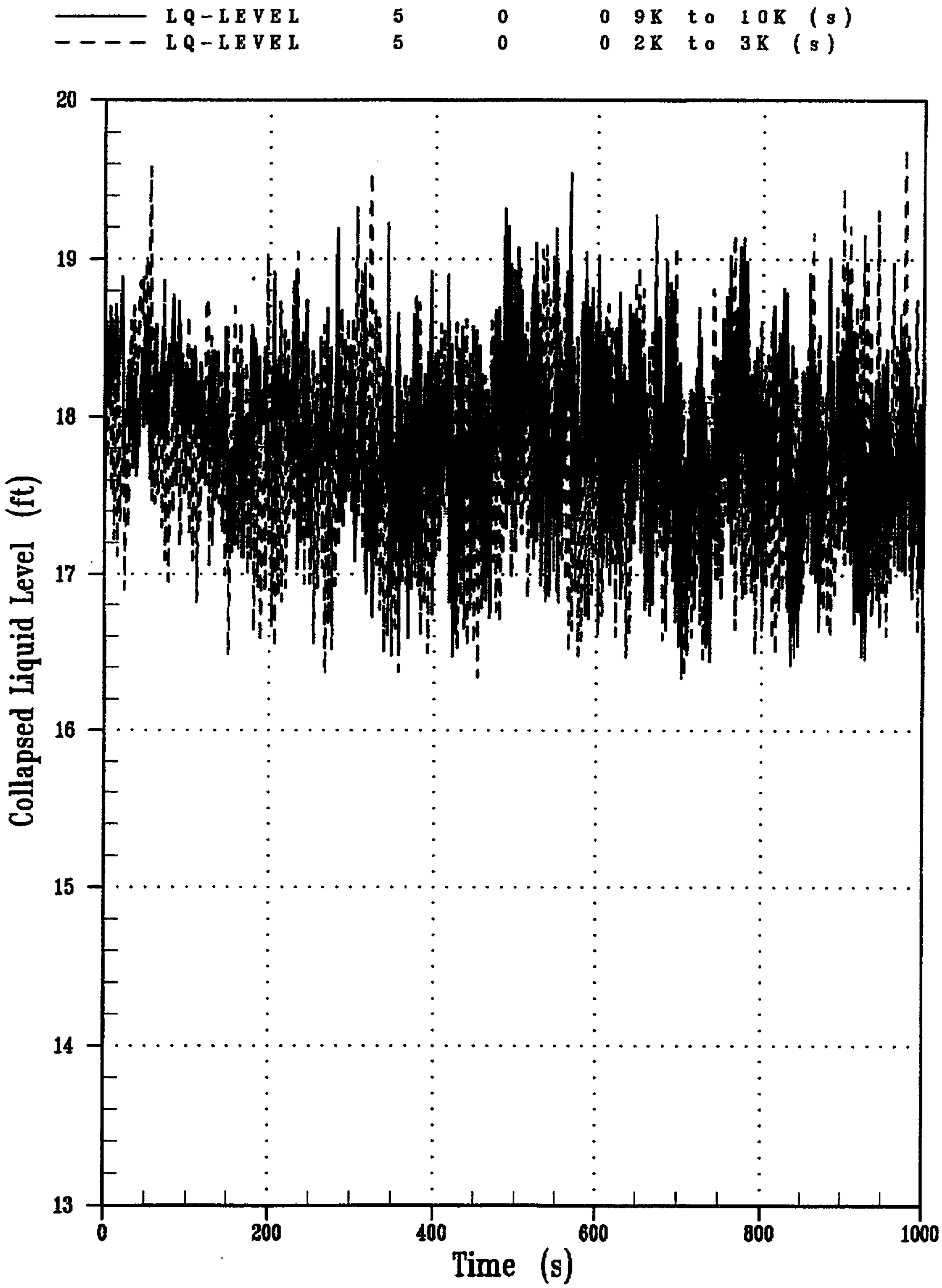


Figure 3.3.3.3-17 Comparison of Downcomer Collapsed Liquid Levels, Continuous (9K to 10K) and Window Mode (2K to 3K) Calculations

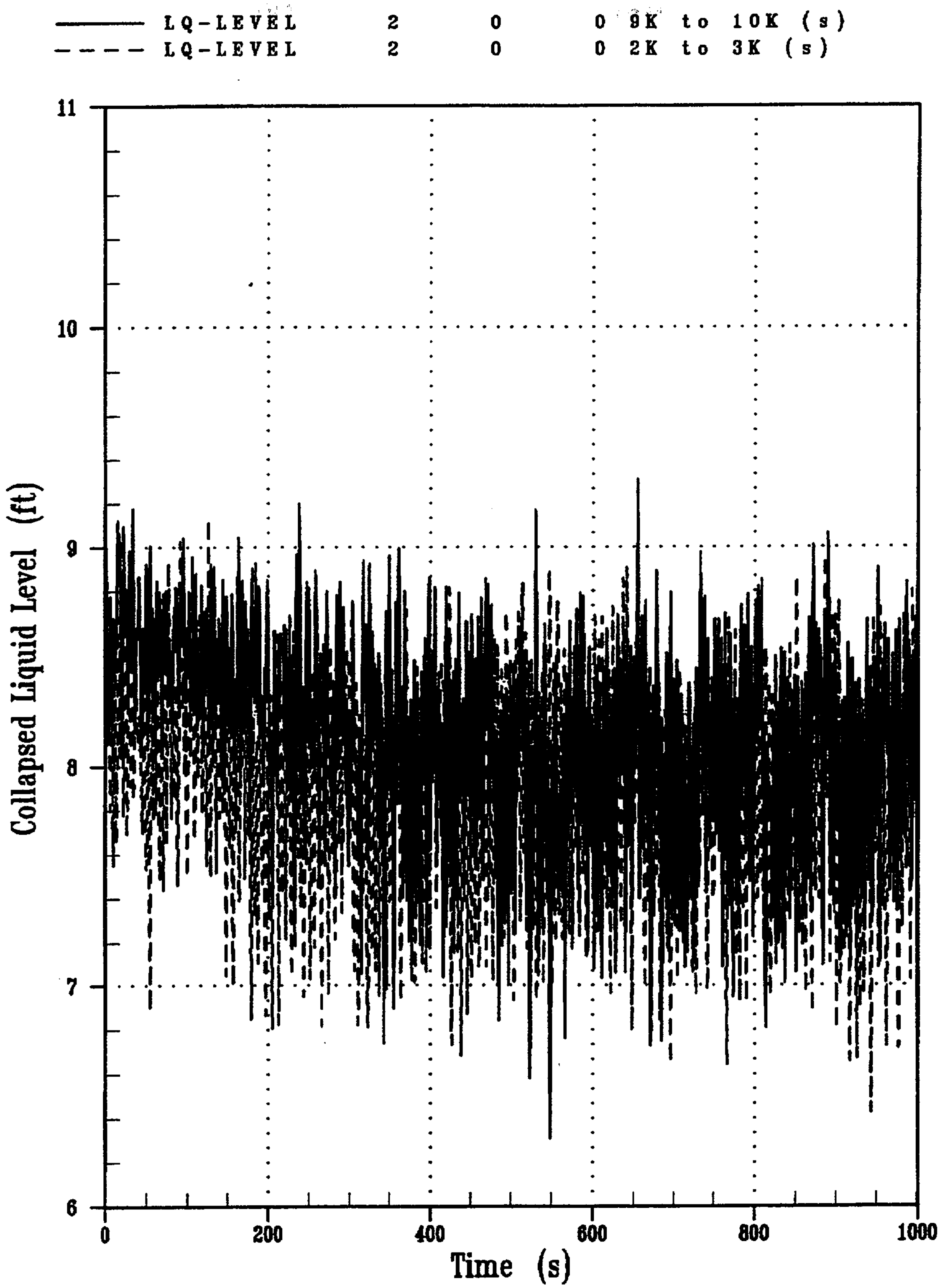


Figure 3.3.3.3-18 Comparison of Core Collapsed Liquid Levels, Continuous(9K to 10K) and Window Mode (2K to 3K) Calculations

3.4 CONTAINMENT ANALYSIS ASSESSMENTS

The AP1000 containment building is designed such that for all break sizes, up to and including the double-ended severance of a reactor coolant pipe or secondary side pipe, the containment peak pressure is below the design pressure.

This capability is maintained by the containment system assuming the worst single failure affecting the operation of the passive containment cooling system (PCS). For primary system breaks, loss of offsite power (LOOP) is assumed. For secondary system breaks, offsite power is assumed to be available when it maximizes the mass and energy released from the break.

The single failure postulated for the containment pressure/temperature calculations is the failure of one of the valves controlling the cooling water flow for the PCS. Failure of one of these valves would lead to cooling water flow being delivered to the containment vessel through one of two delivery headers. This results in reduced cooling flow for PCS operation. No other single failures are postulated in the containment analysis.

The containment integrity analyses for the AP1000 employs a multivolume lumped parameter model to study the long-term containment response to postulated Loss of Coolant Accidents (LOCA) and Main Steam Line Break (MSLB) accidents.

The analyses presented in this section are based on assumptions that are conservative with respect to the containment and its heat removal systems, such as minimum heat removal, and maximum initial containment pressure.

3.4.1 AP1000 Containment Analysis Model

The AP1000 containment model is based on the AP600 Evaluation Model (Ref. 1). The AP1000 containment model has the same diameter as the AP600 model. The AP1000 containment height is 24.5 ft higher to provide increased volume to minimize the containment pressure for design basis events.

Two different WGOTHIC models were used for AP600 containment integrity analysis. A single node model above the operating deck was used for the main steam line break analysis, and multiple node model above the operating deck was used for the double-ended cold leg break LOCA analysis. It was subsequently determined that the single node model was adequate for both cases. Thus, the WGOTHIC model used in this study consists of fifteen volumes inside the containment vessel; fourteen below the operating deck and one above the operating deck. The volumes are assumed to be the same as the AP600 below the operating deck. These volumes are shown in Table 3.4-1.

In addition, there are eighteen volumes outside the containment vessel that represent the passive containment cooling system annulus and air flow path. These volumes are assumed to be the same as AP600, but have been increased in length to reflect the higher containment. All other PCS parameters including the coverage fraction are assumed to be the same as AP600.

The PCS flow rate was increased from AP600 as discussed in Section 2 of this report and is shown in Table 3.4-2.

The WGOTHIC model is shown in Figure 3.4-1.

3.4.2 Main Steam Line Break

The rupture of a main steam line was found to be the limiting design basis event for the AP600 containment. Due to the increased steam generator size relative to the reactor coolant system, it is expected that this event will also be limiting for AP1000 containment.

The primary challenge to the containment integrity for the main steam line break is the nearly adiabatic pressurization resulting from the blowdown of the secondary steam generator inventory and associated piping. For this reason, the key mechanism for limiting the pressure is the containment free volume, and to a lesser extent, the internal heat sink structures inside the containment. Because of the relatively short duration of the event, there is very little influence from the passive containment cooling system water on the outside of the containment shell.

Mass and energy release rates were developed based on the larger steam generators and associated piping. For AP600, a range of break sizes and initial reactor power conditions were studied. The limiting case was found to be a full, double-ended rupture of the main steam line at the highest pipe elevation with the reactor at full power. This is the condition that was analyzed for AP1000.

The mass and energy release rates are input to WGOTHIC as tables of flow from the break and enthalpy. Details of the mass and energy analysis are shown in Reference 2. The resulting mass and energy inputs for this analysis are shown in Figure 3.4-2. The releases are inserted into the volume above the operating deck.

The resulting pressure response is shown in Figure 3.4-3. The blowdown peak pressure is approximately 71 psia, and occurs about 620 seconds after the initiation of the event.

The containment atmosphere temperature response to this event is shown in Figure 3.4-4. The peak temperature is 375°F.

These results show that the containment vessel is adequately sized so that the peak pressure resulting from a main steam line break is less than the design limit. The margin to the design pressure is approximately 3 psia.

3.4.3 Double-Ended Cold Leg Break

The double-ended cold leg break represents a different challenge to the containment integrity. The initial blowdown of the reactor coolant system causes an initial rapid pressure increase. The makeup water sources remove reactor decay heat from the core along with residual heat from the RCS structure, and this energy is slowly reduced as the event progresses. Finally, a

large source of energy in the steam generator secondary side is released over a period of time. The timing of the post-blowdown releases ultimately effect the peak containment pressure for this event.

For conventional plants, emergency core cooling water that is supplied to the core circulates through the steam generator tubes, effectively removing the stored energy in the secondary side. The standard assumption for conventional plants is that the energy is completely removed from the broken loop steam generator in one-half hour, and from the intact loop steam generator in one hour. For passive plants, the passive core cooling safety features tend to isolate the steam generators. AP600 integral system tests (Refs. 3 and 4), show that the steam generator secondary side remains hot several hours after the event initiation for small break LOCA events.

The AP600 containment integrity analysis assumed the same conservative steam generator energy release rates as conventional plants. These inputs resulted in a double-peaked pressure response curve; the first peak resulting from the initial blowdown of the RCS, and the second peak resulting from arbitrarily rapid release of the steam generator energy. Check calculations were performed for AP600 using an integrated RCS and containment model (Ref. 5). These results showed that by mechanistically calculating the energy release from the RCS, the second pressure peak does not occur. The conclusions from this analysis were that the Westinghouse SSAR containment integrity analysis was overly conservative with the largest source of conservatism being the artificial release of the steam generator secondary side energy over a short time span. For the AP1000, a more mechanistic approach is followed concerning the energy stored in the steam generator. It is proposed that for the AP1000 DCD, the time for the steam generators to reach thermal equilibrium be determined in a manner consistent with the approach found in Reference 5.

The mass and energy release rates for the double-ended cold leg LOCA are input to the WGOTHIC model as two separate break flow paths. These are shown in Figures 3.4-5 and 3.4-6.

The resulting containment pressure response is shown in Figure 3.4-7. The peak pressure for this case is 61 psia which is 13 psia less than the design limit.

The containment atmosphere temperature response is shown in Figure 3.4-8.

3.4.4 Sensitivity of Assumptions

This section provides assessments to illustrate the sensitivity to important assumptions that could affect the results of the containment analysis calculations.

As was discussed previously, the assumed timing of the release of energy from the steam generator secondary side has the largest effect on the resulting peak pressure. To determine the sensitivity to this assumption, three WGOTHIC calculations were performed. The first case assumes a steam generator energy release time of five hours, and the second case assumes three

hours. The third case uses the same assumption as AP600; one-half hour for the broken loop, and one hour for the intact loop. The results are shown in Figure 3.4-10.

These results show that even for the most conservative assumption of steam generator energy release, the peak containment pressure is still lower than the design pressure.

3.4.5 Conclusions

The AP1000 containment and passive containment cooling system is adequately sized to maintain containment integrity for design basis events. The limiting accident sequence is the main steam line break. The peak containment pressure for this event is 71 psia, and the margin to the design pressure limit is approximately 3 psia. The double-ended cold leg break results in a peak containment pressure of 61 psia, and the margin for this event is approximately 13 psia.

A comparison of the margins for AP1000 and AP600 is shown in Table 3.4-3.

3.4.6 References

1. DE-AC03-90SF18495, AP600 Standard Safety Analysis Report, June 1992.
2. WCAP-14254, SPES-2 Test Analysis Report, May 1995.
3. WCAP-14292, OSU Test Analysis Report, September 1995.
4. RPSB-98-07, Containment/RCS Analysis of a Large Break Loss-of-Coolant Accident in the AP600 Using RELAP5/MOD3, G. N. Lauben, August 1998.

Table 3.4-1	AP1000 WGOTHIC Model – Control Volumes Inside Containment	
Volume No.	Description	Volume (ft^3)
1	Reactor Cavity	5332.9
2	Accumulator Cavity, SE	10205.8
3	Accumulator Cavity, NE	13286.1
4	SG Room, East	15668.6
5	SG Room, West	15658.8
6	CMT Room, #1	86997.6
7	Upper Refueling Canal	39404.5
8	IRWST Room (Initially 86.4% water)	11316.7
9	Above Operating Deck	1738014
28	CVS Room	15729.9
29	CMT Room, #2	70201.4
32	SG Room – Lower, East	13486.9
33	SG Room – Lower, West	13478.4
34	Lower Refueling Room	5218.8
Total		2054000

Table 3.4-2 AP1000 PCS Flow	
Time (sec)	Flow (lbm/s)
0	0
336.9	0
337	65.2
14400	62.6
14400.1	31.4
39600	30.3
39600.1	24.5
82800	23.1
82800.1	20
280800	14

Table 3.4-3 Summary of Calculated Pressures and Temperatures			
AP600 (45 psig design pressure)	**Peak Pressure (psig)**	**Available Margin (psi)**	**Peak Temperature (°F)**
Break			
Double-ended cold leg guillotine	43.4	1.6	281.2
Full main steamline DER, 102% power, MSIV failure	43.7	1.3	370.9
AP1000 (59 psig design pressure)	**Peak Pressure (psig)**	**Available Margin (psi)**	**Peak Temperature (°F)**
Break			
Double-ended cold leg guillotine	46	13	368
Full main steamline DER, 102% power, MSIV failure	56	3	375

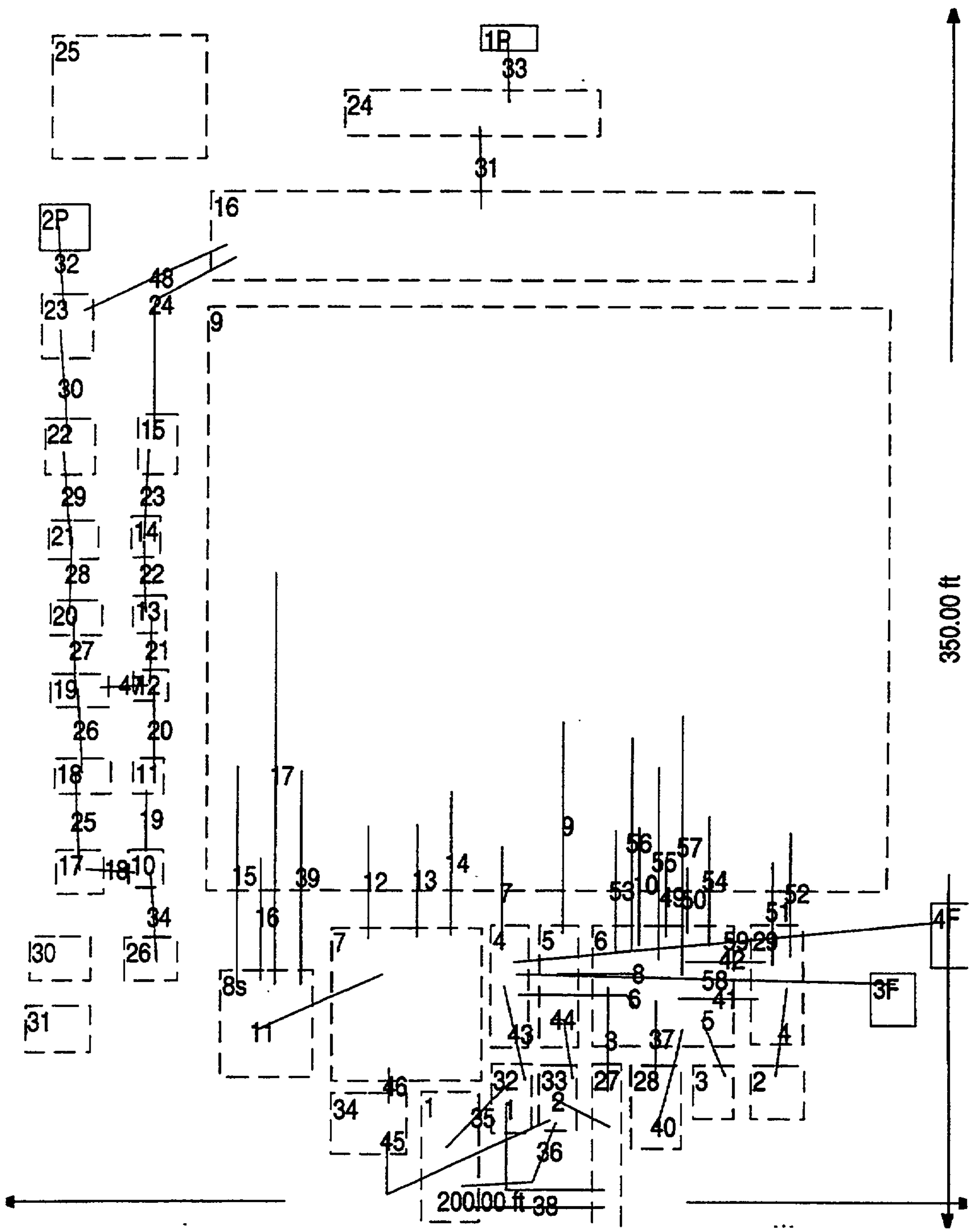


Figure 3.4-1 WGOTHIC Model for AP1000

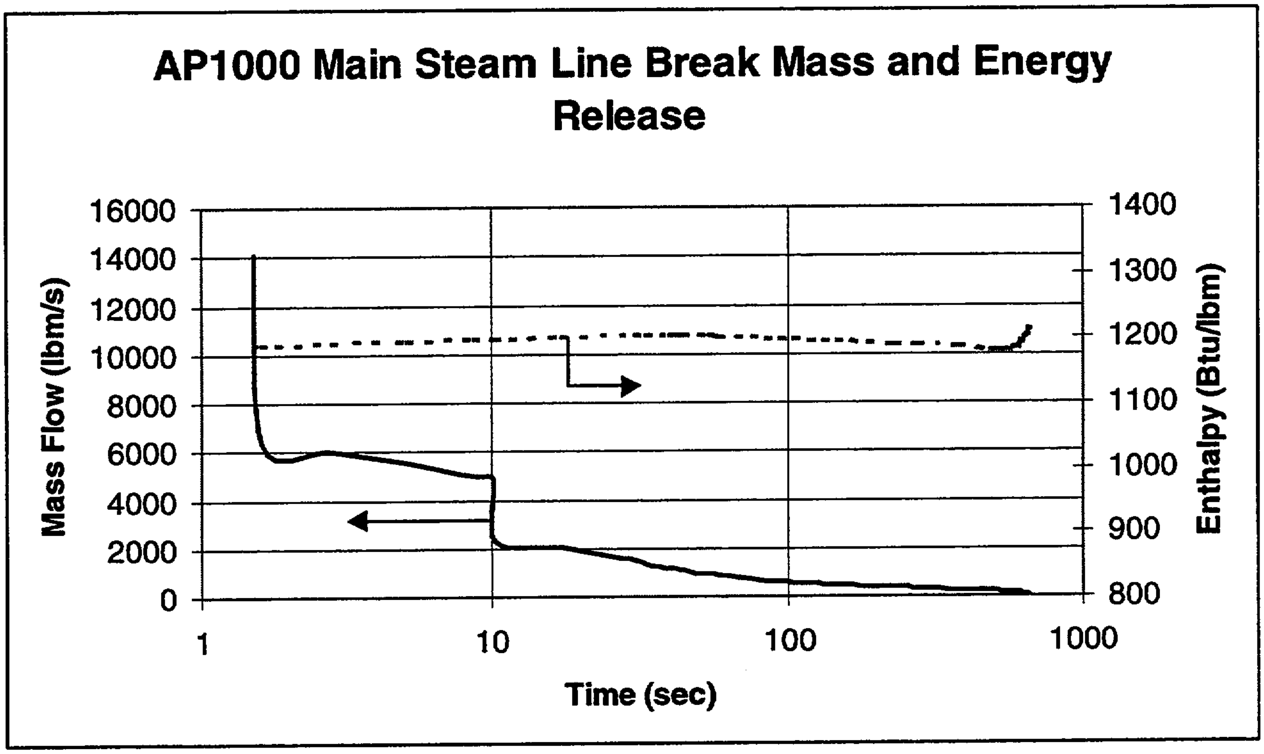


Figure 3.4-2 AP1000 Main Steam Line Break Mass and Energy Release Rates

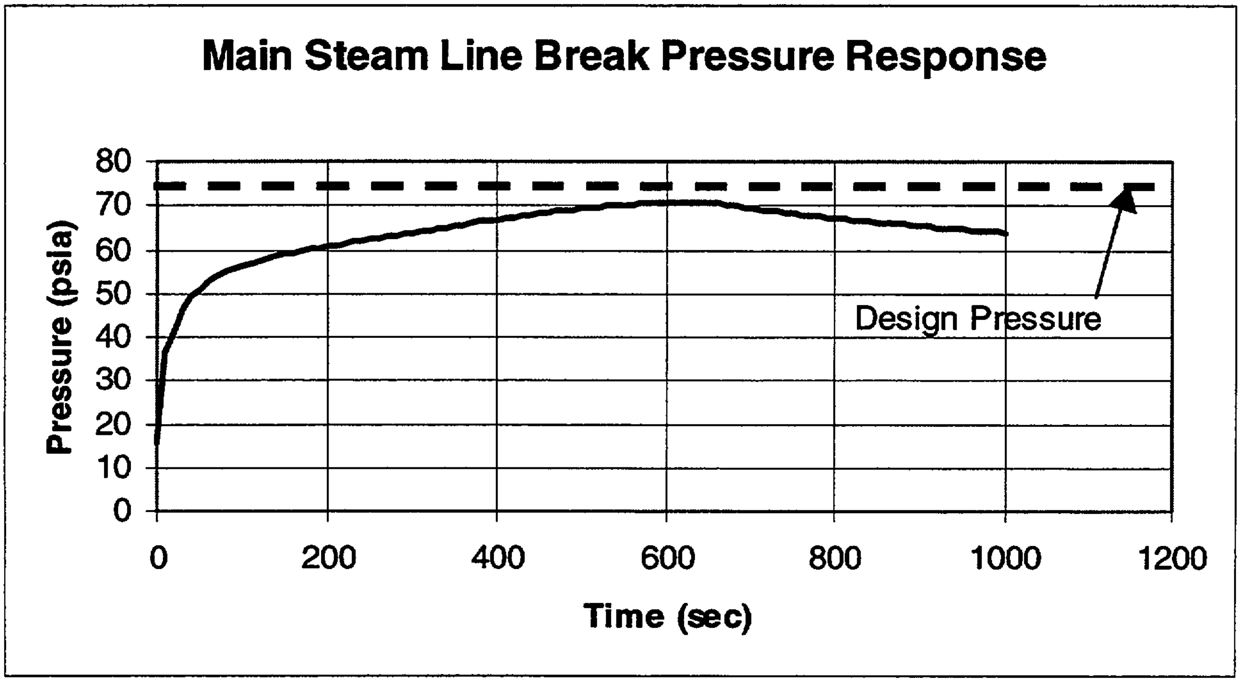


Figure 3.4-3 AP1000 Main Steam Line Break Containment Pressure Response

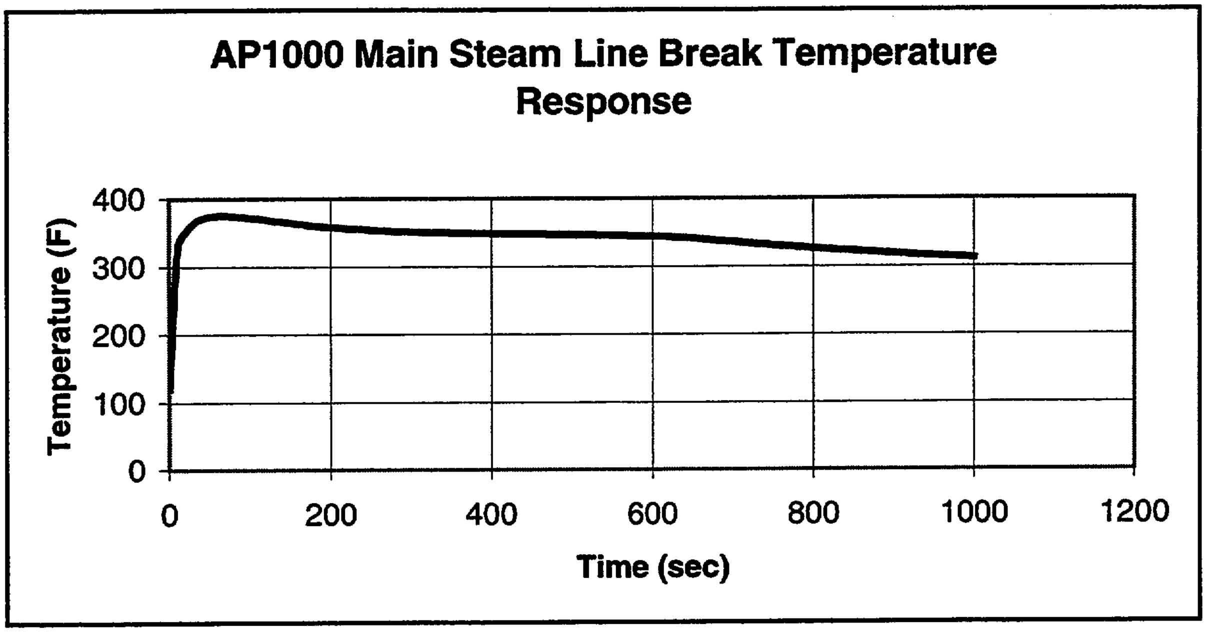


Figure 3.4-4 AP1000 Main Steam Line Break Temperature Response

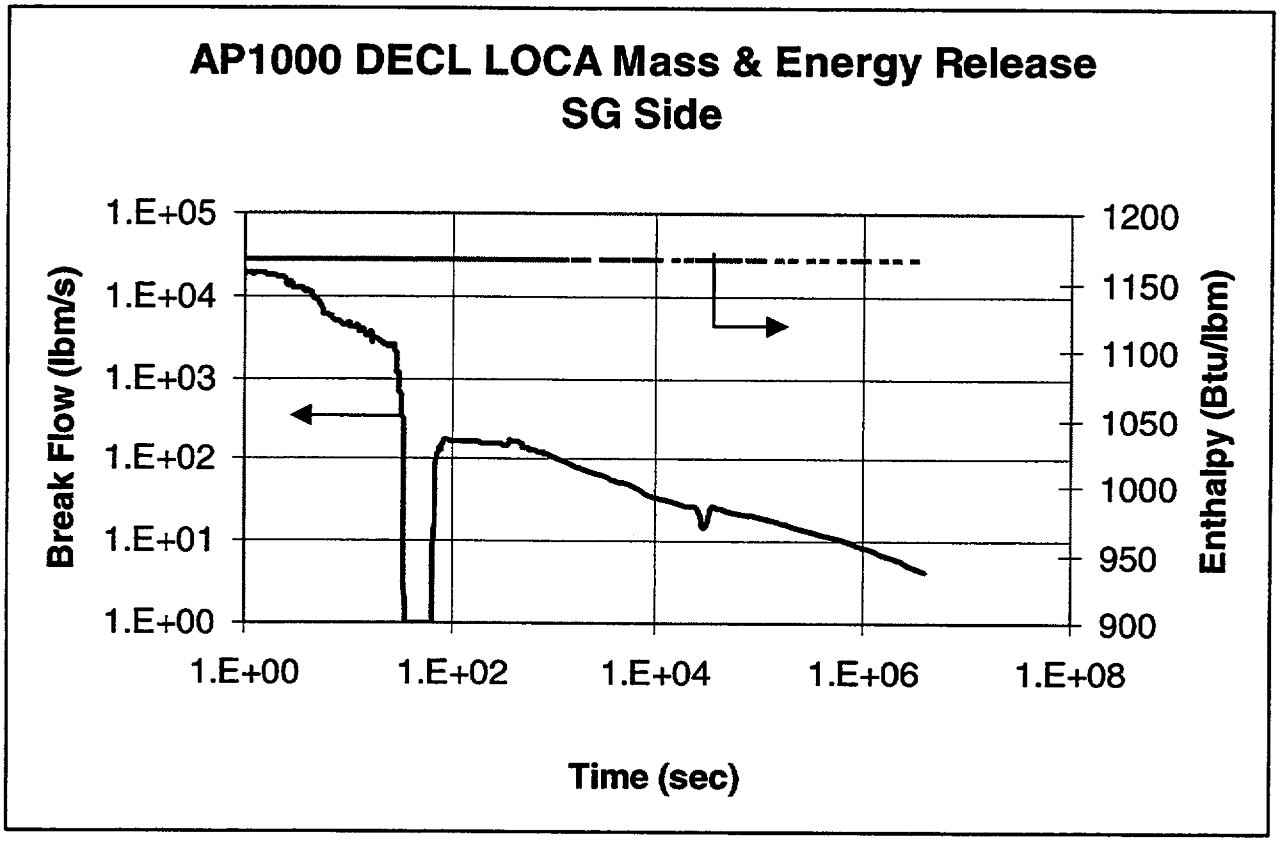


Figure 3.4-5 DECL LOCA Mass & Energy Release – SG Side

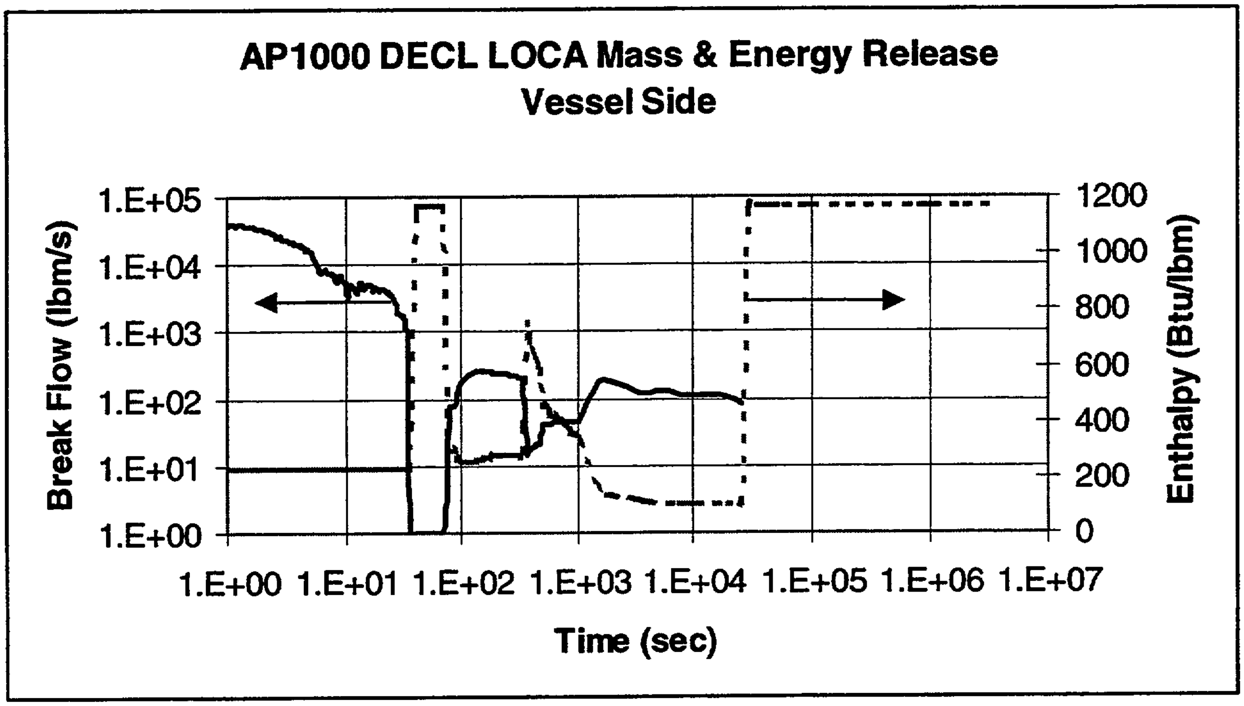


Figure 3.4-6 DECL Mass & Energy Release – Vessel Side

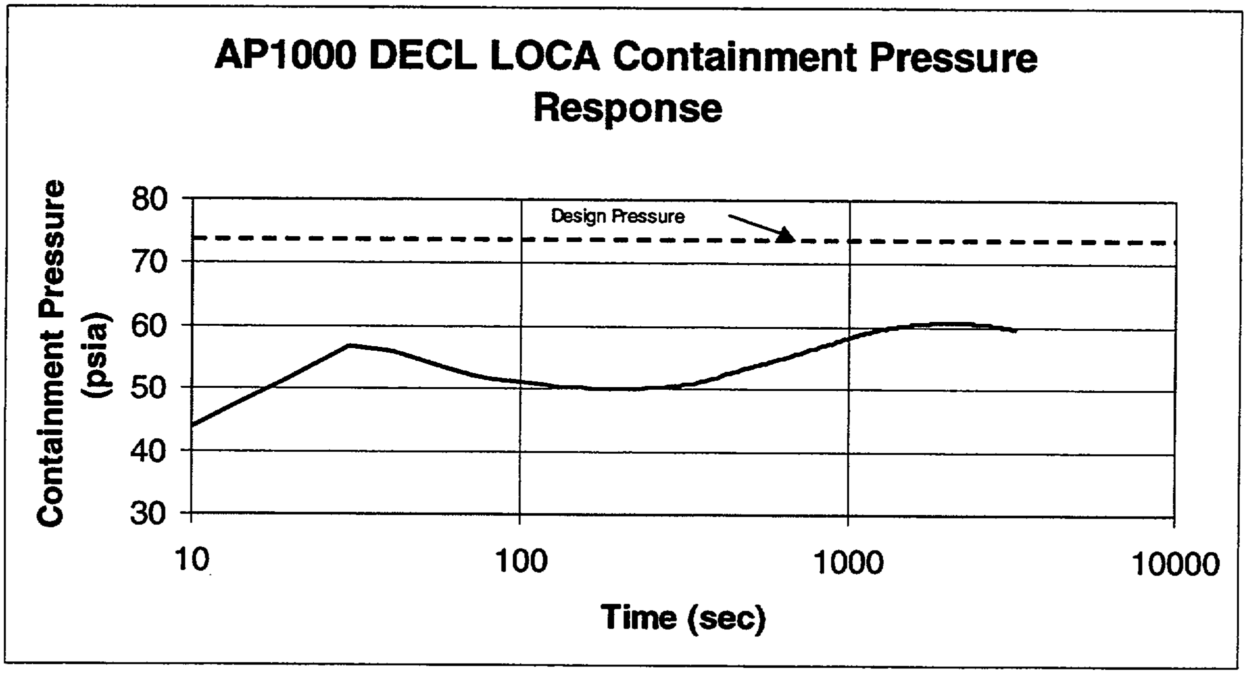


Figure 3.4-7 AP1000 DECL LOCA Containment Pressure Response

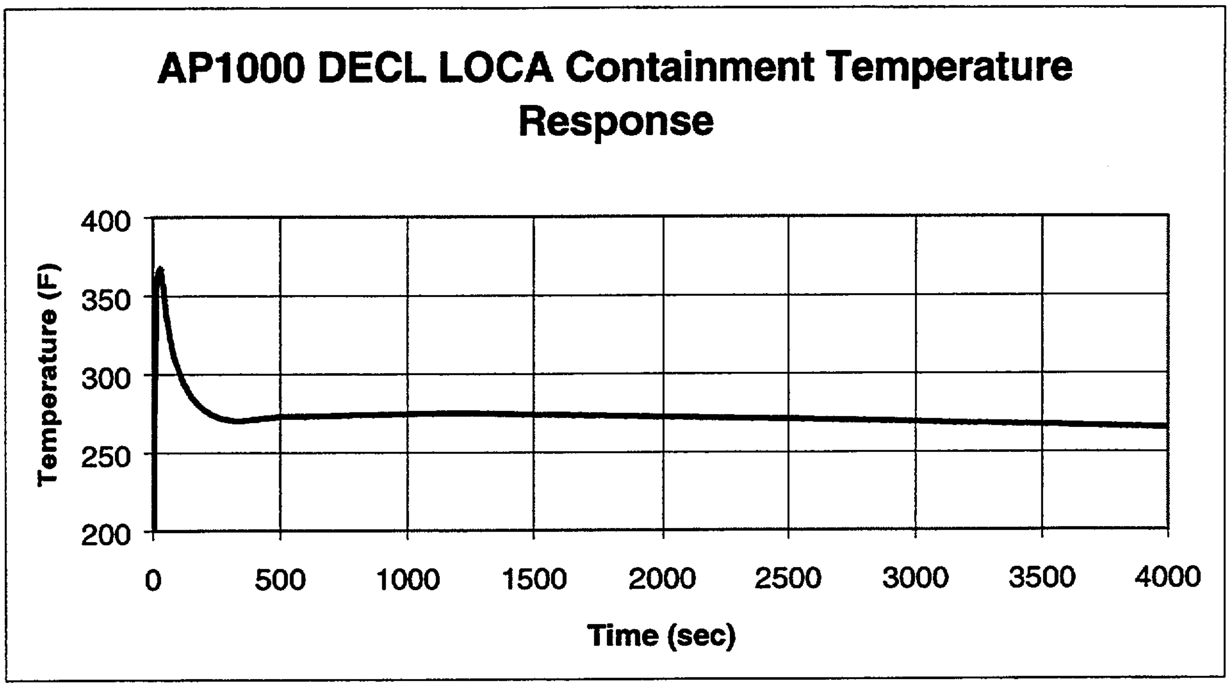


Figure 3.4-8 AP1000 DECL LOCA Temperature Response

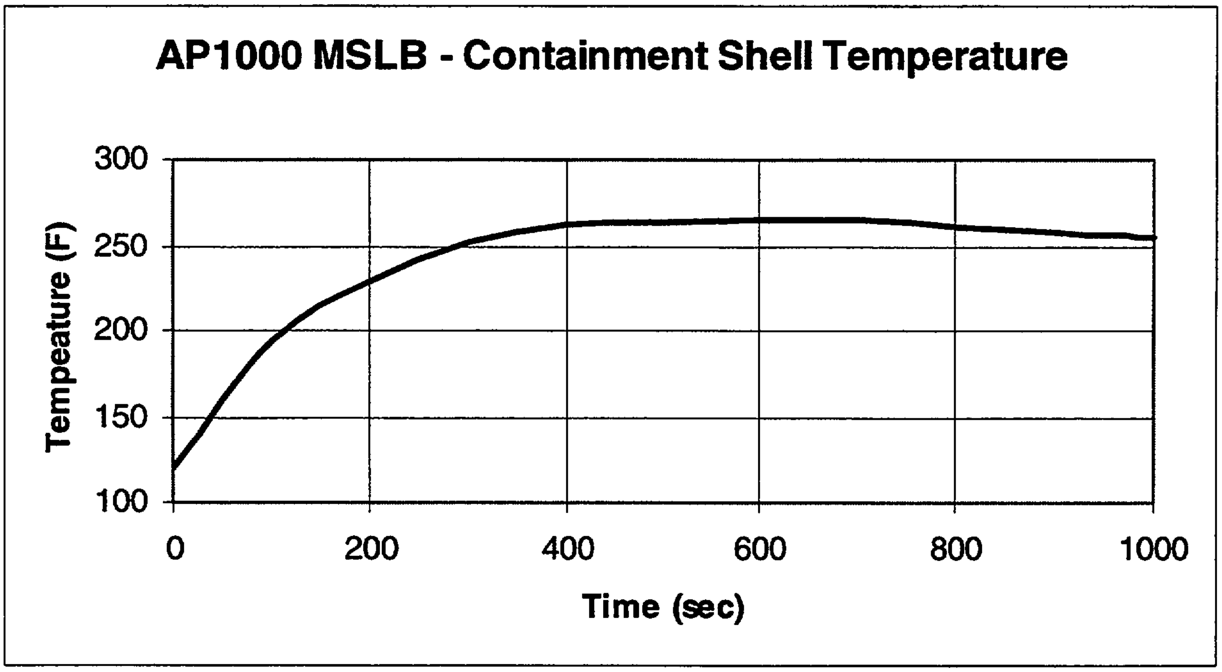


Figure 3.4-9 AP1000 Main Steam Line Break Containment Shell Temperature

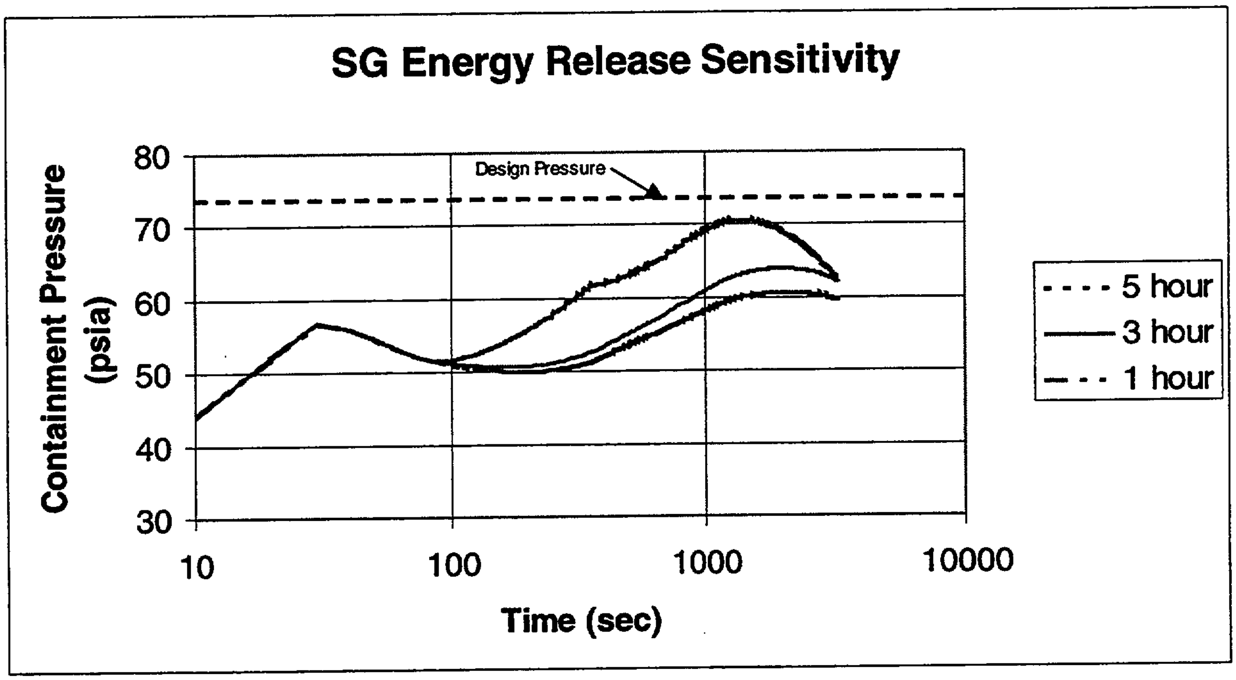


Figure 3.4-10 AP1000 DECL LOCA Containment Pressure Sensitivity to SG Energy Release