SHEARON HARRIS NUCLEAR POWER PLANT
DOCKET NO. 50-400/LICENSE NO. NPF-63
TECHNICAL SPECIFICATION CHANGE REQUEST
STEAM GENERATOR REPLACEMENT

NSSS LICENSING REPORT

BOOK 1 of 2

HNP SGR/UPRATING PROJECT – NSSS LICENSING REPORT

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ACRONYMS

AFWS	Auxiliary Feedwater System
AFW	Auxiliary Feedwater
ALARA	As Low as Reasonably Achievable
AMSAC	ATWS Mitigating System Actuation Circuitry
ANS	American National Standards
ANSI	American National Standards Institute
AOO	Anticipated Operational Occurrence
ARC	Automatic Rod Control
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
AVB	Anti-Vibration Bars
BAT	Boric Acid Tank
BATP	Boric Acid Transfer Pump
BIT	Boron Injection Tank
BOC	Beginning of Cycle
BOCREC	Beginning of Core Recovery
BOL	Beginning of Life
BOP	Balance of Plant
B&PV	Boiler and Pressure Vessel
BRS	Boron Recycle System
BTP	Branch Technical Position
BTRS	Boron Thermal Regeneration System
CAW	Customer Application for Withholding
CCW	Component Cooling Water
CCWS	Component Cooling Water System
C&FS	Condensate and Feedwater System
CFR	Code of Federal Regulations
CG	Center of Gravity
CH/SI	Charging/Safety Injection
COMS	Cold Overpressure Mitigation System
CP&L	Carolina Power and Light
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CRSD	Core Radiation Source Data
CSA	Channel Statistical Allowance
CSLL	Core Safety Limit Lines
CST	Condensate Storage Tank

ACRONYMS

CVCS	Chemical and Volume Control System
DE	Dose Equivalent
DECLG	Double Ended Cold Leg Guillotine
DEGB	Double-ended Guillotine Break
DEHL	Double Ended Hot Leg
DEPS	Double Ended Pump Suction
DF	Decontamination Factor
DNB	Departure from Nucleate Boiling
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOC	End of Cycle
EOL	End of Life
EOP	Emergency Operating Procedure
EQ	Environmental Qualification
ERG	Emergency Response Guidelines
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
ESW	Emergency Service Water
FBCV	Feedwater Bypass Control Valve
FCTF	Fuel Cooling Test Facility
FCV	Feedwater Control Valve
FDB	Flow Distribution Baffle
FIV	Feedwater Isolation Valve
FIV	Flow-Induced Vibration
FSAR	Final Safety Analysis Report
FW	Feedwater
FWLB	Feedwater Line Break
GDC	General Design Criteria
GDT	Gas Decay Tank
GFFDS	Gross Failed Fuel Detection System
GWPS	Gaseous Waste Processing System
HFP	Hot Full Power
HI	Heat Input
HHSI	High Head Safety Injection
HLSO	Hot-Leg Switchover

ACRONYMS

HNP	Harris Nuclear Plant
HX	Heat Exchanger
HZP	Hot Zero Power
IAM	Inputs, Assumptions and Methods
ICRP	International Commission on Radiation Protection
IFM	Intermediate Flow Mixing
ILRT	Integrated Leak Rate Test
IST	In-Service Testing
LBB	Leak Before Break
LBLOCA	Large Break Loss of Coolant Accident
LHGR	Linear Heat Generation Rate
LHSI	Low-Head Safety Injection
LLC	Limited Liability Company
LOCA	Loss-of-Coolant Accident
LOOP	Loss-of-Offsite Power
LPP	Low Pressurizer Pressure
LPZ	Low Population Zone
LSGWL	Low-Low Steam Generator Water Level
LSP	Low Steamline Pressure
LTCC	Long-Term Core Cooling
LTOP	Low Temperature Over Pressurization
LTOPS	Low Temperature Over Pressurization System
LWPS	Liquid Waste Processing System
LWR	Light Water Reactor
M&E	Mass and Energy
MDNBR	Minimum Departure from Nucleate Boiling Ratio
MFW	Main Feedwater
MI	Mass Input
MFCV	Main Feedwater Control Valve
MFIV	Main Feedwater Isolation Valve
MMSBC	Mixed Mean Sump Boron Concentration
MOC	Middle of Cycle
MPC	Maximum Permissible Concentrations
MS	Margin of Safety
MSIS	Main Steam Isolation Signal
MSIV	Main Steam Isolation Valve

ACRONYMS

MSLB	Main Steam Line Break
MSS	Main Steam System
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
NI	Nuclear Instrumentation
NNS	Non-Nuclear Safety
NPSH	Net Positive Suction Head
NRS	Narrow-Range Span
NRC	Nuclear Regulatory Commission
NRL	Narrow Range Level
NSSS	Nuclear Steam Supply System
NUPPSCO	Nuclear Power Plant Standards Committee
OBE	Operating Basis Earthquake
OFA	Optimized Fuel Assembly
OPΔT	Over Power Delta Temperature
OTΔT	Over Temperature Delta Temperature
PA	Postulated Accident
PCT	Peak Cladding Temperature
PCV	Pressure Control Valve
PCWG	Performance Capability Working Group
PI	Proportional and Integral
PLS	Precautions, Limitations and Setpoints
PORV	Power Operated Relief Valve
PRT	Pressurizer Relief Tank
PT	Pressure Transmitter
PWR	Pressurized Water Reactor
QMS	Quality Management System
RAI	Request for Additional Information
RCCA	Rod Cluster Control Assembly
RCL	Reactor Coolant Loop
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RHRS	Residual Heat Removal System

ACRONYMS

RHT	Recycle Holdup Tank
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RSG	Replacement Steam Generator
RTP	Rated Thermal Power
RTS	Reactor Trip System
RV	Reactor Vessel
RWST	Refueling Water Storage Tank
SAFDL	Specified Acceptable Fuel Design Limit
SB	Site Boundary
SBLOCA	Small Break Loss of Coolant Accident
SECLS	Single Ended Cold Leg Split
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SG	Steam Generator
SGBS	Steam Generator Blowdown System
SGLCS	Steam Generator Level Control System
SGR	Steam Generator Replacement
SGTP	Steam Generator Tube Plugging
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIAS	Safety Injection Actuation Signal
SIS	Safety Injection System
SPC	Siemens Power Corporation
SRP	Standard Review Plan
SRSS	Square Root of the Sum of the Squares
SSDC	Systems Standard Design Criteria
SSE	Safe Shutdown Earthquake
SSPS	Solid State Protection System
SW	Service Water
TA	Total Allowance
TDAFW	Turbine Driven Auxiliary Feedwater
TDF	Thermal Design Flow
T/H	Thermal-Hydraulic
TID	Technical Information Document
TSP	Tube Support Plate

ACRONYMS

V5H	Vantage 5H
VCT	Volume Control Tank
WOG	Westinghouse Owners' Group

STEAM GENERATOR REPLACEMENT/UPRATE ANALYSIS AND LICENSING PROJECT

NSSS LICENSING REPORT

EXECUTIVE SUMMARY

PURPOSE

The Steam Generator Replacement/Uprate Analysis and Licensing Project (SGR/Uprate) was conducted to provide the analyses and evaluations required to support both the replacement of steam generators and the power uprate option at the Harris Nuclear Plant (HNP).

In support of the SGR/Uprate, Westinghouse Electric Company (Westinghouse) has performed selected NSSS analyses and evaluations to support the replacement of the original HNP Model D4 steam generators with Model Delta 75 steam generators. The scope of the Westinghouse analyses and evaluations included the NSSS performance parameters, design transients, systems, components, selected accidents, and selected analysis related to the nuclear fuel. The NSSS analyses and evaluations have been performed to also support an uprate of the NSSS power output from 2787.4 MWt to 2912.4 MWt with the Delta 75 steam generators.

Siemens Power Corporation (SPC) provided the results of safety analyses of the events set forth in Chapter 15 of the Final Safety Analysis Report (FSAR) and the fuel design mechanical analyses that support the SPC advanced 17 X 17 fuel design for the HNP SGR/Uprate. The results of the analyses of Anticipated Operational Occurrences (AOO) and Postulated Accidents (PA) demonstrate that the event-specific acceptance criteria are met for SGR/Uprate.

DOCUMENTATION

The NSSS Licensing Report provides a description of the NSSS analyses and evaluations performed for the SGR/Uprate project. A description of the analyses and evaluations performed for the Balance of Plant (BOP) secondary systems and components and the radiological/containment response analyses is provided in the BOP Licensing Report.

For the HNP SGR/Uprate, Westinghouse has drawn from previous experience performing the V. C. Summer Steam Generator Replacement program, in which Westinghouse Model Delta 75 replacement steam generators were installed, and the J. M. Farley Uprate program. The engineering and licensing reports produced for the Farley Uprate program were used as guides for preparing the HNP engineering and licensing documentation. Moreover, the Farley Licensing Report, together with NRC review and comment resolution documentation, has been used as a benchmark for the HNP SGR/Uprate Licensing Report. Accordingly, the HNP Licensing Report addresses

applicable responses based on the NRC Requests for Additional Information (RAI) issued for the Farley Uprate program.

CONCLUSION

The results of the NSSS analyses and evaluations demonstrate that the applicable licensing criteria and requirements are satisfied for the NSSS performance parameters, design transients, systems, components, and selected accidents with the Delta 75 replacement steam generators at the uprated power conditions. The results also show that operation of HNP with the replacement steam generators at the current NSSS power is bounded by the analyses and evaluations performed at the uprated conditions.

2.0 Nuclear Steam Supply System (NSSS) Parameters

As part of the SGR/Uprating Project for HNP, NSSS performance analyses were performed to develop NSSS design parameters. Bounding NSSS Performance Capability Working Group (PCWG) parameters were developed for use in the analyses and evaluations of NSSS design transients, systems, and components.

2.1 Design PCWG Parameters and Additional Cases

2.1.1 Introduction and Background

The NSSS PCWG parameters are the fundamental parameters that are used as primary input in NSSS analyses. They provide the Reactor Coolant System (RCS) and secondary system conditions (temperatures, pressures, flow) that are used as the basis for the analyses and evaluations of design transients, systems, components, and accident analyses in the Westinghouse scope (M&E Releases, Source Terms, Steam Generator Tube Rupture, Anticipated Transients without Scram, etc.).

The design PCWG parameters are established using conservative assumptions in order to provide bounding conditions appropriate for the NSSS analyses. For example, the assumed RCS flow is the Thermal Design Flow (TDF), which is a conservatively low flow that accounts for flow measurement uncertainty and bounds the maximum expected steam generator tube plugging (SGTP) level.

The design PCWG parameters are developed to enable CP&L to have operating flexibility by using a range of conditions based on the vessel average temperature (T_{avg}), the feedwater temperature and the SGTP level. As shown in Table 2-1, the eight PCWG cases specify a T_{avg} range between 572.0°F and 588.8°F, a feedwater temperature range between 440°F and 375°F, and a SGTP level between 0 to 10 percent.

Westinghouse developed a set of design PCWG parameters for those analyses or evaluations performed at the current NSSS power operation of 2787.4 MWt and the uprated NSSS power operation of 2912.4 MWt for the SGR/Uprating Project. Westinghouse also developed part power cases for the Turbine-Generator evaluations.

2.1.2 Description of Analyses and Evaluations

The calculation of the PCWG parameters established for the current full power operation are summarized in Table 2-2 and for the uprated full power operation in Table 2-3. Listed below are the major inputs used in the generation of the PCWG parameters.

- The current NSSS power level is set at 2787.4 MWt (2775 MWt core).
- The uprated NSSS power level is set at 2912.4 MWt (2900 MWt core).

- Siemens Fuel is incorporated into the SGR/Uprating analysis.

- The TDF of 92,600 gpm/loop incorporated sufficient margin to support 10 percent average SGTP. This flow was applied for all eight design cases, even those which assumed zero percent SGTP, in order to be consistent and for conservatism. Both 0-percent and 10-percent SGTP is assumed.

- Design core bypass flow is assumed to be 7.1 percent.

- A range of full power normal operating T_{avg} from 572.0°F to 588.8°F is selected for the analyses.

- A range of full-power feedwater temperature of 375°F to 440°F is selected for the analyses.

2.1.2.1 Current Power Cases

A total of eight design cases were developed, according to Table 2-1, using the current NSSS power of 2787.4 MWt

.

2.1.2.2 Uprated Power Cases

A total of eight design basis cases were developed according to Table 2-1 for the power uprating. These PCWG-approved cases form the design basis for the SGR/Uprating Project.

Westinghouse also provided 32 additional parameter cases (based on HNP Technical Specification minimum and maximum RCS flow conditions and best estimate RCS flow at feedwater temperatures of 375.0°F, 435.0°F, and 440.0°F and SGTP levels of 0, 3, and 10 percent) for use by CP&L in fuel related analyses and accidents and in predicting actual plant operating conditions. Westinghouse evaluated the 32 additional cases to determine whether they provided a more conservative basis for their NSSS design bases analysis. In the cases where they did, the more conservative best estimate parameters were used as conservative input assumptions in the NSSS design bases analysis.

2.1.2.3 Part Power Conditions

The part power cases were developed to support evaluation of the turbine-generator by CP&L. Cases were provided for Delta 75 Steam Generators at power levels of 100 percent, 75 percent, 50 percent, and 25 percent of 2912.4 MWt.

2.1.3 Acceptance Criteria

The primary acceptance criteria for the determination of the design PCWG parameters are: (1) the parameters must provide CP&L with adequate flexibility and margin for plant operation, and (2) the parameters must maintain current thermal design flow and minimum measured flow requirements (shown in Tables 2-4 and 2-5) based on the assumed SGTP level.

2.1.4 Results

Table 2-4 provides the eight design NSSS PCWG parameter cases that are used as the basis for the NSSS design bases analyses or evaluations at the current power conditions.

Table 2-5 provides the eight design NSSS PCWG parameter cases that are used as the basis for the NSSS design bases analyses or evaluations at the uprated power conditions.

Table 2-6 provides the part power cases developed at power levels of 100 percent, 75 percent, 50 percent, and 25 percent of 2912.4 MWt.

2.1.5 Conclusions

The PCWG current and uprated power cases were issued to the various Westinghouse engineering organizations. The Westinghouse analysts performed their analyses and evaluations based on the parameter set or sets that were most limiting so that the analyses would support operation of HNP over the range of conditions specified.

Table 2-1 NSSS PCWG Cases at Current Power and Uprated Power			
Case No.	**SGTP (%)**	**Average Temp. (°F)**	**Feedwater Temp. (°F)**
1	0	572.0	375
2	0	588.8	375
3	10	572.0	375
4	10	588.8	375
5	0	572.0	440
6	0	588.8	440
7	10	572.0	440
8	10	588.8	440

Table 2-2 NSSS PCWG Input Parameters at Current Power Level	
Parameter	**Value**
Fuel Type and Features	
Type	Siemens
IFMs (Yes/No)	Yes
Fuel Rod OD (in.)	0.376
NSSS Thermal Power	
NSSS Power (MWt)	2787.4
Core Power (MWt)	2775
Net Heat Input (MWt)	12.4
RCS Flow	
Thermal Design Flow (gpm/loop)	92,600
Total Core Bypass Flow (%)	7.1
Thimble Plugs (In/Out)	In
RCS Temperature	
Vessel Average (°F)	572.0, 588.8
RCS Pressure (psia)	2250
Steam Generator (Model Δ75)	
Steam Generator Tube Plugging Level, Min/Max (%)	0 / 10
Main Feedwater Temperatures (°F)	375, 440*

* Temperature range specified for the SGR/Uprating project by CP&L and is consistent with the range for the uprated parameter cases.

Table 2-3 NSSS PCWG Input Parameters At Uprated Power Level	
Parameter	
Fuel Type and Features	
Type	Siemens
IFMs (Yes/No)	Yes
Fuel Rod OD (in.)	0.376
NSSS Thermal Power	
NSSS Power (MWt)	2912.4
Core Power (MWt)	2900
Net Heat Input (MWt)	12.4
RCS Flow	
Thermal Design Flow (gpm/loop)	92,600
Total Core Bypass Flow (%)	7.1
Thimble Plugs (In/Out)	In
RCS Temperature	
Vessel Average (°F)	572.0, 588.8
RCS Pressure (psia)	2250
Steam Generator (Model Δ75)	
Steam Generator Tube Plugging Level, Min/Max (%)	0 / 10
Main Feedwater Temperatures (°F)	375, 440

Table 2-4
NSSS PCWG Parameters at HNP Current Power Conditions

THERMAL DESIGN PARAMETERS	Original Basis(1)	Case 1(2)	Case 2(2)	Case 3(2)	Case 4(2)
NSSS Power, %	100	100	100	100	100
MWt	2785	2787.4	2787.4	2787.4	2787.4
10^6 BTU/hr	9503	9511	9511	9511	9511
Reactor Power, MWt	2775	2775	2775	2775	2775
10^6 BTU/hr	9469	9469	9469	9469	9469
Thermal Design Flow, Loop gpm	97,600	92,600	92,600	92,600	92,600
Reactor 10^6 lb/hr	109.0	106.1	103.6	106.1	103.6
Reactor Coolant Pressure, psia	2250	2250	2250	2250	2250
Core Bypass, %	6.1	7.1	7.1	7.1	7.1
Reactor Coolant Temperature, °F					
Core Outlet	623.8	610.6	626.2	610.6	626.2
Vessel Outlet	620.2	605.9	621.8	605.9	621.8
Core Average	592.5	576.1	593.2	576.1	593.2
Vessel Average	588.8	572.0	588.8	572.0	588.8
Vessel/Core Inlet	557.4	538.1	555.8	538.1	555.8
Steam Generator Outlet	557.1	537.8	555.5	537.8	555.5
Steam Generator					
Steam Temperature, °F	540.2	525.6	543.8	523.6	541.8
Steam Pressure, psia	964	852	993	838	978
Steam Flow, 10^6 lb/hr total	12.20	11.21	11.28	11.21	11.27
Feed Temperature, °F	435	375	375	375	375
Moisture, % max.	0.25	0.10	0.10	0.10	0.10
Steam Generator Tube Plugging, %	0	0	0	10	10
Zero Load Temperature, °F	557	557	557	557	557
HYDRAULIC DESIGN PARAMETERS					
Pump Design Point, Flow (gpm)/Head (ft.)	103,400/276				
Best Estimate Flow, gpm		102,200	102,200	100,000	100,000
Mechanical Design Flow, gpm	107,100				
Minimum Measured Flow, gpm total		293,540	293,540	293,540	293,540

FOOTNOTES:
(1) Original parameters reflect operation with a model D4 steam generator.
(2) Parameters assume operation with a model Δ75 steam generator.

Table 2-4 (continued)
NSSS PCWG Parameters at HNP Current Power Conditions

THERMAL DESIGN PARAMETERS	Original Basis(1)	Case 5(2)	Case 6(2)	Case 7(2)	Case 8(2)
NSSS Power, %	100	100	100	100	100
MWt	2785	2787.4	2787.4	2787.4	2787.4
10^6 BTU/hr	9503	9511	9511	9511	9511
Reactor Power, MWt	2775	2775	2775	2775	2775
10^6 BTU/hr	9469	9469	9469	9469	9469
Thermal Design Flow, Loop gpm	97,600	92,600	92,600	92,600	92,600
Reactor 10^6 lb/hr	109.0	106.1	103.6	106.1	103.6
Reactor Coolant Pressure, psia	2250	2250	2250	2250	2250
Core Bypass, %	6.1	7.1	7.1	7.1	7.1
Reactor Coolant Temperature, °F					
Core Outlet	623.8	610.6	626.2	610.6	626.2
Vessel Outlet	620.2	605.9	621.8	605.9	621.8
Core Average	592.5	576.1	593.2	576.1	593.2
Vessel Average	588.8	572.0	588.8	572.0	588.8
Vessel/Core Inlet	557.4	538.1	555.8	538.1	555.8
Steam Generator Outlet	557.1	537.8	555.5	537.8	555.5
Steam Generator					
Steam Temperature, °F	540.2	525.6	543.8	523.6	541.8
Steam Pressure, psia	964	852	993	838	978
Steam Flow, 10^6 lb/hr total	12.20	12.23	12.30	12.22	12.29
Feed Temperature, °F	435	440	440	440	440
Moisture, % max.	0.25	0.10	0.10	0.10	0.10
Steam Generator Tube Plugging, %	0	0	0	10	10
Zero Load Temperature, °F	557	557	557	557	557
HYDRAULIC DESIGN PARAMETERS					
Pump Design Point, Flow (gpm)/Head (ft.)	103,400/276				
Best Estimate Flow, gpm		102,200	102,200	100,000	100,000
Mechanical Design Flow, gpm	107,100				
Minimum Measured Flow, gpm total		293,540	293,540	293,540	293,540

FOOTNOTES:

(1) Original parameters reflect operation with a model D4 steam generator.

(2) Parameters assume operation with a model Δ75 steam generator.

Table 2-5
NSSS PCWG Parameters at HNP Uprated Power Conditions

THERMAL DESIGN PARAMETERS	Original Basis(1)	Case 1(2)	Case 2(2)	Case 3(2)	Case 4(2)
NSSS Power, %	100	104.6	104.6	104.6	104.6
MWt	2785	2912.4	2912.4	2912.4	2912.4
10^6 BTU/hr	9503	9938	9938	9938	9938
Reactor Power, MWt	2775	2900	2900	2900	2900
10^6 BTU/hr	9469	9895	9895	9895	9895
Thermal Design Flow, Loop gpm	97600	92600	92600	92600	92600
Reactor 10^6 lb/hr	109.0	106.3	103.8	106.3	103.8
Reactor Coolant Pressure, psia	2250	2250	2250	2250	2250
Core Bypass, %	6.1	7.1	7.1	7.1	7.1
Reactor Coolant Temperature, °F					
Core Outlet	623.8	612.2	627.7	612.2	627.7
Vessel Outlet	620.2	607.4	623.2	607.4	623.2
Core Average	592.5	576.4	593.4	576.4	593.4
Vessel Average	588.8	572.0	588.8	572.0	588.8
Vessel/Core Inlet	557.4	536.6	554.4	536.6	554.4
Steam Generator Outlet	557.1	536.3	554.1	536.3	554.1
Steam Generator					
Steam Temperature, °F	540.2	523.7	541.9	521.6	539.9
Steam Pressure, psia	964	839	978	824	962
Steam Flow, 10^6 lb/hr total	12.20	11.71	11.78	11.71	11.77
Feed Temperature, °F	435	375	375	375	375
Moisture, % max.	0.25	0.10	0.10	0.10	0.10
Steam Generator Tube Plugging, %	0	0	0	10	10
Zero Load Temperature, °F	557	557	557	557	557
HYDRAULIC DESIGN PARAMETERS					
Pump Design Point, Flow (gpm)/Head (ft.)	103,400/276				
Best Estimate Flow, gpm		102,200	102,200	100,000	100,000
Mechanical Design Flow, gpm	107,100				
Minimum Measured Flow, gpm total		293,540	293,540	293,540	293,540

FOOTNOTES:

(1) Original parameters reflect operation with a model D4 steam generator.

(2) Parameters assume operation with a model Δ75 steam generator.

Table 2-5 (continued)
NSSS PCWG Parameters at HNP Uprated Power Conditions

THERMAL DESIGN PARAMETERS	Original Basis(1)	Case 5(2)	Case 6(2)	Case 7(2)	Case 8(2)
NSSS Power, %	100	104.6	104.6	104.6	104.6
MWt	2785	2912.4	2912.4	2912.4	2912.4
10^6 BTU/hr	9503	9938	9938	9938	9938
Reactor Power, MWt	2775	2900	2900	2900	2900
10^6 BTU/hr	9469	9895	9895	9895	9895
Thermal Design Flow, Loop gpm	97600	92600	92600	92600	92600
Reactor 10^6 lb/hr	109.0	106.3	103.8	106.3	103.8
Reactor Coolant Pressure, psia	2250	2250	2250	2250	2250
Core Bypass, %	6.1	7.1	7.1	7.1	7.1
Reactor Coolant Temperature, °F					
Core Outlet	623.8	612.2	627.7	612.2	627.7
Vessel Outlet	620.2	607.4	623.2	607.4	623.2
Core Average	592.5	576.4	593.4	576.4	593.4
Vessel Average	588.8	572.0	588.8	572.0	588.8
Vessel/Core Inlet	557.4	536.6	554.4	536.6	554.4
Steam Generator Outlet	557.1	536.3	554.1	536.3	554.1
Steam Generator					
Steam Temperature, °F	540.2	523.7	541.9	521.6	539.9
Steam Pressure, psia	964	839	978	824	962
Steam Flow, 10^6 lb/hr total	12.20	12.77	12.85	12.76	12.84
Feed Temperature, °F	435	440	440	440	440
Moisture, % max.	0.25	0.10	0.10	0.10	0.10
Steam Generator Tube Plugging, %	0	0	0	10	10
Zero Load Temperature, °F	557	557	557	557	557
HYDRAULIC DESIGN PARAMETERS					
Pump Design Point, Flow (gpm)/Head (ft.)	103,400/276				
Best Estimate Flow, gpm		102,200	102,200	100,000	100,000
Mechanical Design Flow, gpm	107,100				
Minimum Measured Flow, gpm total		293,540	293,540	293,540	293,540

FOOTNOTES:

(1) Original parameters reflect operation with a model D4 steam generator.
(2) Parameters assume operation with a model Δ75 steam generator.

Table 2-6 Summary of Turbine Evaluation Points For SGR/Uprating Program				
Parameter	**100% of 2912.4 MWt**	**75% of 2912.4 MWt**	**50% of 2912.4 MWt**	**25% of 2912.4 MWt**
NSSS Power (MWt)	2912.4	2184.3	1456.2	728.1
Vessel High T_{avg} (°F)	588.8 @ 0% SGTP	580.8 @ 0% SGTP	572.9 @ 0% SGTP	564.9 @ 0% SGTP
Vessel Low T_{avg} (°F)	572 @ 10% SGTP	568.2 @ 10% SGTP	564.5 @ 10% SGTP	560.7 @ 10% SGTP
Best Estimate Flow Rate, Loop (gpm)	102,200 @ 0% SGTP	102,200 @ 0% SGTP	102,200 @ 0% SGTP	102,200 @ 0% SGTP
Best Estimate Flow Rate, Loop (gpm)	100,000 @ 10% SGTP	100,000 @ 10% SGTP	100,000 @ 10% SGTP	100,000 @ 10% SGTP
Feedwater Temp. (°F)	440	406	369	320
Steam Moisture Content (%)	0.10	0.10	0.10	0.10

3.0 NSSS and Auxiliary Equipment Design Transients

This section discusses the generation of NSSS and Auxiliary Equipment Design Transients for the SGR/Uprating conditions. The design transients were reviewed and revised as necessary, for use at the HNP SGR/Uprating conditions. The revised NSSS design transient curves were provided to the system and component designers for use in their specific analyses. Section 3.1 describes the evaluation performed. Auxiliary equipment design transients were also evaluated to determine whether they remain applicable for use in the SGR/Uprating analysis of all the auxiliary equipment in the NSSS. The results of this evaluation are presented in Section 3.2.

3.1 NSSS Design Transients

3.1.1 Introduction and Background

As part of the original design and analyses of the NSSS components for the HNP, NSSS design transients (i.e., temperature and pressure transients) were specified (Reference 1) for use in the analyses of the cyclic behavior of the NSSS components. To provide the necessary high degree of integrity for the NSSS components, the transient parameters selected for component fatigue analyses are based on conservative estimates of the magnitude and frequency of the temperature and pressure transients resulting from various plant operating conditions. The transients selected for use in component fatigue analyses are representative of operating conditions that would be considered to occur during plant operations of possible significance to component cyclic behavior due to their severity or frequency. The selected transients are representative of plant transients which, when used as a basis for component fatigue analysis, would provide confidence that the component is appropriate for its application over the operating license period of the plant. For purposes of analysis, the number of transient occurrences is based on an operating license period of 40 years.

3.1.2 Description of Analyses and Evaluations

Initial plant conditions for the NSSS design transients are based primarily on the NSSS Performance Capability Working Group (PCWG) parameters as discussed in Section 2 of this report.

The NSSS design transients for the SGR/Uprating program and the original HNP design transients (Reference 1) were compared, and any differences were evaluated. The effect of the following changes on the NSSS design transients were also evaluated:

- Main steam safety valves blowdown
- Moisture separator designs for the HNP Model Delta 75 replacement steam generator

The latest designs of the HNP Model Delta 75 moisture separator have resulted in a change in the steam generator level control setpoint and steam generator mass. Additionally, the steam generator thermal-hydraulic characteristics have changed.

3.1.3 Acceptance Criteria and Results

The NSSS design transients are input to the primary and secondary component structural and fatigue analysis/evaluations. The final acceptance is determined by the component stress and fatigue analyses presented in Section 5.

Consistent with the original NSSS design transients, the NSSS design transients for the SGR/Uprating are conservative representations of transients which, when used as a basis for component fatigue analyses, provide confidence that the component is appropriate for its application over the operating license period of the plant. Also, consistent with the original NSSS design transients, the number of transient occurrences are based on an operating license period of 40 years.

3.1.4 Conclusions

The NSSS design transients for the Model Delta 75 replacement steam generators at the uprated power level are also applicable for the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

3.1.5 Reference

1. Systems Standard Design Criteria (SSDC) 1.3, Rev. 2, April 15, 1974.

3.2 Auxiliary Equipment Design Transients

3.2.1 Introduction

As part of the original design and analysis of the NSSS auxiliary components (i.e., NSSS auxiliary pumps, valves, and heat exchangers) for the Harris Nuclear Plant (HNP), auxiliary equipment design transients (i.e., temperature and pressure transients) were specified for use in the analyses of the cyclic behavior of the NSSS auxiliary components. To provide the necessary high degree of integrity for the NSSS auxiliary components, the transient design parameters selected for component fatigue analyses were based on conservative estimates of the magnitude and frequency of the temperature and pressure transients resulting from various postulated plant operating conditions. The transients selected for use in component fatigue analyses are representative operating conditions that are considered to be sufficiently severe or frequent as to impact component cyclic behavior. The transients are selected to be sufficiently conservative such that, when used as a basis for component fatigue analysis, they provide confidence that the component will perform as intended over the operating license period of the plant. For purposes of analysis, the number of transient occurrences was based on an operating license period of 40 years.

3.2.2 Input Parameters and Assumptions

The review of the NSSS auxiliary equipment design transients was based on a comparison between the NSSS PCWG parameters for the Steam Generator Replacement/Uprating (SGR/Uprating) as discussed in Chapter 2 of this report and the design parameters that make up the current auxiliary equipment design transients. The current transients that are specified for HNP are contained in Reference 1.

3.2.3 Description of Analyses and Evaluation

A review of the current auxiliary equipment transients determined that the only transients that could be impacted by the SGR/Uprating are those temperature transients that are impacted by full-load NSSS operating temperatures, namely T_{hot} and T_{cold}. These transients are currently based on an assumed full-load NSSS worst case T_{hot} of 630°F and worst case T_{cold} of 560°F. These NSSS temperatures were originally selected to ensure that the resulting design transients would be conservative for a wide range of NSSS operating temperatures.

3.2.4 Acceptance Criteria and Results

A comparison of the SGR/Uprating NSSS PCWG parameter ranges for T_{hot} (604.2° to 623.2°F) and T_{cold} (536.6° to 557.4°F) with the T_{hot} and T_{cold} values used to develop the current design transients indicates that the SGR/ Uprating T_{hot} and T_{cold} parameter ranges are lower. Therefore, the actual temperature transients (that is, the change in temperature from T_{hot} or T_{cold} dictated by the SGR/Uprating parameters to a lower auxiliary system-related temperature or visa versa) are less severe than the current design temperature transients.

3.2.5 Conclusions

As the temperature transients dictated by the SGR/Uprating conditions are less limiting than those that established the current auxiliary equipment design transients, it can be concluded that all the applicable auxiliary equipment design transients for HNP still apply for the SGR/Uprating conditions.

The results of the evaluation are consistent with and continue to comply with the current HNP licensing basis acceptance requirements. The results obtained with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound plant operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

3.2.6 References

1. Westinghouse Systems Standard Design Criteria (SSDC) document 1.3, Rev. 2, April 15, 1974.

4.0 NSSS Systems

This section presents the results of the analyses and evaluations performed in the NSSS systems area to support the HNP SGR/Uprating. The systems addressed in this section include fluid systems, NSSS/BOP interface systems, and control systems. The detailed results and conclusions of each analysis/evaluation are presented within each subsection.

4.1 NSSS Fluid Systems

The fluid systems evaluations described in this section were performed at the systems level. For the fluid systems supplied for HNP by Westinghouse, the applicable system functional requirements and performance criteria were reviewed to ensure that each system remains capable of performing its design basis functions at the SGR/Uprating conditions. A justification is provided for systems that are judged to be unaffected by the uprated plant conditions.

4.1.1 Reactor Coolant System

4.1.1.1 Introduction

The RCS consists of three heat transfer loops connected in parallel to the reactor vessel. Each loop contains a reactor coolant pump (RCP), which circulates the water through the loops and reactor vessel, and a steam generator (SG), where heat is transferred to the Main Steam System (MSS). In addition, the RCS contains a pressurizer which controls RCS pressure through electrical heaters, water sprays, power-operated relief valves (PORVs) and spring-loaded safety/relief valves. The steam discharged from the PORVs and safety/relief valves flows through interconnecting piping to the pressurizer relief tank (PRT).

This section identifies the key functions of the RCS and identifies which functions are potentially impacted by the SGR/Uprating program.

The key RCS functions are as follows:

- The RCS transfers heat generated in the reactor core to the MSS via the SGs.
- When the core is subcritical and RCS temperatures are approximately 350°F and lower, the RCS provides means to transfer decay and sensible heat to the RHRS.
- The RCS fluid acts as a moderator of neutrons by slowing the neutrons to lower thermal energy states and increasing the probability of thermal fission.
- The RCS fluid is a solvent and carrier of boric acid, used as a neutron poison.

- The RCS is the second of three "barriers" against fission product release to the environment. (The fuel cladding is the first barrier, and the containment building is the third.)

- The RCS provides means for pressure control via use of pressurizer heaters and spray flow.

The calculated RCS design operating conditions at the uprated power are presented in Section 2 of this report. The primary changes in NSSS Performance Capability Working Group (PCWG) parameters that impact the RCS functions include the increase in core power, the allowable operating range for average RCS temperature (T_{avg}), and reduced thermal design flow.

The potential impact of the SGR/Uprating conditions on the previous RCS functions are described below.

- The core power increase will affect the total amount of heat transferred to the MSS. Verification that the major components can support this normal heat removal function is addressed in Section 5 of this report.

- During the second phase of plant cooldown, the RHRS will be required to remove larger amounts of decay heat from the RCS. Section 4.1.4 of this report addresses the RHRS cooldown capability at uprated conditions.

- Due to the replacement steam generator, the RCS volume will be affected, which will in turn affect the amount of boron required for reactivity control.

- The RCS heat capacity of the primary coolant system will be affected by the Model Delta 75 steam generators that will be installed.

- The pressurizer spray flow rate was affected by changes in the reactor coolant best estimate flow rate, which depends on the steam generator tube plugging level and the associated effect on the pressure drop across the reactor vessel.

4.1.1.2 RCS Loop Operating Pressures

4.1.1.2.1 Introduction

This evaluation was performed to determine if the HNP RCS would undergo any significant pressure changes due to variations in flow and temperature resulting from the SGR/Uprating. The analysis calculated the operating pressures at the SGR/Uprating plant conditions.

The objective of this evaluation was to calculate the RCS pressure at various locations within the RCL at steady-state conditions. These results, coupled with the RCS pressure deviations determined by NSSS design transients and Low Temperature Over Pressurization (LTOP)

analyses, predict the pressure for a range of conditions. This determines the sufficiency of the RCS and associated Class 1 components.

4.1.1.2.2 Description of Analyses and Evaluations

The RCS loop pressures were determined based on hydraulic resistances and pump data. Actual component elevations were used as input to account for elevation effects. The correct pressurizer pressure and fluid density were used as input for the liquid space and surge line to ensure that the correct static pressure was imposed on the hot leg. A fluid density corresponding to cold-leg conditions was used for the RCS loops and vessel. This was done so that the unrecoverable pressure drops would be correctly calculated based on the NSSS hydraulic resistances.

The operating pressure was calculated for the following RCS main-coolant-loop locations:

- Pressurizer Surge Line Connection to Loop 2 Hot Leg
- Reactor Vessel Inlet
- Reactor Vessel Outlet
- Steam Generator Inlet
- Steam Generator Outlet
- Reactor Coolant Pump Inlet
- Reactor Coolant Pump Outlet

Because the variations in the operating pressure are not expected to be great over large segments of the RCS loops (e.g., cold leg, hot leg, etc.), all primary components and connection points to other Class 1 equipment and piping will be bounded by the calculated operating pressures at the locations specified above.

4.1.1.2.3 Acceptance Criteria

For the SGR/Uprating, the operating pressures for the RCS loop cannot exceed the design pressures of the primary loop components and piping.

4.1.1.2.4 Results

The operating pressure was calculated for each location for full-power operation at high and low RCS temperatures. The results demonstrate that at full power the temperature affects the pressure only slightly. However, the pressure in the RCS loop for best estimate flow is shown to be lower than 2300 psig for full-power operation at any temperature.

4.1.1.2.5 Conclusions

This analysis demonstrated that under normal operating conditions the pressure at any location in the RCS loop will not exceed 2300 psig. The results are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Model Delta 75 replacement steam generators at the uprated power of 2912.4 MWt are applicable to operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt at corresponding values of T_{avg} and steam generator tube plugging level.

The revised RCS pressures based on 2912.4 MWt are applicable to operation of HNP at the current NSSS power rating of 2787.4 MWt since the RCS pressure analysis was not based on NSSS power but was dependent upon the RCS temperatures and flow rates.

4.1.1.3 RCS Volume, Mass, and Boron Inventory Analysis

4.1.1.3.1 Introduction

Westinghouse has evaluated the RCS volume, mass, and boron inventory changes that result from the SGR/Uprating plant configuration and conditions. The evaluation considered typical conditions that may occur in the RCS from operating at full power to shutdown mode and no Residual Heat Removal (RHR) trains in service to start-up conditions. The purpose of this calculation was to determine the volume of reactor coolant required for each case. Once the volume had been calculated, the mass and boron inventory of the reactor coolant was determined.

4.1.1.3.2 Description of Analyses and Evaluations

For the evaluation, the relevant systems that impact the volume were determined, and the volume of each applicable system was then calculated. For Mode 1 and Mode 2 operations, a 3-percent thermal expansion was included in the calculation of the RCS volume.

The RCS active volume for each case was the sum of the volumes for each applicable system. The mass was calculated as the product of the volume and the density of the reactor coolant at the temperature of the system.

At full power, the temperature varies throughout the RCS; therefore, the mass was determined for each of the temperature regions in the RCS.

For other RCS configurations and conditions, the RCS temperature was assumed to be relatively uniform. Therefore, the average RCS temperature was used to determine the coolant mass in the RCS. The coolant mass in the CVCS and RHRS were calculated. The total coolant mass was then calculated from the sum of the masses in each system.

The boron mass was then calculated.

4.1.1.3.3 Acceptance Criteria

There are no acceptance criteria for the results of the evaluation. The results are used as input to other efforts where additional evaluations or analyses are performed.

4.1.1.3.4 Results and Conclusions

This evaluation demonstrates the relationship between the RCS volume and boron mass in the system. These RCS volumes will be used in the boron dilution analysis, LTOP analysis, and operating procedure guidance.

This analysis was evaluated at the same temperatures for vessel outlet, core average, and vessel/core outlet as in the original basis for the current NSSS power of 2787.4 MWt. Therefore, the results obtained with the Model Delta 75 replacement steam generators at the uprated power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

4.1.1.4 RCS Heat Capacity

4.1.1.4.1 Introduction

A re-evaluation of the RCS heat capacity was required to reflect the plant configuration of HNP for the SGR/Uprating program. The parameters for this calculation included the masses and specific heat values of the primary side (reactor coolant, the nuclear fuel material, the vessels and piping) and the secondary side of the steam generator (feedwater, steam and piping). This result was incorporated into the revised RHR cooldown analysis (subsection 4.1.4) that was performed for the SGR/Uprating program.

4.1.1.4.2 Description of Analyses and Evaluations

The masses of the reactor coolant, feedwater and steam in the steam generator were determined by their volumes at 350°F. The mass of each parameter was multiplied by its respective specific heat. The heat capacities of the parameters were added to obtain the RCS total heat capacity.

4.1.1.4.3 Acceptance Criteria

There are no acceptance criteria for the results of the evaluation. The results are used as input to other efforts where additional evaluations or analyses are performed.

4.1.1.4.4 Results and Conclusions

For calculating the RCS total heat capacity, each mass was multiplied by its respective specific heat. The individual heat capacities were added to obtain a total RCS heat capacity of 1.29 MBtu/ °F.

The results are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Model Delta 75 replacement steam generators at the uprated power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

The revised RCS heat capacity based on 2912.4 MWt is bounding for operation of HNP at the current NSSS power rating of 2787.4 MWt since the RCS heat capacity analysis was not based on NSSS power but was dependent upon the mass and heat capacity of each component.

4.1.1.5 Pressurizer Spray System

4.1.1.5.1 Introduction

The purpose of this evaluation is to determine the effect of the SGR/Uprating conditions on the capability of the pressurizer spray system in HNP. The pressurizer spray flow rate is affected by changes in the reactor coolant best estimate flow rate, which depends on the steam generator tube plugging level and the associated effect on the pressure drop across the reactor vessel. The effect on the hydraulics of the RCS of the Siemens fuel design currently used in HNP was also considered in this analysis.

4.1.1.5.2 Description of Analyses and Evaluations

A model of the HNP pressurizer spray system was developed using a Bernoulli balance method. This model was used to analyze the hydraulic performance of the spray system for the RCS conditions associated with the SGR/Uprating.

The driving head for the spray flow is the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The velocity head of the loop flow and the static head in the pressurizer add to the spray driving force. Once the head loss components have been determined, the pressurizer spray flow can be calculated.

The calculated pressurizer spray flow rate for the hydraulic conditions associated with the steam generator replacement and power uprating can then be compared to the minimum required flow rates to determine the acceptability of the system performance.

4.1.1.5.3 Acceptance Criteria

The design basis functional requirement for the pressurizer spray system is to prevent challenges to the pressurizer PORVs for a 10-percent step change in load. The minimum design basis flow rate of the HNP pressurizer spray system with both pressurizer spray flow control valves full open was 700 gpm. Although this analysis has demonstrated that flow rates in excess of 700 gpm can pass through the pressurizer spray line with the spray flow control valves full open, flow rates greater than 700 gpm are not required and are not expected to occur. The spray flow control valves will modulate open upon demand from the pressurizer pressure controller until the increase in pressurizer pressure due to the load decrease has been arrested. Therefore, the design flow rate of 700 gpm is the appropriate value for the transient structural analysis of the pressurizer spray nozzle.

4.1.1.5.4 Results and Conclusions

This analysis has determined that the design pressurizer spray flow rate of 700 gpm can be obtained in HNP for the conditions associated with the steam generator replacement and power uprating for the range of 0 to 10-percent steam generator tube plugging.

The results for the SGR/Uprating are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The same RCS best estimate flow rate and core pressure drop apply to the steam generator replacement at the current power level. Therefore, the results obtained with the Model Delta 75 replacement steam generators at the uprated power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

4.1.1.6 Pressurizer Relief Tank Level Alarm Setpoints

4.1.1.6.1 Introduction

The SGR/Uprating program for HNP has prompted a reevaluation of the RCS. The purpose of this analysis is to review the pressurizer relief tank (PRT) level alarm setpoints. The original calculation determined that the alarms should be positioned at 83 percent for the high alarm and 64 percent for the low alarm of the 100-in. range. The objective of this analysis is to determine the revised level alarm setpoints for the PRT under the SGR/Uprating conditions.

4.1.1.6.2 Description of Analyses and Evaluations

The steam discharge calculation assumed that the PRT was capable of quenching 110 percent of the full-load pressurizer steam volume. A steam volume of 577 ft^3 included a 3-percent thermal expansion. The mass of steam in the pressurizer can be determined by dividing the volume by the specific volume.

The minimum volume was obtained by considering the enthalpy balance with conservatism. The water volume was converted from cubic feet to gallons. A conversion that relates water volume to liquid level for a horizontal tank was used to determine the water level in the PRT. Seven inches were subtracted from the water level to adjust for the height of the tank below the tap. For HNP, 3-percent trip accuracy was incorporated into the calculation. For the low-level setpoint, the accuracy was added; however, for the high-level alarm it was subtracted.

4.1.1.6.3 Acceptance Criteria

The low-level alarm setpoint in the PRT was determined such that the water temperature would not exceed the limit of 200°F after steam discharged.

PRT pressure can not exceed 50 psig after the design basis discharge with the selected high-level alarm setpoint.

4.1.1.6.4 Results and Conclusions

The result of the analysis yielded that the level alarm instruments should be positioned at 83 percent and 62 percent for high and low, respectively, of the PRT.

The results are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. Therefore, the results obtained with the Model Delta 75 replacement steam generators at the uprated power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

The revised PRT level alarm setpoints based on 2912.4 MWt are bounding for operation of HNP at the current NSSS power rating of 2787.4 MWt, as the PRT level alarm setpoints were not based on NSSS power, but were dependent upon the initial full-power pressurizer steam volume and operating conditions of the PRT, which are the same for both power ratings.

4.1.2 Chemical and Volume Control System

The Chemical and Volume Control System (CVCS) is a key auxiliary support system to the RCS. The CVCS is physically connected to the RCS and is normally in operation. Its primary design function is to maintain RCS water inventory, boron concentration, and water chemistry. Other RCS support functions include purification and seal injection flow to the reactor coolant pumps (RCPs). Key functions of the CVCS are as follows:

- RCS Pressure Boundary Integrity — Portions of the CVCS that comprise the reactor coolant pressure boundary are designed for expected RCS operating conditions to minimize the probability of pressure boundary failure.

- Boration — Consistent with the requirements of 10 CFR 50 Appendix A (General Design Criteria), the CVCS provides means for reactivity control independent of control rods. This function is accomplished via delivery of boric acid solution, which is a neutron absorber, into the RCS.

- Containment Isolation — Following design basis events, CVCS connections to the RCS that penetrate containment, with the exception of the RCP seal injection line, are automatically isolated during all events that require containment isolation.

The revised RCS operating conditions at the SGR/Uprating conditions are provided in Section 2 of this report. The primary RCS parameter changes include revised steam generator parameters, an increase in core power, allowable operating range for RCS T_{avg}, and reduced Thermal Design Flow.

The effects of the revised operating conditions on CVCS functions are described within this section.

4.1.2.1 Chemical and Volume Control System/ Boron Thermal Regeneration System Heat Exchanger Performance

4.1.2.1.1 Introduction

The Westinghouse CVCS design files for HNP were reviewed to identify existing analysis and inherent assumptions. An evaluation of the performance of the CVCS and Boron Thermal Regeneration System (BTRS) heat exchangers at the SGR/Uprating plant conditions is summarized below. Other existing CVCS performance analyses that remain applicable to the SGR/Uprating conditions are described in subsequent sections of 4.1.2.

4.1.2.1.2 Description of Analyses and Evaluations

The effect of the revised RCS operating temperatures on the following CVCS/BTRS heat exchangers was analyzed:

- Regenerative Heat Exchanger
- Letdown Heat Exchanger
- Excess Letdown Heat Exchanger
- Seal Water Heat Exchanger
- Letdown Reheat Heat Exchanger

The performance of the moderating heat exchanger and the letdown chiller heat exchanger was not evaluated in this analysis for the following reason. The BTRS contains the moderating, letdown chiller, and letdown reheat heat exchangers. The letdown stream, which flows through the BTRS demineralizers, is extracted from, and returns to, the letdown line at points downstream of the letdown heat exchanger. Therefore, as long as the letdown heat exchanger is capable of reducing the letdown temperature to 115°F or lower, there will be no change in the terminal temperatures or heat loads for the BTRS heat exchangers. Additionally, the BTRS heat exchangers do not utilize component cooling water because the moderating and letdown reheat heat exchangers are regenerative types of heat exchangers that recover heat from, and reject heat to, other parts of the CVCS/BTRS systems that are at higher or lower temperature. The letdown chiller heat exchanger utilizes a closed-loop chilled water system for cooling water. The only heat exchanger that is potentially affected by the SGR/Uprating is the letdown reheat heat exchanger.

With respect to CCWS operating temperatures for those CVCS/BTRS heat exchangers cooled by CCW, the maximum expected CCWS supply temperature provided to CVCS components was compared to allowable operating limits (see Section 4.1.6). These operating limits were identified or confirmed in the analysis of the performance of the RHRS during plant cooldown (see Section 4.1.4) and in the thermal analysis of the CCWS (see Section 4.1.6).

4.1.2.1.3 Acceptance Criteria

In the assessment of CVCS operation at revised RCS operating temperatures, the maximum expected RCS T_{cold} must be less than or equal to the applicable CVCS design temperature and less than or equal to the heat exchanger design inlet operating temperature. The former criterion supports the functional operability of the system and its components. The latter criterion provides for heat exchanger design operating conditions that remain bounding.

The letdown line fluid temperature shall be reduced to a temperature less than or equal to 110°F downstream of the letdown heat exchanger and the seal water heat exchanger. The tube-side

outlet temperature of the excess letdown heat exchanger was originally designed to be less than or equal to the original design tube-side outlet temperature of 165°F. The current HNP procedures may control the excess letdown such that the tube side outlet temperature is 174°F. Both limits were considered in the evaluation.

In the assessment of CVCS operation at revised CCWS operating temperatures, the maximum expected CCWS supply temperature must be less than or equal to allowable operating limits, which are 105°F for normal operation and 125°F during plant cooldown. This criterion supports the overall functional operability of the system and the components serviced by the CCWS.

The temperature of the component cooling water leaving the CVCS heat exchangers that are cooled by the CCWS shall remain below the levels at which local cavitation or voiding could occur in the component cooling water system. It was assumed that 50 degrees of subcooling provides adequate margin of local subcooling.

The CVCS heat exchanger terminal temperatures shall remain within design temperature limits specified for the tube and shell sides of the units. The differences in terminal temperatures for the heat exchangers shall be acceptable from the aspect of component stress limits for normal operation.

Heat exchanger flowrates shall remain within mechanical design constraints of the heat exchanger unit with respect to pressure differential and vibration.

4.1.2.1.4 Results and Conclusions

The results of the CVCS heat exchanger performance analysis support the conclusion that the operating flow rates and temperatures are very close to current values, and are bounded by the heat exchanger design conditions.

The operation of the CVCS heat exchangers at the revised RCS temperature conditions was reviewed and the results presented in the previous subsection. The conclusion from this assessment is that the design of the CVCS heat exchangers will remain adequate for the conditions associated with the SGR/Uprating. This portion of the CVCS system supports operation at the current power with steam generator replacement as well as steam generator replacement in conjunction with power uprating. Other aspects of the design of the CVCS are addressed in the remainder of Section 4.1.2.

4.1.2.2 Letdown Line Performance

4.1.2.2.1 Introduction

Westinghouse performed an analysis of the letdown line performance to: (1) verify the adequacy of valve PCV-145 to provide the maximum letdown flowrate of 120 gpm, (2) verify that the

setpoints of relief valves 1-8117 and 1-8119 are not exceeded during normal operation, and (3) determine the nominal setpoint for pressure transmitter PT-145.

4.1.2.2.2 Description of Analyses and Evaluations

The following analyses were performed: (1) verification of adequacy of PCV-145 control range, (2) protection of relief valve set pressures, and (3) determination of nominal setpoint for PT-145.

4.1.2.2.3 Acceptance Criteria

Acceptance criteria applicable to this analysis include: (1) the calculated C_v for valve PCV-145 must be within the range of 2 – 40, (2) the normal operating pressure at the inlet of relief valve 1-8117 must be less than 600 psig, and (3) the normal operating pressure at the inlet of relief valve 1-8119 must be less than 300 psig.

4.1.2.2.4 Results

The results of the analysis are:

1. The maximum required C_v of valve PCV-145 is 9.3.
2. The minimum required C_v of valve PCV-145 is 6.1.
3. The normal operating pressure at the inlet of relief valve 1-8117 is 456.8 psig.
4. The normal operating pressure at the inlet of relief valve 1-8119 is 242.4 psig.
5. The nominal setpoint for PT-145 is 400 psig.

4.1.2.2.5 Conclusions

The performance of the letdown line in the HNP CVCS design, as determined in the above analysis, is projected to meet all the applicable acceptance criteria and is acceptable. There are no changes associated with the implementation of the SGR/Uprating program that would invalidate this analysis or its conclusions.

This portion of the CVCS system supports operation with the replacement steam generators at the current power level as well as at the uprated power level.

4.1.2.3 Charging System Evaluation

4.1.2.3.1 Introduction

Westinghouse performed an analysis of the charging system performance to: (1) determine the adequacy of the charging flow control valve FCV-122 C_v range, (2) determine the net positive

suction head (NPSH) available to the centrifugal charging pump from the VCT, and (3) determine the RCS dilution flow rates at power and during refueling.

4.1.2.3.2 Description of Analyses and Evaluations

The following analyses were performed: (1) verification of adequacy of FCV-122 maximum C_v required, (2) verification of adequacy of available NPSH to centrifugal charging pump, and (3) determination of dilution flow rates to the RCS at power and during refueling.

4.1.2.3.3 Acceptance Criteria

Acceptance criteria applicable to this analysis include: (1) the calculated C_v for valve FCV-122 must be within the range of 0.2 – 22, (2) the NPSH available to the centrifugal charging pump must exceed the required NPSH at the maximum pump flow rate (12 ft at 189 gpm), and (3) the acceptance criteria for the RCS dilution flow rates are determined separately in the inadvertent boron dilution analysis (See Section 6.2).

4.1.2.3.4 Results

The results of the analysis are:

1. The maximum required C_v of valve FCV-122 is 7.21.

2. The NPSH available to the centrifugal charging pump from the VCT at a flow rate of 189 gpm is 50.23 ft.

3. The RCS dilution flow rate for normal power operation is 216 gpm.

4. The RCS dilution flow rate during refueling is 590 gpm.

4.1.2.3.5 Conclusions

The performance of the charging line in the HNP CVCS design, as determined in the above analysis, meets all the applicable acceptance criteria and is acceptable from the system hydraulic standpoint.

There are no changes associated with the implementation of the SGR/Uprating program that would invalidate the analysis or its conclusions.

The basis for the flowrates assumed in the RCS boron dilution analysis for the SGR/Uprating program is consistent with the design basis of the CVCS charging and makeup systems.

This portion of the CVCS system supports operation of the replacement steam generators at the current power level as well as at the uprated power level.

4.1.2.4 Excess Letdown Flow Performance

4.1.2.4.1 Introduction

The purpose of this analysis is to determine the adequacy of valve HCV-137 in the excess letdown line to provide the design flow rate of 25 gpm with the excess letdown flow directed to the VCT.

4.1.2.4.2 Description of Analyses and Evaluations

The pressure drop through the excess letdown line at the design excess letdown flow rate (25 gpm) was calculated. Using the calculated pressure drop information, the minimum pressure drop across valve HCV-137 was calculated. The maximum required C_v value for valve HCV-137 was then determined and compared to the maximum available C_v of the valve to determine that the valve will pass the design excess letdown flow rate.

4.1.2.4.3 Acceptance Criteria

The calculated C_v for valve HCV-137 at a flow rate of 25 gpm must be less than the maximum value of 1.5.

4.1.2.4.4 Results

The results of this analysis indicate that a C_v value of 0.55 is required for valve HCV-137, which is less than the maximum C_v value of 1.5.

4.1.2.4.5 Conclusions

The performance of the excess letdown line in the HNP CVCS design meets all the applicable acceptance criteria and is acceptable. There are no changes associated with the implementation of the SGR/Uprating program that would invalidate this analysis or its conclusions.

This portion of the CVCS system supports operation with the replacement steam generators at the current power level as well as at the uprated power level.

4.1.2.5 Boric Acid System Performance

4.1.2.5.1 Introduction

Westinghouse performed an analysis of the boric acid system performance to: (1) determine the boric acid flow capacity for normal makeup into the VCT or to the VCT outlet (bypassing the tank), (2) determine the ability of the boric acid system to provide emergency boration flow to the suction of the centrifugal charging pump and the NPSH that the boric acid transfer pump (BATP) provides to the centrifugal charging pump in this mode of operation, and (3) determine the maximum runout flow rate of the BATP in the emergency boration mode.

4.1.2.5.2 Description of Analyses and Evaluations

The following analyses were performed: (1) verification of adequacy of FCV-113A maximum C_v required for normal makeup, (2) verification of emergency boration flow rate and NPSH provided to centrifugal charging pump, and (3) determination of maximum boric acid transfer pump runout flow rate in the emergency boration mode of operation.

4.1.2.5.3 Acceptance Criteria

Acceptance criteria applicable to this analysis include: (1) for normal makeup, the calculated maximum C_v for valve FCV-113A must be less than 22.8, (2) the NPSH available to the centrifugal charging pump must exceed the required NPSH at the assumed emergency boration flow rate (10 ft at 61 gpm), and (3) the runout flow rate of the boric acid transfer pump in the emergency boration mode of operation must be less than 150 gpm.

4.1.2.5.4 Results

The results of the analysis are: (1) the maximum required C_v of valve FCV-113A is 11.6 for normal makeup to the VCT operating at a pressure of 30 psig, (2) the NPSH available to the centrifugal charging pump from the BATP with the VCT isolated at a flow rate of 61 gpm in the emergency boration mode of operation is 167.7 ft, and (3) the resistance of the emergency boration flow path limits the maximum flow rate of the boric acid transfer pump to less than 135 gpm.

4.1.2.5.5 Conclusions

The performance of the boric acid system in the HNP CVCS design, as determined in the above analysis, meets all the applicable original acceptance criteria and is acceptable from the system hydraulic standpoint.

There are no changes associated with the implementation of the SGR/Uprating program that would invalidate this analysis or its conclusions.

It has also been confirmed that the refueling concentration for the core design at the uprated power level does not exceed 2600 ppm boron.

This portion of the CVCS system supports operation with the replacement steam generators at the current power level as well as the uprated power level.

4.1.3 Safety Injection System

4.1.3.1 Introduction

The Safety Injection System (SIS) is an Engineered Safeguards System used to mitigate the effects of postulated design basis events. The basic functions of this system include providing short-term and long-term core cooling, and maintaining core shutdown reactivity margin. The SIS is also referred to as the Emergency Core Cooling System (ECCS).

At the Harris Nuclear Plant (HNP), the SIS is comprised of three subsystems. The passive portion of the system is comprised of three accumulator vessels, which are connected to each of the Reactor Coolant System (RCS) cold leg pipes. Each accumulator contains borated water under pressure (nitrogen cover gas). The borated water automatically injects into the RCS when RCS pressure drops below the operating pressure of the accumulators.

The active portion of the SIS is comprised of a high-pressure injection subsystem and a low-pressure injection subsystem. Both subsystems utilize centrifugal pumps, which automatically start following generation of a Safety Injection (SI) signal. There are three High Head Safety Injection (HHSI) pumps, of which two are normally available for safety injection. The third pump is an installed spare to which the power supply is removed. The HHSI pumps provide the normal charging function and are normally aligned to take suction from the volume control tank. Upon receipt of an SI signal, the pump suction is aligned to the Refueling Water Storage Tank (RWST) and isolated from the volume control tank. The HHSI pump discharge is simultaneously aligned from the charging header to the cold-leg safety injection system header. Each operating charging pump has a miniflow line, which recirculates fluid from the pump discharge back to the pump suction. The normal miniflow path is automatically isolated during the initial phases of safety injection and the HHSI pump is either realigned to an alternate miniflow path or pump miniflow is terminated, depending on RCS pressure. In either case, the HHSI pumps continue to provide injection flow to the reactor coolant pump number one seals during post-accident operations. The alternate miniflow path ensures that the HHSI pumps are not "deadheaded" if RCS pressure increases above the pump shutoff head during the injection phase of ECCS operation.

The Residual Heat Removal System (RHRS) is used as the low-pressure subsystem. This Low Head Safety Injection (LHSI) subsystem is initially aligned to take suction from the RWST and deliver borated water to each of the RCS cold legs. This system has two parallel low-head pumps available for duty. LHSI injection flow would occur as soon as RCS pressure drops below the RHRS "Cut-In" pressure (RHRS pump shutoff head adjusted for suction pressure provided by the static head of water in the RWST).

As the design basis event proceeds, the RWST borated water inventory decreases as water is transferred to the RCS and/or containment building. Upon depletion of a majority of the RWST inventory, the operating HHSI and LHSI pumps are required to be realigned, using the sump as a

water source, to support the cold-leg recirculation mode of operation. Upon an RWST low-low level condition, the suction of the RHRS pumps is manually realigned to the containment sump. The sump isolation valves open automatically on a low-low level condition. Component cooling water flow is supplied to the RHR heat exchanger to cool the sump fluid. During the recirculation phase of the LOCA accident, the RHR pumps continue to provide flow to the RCS cold legs. In addition, the suction of the HHSI pumps is manually realigned to take suction from the RHR pump discharge. Long-term core cooling is provided by the LHSI system (RHR) heat exchangers.

After a pre-determined time to prevent boron precipitation in the core, the SIS is realigned to support the hot-leg recirculation mode of operation. Subsequent recirculation operation requires aligning the recirculated coolant flow alternately to the cold legs and the hot legs of the RCS.

In an immediate response to a design basis event, the SIS is designed to perform its safety functions, assuming a loss-of-offsite power, and considering a single active failure. An example of a postulated single failure is the failure of an emergency diesel generator to start. This failure would preclude a train of SIS pumps from operating. In the long-term (beyond 24 hours), if an active failure has not occurred, a system leak (i.e., passive failure specifically identified in the licensing bases) could occur which may require operator actions to realign the system to support adequate performance. Several alternate flow paths exist so that long-term core cooling can be provided should a passive failure occur.

4.1.3.2 Description of Analyses and Evaluations

A review of the Westinghouse Precautions, Limitations and Setpoints (PLS) Document for HNP, relevant to the SIS, was performed and no changes were identified to support implementation of the SGR/Uprating conditions.

The latest Westinghouse calculations of record for the SIS performance flows were provided for use in the NSSS Accident Analysis in Section 6.0. Refer to the applicable summaries of the safety analyses in Section 6.0 for a description of the results applicable to those analyses.

Additional SIS injection flow data provided for the SGR/Uprating Project were used in the following analyses: Steam Generator Tube Rupture, large break LOCA mass and energy releases, and main steamline break mass and energy releases (inside and outside of containment).

Minimum RHR and HHSI flow rates (one RHR pump and one HHSI pump) for the cold leg recirculation mode of ECCS operation were calculated. Hot leg and cold leg recirculation flow rates were used in the long-term core cooling analysis for the HNP SGR/Uprating Project (see Section 6.1.3).

4.1.3.3 Acceptance Criteria

The general acceptability of the SIS operating parameters defined for the SGR/Uprating project are documented in the individual plant safety analyses that utilize such inputs. Refer to Section 6.0.

4.1.3.4 Results and Conclusions

In general, the specified changes in RCS operating conditions addressed by the SGR/Uprating project (higher core power and range in hot full-power T_{avg}) as outlined in Section 2 of this report have no direct effect on the overall performance capability of the SIS. These systems are capable of delivering an acceptable range of calculated flow performance (minimum and maximum) as determined by interfacing system/structure operating conditions (RCS pressure, containment pressure, etc.).

The acceptability of the existing and newly calculated SIS operating parameters is documented in the various individual plant safety analysis results as summarized in Section 6 of this report. The SIS supports operation at the current power and steam generator replacement as well as steam generator replacement in conjunction with power uprate.

4.1.4 Residual Heat Removal System

4.1.4.1 RHR Cooldown Analysis

4.1.4.1.1 Introduction

The Residual Heat Removal System (RHRS) is a dual-function system. During normal power operation, the system is in a stand-by mode to support its Engineered Safeguards function (i.e., safety injection). During the second phase of plant cooldown and the plant shutdown mode of operation, the RHRS is used to remove RCS sensible and core decay heat. The auxiliary feedwater and main steam systems are used for the RCS heat removal during the first phase of plant cooldown and may supplement the second phase of plant cooldown. This section discusses the RHRS normal functions (i.e., heat removal). The Engineered Safeguards functions of the RHRS are discussed in Section 4.1.3, Safety Injection System.

The RHRS is comprised of two centrifugal pumps, two heat exchangers, interconnecting piping and instrumentation. With the RHRS in operation, each RHR pump takes suction from an RCS hot leg and recirculates the flow back to each of the RCS cold legs. System flow passes through the tube side of the RHR heat exchangers (shell and tube design). Cooling flow to the RHR heat exchangers (shell side) is provided via the Component Cooling Water System (CCWS), which in turn, is cooled by the Service Water (SW) System. The CCWS is comprised of three pumps and two heat exchangers. Normally, two CCW pumps and two CCW heat exchangers are in service during cooldown.

In addition, the RHRS is equipped with two relief valves for protection against overpressurization. (Note that Section 4.3.1.5 discusses the LTOP analysis and the use of the RHR relief valves to protect the RCS against overpressure events at low temperatures.)

The maximum heat removal demand on the RHRS occurs during the plant cooldown mode of operation when RCS sensible heat (e.g., metal mass), core decay heat, and heat input from a Reactor Coolant Pump (RCP) must all be removed to support RCS cooldown. In addition, operating restrictions are imposed on the maximum allowable CCWS temperature and flow during cooldown, which can also restrict RHRS heat removal capability.

The overall RHRS heat removal capability can vary significantly depending on system equipment availability, cooling support system equipment availability, cooling support system flows, and SW system inlet temperature. In general, RHRS thermal heat removal capability becomes more restricted when operating conditions change as outlined below.

- Higher RCS heat loads
- Lower RHRS flows
- Lower CCWS flow to the RHRS heat exchanger

- Lower SW flow to the CCWS heat exchanger
- Higher CCWS auxiliary heat loads

4.1.4.1.2 Description of Analyses and Evaluations

Westinghouse evaluated the cooldown analysis. The flow rates were determined as described in BOP Licensing Report Section 2.6. The evaluation used a maximum flow rate of 12,500 gpm of CCW in the CCW heat exchanger. See Section 4.1.6 for additional information concerning the thermal performance of the CCWS.

The Spent Fuel Pool (SFP) heat exchanger heat load also affects the capability of the RHRS to cool the system. A SFP heat load of 17.9 MBtu/hr was evaluated. The higher core power levels and the additional SFP heat load will adversely impact the RHR heat loads, which must be removed during plant cooldown and shutdown conditions. Cooldown was modeled with a maximum allowable supply CCW temperature of 120°F. In addition, the design UA for the RHR heat exchanger and the CCW heat exchanger was adjusted by 0.5 percent to account for future tube plugging.

RHRS thermal performance was calculated for each of the following three cooldown scenarios:

1. The ability of the RHRS to cool down the RCS with all equipment operating to a refueling condition (140°F). Note that RHRS operation with all equipment available (including support systems) is referred to as a "normal" plant cooldown within the context of this section.

2. The ability of the RHRS to cool down the RCS under limiting equipment availability to a cold shutdown condition (200°F). Note that RHRS operation with one subsystem of equipment available (including support systems) is referred to as a "single train" plant cooldown within the context of this section.

3. Single train cooldown without RCP heat load, referred to as "natural circulation" within the context of this section.

Selected cases were run at both the current licensed rated core power of 2775 MWt and the uprated thermal power of 2900 MWt. For scenario 1, the RHRS major components were originally sized to achieve a targeted (desired) overall cooldown from system cut-in (which occurs 4 hours after reactor shutdown) to a refueling RCS temperature (140°F) in approximately 16 hours (20 hours total duration). This normal cooldown (with all cooling equipment available) was reanalyzed at the higher core power level.

For scenario 2, the Standard Review Plan (SRP) requires that the RHRS be capable of cooling the RCS from Hot Standby (350°F) to 200°F within a reasonable time period in the event that one CCWS train is unavailable.

Following are the key inputs used in the various thermal (cooldown) analyses:

• RHRS Cut-in Temperature	- 350°F
• CCWS Maximum Allowable Temperature	- 120°F for normal and single train cooldown
• SW System Maximum Inlet Temperature	- 95°F during normal and single train cooldown
• RCP Heat Input Term to the RCS/RHRS	- 54.96×10^6 Btu/hr (for three RCPs between 350°F and 200°F)
	- 19.67×10^6 Btu/hr (for one RCP below 200°F)
	- 18.05×10^6 Btu/hr (avg. for one RCP between 350°F and 200°F)
• RCS Heat Capacity	- 1.29 E+6 Btu/°F
• SW System Flow to the CCWS Heat Exchangers	- 10,000 gpm to each heat exchanger

For the previously mentioned cooldown scenarios, various cases were analyzed. Provided below is a listing of the specific cases analyzed for each cooldown scenario.

- Normal Cooldown - All equipment available; three RCPs in service from 350°F to 200°F and one RCP in service from 200°F to 160°F. (Two RHRS pumps/heat exchangers and two CCWS pumps/heat exchangers were assumed during this scenario.)

- Single Train Cooldown (cooling equipment out of service) - One train unavailable (one RHRS pump/heat exchanger and one CCWS pump/heat exchanger and one RCP in operation)

- Natural Circulation (with no RCP heat load) - One train unavailable and RCP out of service due to a loss-of-offsite or onsite power (one RHRS pump/heat exchanger and one CCWS pump/heat exchanger)

4.1.4.1.3 Acceptance Criteria

When all cooling equipment is available, the RHRS is expected to perform a normal cooldown. The original RHRS equipment sizing criteria (20 hour cooldown from Hot Standby no-load

conditions at the time of plant shutdown to 140°F, assuming 4 hours for cooldown using the main steam system to Hot Shutdown conditions (RHRS initiation) at 350°F and 16 hours of cooldown using the RHRS to 140°F) was selected based partly on economic considerations. As such, there is not a specific design basis acceptance criterion for the normal cooldown.

4.1.4.1.4 Results and Conclusions

The following are the results and conclusions drawn for the analyzed scenarios:

1. RHRS Cut-in

   It was determined that the RHRS is capable of accepting the RCS cooldown heat loads at the uprated conditions. (See Tables 4.1.4.1-1 and 4.1.4.1-2.) However during the single train cooldown, it was determined that heatup of the RCS above 350°F may occur upon initiation at 6 hours after shutdown, since an RCP remains in operation. The steam generator PORVs can sustain cooling until the RHRS is capable of maintaining the RCS temperature under 350°F. The time at which a single train of RHRS can accept the decay heat and RCP heat load is identified in Table 4.1.4.1-2.

2. Normal Cooldown

   With all cooling equipment trains available and assuming RHRS operation is initiated at 4 hours after plant shutdown, the maximum calculated duration to cool down the RCS from 350° to 200°F (Cold Shutdown) is less than 6 hours. The total calculated duration (8.7 hours) is well within the 30-hour Technical Specification cooldown time.

   Cooldown to temperatures below 200°F is an economic consideration and is not governed by the Technical Specifications. With all cooling equipment trains available, the maximum calculated time to cool down the RCS from 200° to 140°F (Refueling) is less than 20 hours. Any extension of the cooldown time beyond the original design basis is primarily an economic factor. This analysis demonstrates that RHRS is capable of cooling the RCS within 24 hours after shutdown. Results for the normal cooldown analysis are shown in Table 4.1.4.1-1.

3. Single Train Cooldown (Equipment Unavailable)

   If plant cooldown is initiated with only one train of equipment available, and assuming RHRS operation is initiated at 6 hours after plant shutdown, the RHRS can cool the RCS from 350°F to 200°F within the times specified in Table 4.1.4.1-2. However, it was determined for both the SGR and SGR/Uprating system configurations that the RCS temperature could not be maintained below 350°F immediately after RHR cut-in if RHR operation was begun at 6 hours after shutdown. Therefore, cooling would have to be sustained via the SG PORVs until the RHRS was capable of maintaining the RCS

temperature to less than 350°F. It has been determined that RHRS alone cannot remove the decay heat and RCP heat until the times listed in Table 4.1.4.1-2.

4. Natural Circulation (RCP Not in Service)

In the event the plant experiences a loss-of-offsite power, the system must be capable of bringing the reactor to cold shutdown. Upon initiation at 17 hours after shutdown, the RHRS can cool the RCS from 350°F to 200°F within 10 hours with only one train of equipment available. The use of decay heat load at 6 hours is very conservative, since the natural circulation cooldown analysis concludes that when natural circulation and only safety-related equipment are relied upon for the cooldown from 557°F to 350°F, RHR cut-in would occur no sooner than 17 hours from reactor shutdown.

Based on the above discussions, it can be concluded that the operation of the HNP RHRS at thermal uprate RCS operating conditions should not impact its ability to perform intended decay heat removal functions.

The analyzed scenarios showed that the cooldown times are sensitive to the increased core thermal power, increased SFP heat load, and the CCWS flow. During normal operation, actual cooldown times are expected to be shorter than those calculated in the analyzed scenarios, since actual CCWS performance and SW System temperatures are not expected to be at the conservative analytical limits assumed in the analyzed scenarios. In addition, the SFP decay heat load was also conservatively specified. (Refer to the BOP Licensing Report Section 2.9.)

The results are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Model Delta 75 replacement steam generators at the uprated power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt. Operation of HNP at the current NSSS power of 2787.4 MWt with the revised RHR parameters based on 2912.4 MWt are bounding, since the current NSSS power is approximately 96 percent of the uprated NSSS power.

Table 4.1.4.1-1 Normal Cooldown Analysis Input and Results (Normal Cooldown from 350°F to 140°F)	
	SGR/Uprating
Reactor Power (MWt)	2900
SFP Load (Mbtu/hr)	17.9*
Time Cooldown Initiated (hr)	4
Max CCW Temp. (°F)	120
SW Temp. (°F)	95
RCP Load (Mbtu/hr)	54.96/19.7
Cooldown Time (hours since reactor shutdown)	23.3

Table 4.1.4.1-2 Single Train Cooldown Analysis Input and Results (Single Train Cooldown from 350°F to 200°F)		
	SGR	**SGR/Uprating**
Reactor Power (MWt)	2775	2900
SFP Load (Mbtu/hr)	17.9	17.9
Time Cooldown Initiated (hr)	17	20
Max CCW Temp. (°F)	120	120
SW Temp. (°F)	95	95
RCP Load (Mbtu/hr)	18.05	18.05
Cooldown Time (hours since reactor shutdown)	40.3	44

*The selection of the SFP heat load is discussed in the BOP Licensing Report Section 2.9.

4.1.5 Boron Recycle System

This section provides a system review to evaluate the effects of the SGR/Uprating on the Boron Recycle System (BRS).

4.1.5.1 System Function

The function of the BRS is to collect deaerated, tritiated, borated radioactive effluent from the primary plant systems. The BRS decontaminates and processes the effluent, producing 4 wt. percent boric acid solution and reactor makeup water that is of sufficient quality for reuse as recycled makeup to the Reactor Coolant System (RCS) and spent fuel pools.

4.1.5.2 System Design Bases

The original design basis of the BRS is summarized as follows:

1. The BRS shall collect and process reactor coolant effluent via the Chemical and Volume Control System (CVCS) letdown line from the following sources:

    - Dilution of the RCS to compensate for core burnup
    - RCS dilution/boration operations associated with four hot shutdowns in one fuel cycle
    - RCS dilution/boration operations associated with three cold shutdowns in one fuel cycle
    - RCS dilution/boration operations associated with one refueling shutdown in one fuel cycle

2. The BRS shall collect and process reactor coolant effluents from the following additional sources:

    - Leakoff type drains from equipment inside containment via the Reactor Coolant Drain Tank
    - Volume Control Tank (VCT), charging pump suction and residual heat removal pump relief valve discharges
    - Boric Acid Tank maintenance draindown via the CVCS boric acid blender
    - Refueling transfer canal maintenance draindown via the spent fuel pool pumps
    - Gas decay tank drains
    - Boron injection tank valve flush water
    - Primary system valve leakoff and equipment drains

3. The BRS shall process the reactor coolant effluent that is collected by the system and produce 4 wt. percent boric acid solution and reactor makeup water that are of sufficient purity for recycling back to the RCS. This design criterion assumes fission product concentrations in the reactor coolant effluent that are based on operation with cladding defects in 1 percent of the fuel assemblies.

4.1.5.3 Evaluation of SGR/Uprating Effects

The effect of the steam generator replacement on the RCS volume and mass and, consequently, on the sizing basis of the Recycle Holdup Tank (RHT) was evaluated. The original sizing criterion of the RHT is based on a design surge cold shutdown and startup at an RCS boron concentration of 200 ppm. The original sizing of the RHT takes credit for the operation of the BTRS in the RCS boration and dilution operations that are associated with the shutdown and startup to reduce the volume of reactor coolant effluent that is generated by these operations. The size of the existing RHT is evaluated using the following revised design basis for the SGR/Uprating conditions:

- RCS volume and mass are based on the installation of the Model Delta 75 steam generators.

- The HNP BTRS demineralizers are used for deboration of the RCS to compensate for core burnup below a boron concentration of approximately 300 ppm. However, the BTRS is not used to dilute the RCS during plant startup after a cold shutdown, and no credit will be taken for use of the BTRS in this evaluation of the design basis RHT sizing.

- The BRS Recycle Evaporator is no longer used in HNP, but its functionality is provided by the Waste Evaporator, which has the same nominal capacity as the Recycle Evaporator.

4.1.5.4 Conclusion of System Review

This evaluation of the Boron Recycle System in HNP has described the system design bases and functional requirements. On the basis of this evaluation, it can be concluded that the design of the HNP BRS remains capable of performing its intended function for operation at the current power with steam generator replacement as well as steam generator replacement in conjunction with power uprate.

4.1.6 Component Cooling Water System

4.1.6.1 Introduction

The HNP SGR/Uprating requires the evaluation of the performance of the Component Cooling Water System (CCWS) for the new plant conditions. This evaluation involves confirmation that the CCWS can supply the required cooling water flow rates at the required cooling water temperatures for the heat loads on the system in each of several different plant operating situations. The loads on the system consist of those items of equipment in the various NSSS systems that require component cooling water. Westinghouse determined the heat load and cooling water requirements for the various items of equipment in those systems that were originally in the Westinghouse scope of supply. The component cooling water flow distribution depends on the hydraulic losses of the system, the system configuration, as well as the pump curve. (Refer to BOP Licensing Report Section 2.6.) Ten operating configurations were evaluated for which the CCWS will provide cooling. Based on the limiting system resistances (Shutdown at 350°F) and the modified pump performance, flow rates were calculated for the other operating configurations. For each configuration, the following flow scenarios were evaluated:

1. Minimum Flow - Based on increasing the capacity of pump beyond original rated capacity. The calculated flows were reduced by 6 percent to remove built-in margin for calculation and instrumentation uncertainty.

2. Maximum Flow - Based on increasing the capacity of CCW pump beyond original rated capacity. These flow rates were not adjusted.

This analysis determined the following information for the HNP SGR/Uprating:

- Component heat and flow load data for the CCWS
- CCW supply temperatures for 10 operating configurations
- Component outlet temperatures for thermal stress analysis

4.1.6.2 Description of Analyses and Evaluations

In general, there are two ways considered in this evaluation that the auxiliary heat exchangers can be impacted by the SGR/Uprating:

- Operation at higher power level generates a higher level of decay heat during shutdown or accident periods. This factor impacts the heat load for heat exchangers such as the RHR heat exchanger and the SFP heat exchanger, which are directly linked to decay heat generation rate, but it does not impact the other heat exchangers or items of equipment that are serviced by the CCWS.

- Replacement of the steam generators affects coolant volume and metal mass in the RCS. The change in RCS heat capacity affects the sensible heat released during plant cooldown. This "heat," along with the core decay heat and the RCP heat are transferred into the CCWS via the RHR heat exchanger.

A comparison of the uprated RCS conditions to original design conditions demonstrates that the changes in RCS operating temperatures are minor.

The method used for defining the heat loads imposed on the CCWS follows the general method used historically for the original design.

Operating Configurations of the CCWS

There are 10 defined operating configurations of the CCWS considered. These plant operating configurations are defined as follows:

1. Plant Startup at 350°F – This covers the heatup from cold shutdown (mode 5) or refueling (mode 6) to hot shutdown conditions (mode 4). At 350°F, the RHR system is in service.

2. Plant Startup at 557°F – This covers the period from hot shutdown (mode 4) to critical minimum load at operating plant pressure and temperature (mode 2). After the RHR system is isolated, the excess letdown and the letdown system are aligned for maximum flow rate to remove the coolant expansion that occurs during plant heatup.

3. Normal Operation – This includes power operation (mode 1) and operation at hot standby (mode 3) with the RCS at normal operating pressure and temperature.

4. Plant Shutdown at 350°F – This refers to the initiation of residual heat removal operations for plant cooldown at an RCS hot leg temperature of 350°F. The RHR system removes core generated decay heat, RCP work input into the RCS, and also the sensible heat released by reducing the temperature of the RCS primary side and secondary side metal and coolant.

5. Plant Shutdown at 140°F – This refers to the completion of plant cooldown to 140°F in the RCS. The RHR system is in service to remove decay heat and maintain stable RCS temperature.

6. Refueling – The RHR system is in service to remove core generated decay heat and maintain stable temperature in the RCS and in the refueling cavity for refueling operations. The refueling mode considers the plant situation prior to the time that spent fuel is moved from the reactor to the fuel pool.

7. Safety Injection – This corresponds to the injection configuration of safety injection operation with the safety injection pump suction aligned to the RWST. There is no heat

load imposed by the RHR heat exchangers in this configuration. The safety injection event is assumed to initiate a phase A containment isolation signal, which isolates CCW loads inside containment.

8. Recirculation at 243.5°F – During Recirculation at 243.5°F (peak sump temperature), it was assumed that all heat loads are isolated except for the RHR pump seal coolers and the RHR heat exchangers. The RHR heat load is conservatively estimated using an RHR flow rate of 4,500 gpm at 243.5°F through the tube side of the RHR heat exchanger.

9. Recirculation at 200°F - For Recirculation at 200°F, it was assumed that the fuel pool heat and flow loads are reinstated. The RHR heat load is conservatively estimated using an RHR flow rate of 4,500 gpm at 200°F through the tube side of the RHR heat exchanger.

10. Loss of Offsite Power - Loss-of-offsite power causes the reactor to trip. The major plant control systems return the RCS and steam generator secondary side to hot zero power condition (mode 3).

The aforementioned plant configurations are used where the heat loads and flows for the individual components are determined for the different plant configurations.

Components Serviced by the CCW system

The components serviced by the CCWS are listed in Table 4.1.6-1.

Calculated Performance of the CCW Heat Exchanger

For each combination of heat load and flow rate, an analysis was performed to determine the CCW heat exchanger shell inlet and return temperatures.

4.1.6.3 Acceptance Criteria

Acceptance criteria for this analysis are as follows:

1. The maximum actual CCW supply temperature shall be limited to 125°F when RCPs are operating during plant cooldown and to 105°F during normal plant operation. The original CCW supply temperature limit when the RCPs are operating during plant cooldown was 120°F.

2. The heat exchanger terminal temperatures shall remain within design temperature limits specified for the tube and shell sides of the units on the component data sheets.

3. The differences in terminal temperatures for the heat exchangers shall be acceptable from the aspect of component stress limits for normal operation.

4. The temperature of the component cooling water leaving the components cooled by the CCW system shall remain below the levels at which local cavitation or voiding could occur in the CCWS. Sufficient margin of subcooling shall be maintained. Engineering judgement indicates that 50 degrees of subcooling provides adequate margin of local subcooling.

5. Heat exchanger flow rates shall remain within mechanical design constraints of the heat exchanger unit with respect to pressure differential and vibration.

6. The CCWS shall be able to supply the required flow rates, and the flow coefficients for the modulation/throttle valves (either manual or automatic) shall be within the controllable ranges for the valve characteristics.

4.1.6.4 Results and Conclusions

Table 4.1.6-2 provides the CCW supply and component outlet temperatures for each configuration. The maximum allowable outlet temperature for the RCP upper bearing oil cooler is 198°F. Otherwise, the design temperature of the CCWS of 200°F is conservative.

All component outlet temperatures are within the above defined temperature limits for all plant operating configurations. The results of the component outlet temperature evaluation are acceptable.

The CCW supply temperatures exceed the original design basis of 105°F for Plant Start-up at 350°F, Plant Start-up at 557°F, Refueling, and 120°F for Recirculation at 243.5°F and Recirculation at 200°F. These results are acceptable because they can be justified as follows:

The Plant Start-up cases marginally exceed the 105°F requirement.

- During the Recirculation cases there are no RCPs running so the limiting temperature is the CCWS temperature of 200°F.

- For the Refueling case, subsequent evaluation by CP&L and Raytheon has indicated that higher CCW supply temperatures are acceptable.

All component outlet temperatures are sufficiently below the CCWS design temperature of 200°F and are therefore acceptable. The results were provided to Raytheon for use in revised stress analyses of CCWS piping and supports (see the BOP Licensing Report).

4.1.6.5 Conclusions

The analysis described above represents a comprehensive reanalysis of the CCWS forHNP. The reanalysis evaluates the heat removal capability of the CCWS during all modes of plant operation

and demonstrates the projected adequacy of planned modifications to augment the flow capacity of the CCWS. In addition to the increased decay heat from the uprated conditions, the revised analysis evaluated the effects of new spent fuel pool heat loads, CCW and RHR heat exchanger UAs, and new CCW and SW flow rates for each of 10 plant configurations. This analysis demonstrates the ability of the HNP CCW system with proposed modifications to provide the required cooling capacity to the components serviced by the CCW system, based on not only the uprated power level, but also the current plant parameters. The analysis at the NSSS power uprating of 2912.4 MWt with the replacement steam generators bounds plant operation at the current NSSS power level of 2787.4 MWt with the replacement steam generators.

Table 4.1.6-1 Components Serviced by CCW
Letdown Heat Exchangers
Excess Letdown Heat Exchanger
Seal Water Heat Exchanger
Reactor Coolant Pump Thermal Barrier Heat Exchanger
Reactor Coolant Pump Upper and Lower Bearing Oil Coolers
Reactor Coolant Drain Tank Heat Exchanger
Spent Fuel Pool Cooling Heat Exchangers
Residual Heat Exchangers
RHR Pump Seal Coolers
Gross Failed Fuel Detector
Sample Heat Exchanger Package

Table 4.1.6-2 Summary of CCW Performance For Plant Configurations			
Mode of Operation	**CCW Pump Flow Scenario**	**CCW Inlet Temperature (°F)**	**CCW Supply Temperature (°F)**
Plant Startup at 350°F	Min	115.7	106.4
	Max	115.3	106.8
Plant Startup at 557°F	Min	118.8	105.7
	Max	118.0	105.9
Normal Operations	Min	115.9	104.2
	Max	115.2	104.4
Shutdown at 350°F	Min	148.5	124.2
	Max	146.6	124.8
Shutdown at 140°F	Min	132.5	115.4
	Max	131.2	115.8
Refueling	Min	121.1	109.2
	Max	120.2	109.5
Safety Injection	Min	110.9	101.6
	Max	110.4	101.8
Recirculation at 243.5°F	Min	174.1	132.5
	Max	173.6	134.2
Recirculation at 200°F	Min	149.6	124.9
	Max	149.5	126.3
Loss of Offsite Power	Min	115.2	103.9
	Max	114.6	104.1

4.1.7 Gaseous Waste Processing System

This section provides a system review to evaluate the effects of the SGR/Uprating on the Gaseous Waste Processing System (GWPS).

4.1.7.1 System Function

The function of the GWPS is to collect, process and store fission gases that are contained in contaminated fluids within the plant resulting from normal plant operation, including anticipated operational occurrences. The release of gaseous effluents from the plant and expected offsite doses are as low as reasonably achievable (ALARA) and in conformance with the requirements of 10CFR20 and 10CFR50.

4.1.7.2 System Design Bases

The original design criteria of the GWPS is summarized as follows:

1. There will be no regularly scheduled discharge of radioactive fission gases from the GWPS to the atmosphere.

2. The flow of gases into the GWPS that cannot be processed and removed will be kept to an absolute minimum.

3. Fission gases will be removed from other primary plant systems to the extent possible and contained in the GWPS.

4. The accumulation of fission gases in the GWPS will not be permitted to create a radiation hazard either to plant operating personnel or to the general public.

5. In acknowledgment of the fact that it may become necessary to discharge waste gas at some time during the life of the plant, the system will include provisions to sample and control such discharges to ensure that releases are made within limits established by the applicable regulatory agencies. Provision will also be made to permit infrequent removal of small quantities of radioactive gases from the site in gas bottles or tanks.

6. The design of the GWPS is based on continuous plant operation assuming one percent failed fuel. This condition is assumed to exist over the life of the plant.

4.1.7.3 Evaluation of SGR/Uprating Effects

The processing load on the GWPS can be evaluated in terms of both the volumes of non-radioactive gases and the activities of radioactive fission gases that enter the system. The normal inflow to the GWPS is 0.7 SCFM from theVolume ControlTank (VCT) purge. During normal

plant operation, this flow consists of trace contamination of fission gases in a high purity stream of hydrogen. The GWPS can accommodate surges up to 1.7 SCFM such as may result from venting the Recycle Holdup Tank. No other anticipated operational occurrences will cause a significant surge in the GWPS process flow rate. The hydrogen is removed from this gas stream by the hydrogen recombiner, leaving the fission gases to be collected and stored in the Gas Decay Tanks. No change to the normal input flow rate to the GWPS has been identified as a result of the SGR/Uprating for HNP.

The HNP Gaseous Waste Processing System (GWPS) has the capability for long-term storage of radioactive gases generated in the RCS, eliminating the need for frequent routine gaseous discharges and allowing discharges to be made under favorable environmental conditions. The original sizing and number of Gas Decay Tanks (GDTs) for the HNP GWPS was based on a twin-unit station design, in which the GWPS was shared by the two units, and on distributing the activity among the tanks so as to minimize the dose associated with a GDT rupture. The HNP GWPS has the same number of gas decay tanks (ten) and capacity (600 cu. ft. each) as that associated with a twin-unit station. The standard Westinghouse design for a single unit 3-loop plant, such as HNP, includes only seven tanks. Furthermore, the updated waste gas plant inventories for HNP documented in the revised Radiation Analysis Manual (Reference 1) are found to be in the range of 1.5 to 3.7 times lower than that associated with a twin-unit, 4-loop plant design that includes ten gas decay tanks.

The ability of the GWPS to meet the design bases was demonstrated in Chapter 15 of the HNP FSAR, which documents that doses for the GDT rupture accident were calculated to be less than 5% of the applicable 10CFR100 limits. Note that the GDT rupture analysis reported in the FSAR is not based on the system design basis of distributing activity among the tanks but, instead, conservatively assumes that the primary coolant noble gas inventory is transferred to one GDT (with decay taken into account during the coolant degassing process). Note also that the GDT rupture and dose consequence analysis described in the FSAR was performed at a core power level of 2900 MWt, which is the same as the uprated power level.

Westinghouse has determined that the noble gas inventory for the HNP (as dose equivalent Xe-133) in the plant at shutdown for the uprated conditions is not significantly different than that associated with source terms previously provided by Westinghouse in Reference 2. Based on the assumption that the dose values reported in the FSAR are proportional to the dose equivalent Xe-133 at shutdown, it is concluded that the offsite doses remain less than 5% of the limits as reported in the FSAR. Thus, substantial margin remains in the design of the HNP waste gas system with respect to the 10CFR100 limits for offsite radiological consequences of the postulated GDT rupture. From this evaluation it is concluded that the existing waste gas system design of the HNP remains adequate for the waste gas activity inventories associated with the SGR/Uprating conditions.

4.1.7.4 Conclusion of System Review

This evaluation of the HNP Gaseous Waste Processing System has described the system design bases and functional requirements. The bases for the system performance in ensuring that release of gaseous effluents from the plant and expected offsite doses are as low as reasonably achievable (ALARA) and in conformance with the requirements of 10CFR20 and 10CFR50 were also described. On the basis of this evaluation, it can be concluded that the design of the HNP GWPS remains capable of meeting the design basis functional requirements and performance criteria of the system. The GWPS system supports operation at the current power with steam generator replacement as well as steam generator replacement in conjunction with power uprate.

4.1.7.5 References

1. WCAP-15397, "Radiation Analysis Manual, Model 312, Carolina Power and Light Company, Shearon Harris Nuclear Power Plant, Unit 1," April 2000.

2. Westinghouse "Radiation Analysis Manual, Model 312, Carolina Power and Light Company, Shearon Harris Nuclear Power Plant, Units 1, 2, 3 and 4," Rev. 2, December 1978.

4.1.8 Liquid Waste Processing System

This section provides a system review to evaluate the effects of the SGR/Uprating on the Liquid Waste Processing System (LWPS).

4.1.8.1 System Function

The function of the LWPS is to collect, store, process and control the release of radioactive and potentially radioactive liquids associated with operation, refueling and maintenance of the plant. The discharge of treated wastes is controlled and monitored to ensure that any discharges are as low as reasonably achievable (ALARA) and that they are in conformance with the requirements of 10CFR20 and 10CFR50.

4.1.8.2 System Design Bases

The original design basis of the Liquid Waste Processing System is summarized as follows:

1. Fission product concentrations in the reactor coolant are based on operation with cladding defects in one percent of the fuel assemblies.

2. Reactor coolant leakage into the system that cannot be recycled is assumed to be 20 gallons per day at ambient temperature.

3. Non-reactor grade water which enters the system in such a manner as to mix with the reactor coolant leakage is assumed to be 80 gallons (leakage and lab rinses) per day at ambient temperature.

4. Based on normal plant conditions, the system shall be capable of treating the combined leakage so that the final discharge will be less than one percent of the maximum permissible concentrations (MPC) as outlined in 10CFR20 for identified isotopes and 10 percent of MPC for isotopes released on an unidentified basis at the time of release.

5. Laundry, hot shower and decontamination wastes are processed before discharging.

6. A total design overall decontamination factor (DF) of 2×10^9 is assumed for estimating isotopic releases.

4.1.8.3 Evaluation of SGR/Uprating Effects

The processing load on the LWPS can be evaluated in terms of both the volume of liquid waste that the system must process and the radionuclide activity that is present in the waste. Table 11.2.1-1 of the HNP FSAR also contains projected expected annual and daily average inputs to the LWPS subsystems from various sources within the plant. Because no equipment

change is anticipated to be required to implement the steam generator replacement or power uprating, the volumes of liquid wastes from these sources also are not expected to change.

The LWPS limits release of liquid radwaste to the environs to meet the as low as reasonably achievable (ALARA) criteria. The evaluation of releases of radioactive materials is based on the volumes of radwaste, as described above, and radionuclide activities and decontamination factors documented in Sections 11.2 and 11.3 of the HNP FSAR. It is noted that the design basis fission and corrosion product specific activities contained in Table 11.1.1-1 of the HNP FSAR are based on a core thermal power rating of 2900 MWt, which equals the uprated plant condition.

Westinghouse has compared the fission product inventory from the updated Radiation Analysis Manual (Reference 1) to that listed in the original design basis for theLWPS (Reference 2). Some of the isotope activity concentrations are higher due to the plant uprating. A slight increase in RCS activity should result in a corresponding slight increase in waste holdup or floor drain tank contents activity due to RCS equipment drains and leakage. The original effluent calculations were based on nominal decontamination factors (DFs) for the processing equipment (e.g., 10 for demineralizers, 1000 for evaporators for all isotopes except tritium). The effect of the slight increase of RCS activity concentrations is judged to be within the accuracy of the assumed nominal DFs for the processing equipment. Therefore, the uprated fission product inventory remains within the design basis capability of the HNP LWPS.

4.1.8.4 Conclusion of System Review

This evaluation of the Liquid Waste Processing System in HNP has described the system design bases and functional requirements. The bases for the system performance in ensuring that any discharges are as low as reasonably achievable (ALARA) and in conformance with the requirements of 10CFR20 and 10CFR50 were also described. On the basis of this evaluation, it can be concluded that the design of the HNP LWPS remains capable of meeting the design basis functional requirements and performance criteria of the system. The LWPS system supports operation at the current power with steam generator replacement as well as steam generator replacement in conjunction with power uprate.

4.1.8.5 References

1. WCAP-15397, "Radiation Analysis Manual, Model 312, Carolina Power and Light Company, Shearon Harris Nuclear Power Plant, Unit 1," April 2000.

2. Westinghouse Systems Standard Design Criteria 1.1.8.1, "System Requirements and Equipment Sizing, Waste Processing System (Liquid Portion)," Rev. 0, October 1972.

4.1.9 Gross Failed Fuel Detector System

This section provides a system review to evaluate the effects of the SGR/Uprating on the Gross Failed Fuel Detector System (GFFDS).

4.1.9.1 System Function

The GFFDS monitors the delayed neutron activity from fission products in the reactor coolant to provide an alarm indication of possible gross fuel failure. The GFFDS monitors the delayed neutron activity in a continuous fluid sample drawn from the hot leg in either Loop 2 or Loop 3 of the RCS. The GFFDS is a reliable indicator of fuel failure only when the reactor is at power.

4.1.9.2 System Design Bases

The original design basis of the Gross Failed Fuel Detector System is summarized as follows.

The neutron activity in the core arises from the delayed neutron emitting fission products that occur in the core, primarily Br-87, Br-88 and I-137. Consistent with the half-lives of these isotopes, the required sample delay time is approximately 53 seconds measured from the center of the core to the neutron detector in the GFFDS. A minimum of 28 seconds delay is maintained in the GFFDS sample line inside containment to meet N-16 decay requirements. The GFFDS sample flow rate is controlled within the range of 0.34 to 0.44 gpm to meet the delay time requirements described above.

4.1.9.3 Evaluation of SGR/Uprating Effects

The implementation of the steam generator replacement or the power uprating will have no effect on the design bases of the GFFDS. The critical isotopes that indicate fuel failure and their half-lives will remain the same, as will the required delay time in the sample line from the center of the core to the GFFDS detector and the required delay time inside containment. Consequently, the system design and operating parameters of the GFFDS are not expected to change when the SGR/Uprating conditions are put into effect.

4.1.9.4 Conclusion of System Review

This evaluation of the Gross Failed Fuel Detector System in HNP has described the system design bases and functional requirements. The bases for the system performance in monitoring the reactor coolant for fission products indicative of gross fuel failures also were described. On the basis of this evaluation, it can be concluded that the design of the HNP GFFDS remains capable of meeting the design basis functional requirements and performance criteria of the system for the conditions associated with operation of the current power and steam generator replacement as well as steam generator replacement in conjunction with power uprating.

4.2 NSSS/BOP Fluid Systems Interfaces

4.2.1 Introduction

As part of the Harris Nuclear Plant (HNP) Steam Generator Replacement/Uprating (SGR/Uprating) Project, the following Balance-of-Plant (BOP) fluid systems were reviewed to assess compliance with Westinghouse Nuclear Steam Supply Systems (NSSS)/BOP interface requirements:

- Main Steam System
- Steam Dump System
- Condensate and Feedwater System
- Auxiliary Feedwater System
- Steam Generator Blowdown System

The various interface systems were reviewed with the purpose of providing interface information which could be used in the more detailed BOP analyses. The results of those analyses are provided in the BOP Licensing Report.

The review was performed based on the range of NSSS design parameters developed to support steam generator replacement coupled with an uprated NSSS power level of 2912.4 MWt. The eight sets of approved design parameters, shown in Section 2, form the design bases for the project. In addition, 32 cases of best estimate parameters were generated to predict actual plant operating conditions. The 32 best estimate cases provide predictions of how the plant may actually operate. The major difference between design and best estimate parameters are the assumptions with respect to core flow and the steam generator tube fouling. If the range of best estimate parameters versus the range of design parameters provided a more conservative basis for a specific NSSS/BOP interface evaluation, the more conservative best estimate parameters were assumed.

This evaluation was focused on the uprated NSSS power of 2912.4 MWt. However, a review was performed considering the replacement steam generators and the current NSSS power of 2787.4 MWt.

4.2.2 Description of Analyses and Evaluation

Evaluations of the above BOP systems relative to compliance with Westinghouse NSSS/BOP interface guidelines were performed to address design and best estimate parameters for SGR/Uprating analyses, which include ranges for parameters such as T_{avg} (572° to 588.8°F) and steam generator tube plugging (0 to 10 percent average). These ranges of NSSS design and best estimate parameters result in ranges of BOP parameters such as steam generator outlet steam

pressure (824 to 1011 psia). In addition the parameters include a feedwater temperature range of 375° to 440°F. The NSSS/BOP interface evaluations were performed to address these ranges of NSSS and BOP parameters.

A comparison of the SGR/Uprating design parameters with the original Westinghouse Performance Capability Working Group (PCWG) parameters previously evaluated for systems and components indicates differences that could impact the performance of the above BOP systems. For example, the increase in NSSS power of approximately 4.6 percent (to NSSS power of 2912.4 MWt) and the upper limit of T_{avg} (588.8°F) would result in about a 5.3 percent increase in steam/feedwater mass flow rates. Additionally, the average steam generator tube plugging level of 10 percent in combination with the lower limit of T_{avg} (572°F) would result in a reduction in full-load steam pressure from 964 to 824 psia.

4.2.3 Acceptance Criteria

The NSSS/BOP system interface requirements are delineated in the Westinghouse Steam Systems Design Manual. For each BOP System evaluated, the specific NSSS/BOP system interface requirements are delineated in subsection 4.2.4.

4.2.4 Results

The results of the NSSS/BOP interface evaluations are delineated below.

4.2.4.1 Main Steam System

The uprating coupled with the potential reduction in full-load steam pressure to the average minimum value of 824 psia impacts main steam line pressure drop. At the average minimum steam generator pressure of 824 psia, the full-load steam mass flow rate would increase about 4.6 percent; however, due to the reduced operating pressure and the lower-density steam, the volumetric flow rate would increase by approximately 24.1 percent and steam line pressure drop would increase by approximately 29.8 percent. Based on the range of NSSS design parameters for SGR/Uprating to NSSS power of 2912.4 MWt, the lowest steam generator pressure would result in a pressure at the turbine inlet valves of approximately 784 psia.

The following summarizes the Westinghouse evaluation of the major steam system components relative to the SGR/Uprating conditions. The major components of the Main Steam System (MSS) are the Steam Generator Main Steam Safety Valves (MSSVs), the main steam Power Operated Relief Valves (PORVs), and the Main Steam Isolation Valves (MSIVs).

4.2.4.1.1 Steam Generator Main Steam Safety Valves

The setpoints of the MSSVs are determined based on the design pressure of the MSS (1185 psig) and the requirements of the ASME Boiler and Pressure Vessel (B&PV) Code. Since the design pressure of the MSS has not changed with the SGR/Uprating, there is no need to revise the setpoints of the safety valves.

The MSSVs must have sufficient capacity so that main steam pressure does not exceed 110 percent of the MSS design pressure (the maximum pressure allowed by the ASME B&PV Code) for the worst-case loss-of-heat-sink event. Based on this requirement, Westinghouse applies the conservative criterion that the valves should be sized to relieve 105 percent of the maximum calculated steam flow at an accumulation pressure not exceeding 110 percent of the MSS design pressure.

The Harris Nuclear Plant has 15 safety valves with a total capacity of 13.56 x 10^6 lb/hr, which provides about 105.3 percent of the maximum calculated steam flow of 12.87 x 10^6 lb/hr for the uprating. Therefore, based on the range of PCWG NSSS parameters for the SGR/Uprating, the capacity of the installed MSSVs meets the Westinghouse sizing criterion.

Additionally, the capacity of an individual MSSV (as well as each PORV and steam dump valve) is limited to 970,000 lb/hr at 1200 psia. Since the actual capacity of any single safety valve is about equal to 964,119 lb/hr at 1200 psia, the maximum capacity criteria is satisfied.

4.2.4.1.2 Main Steam Power Operated ReliefValves

The PORVs, which are located upstream of the MSIVs and adjacent to the MSSVs, are automatically controlled by steam line pressure during plant operations. The PORVs automatically modulate open and exhaust to the atmosphere whenever the steamline pressure exceeds a predetermined setpoint to minimize safety valve lifting during steam pressure transients. As the steamline pressure decreases, the PORVs modulate closed and reseat at a pressure below the opening pressure. The PORV set pressure for these operations is between zero-load steam pressure and the setpoint of the lowest-set MSSVs. As neither of these pressures change for the proposed range of NSSS design parameters, there is no need to change the PORV setpoint.

The primary function of the PORVs is to provide a means for decay heat removal and plant cooldown by discharging steam to the atmosphere when either the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the PORVs in conjunction with the Auxiliary Feedwater System (AFWS) permit the plant to be cooled down from the pressure setpoint of the lowest-set MSSVs to the point where the Residual Heat Removal System (RHRS) can be placed in service. During cooldown, the PORVs are either automatically or manually controlled. In automatic, each PORV proportional and integral (PI) controller compares steam line pressure to the pressure setpoint, which is manually set by the plant operator.

In the event of a tube rupture event in conjunction with loss of offsite power, thePORVs are used to cool down the Reactor Coolant System (RCS) to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set MSSV. RCS cooldown and depressurization are required to preclude steam generator overfill and to terminate activity release to the atmosphere.

Each steam generator PORV is required to have a capacity at least equal to 64,000 lb/hr at 100-psia inlet pressure. At uprated power, this capacity permits a plant cooldown rate of 50°F/hr to RHRS operating conditions assuming a minimum of two hours at hot standby. This sizing is compatible with normal cooldown capability and minimizes the water supply required by the AFWS. This is based on one train of auxiliary feedwater (AFW) operating and flow going through two steam generators. The design capacity of the installed PORVs is 65,464 lb/hr/valve (full open) at 100 psia. Therefore the capacity of the installed PORVs meets the Westinghouse sizing criterion.

4.2.4.1.3 Main Steam Isolation Valves and Main Steam Isolation Bypass Valves

The MSIVs are located outside the containment and downstream of the MSSVs. The valves function to prevent the uncontrolled blowdown of more than one steam generator and to minimize the RCS cooldown and containment pressure to within acceptable limits following a main steamline break. To accomplish this function, the original design requirements specified that the MSIVs must be capable of closure within 5 seconds of receipt of a closure signal against steam break flow conditions in either the forward or reverse direction.

Rapid closure of the MSIVs following a postulated steam line break causes a significant differential pressure across the valve seats and a thrust load on the main steam system piping and piping supports in the area of the MSIVs. The worst cases for differential pressure increases and thrust loads are controlled by the steam line break area (i.e., mass flow rate and moisture content), the throat area of the steam generator flow restrictors, valve seat bore, and no-load operating pressure. As these variables and no-load operating pressure are not impacted by the SGR/Uprating, the design loads and associated stresses resulting from rapid closure of the MSIVs will not change. Consequently, SGR/Uprating has no significant impact on the interface requirements for the MSIVs.

The MSIV bypass valves are used to warm up the main steam lines and equalize pressure across the MSIVs prior to opening the MSIVs. The MSIV bypass valves perform their function at no-load and low-power conditions where SGR/Uprating has no significant impact on main steam conditions (e.g., steam flow and steam pressure). Consequently, SGR/Uprating has no significant impact on the interface requirements for the MSIV bypass valves.

4.2.4.1.4 Main Steam System Conclusions

The capacity of the installed MSSVs meets the Westinghouse sizing criterion for the proposed range of NSSS operating conditions.

The capacity of the installed main steam PORVs meets the Westinghouse sizing criterion for the proposed range of NSSS operating conditions.

The MSIVs and MSIV bypass valves are not adversely impacted by the SGR/Uprating.

4.2.4.2 Steam Dump System

The Steam Dump System creates an artificial steam load by dumping steam from ahead of the turbine valves to the main condenser. The Westinghouse sizing criterion recommends that the steam dump system (valves and pipe) be capable of discharging 70 percent of the rated steam flow at full-load steam pressure to permit the NSSS to withstand an external load reduction of up to 100 percent of plant rated electrical load without a reactor trip. To prevent a trip, this transient requires all NSSS control systems to be in automatic, including the Reactor Control System, which accommodates about 20 percent of the load reduction. In addition, a steam dump capacity of just 40 percent of rated steam flow at full-load steam pressure prevents MSSV lifting following a reactor trip from full power.

4.2.4.2.1 Steam Dump System Major Components

The Harris Nuclear Plant is provided with six condenser dump valves and eight atmospheric dump valves. The total capacity for all 14 valves provides a steam dump capability of greater than 70 percent of the original maximum guaranteed steam flow with one valve out of service.

NSSS operation within the range of design parameters at lower steam generator pressures and higher steam flows will result in a reduced steam dump capability. An evaluation for the SGR/Uprating indicates that the total steam dump capacity with 14 valves in service could be as low as 68.7 percent of rated steam flow (12.76×10^6 lb/hr), or 8.77×10^6 lb/hr, at a full-load steam pressure equal to 825 psia. These operating conditions are based on an NSSS power level of 2912.4 MWt, an average steam generator tube plugging (SGTP) level of 10 percent, and a T_{avg} in the lower end of the operating range (572°F). Therefore, the calculated steam dump capacity is 68.7 percent versus the Westinghouse recommended capacity of 70 percent for 100 percent load rejection. The NSSS control systems analysis in Section 4.3 provides a further evaluation of the Steam Dump System adequacy at the SGR/Uprating conditions.

Note that at the upper end of the T_{avg} operating range and a full-load best estimate steam generator pressure of 1011 psia, steam dump capacity is about 84.9 percent of rated flow (11.8×10^6 lb/hr), or 10.02×10^6 lb/hr with 13 valves in service.

To provide effective control of flow on large step load reductions or plant trip, the steam dump valves are required to go from full-closed to full-open in 3 seconds at any pressure between 50 psi less than full load pressure and steam generator design pressure. The dump valves are also required to modulate to control flow. Positioning response may be slower with a maximum full stroke time of 20 seconds. These requirements are still applicable for the NSSS operating conditions for the SGR/Uprating.

4.2.4.2.2 Steam Dump System Conclusions

The conclusion of the assessment of the uprated conditions on the Steam Dump System is that for the range of operating conditions for the uprating, steam dump capacity is less than the Westinghouse recommended capacity. The design load rejection capability has been confirmed

by a control systems operability assessment (i.e., margin to trip analysis), and the condenser Steam Dump System has been shown to be acceptable.

4.2.4.3 Condensate and Feedwater System

The Condensate and Feedwater System (C&FS) must automatically maintain steam generator (SG) water levels during steady-state and transient operations. The range of NSSS design parameters will impact both feedwater volumetric flow and system pressure drop. The volumetric flow may increase by as much as 5.8 percent or decrease by as much as 8.4 percent. Therefore, system pressure drop may increase by as much as 11.4 percent or decrease by as much as 12.0 percent respectively during full-power operation. Also, a comparison of the uprated design and best estimate parameters with the original design parameters indicates that the SG full-power operating steam pressure may increase by as much as 47 psi (964 to 1011 psia) or decrease by as much as 139 psi (964 to 825 psia).

The pre-heater bypass lines and associated valves and the feedwater isolation valve bypass lines and associated valves will not be required with the replacement steam generators (RSGs). The general arrangement and layout interface requirements that pertain to the C&FS are provided in the Westinghouse Steam Systems Design Manual and these requirements are not impacted by the Proposed change in NSSS operating conditions.

The major components of the C&FS are the Feedwater Isolation Valves (FIVs), the Feedwater Control Valves (FCVs), Feedwater Bypass Control Valves (FBCVs), and the C&FS Pumps.

4.2.4.3.1 Feedwater Isolation, Feedwater Control and Feedwater Bypass Control Valves

The FIVs are located outside containment and downstream of the FCVs and FBCVs. The valves function in conjunction with the primary isolation signals to the FCVs, FBCVs and backup trip signals to the feedwater pumps to provide redundant isolation of feedwater flow to the steam generators following a steam line break or a malfunction in the steam generator level control system. Isolation of feedwater flow is required to prevent containment overpressurization and excessive RCS cooldowns. To accomplish this function, the FIVs and the backup FCVs and FBCVs must be capable of fast closure, following receipt of any feedwater isolation signal.

The quick-closure requirements imposed on the FIVs, and the backup FCVs and FBCVs cause dynamic pressure changes that may be of a large magnitude and must be considered in the design of the valves and associated piping. The worst loads occur following a steam break from no-load conditions with the conservative assumption that all feedwater pumps are in service providing maximum flow following the break. Maximum feedwater flow may be impacted by the proposed feedwater system design changes that include an increase in feedwater pump head. Further evaluation of the C&FS, including the feedwater system design changes, is contained in the BOP Licensing Report.

4.2.4.3.2 Condensate and Feedwater System Pumps

The C&FS available head in conjunction with the FCV/FBCV characteristics must provide sufficient margin for feed control to ensure adequate flow to the steam generators during steady-state and transient operation. A continuous steady feed flow should be maintained at all loads. Further evaluation of the C&FS, including the feedwater and condensate pumps, is contained in the BOP Licensing Report.

4.2.4.3.3 Condensate and Feedwater System Pumps Conclusions

The evaluations of the Condensate and Feedwater System at the uprated conditions show that the hydraulics of the C&FS should permit operation over the entire range of full power NSSS operating conditions for the uprating. Further evaluation of the C&FS is contained in the BOP Licensing Report.

4.2.4.4 Auxiliary Feedwater System

The AFWS supplies feedwater to the secondary side of the steam generators at times when the normal feedwater system is not available, thereby maintaining the heat sink of the steam generators. The system provides feedwater to the steam generators during normal unit startup, hot standby, and cooldown operations and also functions as an Engineered Safeguards System. In the latter function, the AFWS is directly relied upon to prevent core damage and system overpressurization in the event of transients and accidents such as a loss of normal feedwater or a secondary system pipe break. The minimum flow requirements of the AFWS are dictated by accident analyses, and since the power uprating impacts these analyses, evaluations of the limiting transients and accidents must be performed to confirm that the AFWS performance is acceptable at the uprated conditions.

4.2.4.4.1 Auxiliary Feedwater Storage Requirements

The AFWS pumps are normally aligned to take suction from the condensate storage tank (CST). To fulfill the Engineered Safety Features (ESF) design functions, sufficient feedwater must be available during transient or accident conditions to enable the plant to be placed in a safe shutdown condition.

The limiting transient with respect to CST safety-related inventory requirements is the loss-of-offsite power (LOOP) transient. The HNP licensing basis dictates that in the event of a LOOP, sufficient CST useable inventory must be available to bring the unit from full-power to hot-standby conditions, maintain the plant at hot standby for 12 hours, and then cool down the RCS to the RHRS cut-in temperature (350°F) in 4 hours. In light of these design bases requirements, the analysis-of-record concluded that a minimum useable inventory of 233,726 gal. is required in the CST. The design of the CST permits a maximum safety-related contained inventory of 270,000 gal. and a maximum safety-related useable inventory of about 235,000 gal. The plant Technical Specifications require a safety-related contained inventory of 270,000 gal.

A revised analysis for the range of NSSS design parameters approved for the SGR/Uprating indicates that 238,048 gal. is required to satisfy the present licensing bases: 12-hr hot standby and 4-hr cooldown time to an RHRS cut-in temperature of 350°F.

Further evaluation of the AFW system is contained in the BOP Licensing Report.

4.2.4.4.2 Auxiliary Feedwater System Conclusions

The minimum flow requirements of the AFWS are dictated by accident analysis and since the uprating impacts these analyses, evaluations of the limiting transients and accidents have been performed to confirm that the AFWS performance is acceptable at the uprated operating conditions. These analyses are described in Section 6.0 of this report.

Further analysis of CST minimum inventory requirements for the SGR/Uprating operating conditions is contained in the BOP Licensing Report.

4.2.4.5 Steam Generator Blowdown System

The Steam Generator Blowdown System (SGBS) is used in conjunction with the Chemical Feed and Sampling Systems to control the chemical composition of the steam generator shell water within the specified limits. The blowdown system also controls the buildup of solids in the steam generator water. The RSGs are provided with two blowdown connections, a tube sheet connection and a shell connection. The tube sheet connection is required to control the buildup of particulate matter that enters the steam generator and tends to accumulate by settling in the tube sheet area. Either the tube sheet connection or the shell connection or both can be used to control dissolved solids and maintain chemistry within specifications.

The required blowdown flow rates during plant operation will not be significantly impacted by power uprate, since neither the rate of addition of dissolved solids or the rate of addition of particulates into the steam generators will be significantly impacted by the SGR/Uprating.

A hydraulic analysis was performed to ensure compatibility of the blowdown system control valves with the piping changes dictated by the RSGs and approved a range of NSSS operating conditions. This work also addressed a SGBS design change to locate several valves from inside the secondary shield wall to a location outside the wall. The following summarizes the results of the analysis:

- The pipe re-route required to install the RSGs and to move the system valves from inside to outside the secondary shield wall is acceptable in terms of system hydraulics.

- The required split in tube sheet blowdown versus shell blowdown is compatible with both the hydraulic design of the RSGs and the re-route of the blowdown system pipe.

- The size of the trim in the SGBS flow control valves is adequate to establish and control a maximum blowdown flow of 100,000 lb/hr over the allowable range of steam generator shell side operating pressures.

4.2.4.5.1 Steam Generator Blowdown System Conclusions

The actual required blowdown flow rates during plant operation will not be significantly impacted by the SGR/Uprating, since neither the rate of addition of dissolved solids or the rate of addition of particulates into the steam generators will be significantly impacted by the power uprating.

Further evaluation of the SGBS is contained in the BOP Licensing Report.

4.2.5 NSSS/BOP Fluid Systems Interfaces Conclusion

In general, these evaluation results are applicable to the SGR at the uprated NSSS power of 2912.4 MWt.

HNP operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt was also reviewed. The review confirmed that with one exception, the analyses and evaluations performed at the uprated NSSS power of 2912.4 MWt are bounding for HNP operation with the replacement steam generators at the current NSSS power. The one exception is the analysis and results presented for the main feedwater control valve. The FCV evaluation performed for NSSS operation at the SGR/Uprating conditions is not bounding for NSSS operation with the RSGs at the current NSSS power level of 2787.4 MWt. For NSSS operation at SGR/current power conditions, the minimum FCV lift is expected to vary an additional amount (about 5 percent). This small change in expected valve lift is not significant and should not be a problem in terms of plant operability. Refer to the BOP Licensing Report for additional information.

4.3 NSSS Control Systems

4.3.1 Introduction

As the proposed plant conditions with the HNP steam generator replacement (SGR) and uprated power level are somewhat different from those assumed in the original design, it was necessary to reexamine the control systems, their setpoints, and the sizing of the critical NSSS components. Therefore, the following evaluations were performed for the NSSS control systems:

- Control Systems Stability Analysis
  - Rod Control System
  - Steam Dump Control System
- Plant Operability Margins Evaluation
- NSSS Component Sizing
  - Power Operated Relief Valves
  - Pressurizer Spray Valves
  - Pressurizer Heaters
  - SG Main Steam Safety Valves
  - Pressurizer Safety Valves
- Steam Generator Level Control System Evaluation
- Low Temperature Over Pressurization System Evaluation

The following sections summarize the main results and conclusions of this evaluation.

4.3.1.1 Control Systems Stability Analysis

The NSSS Control Systems are designed to provide a stable and acceptable response to normal condition transients. An unstable control system may lead the plant parameters toward unbounded values and may cause excessive wear and tear on the control systems. In light of this, the stability of the Rod Control System and the Steam Dump Control System were evaluated for the HNP SGR/Uprating program.

Rod Control System

The results of the analysis showed acceptable stability in the Rod Control System for design basis 10-percent load increase, 5-percent ramp load increase, and large-load decrease transients at SGR/Uprating and current power, and beginning-of-life (BOL) and end-of life (EOL) conditions. High and low frequency rod stepping was not observed during the transient. The existing rod control system setpoints and time constant remain valid for the SGR/Uprating and current power conditions.

Steam Dump Control System

SGR and Power Uprating conditions have several effects on the Steam Dump Control Systems: (1) an uprated power ideally requires a larger steam dump capacity because of the higher steam flow, (2) a lower steam pressure reduces the effective steam dump capacity, and (3) the steam dump performance depends on the Steam Dump Control System setpoints, which are different at low and high T_{avg} conditions. Based on this, an evaluation of the Steam Dump Control System at HNP SGR/Uprating conditions was performed.

The evaluation showed that the plant response to normal condition transients was stable, but an automatic reactor trip occurred on the OTΔT trip setpoint on a full-load rejection transient. This is acceptable as full-load rejection capability is no longer an acceptance criterion for HNP due to balance-of-plant (BOP) system limitation at power uprate conditions. The plant response to a 50-percent load reduction from full-power transient was stable at both high and low T_{avg} and BOL and EOL conditions. The results of the turbine trip transient showed an acceptable controller response at high and low T_{avg} conditions. The steam dump system turbine-trip controller setpoint will provide adequate margin to the Engineered Safety Features (ESF) and Main Steam Safety Valve (MSSV) actuation setpoints following a turbine-trip transient.

In summary, performance of the control systems during both steady state and Condition I transients will not be degraded by the HNP SGR/Uprating conditions. The current control systems setpoints and time constants will remain applicable for the SGR/Uprating and current power conditions.

4.3.1.2 Plant Operability Margins Evaluation

The adequacy of available operating margin to various reactor trip and ESF actuation setpoints that are active during and following normal at-power (Condition I) operating transients at HNP SGR/Uprating conditions were evaluated. The Condition I transients considered for evaluation are initiated from full-power and, in some cases, reduced-power conditions.

There are 15 reactor trip and 10 ESF actuation signals active during at-power operation. The general warning alarm trip is also active during at-power operation. Other reactor trips are either manually actuated or are not active during at-power operation (e.g., high source

range/intermediate range Nuclear Instrumentation System trips, presence of a safety injection signal).

The evaluation demonstrated that sufficient margin exists to relevant reactor trips and ESF actuation setpoints during Condition I (normal operating) transients. An automatic reactor trip on OTΔT will occur on a full-load rejection (net-load trip) transient but adequate margin to OTΔT exists on a 50-percent load reduction transient. Since full-load rejection capability is no longer an acceptance criterion for HNP due to BOP system limitation, an automatic reactor trip on a full-load rejection transient is acceptable. The control and protection current and revised setpoints for the SGR/Uprating will provide adequate operating margin during Condition I transients.

The results obtained with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt are also applicable for the SGR at the current NSSS power of 2787.4 MWt.

4.3.1.3 NSSS Component Sizing Evaluation

The HNP SGR/Uprating nominal full-power design conditions are significantly different from those assumed in the original sizing calculations to establish the minimum sizing requirements for the following NSSS components. Therefore, the installed capacities of these components were evaluated at the SGR/Uprating conditions.

- Pressurizer Power Operated Relief Valves
- Pressurizer Spray Valves
- Pressurizer Heaters
- SG Main Steam Safety Valves
- Pressurizer Safety Valves

For comparison purposes, the sizing analyses for the pressurizer and steam generator safety valves were also performed at HNP SGR/Uprating conditions.

Pressurizer PORVs

The sizing basis for the Pressurizer Power Operated Relief Valves (PORVs) is to prevent the pressurizer pressure from reaching the high pressurizer pressure reactor trip setpoint for the design basis full-load rejection with steam dump transient. This criterion is conservatively met if the total PORV capacity is greater than or equal to the peak pressurizer in-surge flow rate during and following this transient. The PORV opening characteristics are not modeled in the sizing analysis to prevent the valve characteristics from interfering with the peak surge-rate calculation. The effect of PORV opening characteristics on peak pressurizer pressure is evaluated in the

control system analysis.

The total capacity of the installed pressurizer PORVs is higher than the required capacity at SGR/Uprating and SGR/current power conditions and is, therefore, acceptable for SGR/Uprating and SGR/current power conditions.

Pressurizer Spray Valves

The sizing basis for Pressurizer Spray Valves is to prevent challenges to the pressurizer PORVs from a 10-percent step-load decrease transient. For load decrease amounts of up to 10-percent power, the spray valves are the sole means of providing pressure control without actuating the pressurizer PORV in the automatic mode of pressure control.

The total capacity of the installed pressurizer spray valves is acceptable for SGR/Uprating and SGR/current power conditions.

Pressurizer Heaters

The Pressurizer Heater total capacity is proportional to the pressurizer volume. For Westinghouse plants, the required capacity for pressurizer heaters is one kilowatt per one cubic foot of pressurizer total volume. With a nominal 1400 ft^3 pressurizer at HNP, this translates to pressurizer heater total capacity of 1400 kW. The total capacity of the installed heaters is 1400 kW and, therefore, meets the Westinghouse standard requirements of 1.0 kW/ft^3 of pressurizer total volume. The adequacy of the pressurizer heater installed capacity at SGR/Uprating conditions was verified, based on analysis of a 10-percent load change and full-load rejection transients.

The total installed heater capacity is acceptable for SGR/Uprating and SGR/current power conditions.

Steam Generator Main Steam Safety Valves

The sizing basis for steam generator MSSVs is to limit the pressure in the steam generator so it does not exceed 110 percent of the steam generator design pressure on a complete loss-of-load transient. Westinghouse applies the conservative criterion that the safety valves should be sized to relieve 105 percent of the maximum calculated steam flow at an accumulation pressure not exceeding 110 percent of the main steam system design pressure.

The installed steam generator MSSV total capacity at each valve's respective setpoint plus 3-percent accumulation will limit the steam generator pressure below 110 percent of the steam generator design pressure on a sizing design basis transient at SGR/Uprating and SGR/current power conditions. The installed MSSVs are acceptable at SGR/Uprating and SGR/current power conditions, since the valve performance was modeled in NSSS LR Section 6.2 (Chapter 15 Non-

LOCA Safety Analysis) which met Chapter 15 event acceptance criteria. Also, these valves were evaluated for other system acceptance criteria in BOP LR Section 2.3 (Steam Systems).

Pressurizer Safety Valves

The sizing basis for the pressurizer safety valves is designed to limit the pressurizer pressure not to exceed 110 percent of the RCS design pressure on a complete loss-of-load transient. This criterion is conservatively met if the total capacity of the pressurizer safety valves is greater than or equal to the peak pressurizer in-surge flow rate during and following this transient.

The total capacity of the installed pressurizer safety valves at setpressure plus 3-percent accumulation is higher than the calculated maximum required capacity at SGR/Uprating and SGR/current power conditions. The installed pressurizer safety valves are acceptable at SGR/Uprating and SGR/current power conditions, since the valve performance was modeled in NSSS Section 6.2 (Chapter 15 Non-LOCA Safety Analysis) which met Chapter 15 acceptance criteria.

4.3.1.4 Steam Generator Level Control System Evaluation

The performance of the Steam Generator Level Control System (SGLCS) has been evaluated as part of the HNP SGR/Uprating program. The predicted responses will allow plant personnel to anticipate margins to level setpoints and deviation alarm limits and can be used in preparation of plant test procedures or training. The predicted responses have also been evaluated to determine some acceptable combinations of SGLCS setpoints that are based on the simulation results. It is intended, however, that both the simulation results and the plant test and operating data, taken together, be considered in determining the final SGLCS setpoint values.

The current SGLCS setpoints will not provide acceptable control system response and margin to the steam generator narrow-range level (NRL) high-high trip setpoint on a large-load reduction transient. Acceptable SGLCS performance and margin to the NRL trip setpoints were obtained with the alternative (i.e., basically those originally implemented) SGLCS setpoints. Alternative sets of these setpoints are recommended based on the analysis results. The final selection of SGLCS setpoint values for operation should be determined based on the analytical results and recommendations, the results of transient testing during plant startup with the replacement steam generators, and plant performance during startup and operation. The results obtained with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt are also applicable for the replacement steam generators at the current NSSS power of 2787.4 MWt.

4.3.1.5 Low Temperature Over Pressurization Transients Analyses

The HNP design basis Low Temperature Over Pressurization (LTOP), Mass Input (MI) and Heat Input (HI) transients were analyzed at SGR/Uprating conditions (LTOP transients are also known as Cold Overpressure Mitigation [COM] transients). The results may be used to determine the

appropriate pressurizer PORV setpoint for low temperature operation. The design basis MI and HI transients for HNP are an inadvertent start of one charging/safety injection pump (MI) and startup of a reactor coolant pump when the steam generator secondary side is 50°F hotter than the RCS primary side (HI). Results of the parameter sensitivity on pressurizer PORV characteristics may be used as necessary.

Using a Residual Heat Removal (RHR) relief valve for theLTOP event, the results indicated a peak RCS pressure of 490 psig for the MI transient and 557 psig (with RCS at 250°F) and 666 psig (with RCS at 300°F) for the HI transient. These results need to be modified by other considerations, such as static head elevation between RHR relief valve and RHR piping, for RHR system overpressure evaluation. The results of this analysis are used as input to subsequent calculations for LTOP transients. Refer to the BOP Licensing Report 2.11.

5.0 NSSS Components

Evaluations were performed to assess the impact of the SGR/Uprating conditions on all the NSSS components. For most cases, the uprating-related input used for these evaluations were the PCWG parameters (given in Section 2), and the NSSS design transient changes (described in Section 3). In addition to these documents, the component designers also reviewed the original design information related to that component. The evaluations were performed to confirm that the components continue to satisfy the applicable codes, standards, and regulatory guides under the revised conditions.

Following is a list of the component areas that were assessed

- Reactor Vessel Structural
- Reactor Vessel Integrity (Not Westinghouse Scope)
- Reactor Internals
- Fuel Assemblies Structural (Not Westinghouse Scope)
- Control Rod Drive Mechanisms Structural
- Reactor Coolant Loop Piping and Supports and Leak Before Break
- Reactor Coolant Pump and Motor
- Steam Generator Structural, Thermal/Hydraulic and Flow Induced Vibration
- Pressurizer Structural
- NSSS Auxiliary Equipment Evaluation

5.1 Reactor Vessel

5.1.1 Reactor Vessel Structural Evaluation

5.1.1.1 Introduction

Evaluations were performed for the various regions of the Harris Nuclear Plant (HNP) reactor vessel to determine the stress and fatigue usage effects of NSSS operation at the revised operating conditions of the SGR/Uprating Project throughout the current plant operating license. The revised operating parameters in Section 2 identify vessel inlet and vessel outlet temperatures that define the steady state operating temperatures for the reactor vessel for a range of high and low temperature operation. The design transients for the reactor coolant system (RCS), in turn, define the temperature and pressure responses for a variety of transients that can occur during either high temperature or low temperature operation. The revised transient temperature and pressure variations may affect both the maximum ranges of primary plus secondary stress

intensity and the maximum cumulative fatigue usage factors for the reactor vessel. The evaluations assess the effects on the maximum ranges of stress intensity and fatigue usage factors at the most limiting locations in each of the regions of the reactor vessel as identified in the reactor vessel stress report and addendum (References 1 and 2).

5.1.1.2 Description of Analyses and Evaluations

The key evaluation input parameters are the revised NSSS parameters in Section 2, the NSSS component design transients, and the reactor vessel/reactor internals interface loads. The temperatures and pressures considered in the reactor vessel structural evaluation for the NSSS parameters are as follows:

Normal Operating Pressure:	2317 psig
Normal Operating Temperatures	
Vessel Inlet Temperature Range:	536.6°F to 557.4°F
Vessel Outlet Temperature Range:	604.2°F to 623.2°F
Zero Load Temperature:	557°F

Other input parameters include design inputs from the HNP reactor vessel equipment specification (Reference 3), revised reactor vessel nozzle and nozzle support pad loads (as necessary), and HNP design changes/modifications.

The revised RCS design transients for the HNP SGR/Uprating Project were reviewed and compared to the original design basis transients from Reference 3. This transient review determined which revised transients are more severe than their design basis counterparts by comparing rates, magnitudes and durations of the transient temperature variations as well as the magnitudes of the pressure variations. Based upon this review, a determination of which revised transients must be considered in the stress evaluations was made.

The transient review concluded that only four of the T_{hot} transient temperature variations were more severe for the SGR/Uprating than for the design basis. The more severe T_{hot} design transients include Loss of Power, Partial Loss of Flow, Control Rod Drop, and Inadvertent Safety Injection Actuation. In addition, RCS Cold Overpressurization was included as a design transient. The stress intensities for these revised transients were examined to determine their effect on the maximum ranges of stress intensity for the outlet nozzle. Calculations were performed to account for the changes in thermal stress due to the modified temperature variations.

The transient review also concluded that eight of the SGR/Uprating T_{cold} transient temperature variations were more severe than their design basis counterparts. The revised transients with more severe T_{cold} temperature variations include Plant Loading, Plant Unloading, Large Step Load Decrease, Loss of Load, Loss of Power, Reactor Trip from Full Power with No Cooldown, Control Rod Drop, and Inadvertent Safety Injection Actuation. RCS Cold Overpressurization

was again considered as a design transient. These transients were applied to all regions of the reactor vessel pressure boundary other than the outlet nozzles, including the vessel inlet nozzles, main closure, bottom head, top head, main shell, and core support pads that are in contact with vessel inlet water (T_{cold}) during normal operation. The change in the transient thermal stress due to the revised and new transient temperature variations were calculated. The incremental thermal stress changes were then factored into the stress intensities, and the effects of the changes on the maximum ranges of stress intensity were evaluated.

In addition to the changes in the temperature variations, many of the revised design transients also exhibited changes in their RCS pressure variation. The incremental pressure stresses were calculated by scaling the original transient pressure stresses proportional to the change in the pressure variation, since pressure stress is directly proportional to pressure. The changes in pressure stress were also added into the revised stress intensities for both the T_{hot} and T_{cold} regions where appropriate. The revised transients that exhibited significant changes from the design basis transients in their pressure variations include Plant Loading, Plant Unloading, Loss of Power, Partial Loss of Flow, Reactor Trip with no Cooldown, Reactor Trip with Cooldown but No Safety Injection, Reactor Trip with Cooldown and Safety Injection, Control Rod Drop, and Inadvertent Safety Injection Actuation. The RCS pressure variation for RCS Cold Overpressurization was also considered. These revised pressure variations were considered in the evaluations of the various vessel regions even if the applicable transient temperature variation was unaffected.

Where appropriate, revised maximum ranges of stress intensity and maximum usage factors were calculated for the SGR/Uprating. In other cases, the original design basis stress analysis remains conservative so that no new calculations were necessary, and the maximum ranges of stress intensity and fatigue usage factors reported in the Chicago Bridge and Iron Co. stress report (Reference 1) and Westinghouse addendum (Reference 2) continue to govern.

Revised LOCA loads for the reactor vessel interfaces with the reactor internals at the main closure flange ledges, the outlet nozzle internal projections and the core support pads were developed. Also included were LOCA loads at the vessel/vessel support interface. These LOCA loads were compared to the faulted condition loads that were considered in References 1 and 2. The comparison revealed that only the LOCA loads at the core support pad interface with the internals lower radial keys exceeded the loads that were previously considered in the reactor vessel stress report. Therefore, a calculation was performed to determine the stresses at the core support pads. The combined normal plus LOCA stresses were then compared to the applicable faulted condition acceptance criteria.

The head adapter plugs were not previously included with the reactor vessel structural analysis because they were supplied separately from the reactor vessel and its associated equipment as defined in Reference 3. The head adapter plugs were also evaluated separately for the HNP SGR/Uprating. The evaluation was performed by applying a head adapter plug analysis that considered design transients that better match the SGR/Uprating transients in lieu of the original design analysis. The reference head adapter plug analysis was then reconciled with the HNP head adapter plug design including design transients, material, analytical methods and acceptance criteria. The reference analysis results were then applied to HNP.

5.1.1.3 Acceptance Criteria

The acceptance criteria for the reactor vessel structural analyses and evaluations are in accordance with the applicable requirements of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with addenda through Winter 1971 (Reference 4). The applicable code for the head adapter plugs is the 1974 Edition of Section III of the ASME Boiler and Pressure Vessel Code (Reference 5). However, the applicable acceptance criteria are the same. The applicable acceptance criteria are as follows:

The maximum range of primary plus secondary stress intensity resulting from normal and upset condition design transient mechanical and thermal loads shall not exceed $3S_m$ at operating temperature, in accordance with Paragraph NB-3222.1 of Reference 4. The maximum cumulative usage factor resulting from the peak stress intensities due to normal and upset condition design mechanical and thermal loads shall not exceed 1.0, in accordance with the procedure outlined in Paragraph NB-3222.4 of Reference 4.

The faulted conditions shall meet the component criteria of Appendix F of the ASME Boiler and Pressure Vessel Code, Section III, 1974 Edition (Reference 5: The 1974 Edition was used, since Appendix F was not yet included in the 1971 Edition). For the core support pad faulted condition analysis, the general primary membrane stress intensity limits are $2.4S_m$ for the Alloy 600 pads and $0.7S_U$ for the low-alloy steel vessel shell. The primary membrane plus bending limits are $3.6S_m$ for the pads and $1.05S_U$ for the vessel shell.

5.1.1.4 Results

The SGR/Uprating affects only one of the maximum ranges of stress intensity reported in the HNP reactor vessel stress report (References 1 and 2). The maximum range of stress intensity for the outlet nozzle safe end increased, but remains below the applicable ASME Boiler and Pressure Vessel Code, Section III limit. The evaluations show that for all other limiting locations, the existing design stress analyses remain conservative when the revised operating parameters and design transients are incorporated. The maximum cumulative fatigue usage factors at all of the limiting locations (except for the closure studs) increase somewhat from the values reported in Reference 2. However, the increases are all minimal, and all of the cumulative fatigue usage factors remain under the 1.0 limit with significant margin.

The updated maximum ranges of primary plus secondary stress intensity and maximum cumulative fatigue usage factors for the HNP reactor vessel accounting for the SGR/Uprating is shown in Table 5.1.1-1.

A comparison of the LOCA interface loads to the corresponding LOCA and faulted condition loads that were previously considered in References 1 and 2 concluded that only the core support pads required additional stress analysis to justify application of LOCA loads. LOCA loads at the core support pad interface were not included in the reactor vessel design as defined by Reference 3. The faulted condition calculations for the core support pads were performed to justify application of a total faulted condition core support pad load that included the total LOCA load. The results are summarized in Table 5.1.1-2.

5.1.1.5 Conclusions

Based upon the satisfactory results of the evaluations, the HNP reactor vessel is acceptable for plant operation at the revised conditions. Such operation of the reactor vessel is shown to be acceptable in accordance with the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with Addenda through Winter 1971 (Reference 4) for the remainder of the plant license. Operation of the head adapter plugs is acceptable in accordance with the 1974 Edition of Section III of the ASME Boiler and Pressure Vessel Code with Addenda through Winter 1976 (Reference 5).

The results obtained with the Model Delta 75 RSGs at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 RSGs at the current NSSS power of 2787.4 MWt.

5.1.1.6 References

1. Chicago Bridge and Iron Company Stress Report Certification and Final (Summary) Stress Report 157 "PWR Vessel Shearon Harris Nuclear Station-Unit 1, Westinghouse P.O. No. 150117," December 22, 1981.

2. Westinghouse Report and Certification MED-PCE-2537, "Addendum to Chicago Bridge and Iron Final Stress Report for the Shearon Harris Unit No. 1 Reactor Vessel," Winston K. Ma and John C. Schmertz, April 12, 1985. (Westinghouse Proprietary)

3. Westinghouse Equipment Specification 679119, Rev. 3, for the Shearon Harris Nuclear Station Unit No. 1 Reactor Vessel, Addendum to Equipment Specification 676413, Rev. 3, March 13, 1985 and Westinghouse Equipment Specification 676413, Rev. 3 for General Reactor Vessel, July 16, 1971. (Westinghouse Proprietary Class 2)

4. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," 1971 Edition with Addenda through Winter 1971, American Society of Mechanical Engineers, New York.

5. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," 1974 Edition with Addenda through Winter 1976, American Society of Mechanical Engineers, New York.

Table 5.1.1-1
Maximum Ranges of Primary Plus Secondary Stress Intensity and Maximum Cumulative Fatigue Usage Factors for the RV

Location	$P_L + P_b + Q$ Range	Previous	U_C	Previous
Outlet Nozzles	Nozzle: [ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi Safe End: [ ]$^{(b,c)}$ < 3 S_m = 56.40 ksi	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
Inlet Nozzles	[ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
Main Closure Flange Region				
1. Closure Head Flange	[ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
2. Vessel Flange	[ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
3. Closure Studs	[ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
CRDM Housings	[ ]$^{(b,c)}$ < 3 S_m = 69.9 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
Vent Pipe	[ ]$^{(b,c)}$ < 3 S_m = 69.9 ksi	N/A	[ ]$^{(b,c)}$ < 1.0	N/A
Bottom Head Juncture	Shell: [ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi Head: [ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
Bottom Head Instrumentation Tubes	[ ]$^{(b,c)}$ < 3 S_m = 69.9 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
Main Vessel Shell	[ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
Core Support Pads	Shell: [ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi Head: [ ]$^{(b,c)}$ < 3 S_m = 80.1 ksi	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$
Head Adapter Plug	[ ]$^{(b,c)}$ < 3 S_m = 48.3 ksi	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ < 1.0	[ ]$^{(b,c)}$

Table 5.1.1-2 Faulted Condition Calculations for the Core Support Pads		
Maximum General Primary Membrane Stress Intensity, P_m		**Previous**
Core Support Pad	$P_m = [\quad]^{(b,c)} < 2.4S_m = 55.92$ ksi	N/A
Vessel Shell	$P_m = [\quad]^{(b,c)} < 0.7S_U = 56.0$ ksi	N/A
Maximum Primary Membrane plus Bending Stress Intensity, $P_L + P_b$		**Previous**
Core Support Pad	$P_L + P_b = [\quad]^{(b,c)} < 2.4S_m = 83.88$ ksi	N/A
Vessel Shell	$P_L + P_b = [\quad]^{(b,c)} < 1.05S_U = 84.0$ ksi	N/A

5.1.2 Reactor Vessel Integrity

5.1.2.1 Introduction

Reactor vessel integrity (RVI) has been evaluated to determine the impacts of Harris Nuclear Plant (HNP) Steam Generator Replacement and Power Uprate Project (SGR/Uprate). The proposed modifications would cause the following changes that are potentially significant to reactor vessel integrity: (a) steam generator replacement impacts system response to certain overpressure transients, and (b) power uprate induced neutron fluence changes, which impact the reactor vessel beltline material properties, such as, adjusted nil ductility transition reference temperature (ART_{NDT}), pressurized thermal shock reference temperature (RT_{PTS}), and Upper Shelf Energy (USE).

These impacts of material property changes were evaluated to determine their effects on the heat up and cooldown curves. Additionally, the heatup and cooldown curves are used to verify the acceptability of over-pressure protection relief valve setpoints for low temperature conditions.

5.1.2.2 Description of Analyses and Evaluations

Reactor vessel integrity is potentially impacted by any changes in plant parameters that affect neutron fluence levels or pressure/temperature transients. The most critical area of the reactor vessel is the beltline region (the region of the reactor vessel that directly surrounds the effective height of the active core that is predicted to experience neutron radiation damage). The changes in neutron fluence resulting from the SGR/Uprate have been evaluated to determine the impact on reactor vessel integrity. This assessment included a review of the current material surveillance capsule withdrawal schedule, ART_{NDT} and upper shelf energy, applicability of the current heatup and cooldown pressure-temperature limit curves, and a revision to the RT_{PTS} values for meeting the requirements of 10 CFR 50.61, "Pressurized Thermal Shock (PTS) Rule". The critical parameters, which have any impact on reactor vessel integrity, are addressed as follows:

<u>Neutron Fluences:</u>
Neutron fluences have been evaluated using the DORT computer program and methodologies recommended in Draft Regulatory Guide DG-1053 and as described in Topical Report BAW-2241P, Rev. 1 (Reference 5). This Topical Report was used as a basis for revising the HNP Technical Specification (T/S) 3/4.4.9.4, Amendment No. 100. In addition, time -average space and energy-dependent neutron sources were analyzed using the SORREL code based on a fuel cycle core design, which has been determined to be representative of an equilibrium cycle for the post-uprate period. Then, the inner wetted-surface and the clad / base metal interface neutron fluence determined by the DORT code, with consideration of the Regulatory Guide (RG) 1.99 attenuation formulas through the reactor vessel wall thickness, were used as an input parameter to evaluate the ART_{NDT}, Pressurized Thermal Shock values, Upper Shelf Energies and the Reactor Vessel Surveillance Capsule Withdrawal Schedule. Further discussion of Neutron Fluence is presented in Section 7.5 of this Licensing Report (LR). Detail related to derivation of this information in provided in Reference 3, which is attached with this Licensing Report

Section. (Reference 3 is a supplementary report to the reactor vessel material surveillance report, BAW-2355, October 1999, which was submitted to the NRC via CP&L Letter, HNP-99-157, dated November 9, 1999).

Adjusted Nil Ductility Transition Reference Temperature (ART_{NDT}):
ART_{NDT} were evaluated by adding the initial Nil-Ductility Transition Reference Temperature (RT_{NDT}), the predicted radiation-induced transition temperature shift (ΔRT_{NDT}), and a margin term to cover the uncertainties in the values of initial RT_{NDT}, copper and nickel content, neutron fluences and the calculational procedures. The ¼ thickness (T) and ¾ T ART_{NDT} results were determined for each beltline material, using the chemistry factors from Tables 1 and 2 in RG 1.99, Rev. 2. Credited neutron attenuation to these depths was determined by the more conservative RG 1.99 formulas, rather than those calculated by DORT. HNP surveillance data were used to recalculate the chemistry factors for the intermediate shell plate, Heat No. B4197-2, and the Heat No. 5P6771 to the intermediate shell to lower shell circumferential weld. Detail related to derivation of this information is provided in Reference 3, which is attac hed with this LR Section.

Reactor Vessel End-Of-License Upper-Shelf Energy (USE)
In addition to the ART_{NDT} study, the reactor vessel end-of-license (36 Effective Full Power Years (EFPY)) upper-shelf energy at the ¼ T wall location was evaluated. HNP surveillance data were used to recalculate the chemistry factors for the intermediate shell plate, Heat No. B4197-2, and the Heat No. 5P6771 to the intermediate shell to lower shell circumferential weld. The method for determining the reduction in USE is R.G. 1.99, Rev. 2. Detail related to derivation of this information is provided in Reference 3, which is attached with this LR Section.

Pressurized Thermal Shock
Evaluation of Pressurized Thermal Shock (PTS) values were determined at the clad/base metal interface in accordance with 10CFR50.61. RT_{PTS} values were recalculated considering the initial RT_{NDT}, the predicted radiation-induced ΔRT_{NDT}, and a margin term to cover the uncertainties in the values of initial RT_{NDT}, copper and nickel content, and neutron fluences and using the calculational procedures of 10CFR50.61. HNP surveillance data were used to recalculate the chemistry factors for the intermediate shell plate, Heat No. B4197-2, and the Heat No. 5P6771 to the intermediate shell to lower shell circumferential weld. Detail related to derivation of this information is provided in Reference 3, which is attached with this LR Section.

Reactor Vessel Surveillance Capsule Withdrawal Schedule
A revised Neutron Fluence Capsule Withdrawal Schedule has been prepared and documented in Reference 3 (which is attached to this LR Section), based on the neutron fluence projected as a result of SGR/Uprate. The schedule is in accordance with ASTM Standard E 185-82, as required by 10CFR50, Appendix H.

Pressure-Temperature Limits
ASME Code Section XI and 10CFR50 Appendix G, provide the method for determining the pressure–temperature limits. Pressure-Temperature Limits of the reactor coolant pressure boundary (RCPB) are established in accordance with the requirements of 10CFR50, Appendix G. The methodology and criteria used to determine the Pressure-Temperature Limits are in

accordance with topical report BAW-10046A, Rev. 2 (Reference 7). Additionally, ASME Code Case N640 is used for the determination of the pressure-temperature limits (previously accepted by the NRC in HNP Technical Specification Amendment No. 100.) The detailed evaluation for implementing this method is contained in the BAW report (Reference 4).

Pressure-Temperature limits are required to prevent nonductile failure of the reactor vessel during any normal operating condition, including anticipated operational occurrences and tests. The loading conditions to which limits apply are the following:

1. Normal heatup and cooldown
2. Inservice leak and hydrostatic (ISLH) tests

The controlling RCPB pressure-temperature limits at low temperatures occur in the beltline region of the reactor vessel. Pressure-temperature limits have been established for each applicable EFPY of reactor operation, based on the predicted values of the ART_{NDT} for the beltline region material.

Pressurizer Power-Operated Relief Valve (PORV) Low Temperature Overpressure Protection Setpoints (LTOPS)

The Pressurizer Power-Operated Relief Valve (PORV) Low Temperature Overpressure Protection Setpoints (LTOPS) have been evaluated against design basis mass input and heat input events under SGR/Uprate conditions. The postulated design bases mass input event is the inadvertent startup of a single safety injection pump. The design basis heat input event is the startup of a reactor coolant pump with a 50°F differential between reactor coolant and secondary coolant (Refer to LR Section 4.3.6). In addition, ART_{NDT} and Pressure–Temperature limits are potentially impacted. The LTOPS setpoints and the enable temperature are re-evaluated for these revised conditions.

5.1.2.3 Acceptance Criteria

The acceptance criteria for the reactor vessel integrity assessment under SGR/Uprate conditions are:

- The fast neutron fluence relating to reactor vessel integrity is used as input to material property degradation and the surveillance capsule withdrawal schedule evaluations.

- The adjusted nil-ductility reference temperatures for the beltline materials are used as input to the development of the pressure-temperature limits.

- The upper-shelf energies of the reactor vessel beltline materials must not fall below 50 ft-lbs at the end-of license (36 EFPY) in accordance 10 CFR 50, Appendix G.

- The reactor vessel beltline materials must not exceed the pressurized thermal shock (PTS) screening criteria before end-of-license (36 EFPY) in accordance with 10 CFR 50.61.

- The reactor vessel surveillance capsule withdrawal schedule must meet the requirements of Appendix H to 10CFR50, "Reactor Vessel Material Surveillance Program Requirements", with testing per ASTM E 185-82 (Reference 2).

- Pressure-Temperature limits of the reactor coolant pressure boundary (RCPB) must be established in accordance with Appendix G to 10CFR50, "Fracture Toughness Requirements".

- 10CFR50 Appendix G, RCS pressure–temperature limits should not be exceeded for the design bases postulated events at low temperatures (below the enable temperature as defined in NUREG 0800 SRP BTP RSB 5-2.)

5.1.2.4 Results

Neutron Fluences

The estimated end-of-license (36 EFPY) peak fast neutron fluences at the clad-base metal interface of the reactor vessel is 4.590 x 10^{19} n/cm^2 (E> 1.0 MeV). The corresponding neutron fluences at ¼T, ½T, ¾T and outside the surface vessel wall peak location are 2.663 x 10^{19}, 1.357 x 10^{19}, 6.614 x 10^{18}, and 2.889 x 10^{18} n/cm^2 (E > 1.0 MeV), respectively. Technical Specification (TS) Bases Figure B 3/4.4-1 depicting fast fluence as a function of full power service life is not discernibly impacted by the change in End-of-License (EOL) fluence at the inside wetted surface from 4.610 x10^{19} n/cm^2 (current operation) to 4.651 x10^{19} n/cm^2 (at SGR/Uprate conditions). Therefore, a revision to the subject T.S. Bases Figure (Amendment No. 100) is not warranted and that Figure remains applicable.

The expected maximum EOL neutron fluences, which affect the reactor vessel beltline region materials, are identified in Table 5.1.2-1. LR Section 7.5.4 and Reference 3 provides additional information related to neutron fluences.

Adjusted Nil Ductility Transition Reference Temperature (ART_{NDT})

Based on the ART_{NDT} results at ¼T and ¾T, the controlling beltline material for the reactor vessel is the intermediate shell plate, Heat No. B4197-2. The ART_{NDT} for the T/4 and 3T/4 locations increased marginally, but not did not exceed the values assumed and cited in Technical Specification 3/4.4.9.2 (Amendment No. 100) Figures 3.4-2 and 3.4-3 for the RCS Pressure-Temperature limits.

The ART_{NDT} values for all beltline materials are identified in Table 5.1.2-1. Reference 3 provides additional information of ART_{NDT} values determination.

Reactor Vessel End-Of-License Upper-Shelf Energy (USE)

The Charpy V notch values for Upper-Shelf Energy (C_vUSE) for the reactor vessel beltline materials are 50 ft-lb or greater at end-of-license (36 EFPY). Table 5.1.2-1 identifies C_vUSE for all beltline materials. Reference 3 provides additional information on C_vUSE determination.

Pressurized Thermal Shock
The reactor vessel beltline materials will not exceed the 10CFR50.61 PTS screening criteria before end-of-license (36 EFPY, See Table 5.1.2-1). Reference 3 provides additional information for PTS results.

Reactor Vessel Surveillance Capsule Withdrawal Schedule
A new capsule surveillance schedule has been prepared. Three capsules remain available for use in the reactor vessel surveillance program. Removal of capsule W is planned at 18 EFPY. This duration was selected so that the expected capsule fluence will be greater than the peak EOL vessel fluence at the clad-base metal interface and less than twice that value. Although capsule W is identified for removal at 18 EFPY, this is a nominal removal period. It may be removed between 13.66 EFPY and 21.32 EFPY and remain in compliance with ASTM E 185-82 criteria.

The other capsules (Y & Z) will be maintained as standbys.

Pressure-Temperature Limits
The existing Pressure–Temperature limits as indicated in the T/S 3/4.4.9.2 (Amendment No. 100) remain applicable since the ART_{NDT} for the controlling beltline material utilized in the pressure-temperature limits for Technical Specification Amendment No. 100 Figures 3.4-2 and 3.4-3 also remain applicable.

Pressurizer Power-Operated Relief Valve (PORV Low Temperature Overpressure Protection System (LTOPS) Setpoints
No changes in the LTOPS setpoints and temperature range of applicability and enable temperature are required due to SGR/Uprate. The Pressure-Temperature limits and the adjusted nil ductility transition reference temperatures used to develop the LTOPS setpoints and temperature range were not impacted by the SGR/Uprate changes. The peak pressure at the reactor vessel beltline assumed the LTOPS setpoints as described in T/S 3/4.4.9.4 (Amendment No. 100) Figure 3.4-4. The peak pressure remains below the 10CFR50 Appendix G, RCS Pressure–Temperature limits. These limits are provided in T/S 3 /4.4.9.2 (Amendment No. 100) Figures 3.4-2 and 3.4-3.

5.1.2.5 Conclusions

Based on the satisfactory results of the evaluations, the SGR/Uprate will not have a significant impact on the reactor vessel integrity. The HNP reactor vessel is acceptable for plant operation at SGR/Uprate conditions.

The results obtained with the Delta 75 RSGs at the uprated NSSS thermal power level of 2912.4 MWt bound operation with the Delta 75 RSGs at the current NSSS thermal power level of 2787.4 MWt.

5.1.2.6 References

1. Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials,"(Rev. 2, 5/88)

2. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels"

3. BAW-2355, "Supplement to the Analysis of Capsule X Carolina Power and Light Company, Shearon Harris Unit 1," Framatome Technologies, Inc., (Supplement 1, 11/99)

4. BAW-2358, "Supplemental Pressure-Temperature Operation Limits for Carolina Power and Light Company, Shearon Harris Unit 1," Framatome Technologies, Inc., (Supplement 1, Revision 1)

5. BAW-2241P, "Fluence and Uncertainty Methodologies," Framatome Technologies, Inc., (Revision 1, 4/99).

6. Draft Regulatory Guide DG-1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," (6/96)

7. BAW-10046A, "Methods of Compliance with Fracture Toughness and Operational Requirements of Appendix G to 10CFR50," Babcock & Wilcox Co., (Rev. 2)

8. 10 CFR 50.61 "Pressurized Thermal Shock (PTS) Rule"

9. 10 CFR 50, Appendix G "Fracture Toughness Requirements"

10. 10 CFR 50, Appendix H "Reactor Vessel Material Surveillance Program Requirements"

11. HNP Technical Specifications

Table 5.1.2-1
Reactor Vessel Material Evaluation Data

Material Description			Chemical Composition/ Chemistry Factors			36 EFPY Fluence, n/cm^2					ART_{NDT}, F At 36 EFPY		Upper-Shelf Energy Decreases Applicable Through 36 EFPY		
Regulatory Guide 1.99, Revision 2, Position 1.1															
Reactor Vessel Beltline Region Matl.	Heat Number	Type	Cu (wt%)	Ni (wt%)	Chemistry Factor	Inside Surface	Clad/ Base Metal Interface	T/4 Location	3/4T Location	RT_{PTS} / Screening Criteria	T/4 Location	3/4T Location	Initial C_VUSE ft-lbs	Predicted C_VUSE Per R.G. 1.99/2 C_VUSE ft-lbs	% Decrease
Intermediate Shell (IS) Plate	A9153-1	SA-533 Gr. B1	0.09	0.46	58.0	4.651E19	4.590E19	2.835E19	1.119E19	174.3 / 270	168.1	153.8	83	63.9	23
Intermediate Shell (IS) Plate	B4197-2	SA-533 Gr. B1	0.09	0.50	58.0	4.651E19	4.590E19	2.835E19	1.119E19	205.3 / 270	199.1	184.8	71	(b)	(b)
Lower Shell (LS) Plate	C9924-1	SA-533 Gr. B1	0.08	0.47	51.0	4.517E19	4.463E19	2.753E19	1.086E19	158.3 / 270	152.8	140.2	98	76.8	21.6
Lower Shell (LS) Plate	C9924-2	SA-533 Gr. B1	0.08	0.47	51.0	4.517E19	4.463E19	2.753E19	1.086E19	161.3 / 270	155.8	143.2	88	69	21.6
IS Longit. Welds (Both 100%)	4P4784	Linde 124	0.05	0.91	68.0	1.817E19	1.801E19	1.108E19	4.370E18	114.9 / 270	106.0	84.8	94	75.7	19.5
IS to LS Circ. Weld (100%)	5P6771	Linde 124	0.03	0.94	41.0	4.457E19	4.398E19	2.717E19	1.072E19	92.4 / 300	83.8	63.6	80	(b)	(b)
LS Longit. Welds Both 100%)	4P4784	Linde 124	0.05	0.91	68.0	1.762E19	1.751E19	1.074E19	4.238E18	114.5 / 270	105.4	83.6	94	75.8	19.3
Regulatory Guide 1.99, Revision 2, Position 2.1 (Using Surveillance Data)															
Intermediate Shell (IS) Plate	B4197-2	SA-533 Gr. B1	0.09	0.50	51.4	4.651E19	4.590E19	2.835E19	1.119E19	[196.2][a] / 270	[190.6][a]	[178.0][a]	88	[54.4][a]	23.3
IS to LS Circ. Weld (100%)	5P6771	Linde 124	0.03	0.94	49.1	4.457E19	4.398E19	2.717E19	1.072E19	75.6 / 300	70.2	58.0	80	59.1	26.1

[a] [ ] – Controlling values of the ART_{NDT}'s, RT_{PTS} and EOL C_VUSE
[b] Calculated using surveillance data in accordance with R.G. 1.99, R2, Position 2.2

BAW-2355, Supplement 1
November 1999

Supplement to the Analysis of Capsule X Carolina Power & Light Company Shearon Harris Nuclear Power Plant

-- Reactor Vessel Material Surveillance Program --

by

M. J. DeVan
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FTI Document No. 77-2355-01
(See Section 6 for document signatures.)

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FRAMATOME TECHNOLOGIES

Executive Summary

This document supplements the FTI Document BAW-2355 and provides the evaluation of the implementation of a 4.5% (to 2900 MWt) power uprate for the Carolina Power and Light Company's (CP&L) Shearon Harris Nuclear Power Plant (HNP) reactor vessel commencing with Cycle 11. The purpose of this evaluation is to document the impact of the power uprate on the HNP reactor vessel surveillance program (RVSP). The fast neutron flux and neutron fluence projections have been calculated for the HNP reactor vessel beltline materials resulting from the implementation of the power uprate in the beginning of Cycle 11. Based on the power uprate calculated flux projections and a 90% capacity factor, the projected end-of-license (36 EFPY) peak fast fluence at the clad-base metal interface of the HNP reactor vessel is 4.590 x 10^{19} n/cm^2. Using the power uprate calculated fluence and flux projections, the withdrawal schedule for the remaining HNP surveillance capsules and the HNP reactor vessel fracture toughness properties have been evaluated.

In accordance with Code of Federal Regulations, Title 10, Part 50.61, (10 CFR 50.61), the HNP reactor vessel beltline materials will not exceed the pressurized thermal shock (PTS) screening criteria before end-of-license (36 EFPY) using the power uprate fluence projections. In addition, the upper-shelf energies of the HNP reactor vessel beltline materials are not predicted to fall below 50 ft-lb at end-of-license (36 EFPY) in accordance with Regulatory Guide 1.99, Revision 2, using the power uprate fluence projections.

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1. Introduction

BAW-2355[1] presents the results of the examination of the third capsule (Capsule X) of the Carolina Power and Light Company's (CP&L) Shearon Harris Nuclear Power Plant (HNP) as part of their reactor vessel surveillance program (RVSP). This supplementary document to BAW-2355 presents the evaluation of the implementation of a 4.5% (to 2900 MWt) power uprate for the HNP reactor vessel commencing with cycle 11.

The fast neutron flux and neutron fluence projections have been calculated for the HNP reactor vessel beltline materials resulting from the implementation of the power uprate in the beginning-of-cycle 11. Based on the HNP power uprate fluence projections, the withdrawal schedule for the remaining HNP surveillance capsules have been evaluated using approved procedures and established methods and techniques in accordance with the requirements of the Code of Federal Regulations, Title 10, Part 50, (10 CFR 50) Appendix H.[2] In addition, the HNP reactor vessel fracture toughness properties have been evaluated using established methods and techniques in accordance with the requirements of Regulatory Guide 1.99, Revision 2[3] and the Code of Federal Regulations, Title 10, Part 50.61 (10 CFR 50.61).[4]

2. Neutron Fluence

2.1. Background Discussion and Objectives

CP&L is implementing a power uprate of 4.5% (to 2900MWt) beginning in cycle 11 for HNP.

To increase power, it is necessary to place once-burned assemblies on or close to the core periphery. This generally results in an increase in the relative power in the peripheral assemblies, and therefore an increase in the fast leakage flux. The power uprate configuration will also result in changes to the thermal-hydraulic parameters of the primary coolant system, which causes an increase in water temperatures, and put fresh (unburned assemblies – one side) close to, or on the core periphery. Higher water temperatures result in a lower neutron thermalization rate, and thus an increase in the fast (E > 1.0 MeV) leakage flux. These increases in fast leakage flux result in increases in the fast fluence incident on the reactor vessel and on the surveillance capsule specimens.

The HNP will operate through 36 EFPY, and the uprate will begin with cycle 11. This means that well over half of the total 36 year fluence accumulation will occur in the post-uprate time frame.

The FTI calculational based fluence analysis methodology[5] was used to calculate the neutron fluence exposure to the pressure vessel. This methodology was developed through a full-scale benchmark experiment that was performed at the Davis-Besse Unit 1 reactor, and the methodology is described in detail in Appendix A. This analysis has been performed to obtain a realistic estimate of the increase in the end-of-license (EOL) vessel fluence that would result from implementation of the power uprate in the beginning-of-cycle 11 (BOC 11).

Explicit values of the fast flux and fluence (E > 1.0 MeV) were computed for the following locations:

- Vessel Inside Surface Maximum Location (wetted surface and base-metal inside surface)
- Circumferential Weld "AB"
- Longitudinal Welds: "BA", "BB", "BC", and "BD"
- ¼T, ½T, ¾T, and Outside Surface.

- Average Neutron Flux for Remaining Surveillance Capsules

The cycle 18 full power flux at each of these locations was calculated, and the corresponding fluence at each location was then calculated by computing the product of each flux by the appropriate effective full power time.

The calculated cycle 18 full power flux was used as the *"extrapolation flux"* since it is representative of the equilibrium cycle for power uprate conditions and is the flux used to project fluences for times beyond end-of-cycle 10 (EOC 10), reported in Tables 2-1 through 2-3.

2.2. Results

The numerical and graphical results are presented in the following Tables and Figures:

- Flux and fluence results at all points of interest in Tables 2-1 through 2-3
- Locations of flux peaks on the various welds and plates in Table 2-4
- Comparison of the cycle 1 to 10 flux to the power uprate flux
- Comparison of DORT Rθ and RZ source normalization factors
- Power uprate capsule flux and lead factor
- Pressure vessel flux profile for cycles 1 through 10 and the power uprate
- Comparison of the radial and relative radial RPDs
- Comparison of the axial and relative axial RPDs
- Azimuthal flux distributions for the IS of the barrel and the PV

In Table 2-2 and Table 2-3, the project fluences were calculated by

$$\phi t(T) = (\phi t)_{cycle1\text{-}8} + \left(\phi^{extrapolated}_{cycle9\text{-}10} \times t_{cycle9\text{-}10}\right) + \left(\phi^{extrapolated}_{cycle11\text{-}EOL} \times t_{cycle11\text{-}T}\right)$$

where

$\phi t(T)$	...	fluence at time T
$(\phi t)_{cycle1\text{-}8}$	...	cycle 1 to 8 fluence[1]
$\phi^{extrapolated}_{cycle9\text{-}10}$	...	extrapolated flux for cycles 9 and 10
$t_{cycle9\text{-}10}$	...	time for cycles 9 and 10
$\phi^{extrapolated}_{cycle11\text{-}EOL}$	...	extrapolated flux for cycles 11 to EOL
$t_{cycle11\text{-}T}$	...	time from BOC 11 to time T

The results of this analysis indicate that, for the analyzed configuration, the power uprate will not cause any significant increases in the EOL vessel fluence at any of the locations of interest (including welds). There are several parameters that affect the flux distribution that can be cycle specific, however, and this analysis only considered one configuration among many possible configurations. The design of future fuel cycles must consider the potential effects on the vessel fluence before they are implemented. This is particularly important in choosing the location of the fresh or once-burned assemblies on the periphery. If fresh or once-burned assemblies were placed on or close to the peak fluence location which deviated significantly from the peripheral power distribution analyzed for cycle 18, it is probable that the flux on the circumferential weld would increase significantly over the values determined in this analysis. The same is true for placing the assemblies close to 45 degrees, because the flux on the longitudinal welds would increase significantly. Since CP&L has stated that it intends to use fuel cycle designs similar to cycle 18 for future operations, it would not be expected that fresh assemblies would be placed at any location significantly different than those analyzed for cycle 18.

Table 2-1. Summary of Base Metal and Weld Metal Fast Flux Values at the HNP Reactor Vessel "Wetted" Inside Surface and Clad-Base Metal Interface

Weld/Shell	Type	Azimuthal Range (degrees)	Axial Location in R-Z Model (cm)[a]	Fast Neutron Flux E > 1.0 MeV (n/cm²/sec)
Welds at Clad-Base Metal Interface				
AB	Circumferential	0 to 45	221.9538	3.88741E+10
BC	Longitudinal	45	221.9538 to 458.2000	1.64523E+10
BD	Longitudinal	45	221.9538 to 458.2000	1.64523E+10
BA	Longitudinal	45	0 to 221.9538	1.59737E+10
BB	Longitudinal	45	0 to 221.9538	1.59737E+10
Welds at "Wetted" Inside Surface				
AB	Circumferential	0 to 45	221.9538	3.93976E+10
BC	Longitudinal	45	221.9538 to 458.2000	1.65991E+10
BD	Longitudinal	45	221.9538 to 458.2000	1.65991E+10
BA	Longitudinal	45	0 to 221.9538	1.60611E+10
BB	Longitudinal	45	0 to 221.9538	1.60611E+10
Plate at Clad-Base Metal Interface				
Intermediate	n/a	0 to 45	458.2000 to 221.9538	4.05768E+10
Lower	n/a	0 to 45	221.9538 to 0.0000	3.93785E+10
Plate at "Wetted" Inside Surface				
Intermediate	n/a	0 to 45	458.2000 to 221.9538	4.11140E+10
Lower	n/a	0 to 45	221.9538 to 0.0000	3.98297E+10
Vessel				
"Wetted" Surface	n/a	0 to 45	0.0000 to 458.2000	4.11140E+10
Clad-Base Metal Interface	n/a	0 to 45	0.0000 to 458.2000	4.05768E+10
¼T	n/a	0 to 45	0.0000 to 458.2000	2.35490E+10
½T	n/a	0 to 45	0.0000 to 458.2000	1.20059E+10
¾T	n/a	0 to 45	0.0000 to 458.2000	5.85809E+09
Outer Surface	n/a	0 to 45	0.0000 to 458.2000	2.56700E+09

[a] The origin of the DORT RZ coordinates is 227.51 cm below the core mid-plane.

Table 2-2. Fast Neutron Fluence (E > 1.0 MeV) for the HNP Reactor Vessel "Wetted" Inside Surface

Location	Cy9-10 Flux (n/cm^2-s)	Cy11-EOL Flux (n/cm^2-s)	FLUENCE (n/cm^2)					
			EOC 8	13 EFPY	14 EFPY	15 EFPY	16 EFPY	17 EFPY
Weld AB	3.891E+10	3.940E+10	1.160E+19	1.598E+19	1.722E+19	1.847E+19	1.971E+19	2.095E+19
Weld BC	1.479E+10	1.660E+10	4.407E+18	6.120E+18	6.644E+18	7.167E+18	7.691E+18	8.215E+18
Weld BD	1.479E+10	1.660E+10	4.407E+18	6.120E+18	6.644E+18	7.167E+18	7.691E+18	8.215E+18
Weld BA	1.441E+10	1.606E+10	4.295E+18	5.961E+18	6.468E+18	6.975E+18	7.482E+18	7.988E+18
Weld BB	1.441E+10	1.606E+10	4.295E+18	5.961E+18	6.468E+18	6.975E+18	7.482E+18	7.988E+18
Int Shell	4.058E+10	4.111E+10	1.210E+19	1.667E+19	1.796E+19	1.926E+19	2.056E+19	2.186E+19
Low Shell	3.961E+10	3.983E+10	1.181E+19	1.626E+19	1.751E+19	1.877E+19	2.003E+19	2.128E+19

Location	Cy9-10 Flux (n/cm^2-s)	Cy11-EOL Flux (n/cm^2-s)	FLUENCE (n/cm^2)					
			18 EFPY	19 EFPY	20 EFPY	21 EFPY	22 EFPY	23 EFPY
Weld AB	3.891E+10	3.940E+10	2.220E+19	2.344E+19	2.468E+19	2.593E+19	2.717E+19	2.841E+19
Weld BC	1.479E+10	1.660E+10	8.739E+18	9.263E+18	9.787E+18	1.031E+19	1.083E+19	1.136E+19
Weld BD	1.479E+10	1.660E+10	8.739E+18	9.263E+18	9.787E+18	1.031E+19	1.083E+19	1.136E+19
Weld BA	1.441E+10	1.606E+10	8.495E+18	9.002E+18	9.509E+18	1.002E+19	1.052E+19	1.103E+19
Weld BB	1.441E+10	1.606E+10	8.495E+18	9.002E+18	9.509E+18	1.002E+19	1.052E+19	1.103E+19
Int Shell	4.058E+10	4.111E+10	2.315E+19	2.445E+19	2.575E+19	2.704E+19	2.834E+19	2.964E+19
Low Shell	3.961E+10	3.983E+10	2.254E+19	2.380E+19	2.506E+19	2.631E+19	2.757E+19	2.883E+19

Location	Cy9-10 Flux (n/cm^2-s)	Cy11-EOL Flux (n/cm^2-s)	FLUENCE (n/cm^2)		
			24 EFPY	25 EFPY	36 EFPY
Weld AB	3.891E+10	3.940E+10	2.966E+19	3.090E+19	4.457E+19
Weld BC	1.479E+10	1.660E+10	1.188E+19	1.241E+19	1.817E+19
Weld BD	1.479E+10	1.660E+10	1.188E+19	1.241E+19	1.817E+19
Weld BA	1.441E+10	1.606E+10	1.154E+19	1.204E+19	1.762E+19
Weld BB	1.441E+10	1.606E+10	1.154E+19	1.204E+19	1.762E+19
Int Shell	4.058E+10	4.111E+10	3.094E+19	3.223E+19	4.651E+19
Low Shell	3.961E+10	3.983E+10	3.008E+19	3.134E+19	4.517E+19

Table 2-3. Fast Neutron Fluence (E > 1.0 MeV) for the HNP Reactor Vessel Clad-Base Metal Interface

Location	Cy9-10 Flux (n/cm^2-s)	Cy11-EOL Flux (n/cm^2-s)	FLUENCE (n/cm^2)					
			EOC 8	13 EFPY	14 EFPY	15 EFPY	16 EFPY	17 EFPY
Weld AB	3.840E+10	3.887E+10	1.144E+19	1.577E+19	1.699E+19	1.822E+19	1.945E+19	2.067E+19
Weld BC	1.465E+10	1.645E+10	4.366E+18	6.064E+18	6.583E+18	7.102E+18	7.622E+18	8.141E+18
Weld BD	1.465E+10	1.645E+10	4.366E+18	6.064E+18	6.583E+18	7.102E+18	7.622E+18	8.141E+18
Weld BA	1.430E+10	1.597E+10	4.263E+18	5.917E+18	6.421E+18	6.925E+18	7.429E+18	7.934E+18
Weld BB	1.430E+10	1.597E+10	4.263E+18	5.917E+18	6.421E+18	6.925E+18	7.429E+18	7.934E+18
Int Shell	4.006E+10	4.058E+10	1.194E+19	1.645E+19	1.773E+19	1.901E+19	2.029E+19	2.157E+19
Low Shell	3.909E+10	3.938E+10	1.165E+19	1.605E+19	1.729E+19	1.853E+19	1.977E+19	2.102E+19
IS Max	4.006E+10	4.058E+10	1.194E+19	1.645E+19	1.773E+19	1.901E+19	2.029E+19	2.157E+19
1/4T	2.321E+10	2.355E+10	6.918E+18	9.533E+18	1.028E+19	1.102E+19	1.176E+19	1.251E+19
1/2T	1.182E+10	1.201E+10	3.522E+18	4.854E+18	5.233E+18	5.612E+18	5.991E+18	6.370E+18
3/4T	5.750E+09	5.858E+09	1.714E+18	2.362E+18	2.547E+18	2.732E+18	2.917E+18	3.102E+18
Outside Surf	2.496E+09	2.567E+09	7.439E+17	1.026E+18	1.107E+18	1.188E+18	1.269E+18	1.350E+18

Location	Cy9-10 Flux (n/cm^2-s)	Cy11-EOL Flux (n/cm^2-s)	FLUENCE (n/cm^2)					
			18 EFPY	19 EFPY	20 EFPY	21 EFPY	22 EFPY	23 EFPY
Weld AB	3.840E+10	3.887E+10	2.190E+19	2.313E+19	2.435E+19	2.558E+19	2.681E+19	2.803E+19
Weld BC	1.465E+10	1.645E+10	8.660E+18	9.179E+18	9.698E+18	1.022E+19	1.074E+19	1.126E+19
Weld BD	1.465E+10	1.645E+10	8.660E+18	9.179E+18	9.698E+18	1.022E+19	1.074E+19	1.126E+19
Weld BA	1.430E+10	1.597E+10	8.438E+18	8.942E+18	9.446E+18	9.950E+18	1.045E+19	1.096E+19
Weld BB	1.430E+10	1.597E+10	8.438E+18	8.942E+18	9.446E+18	9.950E+18	1.045E+19	1.096E+19
Int Shell	4.006E+10	4.058E+10	2.285E+19	2.413E+19	2.541E+19	2.669E+19	2.798E+19	2.926E+19
Low Shell	3.909E+10	3.938E+10	2.226E+19	2.350E+19	2.475E+19	2.599E+19	2.723E+19	2.847E+19
IS Max	4.006E+10	4.058E+10	2.285E+19	2.413E+19	2.541E+19	2.669E+19	2.798E+19	2.926E+19
1/4T	2.321E+10	2.355E+10	1.325E+19	1.399E+19	1.473E+19	1.548E+19	1.622E+19	1.696E+19
1/2T	1.182E+10	1.201E+10	6.749E+18	7.128E+18	7.506E+18	7.885E+18	8.264E+18	8.643E+18
3/4T	5.750E+09	5.858E+09	3.287E+18	3.472E+18	3.656E+18	3.841E+18	4.026E+18	4.211E+18
Outside Surf	2.496E+09	2.567E+09	1.431E+18	1.512E+18	1.593E+18	1.674E+18	1.755E+18	1.836E+18

Table 2-3. (cont.) Fast Neutron Fluence (E > 1.0 MeV) for the HNP Reactor Vessel Clad-Base Metal Interface

Location	Cy9-10 Flux (n/cm^2-s)	Cy11-EOL Flux (n/cm^2-s)	FLUENCE (n/cm^2)		
			24 EFPY	25 EFPY	36 EFPY
Weld AB	3.840E+10	3.887E+10	2.926E+19	3.049E+19	4.398E+19
Weld BC	1.465E+10	1.645E+10	1.178E+19	1.229E+19	1.801E+19
Weld BD	1.465E+10	1.645E+10	1.178E+19	1.229E+19	1.801E+19
Weld BA	1.430E+10	1.597E+10	1.146E+19	1.197E+19	1.751E+19
Weld BB	1.430E+10	1.597E+10	1.146E+19	1.197E+19	1.751E+19
Int Shell	4.006E+10	4.058E+10	3.054E+19	3.182E+19	4.590E+19
Low Shell	3.909E+10	3.938E+10	2.972E+19	3.096E+19	4.463E+19
IS Max	4.006E+10	4.058E+10	3.054E+19	3.182E+19	4.590E+19
1/4T	2.321E+10	2.355E+10	1.771E+19	1.845E+19	2.663E+19
1/2T	1.182E+10	1.201E+10	9.022E+18	9.401E+18	1.357E+19
3/4T	5.750E+09	5.858E+09	4.396E+18	4.581E+18	6.614E+18
Outside Surf	2.496E+09	2.567E+09	1.917E+18	1.998E+18	2.889E+18

Table 2-4. Peak Fast Flux Locations of Welds and Plates

Weld or Plate	Peak Location (cm)		
	Radial (cm)	Azimuthal (degrees)	Axial[a] (cm)
AB	199.7075	0	177.3238
BC & BD	199.7075	45	188.9515
BA & BB	199.7075	45	145.4585
Intermediate Plate	199.7075	0	188.9515
Lower Plate	199.7075	0	145.4585

[a] Relative to the lower active fuel elevation

Table 2-5. Comparison of HNP Power Uprate Fluxes

Location	PVIS Ratio (Uprate / Cy 1-10)	Clad IS Ratio (Uprate / Cy 1-10)
Weld		
AB	1.012	1.012
BC	1.123	1.123
BD	1.123	1.123
BA	1.117	1.115
BB	1.117	1.115
Plate		
Intermediate	1.013	1.013
Lower	1.007	1.006
Vessel		
Inner wetted surface	1.013	-
Clad-base metal interface	1.013	-
¼T	1.015	-
½T	1.016	-
¾T	1.019	-
Outer surface	1.028	-

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Table 2-6. Comparison of DORT Source Normalization Factors

DORT Model	Source Normalization Factor		Ratio (Uprate / Cycles 1-8)
	Cycles 1-10	Uprate	
Rθ	7.65504E+16	7.97087E+16	1.04126
RZ	2.23933E+20	2.33047E+20	1.04070

Table 2-7. HNP 110° Capsule Flux and Lead Factor

110° Capsule Average Neutron Flux (E > 1.0 MeV)	1.90×10^{11} n/cm^2-s
PVIS Maximum Neutron Flux (E > 1.0 MeV)	4.11×10^{10} n/cm^2-s
Lead Factor (110° Location to I. S. Maximum Location)	4.62

Figure 2-1. Fast Flux Profile for HNP Cycles 1 to 10

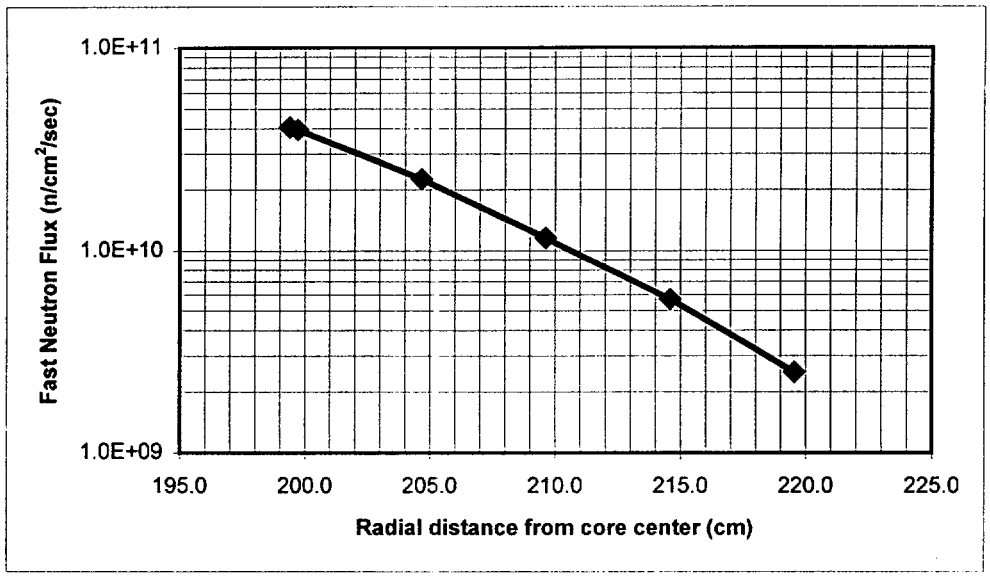

Figure 2-2. Fast Flux Profile for HNP Power Uprate

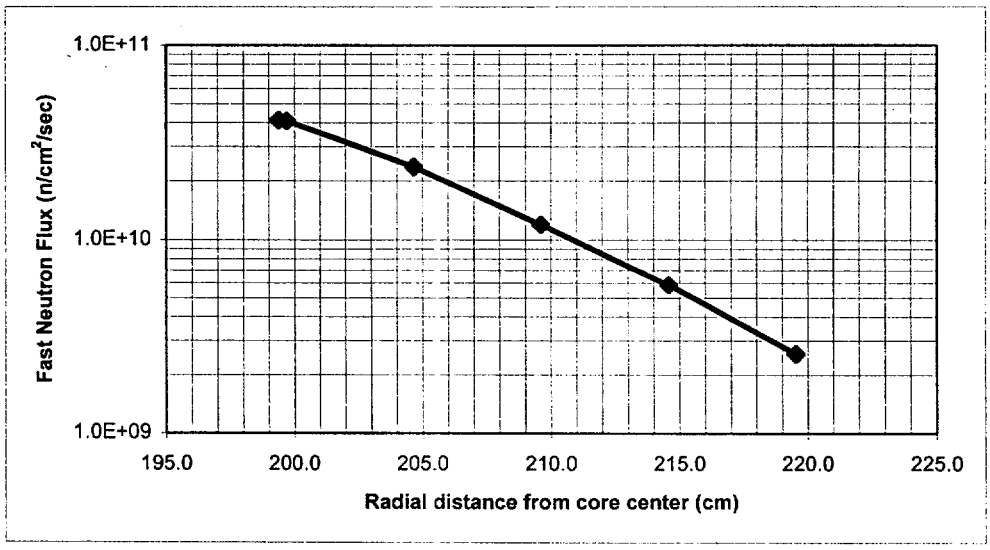

Figure 2-3. Comparison of RZ Radial Sources

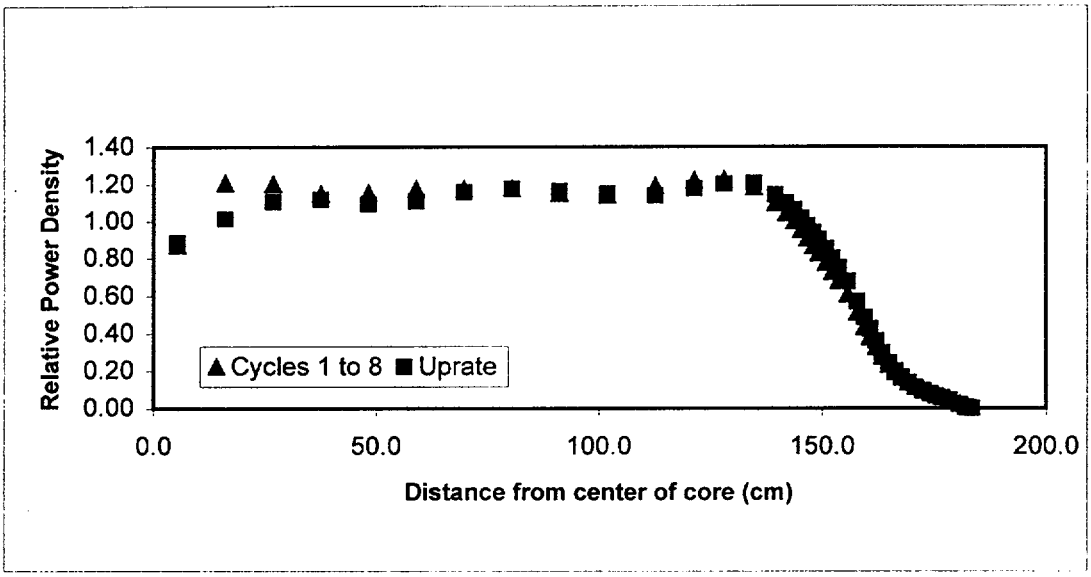

Figure 2-4. Comparison of Relative Radial RPDs

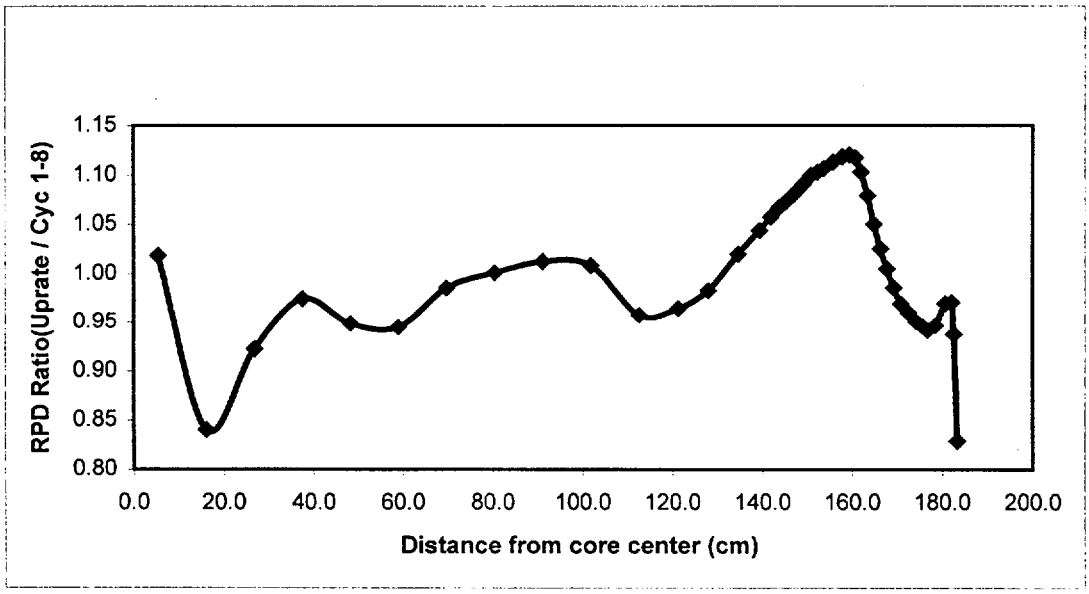

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Figure 2-5. Comparison of Axial RPDs

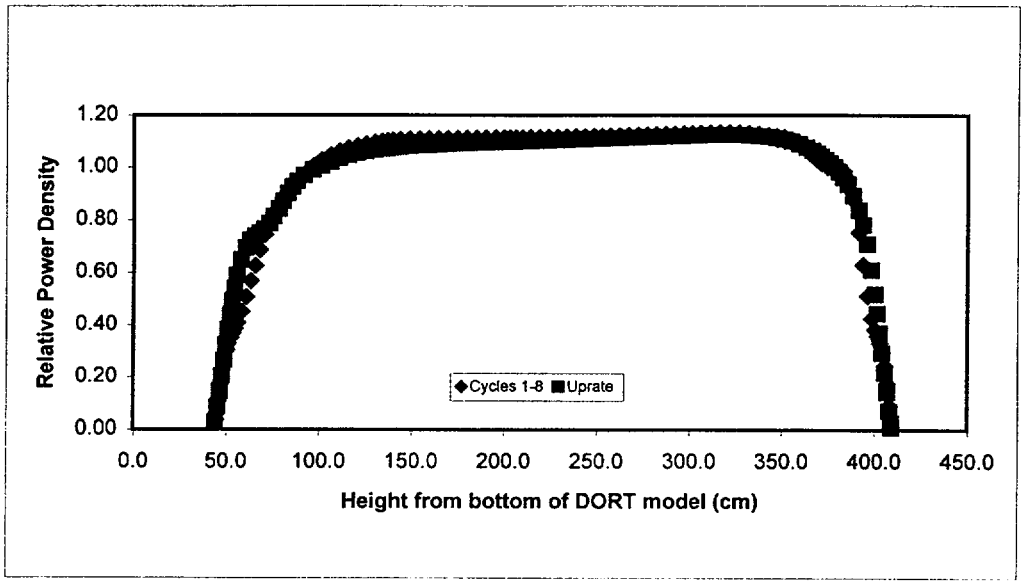

Figure 2-6. Comparison of Relative Axial RPDs

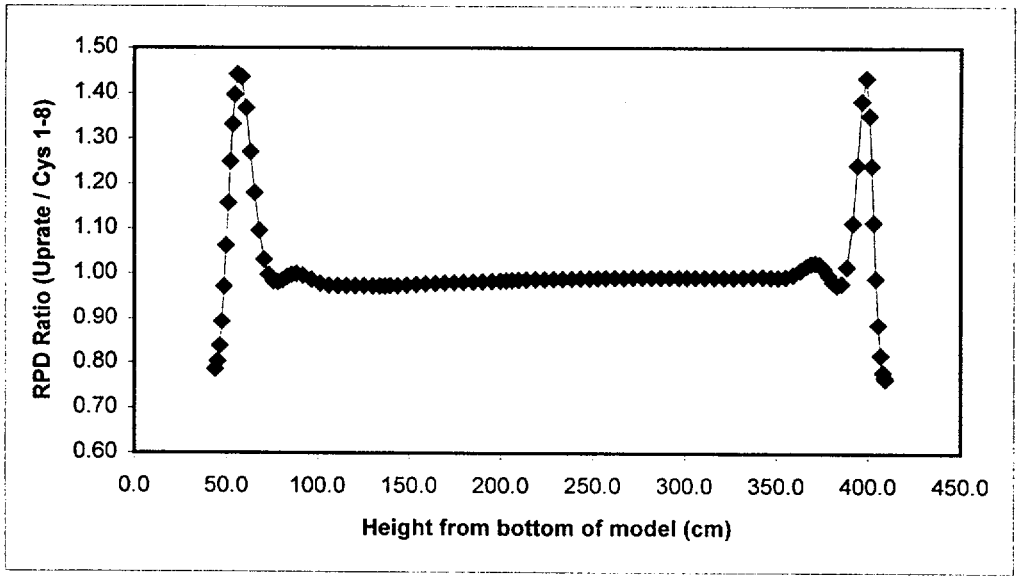

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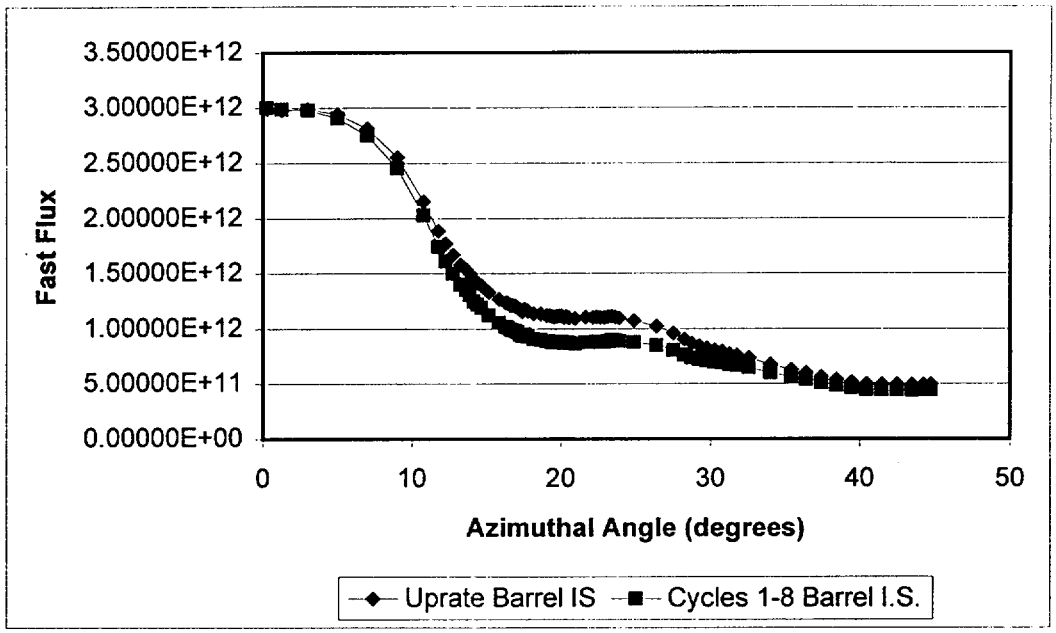
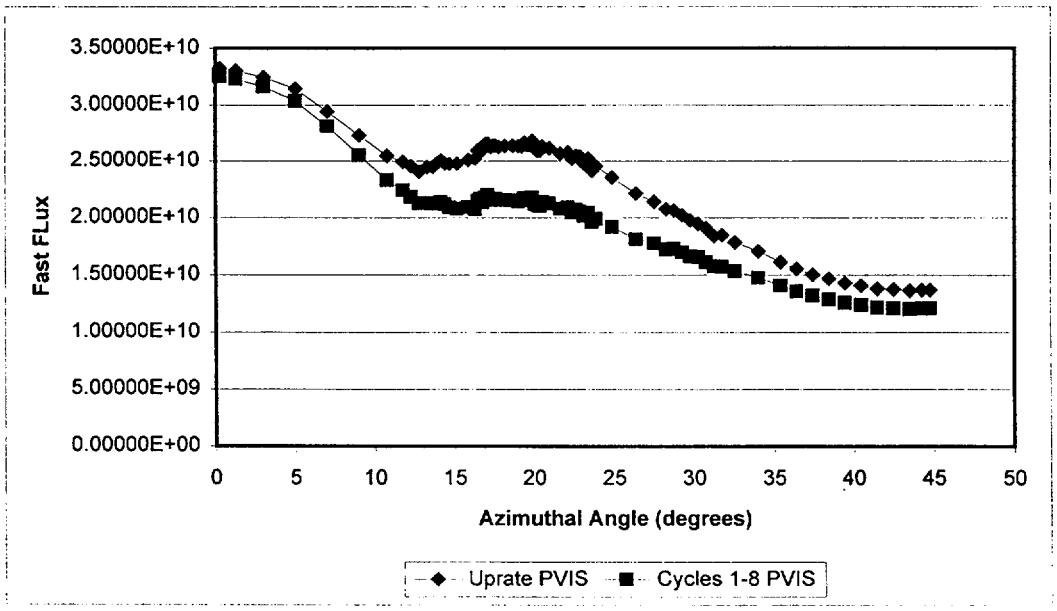
Figure 2-7. Azimuthal Flux Distribution for Core Barrel Inside Surface



Note: Flux values presented do not represent the profile at the elevation of the peak flux.

Figure 2-8. Azimuthal Flux Distribution for HNP Reactor Pressure Vessel "Wetted' Inside Surface (PVIS)



Note: Flux values presented do not represent the profile at the elevation of the peak flux.

3. Reactor Vessel Fracture Toughness

3.1. Adjusted Reference Temperature Evaluation

The adjusted reference temperatures for the HNP reactor vessel beltline region materials are calculated in accordance with Regulatory Guide 1.99, Revision 2. The adjusted reference temperatures are calculated by adding the initial RT_{NDT}, the predicted radiation-induced ΔRT_{NDT}, and the a margin term to cover the uncertainties in the values of initial RT_{NDT}, copper and nickel contents, fluence, and the calculational procedures. The predicted radiation induced ΔRT_{NDT} is calculated using the respective reactor vessel beltline materials copper and nickel contents and the neutron fluence applicable to 13 through 25 and 36 effective full power years (EFPY). The supporting information for the calculated neutron fluence at the "wetted" inside surface of each reactor vessel beltline material location is described in Section 2. The neutron fluence at the ¼-thickness (¼T) and ¾-thickness (¾T) wall location for each beltline material is determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., ¼T = [7.75*0.25]+0.125 = 2.0625 inches and ¾T = [7.75*0.75]+0.125 = 5.9375 inches).[6]

The evaluations for the HNP adjusted reference temperatures were performed at the ¼T and ¾T wall location of each beltline material with chemistry factors determined from Tables 1 and 2 in Regulatory Guide 1.99, Revision 2. In addition, the chemistry factors for the intermediate shell plate, heat no. B4197-2, and the intermediate shell to lower shell circumferential weld are recalculated using the available HNP surveillance data.

The ¼T and ¾T adjusted reference temperature results for the HNP reactor vessel beltline region materials applicable to 13 through 25 and 36 EFPY are presented in Tables 3-1 through 3-14. Based on these results, the controlling beltline material for the HNP reactor vessel is the intermediate shell plate, heat no. B4197-2.

3.2. Decrease in Upper-Shelf Energy Evaluation

An evaluation of the reactor vessel end-of-license (36 EFPY) upper-shelf energy at the ¼T wall location for the HNP reactor vessel beltline materials was performed using the guidelines in Regulatory Guide 1.99, Revision 2. The supporting information for the calculated neutron

fluence at the "wetted" inside surface of each reactor vessel beltline material location is described in Section 2. The neutron fluence at the ¼T wall location for each beltline material is determined by calculating the ¼T depth into the vessel and adding the minimum cladding thickness (i.e., ¼T = [7.75*0.25]+0.125 = 2.0625 inches).[6]

The evaluations for the decreases in upper-shelf energies of the HNP reactor vessel were performed at the ¼T wall location of each beltline material using the respective copper contents and Figure 2 in Regulatory Guide 1.99, Revision 2. In addition, the decreases in upper-shelf energy for the intermediate shell plate, heat no. B4197-2, and the intermediate shell to lower shell circumferential weld are recalculated using the available HNP surveillance data.

The decreases in upper-shelf energy for the HNP reactor vessel beltline materials applicable to end-of-license (36 EFPY) are presented in Table 3-15. The HNP reactor vessel beltline material with the lowest predicted upper-shelf energy is the intermediate shell plate, heat no. B4197-2, however, the predicted value for this material will not fall below the required 50 ft-lb limit.

3.3. Pressurized Thermal Shock Evaluation

A pressurized thermal shock (PTS) evaluation for the HNP reactor vessel beltline materials was performed in accordance with Code of Federal Regulation, Title 10, Part 50.61 (10 CFR 50.61). The PTS reference temperature (RT_{PTS}) values are calculated by adding the initial RT_{NDT}, the predicted radiation-induced ΔRT_{NDT}, and the a margin term to cover the uncertainties in the values of initial RT_{NDT}, copper and nickel contents, fluence, and the calculational procedures. The predicted radiation induced ΔRT_{NDT} is calculated using the respective reactor vessel beltline materials copper and nickel contents and the neutron fluence applicable to the HNP reactor vessel end-of-license (36 EFPY). The supporting information for the calculated neutron fluence at the clad-base metal interface on the inside surface of the reactor vessel beltline where the material in question receives the highest fluence is described in Section 2.

The evaluations for the HNP RT_{PTS} values were performed for each HNP reactor vessel beltline material with chemistry factors determined from Tables 1 and 2 in 10 CFR 50.61. In addition, the chemistry factors for the intermediate shell plate, heat no. B4197-2, and the intermediate shell to lower shell circumferential weld are recalculated using the available HNP surveillance data.

The RT_{PTS} values for the HNP reactor vessel beltline materials at end-of-license (36 EFPY) are shown in Table 3-16. The results of the PTS evaluation demonstrate that the HNP reactor vessel beltline materials will not exceed the PTS screening criteria before end-of-license (36 EFPY). The controlling beltline material for the HNP reactor vessel with respect to PTS is the intermediate shell plate, heat no. B4197-2 with a RT_{PTS} value of 196.2°F which is well below the PTS screening criterion of 270°F.

Table 3-1. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 13 EFPY

Material Description[a]				Chemical Composition[a]				13 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 13 EFPY		Margin		ART, F at 13 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	1.667E19	1.016E19	4.009E18	58.2	43.3	34.0	34.0	152.2	137.3
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	1.667E19	1.016E19	4.009E18	58.2	43.3	34.0	34.0	183.2	168.3
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	1.626E19	9.912E18	3.911E18	50.9	37.7	34.0	34.0	138.9	125.7
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	1.626E19	9.912E18	3.911E18	50.9	37.7	34.0	34.0	141.9	128.7
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	6.120E18	3.731E18	1.472E18	49.4	33.9	49.4	33.9	78.8	47.8
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	1.598E19	9.741E18	3.843E18	40.7	30.1	40.7	30.1	61.4	40.2
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	5.961E18	3.634E18	1.434E18	49.0	33.5	49.0	33.5	78.0	47.0
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	1.667E19	1.016E19	4.009E18	51.6	38.4	34.0[c]	34.0[c]	[176.6]	[163.4]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	1.598E19	9.741E18	3.843E18	48.8	36.1	28.0	28.0	56.8	44.1

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-2. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 14 EFPY

Material Description[a]				Chemical Composition[a]				14 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 14 EFPY		Margin		ART, F at 14 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	1.796E19	1.095E19	4.320E18	59.5	44.5	34.0	34.0	153.5	138.5
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	1.796E19	1.095E19	4.320E18	59.5	44.5	34.0	34.0	184.5	169.5
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	1.751E19	1.067E19	4.211E18	51.9	38.8	34.0	34.0	139.9	126.8
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	1.751E19	1.067E19	4.211E18	51.9	38.8	34.0	34.0	142.9	129.8
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	6.644E18	4.050E18	1.598E18	50.9	35.2	50.9	35.2	81.8	50.4
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	1.722E19	1.050E19	4.142E18	41.6	31.0	41.6	31.0	63.2	42.0
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	6.468E18	3.943E19	1.556E18	50.5	34.7	50.5	34.7	81.0	49.4
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	1.796E19	1.095E19	4.320E18	52.7	39.4	34.0[c]	34.0[c]	[177.7]	[164.4]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	1.722E19	1.050E19	4.142E18	49.8	37.1	28.0	28.0	57.8	45.1

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-3. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 15 EFPY

Material Description[a]				Chemical Composition[a]				15 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 15 EFPY		Margin		ART, F at 15 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	1.926E19	1.174E19	4.632E18	60.6	45.6	34.0	34.0	154.6	139.6
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	1.926E19	1.174E19	4.632E18	60.6	45.6	34.0	34.0	185.6	170.6
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	1.877E19	1.144E19	4.514E18	52.9	39.7	34.0	34.0	140.9	127.7
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	1.877E19	1.144E19	4.514E18	52.9	39.7	34.0	34.0	143.9	130.7
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	7.167E18	4.369E18	1.724E18	52.4	36.3	52.4	36.3	84.8	52.6
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	1.847E19	1.126E19	4.442E18	42.4	31.7	42.4	31.7	64.8	43.4
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	6.975E18	4.252E18	1.678E18	51.8	35.9	51.8	35.9	83.6	51.8
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	1.926E19	1.174E19	4.632E18	53.7	40.4	34.0[c]	34.0[c]	[178.7]	[165.4]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	1.847E19	1.126E19	4.442E18	50.7	38.0	28.0	28.0	58.7	46.0

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-4. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 16 EFPY

Material Description[a]				Chemical Composition[a]				16 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 16 EFPY		Margin		ART, F at 16 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.056E19	1.253E19	4.945E18	61.7	46.6	34.0	34.0	155.7	140.6
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.056E19	1.253E19	4.945E18	61.7	46.6	34.0	34.0	186.7	171.6
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.003E19	1.221E19	4.817E18	53.9	40.6	34.0	34.0	141.9	128.6
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.003E19	1.221E19	4.817E18	53.9	40.6	34.0	34.0	144.9	131.6
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	7.691E18	4.688E18	1.850E18	53.7	37.5	53.7	37.5	87.4	55.0
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	1.971E19	1.201E19	4.740E18	43.1	32.5	43.1	32.5	66.2	45.0
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	7.482E18	4.561E18	1.799E18	53.1	37.0	53.1	37.0	86.2	54.0
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.056E19	1.253E19	4.945E18	54.6	41.3	34.0[c]	34.0[c]	[179.6]	[166.3]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	1.971E19	1.201E19	4.740E18	51.6	38.9	28.0	28.0	59.6	46.9

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-5. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 17 EFPY

Material Description[a]				Chemical Composition[a]				17 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 17 EFPY		Margin		ART, F at 17 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.186E19	1.333E19	5.258E18	62.6	47.6	34.0	34.0	156.6	141.6
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.186E19	1.333E19	5.258E18	62.6	47.6	34.0	34.0	187.6	172.6
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.128E19	1.297E19	5.118E18	54.7	41.5	34.0	34.0	142.7	129.5
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.128E19	1.297E19	5.118E18	54.7	41.5	34.0	34.0	145.7	132.5
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	8.215E18	5.008E18	1.976E18	54.9	38.6	54.9	38.6	89.8	57.2
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.095E19	1.277E19	5.039E18	43.8	33.2	43.8	33.2	67.6	46.4
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	7.988E18	4.869E18	1.921E18	54.3	38.1	54.3	38.1	88.6	56.2
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.186E19	1.333E19	5.258E18	55.5	42.1	34.0[c]	34.0[c]	[180.5]	[167.1]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.095E19	1.277E19	5.039E18	52.4	39.7	28.0	28.0	60.4	47.7

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-6. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 18 EFPY

Material Description[a]				Chemical Composition[a]				18 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 18 EFPY		Margin		ART, F at 18 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.315E19	1.411E19	5.568E18	63.6	48.5	34.0	34.0	157.6	142.5
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.315E19	1.411E19	5.568E18	63.6	48.5	34.0	34.0	188.6	173.5
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.254E19	1.374E19	5.421E18	55.5	42.3	34.0	34.0	143.5	130.3
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.254E19	1.374E19	5.421E18	55.5	42.3	34.0	34.0	146.5	133.3
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	8.739E18	5.327E18	2.102E18	56.0	39.5	56.0	39.5	92.0	59.0
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.220E19	1.353E19	5.339E18	44.4	33.8	44.4	33.8	68.8	47.6
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	8.495E18	5.178E18	2.043E18	55.5	39.1	55.5	39.1	91.0	58.2
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.315E19	1.411E19	5.568E18	56.3	43.0	34.0[c]	34.0[c]	[181.3]	[168.0]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.220E19	1.353E19	5.339E18	53.2	40.5	28.0	28.0	61.2	48.5

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-7. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 19 EFPY

Material Description[a]				Chemical Composition[a]				19 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 19 EFPY		Margin		ART, F at 19 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.445E19	1.490E19	5.880E18	64.4	49.4	34.0	34.0	158.4	143.4
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.445E19	1.490E19	5.880E18	64.4	49.4	34.0	34.0	189.4	174.4
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.380E19	1.451E19	5.724E18	56.3	43.0	34.0	34.0	144.3	131.0
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.380E19	1.451E19	5.724E18	56.3	43.0	34.0	34.0	147.3	134.0
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	9.263E18	5.646E18	2.228E18	57.1	40.5	56.0	40.5	93.1	61.0
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.344E19	1.429E19	5.638E18	45.1	34.4	45.1	34.4	70.2	48.8
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	9.002E18	5.487E18	2.165E18	56.6	40.1	56.0	40.1	92.6	60.2
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.445E19	1.490E19	5.880E18	57.1	43.7	34.0[c]	34.0[c]	[182.1]	[168.7]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.344E19	1.429E19	5.638E18	54.0	41.2	28.0	28.0	62.0	49.2

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-8. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 20 EFPY

Material Description[a]				Chemical Composition[a]				20 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 20 EFPY		Margin		ART, F at 20 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.575E19	1.570E19	6.193E18	65.3	50.2	34.0	34.0	159.3	144.2
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.575E19	1.570E19	6.193E18	65.3	50.2	34.0	34.0	190.3	175.2
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.506E19	1.528E19	6.027E18	57.0	43.8	34.0	34.0	145.0	131.8
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.506E19	1.528E19	6.027E18	57.0	43.8	34.0	34.0	148.0	134.8
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	9.787E18	5.966E18	2.354E18	58.1	41.4	56.0	41.4	94.1	62.8
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.468E19	1.504E19	5.936E18	45.6	35.0	45.6	35.0	71.2	50.0
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	9.509E18	5.796E18	2.287E18	57.6	40.9	56.0	40.9	93.6	61.8
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.575E19	1.570E19	6.193E18	57.8	44.5	34.0[c]	34.0[c]	[182.8]	[169.5]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.468E19	1.504E19	5.936E18	54.6	41.9	28.0	28.0	62.6	49.9

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-9. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 21 EFPY

Material Description[a]				Chemical Composition[a]				21 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 21 EFPY		Margin		ART, F at 21 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.704E19	1.648E19	6.503E18	66.0	51.0	34.0	34.0	160.0	145.0
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.704E19	1.648E19	6.503E18	66.0	51.0	34.0	34.0	191.0	176.0
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.631E19	1.604E19	6.328E18	57.6	44.5	34.0	34.0	145.6	132.5
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.631E19	1.604E19	6.328E18	57.6	44.5	34.0	34.0	148.6	135.5
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.031E19	6.285E18	2.480E18	59.2	42.3	56.0	42.3	95.2	64.6
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.593E19	1.581E19	6.236E18	46.2	35.6	46.2	35.6	72.4	51.2
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.002E19	6.108E18	2.410E18	58.6	41.8	56.0	41.8	94.6	63.6
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.704E19	1.648E19	6.503E18	58.5	45.2	34.0[c]	34.0[c]	[183.5]	[170.2]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.593E19	1.581E19	6.236E18	55.3	42.6	28.0	28.0	63.3	50.6

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-10. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 22 EFPY

Material Description[a]				Chemical Composition[a]		Initial RT_{NDT}[a]	Chemistry Factor	22 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 22 EFPY		Margin		ART, F at 22 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%			Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.834E19	1.728E19	6.816E18	66.7	51.8	34.0	34.0	160.7	145.8
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.834E19	1.728E19	6.816E18	66.7	51.8	34.0	34.0	191.7	176.8
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.757E19	1.681E19	6.631E18	58.3	45.1	34.0	34.0	146.3	133.1
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.757E19	1.681E19	6.631E18	58.3	45.1	34.0	34.0	149.3	136.1
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.083E19	6.602E18	2.605E18	60.1	43.1	56.0	43.1	96.1	66.2
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.717E19	1.656E19	6.535E18	46.7	36.1	46.7	36.1	73.4	52.2
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.052E19	6.413E18	2.530E18	59.5	42.6	56.0	42.6	95.5	65.2
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.834E19	1.728E19	6.816E18	59.1	45.9	34.0[c]	34.0[c]	[184.1]	[170.9]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.717E19	1.656E19	6.535E18	55.9	43.3	28.0	28.0	63.9	51.3

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-11. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 23 EFPY

Material Description[a]				Chemical Composition[a]				23 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 23 EFPY		Margin		ART, F at 23 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	2.964E19	1.807E19	7.129E18	67.4	52.5	34.0	34.0	161.4	146.5
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	2.964E19	1.807E19	7.129E18	67.4	52.5	34.0	34.0	192.4	177.5
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	2.883E19	1.757E19	6.934E18	58.9	45.7	34.0	34.0	146.9	133.7
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	2.883E19	1.757E19	6.934E18	58.9	45.7	34.0	34.0	149.9	136.7
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.136E19	6.925E18	2.732E18	61.0	43.9	56.0	43.9	97.0	67.8
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.841E19	1.732E19	6.833E18	47.2	36.6	47.2	36.6	74.4	53.2
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.103E19	6.724E18	2.653E18	60.5	43.5	56.0	43.5	96.5	67.0
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	2.964E19	1.807E19	7.129E18	59.7	46.5	34.0[c]	34.0[c]	[184.7]	[171.5]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.841E19	1.732E19	6.833E18	56.5	43.8	28.0	28.0	64.5	51.8

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-12. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 24 EFPY

Material Description[a]				Chemical Composition[a]				24 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 24 EFPY		Margin		ART, F at 24 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	3.094E19	1.886E19	7.441E18	68.1	53.2	34.0	34.0	162.1	147.2
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	3.094E19	1.886E19	7.441E18	68.1	53.2	34.0	34.0	193.1	178.2
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	3.008E19	1.834E19	7.234E18	59.5	46.4	34.0	34.0	147.5	134.4
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	3.008E19	1.834E19	7.234E18	59.5	46.4	34.0	34.0	150.5	137.4
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.188E19	7.242E18	2.857E18	61.8	44.7	56.0	44.7	97.8	69.4
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	2.966E19	1.808E19	7.133E18	47.7	37.1	47.7	37.1	75.4	54.2
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.154E19	7.034E18	2.775E18	61.3	44.2	56.0	44.2	97.3	68.4
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	3.094E19	1.886E19	7.441E18	60.3	47.1	34.0[c]	34.0[c]	[185.3]	[172.1]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	2.966E19	1.808E19	7.133E18	57.1	44.4	28.0	28.0	65.1	52.4

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-13. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 25 EFPY

Material Description[a]				Chemical Composition[a]		Initial RT_{NDT}[a]	Chemistry Factor	25 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 25 EFPY		Margin		ART, F at 25 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%			Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	3.223E19	1.965E19	7.752E18	68.7	53.9	34.0	34.0	162.7	147.9
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	3.223E19	1.965E19	7.752E18	68.7	53.9	34.0	34.0	193.7	178.9
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	3.134E19	1.910E19	7.538E18	60.0	47.0	34.0	34.0	148.0	135.0
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	3.134E19	1.910E19	7.538E18	60.0	47.0	34.0	34.0	151.0	138.0
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.241E19	7.565E18	2.985E18	62.7	45.5	56.0	45.5	98.7	71.0
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	3.090E19	1.884E19	7.432E18	48.1	37.6	48.1	37.6	76.2	55.2
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.204E19	7.339E18	2.896E18	62.1	44.9	56.0	44.9	98.1	69.8
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	3.223E19	1.965E19	7.752E18	60.9	47.8	34.0[c]	34.0[c]	[185.9]	[172.8]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	3.090E19	1.884E19	7.432E18	57.6	45.0	28.0	28.0	65.6	53.0

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-14. Adjusted Reference Temperature Evaluation for the HNP Reactor Vessel Beltline Materials at the ¼-Thickness and ¾-Thickness Locations Applicable Through 36 EFPY

Material Description[a]				Chemical Composition[a]				36 EFPY Fluence, n/cm²			ΔRT_{NDT}, F at 36 EFPY		Margin		ART, F at 36 EFPY	
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}[a]	Chemistry Factor	Inside Surface	T/4 Location[b]	3/4T Location[b]	T/4 Location	3/4T Location	T/4 Location	3/4T Location	T/4 Location	3/4T Location
Regulatory Guide 1.99, Revision 2, Position 1.1																
Intermediate Shell Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	+60	58.0	4.651E19	2.835E19	1.119E19	74.1	59.8	34.0	34.0	168.1	153.8
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	58.0	4.651E19	2.835E19	1.119E19	74.1	59.8	34.0	34.0	199.1	184.8
Lower Shell Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	+54	51.0	4.517E19	2.753E19	1.086E19	64.8	52.2	34.0	34.0	152.8	140.2
Lower Shell Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	+57	51.0	4.517E19	2.753E19	1.086E19	64.8	52.2	34.0	34.0	155.8	143.2
IS Longit. Welds (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.817E19	1.108E19	4.370E18	70.0	52.4	56.0	52.4	106.0	84.8
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	41.0	4.457E19	2.717E19	1.072E19	51.9	41.8	51.9	41.8	83.8	63.6
LS Longit. Welds (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	0.91	-20	68.0	1.762E19	1.074E19	4.238E18	69.4	51.8	56.0	51.8	105.4	83.6
Regulatory Guide 1.99, Revision 2, Position 2.1																
Intermediate Shell Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	+91	51.4	4.651E19	2.835E19	1.119E19	65.6	53.0	34.0[c]	34.0[c]	[190.6]	[178.0]
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	0.94	-20	49.1	4.457E19	2.717E19	1.072E19	62.2	50.0	28.0	28.0	70.2	58.0

(a) See BAW-2355.[1]

(b) Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T and ¾T location fluence values are determined by calculating the ¼T and ¾T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in. and "x" for ¾T = 5.9375 in.).[6]

(c) Since two of the six surveillance data points are not credible, a full margin value is used to calculate the ¼T and ¾T ART values

[ ] - Controlling values of the adjusted reference temperatures.

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Table 3-15. Evaluation of Upper-Shelf Energy Decreases for the HNP Reactor Vessel Beltline Materials Applicable Through 36 EFPY

Material Description[a]				Cu wt%	¼T Fluence[b] (x 10^{19}) n/cm^2	Initial C_vUSE[a] ft-lbs	Predicted C_vUSE Per R.G. 1.99/2	
Reactor Vessel Beltline Region Location	Material Identification	Heat Number	Type				C_vUSE ft-lbs	% Decrease
Intermediate Shell Plate (IS)	A9153-1	A9153-1	SA-533 Gr. B1	0.09	2.84	83	63.9	23.0
Intermediate Shell Plate (IS)	B4197-2	B4197-2	SA-533 Gr. B1	0.09	2.84	71	54.4[c]	23.3[c]
Lower Shell Plate (LS)	C9924-1	C9924-1	SA-533 Gr. B1	0.08	2.75	98	76.8	21.6
Lower Shell Plate (LS)	C9924-2	C9924-2	SA-533 Gr. B1	0.08	2.75	88	69.0	21.6
IS Longit. Weld (Both 100%)	BC/BD	4P4784	ASA/Linde 124	0.05	1.11	94	75.7	19.5
IS to LS Circ. Weld (100%)	AB	5P6771	ASA/Linde 124	0.03	2.72	80	59.1[c]	26.1[c]
LS Longit. Weld (Both 100%)	BA/BB	4P4784	ASA/Linde 124	0.05	1.07	94	75.8	19.3

[a] See BAW-2355.[1]

[b] Calculated based on guidelines in Regulatory Guide 1.99, Revision 2.[3] The inside surface fluence is the calculated value at the "wetted" surface of the reactor vessel (Table 2-2). The ¼T location fluence value is determined by calculating the ¼T depth into the vessel and adding the minimum cladding thickness (i.e., "x" for ¼T = 2.0625 in.).[6]

[c] Calculated using surveillance data in accordance with Regulatory Guide 1.99, Revision 2, Position 2.2 (i.e., fitting the surveillance data with a line drawn parallel to the existing lines in Figure 2 as the upper bound of all the data).

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Table 3-16. Evaluation of Pressurized Thermal Shock Reference Temperatures for the HNP Reactor Vessel Beltline Materials Applicable Through 36 EFPY

Material Description[a]				Chemical Composition[a]									
Reactor Vessel Beltline Region Matl.	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Chem. Factor	Initial RT_{NDT},[a] F	36 EFPY Fluence at Clad-Base Metal Interface,[b] n/cm^2	Fluence Factor	ΔRT_{PTS}, F	Margin, F	RT_{PTS}, F	Screening Criteria
RT_{PTS} Calculation Per 10 CFR 50.61 Using Tables													
Intermediate Shell (IS) Plate	A9153-1	A9153-1	SA-533 Gr. B1	0.09	0.46	58.0	60	4.59E+19	1.385	80.3	34.0	174.3	270
Intermediate Shell (IS) Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	58.0	91	4.59E+19	1.385	80.3	34.0	205.3	270
Lower Shell (LS) Plate	C9924-1	C9924-1	SA-533 Gr. B1	0.08	0.47	51.0	54	4.46E+19	1.379	70.3	34.0	158.3	270
Lower Shell (LS) Plate	C9924-2	C9924-2	SA-533 Gr. B1	0.08	0.47	51.0	57	4.46E+19	1.379	70.3	34.0	161.3	270
IS Longit. Welds (Both 100%)	BC/BD	4P4784	Linde 124	0.05	0.91	68.0	-20	1.80E+19	1.161	78.9	56.0	114.9	270
IS to LS Circ. Weld (100%)	AB	5P6771	Linde 124	0.03	0.94	41.0	-20	4.40E+19	1.376	56.4	56.0	92.4	300
LS Longit. Welds (Both 100%)	BA/BB	4P4784	Linde 124	0.05	0.91	68.0	-20	1.75E+19	1.154	78.5	56.0	114.5	270
RT_{PTS} Calculation Per 10 CFR 50.61 Using Surveillance Data													
Intermediate Shell (IS) Plate	B4197-2	B4197-2	SA-533 Gr. B1	0.09	0.50	51.4	91	4.59E+19	1.385	71.2	34.0[c]	[196.2]	270
IS to LS Circ. Weld (100%)	AB	5P6771	Linde 124	0.03	0.94	49.1	-20	4.40E+19	1.376	67.6	28.0	75.6	300

[a] See BAW-2355.[1]

[b] The inside surface fluence is the calculated value at the clad – base metal interface of the reactor vessel; attenuation through the cladding is based on deterministic methods (Table 2-3).

[c] Since two of the six surveillance data points are not credible, a full margin value is used to calculate the RT_{PTS} value.

[ ] – Limiting reactor vessel beltline material in accordance with 10 CFR 50.61.[4]

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4. Summary of Results

The analysis for the implementation of a power uprate of 4.5% (to 2900 MWt) for the HNP beginning in cycle 11 led to the following conclusions:

1. The projected end-of-license (36 EFPY) peak fast fluence at the clad-base metal interface of the HNP reactor vessel is 4.590×10^{19} n/cm^2 (E > 1.0 MeV). The corresponding fluences at the ¼T, ½T, ¾T, and outside surface vessel wall in this peak location are 2.663×10^{19}, 1.357×10^{19}, 6.614×10^{18}, and 2.889×10^{18} n/cm^2 (E > 1.0 MeV) respectively.

2. Based on the ¼T and ¾T adjusted reference temperature results calculated in accordance with Regulatory Guide 1.99, Revision 2, the controlling beltline material for the HNP reactor vessel applicable to 13 through 25 and 36 EFPY is the intermediate shell plate, heat no. B4197-2.

3. In accordance with Regulatory Guide 1.99, Revision 2, the C_VUSE values for the HNP reactor vessel beltline materials are not predicted to fall below 50 ft-lb at end-of-license (36 EFPY).

4. In accordance with 10 CFR 50.61, the HNP reactor vessel beltline materials will not exceed the PTS screening criteria before end-of-license (36 EFPY).

5. Surveillance Capsule Removal Schedule

Based on the uprated power level evaluation for the HNP reactor vessel, the following schedule is recommended for the examination of the remaining capsules in the HNP reactor vessel surveillance program:

Withdrawal / Evaluation Schedule Based on Uprated Power Level Evaluation[a]				
Capsule Identification	Location of Capsules	Lead Factor	Removal Time	Expected Capsule Fluence (n/cm^2)[b]
W	110°	2.38[c] 4.62[d]	18 EFPY[e]	6.895×10^{19} [f]
Y	290°	2.38[c] 4.62[d]	Standby	-----
Z	340°	2.38[c] 4.62[d]	Standby	-----

(a) In accordance with ASTM Standard E 185-82.[6]

(b) Based on 4.5% uprated power level evaluation (Section 2).

(c) Factor by which the capsule fluence leads the vessel's maximum inner wall fluence for cycles 1 through 10.

(d) Factor by which the capsule fluence leads the vessel's maximum inner wall fluence for cycles 11 through EOL.

(e) Approximate fluence not less than peak EOL vessel fluence at clad-base metal interface (4.590×10^{19} n/cm^2) or greater than twice the peak EOL vessel fluence at clad-base metal interface (9.180×10^{19} n/cm^2). Therefore, actual capsule removal times can range from 13.66 EFPY to 21.32 EFPY. This capsule may be held without testing following withdrawal.

(f) The specified fluence represents the peak inside surface vessel fluence at the clad-base metal interface after 60 calendar year (54 EFPY) of operation based on the current fluence estimates for plant license renewal consideration.

6. Certification

The analysis for the implementation of a power uprate of 4.5% (to 2900 MWt) for the HNP reactor vessel beginning in cycle 11 was evaluated using accepted techniques and established standard methods and procedures in accordance with the requirements of 10 CFR 50, Appendix H.

11/5/99

M. J. DeVan (Material Analysis) Date
Materials & Structural Analysis Unit

6 Nov 99

S. Q. King (Fluence Analysis) Date
Performance Analysis Unit

This report has been reviewed for technical content and accuracy.

11-8-99

J. B. Hall, (Material Analysis) Date
Materials & Structural Analysis Unit

11/8/99

E. Giavedoni (Fluence Analysis) Date
Performance Analysis Unit

Verification of independent review.

11-8-99

K. E. Moore, Manager Date
Materials & Structural Analysis Unit

This report is approved for release.

11/8/99

D. L. Howell Date
Program Manager

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7. References

1. M. J. DeVan and S. Q. King, *"Analysis of Capsule X Carolina Power & Light Company Shearon Harris Nuclear Power Plant - Reactor Vessel Material Surveillance Program -,"* BAW-2355, Framatome Technologies, Inc., Lynchburg, Virginia, October 1999.

2. Code of Federal Regulation, Title 10, Part 50, *"Domestic Licensing of Production and Utilization Facilities,"* Appendix H, Reactor Vessel Material Surveillance Program Requirements, Effective Date: January 18, 1996.

3. U.S. Nuclear Regulatory Commission, *"Radiation Embrittlement of Reactor Vessel Materials,"* Regulatory Guide 1.99, Revision 2, May 1998.

4. Code of Federal Regulations, Title 10, *"Domestic Licensing of Production and Utilization Facilities,"* Part 50.61, *"Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock,"* Effective Date: August 28, 1996.

5. J. R. Worsham III, *"Fluence and Uncertainity Methodologies,"* BAW-2241P, Revision 1, Framatome Technologies, Inc., Lynchburg, Virginia, April 1999.

6. Letter from A. R. Stalker (CP&L) to D. L. Howell (FTI), Subject: Design Input, HO-990035 (Corrected), dated May 3, 1999 (FTI Document No. 38-1247892-00).

7. ASTM Standard E 185-82, *"Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels, E 706 (IF)"* American Society for Testing and Materials, Philadelphia, Pennsylvania.

APPENDIX A

Fluence Analysis Methodology

The primary tool used in the determination of the flux and fluence exposure to the welds, plates, and surveillance capsule specimens is the two-dimensional discrete ordinates transport code, DORT.[A-1] Carolina Power & Light Company (CP&L) has provided the cycle 18 pin x pin relative power distribution data necessary for performance of a fluence analysis in accordance with BAW-2241P, Revision 1.[A-2] Cycle 18 has been determined by CP&L to be representative of an equilibrium cycle for the post-uprate time period.

A fluence analysis was performed in accordance with BAW-2241P, Revision 1, to determine the fast flux at each location of interest.

A-1. Cycle 18 Flux Calculational Procedures

The standard Framatome Technologies, Inc. (FTI) fluence analysis procedure was used to determine the fluence accumulated in Capsule X and on the various plates and welds for cycle 18. This procedure will now be described.

Figure A-1 depicts the analytical procedure that is used to determine the incremental fluence accumulated over cycle 18. As shown in the figure, the analysis is divided into seven tasks:

(1) generation of the neutron source,
(2) development of the DORT geometry models,
(3) calculation of the macroscopic material cross sections,
(4) synthesis of the results,
(5) the calculational uncertainty, and
(6) the final fluence.

Each of these tasks is discussed below.

A-2. Generation of the Neutron Source

The time-average space- and energy-dependent neutron source for cycle 18 was calculated using the SORREL code.[A-3] The effects of burnup on the spatial distribution of the neutron source were accounted for by calculating the cycle average fission spectrum for each fissile isotope on an assembly-by-assembly basis, and by determining the cycle-average specific neutron emission rate. These data were then used with the normalized time-weighted-average pin-by-pin relative power density (RPD) distribution to determine the space- and energy-dependent neutron source. The azimuthal-average, time average axial power shape in the peripheral assemblies was used with the fission spectrum of the peripheral assemblies to

determine the neutron source for the axial DORT run. These two neutron source distributions were input to DORT as indicated in Figure A-1.

A-3. DORT Analyses

The cross sections, geometry, and appropriate source were combined to create a set of DORT models (R-Θ and R-Z) for the cycle 18 analysis. Each DORT run utilized a cross section Legendre expansion of three (P_3), a minimum of forty-eight directions (S_8), and the appropriate boundary conditions. All outer boundaries employed vacuum boundary conditions. (Note that when vacuum boundary conditions are used, the location of the vacuum boundary with respect to the location of the boundary flux was checked to ensure that the boundary source is being written sufficiently far into the inner model to ensure that the boundary location does not perturb the flux significantly at the boundary flux location.) A theta-weighted flux extrapolation model was used, and all other requirements of Draft Regulatory Guide DG-1053[A-4] that relate to the various DORT parameters were met or exceeded for all DORT runs.

A-4. Synthesized Three-Dimensional Results

The DORT analyses produced two sets of two-dimensional flux distributions, one for a vertical cylinder and one for the radial plane. The vertical cylinder, which will be referred to as the R-Z plane, is defined as the plane bounded axially by the upper and lower grid plates and radially by the center of the core and a vertical line located 20 cm into the water biological shield. The horizontal plane, referred to as the R-Θ plane, is defined as the plane bounded radially by the center of the core and a point located approximately two feet into the concrete of the primary biological shield, azimuthally by the major axis, and the adjacent 45° azimuth. The vessel flux, however, varies significantly in all three cylindrical-coordinate directions (R, Θ, Z). This means that if a point of interest is outside the boundaries of both the R-Z DORT and the R-Θ DORT, the true flux cannot be determined from either DORT run. Under the assumption that the three-dimensional flux is a separable function, the two two-dimensional data sets were mathematically combined to estimate the flux at all three-dimensional points (R, Θ, Z) of interest. The synthesis procedure outlined in Draft Regulatory Guide DG-1053 forms the basis for the FTI flux-synthesis process.

A-5. Development of the Geometrical Models

The system geometry models for the mid-plane (R-Θ) DORT were developed using standard FTI interval size and configuration guidelines. The R-Θ model for the cycle 18 analysis

extended radially from the center of the core to a point approximately two feet into the concrete of the primary biological shield, and azimuthally from the major axis to 45°. The surveillance capsule was modeled explicitly in the R-Θ model. The axial (R-Z) DORT geometry model was developed using FTI procedures for the radial part, and used the appropriate interval structure in the axial direction. The axial model extended from core plate to core plate. The geometrical models meet or exceed all guidance criteria concerning interval size that are provided in Draft Regulatory Guide DG-1053. In all cases, cold dimensions were used. The geometry models were input to the DORT code as indicated in Figure A-1. These models will be used in all subsequent Code of Federal Regulation, Title 10, Part 50 (10 CFR 50), Appendix H[A-5] and pressure-temperature (P-T) curve analyses.

A-6. Calculation of Macroscopic Material Cross Sections

In accordance with Draft Regulatory Guide DG-1053, the BUGLE-93[A-6] cross section library was used. The GIP code[A-7] was used to calculate the macroscopic energy-dependent cross sections for all materials used in the analysis, from the core out through the cavity and into the concrete and from core plate to core plate. The ENDF/B6 dosimeter reaction cross sections were used to generate the response functions that were used to calculate the DORT-calculated saturated specific activities.

A-7. Calculated Activities and Measured Activities

Since there was no dosimetry, the determination of C and M is not possible.

A-8. C/M Ratios

Since there was no dosimetry, the determination of C/M is not possible.

A-9. Estimation of the Best-Estimate Flux

The flux in the reactor vessel beltline region is determined by best-estimate calculations, which are, by definition, the DORT results corrected for the generic energy-dependent bias removal function. The FTI cavity dosimetry database, which was developed in the cavity dosimetry benchmark experiment, determined that there is a slight bias in the calculations. The energy-dependent bias removal function was developed to remove biases from the DORT results in order to provide best-estimate calculational results.

As discussed in the uncertainty analysis, there is no significant bias associated with this analysis beyond that identified in the Cavity Dosimetry Program. Accordingly, the energy-dependent

benchmark bias function was used with the DORT-calculated flux to determine the best-estimate flux at each point of interest in the reactor vessel in accordance with the procedures discussed in the Fluence and Uncertainty Topical Report, BAW-2241P, Revision 1.

A-10. Extrapolation to the End of Life (EOL)

By necessity, extrapolation of neutron fluence to points in the future is an inexact and approximate process. It is impossible to know with certainty the character of future core operations or to accurately estimate the effect of any given core operation on the fluence at any given location, before the fact. It is possible, however, to make reasonable estimates of the inside surface maximum flux using near-future fuel cycle design trends.

The "extrapolation flux" is defined as the constant flux used to determine the fluence at points in the future. In the FTI methodology, extrapolation flux is based on the DORT-calculated flux determined in the just-completed fluence analysis. Since it is the stated intention of CP&L to continue operation after the power uprate with loadings similar to those used in the HNP cycle 18 operations, the extrapolation fluxes reported herein are appropriate and conservative.

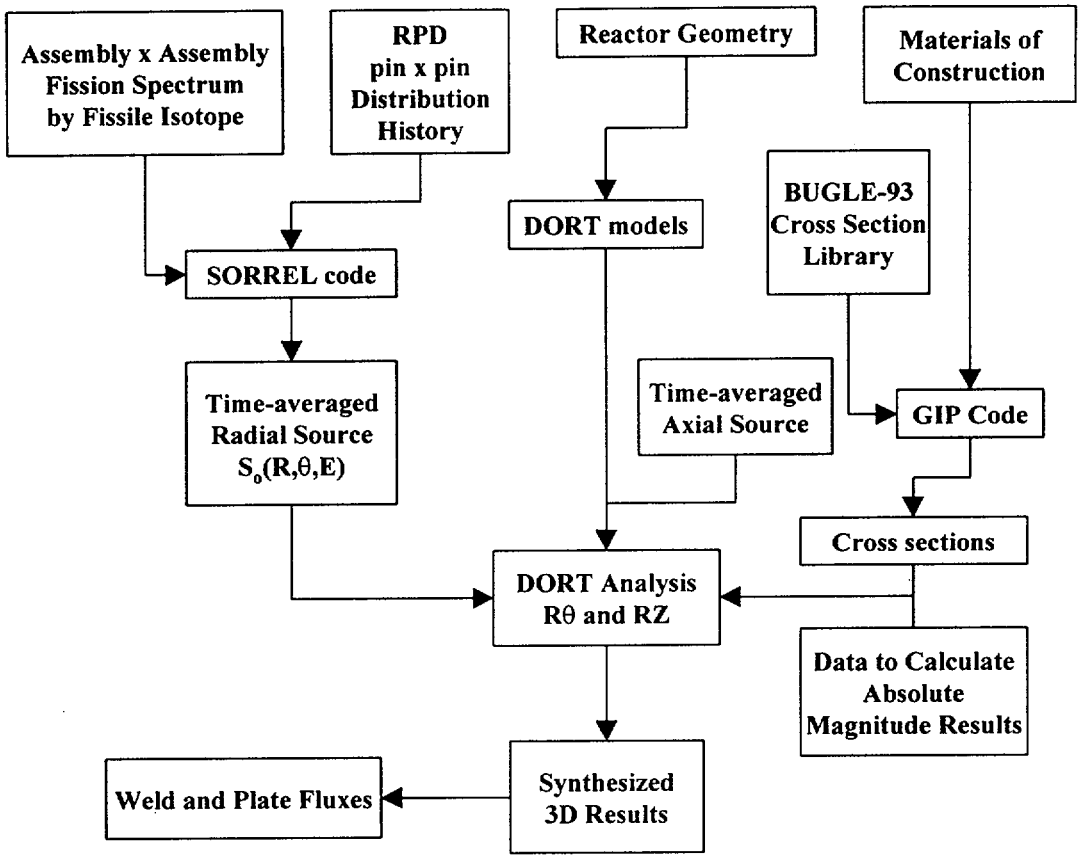
A-11. Uncertainty

The HNP reactor vessel fluence predictions are based on the methodology described in the FTI "Fluence and Uncertainty Methodologies" Topical Report.[A-2] The time-averaged fluxes, and thereby the fluences throughout the reactor, and vessel are calculated with the DORT discrete ordinates computer code using three-dimensional synthesis methods. The basic theory for synthesis is described in Section 3.0 of BAW-2241P, Revision 1, and in the previous Sections of this Appendix. The DORT three-dimensional synthesis results are the bases for the fluence predictions using the FTI "Semi-Analytical" (calculational) methodology. As noted in Sections 6.0 and 7.0 of BAW-2241P, Revision 1, the best-estimate fluence predictions are determined by removing any bias from the calculated fluence results. The bias removal function is dependent on the DORT solution procedures, the BUGLE-93 cross sections, and the FTI dosimetry benchmarks. It is independent of the HNP fluence predictions and any plant-specific comparisons of dosimetry calculations to measurements.

This analysis calculated the estimated effect of the proposed power uprate on vessel flux and fluence, but since it was performed for future operations, no dosimetry was irradiated, and thus no benchmark comparisons (C/M) are possible.

The uncertainty in the cycles 1 - 8 fluence was shown to be within the 20% NRC guideline in the base-scope analysis.[A-8] Assuming the future power distributions do not vary significantly from the cycle 18 analyzed, it can be expected that the uncertainty in the EOL fluence could be within the NRC guidelines.

Figure A-1. Fluence Analysis Methodology



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A-12. References

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5.2 Reactor Internals

5.2.1 Introduction

The reactor pressure vessel (RPV) system consists of the reactor vessel, reactor internals, fuel and control rod drive mechanisms. The reactor internals function to support and orient the reactor core fuel assemblies and control rod assemblies, absorb control rod assembly dynamic loads, and transmit these and other loads to the reactor vessel. The reactor vessel internal components also function to direct coolant flow through the fuel assemblies (core), to provide adequate cooling flow to the various internals structures, and to support in-core instrumentation. They are designed to withstand forces due to structure deadweight, preload of fuel assemblies, control rod assembly dynamic loads, vibratory loads, earthquake accelerations, and Loss of Coolant Accident (LOCA) loads.

Operating a plant at conditions (power, pressure, temperature, flow) other than those considered in the original design requires that the reactor vessel/internals/fuel system interface be addressed in order to assure compatibility and that the structural integrity of the reactor vessel/internals/fuel system is not adversely affected. In addition, thermal-hydraulic analyses are required to determine plant specific core bypass flows, pressure drops and upper head temperatures in order to provide input to the LOCA and non-LOCA safety analyses as well as NSSS performance evaluations.

Generally, the areas of concern most affected by changes in system operating conditions are:

1. Reactor internals system thermal/hydraulic performance;
2. Rod cluster control assembly (RCCA) drop time performance; and
3. Reactor internals system structural response and integrity

The major components and features of the reactor internals system for HNP are summarized as follows. The lower core support assembly consists of the lower support plate, lower support columns, and lower core plate, and supports the fuel assemblies on the sides and at the bottom. The guidance and alignment of the lower core support assembly during insertion into the reactor vessel is provided by the radial support system and the head-vessel alignment pins, and special temporary guide studs attached to the vessel. The hold-down spring rests on top of the flange of the lower core support assembly. The upper core support assembly consists of the upper support plate, upper support columns, and upper core plate, and rests on top of the hold down spring. The guidance and alignment of the upper core support assembly during its insertion is provided by the head-vessel alignment pins, the upper core plate alignment pins in the core barrel assembly, and the special temporary guide studs attached to the vessel. The alignment of the core, i.e., each fuel assembly, is provided through the engagement of the lower core plate fuel pins into the bottom of the fuel assemblies and the upper core plate fuel pins into the top of the fuel assemblies. The vessel upper head compresses the hold-down spring providing joint preload.

The core barrel, which is part of the lower core support assembly, provides a flow boundary for the reactor coolant. When the primary coolant enters the reactor vessel, it impinges on the side of the core barrel and is directed downward through the annulus formed by the gap between the outside diameter of the core barrel and the inside diameter of the vessel. The flow then enters the lower plenum area between the bottom of the lower support plate and the vessel bottom head and is redirected upward through the core. After passing through the core, the coolant enters the upper core support region and then proceeds radially outward through the reactor vessel outlet nozzles. Another portion of the primary coolant bypasses the fuel and cools the upper head region. The perforations in the various components, such as the lower support plate, control and meter the flow through the core.

HNP currently uses Siemens Power Corporation (SPC) fuel. For certain calculations or evaluations, properties of Westinghouse 17 x 17 VANTAGE 5H (V5H) fuel were used in place of the SPC fuel properties. The combination of the Westinghouse and Siemens fuel properties result in a bounding evaluation.

The following sections summarize the work performed to assess the effect on the reactor pressure vessel/internals system due to the SGR/Uprating at HNP.

5.2.2 Description of Analyses and Evaluations

5.2.2.1 Thermal/Hydraulic System Evaluations

5.2.2.1.1 System Pressure Losses

The principal reactor coolant system flow route through the HNP reactor pressure vessel system begins at the three inlet nozzles. At this point, flow turns downward through the reactor vessel core barrel annulus. After passing through this downcomer region, the flow enters the lower reactor vessel dome region. This region is occupied by the internals energy absorber structure, lower support columns, bottom-mounted instrumentation columns, and supporting tie plates. From this region, flow passes upward through the lower core plate, and into the core region. After passing up through the core, the coolant flows into the upper plenum, turns, and exits the reactor vessel through the three outlet nozzles. Note that the upper plenum region is occupied by support columns and RCCA guide columns.

A key area in evaluation of core performance is the determination of hydraulic behavior of coolant flow within the reactor internals system, (i.e., vessel pressure drops, core bypass flows, RPV fluid temperatures and hydraulic lift forces). The pressure loss data is necessary input to the LOCA and non-LOCA safety analyses and to overall NSSS performance calculations. The hydraulic forces are critical in the assessment of the structural integrity of the reactor internals, core clamping loads generated by the internals hold down spring, and the stresses in the reactor vessel closure studs.

The THRIVE computer code (Reference 1) was used to perform this evaluation by solving the mass and energy balances for the HNP reactor internals fluid system. The analysis determined the distribution of pressure and flow within the reactor vessel, internals, and reactor core for the RCS at the SGR/Uprating conditions. The THRIVE computer code has been used for this analysis since the original plant design.

The analysis determined the distribution of pressure and flow within the reactor vessel, internals and the reactor core for the RCS at the SGR/Uprating conditions.

5.2.2.1.2 Bypass Flow Analysis

Bypass flow is the total amount of reactor coolant flow bypassing the core region and is not considered effective in the core heat transfer process. Since variations in the size of some of the bypass flow paths, such as gaps at the outlet nozzles and the core barrel, occur during manufacturing or change due to different fuel assembly designs or due to changes in the RCS conditions, plant specific as-built dimensions are used in order to demonstrate that the bypass flow limits are not violated. Therefore, analyses are performed to determine core bypass flow values to either show that the design bypass flow limit for the plant will not be exceeded or to determine a revised design core bypass flow.

The present design core bypass flow limit is 7.1 percent of the total reactor vessel flow. The purpose of this evaluation is to ensure that the design value of 7.1 percent can be maintained at the uprated RCS conditions. The principal core bypass flow paths are:

- Baffle-Barrel Region

  The HNP reactor vessel internals incorporate an upflow configuration. Reactor coolant flow enters the baffle-barrel region at the bottom former elevation and passes through the flow holes at each successively higher former elevation, past the upper core plate and into the outlet plenum. For the upflow configuration, all the flow that enters the baffle-barrel region is considered core bypass flow.

- Vessel Head Cooling Spray Nozzles

  These nozzles are flow paths between the reactor vessel and core barrel annulus and the fluid volume in the vessel closure head region above the upper support plate. A fraction of the flow that enters the vessel inlet nozzles and into the vessel/barrel downcomer passes through these nozzles and into the vessel closure head region. The purpose of these flow paths is to allow circulation of a small fraction of the cold leg coolant into the upper head region of the reactor vessel.

- Core Barrel - Reactor Vessel Outlet Nozzle Gap

  At HNP some of the flow that enters the vessel/barrel downcomer leaks through the gaps between the core barrel outlet nozzles and the reactor vessel outlet nozzles and merges with the vessel outlet nozzle flow. Since the lower reactor internals are designed to be removable from the reactor vessel, a small circumferential gap exists at each of the outlet nozzle locations. While the gap is designed to be very small and closes down somewhat at operating conditions due to the differential coefficient of thermal expansion between the reactor internals and the reactor vessel, there is some amount of flow which leaks directly from the vessel inlet/downcomer region and out these nozzle gaps.

- Fuel Assembly - Baffle Plate Cavity Gap

  The baffle plates surround the reactor fuel assemblies or core region. The gap between the peripheral fuel assemblies and the baffle plates is referred to as the core cavity region. This is the core bypass flow path between the peripheral fuel assemblies and the core baffle plates.

- Fuel Assembly Thimble Tubes

  Thimble tubes are used as paths for the insertion and removal of control rods, thimble plugging devices and various core components such as burnable absorbers. These tubes are physically part of each fuel assembly and flow within them is partially effective in removing core heat. However, such flow is analytically not considered to be effective in heat removal, and is consequently core bypass flow.

Fuel assembly hydraulic characteristics, system parameters, such as inlet temperature, reactor coolant pressure and flow were used in the calculation to determine the impact of the new SGR/Uprating conditions on the total core bypass flow. The total core bypass flow value (including uncertainties) was determined to be 6.95 percent. Therefore, the design core bypass flow value of 7.1 percent of the total vessel flow is maintained.

5.2.2.1.3 Hydraulic Lift Forces

The reactor internals hold-down spring is essentially a large diameter belleville type spring of rectangular cross section. The purpose of this spring is to maintain a net clamping force between the reactor vessel head flange and upper internals flange and the reactor vessel shell flange and the core barrel flange of the internals. An evaluation was performed to determine hydraulic lift forces on the various reactor internal components to ensure that the reactor internals assembly would remain seated and stable for all conditions. A calculation was performed to determine if the hydraulic lift forces with SPC fuel are comparable to or less than those previously evaluated using Westinghouse 17x17 V5H fuel.

The results of this evaluation indicate that the SPC fuel lift forces are bounded by the Westinghouse V5H forces previously evaluated. Therefore, the HNP reactor internals assembly would remain seated and stable for all conditions under SGR/Uprating conditions. The SGR/Uprating effects on the SPC fuel are further addressed in Section 5.3.

5.2.2.1.4 RCCA Drop Time Performance Evaluation

The RCCAs represent perhaps the most critical interface between the fuel assemblies and the other internals components. It is imperative to show that the new RCS conditions will not adversely impact the operation of the control rods, either during accident conditions or normal operation.

The purpose of this section is to determine the potential impact due to the SGR/Uprating at HNP on RCCA drop time characteristics used in the FSAR for accident analyses. This analysis is based on 17 x 17 V5H fuel assemblies with intermediate flow mixing (IFM) grids.

Calculations were performed which indicated that the maximum drop time-to-dashpot entry of 2.7 seconds for HNP remains conservatively applicable for accident analyses.

5.2.2.1.5 Momentum Flux and Fuel Rod Stability

No detailed treatment of momentum flux and associated fuel rod stability is needed due to the upflow configuration in the baffle-barrel region. There is very minimal pressure drop across the baffle plates since the flow is upward on both sides, and pressure relief holes further reduce the pressure differential across the plates.

5.2.2.2 Mechanical System Evaluations

The evaluation of the mechanical response of the RCS subjected to auxiliary line breaks of a LOCA transient is performed in three steps. First, the RCS is analyzed for the effects of loads induced by normal operation, which includes thermal, pressure, and deadweight effects. From this analysis, the mechanical forces acting on the RPV that would result from the release of the equilibrium forces at the break locations are obtained. In the second step, the loop mechanical loads and the reactor internals hydraulic forces are simultaneously applied, and the RPV displacements due to the LOCA are calculated. Finally, the structural integrity of the reactor coolant loop and component supports to deal with the LOCA is evaluated by applying the reactor vessel displacements to a mathematical model of the reactor coolant loop. Thus, the effects of vessel displacements upon loop and reactor vessel and its internals are evaluated.

Since HNP takes credit for leak-before-break (LBB) applied to the primary loop (Reference 2), the LOCA analyses of the reactor pressure vessel system for postulated ruptures of the primary loop piping are not required. The next limiting breaks to be considered are the branch line breaks which consists of (a) accumulator line, (b) pressurizer surge line, and (c) residual heat removal

(RHR) line breaks. Of these branch line breaks, the most limiting breaks considered for the dynamic analysis of the HNP reactor pressure vessel system are the accumulator line break (cold leg) and the pressurizer surge line break (hot leg).

The analysis model of the RPV is a three-dimensional nonlinear finite element model that represents the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. The model was developed using the WECAN computer code (Reference 3). The WECAN computer code has been used for this analysis since the original plant design.

5.2.2.2.1 Loss-of-Coolant Accident (LOCA) Loads

The LOCA loads applied to the HNP reactor pressure vessel system consist of (1) reactor internal hydraulic loads (vertical and horizontal), (2) reactor coolant loop mechanical loads, and (3) pressure loads acting on the baffle plates. All the loads are calculated and combined in a time-history manner. The MULTIFLEX computer code (Reference 4) was used to calculate the hydraulic transients within the entire primary coolant system (see Section 6.6). The MULTIFLEX code has been used for this analysis since the original plant design.

The severity of a postulated break in a reactor vessel is related to two factors: the distance from the reactor vessel to the break location, and the break opening area. The nature of the reactor vessel decompression following a LOCA, as controlled by the internals structural configuration previously discussed, results in larger reactor internal hydraulic forces for pipe breaks in the cold leg than in the hot leg (for breaks of similar area and distance from the RPV). Pipe breaks farther away from the reactor vessel are less severe because the pressure wave attenuates as it propagates toward the reactor vessel. With the consideration of LBB, the auxiliary line breaks, such as the accumulator line break and the pressurizer surge line break, are not as severe as the main line breaks (e.g., RPV inlet nozzle or RCP outlet nozzle break).

The reactor vessel impact forces were calculated. The reactor pressure vessel peak displacements and rotations for the accumulator line break, the pressurizer surge line break, and the RHR line break were also determined. The impact forces calculated at the vessel/internals interfaces were used to evaluate the structural integrity of the reactor vessel and its internals. The core plate motions for this analysis were provided as input to the fuel assembly grid load evaluation. The resultant fuel assembly loads were used in additional fuel evaluations. (See Section 5.3.)

5.2.2.2.2 Flow-Induced Vibrations

Flow-induced vibrations (FIV) of pressurized water reactor internals have been studied at Westinghouse for a number of years. The objective of these studies was to demonstrate the structural integrity and reliability of reactor internal components.

Lower Internals Response

Results from the scale model and in-plant tests indicate that the primary cause of lower internals' excitations is the flow turbulence generated by the expansion and turning of the flow at the transition from the inlet nozzle to the barrel-vessel annulus, and the wall turbulence generated in the downcomer.

The response of the HNP lower internals to the uprated power can possibly be influenced by changes in fuel assembly mechanical characteristics and NSSS parameters. The impact of these factors on the response of the HNP lower internals is discussed in the following sections.

Impact of NSSS Parameters

The NSSS parameters that could potentially influence the FIV response of the reactor internals include the inlet nozzle flow velocities, vessel/core inlet temperatures, and the vessel outlet temperatures.

Generally, the inlet nozzle velocity for the FIV response during hot functional testing is calculated at the mechanical design flows, which are approximately 15 percent higher than the thermal design flows. Since the thermal design flows for the SGR/Uprating are lower than the original thermal design flowrates and since HNP hot functional tests were performed at flowrates higher than those for the SGR/Uprating conditions, the existing test results are conservative and remain applicable.

The other parameter that would influence the FIV response is the core inlet temperature. For the most limiting case of the SGR/Uprating changes, the vessel/core inlet temperature is 536.6°F. The originally analyzed vessel/core inlet temperature is 543.5°F. This temperature change implies a change in water density, which had a negligible impact on the core barrel response due to the SGR/Uprating conditions.

Upper Internals Response

The significant flow-induced forces on upper internals are due to random turbulence generated by the cross flows that converge on the outlet nozzles. Therefore, the guide tubes and the upper support columns that lie in the vicinity of the outlet nozzles will experience the maximum flow-induced forces.

The flow-induced vibration loads on the guide tubes and the upper support columns increase by approximately 2.8 percent for the SGR/Uprating. Previous FIV analyses on the guide tubes and the upper support columns have shown that sufficient margins exist to accommodate this increase in the FIV loads. Consequently, the structural integrity of the HNP reactor internals remains acceptable with regard to flow-induced vibrations.

5.2.2.3 Structural Evaluation of Reactor Internal Components

5.2.2.3.1 Introduction

In addition to supporting the core, a secondary function of the reactor vessel internals assembly is to direct coolant flows within the vessel. While directing the primary flow through the core, the internals assembly also establishes secondary flow paths for cooling the upper regions of the reactor vessel and for cooling the internals structural components. Some of the parameters influencing the mechanical design of the internals lower assembly are the pressure and temperature differentials across its component parts and the flowrate required to remove the heat generated within the structural components due to radiation (e.g., gamma heating). The configuration of the internals provides for adequate cooling capability. Also, the thermal gradients, resulting from gamma heating and core coolant temperature changes, are maintained below acceptable limits within and between the various structural components.

Structural evaluations are required to demonstrate that the structural integrity of the reactor components is not adversely affected directly by the change in RCS conditions and transients and/or by secondary effects of the change on reactor thermal hydraulic or structural performance. The presence of heat generated in reactor internal components, along with the various fluid temperatures, results in thermal gradients within and between components. These thermal gradients result in thermal stresses and thermal growth, which must be accounted for in the design and analysis of the various components.

Since the HNP reactor internals were designed prior to the introduction of Subsection NG of the ASME Boiler and Pressure Code Section III, a plant-specific stress report on the reactor internals was not required. However, the design of the HNP reactor internals was evaluated according to the Westinghouse internal criteria which were similar to the criteria described in Subsection NG of the ASME Code, 1989 edition, 1990 addenda. Moreover, the structural integrity of the HNPs reactor internals design has been shown by analyses performed on both generic and plant specific bases. These analyses were used as the basis for the evaluation of the critical reactor internal components for the plant uprating and the revised thermal transients.

5.2.2.3.2 Component Evaluations

In addition to the loads developed as a result of the thermal performance of the reactor pressure vessel system and components, the internals will also experience other loadings, for example:

- Pressure differentials due to coolant flow
- Weight of the structure
- Superimposed loads from other components
- Earthquake (or seismic) loads,

- LOCA loads,
- Vibratory loads, and
- Preloads.

The purpose of this section of the report is to summarize the work performed to assess the impact of the SGR/Uprating program on the structural integrity of the critical reactor internal components, such as the lower core plate and the upper core plate.

5.2.2.3.2.1 Lower Core Plate Evaluation

A fatigue evaluation was performed for the lower core plate, which is known to be the most critically cycled component in the reactor internals assembly (i.e., cumulative fatigue usage closest to 1).

Structural evaluations were performed to demonstrate that the structural integrity of the lower core plate is not adversely affected directly by the change in RCS conditions and/or by secondary effects of the change on reactor thermal hydraulic or structural performance. For this lower core plate evaluation, the criteria described in Section III, Subsection NG of the ASME Code, 1989 Edition, 1990 Addenda (Reference 5) were utilized.

The method of analysis of the lower core plate consisted of the following three steps:

1. Determination of temperature distributions in the plate

2. Determination of stresses in the plate

3. Determination of margin of safety and fatigue usage factor for the most severely stressed location of the plate

The ANSYS computer code (Reference 6) was used for the thermal and stress analyses performed on the lower core plate. ANSYS is an industry-accepted code for performing finite element analysis. The code has been verified and is under Westinghouse configuration control for use in this application. This is the first application of ANSYS to HNP. The analysis was previously performed by WECAN.

Load Case Combinations

The normal/upset load case combination used is considered to envelop all other possible load combinations. The normal/upset load combination includes:

1. Fuel assembly and core plate deadweight
2. Hold down spring preload

3. Hydraulic lift forces
4. Operating Basis Earthquake (OBE) seismic acceleration
5. Short term heat generation rates
6. Control Rod Drop

Under faulted conditions, LOCA and safe shutdown earthquake (SSE) loads were also considered without secondary loadings. The faulted condition assumes simultaneous occurrence of the SSE and LOCA (loss of coolant accident or blow down) loads. According to the F-1323.1(b) guidelines described in the ASME Section III, Appendix F (Reference 7), only the primary stresses (primary membrane, and primary membrane plus bending) are needed to be considered for the faulted conditions. Note that the SSE and LOCA loads are statistically independent events. The total faulted stress was determined due to stresses combined using the square root of the sum of the squares (SRSS) method. The square root of the sum of the SSE stress squared and LOCA stress squared were calculated before the stress ranges and stress intensities were calculated.

Method of Evaluation

The approach used for this evaluation was to assume the most severe conditions were applied for all of the design transients. By developing the maximum possible thermal stresses, conservative stress intensity margins of safety and fatigue usage resulted. The lower core plate temperatures were determined using the short term heating rates combined with convection to the reactor coolant. In the stress analysis the thermal stresses were combined with the mechanical stresses produced by the mechanical loads. This solution then provided the boundary conditions and structural temperatures for the detailed model. The stress intensity calculated at the bottom of the fuel pin counterbore (which was the location of peak stress intensity) was used to determine the lower core plate fatigue usage.

Discussion of Results Regarding Lower Core Plate

The overall temperature distribution in the lower core plate was obtained at 100 percent steady state full power for the SGR/Uprating.

The temperature distribution followed the flow hole pattern, with the peak temperatures occurring in the larger ligaments in the plate. The heating rates at the perimeter of the plate were low enough that the outer edge of the plate was cooled close to the inlet temperature of the RCS coolant. The outer edge of the plate provided a radial constraint that restricted the inner flow hole region from expanding freely. Subsequently, stresses at the inner region of the core plate were generated. The largest gradients in temperature occurred at the thickest ligaments between flow holes in the inner region.

The stresses calculated were compared to ASME Code allowables to determine the margin of safety. Margin of safety is defined as follows:

$$\text{Margin of Safety} = \frac{\text{Allowable Stress}}{\text{Calculated Stress}} - 1$$

Therefore, a margin of safety equal to zero means that the actual stress is equal to the code allowable stress. In the ASME Code Section III, Subsection NG (Reference 5) the following four conditions were identified:

1. Normal Conditions (Service Level A)
2. Upset Conditions (Service Level B)
3. Emergency Conditions (Service Level C)
4. Faulted Conditions (Service Level D)

Normal operation (Service Level A) conditions include any condition in the course of system startup, operation in the design power range, hot standby and system shutdown, other than Upset, Emergency, Faulted or Testing conditions. Upset (Service Level B) occurrences include any deviations from Normal conditions anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment. Emergency (Service Level C) conditions include those deviations from normal conditions that require shutdown for correction of the condition or repair. Faulted (Service Level D) conditions include those combinations of conditions associated with extremely low probability postulated events whose consequences are such that the integrity and operability of the system may be impaired to the extent that consideration of the public health and safety are involved.

An actual margin of safety against failure is assured by the inherent conservatism in the code stress limits. The margins of safety for the lower core plate were determined for the normal, upset, emergency and faulted conditions.

The fatigue usage factor for HNP is evaluated by:

$$U_f = \sum_{i=1}^{M} \frac{n_i}{N_i}$$

where M is the total number of stress cycling ranges considered, n_i is the number of cycles allocated for range i, and N_i is the allowable cycles corresponding to the alternating stress for range i. For the present analysis, M=3. The ASME code acceptance criterion is $U_f < 1.0$.

The margins of safety and cumulative fatigue usage factors are shown in Table 5.2-1.

Conclusions Regarding Lower Core Plate

The objective of the lower core plate evaluation was to determine the effects on the structural integrity of the lower core plate due to SGR/Uprating conditions. The conclusion of these evaluations is that the structural integrity of the lower core plate is maintainable. The evaluations of the new reactor coolant system conditions, which are due to the SGR/Uprating conditions, demonstrate acceptable margins of safety and acceptable fatigue utilization factors for all loading conditions.

5.2.2.3.2.2 Upper Core Plate Evaluations

The upper core plate positions the upper ends of the fuel assemblies and the lower ends of the control rod guide tubes, thus serving as the transitioning member for the control rods in entry and retraction from the fuel assemblies. It also controls coolant flow in its exit from the fuel assemblies and serves as a boundary between the core and the exit plenum. The upper core plate is restrained from vertical movement by the upper support columns that are attached to the upper support plate assembly. The lateral movement is restrained by four equally spaced core plate alignment pins.

The stresses in the upper core plate are mainly due to hydraulic, seismic, and thermal loads. The total thermal stresses are due to thermal bending moments through the thickness and surface peak stresses. Evaluations were performed to determine the impact of the uprating program on the structural integrity of the upper core plate. As a result of this evaluation, it is concluded that the upper core plate is structurally adequate for the new RCS conditions with regard to the SGR/Uprating program.

5.2.2.3.2.3 Additional Reactor Internal Components

Additional components were not further analyzed in detail because either (a) experience from similar programs and modifications indicate that these components are less critically affected by an uprating; or (b) HNP uses an upflow configuration in the core barrel/baffle region, which results in very minimal pressure differential across the baffle plates and, correspondingly lower baffle-barrel bolt stresses.

A series of assessments for similar programs have been performed for reactor internal components that are not significantly impacted by the SGR/Uprating conditions (and the resulting internal heat generation rates), but are affected by the new RCS conditions due to the primary loop transients. These components are:

- Lower core support plate
- Lower support columns
- Core barrel outlet nozzle

- Core barrel
- Core barrel flange
- Core baffle plate
- Lower radial restraints (clevis inserts)
- Baffle/barrel bolts
- Upper core plate alignment pin
- Upper support columns
- Upper support plate
- Guide tubes and support pins
- Neutron pads

These components are structurally adequate for the new RCS conditions at HNP.

5.2.3 Acceptance Criteria

The applicable criteria for the reactor internals evaluation are:

- Control Rod Drop Analysis: The rod drop time values generated consistent with plant operating parameters and configuration should be within the Tech Spec Limit.

- Flow-Induced Vibration Response: The flow-induced vibration response of reactor internal components, in general, depends upon reactor vessel inlet flow rates (such as mechanical design flow), reactor vessel inlet temperature, reactor vessel outlet temperature, and the fuel assembly design. The response of lower internals (core barrel) depends on the vessel inlet temperature and the inlet flow rates, and the response of upper internals (guide tubes and upper support columns) depends on the vessel outlet temperature and the flow exiting through the outlet nozzles. The acceptance criteria for the flow-induced vibration response is that the stresses from the FIV amplitudes remain within the endurance limit of the material for high cycle fatigue and component loads.

- Fuel Grid Forces: The grid forces were generated, verified, and documented. Analytical results were used in qualifying the fuel. (See Section 5.3.)

- Structural Adequacy of Reactor Internal Components: Subsection NG of the ASME Boiler and Pressure Vessel Code edition applicable to the HNP reactor internals did not include design criteria for the internals. The internals were originally designed to meet the intent of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with addenda through the Winter 1971 Addenda (Reference 8).

5.2.4 Results and Conclusions

Analyses have been performed to evaluate the effect of the SGR/Uprating on the reactor pressure vessel system and reactor internal components. Specifically, the following changes were assessed:

- SGR/Uprating Steady State RCS Conditions
- SGR/Uprating Internal Heat Generation Rates
- SGR/Uprating Reactor Coolant System Design Transients
- Plant Uprating to a NSSS Core Power Level of 2900 MWt

The calculated total reactor vessel pressure drop values and other pressure loss data were transmitted to interface groups for use in their respective analyses (e.g., LOCA and non-LOCA safety analyses — see Sections 6.1 and 6.2).

The total core bypass flow values (with uncertainties) were determined to be 6.95 percent. Therefore, the design core bypass flow value of 7.1 percent of the total vessel flow can be maintained.

The results of the Hydraulic Lift Forces evaluation indicated that the SPC fuel lift forces are bounded by the Westinghouse V5H forces previously evaluated. Therefore, the HNP reactor internals assembly would remain seated and stable for all conditions under SGR/Uprating. The SGR/Uprating effects on the SPC fuel are further addressed in Section 5.3.

The RCCA performance evaluation indicated that the current 2.7 second RCCA drop time to dashpot entry limit (from gripper release of the drive rod) is satisfied at SGR/Uprating conditions.

Evaluations indicated the SGR/Uprating RCS conditions will not adversely impact the response of reactor internals systems and components due to LOCA excitations and flow-induced vibrations. Reactor internals interface loads and core plate motions were re-calculated and transmitted to the appropriate interface groups for their respective evaluations.

Evaluations of the critical reactor internal components (lower and upper core plates) indicated that the structural integrity of the reactor internals is maintained with the SGR/Uprating RCS conditions.

The results for the SGR/Uprating are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

The critical LOCA loads on reactor internals are caused by LOCA forces input from Section 6.6.5, for which current 2787.4 MWt NSSS power operation is bounded.

5.2.5 References

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6. ANSYS Computer Code, Version 5.5.1.

7. ASME Code, Section III, Division 1, Appendices, 1989 Edition.

8. ASME Boiler and Pressure Vessel Code, Section III, 1971 Version including Addenda through the Winter 1971.

Table 5.2-1a Margin of Safety (MS) Values for HNP Lower Core Plate ($MS = S_{allowable}/S_{actual} - 1$)				
	Section A	**Section B**	**Section C**	**Section D**
Allowable Stress, psi	4.86E+04	4.86E+04	4.86E+04	4.86E+04
Previous Maximum Stress,(1) psi	[ ](b,c)	[ ](b,c)	[ ](b,c)	[ ](b,c)
Previous MS (1)	[ ](b,c)	[ ](b,c)	[ ](b,c)	[ ](b,c)
SGR/Uprating Maximum Stress	[ ](b,c)	[ ](b,c)	[ ](b,c)	[ ](b,c)
SGR/Uprating MS	[ ](b,c)	[ ](b,c)	[ ](b,c)	[ ](b,c)

Table 5.2-1b Limiting Fatigue Stress HNP SGR/Uprating (Usage <1.0 is Acceptable)			
Max Alternating Stress,(1) ksi (Reference 8)	**Fatigue Usage (Reference 8)**	**HNP SGR/Uprating Max Alternating Stress, ksi**	**HNP SGR/Uprating Fatigue Usage**
[ ](b,c)	[ ](b,c)	[ ](b,c)	[ ](b,c)

Note:

(1) Sections "A" through "D" are critical ligaments in the lower core plate.

5.3 Fuel Assemblies

5.3.1 Introduction

The Siemens Power Corporation (SPC) advanced 17x17 fuel assembly design has been analyzed to support steam generator replacement/uprating project (SGR/Uprating) to an uprate of 4.5% at Harris Nuclear Plant (HNP). With the exception of the analyses referenced in Section 5.3.2.5 (which support a 4.5% power uprate), the mechanical analyses included an evaluation of the fuel assembly during both normal and anticipated operational occurrences (AOO) for a bounding 6% power uprate. These analyses were performed in accordance with the U. S. Nuclear Regulatory Commission (NRC)-approved methodology (References 1 and 2) to demonstrate compliance with the requirements of the SPC generic Pressurized Water Reactor (PWR) design criteria (Reference 3). These analyses evaluate the fuel assembly mechanical criteria presented in the Reference 3 topical report for a maximum assembly discharge exposure of 59.8 GWd/MTU.

5.3.2 Description of Analyses and Evaluations

A description of the fuel assembly analyses and evaluations for the SGR/Uprating at HNP is described below.

5.3.2.1.1 Stress, Strain and Loading Limits

Fuel assembly structural integrity is assured by setting design limits on stresses and deformations due to various handling, operational, and accident loads. These limits are applied to the design and evaluation of the assembly components. The capability of the design to withstand possible loads incurred during handling is described in Section 5.3.2.8. Acceptability of the assembly to withstand postulated accident conditions is discussed in Section 5.3.2.9.

5.3.2.1.2 Fatigue

Stresses due to the combination of assembly weight, holddown forces, and differential thermal expansion at beginning of life (BOL) were used to evaluate the guide tube fatigue damage through the end of life (EOL) due to the cyclic power variations. Cyclic power variations were also used to estimate the fatigue usage factor for the spacer-to-guide tube welds. For conservatism, all cycles were considered to cause the extreme maximum stresses for the fatigue evaluations.
The stress results were evaluated to determine the fatigue usage for each cycle based on the O'Donnel and Langer (Reference 4) design curve. These results were accumulated to determine the total fatigue usage factor.

5.3.2.2 Fretting Wear

Each spacer type is designed to support the fuel rod without fretting wear through the design life of the fuel.

5.3.2.2.1 Bi-metallic Spacers

For the bi-metallic spacer, prevention of fretting wear is assured by maintaining a positive spring force. SPC performs fretting tests (long-term flow tests) to verify consistent performance for new spacer designs.

5.3.2.2.2 High Thermal Performance Spacers and Intermediate Flow Mixers

The prevention of fretting corrosion in the High Thermal Performance (HTP) spacers and Intermediate Flow Mixers (IFMs) is demonstrated by a combination of analysis and fretting tests. Flow test data are used to confirm that fretting corrosion will not occur throughout life even with a cladding-to-spacer spring gap.

5.3.2.3 Oxidation, Hydriding, and Crud Buildup

External corrosion is calculated using an NRC-approved model with the inclusion of an enhancement factor. As stated in Reference 3, effects of crud are modeled in the NRC-approved SPC fuel performance codes.
The limiting Zircaloy-4 cage components were analyzed for oxidation and hydrogen pickup. For structural components, the corrosion enhancement factor was selected based on benchmarking data.

The hydrogen absorption rate per surface area was applied to the applicable cross-sectional areas of the limiting components.

5.3.2.4 Rod Bow

As described in Reference 3, SPC has conducted extensive post-irradiation examinations of rod bow. The potential effect of such bow on thermal margins is covered in Section 7.1.4.

5.3.2.5 Growth

Projected fuel assembly growth behavior is based on the SPC measured data. The data at all burnups are statistically bounded by the SPC growth prediction curves.

5.3.2.6 Liftoff

The design of the holddown springs in the upper tie plate provides sufficient force to prevent fuel assembly liftoff due to hydraulic loads.

Fuel assembly irradiation growth, differential thermal expansion between the assembly and the core support structure, and fuel assembly dimensional tolerances are accounted for in the design. The holddown spring must retain its ability to counteract the hydraulic lift force throughout life. Although a small amount of spring relaxation may occur, this relaxation is compensated for by increased compression due to assembly growth. This allows the holddown springs to continue to provide sufficient holddown force throughout the design life of the fuel.

5.3.2.7 Handling

The assembly design must withstand axial loads from handling operations. SPC uses a load factor times the dry assembly weight to satisfy this criterion. Additional handling requirements for the design include acceptable plenum spring axial restraint/compliance and assembly features to ensure acceptable fuel shuffling characteristics.

5.3.2.8 Structural Deformations

The accident strength criteria for the fuel assembly structure is that it shall sustain, without impairing coolability or control rod insertability, the forces resulting from seismic and loss of coolant accident (LOCA) events. The loads arise from inertial forces caused by the motion of the upper and lower core plates, and lateral deflections and impacts transmitted to the assembly through adjacent assemblies, the core plates, and the core baffle.

5.3.3 Acceptance Criteria

Table 5.3.3-1 identifies the criteria for the SGR/Uprating evaluation and includes references to the appropriate criteria given in Section 3 of the design criteria topical report (Reference 3).

5.3.4 Results

The far right-hand column of Table 5.3.3-1 provides the limiting results from the SGR/Uprating evaluation.

5.3.5 Conclusions

The analyses demonstrate that the mechanical criteria applicable to the 17x17 fuel assembly design are satisfied for a 4.5% power uprate at HNP for normal operation and during AOOs subsequent to steam generator replacement. The same conclusion applies to just a steam generator replacement at HNP without power uprate. By demonstrating criteria compliance, the evaluation results continue to comply with the current HNP licensing basis/acceptance requirements.

5.3.6 References

1.XN-NF-82-06(P)(A) Revision 1, and Supplements 2, 4, and 5, Qualification of Exxon Nuclear Fuel for Extended Burnup, Exxon Nuclear Company, October 1986.

2.ANF-88-133(P)(A) and Supplement 1, Qualification of Advanced Nuclear Fuels' PWR Design Methodology for Rod Burnups of 62 GWd/MTU, Advanced Nuclear Fuels Corporation, December 1991.

3.EMF-92-116(P)(A) Revision 0, Generic Mechanical Design Criteria for PWR Fuel Designs, Siemens Power Corporation, February 1999.

4.W. J. O'Donnel and B. F. Langer, "Fatigue Design Bases for Zircaloy Components," Nuclear Science and Engineering, Volume 20, January 1964.

Table 5.3.3-1 Fuel Assembly Mechanical Design Evaluation Criteria and Results

Criteria Section[1]	Description	Criteria	Results or Disposition
3.3	Fuel System Criteria		
3.3.1	Stress, strain, and loading limits on assembly components. (See 3.3.9 for handling and 3.4 for accident conditions.)		
	Spacer grid	Lateral load < load limit.	See Sections 3.3.9 and 3.4 in this table.
	Guide tube	ASME Section III, Appendix III, Article III-2000 and Subsection NG.	Primary membrane stress, compressive, margin is maintained. Primary + secondary stress, compressive, margin is maintained. Buckling load margin is also maintained. ASME criteria met. Also see Sections 3.3.9 and 3.4 in this table.
	Connecting hardware	ASME Section III, Appendix III, Article III-2000 and Subsection NG.	Margin of safety is maintained. Margins are maintained for other connecting components.
	Upper tie plate (UTP) and lower tie plate (LTP)	Limiting loads occur during handling and postulated accidents.	UTP and LTP margins during normal operation are maintained. Also see Sections 3.3.9 and 3.4 in this table.
3.3.2	Fatigue		
	Guide tube	Cumulative usage factor (CUF) <0.67.	CUF is well below the allowable limits.
	Spacer/Guide tube joint	CUF <0.67.	CUF is well below the allowable limit.

1 Section numbers correspond to Reference 3 sections.

Table 5.3.3-1 Fuel Assembly Mechanical Design Evaluation Criteria and Results (Cont.)

Criteria Section[2]	Description	Criteria	Results or Disposition
3.3.3	Fretting wear	No fuel rod failures due to fretting wear.	Bi-metallic spacer: Spring force maintained at EOL. HTP spacer: Gap criteria met. IFM: Gap criteria met. Previous fretting tests remain applicable.
3.3.4	Oxidation, hydriding, and crud buildup	Assembly components shall be sufficiently corrosion resistant to ensure proper functional operations. Hydriding shall be sufficiently low so as to preserve strength and ductility during shipping and handling.	Design criteria are met for fuel assembly cage components.
3.3.5	Rod bow	Lateral displacement of the fuel rods shall not be of sufficient magnitude to impact thermal margins.	NRC-accepted model used to compute impact for transient analyses. Effect is addressed in Section 7.1.4.
3.3.6	Axial irradiation growth		
	Fuel assembly	The fuel assembly length shall not exceed the minimum space between upper and lower core plates.	EOL clearance exists between fuel assembly and core plates.
3.3.8	Assembly liftoff during normal operation (including AOOs)	No liftoff from core lower support.	Fuel assembly does not lift off during normal operation and AOOs.

2 Section numbers correspond to Reference 3 sections.

Table 5.3.3-1 Fuel Assembly Mechanical Design Evaluation Criteria and Results (Cont.)

Criteria Section2	Description	Criteria	Results or Disposition
3.3.9	Fuel assembly handling	Assembly withstands a load factor times the weight.	Fuel assembly handling not affected by SGR/Uprating. Design margin for the UTP strength is maintained.
3.4	Fuel Coolability		
3.4.4	Structural deformations	Maintain coolable geometry and ability to insert control rods. SRP 4.2, Appendix A, and ASME Section III, Appendix F.	Coolable geometry and control rod insertability are maintained during the safe shutdown earthquake (SSE) and LOCA accident.

* Section numbers correspond to Reference 3 sections.

5.4 Control Rod Drive Mechanisms

5.4.1 Introduction

This section addresses the ASME Code structural considerations for the pressure boundary components of the Westinghouse full-length L-106A-1 Control Rod Drive Mechanisms (CRDMs) and seismic sleeves for the Harris Nuclear Plant (HNP) SGR/Uprating conditions.

5.4.2 Description of Evaluations

The Westinghouse full-length L-106A-1 CRDMs were designed and analyzed to meet the Harris specifications (References 1, 2 and 3) and the ASME Code (Reference 4). The SGR/Uprating seismic and LOCA loads remain bounded by the current operating conditions.

The HNP CRDMs are exposed to the RCS cold-leg temperature defined by the vessel/core inlet temperature. The SGR/Uprating parameters that were evaluated indicate that none of the temperatures exceed the original operational basis temperature for the CRDMs. The revised parameters also indicate the RCS pressure remains the same at 2250 psi for all parameter cases. The original analysis for the CRDM was performed for a pressure of 2250 psig. Therefore, the SGR/Uprating NSSS parameters are bounded by the original site specific analyses that are documented in the applicable HNP stress, pressure boundary, and seismic sleeve summary reports.

The NSSS design transients were evaluated for any impact on the site-specific and generic CRDM analyses. The HNP CRDM evaluation of the generic and site-specific reports showed that the fatigue analysis based on the current normal, upset and test transients was performed using the Code (NB-3222.4(d)) waiver of fatigue requirements. The present HNP transients and the SGR/Uprating transients were compared for the normal, upset, emergency, faulted and test conditions.

The comparison showed that the normal and upset conditions contain similar groups of transients, but that some of the specific transients have been modified in number of cycles, pressure range and temperature range. For cases that changed, the effect on the various HNP-specific and generic stress reports was evaluated. Since the generic reports use the Code fatigue waiver, only a significant fluctuation in fatigue is of interest.

The SGR/Uprating transients added the RCS Cold Overpressurization transient. The review of the site-specific stress analysis report for the CRDM lower joint canopy indicated that it becomes a transient with a significant normal operation pressure fluctuation. Therefore, an actual fatigue evaluation was performed for this transient.

Also, review of the generic and HNP-specific CRDM stress and thermal analysis reports revealed that the Unit Loading/Unloading at 5 percent of Full-Power transient resulted in a normal

temperature fluctuation that is considered as significant in the fatigue waiver analysis. Consequently, an additional investigation was required for the SGR/Uprating transients to show that the CRDMs are satisfactory. The evaluation was performed and the CRDMs were found to be acceptable.

It should be noted that the only change to the Emergency and Faulted Conditions is an increase in Steam Generator Tube Rupture from 1 to 6 occurrences. Since, per the ASME B&PV Code (Reference 4), only the stresses and not the cycles are included in the fatigue evaluation, the SGTR transient increase in occurrences has no effect on the current satisfactory evaluation of the CRDMs.

5.4.3 Results

The review of the effects of the SGR/Uprating NSSS parameters and NSSS design transients on the CRDM site specific and generic reports, as described in the previous section, shows that the ASME Code of record (Reference 4) is still met. The E-Spec criteria for the CRDMs per References 1, 2 and 3 remain satisfied.

5.4.4 Conclusions

The results for the SGR/Uprating are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. These evaluations demonstrate that the CRDMs satisfy the appropriate editions of the ASME Code, stress limits, and fatigue usage criteria. The results obtained with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

5.4.5 References

1. Plant Design Specification 955578, Revision 0 (EM 5859), Project: Carolina Power and Light Company, Shearon Harris No. 1 and 2, Equipment: Control Rod Drive Mechanism Model L-106A-1, Westinghouse Nuclear Energy System, Pittsburgh, PA, December 7, 1982.

2. Plant Design Specification 955578, Revision 1 (EM 6001), Project: Carolina Power and Light Company, Shearon Harris No. 1 and 2, Equipment: Control Rod Drive Mechanism Model L-106A-1, Westinghouse Nuclear Energy System, Pittsburgh, PA, April 17, 1984.

3. General Equipment Specification G-677470, Revision 5, Westinghouse Electric Corporation - Nuclear Energy System Design, Pittsburgh, PA, May 14, 1982.

4. "ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components," American Society of Mechanical Engineers, NY, 1974 Edition with Addenda through Summer 1974.

Table 5.4-1 Summary of Fatigue Usage of CRDM Areas	
Area	**Fatigue Usage**
CRDM Generic Report, Lower Joint Canopy Area	[ ]$^{(b,c)}$
Lower Joint Canopy Area, ASN 23 Outside Surface	[ ]$^{(b,c)}$
Lower Joint Head Adapter, ASN 8 Inside Surface	[ ]$^{(b,c)}$
Lower Joint Latch Housing, ASN 14 Inside Surface	[ ]$^{(b,c)}$
Middle Joint Latch Housing, ASN 43 Outside Surface	[ ]$^{(b,c)}$
Middle Joint Rod Travel Housing, ASN 53 Inside Surface	[ ]$^{(b,c)}$
Middle Joint Canopy Area, ASN 69 Inside Surface	[ ]$^{(b,c)}$
Upper Joint Rod Travel Housing, ASN 95 Inside Surface	[ ]$^{(b,c)}$
Upper Joint CRDM Cap, ASN 131 Outside Surface	[ ]$^{(b,c)}$
Upper Joint Vent Plug, ASN 142 Inside Surface	[ ]$^{(b,c)}$
Upper Joint Canopy Area, ASN 118 Inside Surface	[ ]$^{(b,c)}$
CLH Latch Housing, ASN 47 Outside Surface	[ ]$^{(b,c)}$
CLH Cap, ASN 152 Inside Surface	[ ]$^{(b,c)}$
CLH Vent Plug, ASN 142 Inside Surface	[ ]$^{(b,c)}$
CLH Canopy Area, ASN 70 Inside Surface	[ ]$^{(b,c)}$

5.5 Reactor Coolant Loop Piping/Supports and Class 1 Auxiliary Line Piping

The Reactor Coolant Loop Piping and Supports for the SGR/Uprating were evaluated in three areas: the primary piping, equipment nozzles, and supports (Section 5.5.1); the application of leak before break (LBB) criteria to the reactor coolant loop piping (Section 5.5.2); and the Class 1 auxiliary line piping (Section 5.5.3). A discussion of each of these evaluations is provided below.

5.5.1 Reactor Coolant Loop Piping and Supports

5.5.1.1 Introduction

Evaluations have been made for the Harris Nuclear Plant (HNP) reactor coolant loop (RCL) piping and support system to consider the impact of the design parameters (Section 2) for the SGR/Uprating program, including the revised weight and center of gravity (CG) of the replacement steam generators (RSGs). The revised NSSS parameters for the SGR/Uprating were also considered in the RCL piping and support system qualification.

RCL Piping

Conservative Model Delta 75 steam generator weights were used in the RCL piping system evaluation. In addition, the revised steam generator upper support stiffness values were used. These revised stiffness values are due to modification between the new steam generator feedwater nozzle and the upper support ring.

During RSG installation, the main feedwater nozzle on the Model Delta 75 RSG and the feedwater piping is relocated so that it attaches higher on the RSG than in the original analysis. The effect of the nozzle break at the higher location and the subsequent compartment pressurization and jet impingement effect were also included in the evaluation in Reference 5.

Support System

The objective of the primary equipment/piping support system is to transfer all loads from the RCL equipment and piping to the supporting building structure. These support/restraint-modeling considerations require that the support bearing surfaces be in direct contact with the support component and that the restraints maintain their specified gap in the final hot operating position, normally considered to be 100 percent power.

The computation of stresses and/or loads in the RCL supports for all loading conditions is presented, along with the allowable stresses. The supports considered include the following: steam generator columns and upper and lower lateral, reactor coolant pump columns and tie rods, reactor vessel, and pressurizer. As-built deviations such as material substitutions, misalignments, pipe support attachments, etc., have been incorporated into this evaluation.

5.5.1.2 Description of Analyses and Evaluations

The SGR/Uprating program and its associated parameters were reviewed for impact on the existing design basis. The analyses, methods and criteria used in the existing design basis for HNP continue to be used.

5.5.1.2.1 Thermal Expansion

The SGR/Uprating NSSS design transients were compared with the design transients used for the T_{hot} Reduction/RSG program. The results of the comparison showed that there are no significant differences between the set of design transients. Also, there is no significant change in the reactor vessel inlet and outlet operating temperatures for the SGR/Uprating program and the temperatures used in the thermal analyses. Therefore, the thermal analyses remain valid. The existing inadvertent startup and loss of power transient temperatures identified in Section 3.1.2 of Reference 1 are still the governing over-temperature conditions. Effects on the fatigue evaluation are discussed in Section 5.5.1.3.4.

5.5.1.2.2 Design Pressure and Weight

The design pressure, which is also the pressure used in the qualification of the RCL piping, is 2485 psig. Uprating pressure variations around the RCL are all less than those used in the piping qualifications. Since the layout of the RCL piping has not changed from the original plant configuration, except for small attached lines, the distributed weight of the pipe, insulation and fluid remain essentially the same. The new weights of the steam generators and water content are considered to be fully supported by the steam generator columns and have negligible effect on the RCL piping.

5.5.1.2.3 Seismic Analysis

The seismic analysis methodology is discussed in detail in Section 4.2 of Reference 1. Seismic analysis is performed by the time history method to consider effects of the RSGs and the revised weight and center of gravity.

5.5.1.2.4 LOCA and Application of Leak Before Break (LBB)

Eleven LOCA break locations were identified in Table 3-1 of Reference 1. With the application of LBB technology to HNP, only three auxiliary line RCL nozzle break locations remain. They are the Residual Heat Removal line RCL connection, the Safety Injection System Accumulator line RCL connection, and the Pressurizer Surge line RCL connection. Time history RCL LOCA analyses were performed (Section 5.5.1.3.3) for the SGR/Uprating program by applying the LOCA Hydraulic Forcing Functions and the RPV motion developed for the project.

5.5.1.5.5 Loading Combinations

Loading combinations and stress evaluation criteria for the RCL piping are defined in Table 3-2 of Reference 1.

The types of loadings considered for the primary equipment supports include deadweight, thermal expansion, operating pressure, seismic events, LOCA, pipe ruptures and jet impingement loadings. Table 5.5.1-1 presents a summary of the loading combinations and stress limits for the primary equipment support loading conditions.

5.5.1.3 Description of Analyses Areas

5.5.1.3.1 Static Analysis

The static analytical model developed for the previous analyses in Reference 1 was revised to reflect the reactor coolant pump (RCP) column tilt effect and individual SG and RCP column stiffness values with the applicable support configurations. Only these column supports are active during normal operating conditions.

The temperatures consistent with the range identified for the SGR/Uprating program were considered in the thermal expansion analyses, as explained in Section 5.5.1.2.1. Active lateral equipment supports and the revised steam generator upper support stiffness values (due to potential interference between the new steam generator feedwater nozzle and the upper support ring) were also considered. The pressure and deadweight loadings have not changed since the original plant design analysis. The weight of the RSGs is considered to be supported by the steam generator columns for deadweight.

The WESTDYN computer code has been used for this analysis since the original plant design (FSAR Section 3.9.1.2.1 Item a, Section 3.9.1.4.3 and Reference 2).

5.5.1.3.2 Seismic Analysis

The dynamic four-massed steam generator model was developed based on the method described in Section 4.2.1 of Reference 1 to reflect the RSG with the revised CG and weight. A dynamic time history seismic analysis for the RSG was performed.

The WECAN computer code (Reference 3) has been used for the seismic analysis since the original plant design (FSAR Section 3.9.1.2.1 Item f).

5.5.1.3.3 LOCA Analysis and Pipe Thrust Force

Time history RCL LOCA analyses were performed for the SGR/Uprating program by applying the LOCA auxiliary line branch nozzle break Hydraulic Forcing Functions and the RPV motions. The WESTDYN computer code used for this analysis has been used for this analysis since the

original plant design (FSAR Section 3.9.1.2.1 Item a and Section 3.9.1.4.3). Broken and Unbroken Loop time history LOCA analyses were performed. With the application of LBB technology, the main loop breaks are eliminated.

For the replacement steam generator (RSG), the feedwater nozzle is located higher on the shell than for the original steam generator. It is located close to the steam generator upper support elevation, and a postulated nozzle break will cause the reactor coolant system to respond differently. Changes to steam generator support loads and changes to displacements of the RSG and attached piping are also expected. In the original plant configuration, the feedwater nozzle was located much lower on the steam generator shell, and the response of the system was much different. Consequently, a new RCL system analysis for the feedwater nozzle break was performed. Since the steam generator compartment walls are closer to the steam generator shell at the new feedwater nozzle elevation, it was necessary to consider compartment pressures and their effects on the steam generator. Compartment differential pressure forces across the steam generator shell were determined and combined with all other forces occurring from the break. The applied loads considered were thrust forces from the fluid escaping from the steam generator, jet impingement forces onto the steam generator from the broken side of the whipped pipe, and differential compartment forces around the steam generator. The analysis method performed was a dynamic time history analysis, with forces applied onto the steam generator model at various elevations and thrust/jet forces applied at the feedwater nozzle with respect to time. Results from this feedwater nozzle break analysis show that the reactor coolant piping is qualified. In addition, all equipment nozzles, displacements at all Class 1 auxiliary piping attached to the RCL, and equipment support loads were shown to be acceptable.
Feedwater break embedment loads and compartment pressure loads were provided for evaluation of compartment walls and structures. Steam generator displacements were also provided for evaluation of piping attached to the RSG. See the BOP Licensing Report.

No new main steamline break analysis was performed for the SGR/Uprating program, as there is no significant change in either the frequencies or the mass.

5.5.1.5.5 Fatigue Analysis

Since the temperature and pressure changes for the SGR/Uprating NSSS design transients are small, changes to the forces and moments for normal operating thermal expansion and operating pressure are also small, and are judged to be insignificant. The forces and moments for deadweight remain the same because the RCL piping properties have not changed. The change in seismic loads from the analysis due to the change in RSG weight and CG to the existing Model D-4 steam generator analysis is also insignificant. Furthermore, the comparison of the NSSS design transients for the SGR/Uprating with the design transients used for the T_{hot} Reduction/RSG program showed that there is no change in the number of cycles for the design transients. Therefore, the fatigue evaluations for the RSG done for the T_{hot} Reduction program remain valid and the fatigue usage factors for all selected locations are below the allowable. The results for the RCL piping stress analysis are summarized in Table 5.5.1-2.

The WESTDYN computer code has been used for the fatigue analysis since the original plant design (FSAR Section 3.9.1.2.1 Item a and Section 3.9.1.4.3).

5.5.1.5.6 Support Analysis

This section presents the structural evaluation of the as-built primary equipment supports for the SGR/Uprating design conditions. The evaluation of the primary equipment supports compares the stresses associated with loads obtained from piping system analyses with the acceptance criteria set forth by the 1974 ASME Boiler and Pressure Vessel Code, Section III, Subsection NF, including all Addenda up to and including Winter 1974 (Reference 4). In addition, for finding material strengths, "Cases of ASME Boiler and Pressure Vessel Code," Case 1644-4, approved by Council, March 1, 1976 was used (Reference 5).

The static and dynamic structural support analyses assume linear elastic behavior; they employ the matrix method and normal mode theory for the solution of lumped-parameter multi-mass structural models. The complexity of the physical system to be analyzed requires the use of a computer for solution. The equipment support structure models are dual-purpose since they are required to: (1) quantitatively represent, in terms of spring stiffness matrices, the elastic restraints which the supports impose upon the loop and (2) evaluate the individual support member stresses due to the forces imposed on the supports by the loop.

To accurately represent the elastic behavior of the supports, structural geometry, topology, member releases, and concrete flexibility are all considered in developing the support stiffness characteristics. These support stiffness characteristics are included in the RCL model.
To evaluate the effect of the support loads obtained from the RCL analysis, each element of the support that would assist in transferring these loads to the building structure concrete was considered.

The steam generator lower lateral supports are a series of bumpers that act in compression. Each was designed and evaluated as a linear-type support according to the ASME Code (Reference 4). Elements of this system include the struts that transfer the loads directly to the building structure concrete and the cross-compartment beam. To ensure the integrity of the beam, the built-up steel section, the beam splice bolts, and the anchorage were all considered in the evaluation.
The steam generator upper supports consist of a main circular ring band that transfers loadings at this elevation to a series of bumpers and hydraulic snubbers. Each was evaluated as a linear-type support that is active during seismic and LOCA events. Capacities of each element represent the capacity of the support system in the three orthogonal directions. The back-up structures for the SG upper lateral support ring band/snubbers assemblies are supplied by others and are not included in the evaluation.

The steam generator and reactor coolant pump columns are support members that transfer tensile or compressive loads from the equipment to the building structure concrete. These supports were designed and evaluated as linear-type supports as defined in the ASME Code (Reference 4). The support elements considered were the Type A and B forgings, the shear pins, column clevis plates, the pipe column section and the column base assembly. Tensile and compressive

capacities of each element were generated and compared to one another to determine the critical load capacity of this support.

The reactor coolant pump is supported laterally by the tie rods. These tie rods carry pump lateral loads in the form of tensile loads to the building structure concrete and were considered as linear-type supports. Capacities of the Type A column adapter forgings, the tie rods, shear pins, and the tie rod brackets were developed and compared to determine the critical load-carrying element.

The cross-compartment beams are modeled as linear elastic supports for analysis with the STRUDL computer code (Reference 6). The STRUDL computer code has been used for this analysis since the original plant design (HNP FSAR subsection 3.9.1.4.4).

The reactor vessel support system consists of six identical support members. Each member has three elements that were evaluated. The shoe and the shear pins were evaluated as linear-type supports with the box structure evaluated using the plate and shell criteria of the ASME Code (Reference 4). The finite element analysis of the box structure, produced primary membrane (P_m) and primary membrane plus bending ($P_m + P_b$) stresses for each finite element of the model. Vertical and horizontal loads are transmitted from the reactor vessel nozzle pad to the reactor vessel support box structure. Each box structure consists of a horizontal top plate, which receives loads from the forged reactor vessel shoe. Intermediate vertical plates transmit these loads to a horizontal bottom plate. The box was modeled as a plate-and-shell-type support for a finite element analysis with the WECAN computer code (Reference 3). The WECAN computer code has been used for this analysis since the original plant design (HNP FSAR subsection 3.9.1.4.4).

5.5.1.6 Acceptance Criteria

The design criteria used for the piping qualification of the HNP RCL system are defined in the design specifications. They are based on the ASME B&PV Code Section III (NB) through the Winter 1979 Addenda (Reference 7).

Table 5.5.1-1 presents a summary of the loading combinations and stress limits for the primary equipment support evaluation.

5.5.1.5 Results

5.5.1.5.1 Piping Stresses and Fatigue Qualification

The deadweight and thermal analysis results for the RCL piping are summarized in Table 5.5.1-2. Differences between the displacements from the seismic analyses due to the RSG (with the revised weight and center of gravity) and the displacements from the existing Model D4 steam generator analysis are insignificant. The evaluation showed that the Model D4 existing steam generator seismic analysis support loads envelop the seismic support loads for the RSG. The fatigue analysis results remain valid, as discussed in Section 5.5.1.3.4.

The stresses due to primary loadings of pressure, weight, OBE, SSE, and LOCA are combined in accordance with the methods described in Section 5.1 of Reference 1. The maximum primary stresses due to pressure, weight, OBE, SSE, and LOCA in the RCL piping and the ASME Code allowable stress values are presented in Table 5.5.1-2. The table also provides the maximum secondary or fatigue stresses, the usage factors, and the ASME Code allowable values. The RCL piping stresses are all acceptable.

5.5.1.5.2 Primary Equipment Nozzle Loads

The primary equipment nozzle loads are compared to the allowable nozzle loads provided in the equipment design specifications. In cases where the nozzle loads exceed the allowable values, principal stresses are calculated to qualify the primary equipment nozzle loads. The primary equipment nozzle loads are all acceptable.

5.5.1.5.3 Leak Before Break (LBB)

The LBB loads are acceptable as indicated by Reference 8. The LBB loads qualification is presented in Section 5.5.2 of this report.

5.5.1.5.4 As-built Condition and Pipe Wall Thickness Issues

The existing as-built condition has been reconciled in Section 5.4 of Reference 1. The pipe wall thickness issues have been considered in the analyses and found to be acceptable. The results are incorporated in Table 5.5.1-2.

5.5.1.5.5 Primary Equipment Supports

Table 5.5.1-3 defines the maximum support stresses for the steam generator columns, lower and upper lateral, reactor coolant pump columns and tie rods, reactor vessel support, and the pressurizer supports. Member loads are shown for each support with its corresponding maximum stress level expressed as a percentage of the allowable stress. For the faulted loading condition, the controlling pipe rupture or LOCA break case is listed.

The stress evaluation for the Upset conditions shows that the stresses are below the allowable values established by the ASME Code (Table 5.5.1-3). The contribution to the Faulted condition stresses is predominantly from the LOCA and seismic loadings; the contribution from the loadings due to pressure and weight is relatively minor. The supports system stress evaluation for the Faulted condition shows that the stresses are below the allowable values for all support members as established in the Code.

5.5.1.6 Conclusions

A piping stress analysis of the RCL was performed for HNP to consider the design parameters of the SGR/Uprating program, and the design has been found to be adequate. The RCL system will maintain its structural integrity and meet all safety related design requirements.

The analysis results show that the primary stresses are below the allowable limits established in the Code (Reference 7) under the design, upset, and faulted conditions. The RCL piping secondary stresses and fatigue usage factors are in conformance with the requirements of the Code for the fatigue damage evaluation performed under all normal, upset, and test conditions. The primary equipment nozzle loads are all acceptable. Therefore, the RCL piping system is adequate for all design loading conditions.

The as-built primary equipment supports system is adequate. It is calculated to maintain its structural integrity and meet the safety-related design requirements under all specified design conditions, as defined by the ASME Code (Reference 4), the original code of record for the HNP primary equipment supports. The stress report was updated in Reference 9.

Operation of HNP with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bounds operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt. Operation at the uprated NSSS power is bounding since the associated NSSS parameters (e.g., maximum and minimum temperatures) and the design transients of concern for this evaluation result in maximum stresses that remain acceptable to the ASME criteria and would bound those determined at the lower power level.

5.5.1.7 References

1. WCAP-9990, Volume 1, Rev. 2 "Structural Analysis of the Reactor Coolant Loop for Shearon Harris Nuclear Power Plant Unit 1 - Analysis of the Reactor Coolant Loop Piping," September 1988.

2. Westinghouse Letter EDRE-SMT-98-121, "Release of WESTDYN Version 7.1," W. R. Morrison, November 3, 1998.

3. WECAN - Westinghouse Electric Computer Analysis, Version Date 1997.

4. ASME Boiler and Pressure Vessel Code, Section III (NF), including Addenda up to and including Winter 1974, "Nuclear Power Plant Components," American Society of Mechanical Engineers, New York, 1974.

5. "Cases of ASME Boiler and Pressure Vessel Code," Case 1644-4, approved by Council March 1, 1976.

6. User Manual for ICES-STRUDL-II, Version 2-M2, June 1972.

7. ASME Boiler and Pressure Vessel Code, Section III (NB), Through Winter of 1979 Addenda.

8. WCAP-14549, "Technical Justification For Eliminating Large Primary Loop Pipe Rupture As The Structural Design Basis For The Shearon Harris Unit 1 Nuclear Power Plant," December 1996.

9. WCAP-9990, Volume 2, Rev. 1, "Structural Analysis of the Reactor Coolant Loop for Shearon Harris Nuclear Station Units No. 1 and 2," March 2000.

Table 5.5.1-1

Support Structure Loading Combinations and Stress Criteria For Normal, Upset, and Faulted Conditions

Operating Condition	Loading Combination	Stress Limit	
		Linear-Type Supports	**Plate and Shell Supports**
Normal	Thermal expansion Weight Operating pressure	Within working limits	$P_m \leq 1.0\ S_m$ $P_m + P_b \leq 1.5\ S_m$
Upset	Thermal expansion Weight Operating pressure OBE Pipe support attachments	Within working limits	$P_m \leq 1.0\ S_m$ $P_m + P_b \leq 1.5\ S_m$
Faulted[3]	Operating pressure Weight LOCA SSE Jet impingement Pipe support attachments	Smaller factor of 2.0 or $1.167\ S_u/S_y$ if $S_u \geq 1.2\ S_y$ or 1.4 if $S_u < 1.2\ S_y$ Times working limits	$P_m \leq 1.5\ S_m$ or $1.2\ S_y$ (greater)[1] $P_m+P_b \leq 2.25\ S_m$ or $1.8\ S_y$ (greater)[2]

Notes:

(1) Not to exceed $0.7\ S_u$

(2) Not to exceed $1.05\ S_u$

(3) Faulted = Deadweight + Pressure $\pm\sqrt{(SSE)^2 + (LOCA)^2}$

Table 5.5.1-2 Piping Stress Analysis Summary						
	Hot Leg		Crossover Leg		Cold Leg	
Evaluation	Maximum	Allowable	Maximum	Allowable	Maximum	Allowable
Equation 9, Design Stress (ksi) (DW, P)	[ ]$^{(b,c)}$	26.32	[ ]$^{(b,c)}$	26.32	[ ]$^{(b,c)}$	26.32
Equation 9, Upset Stress (ksi) (DW, P, OBE)	[ ]$^{(b,c)}$	29.25	[ ]$^{(b,c)}$	29.25	[ ]$^{(b,c)}$	29.25
Equation 9, Faulted Stress (ksi) (DW, P, SSE, LOCA)	[ ]$^{(b,c)}$	52.64	[ ]$^{(b,c)}$	52.64	[ ]$^{(b,c)}$	52.64
Equation 12, Stress (ksi)	[ ]$^{(b,c)}$	53.10	[ ]$^{(b,c)}$	53.10	[ ]$^{(b,c)}$	53.10
Equation 13, Stress (ksi)	[ ]$^{(b,c)}$	53.10	[ ]$^{(b,c)}$	53.10	[ ]$^{(b,c)}$	53.10
Fatigue Usage Factor	[ ]$^{(b,c)}$	1.0	[ ]$^{(b,c)}$	1.0	[ ]$^{(b,c)}$	1.0

Note: All Allowable Stresses in the table are based on design temperature.

Table 5.5.1-3 Primary Equipment Support Member Stresses					
	Member Stresses (Percent of Allowable/Loading Condition) Units (kips)				
	Upset		Faulted		
Member	Load	Percent Stressed	Load	Break	Percent Stressed
SG Lower Support Bumpers	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
SG Lower Support Beams (1, 2)	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
SG Columns (3)	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$
SG Upper Supports (4)	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
RCP Tie Rods	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
RCP Columns (3)	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$
RV Support	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(5)(b,c)}$	[ ]$^{(b,c)}$
Pressurizer Skirt	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Pressurizer Struts	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$ [ ]$^{(b,c)}$	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$

Notes:

(1) Ratio includes seismic loads, anchor wall motion and restrained thermal expansion (+50°F) of SGLL Beam.

(2) Effects of pipe support attachment loads are included.

(3) (+) = Tension, (–) = Compression for column loadings.

(4) Loads shown are the controlling total resultant loads applied at the centerline of the steam generator

(5) RV support LOCA loads and stresses are conservative

5.5.2 Reactor Coolant Loop Piping LBB Analysis

5.5.2.1 Introduction

The original structural design basis of the Reactor Coolant System (RCS) for HNP required that the dynamic effects resulting from pipe break be considered and that protective measures for such breaks be incorporated into the design. Subsequent to the original HNP design, additional concern regarding asymmetric blowdown loads was raised as described in Unresolved Safety Issue A-2 (Asymmetric Blowdown Loads on the Reactor Coolant System). The resolution of the Unresolved Safety Issue A-2 was identified in Generic Letter 84-04 (Reference 1). However, research by the NRC and industry coupled with operating experience determined that safety could be negatively impacted by placement of pipe whip restraints on certain systems. As a result, NRC and industry initiatives demonstrated that leak-before-break (LBB) criteria can be applied to RCS piping based on fracture mechanics technology and material toughness. Westinghouse performed the initial primary loop LBB analysis for HNP in 1984, which was documented in WCAP-10699 (Reference 2) and then approved by the NRC in 1985 (Reference 3).

In 1996 Westinghouse performed a LBB analysis for the replacement steam generator program using updated LBB criteria. The results were documented in WCAP-14549 (Reference 4).

5.5.2.2 Description of Analyses and Evaluations

Westinghouse has performed the LBB evaluation of HNP primary loop piping to justify the elimination of RCS primary loop pipe breaks with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt. The evaluation was performed to demonstrate that the following objectives were achieved:

1. Demonstrate that margin exists between the critical crack size and a postulated crack that yields a detectable leak rate.

2. Demonstrate that there is sufficient margin between the leakage through a postulated crack and the leak detection capability of the HNP.

3. Demonstrate margin on applied load.

4. Demonstrate that fatigue crack growth is negligible.

The flaw stability criteria applied in the analysis considered both global and local stability for a postulated through-wall circumferential flaw. The global analysis was carried out using the plastic instability method, based on traditional plastic limit load concepts, but accounting for strain hardening, and taking into account the presence of a flaw. The local stability criteria were based on the J integral-tearing modulus (J-T) approach.

5.5.2.3 Acceptance Criteria

The LBB acceptance criteria are based on the Standard Review Plan 3.6.3. The recommended margins are as follows:

- Margin of 10 on the Leak Rate
- Margin of 2.0 on Flaw Size
- Margin of 1.0 on Loads (Using Faulted Load combination by Absolute Summation Method)

5.5.2.4 Results and Conclusions

Based on the evaluation performed, it is concluded that the LBB analysis results shown in WCAP-14549 (Reference 4) are acceptable for the HNP SGR/Uprating program. Therefore, the conclusions derived in References 2 and 4 remain valid, and the dynamic effects of the RCS primary loop pipe breaks need not be considered in the structural design basis of the HNP SGR/Uprating program.

Since the current evaluation has shown that the existing LBB analysis is acceptable for the SGR/Uprating program, the results continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt are also consistent with the results obtained with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

5.5.2.5 References

1. USNRC Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops," February 1, 1984.

2. WCAP-10699, "Technical Justification for Eliminating Large Loop Pipe Rupture as the Structural Design Basis for the Shearon Harris Unit 1," September 1984.

3. Nuclear Regulatory Commission Docket No. 50-400; Letter from George W. Knighton, Chief Licensing Branch No. 3 Division of Licensing of the NRC to E. E. Utley, Executive Vice President Power Supply and Engineering and Construction of Carolina Power and Light Company, June 5, 1985.

4. WCAP-14549, "Technical Justification for Eliminating Large Loop Pipe Rupture as the Structural Design Basis for the Shearon Harris Unit 1 Nuclear Power Plant," December 1996.

5.5.3 Class 1 Auxiliary Lines

5.5.3.1 Introduction

The Harris Nuclear Plant (HNP) Class 1 Auxiliary Lines have been evaluated to determine the impact of the SGR/Uprating program design parameters on the qualification of the Class 1 Auxiliary Lines piping system.

5.5.3.2 Description of Analyses and Evaluations

The evaluation of the Class 1 Auxiliary Lines for the SGR/Uprating program includes the following:

- The weight and center of gravity (CG) of the replacement steam generator
- The design transients for the SGR/Uprating program
- The NSSS parameters for the SGR/Uprating program
- Revised Class 1 Auxiliary Line pipe support stiffness values

All other input data and parameters other than those listed above remain the same as those used in Reference 1.

The six Class 1 Auxiliary Lines with pipe diameter sizes larger than 6 in. were reanalyzed for the SGR/Uprating program. The existing seismic displacements at these large bore Class 1 Auxiliary Line connections to the RCL have changed and new seismic analysis for these lines was performed for the SGR. The following six Auxiliary Lines were re-analyzed:

- Pressurizer Surge Line
- Accumulator Line Loop 1
- Accumulator Line Loop 2
- Accumulator Line Loop 3
- RHR Line Loop 1
- RHR Line Loop 3

These six lines were re-analyzed to assess the seismic impact of the SGR/Uprating on support loads and pipe stresses. The response spectra used is the same as that used for the existing design basis analysis. All other analyses, deadweight, thermal, LOCA, and fatigue were reconciled for the uprating conditions and the impact on the results were judged to be insignificant due to the uprating conditions.

The Class 1 Auxiliary Lines with pipe diameter sizes 6 in. and less were not re-analyzed for the SGR/Uprating program, since the existing seismic displacements at these small bore Class 1 Auxiliary Line connections to the RCL have not significantly changed and no new seismic analysis for these lines was performed for the SGR.

5.5.3.3 Acceptance Criteria

The acceptance criteria for the structural evaluation of the Class 1 Auxiliary Line piping system are provided in the design specification and procedure of References 2 and 3. As shown in Reference 2, the piping stress evaluation for the Class 1 Auxiliary Line piping stresses and the fatigue usage factors must be below the allowable limits as established in the ASME Code (References 4 and 5). The actual and allowable piping stresses and the actual and allowable cumulative usage fatigue factors are shown in Table 5.5.3-1

5.5.3.4 Results

The results of the evaluation for the six Class 1 Auxiliary Lines - Pressurizer Surge Line, Accumulator Line Loop 1, Accumulator Line Loop 2, Accumulator Line Loop 3, RHR Line Loop 1, and RHR Line Loop 3 are summarized in Table 5.5.3-1. The table lists the maximum Equation 9 Upset and maximum Equation 9 Faulted pipe stresses including the maximum cumulative fatigue usage factor in the Class 1 portion of the lines. The evaluation for the Class 1 Auxiliary piping determined the stresses and the fatigue usage factors to be below the allowable limits as established in the ASME Code (References 4 and 5).

The results of the remaining Class 1 Auxiliary Lines not listed in Table 5.5.3-1 remain unchanged from the original design basis for the SGR/Uprating program.

5.5.3.5 Conclusions

The HNP Class 1 Auxiliary Line piping has been evaluated for the SGR/Uprating program. The Class 1 Auxiliary piping, as stipulated in the design specification (Reference 2) is calculated to maintain its structural integrity and meet safety-related design requirements.

HNP operation with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bounds operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt. Operation at the uprated NSSS power is bounding since the associated NSSS parameters (e.g., maximum and minimum temperatures) and the design transients of concern for this evaluation result in calculated maximum stresses that remain acceptable with respect to the ASME criteria.

5.5.3.6 References

1. WCAP-9990 Volume IV, "Structural Analysis of Reactor Coolant Loop For Shearon Harris Nuclear Power Plant Unit 1 - Analysis Of The Class 1 Auxiliary Piping," November 1984.

2. Westinghouse Design Specification 955239, Revision 3, "Shearon Harris Nuclear Power Plant, Unit No. 1, Piping Design Specification, ANS Safety Class 1," and G-677458 Revision 4 plus Interim Revision 1 to G-677458 Revision 4, "General Piping Design Specification, ANS Safety Class 1."

3. CP&L Nuclear Generation Group Standard Procedure, Volume 99 Book/Part 99, EGR-NGGC-0308, "Pipe Stress Analysis," Revision 5.

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB and NC, "Nuclear Power Plant Components," 1977 Edition and all addenda through Summer 1979, ASME, New York.

5. ASME Boiler and Pressure Vessel Code, Section III, Subsection NC, "Nuclear Power Plant Components," 1980 Edition, ASME, New York.

Table 5.5.3-1 Auxiliary Lines Class 1 Piping Stress Analysis Summary						
Auxiliary Line	**Maximum Equation 9 Upset Pipe Stress (KSI)**		**Maximum Equation 9 Faulted Pipe Stress (KSI)**		**Maximum Cumulative Usage Factor**	
	Actual Stress	**Allowable Stress**	**Actual Stress**	**Allowable Stress**	**Actual**	**Allowable**
RHR Loop 1	[ ]$^{(b,c)}$	28.03	[ ]$^{(b,c)}$	50.1	[ ]$^{(b,c)}$	1.0
RHR Loop 3	[ ]$^{(b,c)}$	28.03	[ ]$^{(b,c)}$	50.1	[ ]$^{(b,c)}$	1.0
Pressurizer Surge	[ ]$^{(b,c)}$	27.4	[ ]$^{(b,c)}$	48.2	[ ]$^{(b,c)}$	1.0
Accumulator Loop 1	[ ]$^{(b,c)}$	28.2	[ ]$^{(b,c)}$	50.1	[ ]$^{(b,c)}$	1.0
Accumulator Loop 2	[ ]$^{(b,c)}$	27.7	[ ]$^{(b,c)}$	50.1	[ ]$^{(b,c)}$	1.0
Accumulator Loop 3	[ ]$^{(b,c)}$	27.7	[ ]$^{(b,c)}$	50.1	[ ]$^{(b,c)}$	1.0

5.6 Reactor Coolant Pumps and Motors

The Harris Nuclear Plant (HNP) Model 93A Reactor Coolant Pumps (RCPs) were evaluated at SGR/Uprating conditions for structural adequacy (Section 5.6.1) and acceptability of the RCP motors (Section 5.6.2).

5.6.1 Reactor Coolant Pumps (Structural)

5.6.1.1 Introduction

This section addresses the structural adequacy of the HNP Model 93A RCPs at the SGR/Uprating conditions.

5.6.1.2 Description of Evaluations and Acceptance Criteria

The Westinghouse Model 93A RCPs were designed and analyzed to meet the HNP pump specifications (References 1 and 2) and the ASME Code of record (Reference 3). The SGR/Uprating seismic and LOCA loads remain bounded by the current operating conditions.

The evaluation of revised NSSS parameters indicates the RCP inlet temperature, which corresponds to the steam generator outlet temperature, is slightly lower, and thus bounded by the original design basis temperature. The normal operating pressure of 2250 psia remains the same as the original design basis for all of the cases. Therefore, the SGR/Uprating NSSS parameters are acceptable for the HNP RCPs.

The NSSS design transients were evaluated at SGR/Uprating conditions for any impact on the site specific and generic RCP analyses. The HNP RCP evaluation of the generic and site-specific pressure boundary summary reports showed that the fatigue analysis was performed using the Code [NB-3222.4(d)] waiver of fatigue requirements. The present HNP transients and the SGR/Uprating transients were compared.

The total number of Normal Condition transient cycles has decreased from the number required in Reference 1. A reactor coolant system (RCS) Cold Overpressurization transient was added to the original design basis upset transients. This transient is defined to occur 10 times. Each occurrence entails a thermal cycle along with an additional series of 600 pressure cycles. The RCS Cold Overpressurization transient is not a critical transient in the analysis of the RCP since it meets the ASME code fatigue waiver criteria. Therefore, the additional RCS Cold Overpressure transient cycles have no effect on the RCP fatigue evaluation.

The Normal Condition and Upset Condition transients are concerned with the temperature changes (ΔT) and the pressure changes (ΔP) related to the SGR/Uprating program. These parameters are of interest to the stress intensity range and fatigue considerations. In some cases, the SGR/Uprating ΔP and/or the ΔT are equal to or less than the current E-Spec (Reference 1) values and are thus bounded and require no additional investigation.

For cases in which ΔP or ΔT increased, the effect on the various generic stress reports was evaluated. Since the generic reports use the ASME Code fatigue waiver, only a significant fluctuation of pressure or temperature is of interest in fatigue. None of the changes to the Normal or Upset transients for the SGR/Uprating cause a non-significant pressure or thermal transient to become a significant transient. The RCS Cold Overpressurization transient is also observed to be a non-significant transient for fatigue. Thus, the fatigue waiver evaluation for the current HNP licensing basis/acceptance requirements bounds the SGR/Uprating.

5.6.1.3 Results

The review of the effects of the SGR/Uprating NSSS parameters and NSSS design transients on the RCP site-specific and generic reports shows that the appropriate editions of record for the (Reference 3) are still met.

5.6.1.4 Conclusions

The revised NSSS parameters and NSSS design transients for the HNP SGR/Uprating are considered acceptable for the Model 93A RCPs from a structural standpoint. The pump pressure boundary parts continue to satisfy the RCP E-Specs (References 1 and 2) and the ASME Code of record (Reference 3). Therefore, the results of the structural evaluation of the HNP RCPs for the SGR/Uprating are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

5.6.1.5 References

1. Plant Design Specification 679138, Revision 6, "Carolina Power and Light Company Shearon Harris Nuclear Stations 1 & 2, Reactor Coolant Pump Model 93A, 60 Hertz," and Interim Revision No. 4, Westinghouse Nuclear Energy Systems, Pittsburgh, PA, D. R. Collier; Revised by C. T. Holmes and L. S. Jenkins, August 9, 1984.

2. General Equipment Specification G-677188, Revision 4, "Reactor Coolant Pump," Westinghouse Nuclear Energy Systems, Pittsburgh, PA, J. Green; Revised by A. A. Anderson, January 15, 1976.

3. "ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components," American Society of Mechanical Engineers, NY, 1971, with Addenda through the summer of 1972.

5.6.2 Reactor Coolant Pump Motors

5.6.2.1 Introduction

This section addresses the effect of the SGR/Uprating on the operation of RCP motors at the Harris Nuclear Plant (HNP) based on the NSSS parameters shown in Section 2.0 of this Licensing Report and a decrease in Best Estimate flow of 3400 gpm per loop.

5.6.2.2 Description of Evaluation and Acceptance Criteria

The seismic and LOCA loads remain bounded by the original requirements. Changes to the Component Cooling Water (CCW) system temperatures have an insignificant effect on motor operation. Due to insignificant effects from the SGR/Uprating transients, only the motor operation needs to be evaluated under the higher loads from the SGR/Uprating program. The effects of the SGR/Uprating on RCP motor components structural integrity, motor heat dissipation to the environment, and motor oil cooler temperature are insignificant.

The RCP motor performance is evaluated based on the maximum calculated hydraulic loads using the limiting NSSS parameters. The pump operating temperature of 536.3°F (steam generator outlet temperature) and the pump best estimate flow of 100,000 gpm are used to calculate the highest pump power requirements among the three RCPs at the HNP site. In addition, corresponding pump loads are calculated at cold condition (70°F).

All Westinghouse RCP motors are dual rated with a hot-loop rating (at which the NEMA Class B stator winding temperature rise limits are not to be exceeded) and a cold-loop rating (at which the NEMA Class F stator winding temperature rise limits are not to be exceeded). The motor does not have a service factor, but the cold-loop rating is 125 percent of the hot-loop rating.

The cold-loop rating is based on the water at 70°F. The hot-loop rating is based on the water temperature at the steam generator outlet during full-power operation. Both are considered to be steady-state cases.

5.6.2.2.1 Continuous Operation at Revised Hot-Loop Rating

The motor is required to drive the pump continuously under hot-loop conditions without exceeding a stator winding temperature rise of 75°C (corresponding to the NEMA Class B temperature rise limit in a 50°C ambient). The calculated hot-loop load is essentially at the motor nameplate rating of 7000 Hp. The motors have been shown by test to operate within the specification limits at the hot-loop nameplate rating. Therefore, continuous operation at the revised load is acceptable.

5.6.2.2.2 Continuous Operation at Revised Cold-Loop Rating

The motor is required to drive the pump for up to 3000 hours (continuous) under cold-loop conditions without exceeding a stator winding temperature rise of 100°C (corresponding to the NEMA Class F temperature rise limit in a 50°C ambient).

The worst-case cold-loop load under the revised operating conditions is 8907 Hp. This represents a 1.8-percent increase over the nameplate rating of the motor. The increase in stator winding temperature rise due to this new load is calculated to be 4.5°C above the NEMA guaranteed limit for Class F windings. Exceeding the Class F limits by 4.5°C during the 3000 hours of operation at cold conditions (70°F) can accelerate stator insulation thermal aging and reduce its life by approximately 1100 hours over the 40-year design life. Therefore, the motor cold operation time is reduced to 1900 hours over the 40-year RCP design life. With the increased loading, all available thermal margin has been utilized.

The analysis of the operation time at the cold condition is conservative.

5.6.2.2.3 Starting

The motor is required to start across the line with a minimum 80-percent starting voltage, against the reverse flow of the other pumps running at full speed, under cold-loop conditions. The limiting component for this type of starting duty is the rotor cage winding. A conservative all-heat-stored analysis is used to determine if the cage winding temperature exceeds the design limits (300°C on the bars and 50°C on the resistance rings).

Using a revised load torque curve, based on the SGR/Uprating conditions, the starting temperature rise for the rotor bars and resistance rings has been calculated. The results show bar temperature of 246.6°C and ring temperature of 32.95°C. These temperatures do not exceed design limits. Therefore, the motor can safely accelerate the load under worst case conditions.

5.6.2.2.4 Loads on Motor Bearings

Performance of the thrust bearings in an RCP motor can be adversely affected by excessive or inadequate loading. The axial down thrust for the revised parameters decreased from 55,000 lbs. to 53,604 lbs. for hot-loop operation and reduced from 75,000 lbs. to 72,251 lbs. for cold-loop operation. The thrust and radial bearing load changes that result from the SGR/Uprating program are well within the radial and thrust bearing capacities.

5.6.2.3 Conclusions

The worst case loads for the RCP motors were calculated for the SGR/Uprating conditions. Using the revised loads, all of the HNP RCP motors were evaluated in the four areas where parameter changes affect performance. These areas are as follows:

- Continuous operation at the revised hot-loop rating
- Continuous operation at the revised cold-loop rating
- Starting loads
- Bearing loads

Based on this evaluation, the RCP motors are considered acceptable for operation at the revised SGR/Uprating conditions.

The results for the SGR/Uprating are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Delta Model 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

5.7 Steam Generators

The Harris Nuclear Plant (HNP) Model Delta 75 replacement steam generators (RSGs) were analyzed at the uprated power conditions in the areas of structural acceptability (5.7.1), thermal-hydraulic (T/H) performance (5.7.2), and flow-induced vibration and wear (5.7.3). These three areas are discussed in detail below.

5.7.1 Steam Generator Structural Evaluation

5.7.1.1 Introduction

The uprating of HNP to 2912.4 MWt NSSS power incorporates steam generator tube plugging (SGTP) in the range of 0 percent to 10 percent maximum in any steam generator operating with the maximum feedwater temperature at either 440°F or 375°F, and a range of RCS temperature conditions in addition to the power increase. These conditions are considered in the RSG structural evaluations discussed below. The transients and load conditions for the RSG design specification are given in Reference 1.

The appropriate NSSS parameters were used for the steam generator structural integrity evaluation. In the evaluation, two sets of parameters were considered: high and low RCS temperatures. The enveloping condition for the primary side components is the one that results in a high primary to secondary side ΔP. The low temperature condition results in the lower steam pressure during normal operation. The lower pressure causes an increase in the corresponding primary to secondary ΔP, which results in higher stresses and slightly higher usage for the primary side components. For the secondary side components, the decrease in the maximum feedwater temperature and the resulting change in the temperature difference across some components can result in higher stresses and fatigue usage. Those components in direct contact with the feedwater and the subcooled fluid in the downcomer region are most affected by the change in feedwater temperature and are evaluated.

Those components that are within the steam space, or entirely within the confines of the steam generator, or whose fatigue usage factor is based on transients unaffected by the uprate, were not evaluated. These components are either not impacted by the change in the maximum feedwater temperature, since other transients not impacted by the uprate are controlling, or the thermal effects are not significant and so have negligible effect on the analysis results. The following components were not evaluated:

- Steam nozzle, elliptical head and upper shell
- Lower internals
- Sludge collector maintenance opening
- Upper internals

The NSSS design transients applicable for the uprating conditions were also used in this evaluation.

Feedwater line break (FWLB) effects have been considered both from the standpoint of the design pressures of the steam generator and the steam generator collapse pressure. Results show that the maximum external pressure exerted by the asymmetric loading of the FWLB is less than 6 percent of the pressure required to collapse the SG shell. Since the calculated collapse pressure is over-and-above the internal pressure of the SG, and the maximum applied sub-compartment load is less than 30 psi, the qualification of the SG is not impacted by this event. Therefore, FWLB asymmetric loading effects have been shown to be acceptable.

5.7.1.2 Description of Analyses and Evaluations

The structural evaluations were performed using the results of the previous structural analysis of the HNP Delta 75 steam generators. Components not discussed below were not evaluated for the uprate, as discussed in Section 5.7.1.1, since the previous analysis results remain valid without further evaluation.

These evaluations were performed for the following SGR/Uprating primary and secondary side design conditions:

1. Uprated NSSS power of 2912.4 MWt
2. RCS vessel average temperature window of 572.0°F - 588.8°F
3. Model Delta 75 replacement steam generators
4. Maximum SGTP level up to 10 percent
5. Full-power feedwater temperature of 440°F or 375°F
6. Maximum and minimum nominal steam pressure of 979 psia (0 percent SGTP) and 825 psia (10 percent SGTP), respectively.

The transients/NSSS parameters previously evaluated for the SGR were compared for differences that could affect the current evaluation. Conservative ratios, based on temperature differences, were used to modify the design analysis results, if required, to determine the stresses and usage factors at the SGR/Uprating conditions.

The structural evaluation of the critical components of the Model Delta 75 steam generators was used as the basis to justify operation at the uprated conditions. The evaluations were performed to the requirements of the ASME B&PV code Section III, 1971 edition, Summer 1972 Addendum, Reference 2.

Material strength properties from the Summer 1972 Addendum to the 1971 ASME Code Section III were used except for those values not available in the 1971 Code. Where the material strength properties were not available in the 1971 ASME Code, Summer 1972 Addendum, material strength properties were taken from the 1986 Edition, Reference 3.

5.7.1.3 Acceptance Criteria

The critical steam generator components that were evaluated for structural adequacy are:

Primary side: Primary chamber, tubesheet, primary nozzles, primary manway, divider plate, and tube to tubesheet weld. The primary side of the replacement steam generators was evaluated as a whole through a review of the uprating transients that affect the primary side of the steam generator, i.e. RCS transients.

Secondary side: Upper shell, transition cone, lower shell, junction of tubesheet and stub barrel, main and auxiliary feedwater and spray nozzles, secondary manway opening and bolts, 6-in hand-hole, 2-in. and 4-in. inspection ports, and minor shell taps.

These components were evaluated for the effects of changes to the thermal transients due to the uprate. The acceptance criteria for each component is consistent with the criteria used in the design basis analysis referenced for each component.

5.7.1.4 Results

A summary of the results for each of these components follows. A summary of the maximum stress range/allowable stress range ratios and fatigue usage of the steam generator components is provided in Tables 5.7.1-1 and 5.7.1-2.

5.7.1.4.1 Primary Side Components

Primary side transients for uprating were compared to the applicable transients used in the design specification for the HNP RSGs. The comparison showed that the uprating transients for the RCS are the same as those used in the design specification (Reference 1).

Pressure conditions for the tubesheet are a function of both the primary and secondary side pressures. The primary side conditions are unchanged due to the uprating. The maximum primary-to-secondary side pressure difference would result from considering the maximum primary-side pressure and minimum secondary-side pressure. The minimum operational steam pressure specified for both the design basis analysis (Reference 1) and for SGR/Uprating (Section 2.1, Tables 2-5 and 2-6) is limited to 825 psia. Therefore, the design pressure difference of 1600 psia is not exceeded.

The current structural analysis of the SG tubes was reviewed. This analysis is based on an evaluation for the effects of:

- Deadweight,
- Tube – Tube sheet/flow distribution baffle/tube support plate interactions,
- Flow induced vibration and wear,
- Earthquake loadings,
- LOCA and pipe break transients, including LOCA rarefaction wave and shaki ng effects.

With the exception of flow-induced vibration and wear, which is addressed in Section 5.7.3 of this report, the other parameters are unaffected by the uprating. LOCA effects, which would show some impact due to uprate, were evaluated for the effects of a loop pipe break. Since leak-before-break has been applied to HNP, only the large auxiliary line breaks need to be considered. Therefore, the current analysis is conservative and will continue to envelop the LOCA effects in the uprate condition.

It can therefore be concluded that the effects of uprating on the primary side of the HNP RSGs has already been evaluated in the design basis analysis and remains valid for the SGR/Uprating conditions.

5.7.1.4.2 Secondary Side Components

For the analysis of the RSG secondary side components, the HNP design parameters were compared to those considered for the uprating. The major change identified is the change in the nominal feedwater temperature (either 375°F or 440°F). The other major change that affects the secondary side of the steam generator is the low-power feedwater introduction to the steam generator (either through the main or auxiliary nozzles). This change to the SG transients has been evaluated. The conclusion of the evaluation is that this change, while a more severe transient for some components, is enveloped by the current design basis analyses and has no impact on the currently reported stress levels and usage factors.

An evaluation of the effects of reducing the full-power feedwater temperature from 440°F to 375°F on the secondary-side thermal boundary conditions was performed. This evaluation used thermal-hydraulic boundary conditions such as pressure drops across internal components, heat transfer coefficients on internal surfaces and fluid pressures and temperatures for design and structural analysis of the steam generator. The evaluation was performed for the combined unit loading cases 0–15 percent and 15–100 percent power for each of the feedwater temperature case scenarios with the maximum feedwater temperature of either 375°F or 440°F.

The following subsections provide a summary of the stress analysis performed for each critical component in the secondary side of the steam generator. The calculated stresses are compared to

the allowable stress and stress range values calculated using S_m, S_y, and S_u values obtained from the ASME Code, Section III. For materials whose S_m, S_y, or S_u values are not available in the 1971 Edition of the Code, including Addenda through Summer of 1972, material strength properties are obtained from the ASME Code, Section III, 1986 Edition.

An evaluation for each component was performed to assess the impact on the HNP plant-specific component stress reports. In the subsections below, the maximum stress intensity ranges and fatigue usage factors associated with the Normal and Upset Loading Conditions are reported, if changed. All of the other loading condition stresses are unaffected by the uprate.

Main Feedwater, Auxiliary Feedwater and Spray Nozzles

An evaluation of the auxiliary feedwater, main feedwater, and spray nozzles was performed to address:

- Nozzle loads that exceed allowable values resulting from the reanalysis of the attached piping

- Changes to the design basis transients for the HNP SGR/Uprating

Results show that the design basis nozzle loads (Reference 1) remain applicable to the evaluation of the nozzles and produce stresses that envelop those produced by the mechanical loads. Thus, there is no impact on the current design basis analysis.

The evaluation of the changes to the design transients against the design analyses show that the major difference in the design transients due to the uprating is the result of considering a low maximum feedwater temperature of 375°F. This is in addition to the high maximum feedwater temperature of 440°F that has already been evaluated. All other differences in the transients are not significant and will not impact the current design basis analysis.

The evaluation of the steam generator feedwater and spray nozzles for the lower maximum feedwater temperature of 375°F show that the current design basis analysis contains sufficient conservatism to account for any increase in stress that may result from the lower maximum feedwater temperature. Also, the transients that contribute most to the fatigue usage factor for the components are unaffected by the uprating. Therefore the effect of changes in the uprating transients from those considered in the design basis analysis is further minimized.

The conclusion is that the design basis analysis for the main and auxiliary feedwater nozzles and the spray nozzles remains acceptable for SGR/Uprating conditions.

Secondary Manway Opening

The HNP Delta 75 steam generator contains two secondary -side manways, which are located in the upper shell, 180 degrees apart. The manway is a forged component welded to the shell opening. A manway cover and insert are fastened to the pad with studs and nuts, and a spiral wound graphite filled gasket is used to seal the joint.

An evaluation for the effects of uprating was performed. The primary stresses for the pad and cover, and the bolt sections, are within the applicable limits of the ASME Code. The engagement lengths and the bolt areas are adequate. The secondary manway sections were analyzed for maximum stress intensity range and fatigue. The maximum stress range/allowable stress range ratios and fatigue usage factors for the baseline and uprated cases are indicated in Tables 5.7.1-1 and 5.7.1-2. All the calculated fatigue usage factors are below unity and are acceptable, with the exception of the bolts, which demonstrate a cumulative usage factor of greater than 1.0 over a 40-year life. Based on conservative evaluations, the bolts must be replaced prior to 27 years of service to meet the fatigue usage of 1.0. The bolts must be replaced as part of normal maintenance activities, whenever it is convenient, prior to the 27th year of the operating period. If some of the bolts are replaced for reasons other than fatigue, and records are available which indicate when and which bolts have been replaced, those bolts would not need to be replaced again as long as they did not exceed the 27-year operation limit.

Hand-Hole, 6.00 Inch

The Delta 75 steam generator contains six hand-holes located in the secondary shell directly above the tubesheet. These hand-holes permit 6-inch access to the tube bundle.

An evaluation for the effects of uprating was performed. The primary stresses for the shell/pad and cover, and the bolt sections are within the applicable ASME Code limits. The engagement lengths and bolt areas are adequate. All the calculated fatigue usage factors are below unity. The hand-hole sections were analyzed for maximum stress intensity range and fatigue. The maximum stress range/allowable stress range ratios and fatigue usage appear in Tables 5.7.1-1 and 5.7.1-2, respectively. While the maximum primary plus secondary stress intensity ranges are unaffected by the uprating, the fatigue usage factors are affected. The maximum usage factor is less than the ASME Code allowable of 1.0 and is therefore acceptable.

Inspection Port, 4.00 Inch Bolted Closure

The 4-in. bolted closure inspection port for the Delta 75 steam generator is located at the lower shell to transition cone junction, which allows visual access to the tubes at the top tube support plate. The inspection port is exposed to down-comer fluid temperature changes and secondary-side pressure fluctuations.

An evaluation for the effects of uprating was performed. The primary stresses for the pad and cover, and the bolt sections are within the applicable limits of the ASME Code. The engagement lengths and the bolt areas are adequate. The inspection port sections were analyzed for maximum stress intensity range and fatigue. The maximum stress range/allowable stress range ratios and fatigue usage factors for the baseline and uprated cases are indicated in Tables 5.7.1-1 and 5.7.1-2. All the calculated fatigue usage factors are below unity and are acceptable with the exception of the bolts. Based on conservative evaluations, the bolts will need to be replaced prior to 30 years of operation. If some of the bolts are replaced for reasons other than fatigue, and records are available which indicate when and which bolts have been replaced, those bolts would not need to be replaced again as long as they did not exceed the 30-year operation limit.

Inspection Port, 2.00 Inch Unreinforced

The Delta 75 steam generator contains sixteen 2-in. inspection ports. These are located in the lower shell approximately 3 inches above the tube support plates B-J. The inspection ports directly above the tube support plate B are located in the reinforced area of the stub barrel, while all the other inspection ports are located in the lower shell and are not reinforced. The following analyses apply to the unreinforced 2-in. inspection ports of the HNP RSGs.

An evaluation for the effects of uprating was performed. The primary stresses for the shell and cover, and the bolt sections are within the applicable limits of the ASME Code. The engagement lengths and the bolt areas are adequate. The inspection port sections were analyzed for maximum stress intensity range and fatigue. The maximum stress range/allowable stress range ratios and fatigue usage factors for the baseline and uprated cases are indicated in Tables 5.7.1-1 and 5.7.1-2. All the calculated fatigue usage factors are below unity and are therefore acceptable.

Minor Shell Taps

The HNP Delta 75 steam generator shell has several drilled penetrations that provide ports for instrumentation and small-bore piping connections. A counter bore into the shell provides a weld-prep for the bosses that are welded to the shell. The bosses provide an internally machined pipe connection for the water-level instrumentation system, the wet lay-up system, the blowdown system, and the secondary-side drain system.

An evaluation for the effects of uprating was performed. The primary stresses for the critical sections are within the applicable limits of the ASME Code. The minor shell tap sections were analyzed for maximum stress intensity range and fatigue. The maximum stress range/allowable stress range ratios and fatigue usage factors for the baseline and uprated cases are indicated in Tables 5.7.1-1 and 5.7.1-2. The fatigue usage factor at the most critical section was acceptable.

Tubesheet/Stub Barrel Junction

The critical region is the weld between the tubesheet and the stub barrel. The effect of a change in feedwater temperature from 440°F to 375°F was evaluated

The stresses were scaled based on a ratio of the temperature differences in the lower downcomer region. The resulting stress intensity ranges were compared against the ASME Code allowable of $3S_m$. The stress intensity ranges remain acceptable. The scaling factor was conservatively applied to all load combination thermal alternating stresses for the critical region. The maximum usage factor is less than 1.0 and is acceptable. The maximum stress range/allowable stress range ratios and fatigue usage factors are indicated in Tables 5.7.1-1 and 5.7.1-2.

Upper Shell/Transition Cone/Lower Shell

The evaluation of the upper shell, transition cone and lower shell regions was performed to address temperature differences resulting from a full-power feedwater temperature reduction of 440°F to 375°F.

The feedwater temperature affects only the following transients:

- Loading/unloading from 0–100 percent loading
- 10-percent step load increase/decrease
- Large step load w/steam dump
- Loop out-of-service loop startup/shutdown
- Reactor trip cases (A, B and C)
- A large feedwater line break

A scaling factor due to the feedwater temperature change was applied conservatively to all thermal alternating stresses for all of the thermal transients in the fatigue evaluation.

The resulting stress intensity ranges were compared against the Code allowable of $3S_m$. For those stresses that exceeded the Code limit, an analysis was performed per paragraph NB -3228.3 of the ASME Code, and the conditions were satisfied. The results of the evaluation are presented in Tables 5.7.1-1 and 5.7.1-2. The maximum fatigue usage factor is less than the allowable of 1.0 and is acceptable.

5.7.1.5 Conclusions

A summary of the maximum stress range/allowable stress range ratios and fatigue-usage factors for the various steam generator components evaluated/analyzed is provided in Tables 5.7.1-1 and

5.7.1-2. Results of the analyses performed on the HNP Model Delta 75 steam generators show that ASME Code Section III is satisfied at the uprated power conditions with up to 10-percent steam generator tube plugging, with the exception of the secondary manway bolts and 4-in. inspection port bolts. For these bolts it was found that the maximum fatigue usage exceeds the limit of 1.0. Therefore, these bolts will be replaced at a convenient time as part of normal maintenance activities, prior to the bolts reaching the stated fatigue life of 27 and 30 years of service for the manway and 4-in. inspection port bolts, respectively.

The results of the evaluation for the Delta75 RSGs at the uprated NSSS power of 2912.4 MWt bound operation with the Delta 75 RSGs at the current NSSS power of 2787.4 MWt.

5.7.1.6 References

1. Design Specification 412A86, Revision 4, "Carolina Power and Light Company HNP Delta 75 Steam Generator," October 23, 1998.

2. 1971 ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Power Plant Components, including Summer 1972 Addenda.

3. 1986 ASME Boiler and Pressure Vessel Code, Section II, Materials.

Table 5.7.1-1 Summary of Maximum Stress Range/Allowable Stress Range Ratios in Steam Generator Components		
Components	**HNP Baseline**	**Uprating Lower FW Temperature**
Primary Side Components (Max. of all Components)	(1)	(1)
Main Feedwater	(1)	(1)
Auxiliary Feedwater	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Spray Nozzles	(1)	(1)
Secondary Manway Opening	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Hand-Hole	(1)	(1)
4-in. Inspection Port	(1)	(1)
2-in. Un-reinforced Inspection Port	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Minor Shell Taps	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Tubesheet/Stub Barrel Junction	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Upper Shell/Transition Cone/Lower Shell	[ ]$^{(b,c)}$	(1)

Note:

(1) Exceeded the $3S_m$ allowable criteria. Per paragraph NB-3228.3 of the ASME Code, a simplified elastic-plastic analysis was performed, and all Code requirements were met.

Table 5.7.1-2 Summary of Fatigue Usage of Steam Generator Components		
	Fatigue Usage	
Components	HNP Baseline	Uprating Lower FW Temperature
Primary Side Components (Max. of all Components)	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Main Feedwater	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Auxiliary Feedwater	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Spray Nozzles	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Secondary Manway Opening	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Secondary Manway Bolts	[ ]$^{(b,c)}$	[ ]$^{(b,c)(1)}$
Hand-Hole	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Hand-Hole Bolts	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
4-in. Inspection Port	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
4-in. Inspection Port Bolts	[ ]$^{(b,c)}$	[ ]$^{(b,c)(2)}$
2-in. Un-Reinforced Inspection Port Opening	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
2-in. Un-Reinforced Inspection Port Bolts	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Minor Shell Taps	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Tubesheet/Stub Barrel Junction	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Upper Shell/Transition Cone/Lower Shell	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$

Notes:

(1) Bolts must be replaced prior to 27 years of service.

(2) Bolts must be replaced prior to 30 years of service.

5.7.2 Steam Generator Thermal-Hydraulic Evaluation

5.7.2.1 Introduction

The Model Delta 75 replacement steam generator installed for HNP has been designed and evaluated at the uprated NSSS power conditions, 2912.4 MWt (970.8 MWt/loop). The thermal-hydraulic design for these steam generators evaluated multiple operating points at the uprated power level as well as the original HNP NSSS power level, 2787 MWt (929 MWt/loop). The SGR/Uprating program thermal-hydraulic evaluation considers only the effect of reducing feedwater temperature from 440°F to 375°F. Evaluations at 440°F were repeated for the SGR/Uprating program, as the current parameter assumptions in Section 2 of this NSSS Licensing Report are slightly different.

Applicable design parameters for operation at the current and reduced feedwater temperatures were used for the thermal-hydraulic evaluation. The operating steam generator water level was set at the normal level, 520 inches above the tubesheet surface. The fouling factor was taken at the design value for all conditions.

5.7.2.2 Description of Analyses and Evaluations

The eight parameter cases used for the steam generator thermal-hydraulic evaluations for the SGR/Uprating Project are defined in Section 2 of this NSSS Licensing Report.

The thermal-hydraulic evaluation of the steam generators focused on secondary side operating characteristics. Comparisons with the conditions at the current design feedwater temperature are used to demonstrate the acceptability of the characteristics at the reduced feedwater temperature. Special attention is given to hydrodynamic stability margin that decreases as a result of the operating condition changes.

5.7.2.3 Acceptance Criteria

Several secondary-side operating characteristics were used to assess the acceptability of steam generator operation at reduced feedwater temperature. These parameters include steam flow and pressure; circulation ratio; damping factor, which is a measure of hydrodynamic stability; secondary mass; heat flux; and secondary side pressure drop. Moisture carryover is also affected and is addressed.

5.7.2.4 Results

5.7.2.4.1 Thermal-Hydraulic Operating Characteristics

Secondary-side steam generator performance characteristics can be affected by changes in steam flow and steam pressure. The current HNP evaluations are performed for uprated power

conditions. The primary temperature and SGTP level determine steam pressure. Steam flow at constant power is affected by feedwater temperature changes. This section assesses the magnitude and importance of changes in the secondary-side thermal-hydraulic performance characteristics that will result from a reduction in feedwater temperature.

Most of the operating characteristics displayed expected small or benign changes as a result of a reduction in the feedwater temperature. Steam flows decrease for the reduced feedwater temperatures as a result of the increased enthalpy difference at constant power. The steam pressures are not affected by feedwater temperature. Circulation ratio increases proportionally to the decrease in steam flow as is typical for re-circulating steam generators. Bundle liquid flow is related to clearing and reducing the concentration of contaminants in the bundle. The increased bundle liquid flows, at reduced feedwater temperature, will improve the effectiveness of this useful function.

At a given power, average heat fluxes are proportional to the heat transfer area in service and are not affected by the feedwater temperature. Peak heat fluxes are similarly unaffected by feedwater temperature. Total secondary-side pressure drop is smaller as a result of the reduced steam flows. Steam generator mass increases with reduced feedwater temperature. The reduced steam flow simulates reduced power with its attendant reduction in tube bundle void.

5.7.2.4.2 Moisture Carryover

Moisture separator performance benefits from the reduced steam flows. Steam flow usually dominates separator loading and therefore performance. This is especially true in the present case since the other factors that affect moisture carryover, steam pressure and water level, remain constant. The evaluation results indicated a reduced separator loading with improved performance and lower moisture carryover at the low feedwater temperature.

5.7.2.4.3 Hydrodynamic Stability

The hydrodynamic stability of a steam generator is characterized by the damping factor. A negative value of this parameter indicates a stable unit. That is, small perturbations of steam pressure or circulation ratio will die out rather than grow in amplitude. A number of factors can have a destabilizing effect on steam generators. Two of these factors are increased downcomer sub-cooling and increased pressure drop in the two-phase region. For the HNP the reduced stability is caused by increased downcomer sub-cooling, resulting from colder feedwater added to the downcomer.

For the reduced feedwater temperature cases, the damping factor increases (becomes less negative) in relation to the value for the 440°F feedwater temperature. The damping factors at reduced feedwater temperature, however, remain substantially negative. It can therefore be inferred that the HNP units will continue to be hydrodynamically stable.

5.7.2.5 Conclusions

All projected thermal-hydraulic operating characteristics are acceptable for both the 375°F and 440°F feedwater temperature and SGR/Uprate operating conditions. Though the evaluations were performed at the uprated NSSS power of 2912.4 MWt, this conclusion is also applicable to the current NSSS power of 2787.4 MWt. The results are compatible with the current HNP licensing basis/acceptance requirements.

The effect of feedwater temperature reduction was shown to have a small or benign effect on thermal-hydraulic operating characteristics for a wide range of operating conditions at the uprated NSSS power, 2912.4 MWt. The changes observed for the feedwater temperature reduction evaluated are consistent with experience and are expected to be similar at other operating conditions that are not far from the uprated conditions. On this basis, the current rating, about 96 percent of the uprated power level, will show similarly small or benign effects due to feedwater temperature changes.

5.7.3 Flow Induced Vibration and Wear

5.7.3.1 Introduction

The tube bundle support assembly is primarily a Safety Class 3 structure (support plates and anti-vibration bars [AVBs]) with some parts (wrapper barrels, AVB end caps, retaining rings, and retainer bars) classified as non-nuclear safety (NNS) according to ANSI/ANS N18.2a (Reference 1). The tubes comprise part of the Class 1 primary-side pressure boundary, which must satisfy ASME Code limits consistent with the original design basis, Reference 2. The original vibration/wear report assessed vibration and wear analyses and corrosion/erosion conditions, considering interaction with the flow distribution baffle (FDB), nine tube support plates (TSPs), and four sets of AVBs. The resulting bending stresses and the maximum potential for localized wear due to tube vibration were inputs to the original structural evaluation of the tube. The structural evaluation of the tubes evaluates the effects of pressure and temperature resulting from the transients. The tube structural evaluation also considers the:

- Deadweight
- Tube – Tube sheet/flow distribution baffle/tube support plate interactions
- Earthquake loadings
- LOCA and pipe break transients, including LOCA rarefaction wave and shaking effects

These effects are discussed in Section 5.7.1 of this report.

The only significant change identified as a result of the SGR/Uprating is the reduced feedwater temperature which can be maintained at an upper temperature at full power of 375°F rather than the 440°F, as specified in the Model Delta 75 design specification. An evaluation was performed to determine if tube vibration, which can affect wear rates and tube fatigue, is affected by the 375°F feedwater temperature option specified for the SGR/Uprating.

5.7.3.2 Description of Analyses and Evaluations

An evaluation of the thermal-hydraulic boundary conditions was performed for the heatup transient from 0-percent to 100-percent power for each scenario of maximum feedwater temperature, 375°F and 440°F. The results of the evaluation were used in evaluating the impact on flow-induced vibration on the original analysis.

5.7.3.3 Results

The original analysis case differs from the SGR/Uprating case only in terms of the feedwater temperature reduction.

The current evaluation is based on the following:

- The original analysis evaluation (440°F) concluded that tube wear would be relatively benign.

- The wear and flow-induced vibration conditions for the lower feedwater temperature conditions (375°F) show a reduction in the wear related parameters.

5.7.3.4 Conclusions

It is concluded that flow induced vibration and wear for the 375°F feedwater case is acceptable since the previous analysis for the 440°F feedwater case envelops the 375°F feedwater case. It can further be concluded that the previous structural analysis of the tubes remains bounding relative to the SGR/Uprating since the input parameters related to flow-induced vibration are unchanged.

This evaluation at the uprated NSSS power of 2912.4 MWt bounds operation with the replacement steam generators at the current NSSS power of 2787.4 MWt.

5.7.3.5 References

1. "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants," ANSI/ANS N.18.2a, 1975

2. ASME Boiler and Pressure Vessel Code Section III, "Rules for Construction of Nuclear Power Plant Components," 1971 Edition plus Addenda through Summer 1972 and Case N-20-3, The American Society of Mechanical Engineers, New York, New York

5.8 Pressurizer

5.8.1 Introduction

The functions of the pressurizer are to absorb any expansion or contraction of the primary reactor coolant due to changes in temperature and/or pressure and, in conjunction with the pressure control system components, to keep the reactor coolant system (RCS) at the desired pressure. The first function is accomplished by keeping the pressurizer approximately half-full of water and half-full of steam at normal conditions, connecting the pressurizer to the RCS at the hot leg of one of the reactor coolant loops and allowing inflow to or outflow from the pressurizer as required. The second function is accomplished by keeping the temperature in the pressurizer at the water saturation temperature (T_{sat}) corresponding to the desired pressure. The temperature of the water and steam in the pressurizer can be raised by operating electric heaters at the bottom of the pressurizer and can be lowered by introducing relatively cool spray water into the steam space at the top of the pressurizer.

The components in the lower end of the pressurizer (such as the surge nozzle, lower head/heater well and support skirt) are affected by pressure and surges through the surge nozzle. The components in the upper end of the pressurizer (such as the spray nozzle, safety and relief nozzle, upper head/upper shell, manway and instrument nozzle) are affected by pressure, spray flow through the spray nozzle, and steam temperature differences.

The limiting operating conditions of the pressurizer occur when the RCS pressure is high and the RCS hot-leg (T_{hot}) and cold-leg (T_{cold}) temperatures are low. This maximizes the ΔT that is experienced by the pressurizer. Due to flow out of and into the pressurizer during various transients, the surge nozzle alternately sees water at the pressurizer temperature (T_{sat}) and water from the RCS hot leg at T_{hot}. If the RCS pressure is high (which means, correspondingly, that T_{sat} is high) and T_{hot} is low, then the surge nozzle will see maximum thermal gradients; and, thus experience the maximum thermal stress. Likewise, the spray nozzle and upper shell temperatures alternate between steam at T_{sat} and spray water, which, for many transients, is at T_{cold}. Thus, if RCS pressure is high (T_{sat} is high) and T_{cold} is low, then the spray nozzle and upper shell will also experience the maximum thermal gradients and thermal stresses.

The original evaluation of the Harris Nuclear Plant (HNP) pressurizer was performed in Reference 1 considering the vessel operating temperatures, design transients and design loads in References 2 and 3. The design transients in References 2 and 3 are the design transients from Systems Standard Design Criteria (SSDC) 1.3, Rev. 2 (Reference 4) except for several special HNP transients (i.e., Plant Loading and Unloading at 10-Percent per Minute and 20-Percent Step Load Increase and Decrease). Therefore, References 1 through 4 document the original HNP pressurizer design basis. This evaluation was updated in Reference 5 to include the Cold Overpressure Mitigation System (COMS) transient added to the plant specific design specification in Reference 6.

The pressurizer stress report was updated again in 1993 (Reference 7) in order to incorporate revised operating temperatures and NSSS design transients associated with the T-Hot

Reduction/Replacement Steam Generator (RSG) Program into the pressurizer design. Reference 7 contained the evaluations necessary to justify pressurizer operation with T_{cold} temperatures within a range from 536.6°F to 555.5°F, and T_{hot} temperatures within a range from 605.9°F to 623.2°F. The evaluations in Reference 7 also considered the surge line stratification loads and the revised NSSS design transients, which were applicable to the respective high T_{avg} and low T_{avg} programs, that were developed to cover the entire operating temperature window. The evaluations documented in Reference 7 were performed using the most conservative design inputs so that pressurizer operation in accordance with the HNP T_{hot} Reduction/RSG Program, the original design basis, or a combination thereof is acceptable for the remainder of the operating license. The HNP pressurizer was subsequently reviewed for the SGR/20-Percent SGTP and Operating Temperature Range Program (Reference 8) in 1996. That report stated that the T_{hot} Reduction/Replacement Steam Generator (RSG) Program analysis (Reference 7) remains bounding for the RSG case.

The HNP SGR/Uprating program requires additional pressurizer structural analyses and evaluations for the purpose of incorporating hot and cold-leg temperatures, NSSS design transients and design loads that are not bounded by the current HNP pressurizer stress report and addenda.

5.8.2 Description of Analyses and Evaluations

The evaluation of the pressurizer for the SGR/Uprating used the following as input:

- NSSS Parameters (Section 2.0)
- NSSS Component Design Transients (Section 3.0)
- Pressurizer Spray (up to 1200 gpm)
- Design Loads
- Pressurizer Nozzle and Support Skirt Loads

The input parameters associated with the HNP SGR/Uprating program were reviewed and compared to the design inputs considered in the current pressurizer stress report. In cases where revised input parameters are not obviously bounded, pressurizer structural analyses and evaluations were performed. Any impacts to the existing design basis analysis were evaluated. Using the existing analyses as the basis of the evaluation, scaling factors were utilized to assess the impact of the changes in the parameters such as the system transients, temperatures, and pressures. New stresses and revised cumulative usage factors were calculated, as applicable, and compared to previous licensed results. The evaluation results were then compared with the ASME Code (Reference 9) to confirm that the allowable limits are maintained.

A review of the design transients shows that some of the transients have been revised, although not all parameters affecting the pressurizer have been revised for each transient. The number of

occurrences for the SGR/Uprating transients are identical to those considered in the pressurizer specification (Reference 6).

The review of the pressure fluctuations showed that the differences are very small and will not have any significant effect on the stress analysis and fatigue evaluation of the pressurizer components that were originally analyzed in Reference 5.

The ΔTs between the pressurizer and the incoming T_{cold} were reviewed. The ΔTs listed for the stress report volumes (Reference 10) were the values used in the original analyses. For the spray nozzle, the ΔTs for all transients are less than or equal to the ΔTs used in the original analyses. The spray flow rates, however, are higher in the SGR/Uprating program for the heatup and cooldown transients (which have the same ΔTs as before), as well as for some of the other transients that have lower ΔTs. Of the equipment design transients that have lower ΔTs, the Loss-of-Load and Inadvertent Startup of an Inactive Loop would result in higher stresses in the spray nozzle than were calculated originally.

For the upper shell and trunnion buildup, the only transients that affect these locations are plant heatup and cooldown. Flow rate and ΔT comparisons for transients other than heatup and cooldown, therefore, have no bearing on the fatigue calculations for these components.

The ΔTs between the pressurizer and the incoming T_{hot} were reviewed. The ΔTs listed for the stress report volumes (Reference 10) were the values used in the original analyses. The lower head/heater well and immersion heaters' ΔTs used in the stress report are higher than those for the revised transients. Therefore, the stress analysis of these components does not need to be updated. For the surge nozzle, the lower head/support skirt, and instrument nozzle, some of the revised transients have higher ΔTs than those used in the original stress report volumes. The analyses for these components were updated.

The review of the Emergency and Faulted transient temperatures showed that there were no changes that would affect the pressurizer.

The design loads considered in the pressurizer structural analysis documented in Reference 7 remain conservative for the HNP SGR/Uprating program. Reconciliation of the pressurizer nozzle and support skirt loads with the generic design loads was done as part of the loop analysis effort. The nozzle loads and support skirt loads are design inputs for the pressurizer structural analysis only if additional load conformance or stress calculations become necessary to show compliance. The pressurizer nozzle and skirt loads were shown to remain limiting.

5.8.3 Acceptance Criteria

The initial set of acceptance criteria for evaluating design inputs affecting the pressurizer stress report are as follows:

1. Hot and cold-leg temperatures shall remain within the ranges of the operating temperatures that have previously been considered and justified in the pressurizer stress report. (The effect of the higher spray flow rate at HNP is incorporated in the comparisons for T_{cold}.)

2. NSSS design transients shall be less than or equal to the design transients previously considered in the pressurizer stress report with regard to both severity and numbers of occurrences. Additionally, no new NSSS design transients that have not previously been considered shall be identified. (The pressurizer temperature and pressure variations for each transient shall be considered in this comparison review to determine the relative severity of the revised design transients compared to the existing design transients.

3. Design loads shall be less than or equal in magnitude to the loads that were previously considered in the pressurizer stress report with no changes to the load application points and numbers of occurrences.

The acceptance criteria for the pressurizer structural analyses and evaluations are in accordance with the applicable requirements of the 1971 Edition of Section III of the ASME Boiler and Pressure Vessel Code with addenda through the Summer 1972 Addenda (Reference 9) to which the HNP pressurizer was originally designed.

5.8.4 Results

The analysis of the pressurizer for the HNP SGR/Uprating program transients will have a minimal effect on the pressurizer components. Table 5.8-1 compares the fatigue usages calculated for the SGR/Uprating with those of the T_{hot} Reduction/RSG Program. The T_{hot} Reduction/RSG Program forms the current analysis basis of the pressurizer for HNP (Reference 7). The fatigue usages for the upper shell and trunnion bolt hole decreased significantly due to the removal of excessive conservatism in the original evaluation. For components with no change in fatigue usage factor in Table 5.8-1, the existing analyses envelop the revised transients. From this analysis, it is concluded that the HNP pressurizer components satisfy the requirements of the ASME Code for the revised transients of the SGR/Uprating.

5.8.5 Conclusions

The results of the pressurizer analysis show that the HNP pressurizer components meet the stress/fatigue analysis requirements of the ASME Code, Section III (Reference 9) at the SGR/Uprating conditions.

The results are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

5.8.6 References

1. "Model D Series 84 Pressurizer Stress Report for Carolina Power and Light Shearon Harris Unit 1," WNET-130 (CQL), Rev. 1, Westinghouse Electric Corporation, Tampa Division, Tampa, Florida, January 1984.

2. Equipment Specification 676440, Revision 5, "General Pressurizer Vessel Assembly Series 84," Westinghouse Electric Corporation, Nuclear Energy Systems, Pittsburgh, PA, October 1973.

3. Equipment Specification 952407, Revision 5, "Addendum to Equipment Specification 676440, Revision 5, Carolina Power and Light, Shearon Harris Nuclear Plant Unit 1 Pressurizer," Westinghouse Electric Corporation, Nuclear Energy Systems, Pittsburgh, PA, November 1983.

4. Westinghouse System Standard Design Criteria (SSDC) 1.3, Rev. 2, April 15, 1974.

5. "Model D Series 84 Pressurizer Stress Report for Carolina Power and Light Shearon Harris Unit 1," WNET-130 (CQL), Rev. 2, Westinghouse Electric Corporation, Tampa Division, Tampa, Florida, August 1989.

6. Equipment Specification 952407, Revision 6, "Addendum to Equipment Specification 676440, Revision 5, Carolina Power and Light, Shearon Harris Nuclear Plant Unit 1 Pressurizer," Westinghouse Electric Corporation, Nuclear Energy Systems, Pittsburgh, PA, January 1989.

7. "Shearon Harris (CQL) Pressurizer Evaluation for Uprating/T-Hot Reduction/Steam Generator Replacement Program," EA-93-260, Westinghouse Electric Corporation, Pensacola Plant, Pensacola, FL, December 7, 1993.

8. WCAP-14778, "Carolina Power and Light, Shearon Harris Nuclear Power Plant Steam Generator Replacement with 20% Steam Generator Tube Plugging and Operating Temperature Range Engineering Report," Westinghouse Electric Corporation, Nuclear Energy Systems, Pittsburgh, PA, December, 1996.

9. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," 1971 Edition through the Summer 1972 Addenda.

10. Model D Series 84 Pressurizer Generic Stress Report, WNET-130 Volumes 2–16, Westinghouse Electric Corporation, Tampa Division, Tampa, Florida, 1977 (Westinghouse Proprietary Class 1 Document).

Table 5.8-1 HNP Fatigue Usage Comparisons		
Component	**SGR/Uprating Fatigue Usage**	**T-hot Red/ RSG Fatigue Usage**
Surge Nozzle	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Spray Nozzle – Safe End	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Spray Nozzle – Nozzle Body/Shell Intersection	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Safety and Relief Nozzle	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Lower Head	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Heater Well	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Upper Shell	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Support Skirt/Flange	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Support Skirt/Lower Shell	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Seismic Lug at Lug/Shell Junction	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Manway Cover/Bolts	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Trunnion Bolt Hole	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Instrument Nozzle	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Immersion Heater/Sheath	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$
Valve Support Bracket	[ ]$^{(b,c)}$	[ ]$^{(b,c)}$

5.9 NSSS Auxiliary Equipment

5.9.1 Introduction

This report evaluates the Harris Nuclear Plant (HNP) auxiliary tanks, heat exchangers, pumps and valves, on a system basis, for impact by the thermal transients and maximum operating temperatures, pressures, and flow rates resulting from the SGR/Uprating conditions. The evaluation consists of a structural and flow-capacity review of the component pressure boundaries.

The NSSS Auxiliary Systems associated with this evaluation include:

- Gaseous Waste Processing System (GWPS)
- Chemical and Volume Control System (CVCS)
- Boron Thermal Regeneration System (BTRS)
- Residual Heat Removal System (RHRS)
- Safety Injection System (SIS)
- Boron Recycle System (BRS)
- Component Cooling Water System (CCWS)
- Liquid Waste Processing System (LWPS)

5.9.2 Description of Analyses and Evaluations

The PCWG parameters provided in Section 2 document the impact of the SGR/Uprating on the NSSS system operating temperatures and pressures. This information was applied where applicable for evaluation of the auxiliary equipment maximum operating temperatures and pressures. Any impacts on the NSSS and auxiliary equipment design transients due to the SGR/Uprating conditions were considered.

The original design parameters (design temperature, pressure, thermal transients and flow rates) for the auxiliary tanks, heat exchanger, pumps and valves, were compared to those used in the SGR/Uprating to determine if the original design parameters envelop those for the SGR/Uprating.

5.9.2.1 Auxiliary System Tanks

The NSSS auxiliary tanks that were evaluated are listed in Table 5.9-1. From an evaluation of the revised SGR/Uprating conditions, the operating temperatures and pressures for these vessels remain within the design basis for these tanks, and the equipment design transients for the boron injection tank and the safety injection accumulators remain bounded by the original design transients. No design transients were identified for Auxiliary System Tanks other than the boron

injection tank and the safety injection accumulators. As a result, none of the auxiliary tanks are impacted and are therefore acceptable for operation at the SGR/Uprating conditions.

Although the CCW System is subject to higher operating temperatures under the uprated conditions, these operating conditions are bounded by the original design conditions.

The pressurizer relief tank sparger was not included in this evaluation because it is not impacted by either the SGR or Uprating.

5.9.2.2 Auxiliary System Heat Exchangers

The NSSS auxiliary heat exchangers that were evaluated are listed in Table 5.9-2. Several heat exchangers have two systems listed. This is because the tube-side and shell-side circulate water from two different systems.

The CCW system is subject to higher operating temperature conditions as a result of the SGR/Uprating. All of these temperatures remain bounded by the original design conditions. New flow rates were defined as a result of the SGR/Uprating. Westinghouse has reviewed the increased flow rates against the original design calculations. The design specification includes criteria defined to prevent flow-induced vibration at twice the design flow. The increased flow rates are sufficiently less than the two times limit such that the heat exchangers are determined to be acceptable for the increased flows.

Based on the revised NSSS parameters for the SGR/Uprating conditions, there is no impact on the auxiliary systems heat exchangers listed in Table 5.9-2. The operating temperature and pressure ranges for these vessels remain bounded by the original design parameters. The original design transients for the auxiliary equipment bound the transients associated with the SGR/Uprating. Therefore, the auxiliary heat exchangers are acceptable for operation at the SGR/Uprating conditions.

5.9.2.3 Auxiliary System Pumps

The NSSS auxiliary pumps that were evaluated are listed in Table 5.9-3. There is no adverse impact on the auxiliary systems pumps listed in Table 5.9-3 as a result of the revised SGR/Uprating conditions. The operating temperature and pressure ranges for these pumps remain bounded by the original design parameters. The original design transients for the auxiliary equipment bound the transients associated with the SGR/Uprating. Therefore, the auxiliary system pumps are acceptable for operation at the SGR/Uprating conditions.

5.9.2.4 Auxiliary System Valves

There is no adverse impact on the auxiliary system valves as a result of the SGR/Uprating. The operating temperature and pressure ranges for the valves remain bounded by the original design parameters. The original design transients for the auxiliary equipment bound the transients

associated with the SGR/Uprating. Therefore, the auxiliary system valves are acceptable for operation at the SGR/Uprating conditions.

The CCW system is subject to higher operating temperature as a result of the SGR/Uprating. All of these temperatures remain bounded by the original design conditions. New flow rates also result from the SGR/Uprating. All of these flow rates remain bounded by the original design flow rate. Flow-induced vibration potential is a function of the flow rates (i.e., flow velocities) through the various valves. Therefore, flow-induced vibration is not a concern in any of the auxiliary valves following the SGR/Uprating.

5.9.3 Acceptance Criteria

The maximum system operating temperatures, pressures, and flow rates for the SGR/Uprating program shall be bounded by the original system design conditions for the auxiliary tanks, heat exchangers, pumps and valves.

The original design transients shall bound the revised auxiliary tanks, heat exchangers, pumps and valve transients for the SGR/Uprating program.

5.9.4 Results

A comparison of the revised SGR/Uprating conditions shows that all maximum operating temperatures and pressures for systems within Westinghouse scope are bounded by the existing design basis. Since all tanks, heat exchanger, pumps and valves were designed and manufactured consistent with the system design and applicable codes and standards, all of the NSSS tanks, heat exchangers, pumps and valves are acceptable for the maximum system operating temperatures and pressures resulting from the SGR/Uprating. The auxiliary equipment and NSSS design transients resulting from the SGR/Uprating are bounded by the original HNP design parameters. Therefore, the auxiliary tanks, heat exchangers, pumps and valves remain acceptable for the thermal transients resulting from the SGR/Uprating.

5.9.5 Conclusions

The HNP auxiliary tanks, heat exchangers, pumps and valves are acceptable for the SGR/Uprating conditions, since there is no change to the auxiliary systems operating conditions identified as a consequence of the SGR/Uprating.

The results for the SGR/Uprating are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

Table 5.9-1 Harris Nuclear Plant Auxiliary Tanks	
Component	**System**
Recycle Evaporator Reagent Tank	BRS
Recycle Evaporator Condensate Demineralizer	BRS
Recycle Evaporator Feed Demineralizer	CCWS
Component Cooling Surge Tank	CCWS
Boric Acid Batching Tank	CVCS
Chemical Mixing Tank	CVCS
Reactor Coolant Pump Seal Standpipe	CVCS
Volume Control Tank	CVCS
Cation Bed Demineralizer	CVCS
Mixed Bed Demineralizer	CVCS
Pressurizer Relief Tank	RCS
Safety Injection Accumulator Tank	SIS
Boron Injection Tank	SIS
Boron Injection Surge Tank	SIS
Chiller Surge Tank	BTRS
Thermal Regeneration Demineralizer	BTRS
Waste Evaporator Feed Condensate Demineralizer	LWPS
Waste Gas Decay Tank	GWPS
Chemical Drain Tank	LWPS
Waste Evaporator Condensate Tank	LWPS
Reactor Coolant Drain Tank	LWPS
Waste Processing Reagent Tank	LWPS

Table 5.9-2 Harris Nuclear Plant Auxiliary Heat Exchangers	
Component	**System**
Regenerative Hx	CVCS
Residual Hx	RHRS/CCWS
Seal Water Hx	CVCS/CCWS
Excess Letdown Hx	CVCS/CCWS
Letdown Hx	CVCS/CCWS
Reactor Coolant Drain Tank Hx	LWPS/CCWS
Moderating Hx	BTRS
Letdown Chiller Hx	BTRS
Letdown Reheat Hx	BTRS
CCW Hx	CCWS/SWS

Table 5.9-3 Harris Nuclear Plant Auxiliary System Pumps
Boric Acid Transfer Pump
Boron Injection Recirculation Pump
Centrifugal Charging Pump
Chemical Drain Tank Pump
Chiller Pump
Component Cooling Water Pump
Floor Drain Tank Pump
Gas Decay Tank Drain Pump
Hydrotest Pump
Laundry & Hot Shower Tank Pump
RCS Drain Tank Pump
Reactor Makeup Water Pump
Recycle Evaporator Feed Pump
Residual Heat Removal Pump
Spent Resin Sluice Pump
Waste Evaporator Condensate Pump
Waste Evaporator Feed Pump
Waste Gas Compressor Package
Waste Monitor Tank Pump

6.0 NSSS Accident Analysis

6.0.1 Initial Condition Uncertainties

6.0.1.1 Introduction

This section addresses the initial condition uncertainties used in the accident analyses that were reanalyzed or evaluated to support the Harris Nuclear Plant (HNP) operation at the SGR/Uprating conditions. The uncertainties are included in the non-LOCA analyses, large and small break LOCA, LOCA forces (which are provided as input to component structural analyses), and main steamline break and LOCA mass and energy releases (which are provided as input to the containment integrity analyses).

Six parameters include initial condition steady-state uncertainties that are explicitly modeled in various transient and accident analyses.

- Pressurizer Pressure—Automatic pressurizer pressure control system
- RCS T_{avg} —Automatic reactor control system
- Reactor Power—Daily calorimetric power measurement [Rated Thermal Power (RTP)] used to normalize power range instruments
- RCS Total Flow—Loop RCS flow measurements based on RCS loop flow channels normalized to a once per fuel cycle calorimetric RCS flow measurement to verify Thermal Design Flow (TDF)
- Steam Generator Water Level—Automatic steam generator water level control system
- Pressurizer Water Level—Automatic pressurizer water level control system

The uncertainty calculations were performed for HNP with the plant-specific instrumentation and plant calibration and calorimetric procedures.

6.0.1.2 Description of Analyses and Evaluations

The uncertainty analysis uses the square root of the sum of the squares (SRSS) method to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups of components, which are statistically independent. Those uncertainties that are not independent are arithmetically summed to produce groups that are independent of each other, which can then be statistically combined.

6.0.1.3 Acceptance Criteria

The acceptance criteria for the initial condition uncertainties are the values used in the FSAR Chapter 15 analysis. The design verified uncertainties must be less than or equal to the initial condition uncertainty values used in the FSAR Chapter 15 analysis.

6.0.1.4 Results

The results of the uncertainty analysis are provided in Table 6.0-1 and in References 1 and 2.

6.0.1.5 Conclusions

The results are consistent with and continue to comply with the current HNP licensing basis/acceptance requirements. The results obtained with the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generators at the current NSSS power of 2787.4 MWt.

6.0.1.6 References

1. WCAP-12340, Rev.1, "Westinghouse Improved Thermal Design Procedure Instrument Uncertainty Methodology for Carolina Power & Light Harris Nuclear Plant (for Uprate to 2912.4 MWt - NSSS Power and Replacement Steam Generators)," January 2000.

2. WCAP-15239, Rev.0, "Westinghouse Pressurizer Water Level Control Uncertainty Methodology for Harris Nuclear Plant (Uprate to 2912.4 MWt - NSSS Power)," November 1999.

Table 6.0-1 Summary of Initial Condition Uncertainties		
Parameter	**Calculated Uncertainty**	**Uncertainty Allowance Used in Safety Analysis**
Pressurizer Pressure	[ ]$^{(a,c)}$ [ ]$^{(a,c)}$	+38.0 psi -50.0 psi
T_{avg}	[ ]$^{(a,c)}$ [ ]$^{(a,c)}$	+6.0°F -6.8°F
Power	[ ]$^{(a,c)}$	±2.0% RTP (random)
RCS Flow (plant computer) (control board indicator)	±1.9% Flow (random) ±2.1% Flow (random)	±2.2% TDF (random) (includes 0.1% bias for feedwater venturi fouling)
Steam Generator Water Level (100% RTP)	[ ]$^{(a,c)}$ [ ]$^{(a,c)}$	Not Applicable
Steam Generator Water Level (0% RTP)	[ ]$^{(a,c)}$ [ ]$^{(a,c)}$	Not Applicable
Pressurizer Water Level (100% RTP)	[ ]$^{(a,c)}$ [ ]$^{(a,c)}$	±6.75% (random)

6.1 LOCA Transients

6.1.1 Large Break LOCA

6.1.1.1 Introduction

The purpose of performing a large break loss of coolant accident (LBLOCA) analysis is to verify the Technical Specification peaking limits and axial dependent power peaking limit (K(z)) curve as well as the adequacy of the Emergency Core Cooling System (ECCS) by demonstrating that the criteria set forth in 10 CFR 50.46(b) are met. The SGR/Uprating conditions supported by this analysis include:

- A rated thermal core power of 2900 MW;
- Model Delta 75 steam generators with 3% tube plugging;
- A total peaking factor (F_Q^T) of 2.41 and a nuclear enthalpy rise factor ($F_{\Delta H}$) of 1.66; and,
- Vessel average coolant temperatures from 580.8°F to 588.8°F, inclusive.

6.1.1.2 Description of Analyses and Evaluations

A LBLOCA is initiated by a postulated large rupture of the Reactor Coolant System (RCS) piping. A spectrum of double ended cold leg guillotine (DECLG) and single ended cold leg split (SECLS) breaks are considered. The limiting break location is on the pump discharge side of a cold leg pipe.

A Loss of Offsite Power (LOOP) is conservatively assumed to occur at event initiation, resulting in reactor coolant pump (RCP) coastdown. RCP coastdown at event initiation exacerbates flow stagnation and decreases the time to departure from nucleate boiling (DNB), leading to higher cladding temperatures during blowdown.

The break initiates a rapid depressurization of the RCS. A reactor trip signal is issued when the Low Pressurizer Pressure trip setpoint is reached; however, reactor trip and scram are conservatively neglected in the analysis.

A Safety Injection Actuation Signal (SIAS) is issued when the High Containment Pressure setpoint is reached. Due to LOOP, there is a time delay for diesel generator startup in addition to the time delays for high head safety injection (HHSI) and low head safety injection (LHSI) pump startup. The single failure criterion is met by assuming that either one diesel generator fails (loss of diesel generator) or one LHSI pump fails (loss of LHSI pump).

When the RCS pressure falls below the accumulator pressure, fluid from the accumulators is injected into the cold legs. This fluid is assumed to bypass the core and flow to the break until the time sustained downflow in the downcomer is predicted to occur.

Following the end of bypass, ECCS fluid from the accumulators and, later, the HHSI and LHSI fills the downcomer and lower plenum until the time liquid level reaches the bottom of the core, which is defined as the beginning of core recovery (BOCREC) time. During the refill period, the fuel rods are cooled by radiation heat transfer.

The reflood period begins at the BOCREC time. ECCS fluid filling the downcomer provides the driving head for reflooding the core. As the quench front moves up the core, steam is generated. Steam binding occurs as the steam flows through the intact and broken loop steam generators and RCPs. It is conservatively assumed that the rotor of each RCP has seized (per Appendix K of 10 CFR 50), which tends to reduce the reflood rate. The fuel rods are cooled by radiation and, eventually, by convection as the quench front moves up the core.

A full break spectrum and axial shape study was performed to determine the limiting break size, break configuration, single failure and axial shape. The analysis considered beginning of cycle (BOC) stored energy with both BOC and middle of cycle (MOC) axial shapes and MOC stored energy with an end of cycle (EOC) axial shape. The effects of gadolinia bearing fuel rods and end of life (EOL) peak average rod exposure were also considered.

The U. S. Nuclear Regulatory Commission (NRC) approved SPC evaluation model (SEM/PWR-98) (Reference 1) was used to perform the analysis. This model incorporates the requirements of 10 CFR 50 Appendix K and consists of the following computer codes:

- RODEX2 for computation of the initial fuel stored energy, fission gas release, and fuel cladding gap conductance;
- RELAP4-EM for the system blowdown and Accumulator/SIS flow calculations;
- CONTEMPT/LT-22, as modified in accordance with NRC Branch Technical Position CSB 6-1, for computation of the containment backpressure;
- REFLEX for the system reflood calculation; and,
- TOODEE2 for the fuel rod heatup calculation during the refill and reflood portions of the LBLOCA event.

The quench time, quench velocity, and carryover rate fraction correlations in REFLEX and the heat transfer correlations in TOODEE2 were based on SPC Fuel Cooling Test Facility (FCTF) data.

The governing conservation equations for mass, energy, and momentum transfer were used, along with appropriate correlations consistent with Appendix K of 10 CFR 50. The reactor core was modeled in RELAP4 with heat generation rates determined from reactor kinetics equations with reactivity feedback, and with actinide and decay heating as required by Appendix K. The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.1.1.3 Acceptance Criteria

The acceptance criteria are stated in 10 CFR 50.46(b), specifically:

- The calculated peak fuel cladding temperature does not exceed 2200°F;
- The amount of fuel cladding which reacts chemically with water or steam does not exceed 1% of the total amount of zircaloy in the core;
- The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. The hot fuel rod cladding oxidation does not exceed 17% during or after quenching; and,
- The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long lived radioactivity remaining in the core.

6.1.1.4 Results

Calculations were performed for a spectrum of DECLG and SECLS break sizes. Three axial power shapes were analyzed for each break size to bound the limiting peak cladding temperature (PCT) and to verify the K(z) curve. Table 6.1.1-1 summarizes the results of the break spectrum and axial shape study.

The results of these calculations indicate that the 1.0 DECLG break with the MOC axial shape, BOC stored energy and loss of LHSI pump single failure was the limiting case. The hot rod results, event times and transient plots for the limiting case are shown in Tables 6.1.1-2 and 6.1.1-3 and Figures 6.1.1-1 through 6.1.1-19.

Additional calculations were performed to address peak rod average exposures to EOL and the effects of gadolinia upon PCT. The results of these calculations are bounded by the limiting case.

6.1.1.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that 10 CFR 50.46(b) acceptance criteria are met for SGR/Uprating conditions. The analysis for this event supports operation with the Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%.

6.1.1.6 References

1. EMF-2087(P)(A), SEM/PWR-98: ECCS Model for PWR LBLOCA Applications, Siemens Power Corporation, June 1999.

Table 6.1.1-1 Summary of PCT Results

Single Failure Assumption	Break Type	Break Size	Peak Clad Temperature (°F)		
			BOC	MOC	EOC
Loss of LHSI Pump	DECLG	**1.0**	1795	**2100**	2020
		0.8	1796	2092	2013
		0.6	1741	2073	1990
		0.4	1653	1989	1928
	SECLS	1.0	1759	2069	1996
		0.8	1673	1997	1929
Loss of Diesel Generator	DECLG	1.0	-	2081	2002
		0.8	-	2074	1996

Table 6.1.1-2 Summary of Results for 1.0 DECLG Break With MOC Axial Shape and Loss of LHSI Pump Single Failure

PCT	
Temperature	2100°F
Time	151.62 sec
Elevation	11.125 ft
Hot Rod Burst	
Time	38.64 sec
Elevation	8.875 ft
Channel Blockage Fraction	0.389
Metal Water Reaction	
Local Maximum	8.22%
Elevation of Local Maximum	11.125 ft
Core Maximum	< 1.0%

Table 6.1.1-3 Calculated Event Times for 1.0 DECLG Break With MOC Axial Shape and Loss of LHSI Pump Single Failure

Event	Time [sec]
Begin Analysis	0.0
Break Opened	0.05
SIAS Issued	1.15
Start of Broken Loop Accumulator Injection	1.64
Start of Intact Loop Accumulator Injection	12.06
End Of Bypass (Beginning of Refill)	18.65
Broken Loop Accumulator empties	23.26
Begin of Core Recovery (Beginning of Reflood)	29.29
Start of HHSI and LHSI	30.16
Intact Loop Accumulator empties	33.30
Fuel Cladding Rupture Occurred	38.64
PCT Occurred	151.62

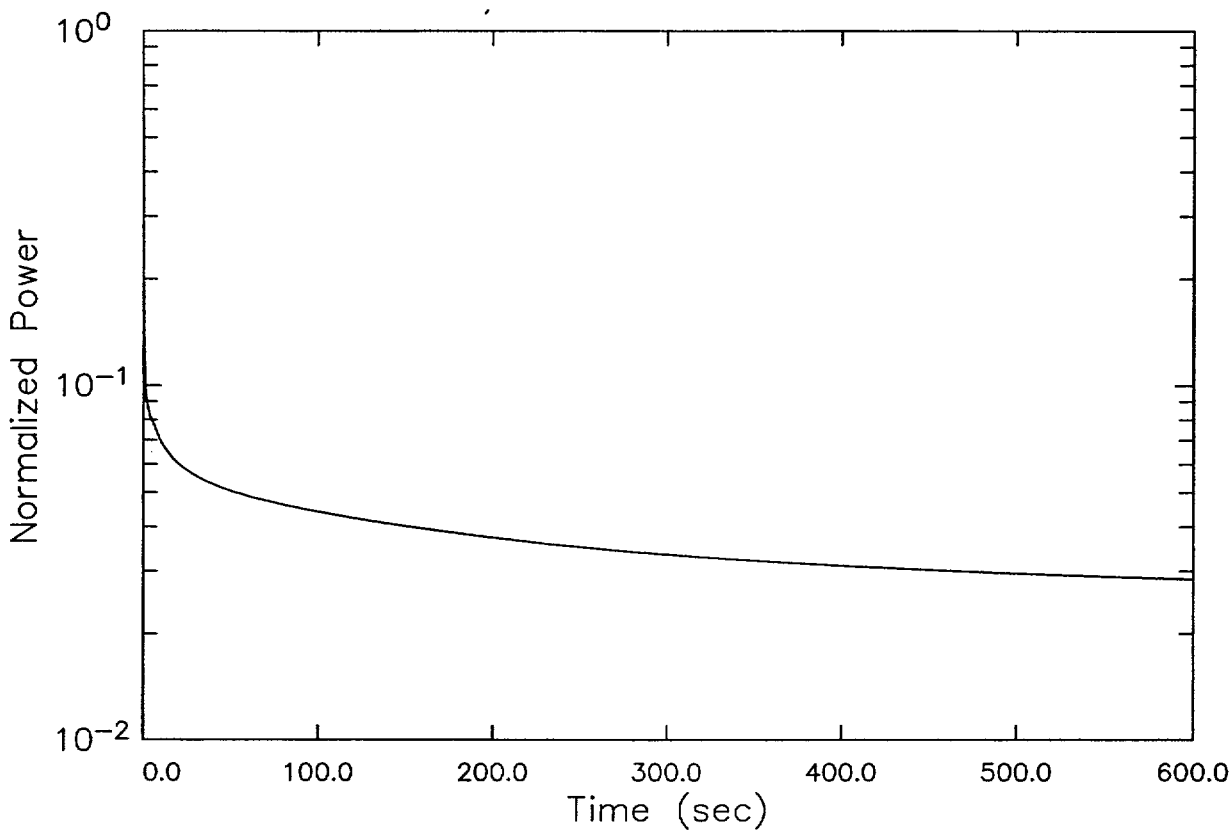

Figure 6.1.1-1 Normalized Power

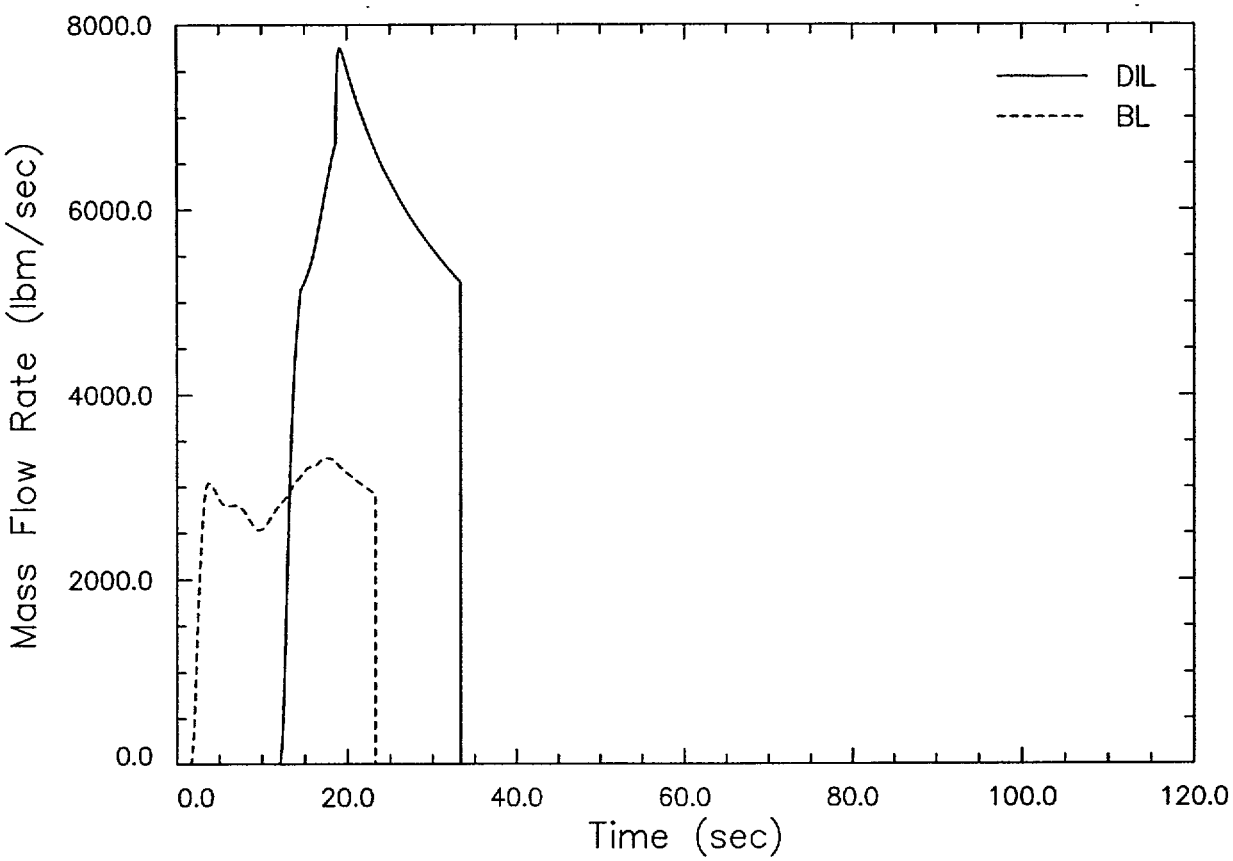

Figure 6.1.1-2 Accumulator Discharge Rates

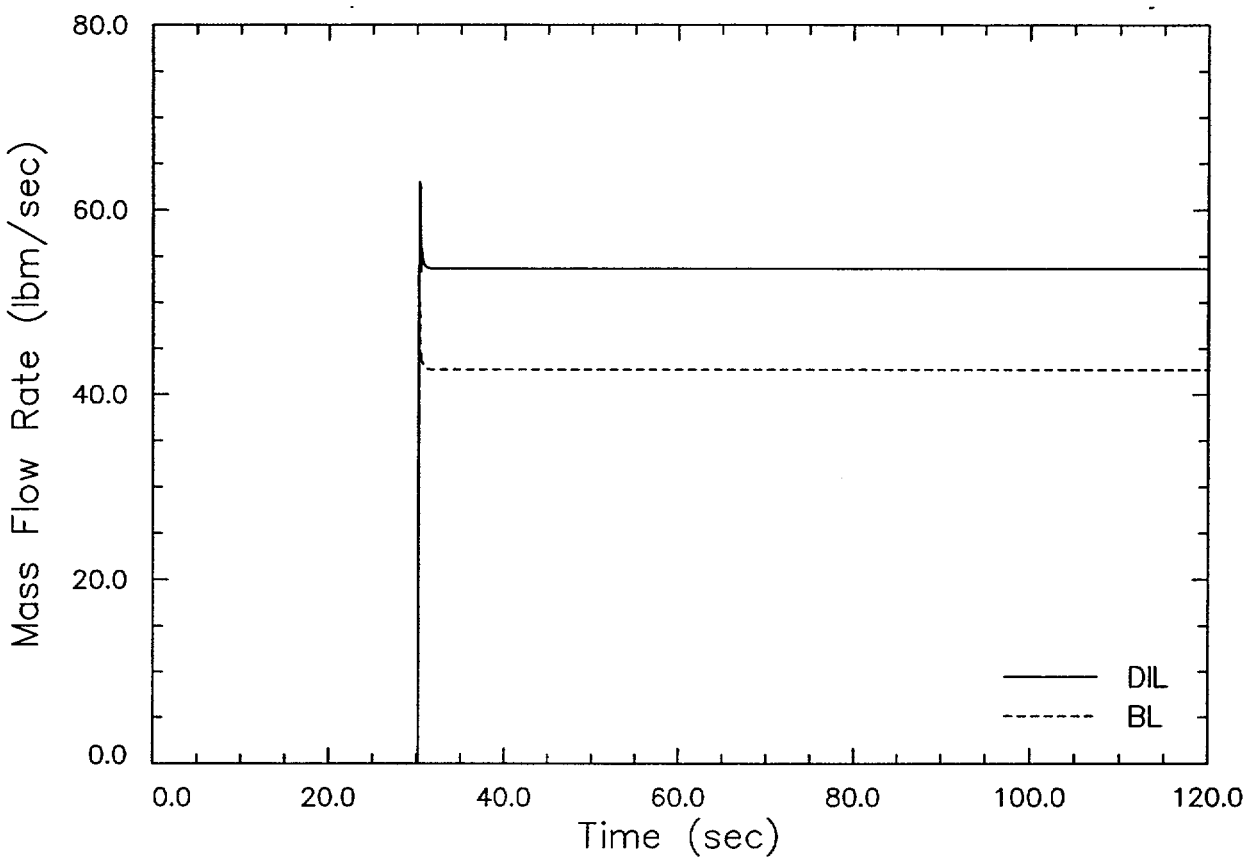

Figure 6.1.1-3 HHSI Flow Rates

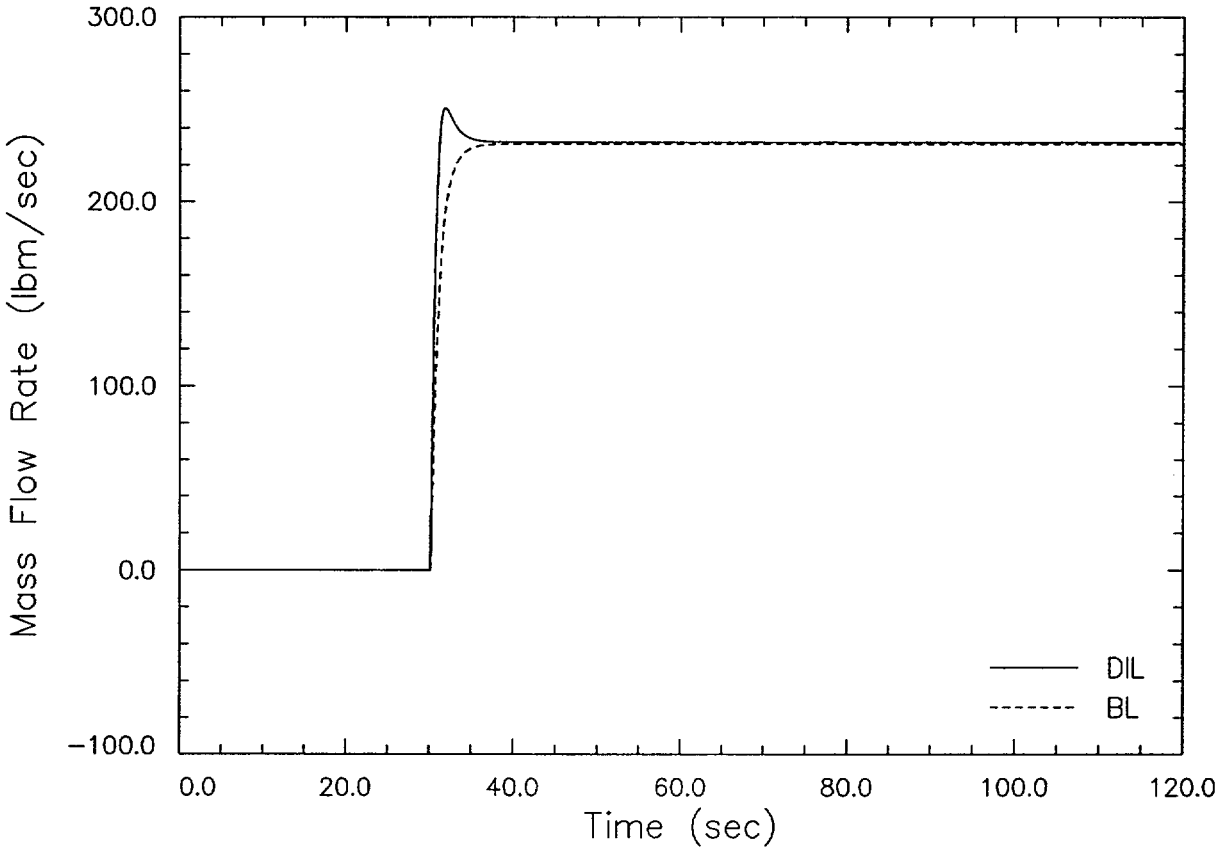

Figure 6.1.1-4 LHSI Flow Rates

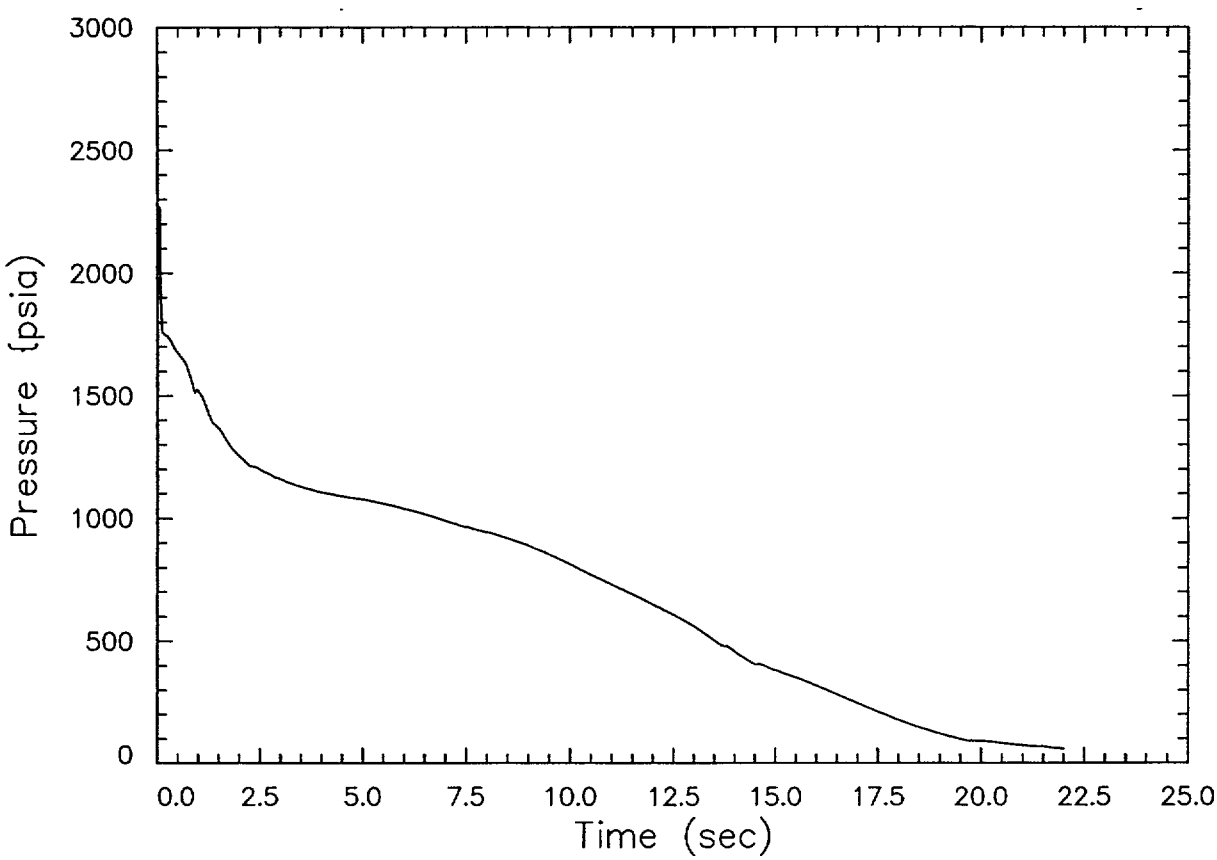

Figure 6.1.1-5 Upper Plenum Pressure During Blowdown

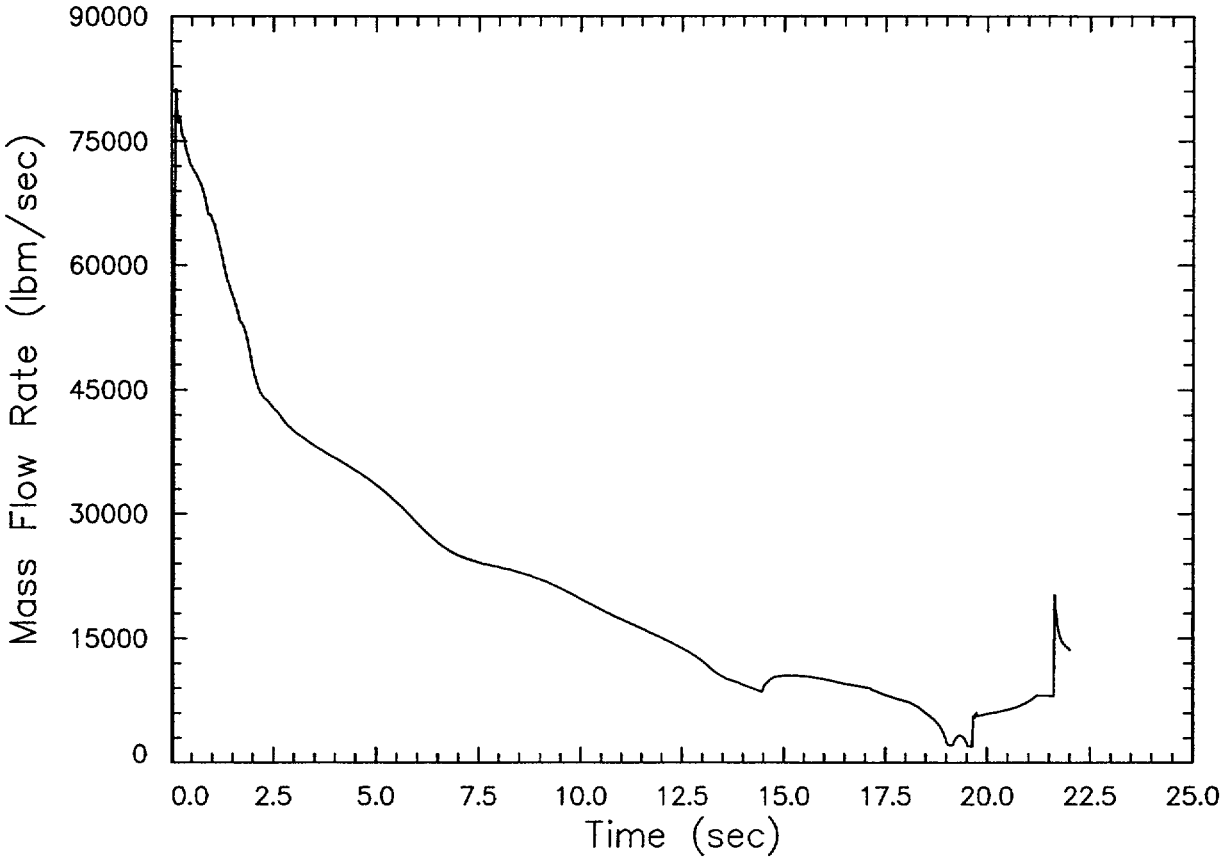

Figure 6.1.1-6 Total Break Flow Rate During Blowdown

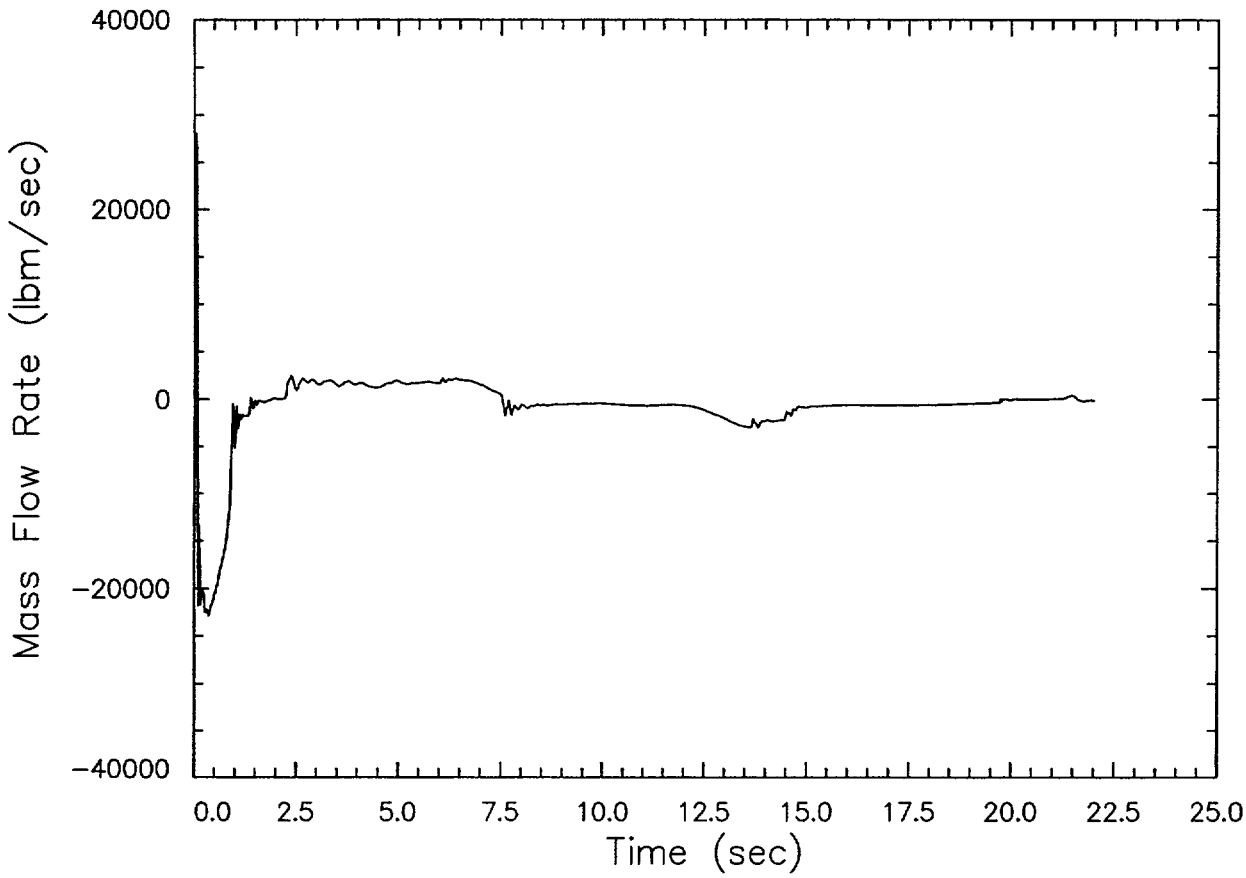

Figure 6.1.1-7 Average Core Inlet Flow Rate During Blowdown

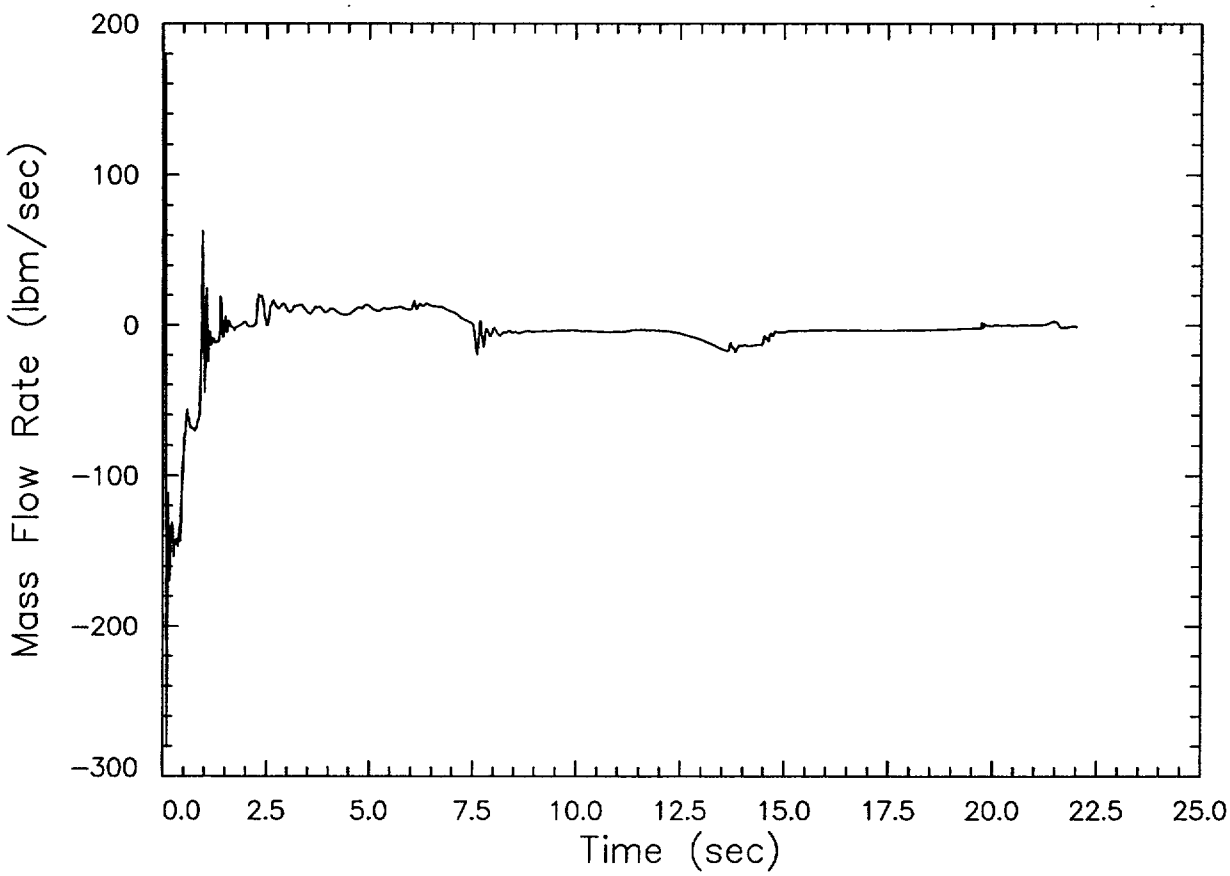

Figure 6.1.1-8 Hot Assembly Inlet Flow Rate During Blowdown

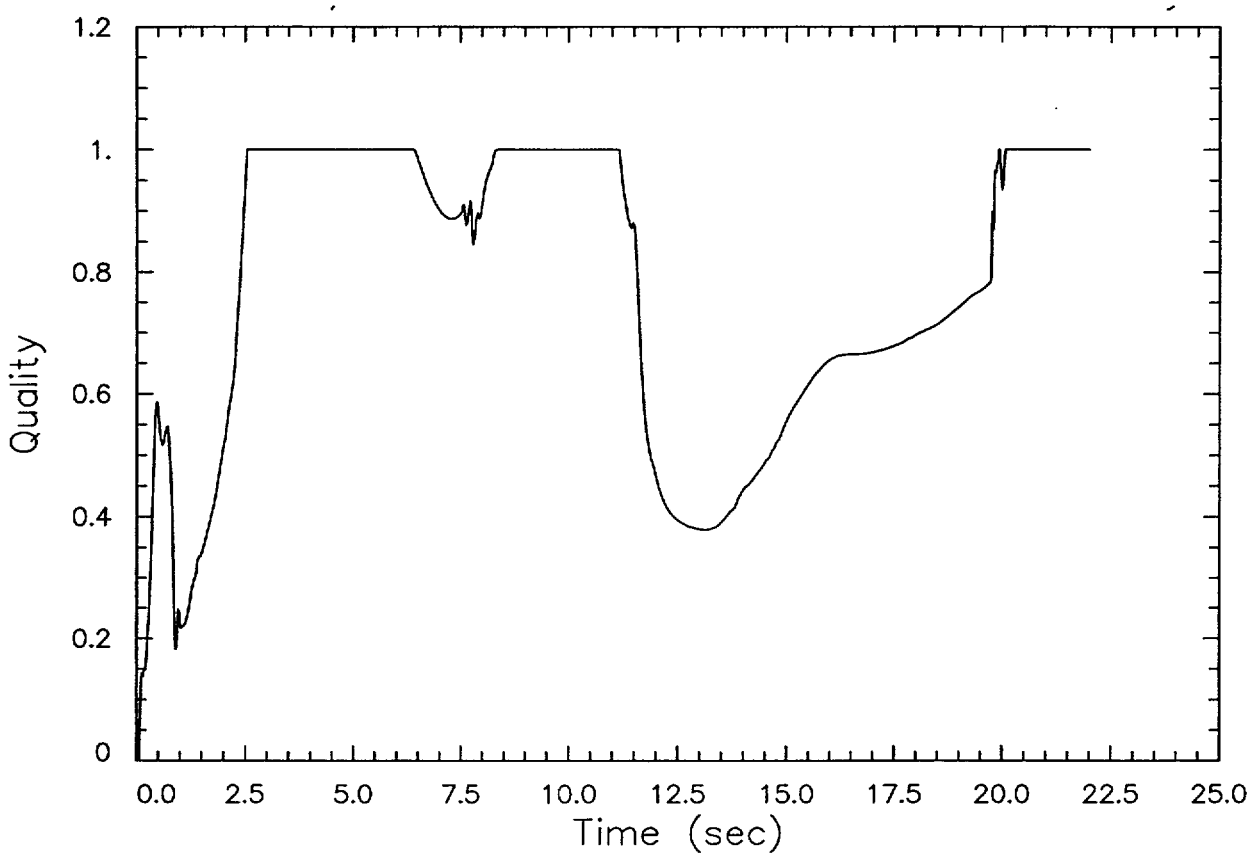

Figure 6.1.1-9 PCT Node Fluid Quality During Blowdown

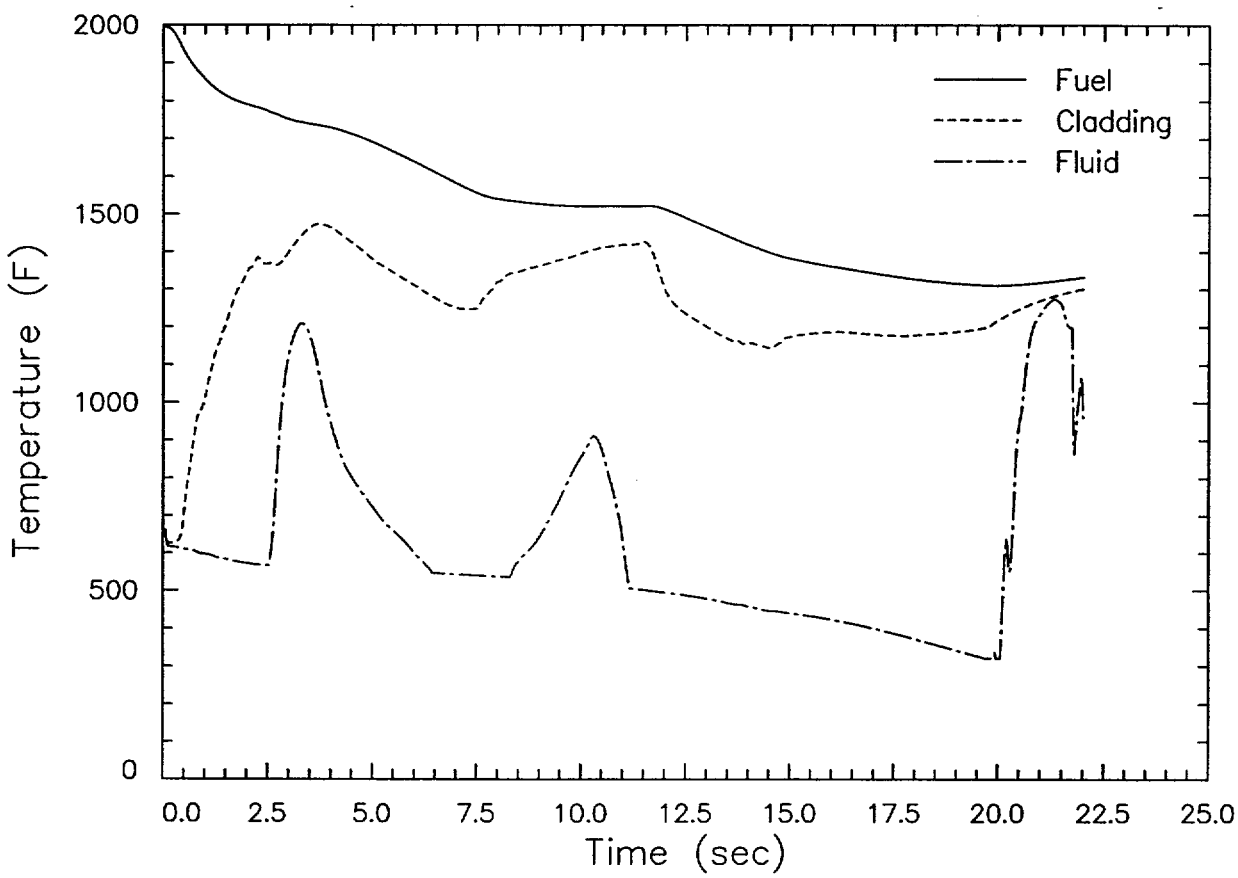

Figure 6.1.1-10 PCT Node Fuel (Average), Cladding and Fluid Temperatures During Blowdown

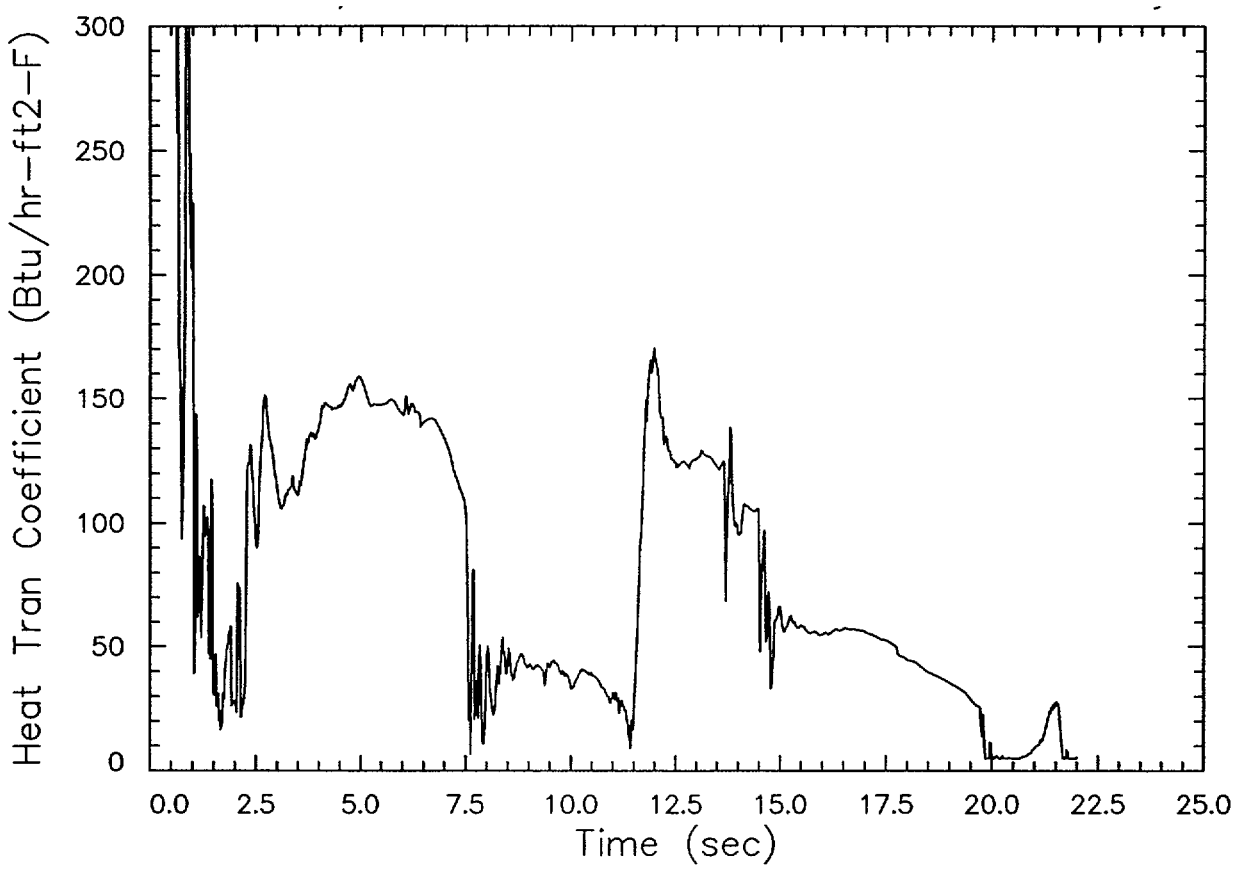

Figure 6.1.1-11 PCT Node Heat Transfer Coefficient During Blowdown

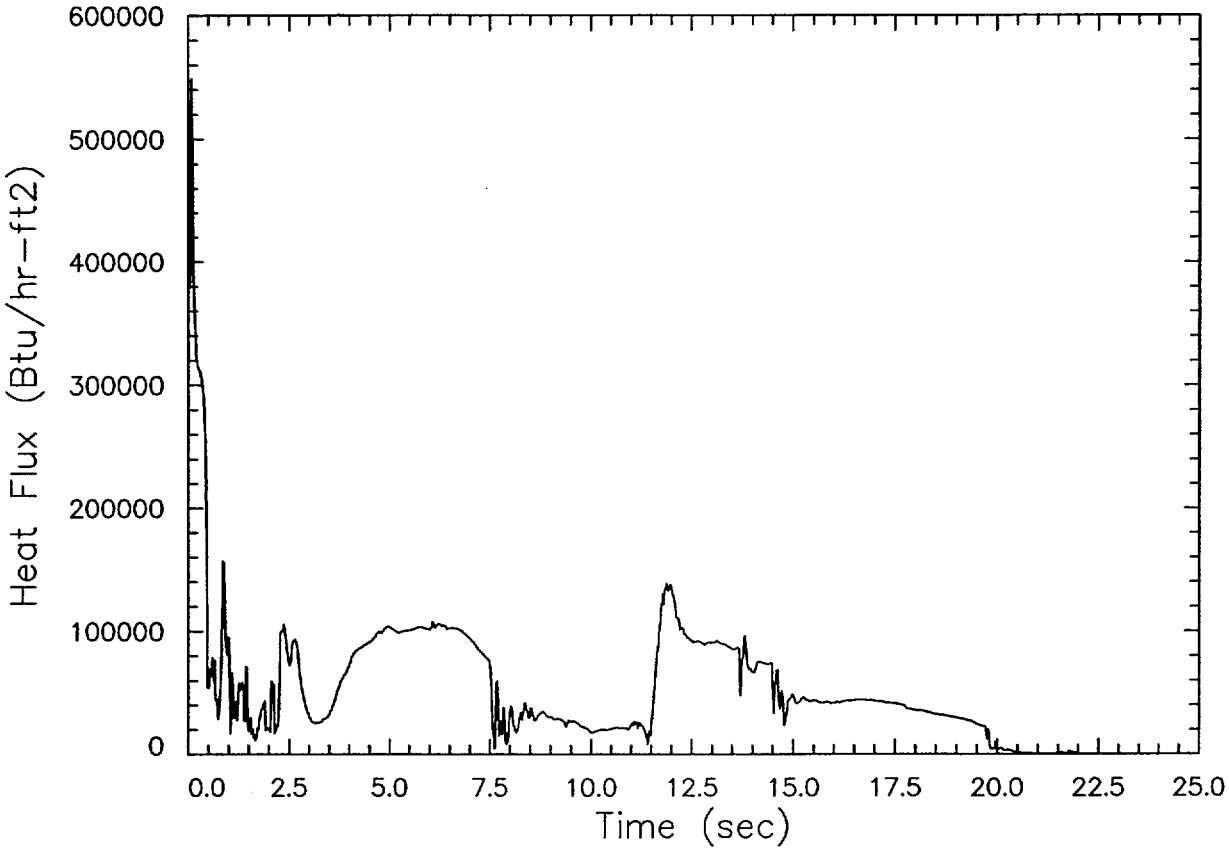

Figure 6.1.1-12 PCT Node Heat Flux During Blowdown

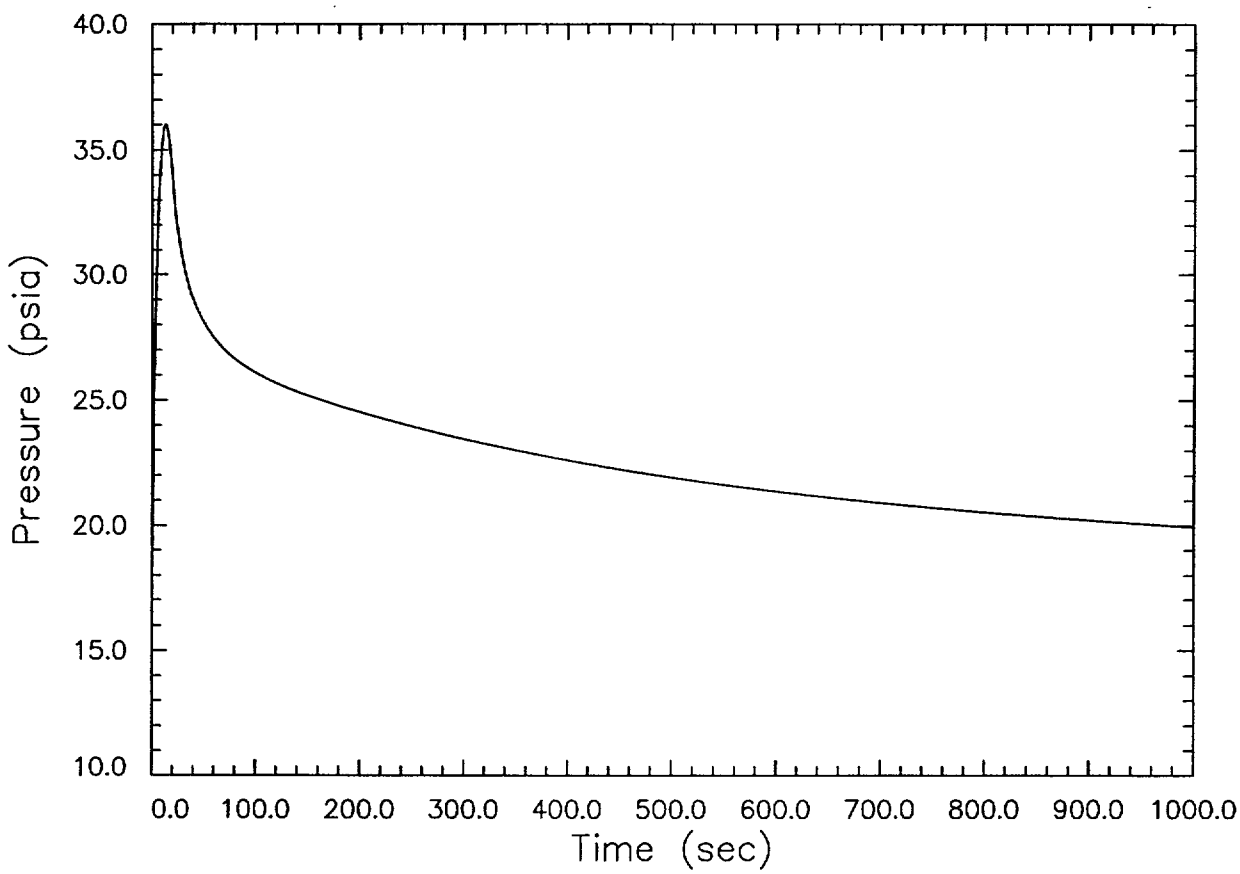

Figure 6.1.1-13 Containment Pressure

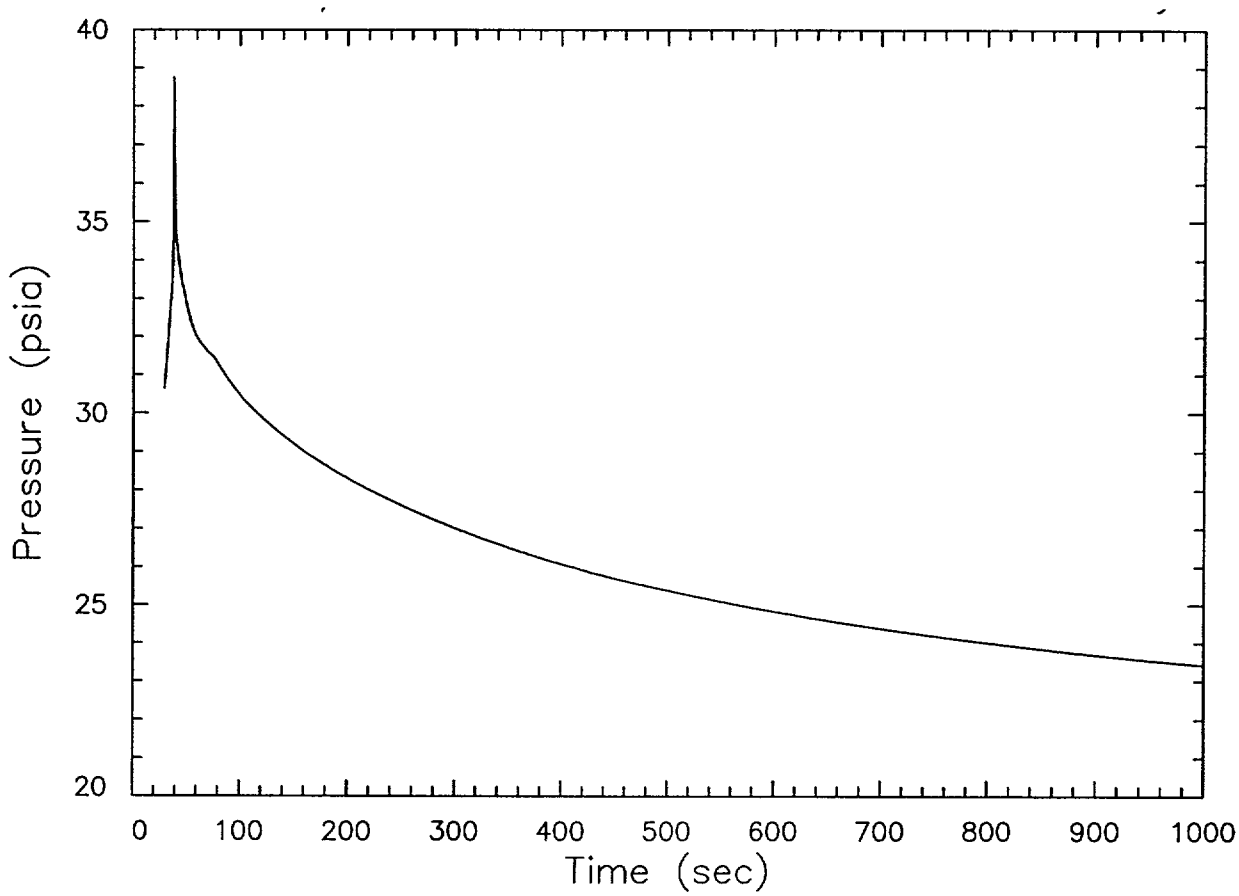

Figure 6.1.1-14 Upper Plenum Pressure After Blowdown

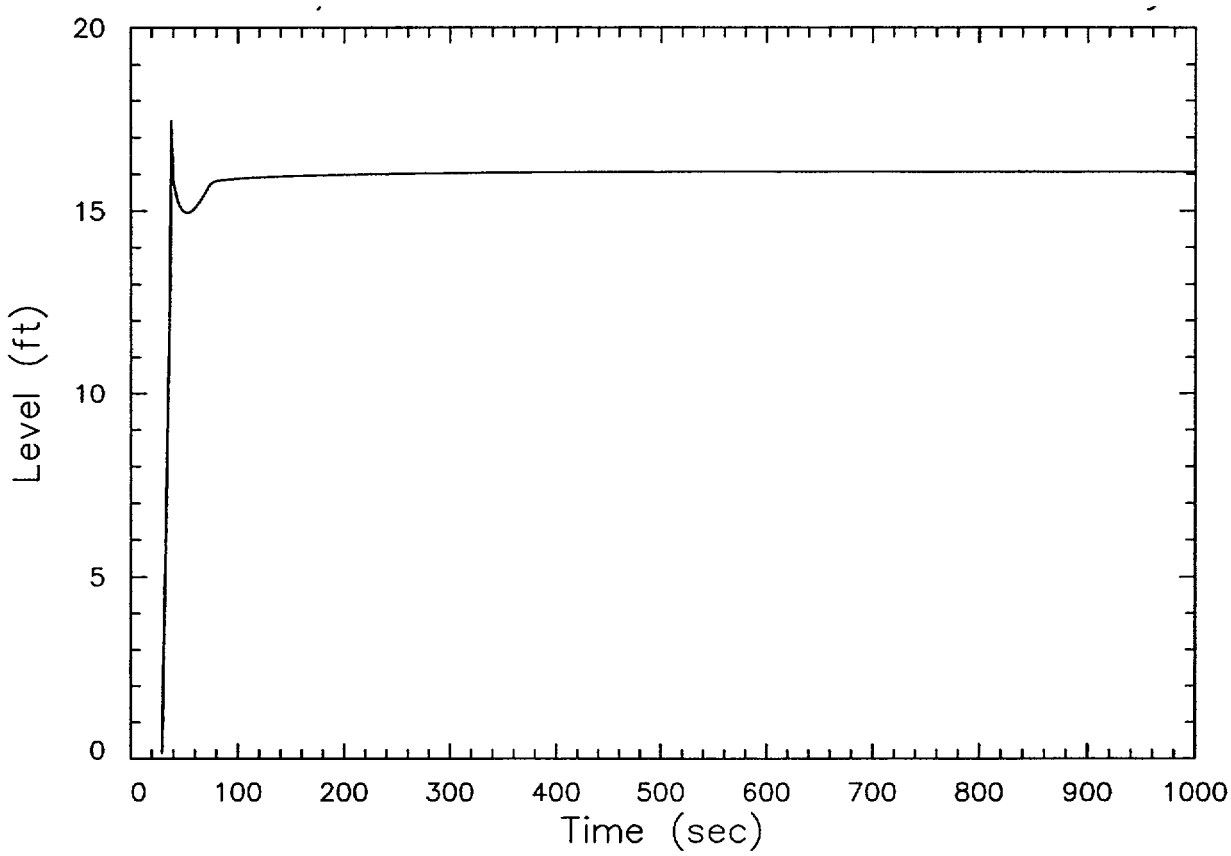

Figure 6.1.1-15 Downcomer Collapsed Liquid Level

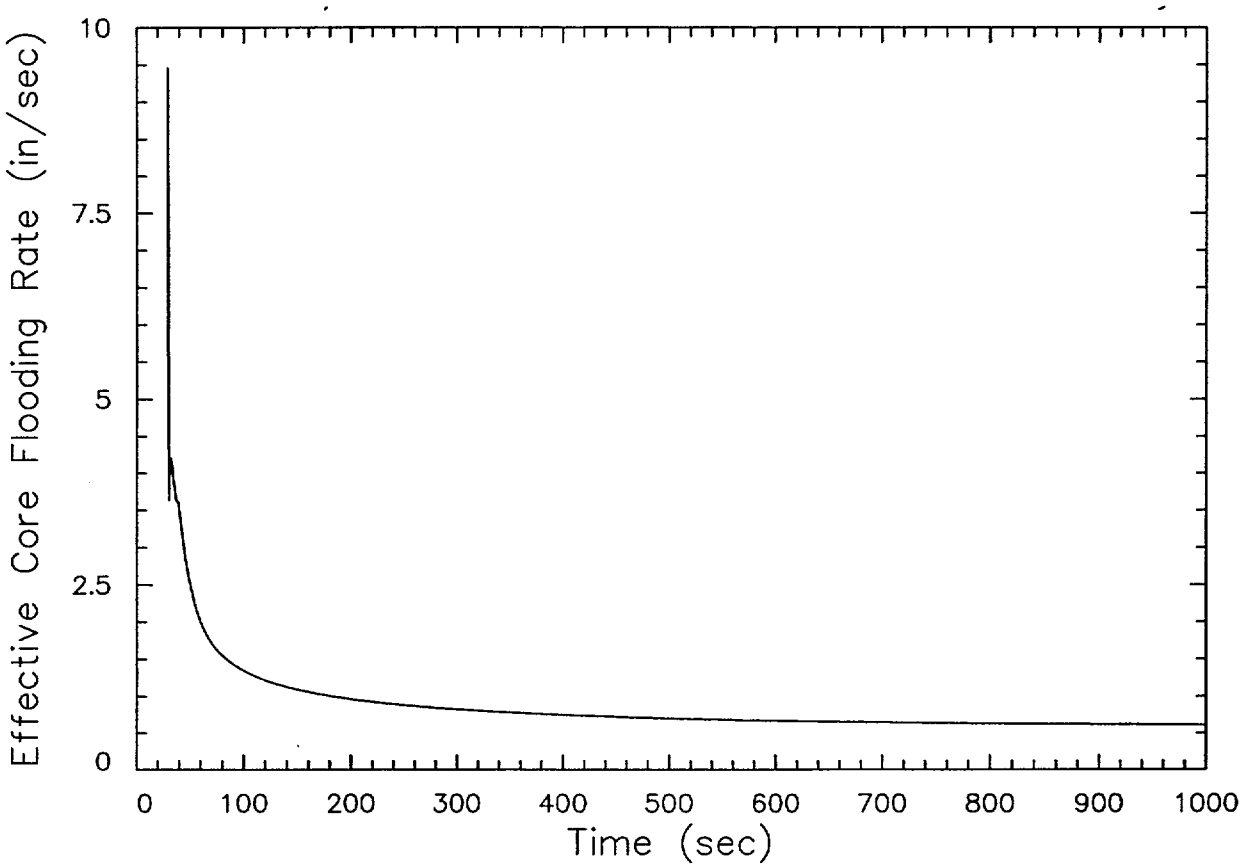

Figure 6.1.1-16 Core Effective Flooding Rate

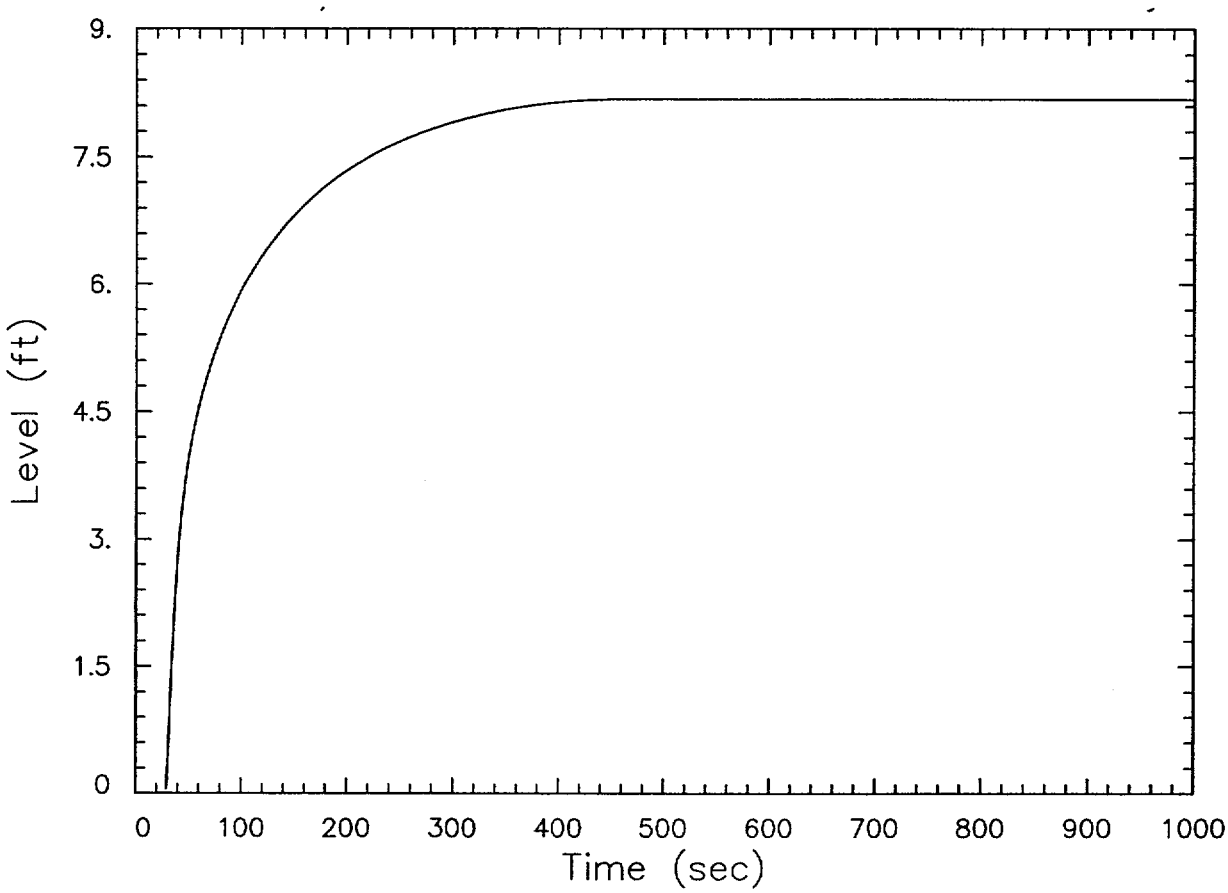

Figure 6.1.1-17 Core Collapsed Liquid Level

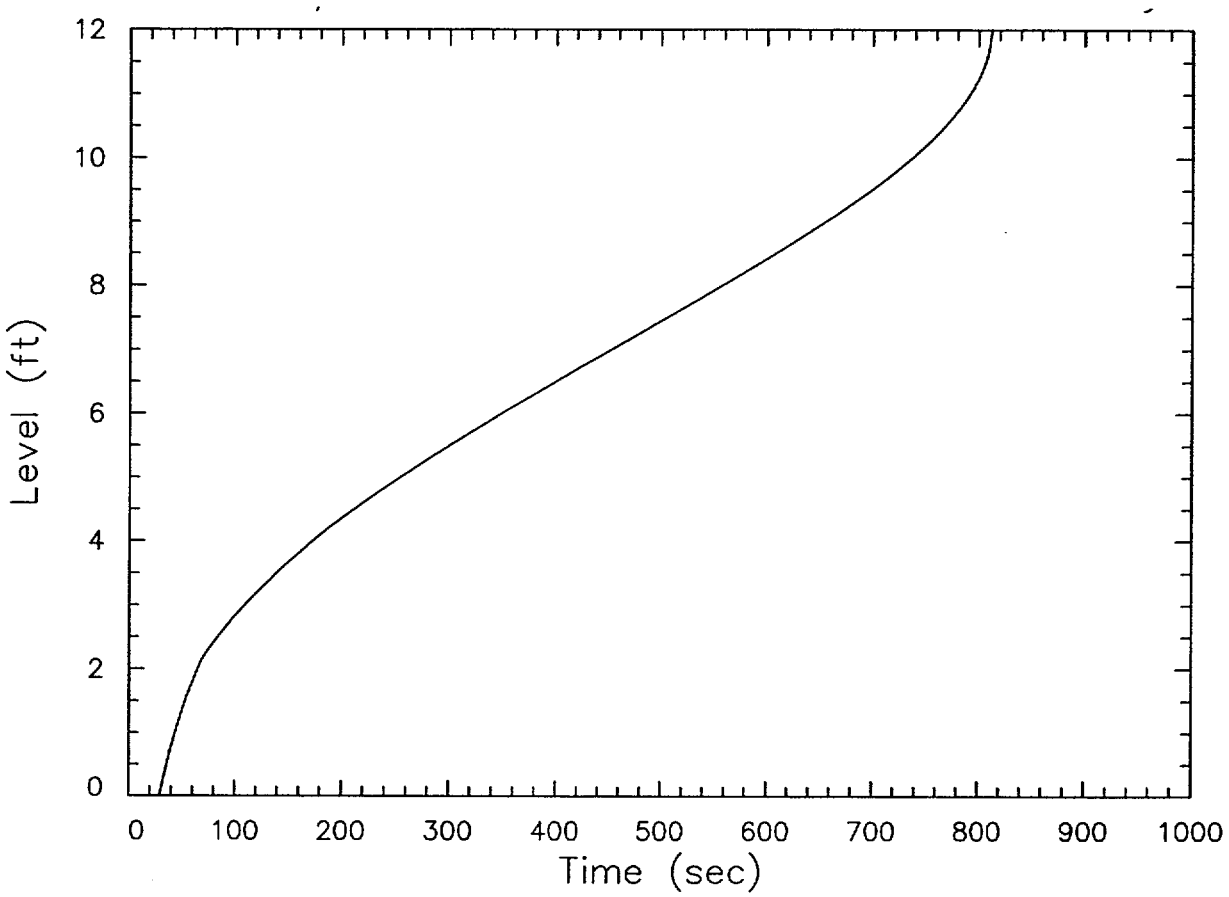

Figure 6.1.1-18 Core Quench Level

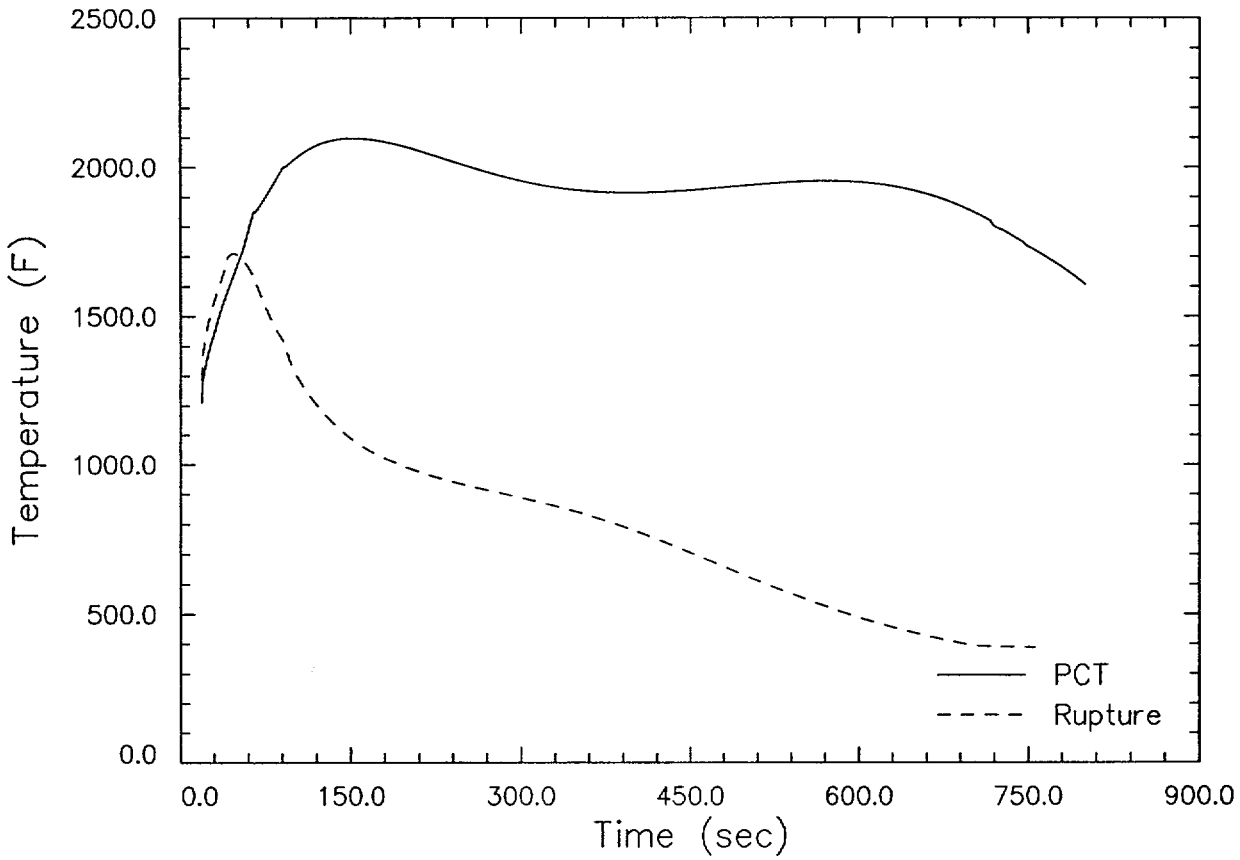

Figure 6.1.1-19 PCT Node and Ruptured Node Cladding Temperatures

6.1.2 Small Break LOCA

6.1.2.1 Introduction

The purpose of performing an SBLOCA analysis is to verify the Technical Specification peaking limits and axial dependent power peaking limit (K(z) curve) as well as the adequacy of the Emergency Core Cooling System (ECCS) by demonstrating that the criteria stated in 10 CFR 50.46(b) are met. The SGR/Uprating conditions supported by this analysis include:

- A rated thermal core power of 2900 MW;
- Model Delta 75 steam generators with 3% tube plugging,
- A total peaking factor $\left(F_Q^T\right)$ of 2.41 and a nuclear enthalpy rise factor ($F_{\Delta H}$) of 1.66; and
- Vessel average coolant temperatures from 580.8°F to 588.8°F, inclusive.

6.1.2.2 Description of Analyses and Evaluations

The SPC SBLOCA evaluation models (References 1 and 2) consist of three computer codes. The appropriate conservatisms, prescribed by Appendix K of 10 CFR 50, are incorporated. The sensitivity analyses, including the time step analysis, that were required in the NRC approval were run. The three computer codes are:

1. The RODEX2 code, which is utilized to determine the initial fuel stored energy and gap conditions for the initialization of the system blowdown and hot rod response calculations.
2. ANF-RELAP, which is used to model the primary system and secondary side of the steam generators during the blowdown. The governing conservation equations for mass, energy, and momentum transfer are used along with appropriate correlations consistent with Appendix K of 10 CFR 50.
3. The TOODEE2 code, which is employed to simulate the behavior of the hot rod during the entire transient using boundary conditions from the ANF-RELAP system calculation.

A break spectrum study was performed to determine the limiting break size.

6.1.2.3 Acceptance Criteria

The acceptance criteria are stated in 10 CFR 50.46(b), specifically:

- The calculated peak fuel cladding temperature does not exceed 2,200°F;

- The amount of fuel cladding which reacts chemically with water or steam does not exceed 1% of the total amount of zircaloy cladding in the heated length region of the core;

- The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. The hot fuel rod cladding oxidation does not exceed 17% during or after quenching; and,

- The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long lived radioactivity remaining in the core.

6.1.2.4 Results

A break spectrum study was performed for breaks of 2.0, 3.0 and 4.0-inch diameter in the pump discharge cold leg. This is the limiting break location because it produces the greatest: loss of Reactor Coolant System (RCS) inventory, ECCS fluid lost out the break, core uncovery and fuel rod heatup time. The break spectrum study identified the 3.0-inch diameter break to be the limiting break size. Additional analyses for the limiting break size were performed to evaluate the sensitivity of results to system modeling and calculational time step size effects. The sequence of events for the limiting case is shown in Table 6.1.2-1 and the calculated hot rod results for this case is shown in Table 6.1.2-2.

Results for the limiting case are shown in Figures 6.1.2.-1 through 6.1.2-7. The limiting peak cladding temperature (PCT) was calculated to be 1,742°F, the maximum local cladding oxidation was calculated to be 3.38% and the core-wide metal water reaction was calculated to be less than 1%.

The effects of the Reactor Coolant Pump (RCP) coastdown caused by the analysis assumption of a Loss of Offsite Power (LOOP) at the time of reactor trip are demonstrated to be conservative relative to those that would be caused by an operator RCP trip. Review of the predicted results shows that the minimum time difference between the time that the RCP trip criteria are satisfied and break uncovery is approximately six minutes (from the 4.0-inch break case). Therefore, a conservative minimum time of five minutes is available for operator action to manually trip the RCPs prior to break uncovery.

6.1.2.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that 10 CFR 50.46(b) acceptance criteria are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.1.2.6 References

1. XN-NF-82-49(P)(A) Revision 1, Exxon Nuclear Company Evaluation Model EXEM PWR Small Break Model, Advanced Nuclear Fuels Corporation, April 1989.

2. XN-NF-82-49(P)(A) Revision 1 Supplement 1, Exxon Nuclear Company Evaluation Model Revised EXEM PWR Small Break Model, Siemens Power Corporation, December 1994.

Table 6.1.2-1 Sequence of Events for Limiting SBLOCA Case

Event	Time (sec)
Break opens	0
Reactor trip and RCP trip	17
SIAS signal	31
HHSI initiated	60
AFW initiated	87
Loop seal clearing (Loop 1, Intact)	~680
Loop seal clearing (Loop 2, Intact)	---
Loop seal clearing (Loop 3, Broken)	---
Break uncovery	~690
Accumulator injection started	1,306
PCT Occurs (from TOODEE2)	1,387

Table 6.1.2-2 Summary of Hot Rod Response Results for Limiting SBLOCA Case

Parameter	Value
Hot Rod Burst	
Time (sec)	1,280
Elevation (ft)	11.375
Channel blockage fraction (%)	71.06
Peak Clad Temperature	
Temperature (°F)	1,742
Time (sec)	1,387
Elevation (ft)	11.625
Metal-Water Reaction	
Local maximum (%)	3.38
Elevation of local maximum (ft)	11.375
Core Wide (%)	<1%

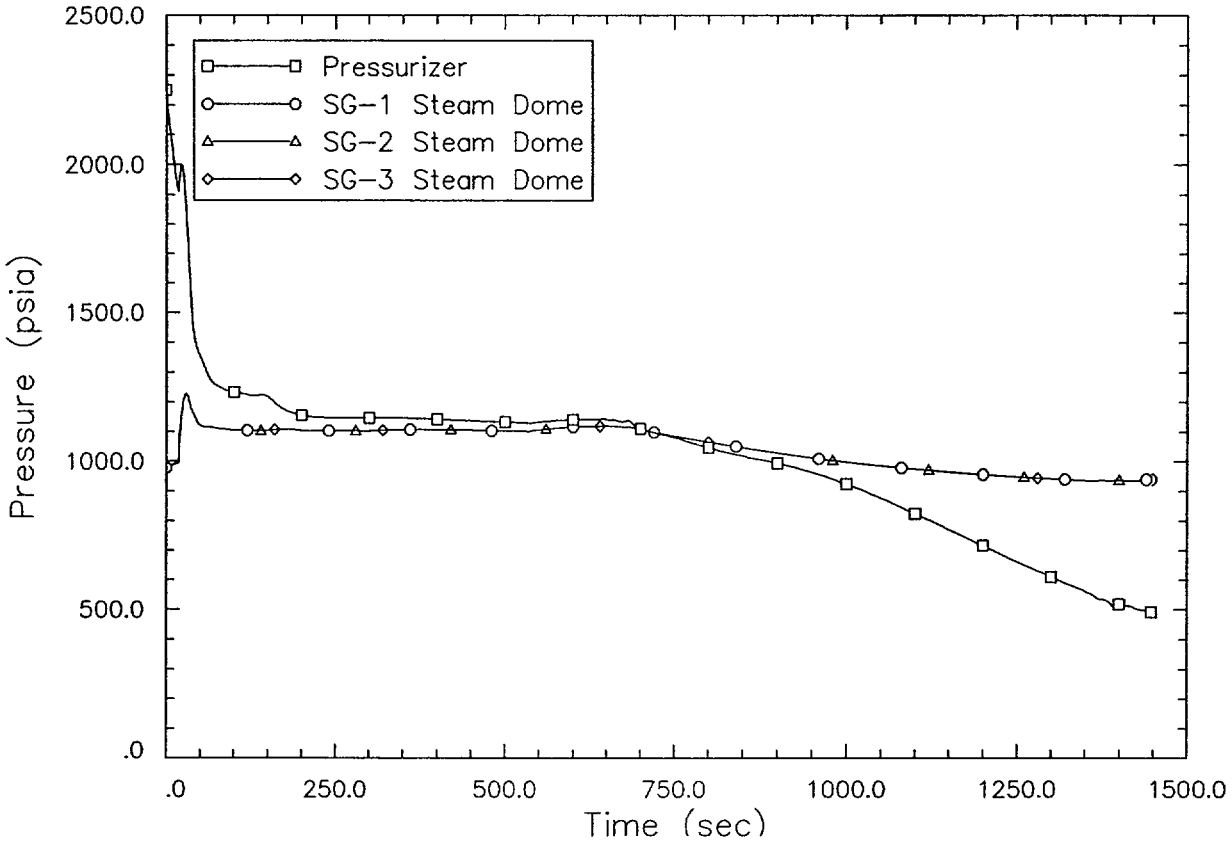

Figure 6.1.2-1 System Pressures for Limiting Break (3.0-Inch SBLOCA)

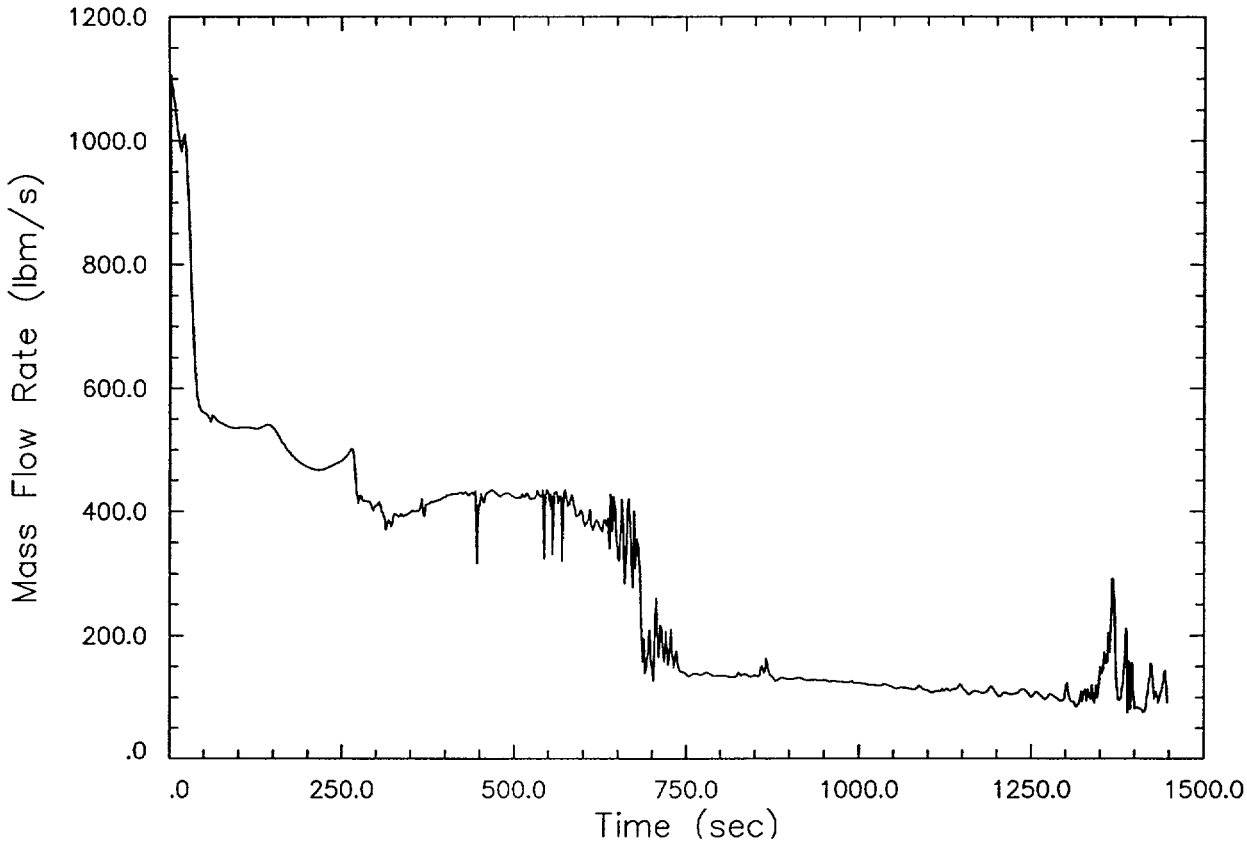

Figure 6.1.2-2 Break Flow Rate for Limiting Break (3.0-Inch SBLOCA)

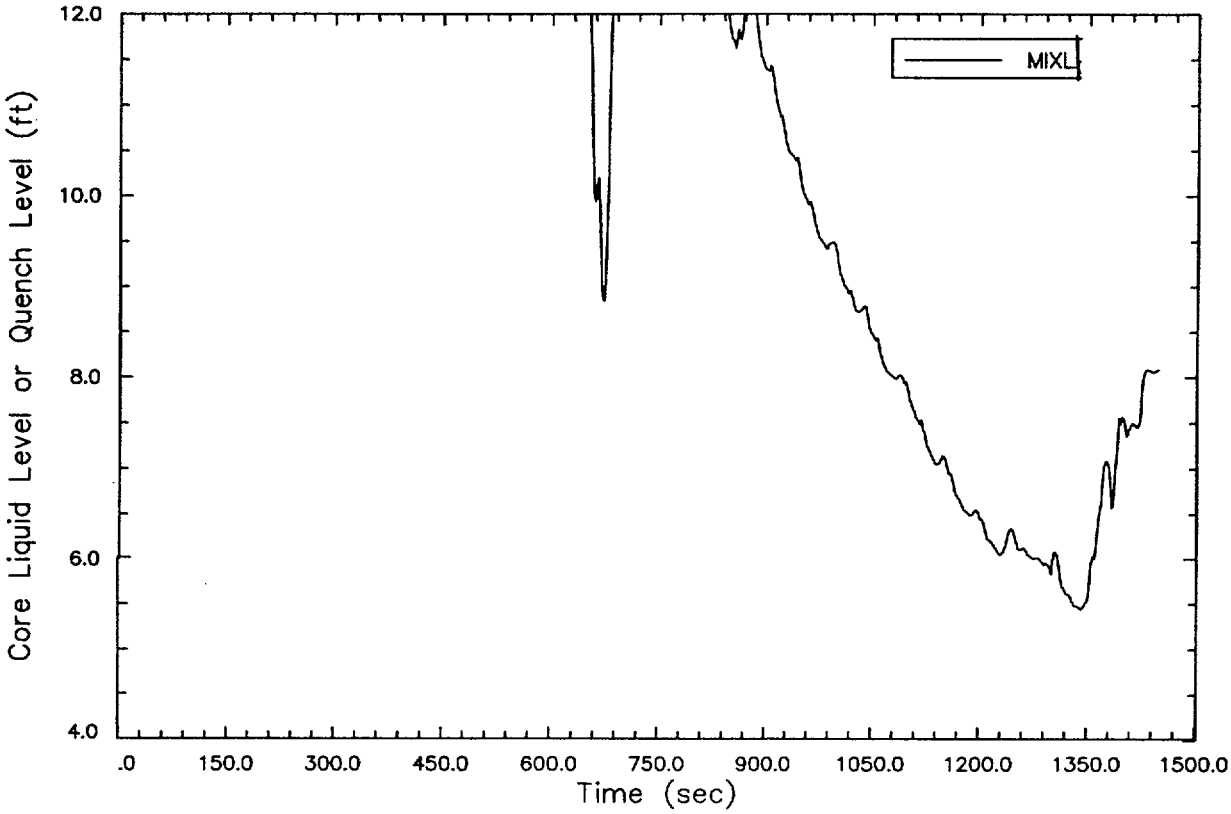

Figure 6.1.2-3 Core Mixture Level for Limiting Break (3.0-Inch SBLOCA)

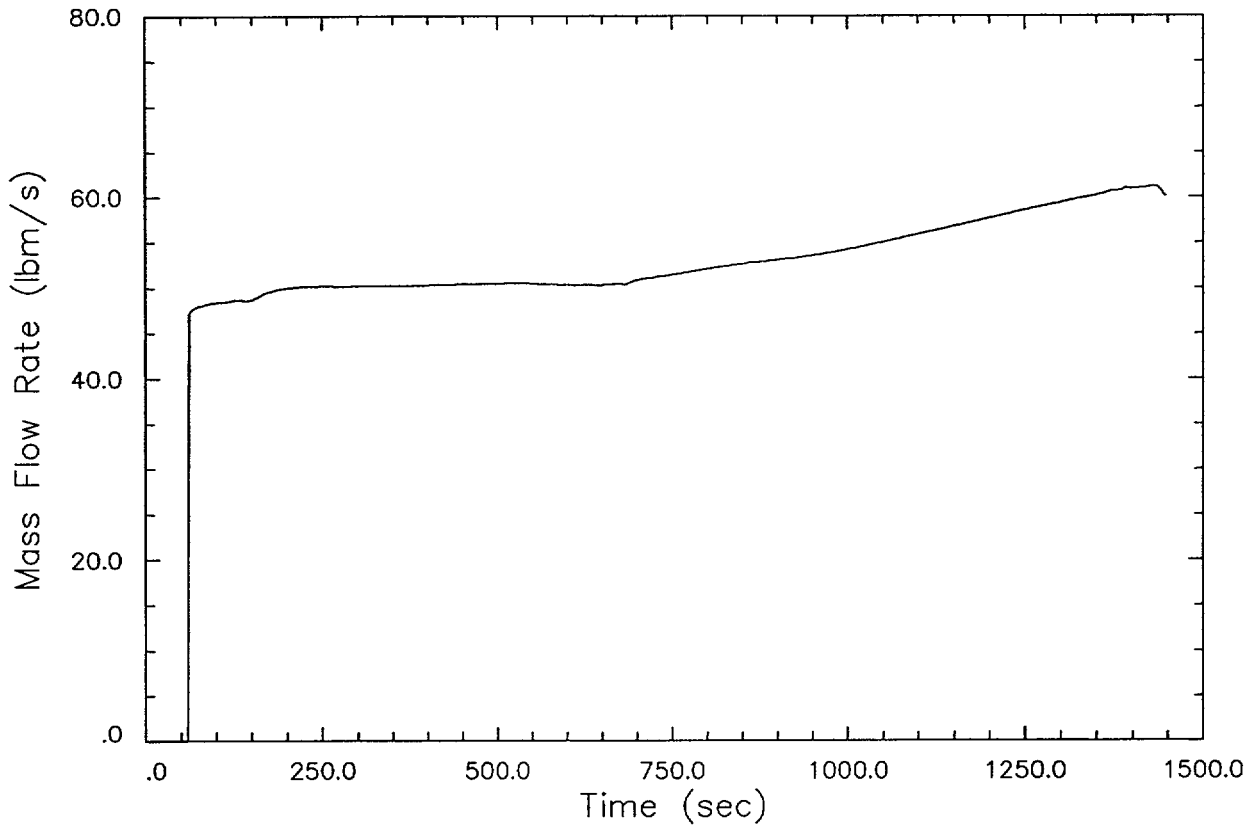

Figure 6.1.2-4 Combined HHSI Flow for Limiting Break (3.0-Inch SBLOCA)

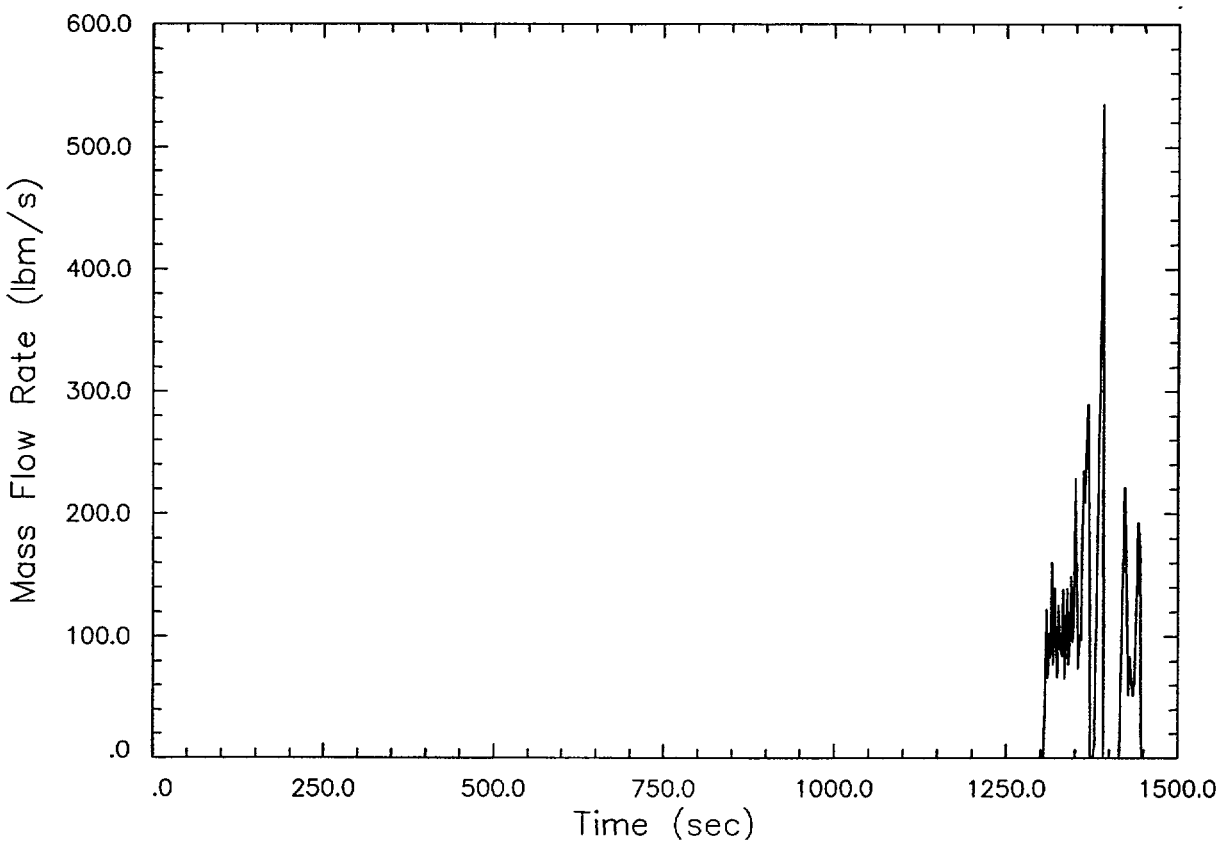

Figure 6.1.2-5 Combined Accumulator Flow for Limiting Break (3.0-Inch SBLOCA)

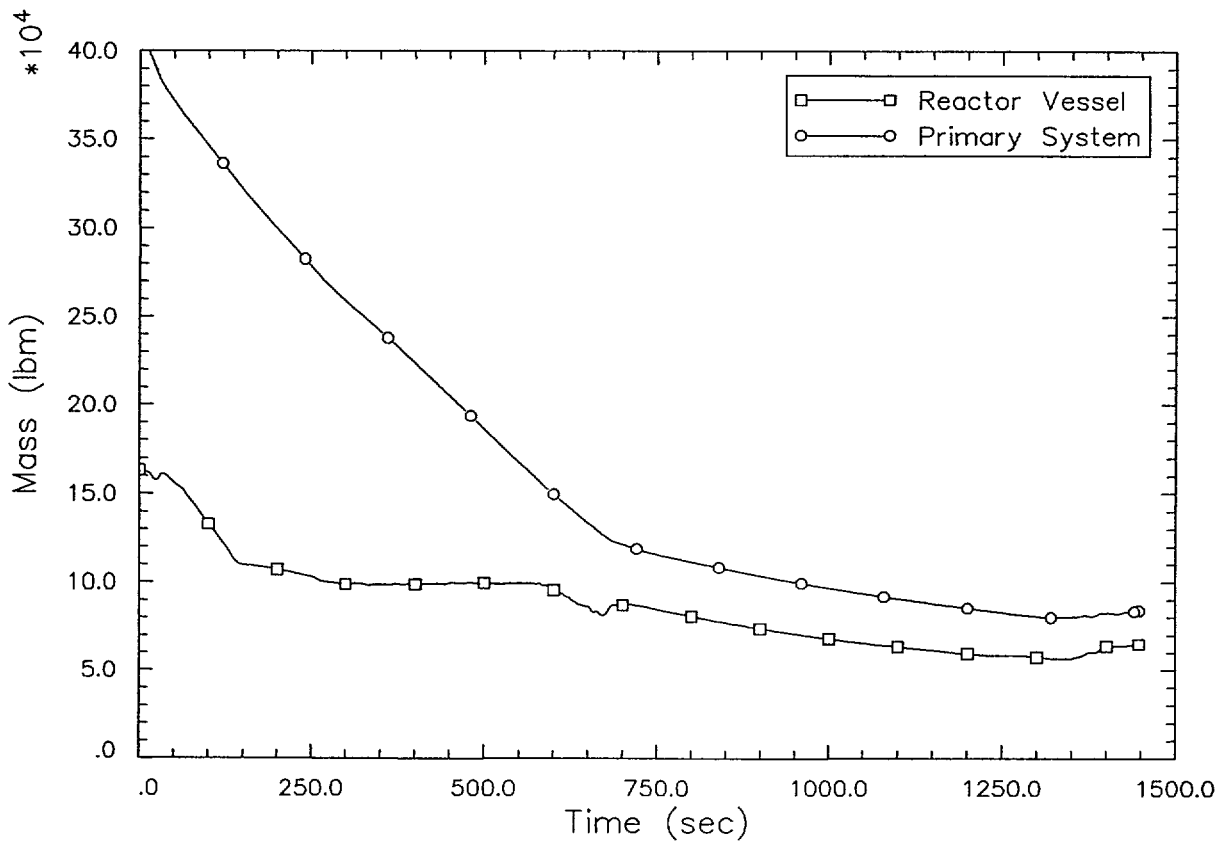

Figure 6.1.2-6 Reactor Vessel and Total RCS Mass for Limiting Break (3.0-Inch SBLOCA)

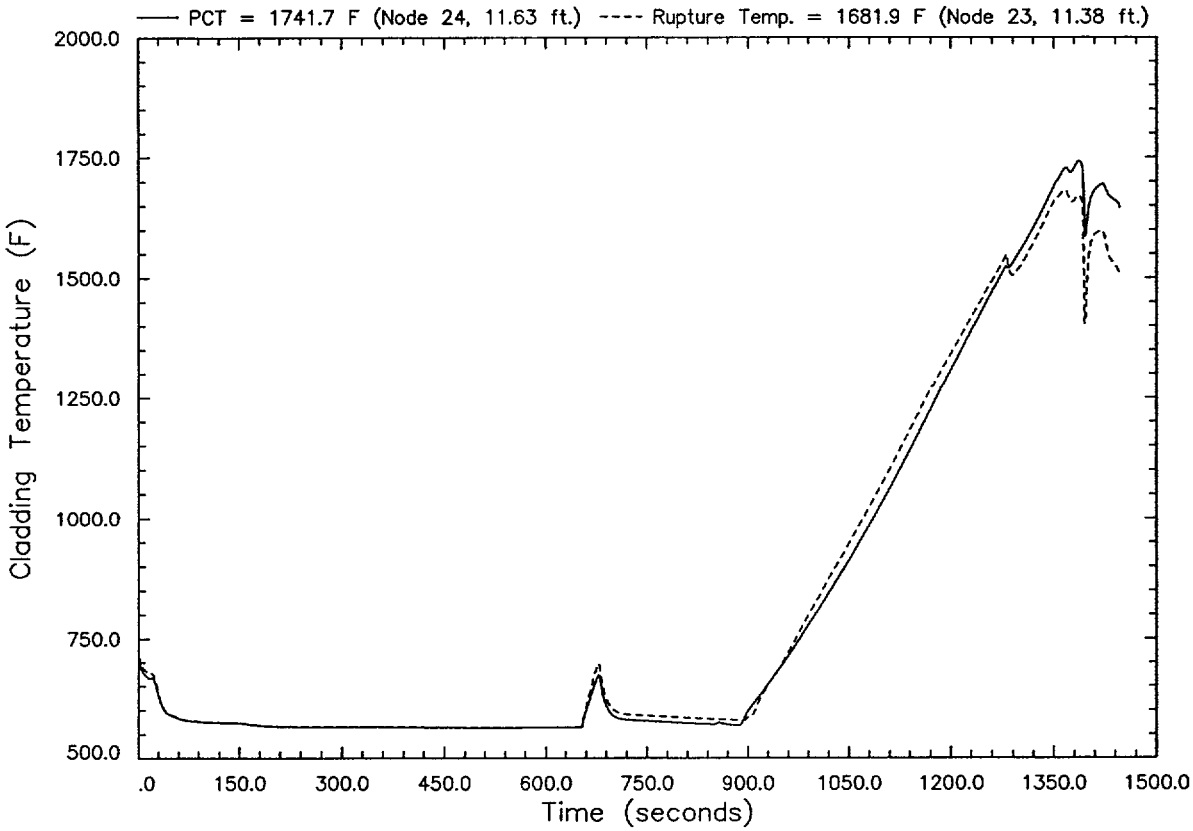

Figure 6.1.2-7 Hot Rod Cladding Temperature Response for Limiting Break (3.0-Inch SBLOCA)

6.1.3 Post-LOCA Long-Term Core Cooling

6.1.3.1 Introduction

Post-LOCA long-term core cooling (LTCC) analyses are performed to satisfy the requirements of 10 CFR 50.46(b)(5), Long-term cooling. The requirements of 10 CFR 50.46(b)(5) are stated below:

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

There are three aspects of the post-LOCA LTCC analyses that must be addressed, as follows:

1. Maintaining the core in a subcritical condition following a LOCA.

2. Preventing boron precipitation in the core by calculating a suitable time to switch from cold-leg recirculation to hot-leg recirculation.

3. Establishing the minimum flow requirements for the hot-leg recirculation configuration.

The first item is addressed in this section, and the second and third issues are addressed in Section 6.1.4.

The Westinghouse position on maintaining the core in a sub-critical condition post-LOCA, initially summarized in Reference 1, states that subcriticality for large breaks is maintained without credit for control rods. For the SGR/Uprating program, a range of Mixed Mean Sump Boron Concentrations (MMSBC) corresponding to various initial Reactor Coolant System (RCS) boron concentrations was determined. Note that the calculation of MMSBC is primarily impacted by the change in RCS mass associated with the Model Delta 75 replacement steam generator, as the change in RCS mass associated with uprated power conditions is not considered significant. The minimum boron requirement for post-LOCA sub-criticality is verified on a cycle-specific basis during the reload process.

For the post-LOCA sump boron calculation, the key inputs are the minimum masses and boron levels of the fluids that have the potential to arrive in the sump, post-LOCA, along with the maximum masses of fluid sources that are potential dilution sources for the sump. The primary boron sources include the Refueling Water Storage Tank (RWST), the RCS, the Accumulators, and various ECCS and Containment Spray piping. Dilution sources include the Containment Spray Additive Tank and associated piping, and the (deactivated) Boron Injection Tank (BIT) and associated piping.

To generate the mixed mean sump boron curve, the pre-trip RCS boron concentration for peak-xenon conditions is assumed to be 100 ppm lower than the equilibrium xenon case. The equation that generates the mixed mean sump boron curve is also expressed so that an equivalent

curve can be generated for the highest reasonable postulated peak to equilibrium xenon RCS boron ratio for the particular core design considered.

6.1.3.2 Description of Analyses and Evaluations

The minimum MMSBC is calculated by assuming that all available post-LOCA boron sources to the sump are at minimum volumes, masses, and boron concentrations, while all dilution sources to the sump are at maximum volumes, masses, and minimum (0 ppm) boron concentration.

6.1.3.3 Acceptance Criteria

The acceptance criterion for the LTCC post-LOCA sump boron calculation is that the core design must remain such that the minimum post-LOCA sump boron concentration remains sufficient to preclude a return to criticality in the long term post-LOCA.

6.1.3.4 Results

Mixed Mean Sump Boron Calculation: The results were tabulated for RCS boron concentration of 0 and 1500 ppm assuming the pre-trip RCS boron concentration for peak xenon concentration to be 100 ppm lower than the equilibrium xenon case. The straight-line curve (See Figure 6.1.3-1.) fit for the two points provided above is:

$$y = 0.20969\ x + 1839.35$$

An alternate equation is provided below where "n" is the difference in boron concentration between the peak and equilibrium xenon concentration case.

$$y = 0.20969\ x + 0.038036\ n + 1835.542$$

6.1.3.5 Conclusions

The Westinghouse licensing position for satisfying the requirements of 10CFR50.46 Paragraph (b) Item (5), "Long-Term Cooling" is documented in Reference 1. The Westinghouse position is that the core will remain subcritical post-LOCA by borated water from various ECCS water sources residing in the RCS and containment sump. Since credit for control rod insertion is not taken for large-break LOCA, the borated ECCS water provided by the accumulators and RWST must have a sufficiently high boron concentration so that, when mixed with other sources of borated and non-borated water, the core will remain subcritical, assuming that all control rods remain withdrawn from the core.

The revised post-LOCA long-term core cooling boron limit curve is used for cycle-specific core designs to ensure post-LOCA subcriticality for either the current NSSS power of 2787.4 MWt or the uprated NSSS power of 2912.4 MWt with the Model Delta 75 replacement steam generators.

The curve has been generated such that the revised post-LOCA LTCC analyses remain consistent with the current HNP acceptance requirements; the core remains subcritical post-LOCA, and decay heat can be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

6.1.3.6 References

1. Westinghouse Technical Bulletin NSID-TB-86-08, "Post-LOCA Long-Term Cooling: Boron Requirements," October 31, 1986.

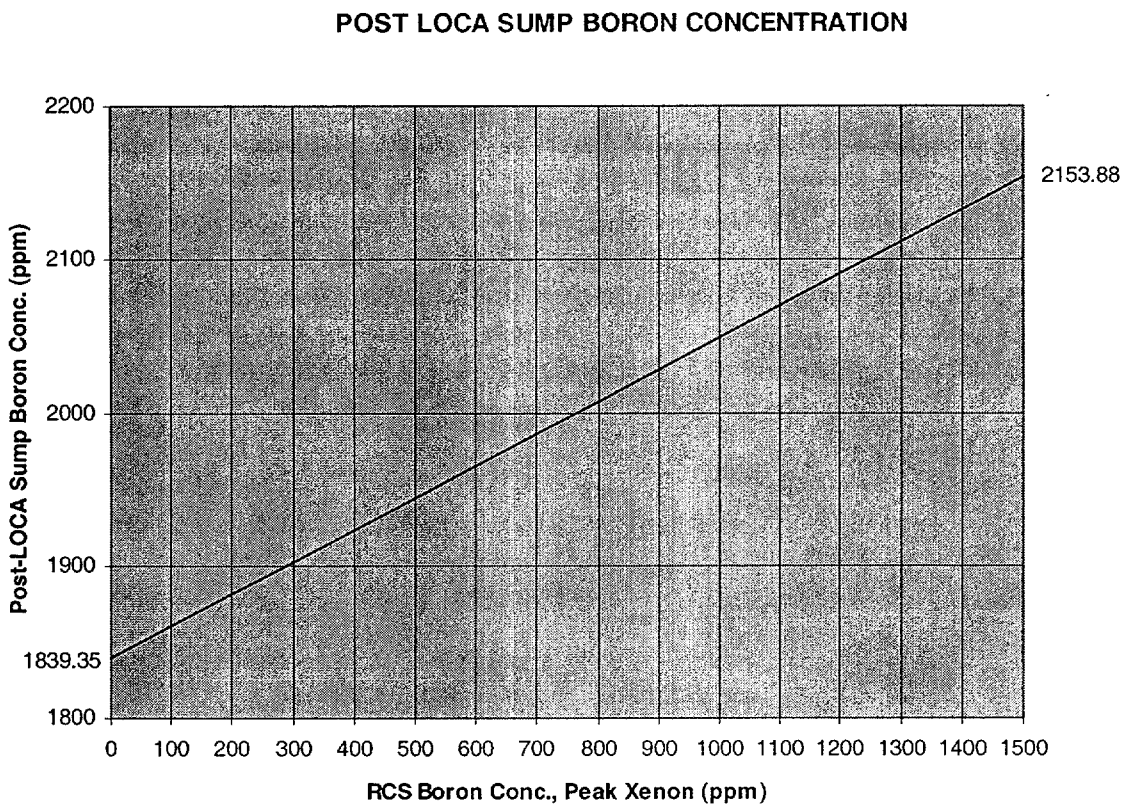

Figure 6.1.3-1 Post-LOCA Sump Boron Concentration

6.1.4 Hot-Leg Switchover

6.1.4.1 Introduction

As described in Section 6.1.3, there are three aspects of the post-LOCA LTCC analyses. The first is maintaining the core in a subcritical condition following a LOCA, which is addressed in Section 6.1.3. The second is preventing boron precipitation in the core by calculating a suitable time to switch from cold-leg recirculation to hot-leg recirculation. The third is establishing the minimum flow requirements for the hot-leg recirculation configuration.

The second issue, preventing boron precipitation in the core through switchover to hot-leg recirculation, is fundamentally described by Reference 1, which is consistent with the current HNP licensing basis as documented in FSAR Section 6.3.2.5.2.3.

The third issue, establishing minimum flow requirements for the hot-leg switchover (HLSO) time for various configurations, is primarily documented in Reference 2 (issued by Westinghouse) and Reference 3 (issued by the NRC). These minimum flow requirements, which depend on calculated core boil-off rates, can then be used to establish the minimum allowable HLSO time based on the decay heat assumptions required in 10CFR50 Appendix K.

6.1.4.2 Description of Analyses and Evaluations

The calculation of the maximum allowable hot-leg switchover time begins with a calculation of the maximum Mixed Mean Sump Boron Concentration (MMSBC). This is calculated assuming that all available post-LOCA boron sources to the sump are at maximum volumes, masses, and boron concentrations, while all dilution sources to the sump are at minimum volumes and masses, and maximum boron concentrations. Then, a minimum vessel mixing volume is computed and a core boil-off calculation is performed, which assumes that fluid enters the vessel at the sump boron concentration, and leaves the vessel as steam (0 ppm boron concentration). The steam is then condensed in containment and added to the sump. As boron accumulates in the vessel mixing volume, boron is depleted from the sump. When the boron concentration in the vessel mixing volume gets to within 4 weight percent of the solubility limit for boron at 14.7 psia (a value of 23.53 weight percent), the maximum allowable hot-leg switchover time is established.

For plants such as the HNP where both high-head and low-head safety injection are aligned to inject to the hot legs at the hot-leg switchover time, a second calculation is performed to establish the required cycling time. This calculation assumes that the initial LOCA occurs in the hot leg, so boron buildup in the vessel does not begin until the initial hot-leg switchover occurs. The second calculation assumes flow comes in from the hot-legs only and similarly is carried out until the 23.53 weight percent boron limit is reached.

Note that for the first of these calculations, it is conservatively assumed that the recirculation flow enters the lower plenum at 212°F (no subcooling). For the second calculation to establish the cycling time, a higher subcooling value (based upon 180°F Residual Heat Removal (RHR) outlet temperatures) is considered justified.

6.1.4.3 Acceptance Criteria

The two acceptance criteria for the maximum allowable hot-leg switchover time calculation are as follows:

- The boron buildup process must be halted by switchover to hot-leg recirculation by the time the margin to the boron solubility limit in the vessel is 4 weight percent (23.53 weight percent boron). Thus, the maximum allowable HLSO time is established by the above described calculation to establish the minimum credible time under which the vessel could reach the boron solubility limit for the range of operating conditions considered.

- This maximum allowable HLSO time must be validated as an acceptable upper limit on the cycling time between hot-leg injection and cold-leg injection, due to HNP's ECCS configuration. Provided the cycling time calculated exceeds the HLSO time calculated, this acceptance criterion is shown to be met.

The two acceptance criteria for the minimum flows following hot-leg switchover are as follows:

- Flow following HLSO must be sufficient to preclude a reduction of core liquid inventory. This ensures compliance with the requirements of 10 CFR 50.46 for the long term.

- Flow following HLSO must be sufficient to preclude precipitation of boron in the vessel (with a 4 weight-percent margin to the solubility limit).

Any time beyond which both of these criteria are met is considered acceptable to enter hot-leg recirculation. With the first criterion met, the core is demonstrated to remain quenched (and potential loss of vessel inventory is precluded) when hot-leg recirculation is established. If the second criterion is not met, the commitment to preclude boron precipitation cannot be demonstrated. Reasonable justifications may be established to support that boron precipitation in and of itself does not constitute a safety issue. Nevertheless both acceptance criteria are considered in this analysis to establish the minimum acceptable HLSO time.

6.1.4.4 Results and Conclusions

The analysis demonstrates that the current HLSO time and cycling time of 6.5 hours remain acceptable. The maximum HLSO time based on an uprated core power of 2900 MWt is 8.5 hours. The current HLSO time of 6.5 hours as discussed in FSAR Section 6.3.2.5.2.3 was assumed to be the initial time for the cycling calculation. Using the alternating hot-leg and cold-leg recirculation method, the maximum time for cycling between hot-leg and cold-leg recirculation is 14 hours after initially switching over to hot-leg recirculation. The minimum HLSO time based on recirculation flows requirements is 3 hours.

The results obtained from the HLSO calculation for the Model Delta 75 replacement steam generators at the uprated NSSS power of 2912.4 MWt bound operation with the Model Delta 75 replacement steam generator at the current NSSS power of 2787.4 MWt.

6.1.4.5 References

1. Westinghouse Letter CLC-NS-309, C. L. Caso to T. M. Novak (NRC), April 1, 1975.

2. Westinghouse Nuclear Safety Advisory Letter NSAL-92-010, "Hot Leg Switchover Methodology," January 9, 1993.

3. NRC Information Notice 93-66: "Switchover to Hot-Leg Injection Following a Loss-of-Coolant Accident in Pressurized Water Reactors," August 16, 1993.

6.1.5 Spectrum of Control Rod Ejection Accidents (FSAR Event 15.4.8)

6.1.5.1 Identification of Causes and Accident Description

This event is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of a rod cluster control assembly (RCCA) and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. Also, the rapid nuclear power excursion can result in a significant short term heatup of the coolant with a resultant reactor coolant system pressure increase. However, in the long term the reactor coolant system will depressurize due to the break in the reactor coolant pressure boundary. The transient is mitigated by the Doppler reactivity effects of increased fuel temperature and terminated by an automatic reactor trip on high neutron flux. This event challenges deposited enthalpy and radiological consequences criteria.

No single failure of the reactor protection system (RPS) will negate the protection functions required for this event.

6.1.5.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Modes 1 and 2: The event is analyzed to assess the challenge to fuel energy deposition and the radiological consequences. The overpressurization consequences of this event are bounded by those of the Turbine Trip (Event 15.2.3), as shown in previous analyses supporting the Harris Nuclear Plant (Reference 1). This conclusion is not affected by the SGR/Uprating.

Reactor protection is provided by the power range neutron flux trip, high and low setting, and the power range flux trip on high positive rate.

Modes 3 through 6: The reactor must be subcritical by at least 1770 pcm by the mode definitions. No single control rod has sufficient worth to make the event limiting from this condition. The event is therefore bounded in these modes by the Mode 1 analysis.

Based on the above evaluations, two sets of cases are analyzed for this event: one at hot full power (HFP) and one at hot zero power (HZP). Both of these cases are evaluated using both Beginning of Cycle (BOC) and End of Cycle (EOC) conditions.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 2). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the minimum departure from nucleate boiling ratio (MDNBR) for the event (References 3 and 4). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.
The rod ejection accident is also evaluated with the procedures developed in the SPC Generic Rod Ejection Analysis to determine the pellet energy deposition resulting from an ejected rod (Reference 5).

6.1.5.3 Acceptance Criteria

The Control Rod Ejection event is classified as a Condition IV event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) Reactivity excursions should not result in a radially averaged enthalpy greater than 280 cal/gm at any axial location in any fuel rod.

(2) The maximum reactor pressure during any portion of the assumed excursion should be less than the value that will cause stresses to exceed the "Service Limit C" as defined in Section III of the ASME Boiler and Pressure Vessel Code (i.e., maximum reactor pressure should be less than 120% of design values).

(3) Radiological consequences should be well within the guidelines of 10 CFR 100. Well within is defined as 25% of the 10 CFR 100 exposure guideline values or 75 rem for the thyroid and 6 rem for whole-body doses.

6.1.5.4 Results

The results of the analysis demonstrate that the acceptance criteria are met, with the exception of the radiological consequences. [The results of this analysis were provided for use in the analysis of the radiological dose consequences, which is documented in the Balance of Plant (BOP) Licensing Report Section 2.22.] The predicted MDNBR is greater than the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, Departure from Nucleate Boiling (DNB) is not expected to occur; thus, no fuel is expected to fail due to DNB. The fuel centerline melt threshold is not penetrated during this event; thus, no fuel is expected to fail due to fuel melting. The rod ejection accident results in an energy deposition of less than the 280 cal/gm limit.

The limiting MDNBR occurred at HFP with BOC kinetics and the limiting fuel centerline melt occurred at HZP with EOC kinetics.

The over pressurization consequences of this event are bounded by those of turbine trip (Event 15.2.3).

The sequence of events for the limiting MDNBR case is given in Table 6.1.5-1. This transient tripped on power range neutron flux, high setting. The responses to key system variables are given in Figure 6.1.5-1 to Figure 6.1.5-8.

The sequence of events for the limiting fuel centerline melt case is given in Table 6.1.5-2. This transient tripped on power range neutron flux, low setting. The responses to key system variables are given in Figure 6.1.5-9 to Figure 6.1.5-16.

The rod ejection accident is evaluated for deposited enthalpy with the SPC Generic Rod Ejection Analysis Methodology (Reference 5). The ejected rod worths and hot pellet peaking factors were

calculated using the XTGPWR code (Reference 6). No credit was taken for the power flattening effects of Doppler or moderator feedback in the calculation of ejected rod worths or resultant post-transient peaking factors. The pellet energy deposition resulting from an ejected rod was conservatively evaluated explicitly for BOC and EOC conditions, at HFP and HZP. The rod ejection accident results in a peak pellet enthalpy less than the 280 cal/gm limit.

6.1.5.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions, with the exception of conclusions related to radiological consequences. The conclusions of the analysis of the radiological dose consequences are documented in the BOP Licensing Report. The analysis for this event supports operation with the Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.1.5.6 References

1. EMF-93-163, Shearon Harris Cycle 6: Disposition of Chapter 15 Events and Analysis of Plant Transient, Siemens Power Corporation, March 1994.

2. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

3. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

5. XN-NF-78-44(A), A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors, Exxon Nuclear Company, October 1983.

6. XN-CC-28(A) Revision 3, XTG: A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing, Exxon Nuclear Company, September 1975.

Table 6.1.5-1 Event Summary for Control Rod Ejection Limiting MDNBR Case (HFP, BOC kinetics)

Event	Time (s)
Reactor at HFP, BOC conditions	0.0
RCCA ejection	0.50
RCCA fully ejected	0.60
Power range high neutron flux (high setting) reactor trip	11.72
Turbine trip	11.72
MDNBR occurred	12.00
Peak power	12.10
Maximum core-average temperature	12.90
Peak primary pressure	14.25
Scram rods fully inserted	15.50

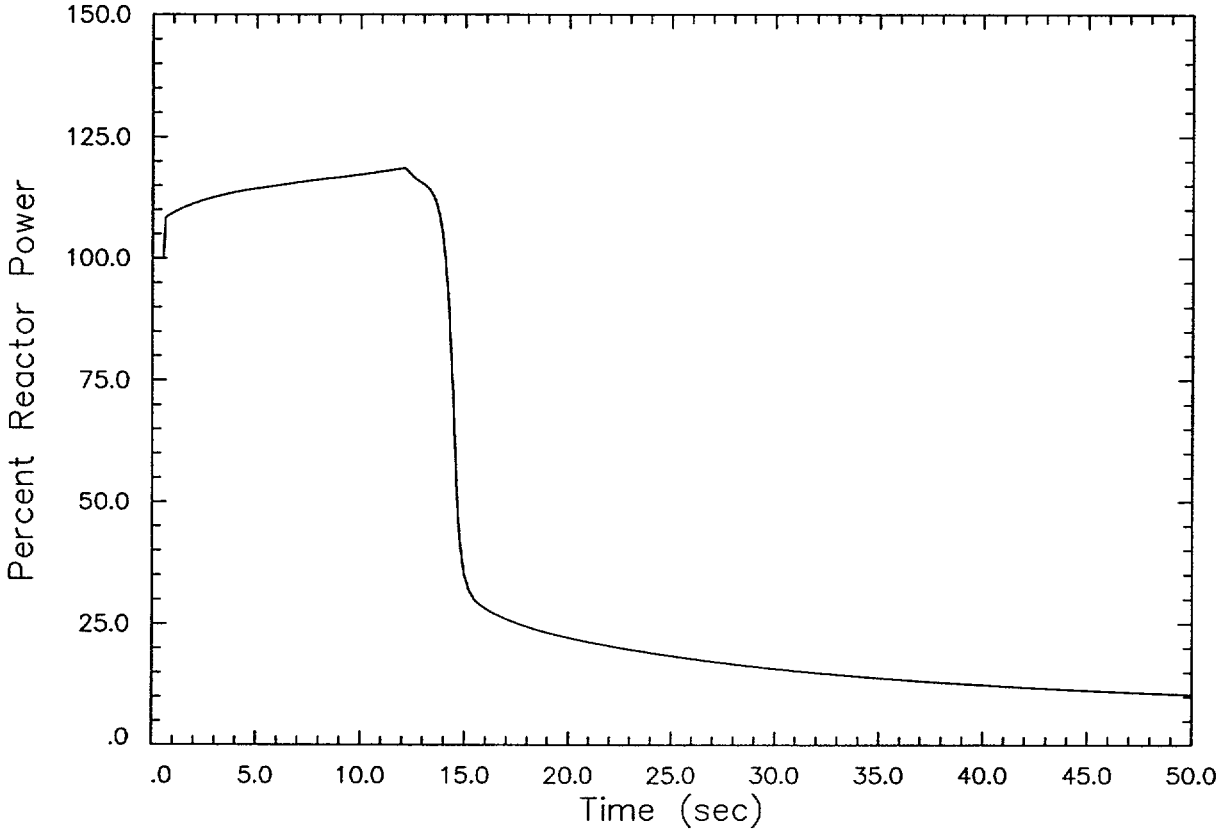

Figure 6.1.5-1 Reactor Power for RCCA Ejection – Limiting MDNBR Case

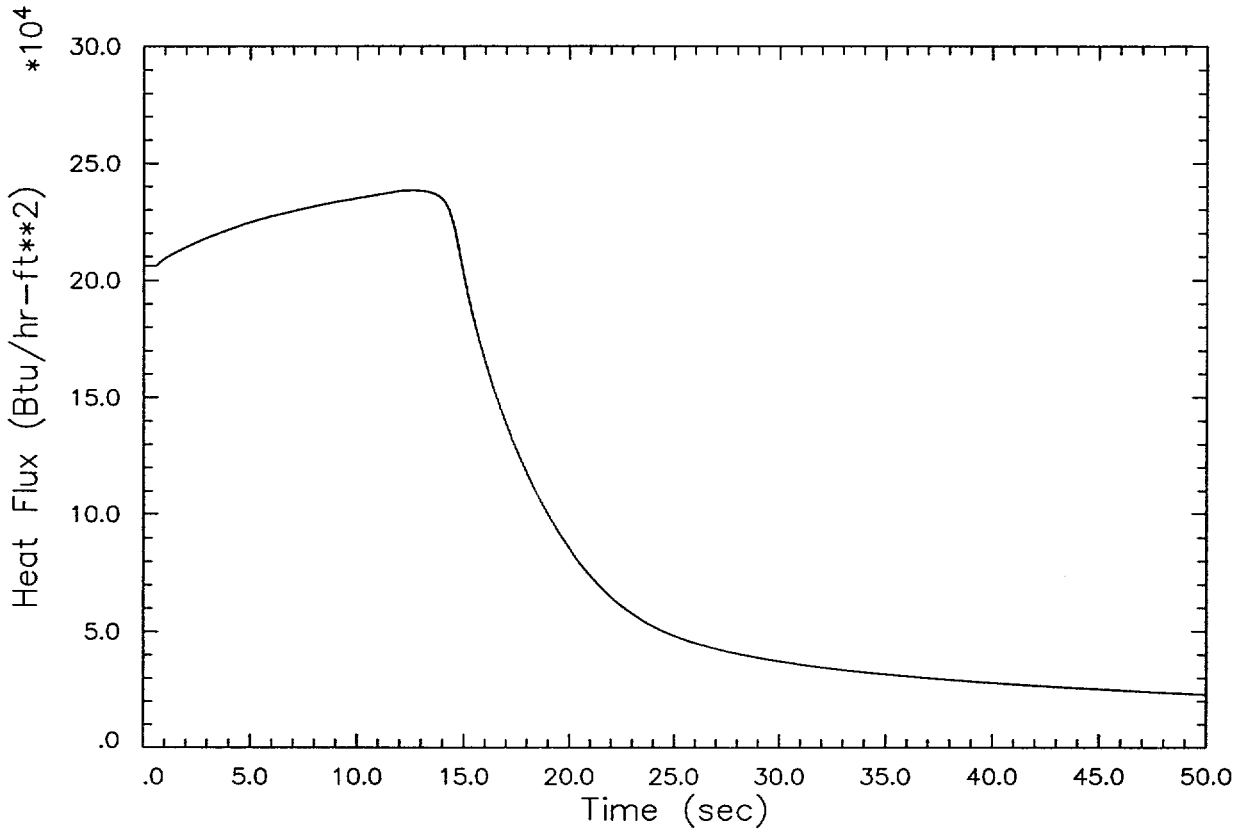

Figure 6.1.5-2 Core Average Heat Flux for RCCA Ejection – Limiting MDNBR Case

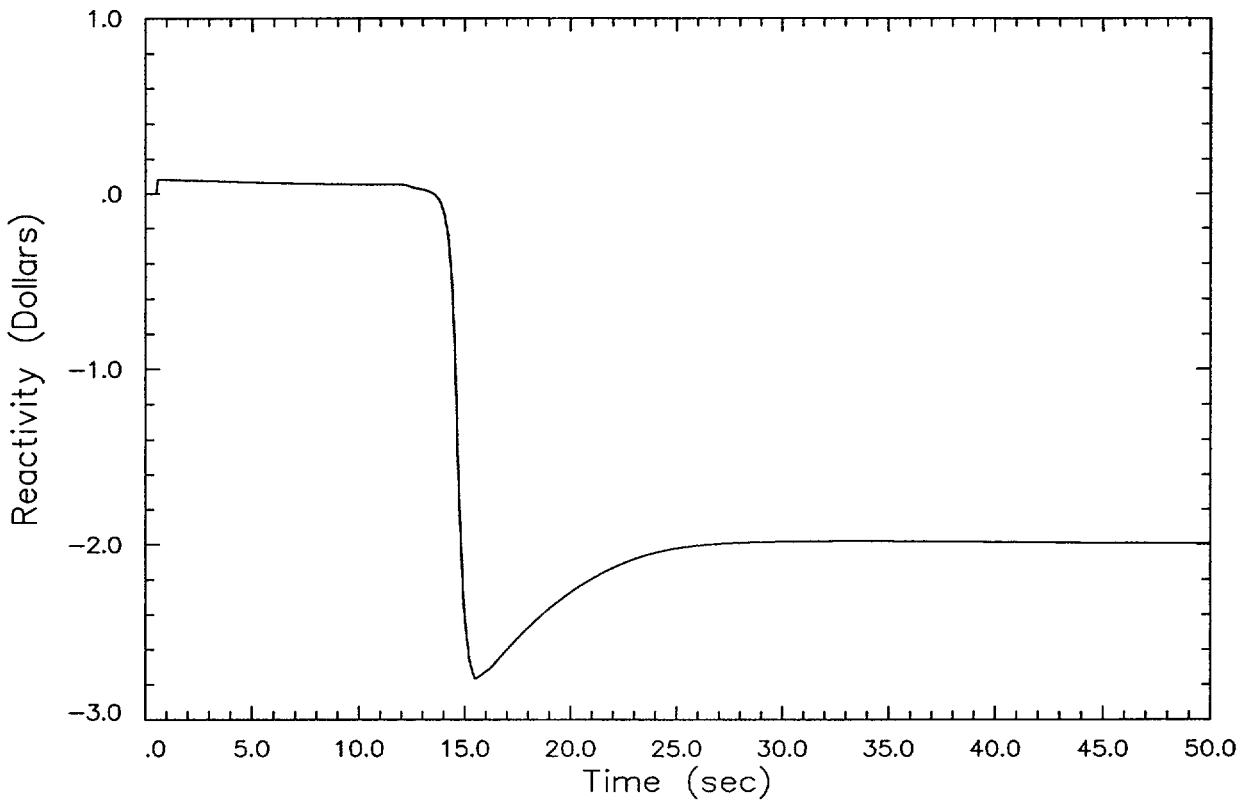

Figure 6.1.5-3 Total Core Reactivity for RCCA Ejection – Limiting MDNBR Case

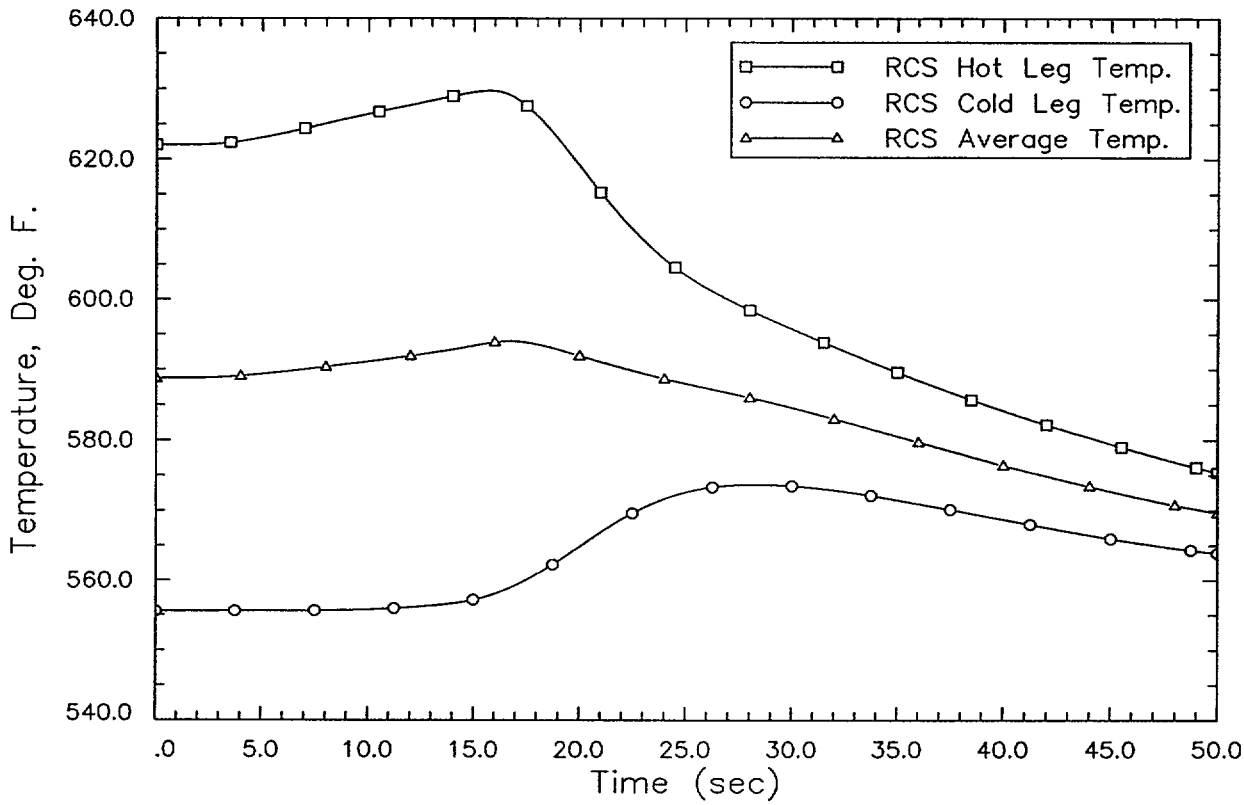

Figure 6.1.5-4 Primary System Temperatures for RCCA Ejection – Limiting MDNBR Case

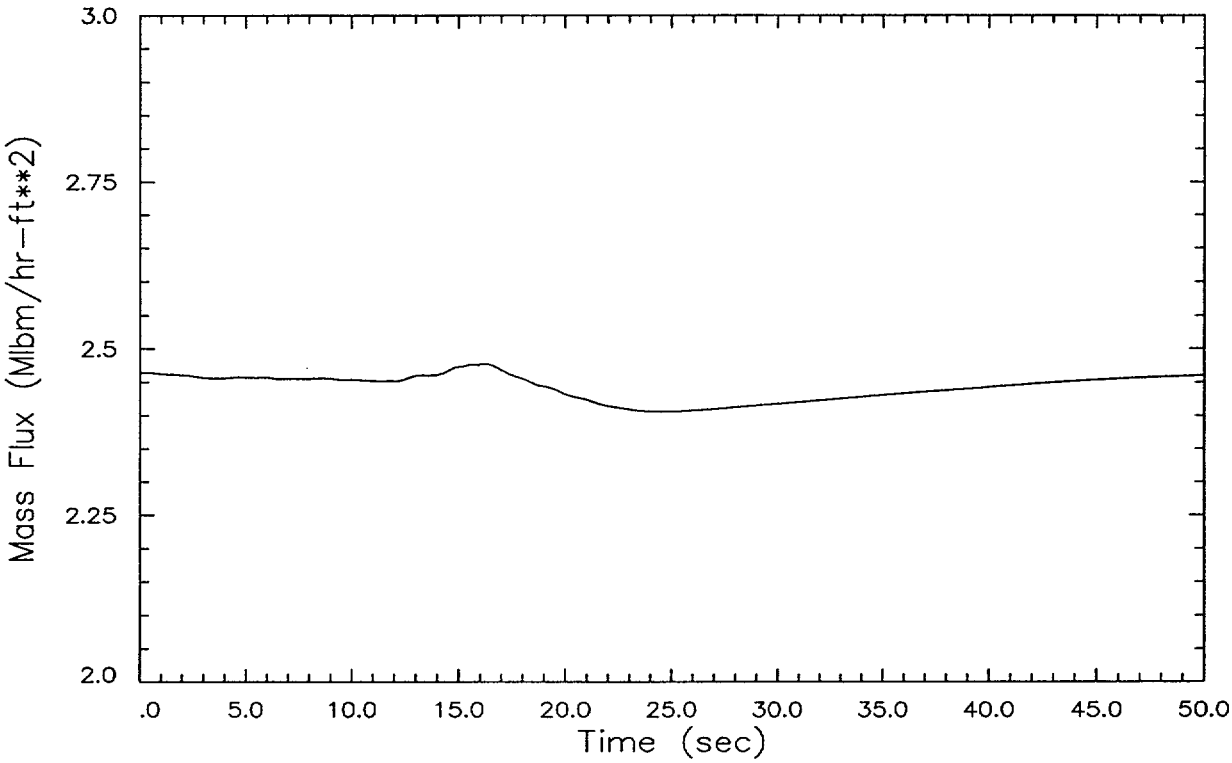

Figure 6.1.5-5 Core Inlet Mass Flux for RCCA Ejection – Limiting MDNBR Case

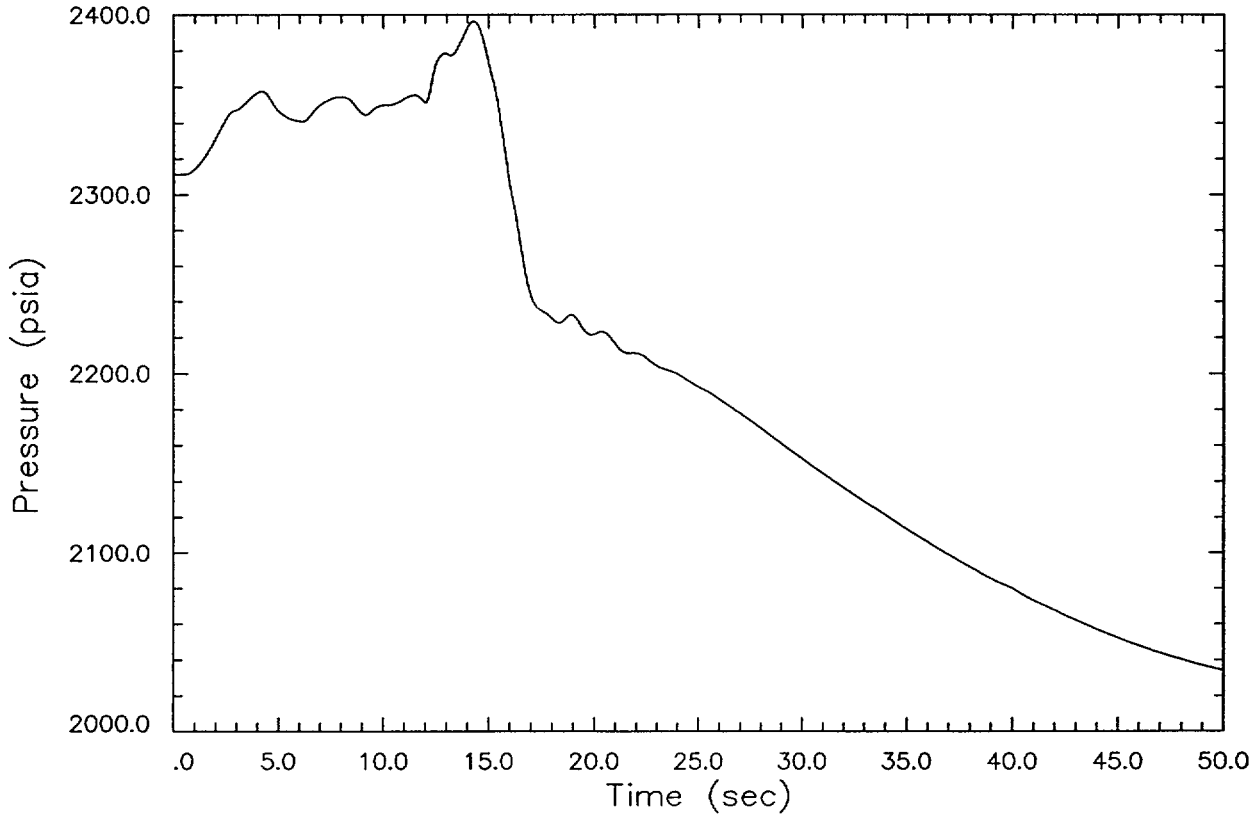

Figure 6.1.5-6 Lower Head Pressure for RCCA Ejection – Limiting MDNBR Case

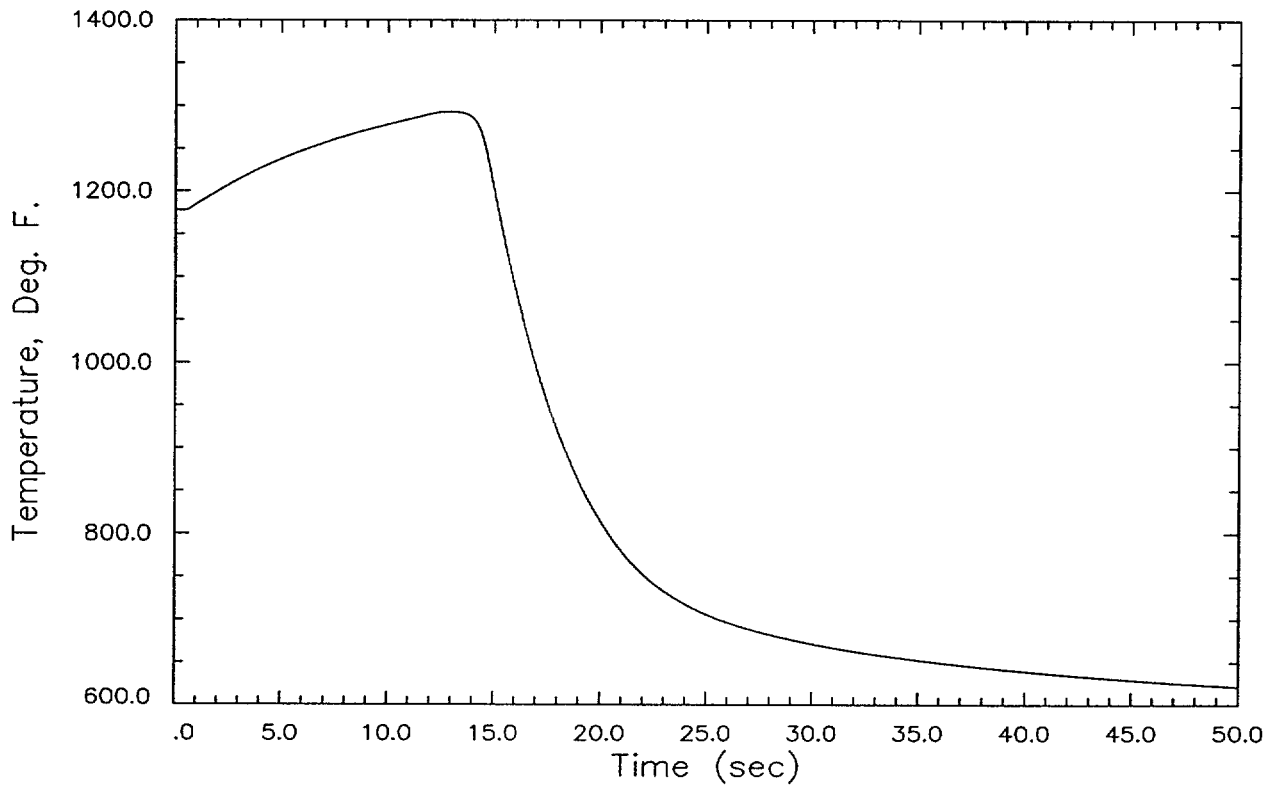

Figure 6.1.5-7 Average Fuel Temperature for RCCA Ejection – Limiting MDNBR Case

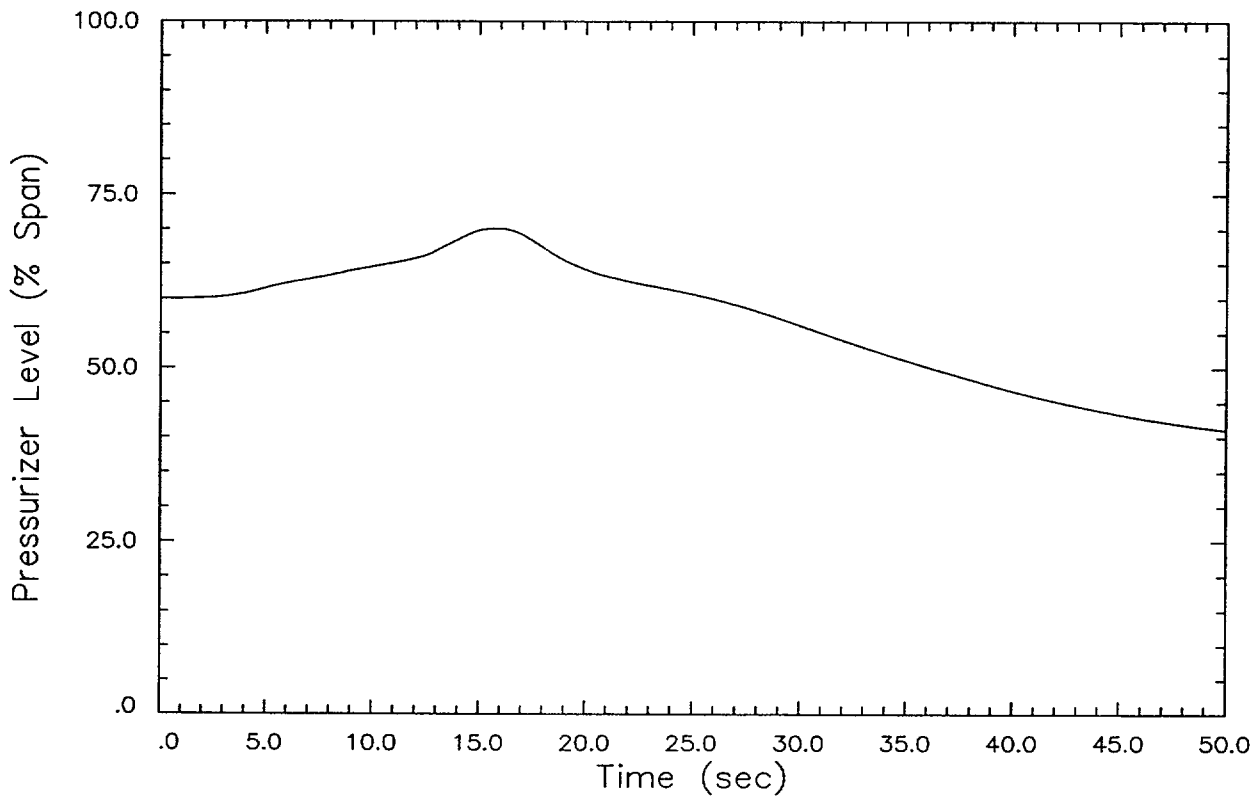

Figure 6.1.5-8 Pressurizer Level for RCCA Ejection – Limiting MDNBR Case

Table 6.1.5-2 Event Summary for Control Rod Ejection Limiting Fuel Centerline Melt Case (HZP, EOC kinetics)

Event	Time (s)
Reactor at HZP, EOC conditions	0.0
RCCA ejection	0.50
RCCA fully ejected	0.60
Peak power	1.90
Power range high neutron flux (low setting) reactor trip	2.20
Turbine trip	2.20
Peak primary pressure	4.3
Maximum fuel centerline temperature	4.55
Scram rods fully inserted	6.00

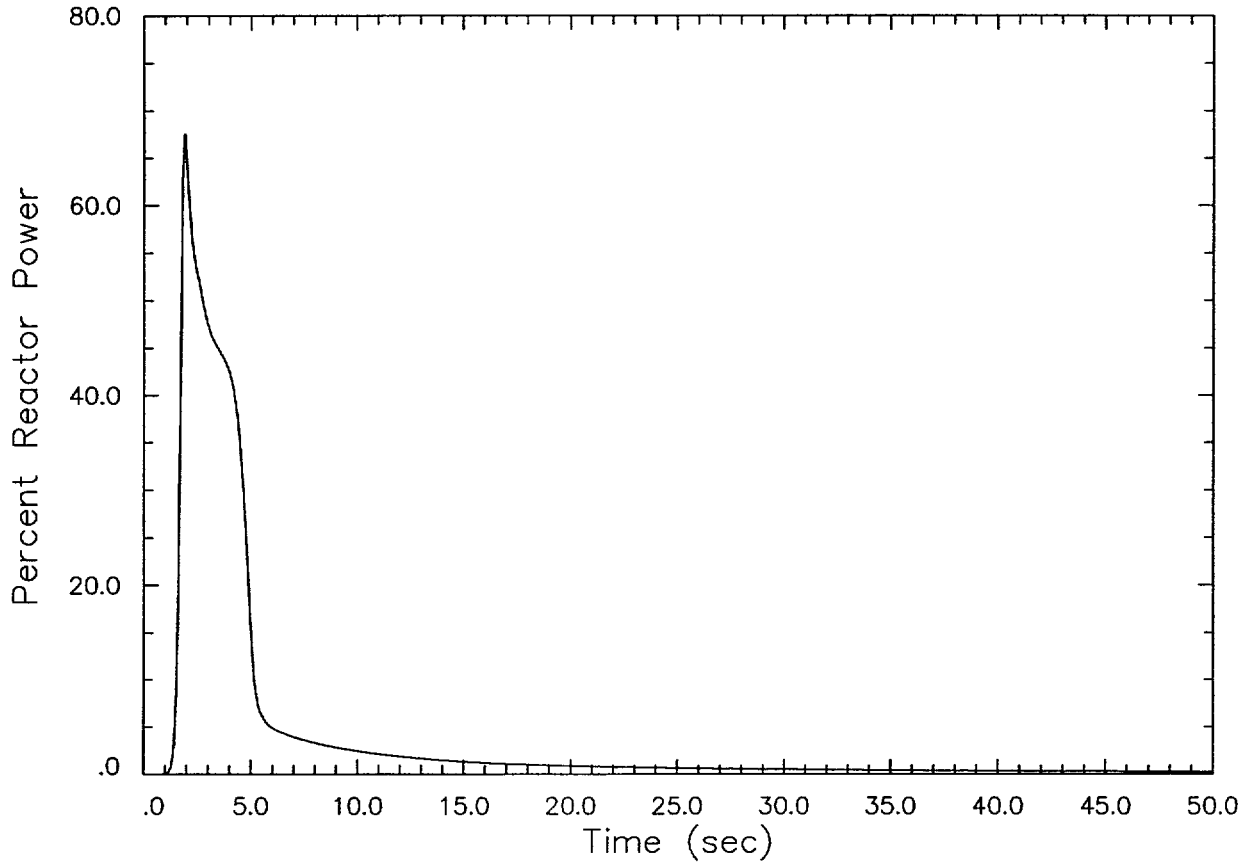

Figure 6.1.5-9 Reactor Power for RCCA Ejection – Limiting Fuel Centerline Melt Case

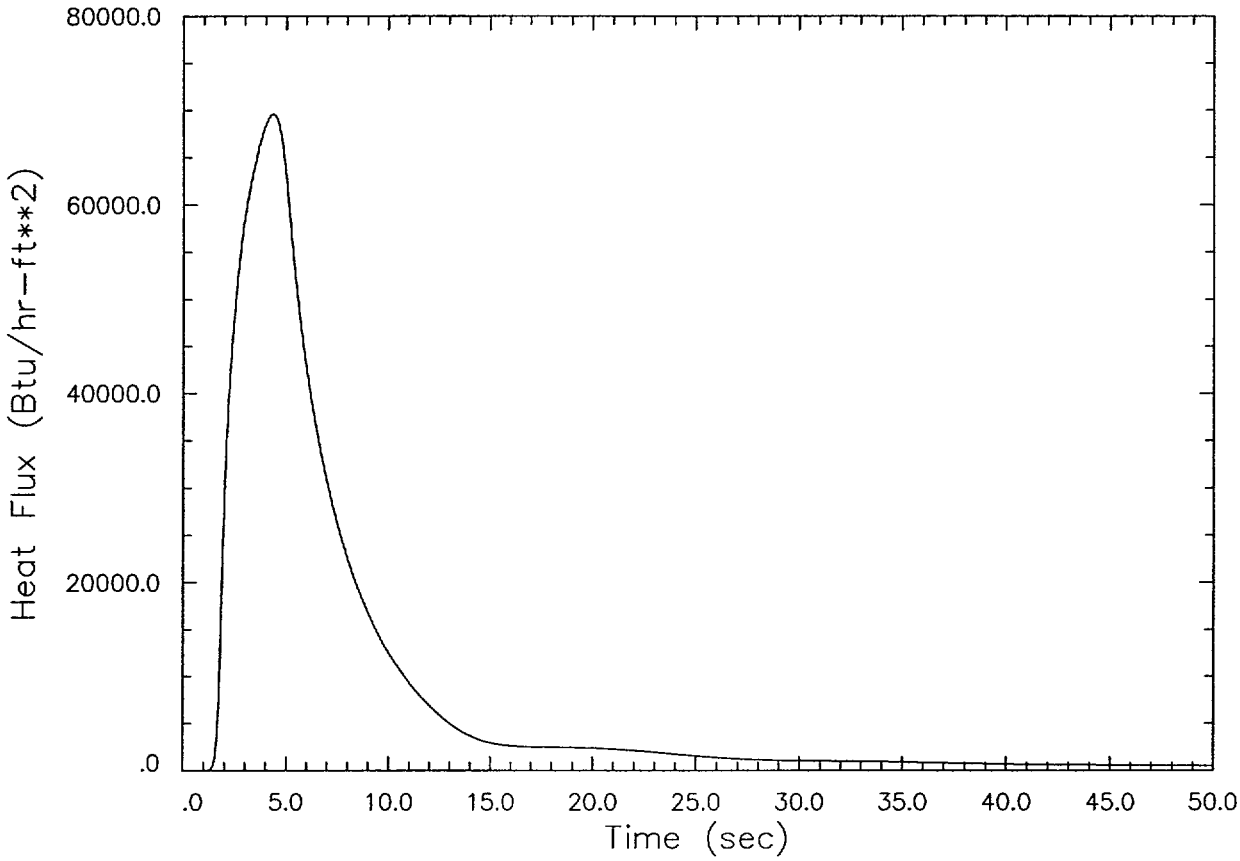

Figure 6.1.5-10 Core Average Heat Flux for RCCA Ejection – Limiting Fuel Centerline Melt Case

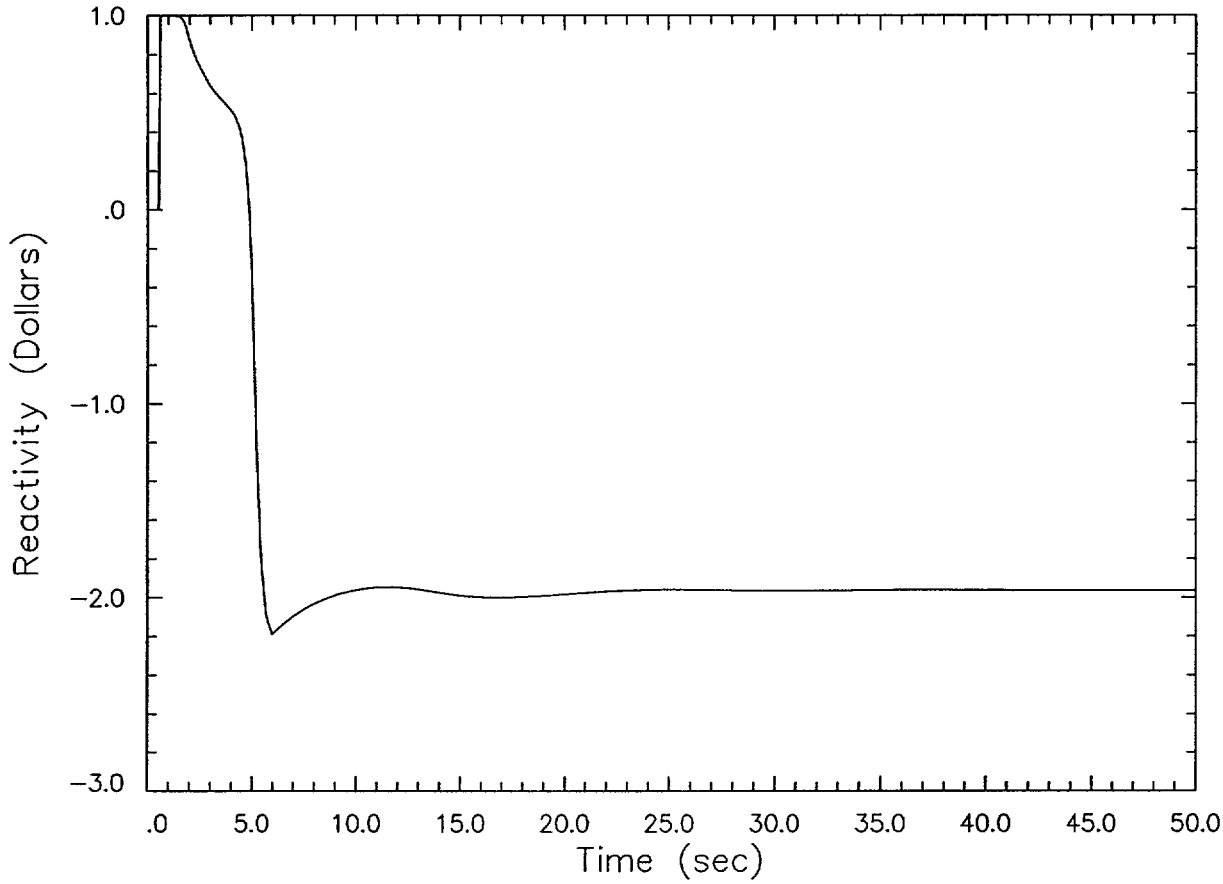

Figure 6.1.5-11 Total Core Reactivity for RCCA Ejection – Limiting Fuel Centerline Melt Case

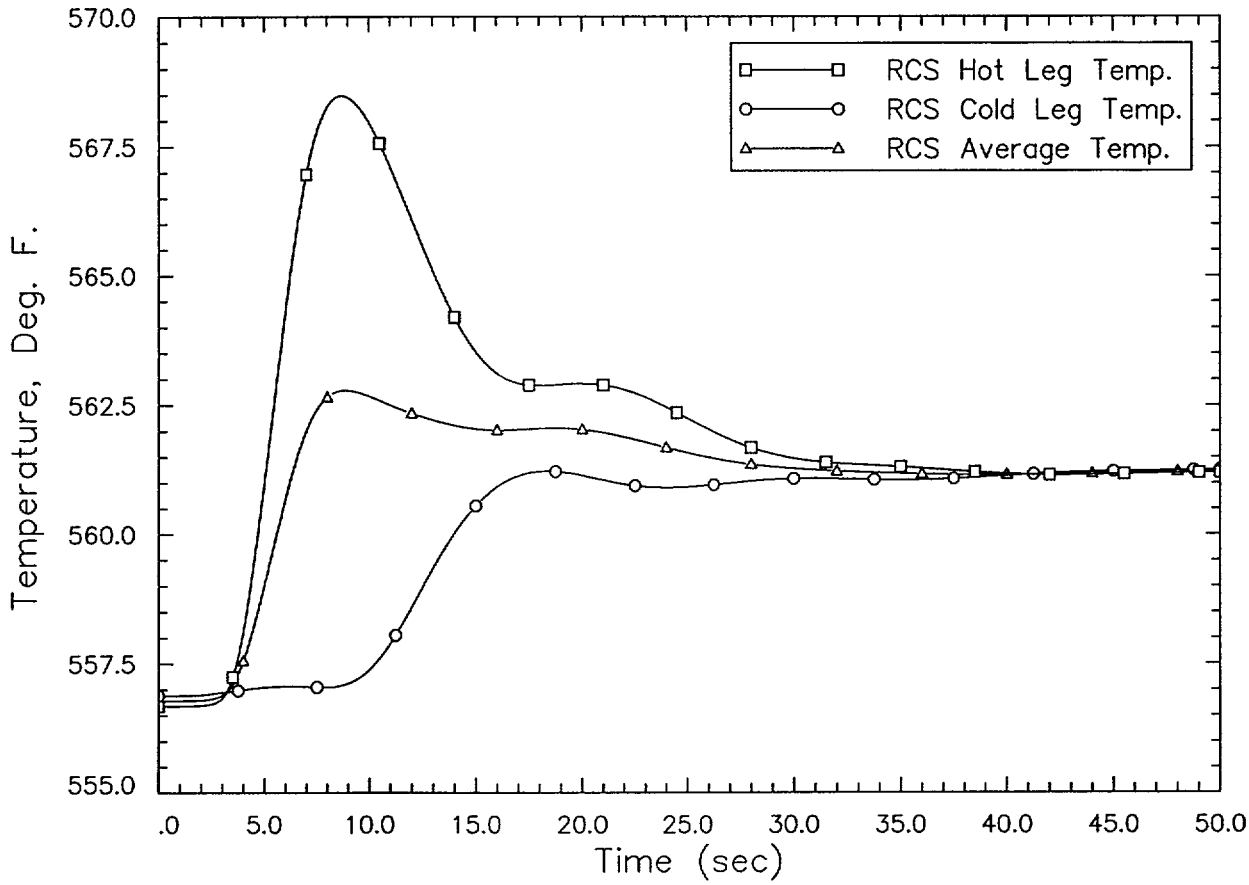

Figure 6.1.5-12 Primary System Temperatures for RCCA Ejection – Limiting Fuel Centerline Melt Case

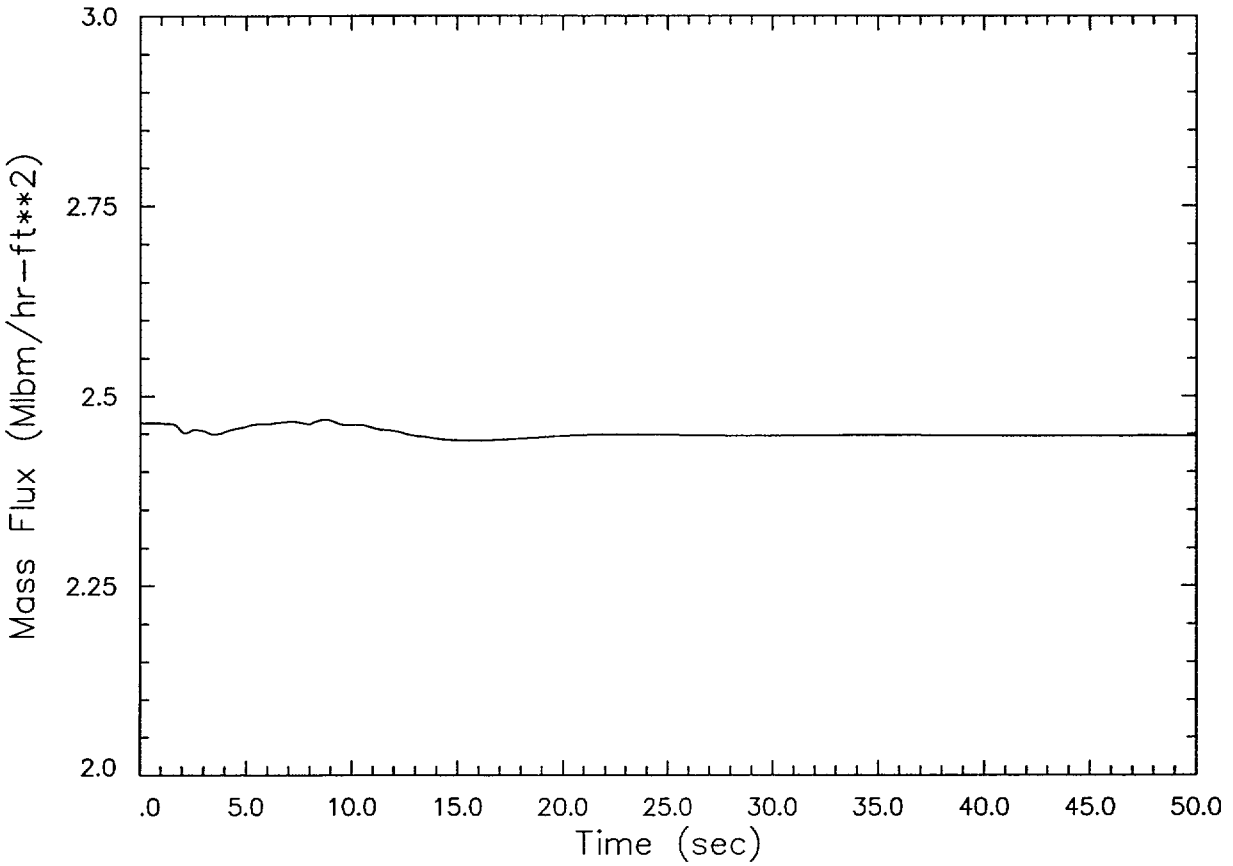

Figure 6.1.5-13 Core Inlet Mass Flux for RCCA Ejection – Limiting Fuel Centerline Melt Case

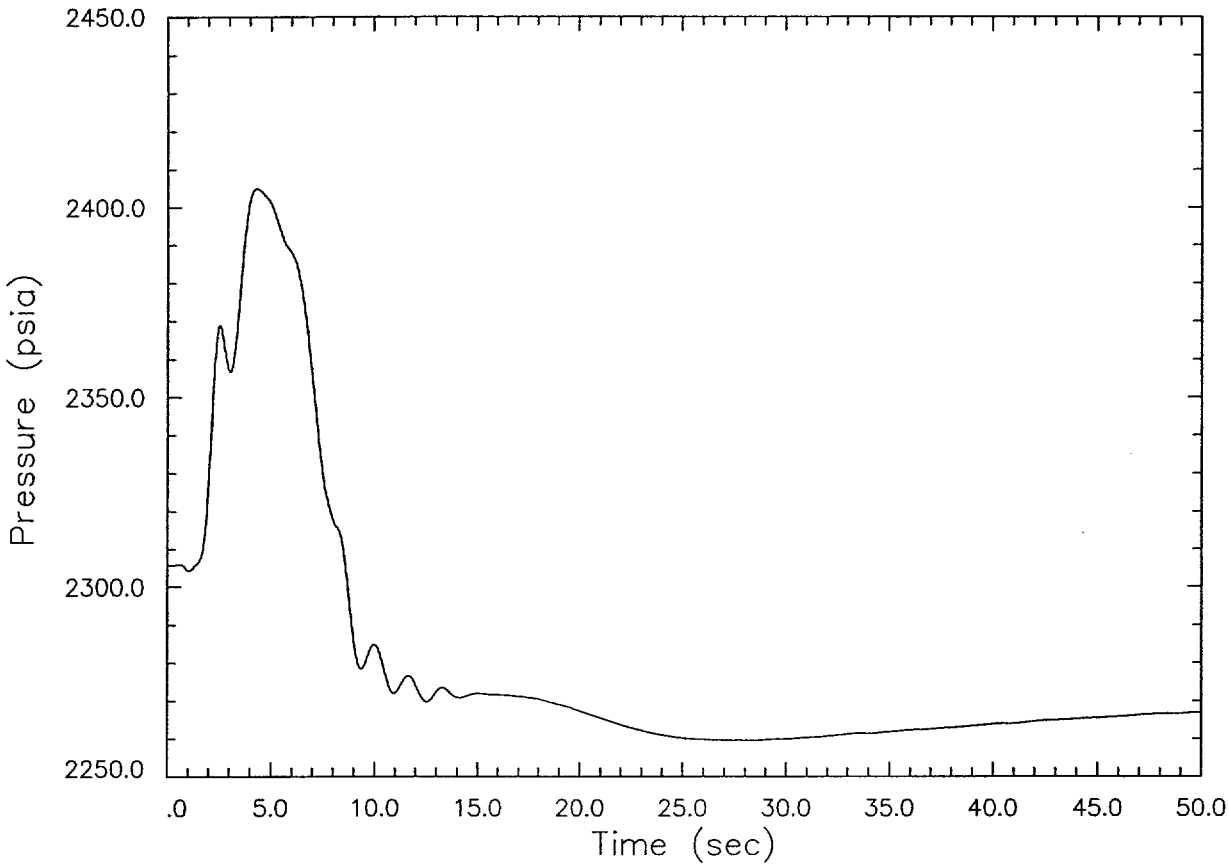

Figure 6.1.5-14 Lower Head Pressure for RCCA Ejection – Limiting Fuel Centerline Melt Case

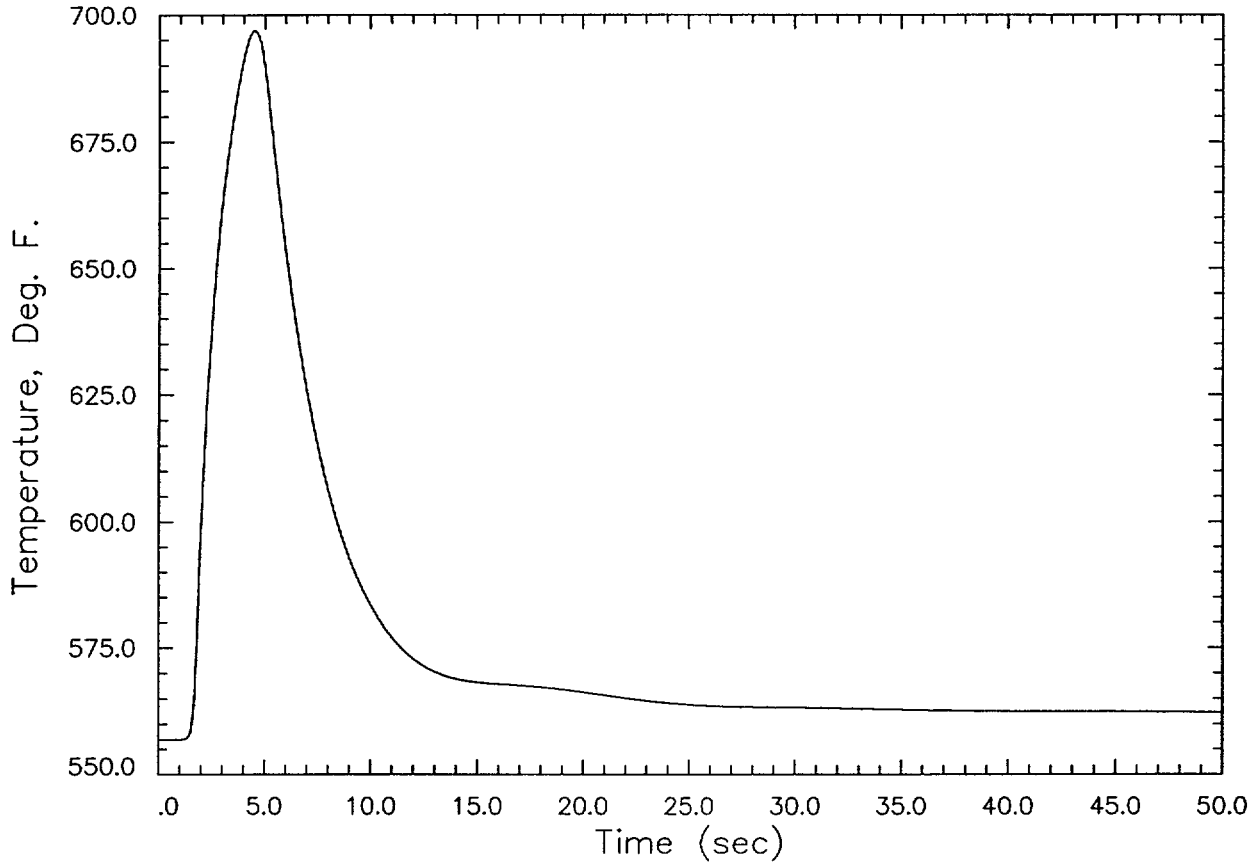

Figure 6.1.5-15 Average Fuel Temperature for RCCA Ejection – Limiting Fuel Centerline Melt Case

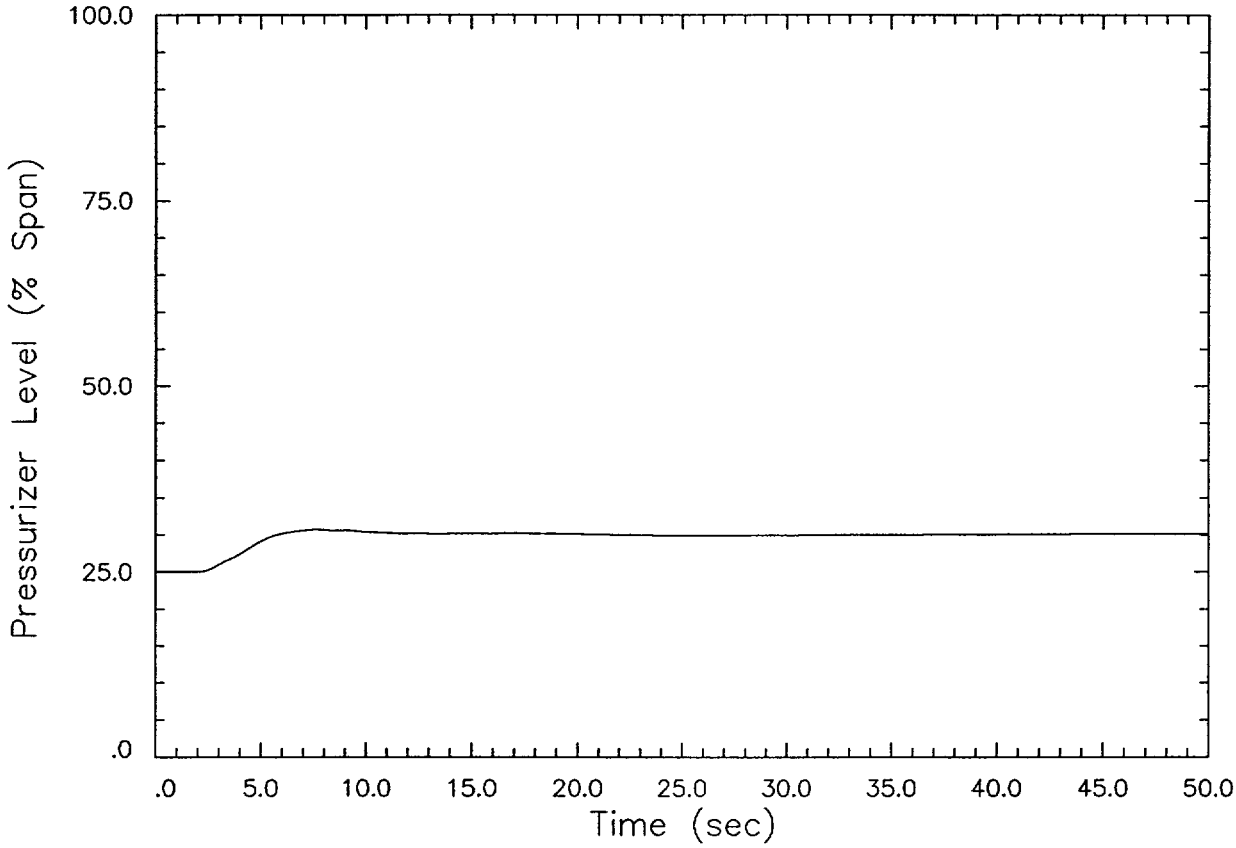

Figure 6.1.5-16 Pressurizer Level for RCCA Ejection – Limiting Fuel Centerline Melt Case

6.2 Non-Loss of Coolant Accident (non-LOCA) Transients

6.2.0 Introduction

This chapter provides the results of the disposition of events review and the non-LOCA transient event analysis performed to support SGR/Uprating operation. Event numbering and nomenclature are consistent with the FSAR.

In accordance with the SPC methodology (Reference 1), all events described in the FSAR (with the exception of those identified as outside the scope of SPC responsibility) were reviewed and dispositioned into one of the following four categories:

(1) The event initiator or controlling parameters have been changed from the analysis of record so that the event needs to be reanalyzed for the current licensing action;

(2) The event is bounded by another event which is to be analyzed;

(3) The event causes and principal variables which control the results of the event are unchanged from or bounded by the analysis of record; or

(4) The event is not in the licensing basis for the plant.

A summary of the event disposition for the SGR/Uprating is given in Table 6.2.0-1. Table 6.2.0-1 lists each FSAR Chapter 15 event, indicates whether that event is reanalyzed for SGR/Uprating, and provides a reference to the bounding event or analysis of record for events not documented in this report.

The disposition and analysis (if required) for each event is provided in Sections 6.2.1 to 6.2.38.

The results of the analyses of Anticipated Operational Occurrences (AOO) and Postulated Accidents (PA) demonstrate that the event-specific acceptance criteria are met for SGR/Uprating operation.

6.2.0.1 Classification of Events

The classification of events is given below. Each event is placed in one of four categories. These categories are those adopted by the American Nuclear Society (ANS) (Reference 2).

Condition I: Normal Operation and Operational Transients

Events which are expected to occur frequently in the course of power operation, refueling, maintenance, or plant maneuvering.

Condition II: Faults of Moderate Frequency (Anticipated Operation Occurrences)

Events which are expected to occur, in general, no more often than once per year.

Condition III: Infrequent Faults (Postulated Accidents)

Events which might be expected to occur once during the lifetime of the plant, at most.

Condition IV: Limiting Faults (Postulated Accidents)

Events which are not expected to occur but which are evaluated to demonstrate the adequacy of the design.

6.2.0.2 Plant Operating Modes

Six operational modes have been considered in the disposition and analysis. These are shown in Table 6.2.0-2. These operational modes have been considered in establishing the subevents associated with each event initiator.

6.2.0.3 Reactor Protection System Trip Setpoints and Time Delays

The trip setpoints, uncertainties, and time delays used in the non-LOCA transient analyses are shown in Table 6.2.0-3 The OTΔT and OPΔT setpoints have been verified to adequately protect Specified Acceptable Fuel Design Limits (SAFDLs) for SGR/Uprating operation. The verification was performed in accordance with the SPC statistical setpoint methodology for Westinghouse reactors (Reference 3).

6.2.0.4 References

1. EMF-89-151(P)(A) ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. ANSI N18.2-1973, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.

3. EMF-92-081(P)(A) and Supplement 1, Statistical Setpoint/Transient Methodology for Westinghouse-Type Reactors, Siemens Power Corporation, February 1994.

Table 6.2.0-1 Disposition of Events Summary for Harris SGR/Uprating

FSAR Event Designation	Event Name	Condition	Disposition	Bounding Event or Reference
15.1	**INCREASE IN HEAT REMOVAL BY SECONDARY SYSTEM**			
15.1.1	Decrease in Feedwater Temperature	II (AOO)	Bounded	15.1.3
15.1.2	Increase in Feedwater Flow	II (AOO)	Analyze	
15.1.3	Increase in Steam Flow	II (AOO)	Analyze	
15.1.4	Inadvertent Opening of a Steam Generator Relief or Safety Valve	II (AOO)	Bounded	15.1.3
15.1.5	Steam Line Break	IV (PA)	Analyze	
15.2	**DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM**			
15.2.1	Steam Pressure Regulator Malfunction	II (AOO)	N/A	BWR Event
15.2.2	Loss of External Load	II (AOO)	Bounded	15.2.3
15.2.3	Turbine Trip	II (AOO)	Analyze	
15.2.4	Inadvertent Closure of MSIV's	II (AOO)	Bounded	15.2.3
15.2.5	Loss of Condenser Vacuum	II (AOO)	Bounded	15.2.3
15.2.6	Loss of Nonemergency AC Power	II (AOO)	Analyze	
15.2.7	Loss of Normal Feedwater	II (AOO)	Analyze	
15.2.8	Feedline Break	IV (PA)	Analyze	
15.3	**DECREASE IN REACTOR COOLANT SYSTEM FLOW**			
15.3.1	Partial Loss of Forced Reactor Coolant Flow	II (AOO)	Bounded	15.3.2[a]
15.3.2	Complete Loss of Forced Reactor Coolant Flow	III (PA)	Analyze	
15.3.3	RCP Shaft Seizure (Locked Rotor)	IV (PA)	Analyze	
15.3.4	RCP Shaft Break	IV (PA)	Bounded	15.3.3

[a] Bounded by Event 15.3.2 since 15.3.2 satisfies SAFDLs for SGR/UPRATING.

FSAR Event Designation	Event Name	Condition	Disposition	Bounding Event or Reference
15.4	**REACTIVITY AND POWER DISTRIBUTION ANOMALIES**			
15.4.1	Uncontrolled RCCA Bank Withdrawal from a Subcritical or Low Power Startup Condition	II (AOO)	Analyze	
15.4.2	Uncontrolled RCCA Bank Withdrawal at Power	II (AOO)	Analyze	
15.4.3	RCCA Misoperation			
	1) Dropped Rod/Bank	II (AOO)	Analyze	
	2) Single Rod Withdrawal	III (PA)	Analyze	
	3) Statically Misaligned RCCA	II (AOO)	Analyze	
15.4.4	Startup of an Inactive RCP at an Incorrect Temperature	II (AOO)	Bounded	15.4.1
15.4.5	A Malfunction or Failure of the Flow Controller in a BWR Loop that Results in an Increased Reactor Coolant Flow Rate	II (AOO)	N/A	BWR Event
15.4.6	CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant	II (AOO)	Analyze	
15.4.7	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position	III (PA)	Analyze	
15.4.8	Spectrum of Rod Cluster Control Assembly Ejection Accidents	IV (PA)	Analyze	
15.5	**INCREASE IN REACTOR COOLANT INVENTORY**			
15.5.1	Inadvertent Operation of the ECCS During Power Operation	II (AOO)	Outside scope of SPC responsibility	
15.5.2	CVCS Malfunction that Increases RCS Inventory	II (AOO)	Bounded	15.5.1 and 15.4.6
15.6	**DECREASE IN REACTOR COOLANT INVENTORY**			
15.6.1	Inadvertent Opening of a Pressurizer Safety or PORV	II (AOO)	Analyze	
15.6.2	Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment	II (AOO)	Analyze	BOP LR Section 2.22
15.6.3	Radiological Consequences of Steam Generator Tube Rupture	IV (PA)	Analyze	BOP LR Section 2.22

FSAR Event Designation	Event Name	Condition	Disposition	Bounding Event or Reference
15.6.4	Radiological Consequences of a Main Steam Line Failure Outside Containment	N/A	N/A	BWR Event
15.6.5	Loss of Coolant Accidents			
	1) Large Break LOCA	IV (PA)	Analyze	
	2) Small Break LOCA	III (PA)	Analyze	
15.7	**RADIOACTIVE RELEASE FROM A SUBSYSTEM OR COMPONENT**			
15.7.1	Radioactive Waste Gas System Leak or Failure	III (PA)	Analyze	BOP LR Section 2.22
15.7.2	Liquid Waste System Leak or Failure	III (PA)	Analyze	BOP LR Section 2.22
15.7.3	Postulated Radioactive Releases Due to Liquid Tank Failure	III (PA)	Analyze	BOP LR Section 2.22
15.7.4	Fuel Handling Accidents	IV (PA)	Analyze	BOP LR Section 2.22
15.7.5	Spent Fuel Cask Drop Accidents	III (PA)	Analyze	BOP LR Section 2.22

Table 6.2.0-2 Plant Operational Modes

Mode	Reactivity Condition, K_{eff}	% Rated Thermal Power[a]	Average Coolant Temperature
1. Power Operation	≥ 0.99	$> 5\%$	$\geq$350°F
2. Startup	≥ 0.99	$\leq 5\%$	$\geq$350°F
3. Hot Standby	< 0.99	0 %	$\geq$350°F
4. Hot Shutdown	< 0.99	0 %	200°F $< T_{avg} <$ 350°F
5. Cold Shutdown	< 0.99	0 %	$\leq$200°F
6 Refueling[b]	≤ 0.95	0 %	$\leq$140°F

[a] Does not include decay heat.

[b] Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

Table 6.2.0-3 Trip Setpoints for SGR/Power Uprating

Item	Tech. Spec. Trip Setpoint	Tech. Spec. Total Allowance	Analysis Value	Response Time[a]
Power range, neutron flux				
High setting	≤ 109% of RTP	+(0.075)(120% of RTP)	118% of RTP	≤ 0.5 sec
Low setting	≤ 25% of RTP	+(0.083)(120% of RTP)	35% of RTP	≤ 0.5 sec
High negative flux rate	≤ 5% of RTP with a time constant ≥ 2 sec		-8.00% of RTP with a time constant ≥ 2 sec	≤ 0.5 sec
High pressurizer pressure	≤ 2385 psig	+(0.075)(800 psi)	2445 psig	≤ 2.0 sec
Low pressurizer pressure	≥ 1960 psig	-(0.05)(800 psi)	1920 psig	≤ 2.0 sec
Lead time constant, t_4	2 sec		1.8 sec	
Lag time constant, t_5	1 sec		1.1 sec	
High pressurizer water level	≤ 92% of instrument span		93.8% of instrument span	
Low primary coolant flow	≥ 90.5% of full flow		85% of full flow	≤ 1.0 sec
Low-low SG level (Loss of Normal Feedwater)	≥ 25.0% of narrow range span		16.1% of narrow range span	≤ 3.5 sec
Low-low SG level (Feedwater Line Break and MSLB)	≥ 25.0% of narrow range span		0.0% of narrow range span	≤ 3.5 sec
Undervoltage-RCPs[b]	≥ 5148 volts			≤ 1.5 sec
Underfrequency-RCPs	≥ 57.5 Hz	-(0.05)(10 Hz)	57.0 Hz	≤ 0.6 sec
Reactor trip system interlocks				
P-7 (fed by both P-10 and P-13)				
P-10 (NI power indication)	10% of RTP	N/A	10.6% of RTP	
P-13 (turbine impulse pressure equivalent power indication)	10% of RTP	N/A	10.6% of RTP	
P-8 (single loop loss-of-flow trip block)	≤ 49% of RTP	+(0.075)(120% of RTP)	58% of RTP	
Over Temperature ΔT				
ΔT_o			$\Delta T/\Delta T_o$=1.0	4.75 sec RTD lag time and 1.25 sec delay
K_1	1.185		1.320	
K_2	0.0224/°F		0.0224/°F	
K_3	0.0012/psi		0.0012/psi	
τ_1	0.0 sec		0.0 sec	
τ_2	0.0 sec		0.0 sec	

[a] The reactor trip system response time is defined as the time interval from when the monitoring parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

[b] A specific undervoltage setpoint was not assumed in the analysis.

Item	Tech. Spec. Trip Setpoint	Tech. Spec. Total Allowance	Analysis Value	Response Time[a]
τ_3	4.0 sec		4.0 sec	
τ_4	22.0 sec		19.8 sec	
τ_5	4.0 sec		4.4 sec	
τ_6	0.0 sec		0.0 sec	
$f_1(\Delta I)$	0 when $+12\% \geq \Delta I \geq -21.6\%$ 1.75% per neg. %ΔI 1.50% per pos. %ΔI		0 when $+12\% \geq \Delta I \geq -21.6\%$ 1.75% per neg. %ΔI 1.50% per pos. %ΔI	
Over Power ΔT				
ΔT_o			$\Delta T/\Delta T_o=1.0$	
K_4	1.120		1.180	
K_5	0.02/°F for increasing average temperature 0.0/°F for decreasing average temperature		0.02/°F for increasing average temperature 0.0/°F for decreasing average temperature	
K_6	0.002/°F for T > T" 0.0/°F for T ≤ T"		0.002/°F for T > T" 0.0/°F for T ≤ T"	
τ_7	13 sec		11.7 sec	
$f_2(\Delta I)$	0 for all ΔI		0 for all ΔI	

6.2.1 Decrease in Feedwater Temperature (FSAR Event 15.1.1)

6.2.1.1 Identification of Causes and Accident Description

A Decrease in Feedwater Temperature event may be caused by the accidental opening of a feedwater bypass valve, which diverts flow around a portion of the feedwater heaters. This causes a reduction in the feedwater inlet temperature. The event results in a decrease of the secondary side enthalpy leading to an increase in the primary-to-secondary side heat transfer rate. The steam generator outlet temperature on the primary side decreases causing the core inlet temperature to decrease. In the presence of a negative moderator coefficient, a reduced core inlet temperature results in an increase in the core power. The combination of a primary system pressure decrease due to coolant contraction and the power increase introduces a challenge to the DNB SAFDL.

No single active failure will prevent operation of the RPS.

6.2.1.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The greatest credible feedwater enthalpy reduction occurs at full load as a result of the inadvertent opening of the low pressure feedwater heater bypass valve. The flow passing through the bypass line is unheated by heaters number 1 through 4, but must pass through the high pressure heater, number 5. Several conservative cases were evaluated and all cases showed a thermal load increase less than the 10% thermal load increase simulated in Event 15.1.3 (Increase in Steam Flow). As such, Event 15.1.1 is bounded in Mode 1 by Mode 1 of Event 15.1.3 and need not be further analyzed.

The OPΔT, OTΔT, and high neutron flux reactor trips provide reactor protection in Mode 1.

Mode 2: Because reactor power is at or below 5% of rated, the initial margin to SAFDLs is large compared to that in Mode 1. The magnitude of the event initiator in Mode 2 is equal to or less than that in Mode 1, due to reduced feedwater flow rate. The high neutron flux trip, low setting, the intermediate range neutron flux trip, and the source range flux trip will ensure that reactor power remains well below rated if the event occurs. The Mode 2 event is bounded by Mode 1.

The high neutron flux trip, low setting, the intermediate range neutron flux trip, and the source range neutron flux trip provide reactor protection in Mode 2.

Modes 3 through 6: The feedwater flow rate is zero or very small. A significant thermal load increase due to a reduction in feedwater enthalpy is not credible. The event need not be considered in Modes 3 through 6.

6.2.1.3 Acceptance Criteria

A Decrease in Feedwater Temperature event is classified as a Condition II event. The acceptance criteria for this event are the same as those listed for the Increase in Steam Flow event in Section 6.2.3.3.

6.2.1.4 Results

The evaluation demonstrates that the Decrease in Feedwater Temperature (Event 15.1.1) is bounded in Mode 1 by Mode 1 of Increase in Steam Flow (Event 15.1.3), and need not be further analyzed. The Mode 2 event is bounded by Mode 1. The event is not credible in Modes 3 through 6.

6.2.1.5 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.1.6 References

None.

6.2.2 Increase in Feedwater Flow (FSAR Event 15.1.2)

6.2.2.1 Identification of Causes and Accident Description

The Increase in Feedwater Flow event is assumed to be initiated by a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. The event results in an increase in the primary-to-seconday side heat transfer rate due to increased feedwater flow. The steam generator outlet temperature on the primary side decreases causing the core inlet temperature to decrease. In the presence of a negative moderator coefficient, a reduced core inlet temperature results in an increase in the core power. The combination of a primary system pressure decrease due to coolant contraction and the power increase introduces a challenge to the DNB SAFDL.

No single active failure will prevent operation of the RPS.

6.2.2.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The event considered is the inadvertent opening to full open position of one main feedwater control valve. The event will be analyzed to ensure that adequate margin to SAFDLs is maintained, and that adequate protection against steam generator overfill is maintained. The analysis will include a 22% of steam generator level span total allowance for the high-high steam generator level signal.

Reactor protection for this event is provided by the OPΔT, OTΔT, and high neutron flux reactor trips. Protection against steam generator overfill is provided by the high-high steam generator level signal, which trips the main feedwater pumps and closes the main feedwater pump discharge valves to terminate the event.

Mode 2: The event considered is an increase in feedwater flow to one steam generator from zero to 120% of the nominal full load feedwater flow to one steam generator. The event assumes the addition of unheated feedwater, since extraction steam is unavailable as a feedwater heat source. The event is analyzed from hot zero power critical conditions with three reactor coolant pumps operating. The event analysis is thus structured to conservatively bound Mode 2 events. Reactor protection is provided by the source range neutron flux trip, the intermediate range neutron flux trip, the power range neutron flux trip, high and low settings, and by the high steam generator level signal.

Modes 3 through 6: The main feedwater isolation valves are closed in Modes 3 through 6. Therefore, the event is deemed incredible in these modes.

Based on the above evaluations, this event is analyzed at both HFP conditions and HZP conditions. The HFP and HZP cases analyzed are:

- HFP conditions, minimum (BOC) reactivity feedback, automatic rod control, full open main feedwater valve used to initiate the transient

- HFP conditions, maximum (EOC) reactivity feedback, manual rod control, full open main feedwater valve used to initiate the transient

- HFP conditions, maximum reactivity feedback, automatic rod control, full open main feedwater valve used to initiate the transient

- HZP conditions, maximum reactivity feedback, manual rod control, step change in main feedwater flow from 0 to 120% nominal used to initiate the transient

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.2.3 Acceptance Criteria

An Increase in Feedwater Flow event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are :

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling rate (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

(3) The event should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained.

6.2.2.4 Results

The results of the analysis demonstrate that the event acceptance criteria are met. Neither the primary system pressure design limit (2750 psia) nor the secondary system pressure design limit (1320 psia) is significantly challenged during this event. The predicted MDNBR is greater than

the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event.

The limiting case is the HFP case with maximum (EOC) reactivity feedback and manual rod control. This transient tripped on turbine trip due to a high-high steam generator level signal. The sequence of events for the limiting case is given in Table 6.2.2-1. The responses to key system variables are given in Figure 6.2.2-1 to Figure 6.2.2-5.

6.2.2.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.2.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.2-1 Event Summary for Increase in Feedwater Flow Limiting Case (HFP, EOC, Manual Rod Control)

Event	Time (s)
Initiate transient (step increase in feedwater flow)	0.0
MDNBR	18.0
High-high steam generator level signal	48.6
Turbine trip	48.6
Reactor trip	49.1
Feedwater valve closes	60.0

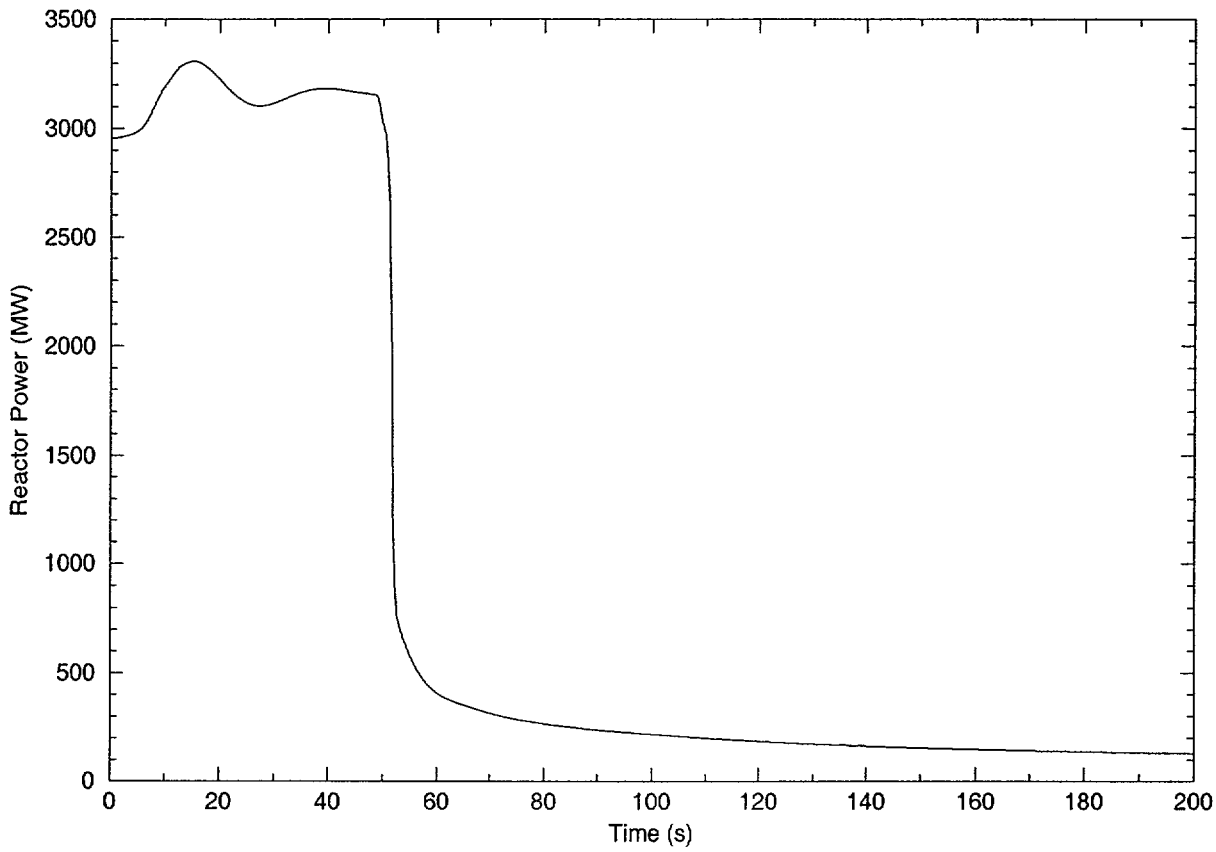

Figure 6.2.2-1 Reactor Power for Increase in Feedwater Flow – Limiting Case

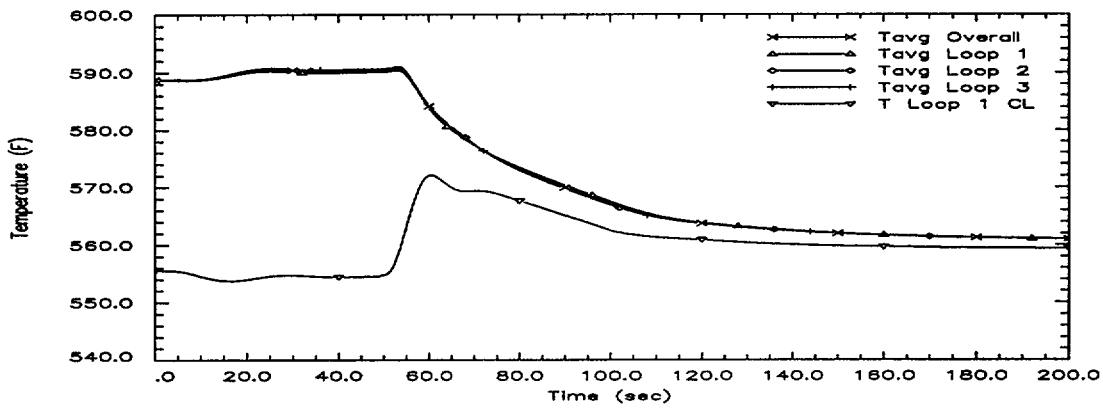

Figure 6.2.2-2 Primary System Temperatures for Increase in Feedwater Flow – Limiting Case

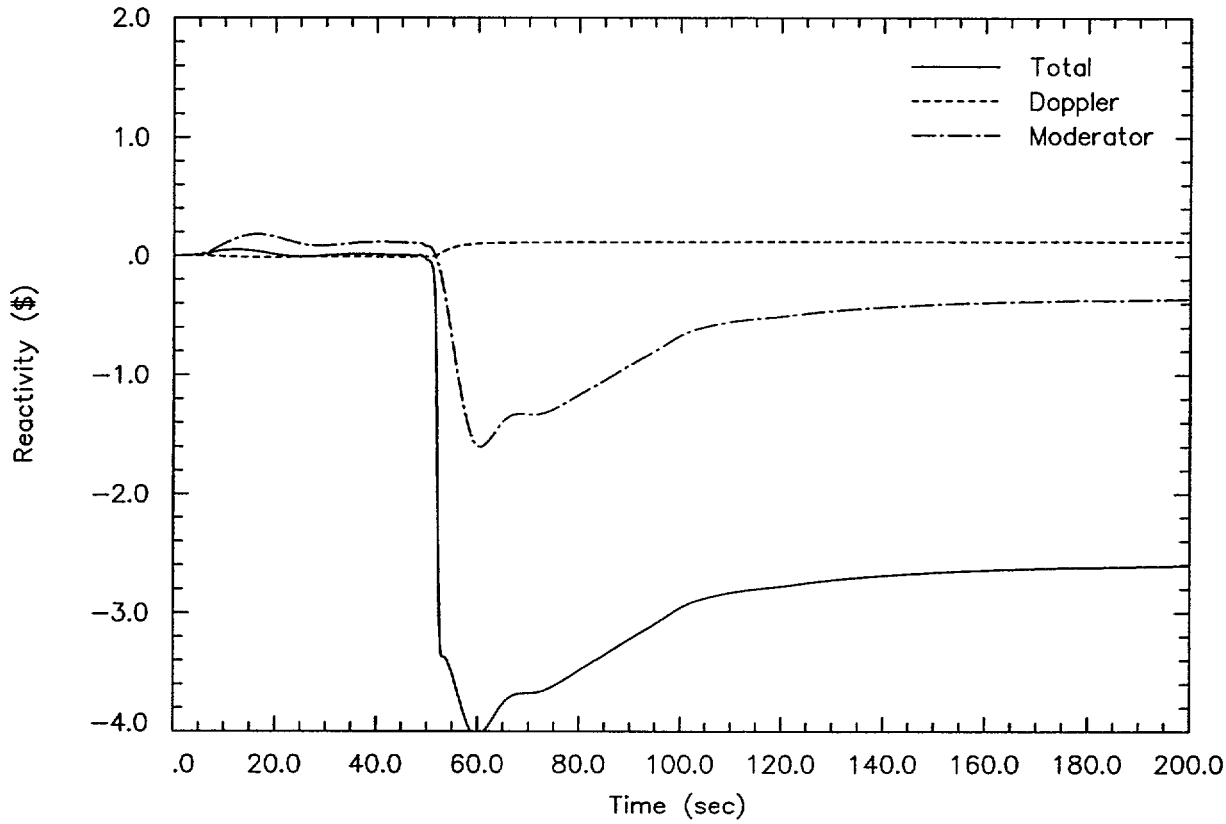

Figure 6.2.2-3 Reactivities for Increase in Feedwater Flow – Limiting Case

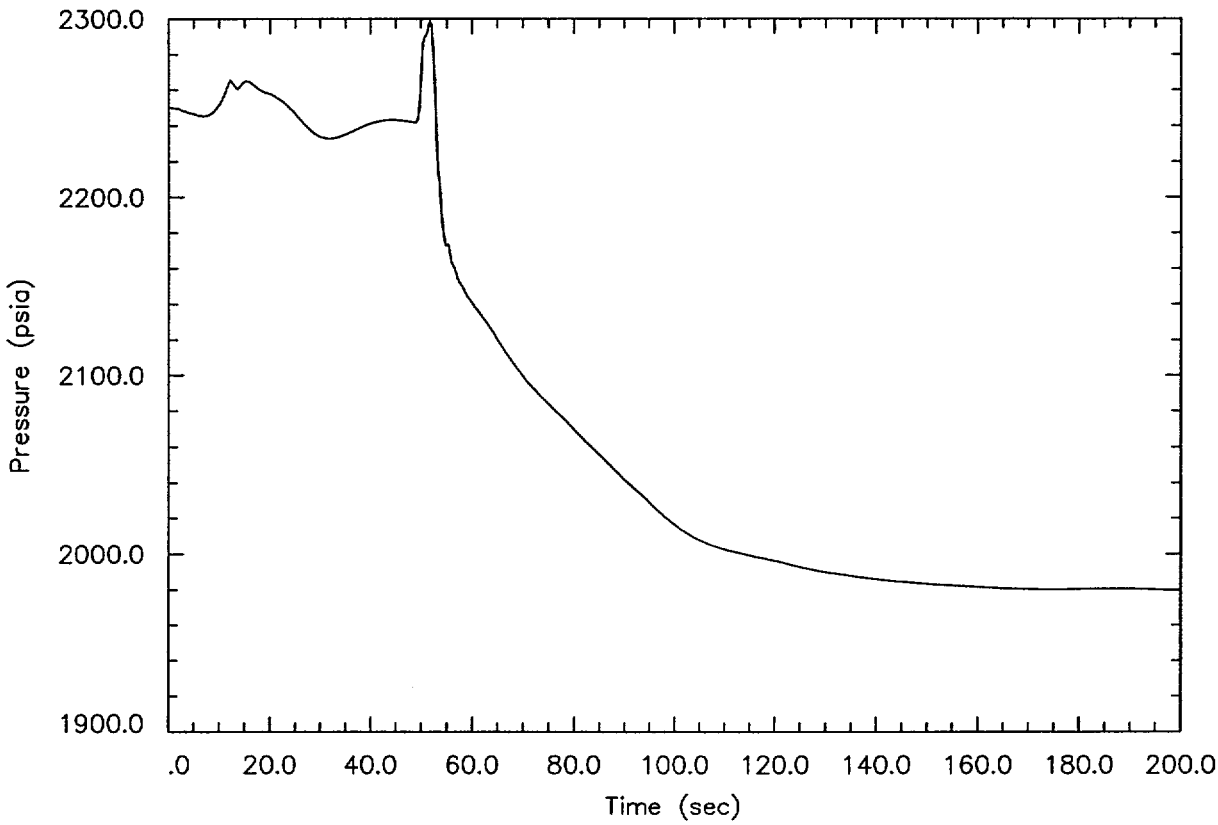

Figure 6.2.2-4 Pressurizer Pressure for Increase in Feedwater Flow – Limiting Case

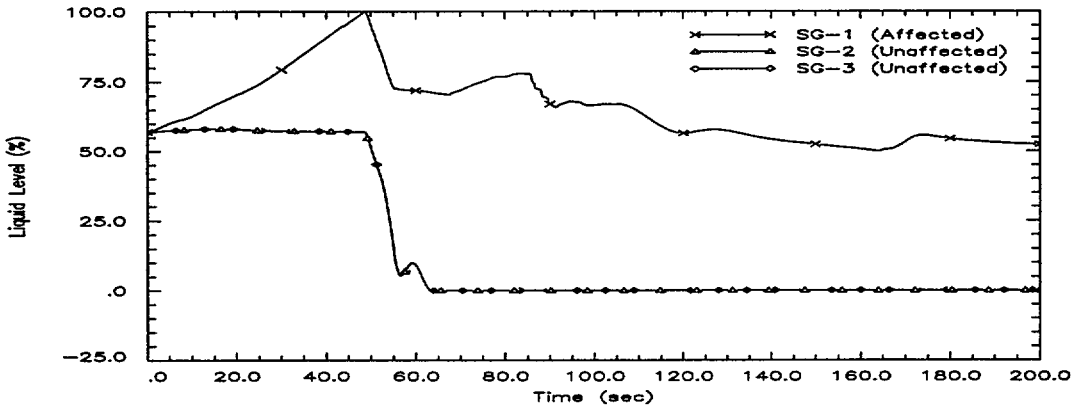

Figure 6.2.2-5 Steam Generator Collapsed Level for Increase in Feedwater Flow – Limiting Case

6.2.3 Increase in Steam Flow (FSAR Event 15.1.3)

6.2.3.1 Identification of Causes and Accident Description

The Increase in Steam Flow event is defined as a rapid increase in steam demand. The accident could result from either an administrative violation such as excessive loading by the operator, or an equipment malfunction in the steam dump control or turbine speed control.

The event initiator is a 10% step increase in steam flow. The feedwater regulating valves open to increase the feedwater flow in an attempt to match the increased steam demand and maintain steam generator water level. The mismatch between the energy being generated in the reactor core and the energy being removed by the secondary system results in a decrease in the primary system core average temperature and the primary system fluid contracts, resulting in an outsurge of fluid from the pressurizer. The pressurizer level and pressure decrease as fluid is expelled from the pressurizer. If the moderator temperature coefficient (MTC) is negative, the reactor core power increases as the moderator temperature decreases due to the mismatch between the power being removed by the steam generators and the power being generated in the core. The reactor responds to the mismatch between the power being removed by the steam generators and the power being generated in the core. The rod control system is assumed to be in the automatic state.

The OTΔT, OPΔT, and high neutron flux reactor trips are available to prevent the violation of the acceptance criteria. Depending on the magnitude of the increase in steam demand, a reactor trip may not be activated. Instead, the reactor system will reach a new steady-state condition at a power level greater than the initial power level which is consistent with the increased heat removal rate. The final steady-state conditions which are achieved will depend upon the capacity of the turbine control valves, the magnitude of the MTC, and whether or not the rod control system is in automatic. If the MTC is positive, the reactor power would decrease as the core average coolant temperature decreased, and this event would not produce a challenge to the acceptance criteria.

No single active failure will prevent operation of the RPS.

6.2.3.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The event considered is a step increase in steam flow equal to 10% of that at rated power. The event will be analyzed to ensure that margin to SAFDLs is maintained.
Reactor protection for this event is afforded by the OTΔT, OPΔT, and high neutron flux reactor trips.

Modes 2, 3, and 4: The event considered is inadvertent opening to full open position of the turbine control valve, resulting in an initial steam flow rate of about 120% of that at rated power. The event results in rapid depressurization of the steam system, and will generate an engineered safety features actuation system (ESFAS) main steamline isolation via the main steam isolation

valves (MSIVs). The ESFAS signal is generated by low steamline pressure or high rate of decrease in steamline pressure, one of which is available throughout Modes 2, 3, and 4. Closure of the MSIVs will terminate the event without significant challenge to SAFDLs. The event is bounded in these modes by the Mode 1 event, because the initial margin to SAFDLs is much larger than in Mode 1.

Reactor protection is provided by MSIV closure on low steamline pressure or high rate of decrease in steamline pressure.

Modes 5 and 6: The secondary system temperature is below the saturation temperature at atmospheric conditions, so that a significant steam flow will not develop. The event is without consequence in these modes, and is therefore considered incredible.

Based on the above evaluations, this event is predominantly a cooldown event and is evaluated at full power conditions. At full power, the margin to limits is the smallest and, therefore, bounds operation at lower power levels. The reactor control system is designed to accommodate a 10% increase in load (step increase) or a 5% per minute load ramp for power levels between 15% and 100% of full power. The 10% step increase in load is analyzed because it is the highest expected increase that would occur. Two cases are analyzed: one for minimum neutronics feedback (BOC conditions) and the other for maximum neutronics feedback (EOC conditions). Both cases are evaluated with automatic rod control.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.3.3 Acceptance Criteria

An Increase in Steam Flow event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressure in the reactor coolant and main steam systems should be less than 110% of the design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

(3) The event should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained.

6.2.3.4 Results

The results of the analysis demonstrate that the event acceptance criteria are met. Neither the primary system pressure design limit (2750 psia) nor the secondary system pressure design limit (1320 psia) is significantly challenged during this event. The predicted MDNBR is greater than the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event.

The event is initiated by a rapid opening of the turbine control valves, the atmospheric dump valves and/or the turbine bypass valves resulting in a 10% step increase in steam flow. The maximum increased steam flow rate at full power is 110% of rated. The limiting case is the minimum (BOC) neutronics feedback case. There was no reactor trip for this transient. The sequence of events is given in Table 6.2.3-1. The responses to key system variables are given in Figure 6.2.3-1 to Figure 6.2.3-4.

6.2.3.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.3.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.3-1 Event Summary for Increase in Steam Flow Limiting Case (Minimum Feedback-BOC)

Event	Time (s)
10% step increase in steam flow	0.0
Peak power	143.0
MDNBR	204.0

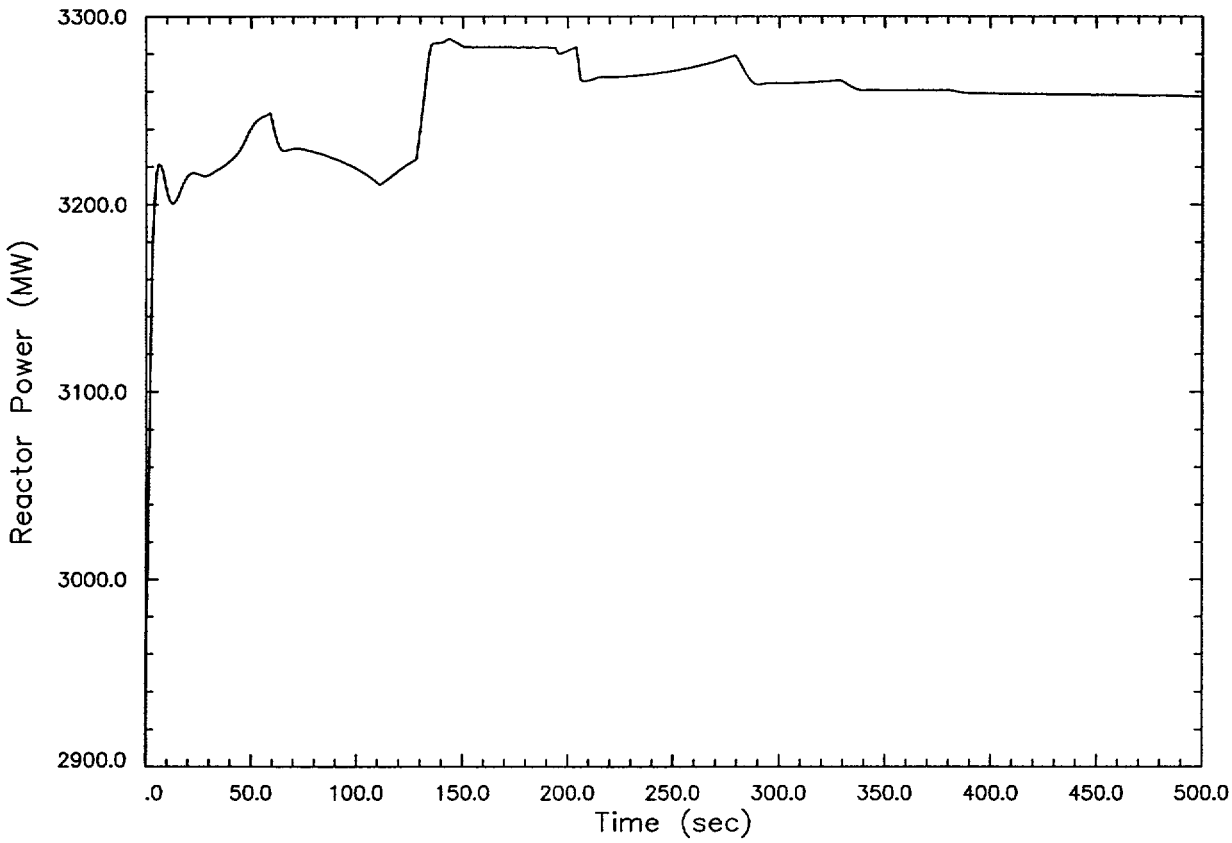

Figure 6.2.3-1 Reactor Power for Increase in Steam Flow - Limiting Case

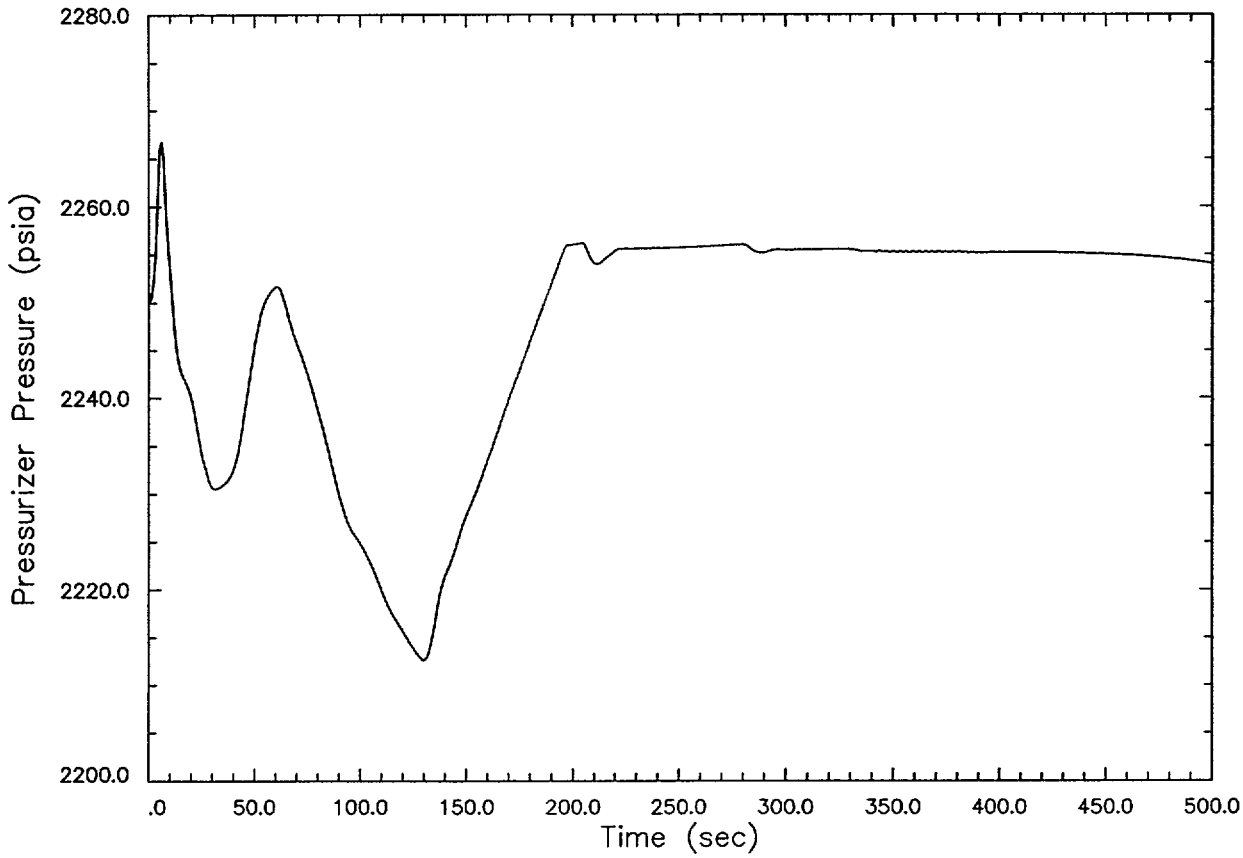

Figure 6.2.3-2 Pressurizer Pressure for Increase in Steam Flow - Limiting Case

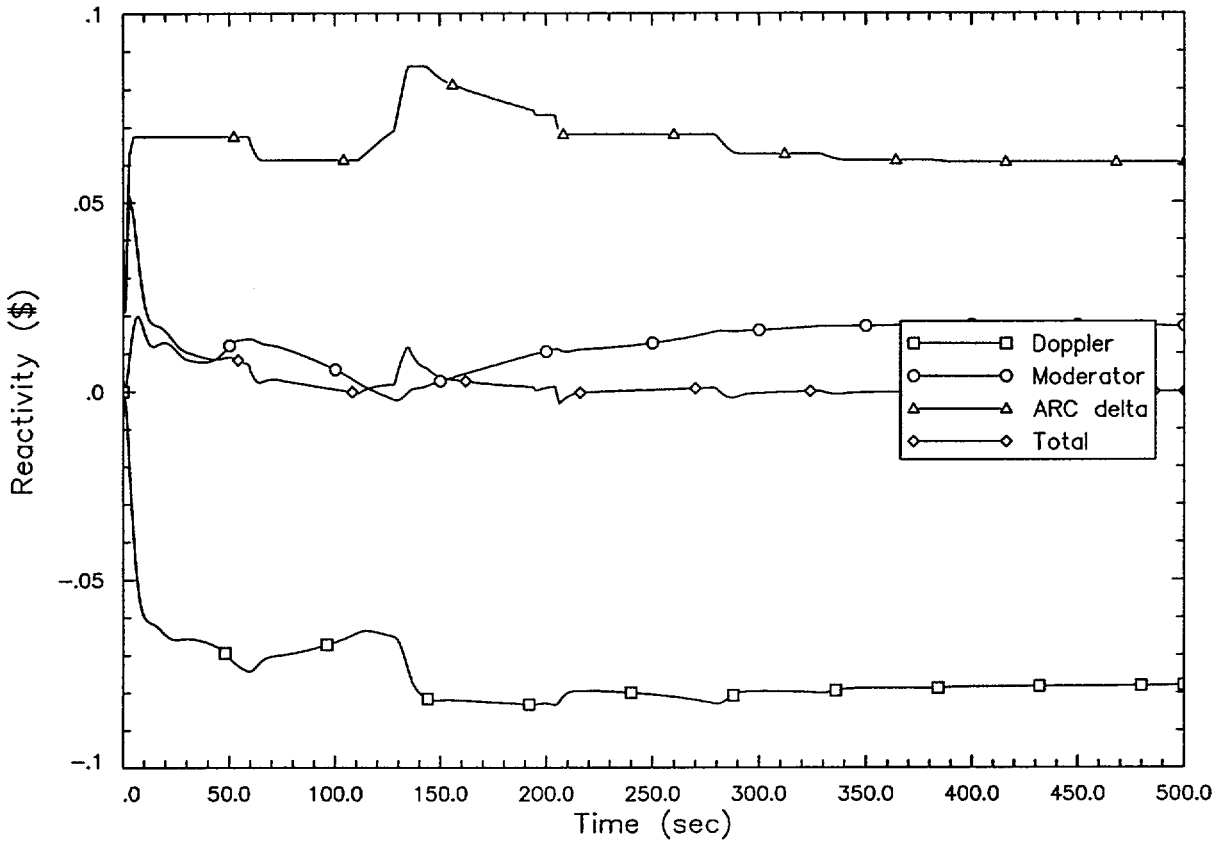

Figure 6.2.3-3 Reactivities for Increase in Steam Flow - Limiting Case

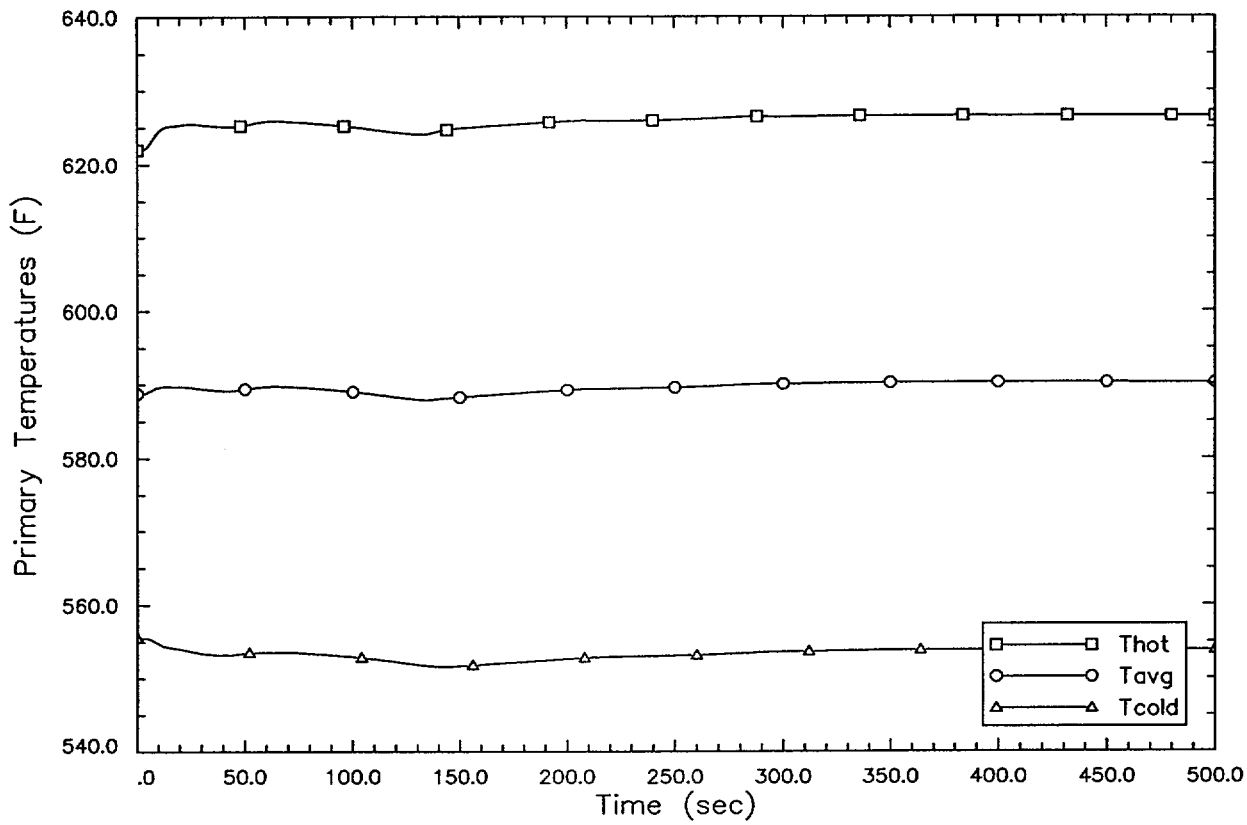

Figure 6.2.3-4 Primary System Temperatures for Increase in Steam Flow - Limiting Case

6.2.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve (FSAR Event 15.1.4)

6.2.4.1 Identification of Causes and Accident Description

This event is initiated by an increase in steam flow caused by the inadvertent opening of steam generator relief or safety valve. The increase in steam flow rate causes a mismatch between the heat generation rate on the primary side and the heat removal rate on the secondary side, and a cooldown of the Reactor Coolant System (RCS). In the presence of a negative MTC, the cooldown results in an insertion of positive reactivity and the reactor power will increase. Also, the reactor control system, if it is in automatic, will respond by pulling out the reactor control rods to match the increase load demand.

6.2.4.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The maximum steam flow through a single steam dump, power operated relief, or safety valve drives a thermal load increase less than that considered in Event 15.1.3. Ultimate reactor power level and the potential challenge to SAFDLs is greater for Event 15.1.3. The event is therefore bounded by Event 15.1.3.

Reactor protection for this event is afforded by the OPΔT, OTΔT, low pressurizer pressure, Safety Injection Actuation System (SIAS) on low pressurizer pressure, and high neutron flux reactor trips.

Mode 2: The reactor will achieve a steady state power level equal to its initial power plus the additional load imposed by the steam flow through the failed valve. Because the initial power level is less than 5% of rated, and the additional load is less than 10% of rated power, the reactor power will not rise to a level at which a significant challenge to SAFDLs is posed. Event 15.1.4 is bounded in Mode 2 by Mode 2 of Event 15.1.5, because the thermal load increase associated with the latter event is significantly greater and the more restrictive Condition II criteria are met.

Reactor protection is provided by the source range and intermediate range high neutron flux trips.

Mode 3: The event will proceed as described for Mode 2, except that the reactor is subcritical by at least 1000 pcm at event initiation for Mode 3. The initial margin to criticality for Mode 3 will slow the evolution of the event relative to Mode 2. Event 15.1.4 is bounded in Mode 3 by Mode 3 of Event 15.1.5, because the thermal load increase associated with the latter event is significantly greater and the more restrictive Condition II criteria are met.

Reactor protection is provided by the source range neutron flux trip.

Modes 4, 5, and 6: The reactor coolant temperature and secondary pressure are significantly reduced relative to Mode 3 for these modes. Thus, the potential cooldown is smaller than that in Mode 3 due to the decreased steam flow through the affected valve in these modes. The challenge

to SAFDLs is reduced directly by the lower coolant temperatures. The Mode 3 event, therefore, bounds the event in Modes 4, 5, and 6. In Modes 5 and 6, the event cannot occur with consequences because the primary and secondary temperatures are below saturation at atmospheric pressure.

Reactor protection is provided by the source range neutron flux trip.

6.2.4.3 Acceptance Criteria

The Inadvertent Opening of a Steam Generator Relief or Safety Valve event is classified as a Condition II event. The acceptance criteria for this event are the same as those listed for the Increase in Steam Flow event in Section 6.2.3.3.

6.2.4.4 Results

The Inadvertent Opening of a Steam Generator Relief or Safety Valve event is bounded in Mode 1 by Mode 1 of Increase in Steam Flow (Event 15.1.3), and need not be further analyzed. The Mode 2 event is bounded by Mode 2 of the Steam System Piping Failures Inside and Outside of Containment (Event 15.1.5). The Mode 3 event is bounded by Mode 3 of the Steam System Piping Failures Inside and Outside of Containment (Event 15.1.5). The event in Modes 4-6 is bounded by Mode 3.

6.2.4.5 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.4.6 References

None.

6.2.5 Steam System Piping Failures Inside and Outside of Containment (FSAR Event 15.1.5)

6.2.5.1 Identification of Causes and Accident Description

The steam line break event is initiated by a double ended guillotine break in a main steam line outside containment between the flow restrictor at the steam generator outlet nozzle and the MSIV. The increase in energy removal through the secondary system results in a severe overcooling of the primary system. In the presence of a negative MTC, this cooldown results in a positive reactivity insertion, a decrease in the shutdown margin, and a potential return to power. This return to power is exacerbated because of the high power peaking factors which exist as a result of the most reactive control rod being assumed stuck in a fully withdrawn position. The core is ultimately shut down by the boric acid injection delivered by the safety injection system.

6.2.5.2 Description of Analysis

Modes 1 and 2: The event is analyzed from the HFP and HZP conditions to assess the challenge to SAFDLs. Cases with and without offsite power available are analyzed, at both HFP and HZP. Reactor protection is provided by the low pressurizer pressure trip (above P-7), the ESFAS sequence for MSIV isolation initiated on low steam line pressure, or high rate of decrease of steam line pressure.

Modes 3 through 6: The event is less limiting in these modes because the reactor is initially at least 1000 pcm subcritical at event initiation. As the initial reactor coolant temperature decreases through these modes, the steam release through the break falls due to the lower secondary pressure at event initiation. This effect, coupled with the initial subcritical state renders the event less limiting in these modes than in Modes 1 and 2. The event is bounded in Modes 3 through 6 by the Mode 1 and 2 events.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XTGPWR (Reference 2) and XCOBRA-IIIC (References 3 and 4) computer codes. The XTGPWR code is used to calculate the axial and radial power distributions and reactivity at the time of MDNBR and peak power as calculated by ANF-RELAP. The calculated power distributions are used as input to the XCOBRA-IIIC computer code. The XCOBRA-IIIC code is used to predict the MDNBR for the event. The reactivity calculated by XTGPWR is compared with the reactivity calculated by ANF-RELAP to ensure conservatism in the ANF-RELAP representation of reactivity feedback. The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.5.3 Acceptance Criteria

The Steam System Piping Failures Inside and Outside of Containment event is classified as a Condition IV event. Consistent with the current licensing basis, the acceptance criteria for this event are:

1. Pressure in the reactor coolant and main steam systems should be maintained below acceptable design limits.

2. Any fuel failure calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability.

3. The integrity of the reactor coolant pumps should be maintained, such that a loss of AC power and containment isolation will not result in pump seal damage.

4. The auxiliary feedwater system must be safety grade and, when required, automatically initiated.

5. Tripping of the reactor coolant pumps should be consistent with the resolution of TMI Action Plan Item II.K.3.5.

6. The radiological criteria are

   a) For an MSLB with an assumed preaccident iodine spike with the highest worth control rod stuck out of the core and including any fuel failures, the calculated doses should not exceed the 10 CFR 100, Section 11 values, i.e., 25 rem and 300 rem, respectively, for the whole-body and thyroid doses.

   b) For an MSLB with an assumed preaccident iodine spike and for an MSLB with the highest worth control rod stuck out of the core, the calculated doses should not exceed the 10 CFR 100, Section 11 values, i.e., 25 rem and 300 rem, respectively, for the whole-body and thyroid doses.

   c) For an MSLB with the equilibrium iodine concentration for continued full power operation in combination with an assumed accident initiated iodine spike and without the stuck rod, the calculated doses should not exceed a small fraction of the 10 CFR 100, Section 11 values, i.e., 10 percent or 2.5 rem and 30 rem, respectively, for the whole-body and thyroid doses.

6.2.5.4 Results

The limiting case from both the MDNBR and fuel centerline melt standpoint was the HZP case with offsite power available with a stuck rod. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable and not precluded by the acceptance criteria, the analysis shows that no fuel failure is predicted to occur as a result of this accident.

The sequence of events for this case is given in Table 6.2.5-1. The responses to key system variables are given in Figures 6.2.5-1 to 6.2.5-6. With offsite power available, the Reactor Coolant Pumps (RCPs) operated throughout the event. For the cases evaluated without offsite power

available, the timing of Loss of Offsite Power (LOOP) was determined to have a negligible impact on the results.

As shown in Figure 6.2.5-1, the pressure in all three steam generators declined immediately after transient initiation due to steam flow out of the break (Figure 6.2.5-2). After MSIV closure, the flow from the unaffected steam generators was terminated and the pressure recovered. The unaffected steam generators' pressure declined slowly thereafter due to heat transfer from the shell side fluid to the primary side fluid. Once the affected steam generator dried out, the secondary side pressure declined.

The break flow (Figure 6.2.5-2) from the unaffected steam generator was terminated when the MSIVs closed. After reaching an early maximum, the break flow from the affected steam generator gradually declined throughout the remainder of the transient. (The oscillatory behavior in the affected steam generator pressure and break flow beginning at approximately 360 seconds was due to the continual dryout and rewetting of the steam generator tubes.)

The mass inventory (Figure 6.2.5-3) in all three steam generators decreased until the MSIVs closed. Thereafter, the mass in the unaffected steam generators stabilized and remained essentially constant. The mass in the affected steam generator continued to decrease until it dried out at approximately 360 seconds.

The pressurizer pressure (Figure 6.2.5-4) decreased rapidly during the initial phase of the transient due to thermal contraction of the primary system coolant. The pressurizer pressure began to recover at approximately 40 seconds due to the addition of inventory via the SIS.

The reactor power was initially at 1 W. The cooldown resulted in power increasing significantly at about 20 seconds (Figure 6.2.5-5), reaching a peak value at approximately 260 seconds, and then began to decline due to boron injection.

Initially, the total core reactivity (Figure 6.2.5-6) increased due to moderator and Doppler feedback associated with the primary cooldown. Once the reactor power began to increase, the Doppler feedback changed from positive to negative and the reactor was brought to a quasi steady-state. The boron component of reactivity began to show an effect at approximately 260 seconds as boron from the High Head Safety Injection (HHSI) system began to reach the upper part of the stuck rod region.

6.2.5.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions, with the exception of conclusions related to radiological consequences. The conclusions of the analysis of the radiological consequences are documented in the BOP Licensing Report. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam

generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.5.6 References

1. EMF-84-093(P)(A) Revision 1, Steam Line Break Methodology for PWRs, Siemens Power Corporation, February 1999.

2. XN-CC-28(A) Revision 3, XTG: A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing, Exxon Nuclear Company, September 1975.

3. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.5-1 Event Summary for Main Steamline Break Limiting Case (HZP, Offsite Power Available, Stuck Rod)

Event	Time (s)
Reactor at EOC HZP conditions	0.0
Double-ended guillotine break in main steam line occurs	0.0
Full AFW flow to affected steam generator	0.0
MSIVs closed	7.1
Scram worth is overcome by moderator and Doppler feedback	18.0
HHSI pumps at rated speed	37.1
Borated water has filled SI lines and begins to enter cold legs	258.6
Peak post-scram power reached	260.0

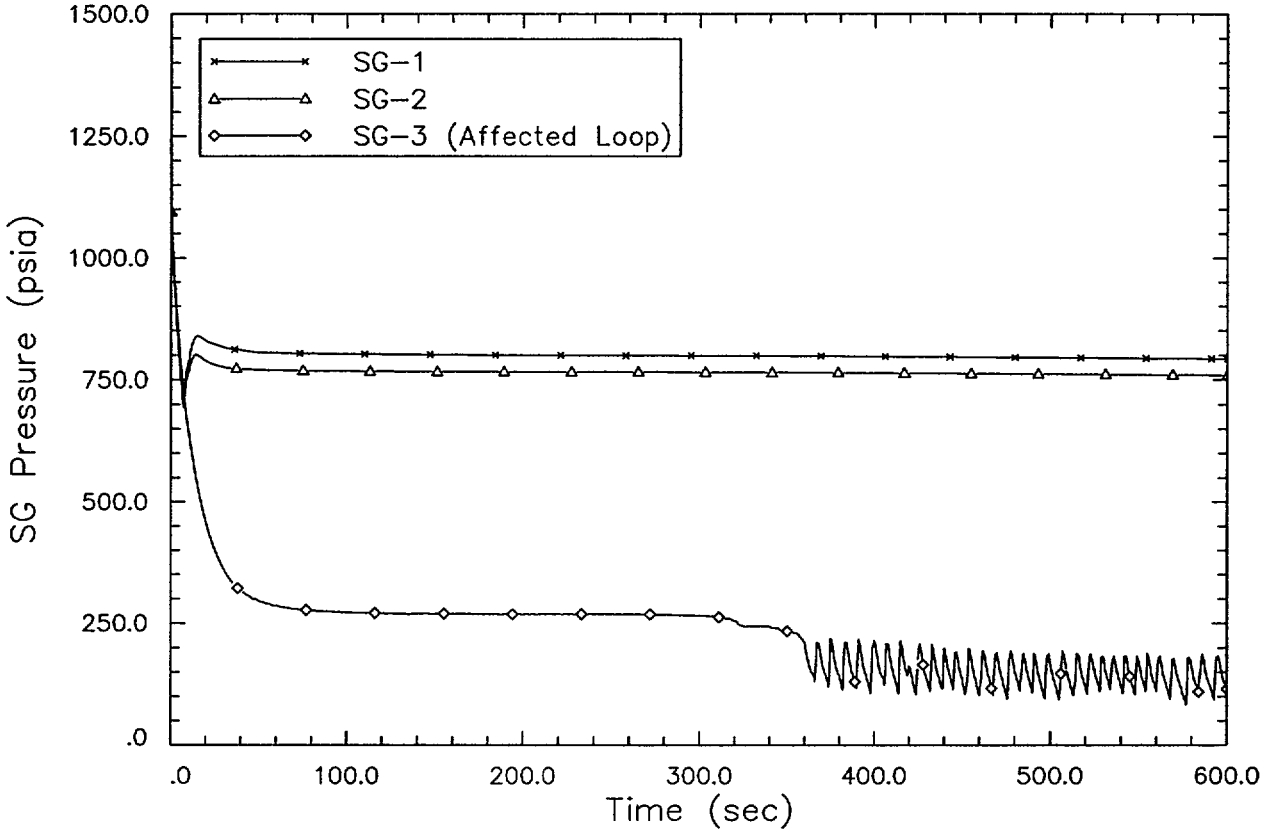

Figure 6.2.5-1 Steam Generator Pressure for Main Steamline Break Limiting Case (HZP, Offsite Available, Stuck Rod)

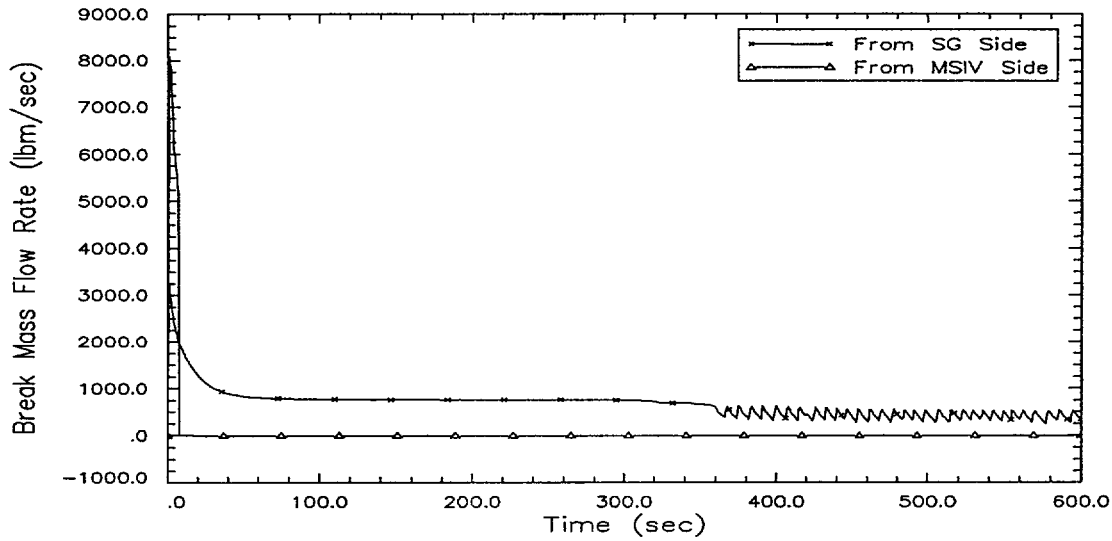

Figure 6.2.5-2 Break Mass Flow Rates for Main Steamline Break Limiting Case (HZP, Offsite Available, Stuck Rod)

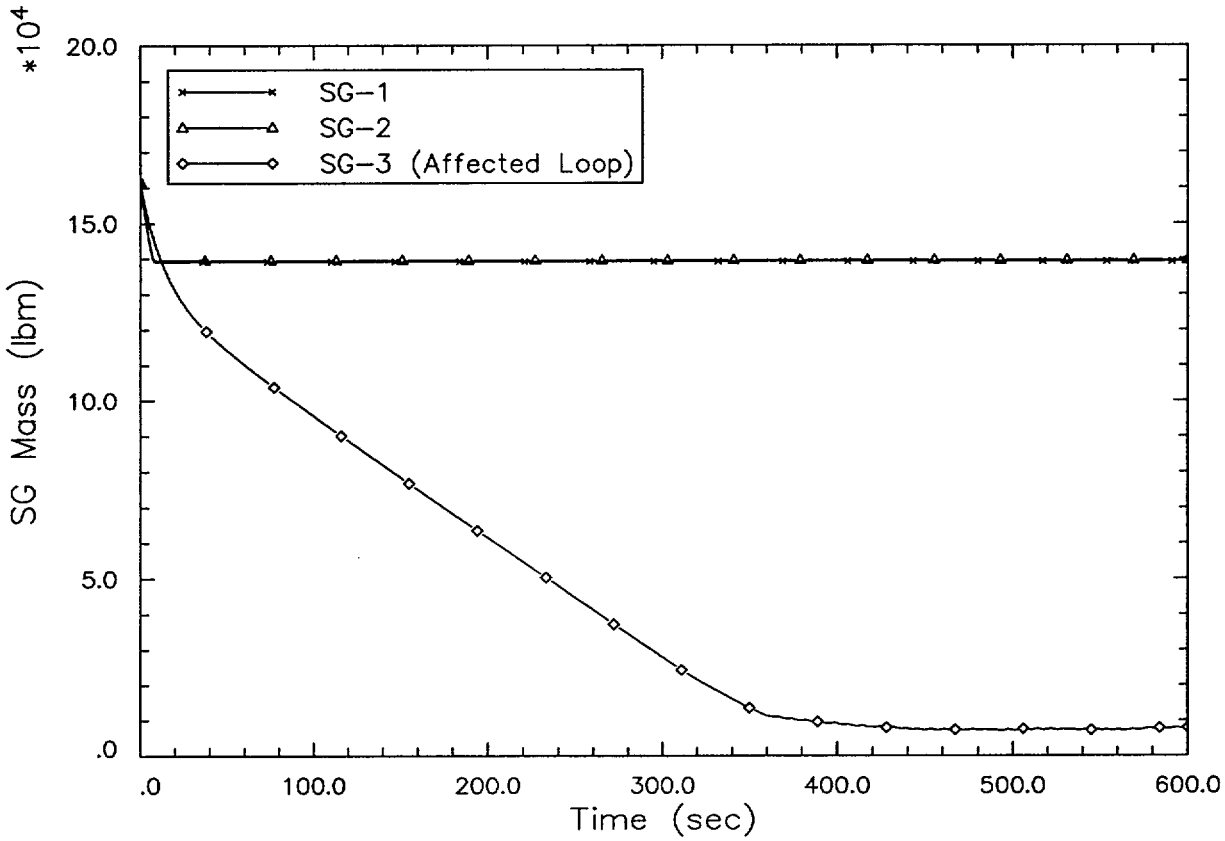

Figure 6.2.5-3 Steam Generator Secondary Mass Inventory for Main Steamline Break Limiting Case (HZP, Offsite Available, Stuck Rod)

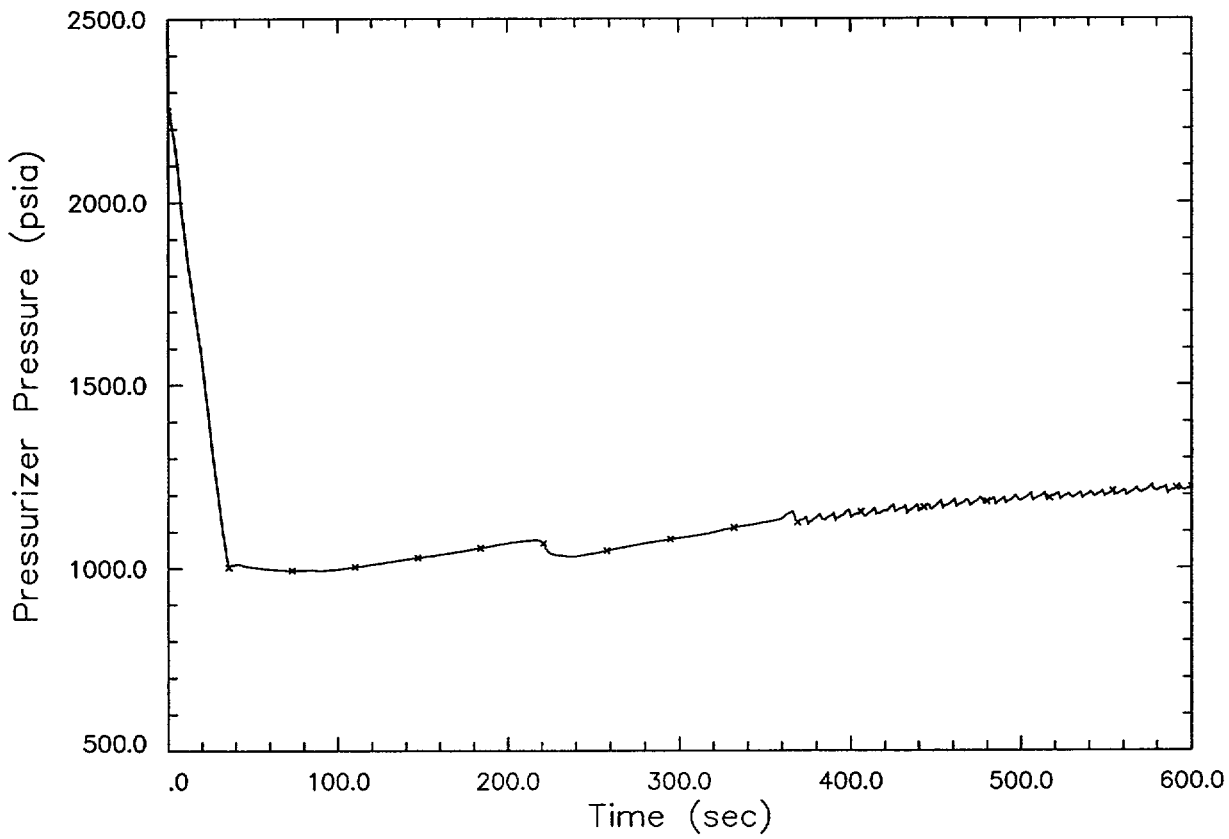

Figure 6.2.5-4 Pressurizer Pressure for Main Steamline Break Limiting Case (HZP, Offsite Available, Stuck Rod)

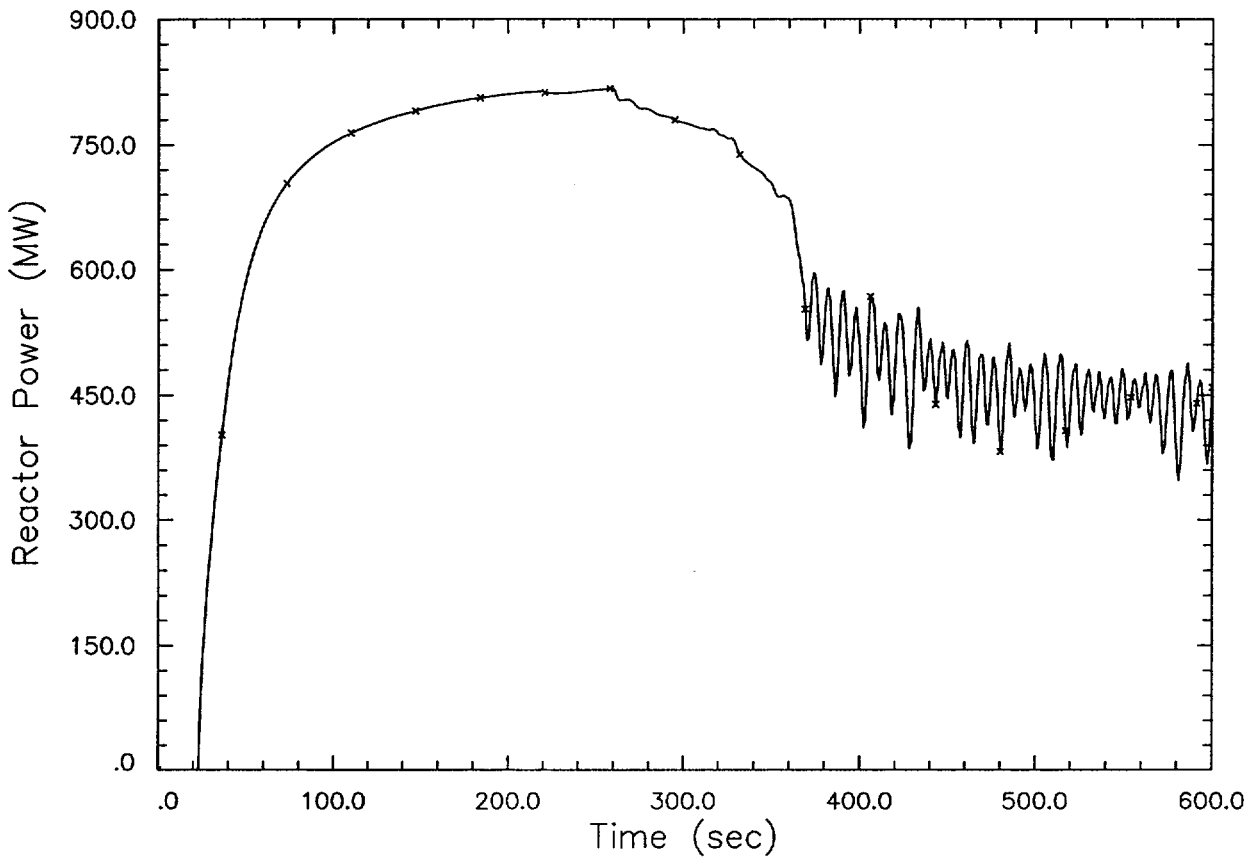

Figure 6.2.5-5 Reactor Power for Main Steamline Break Limiting Case (HZP, Offsite Available, Stuck Rod)

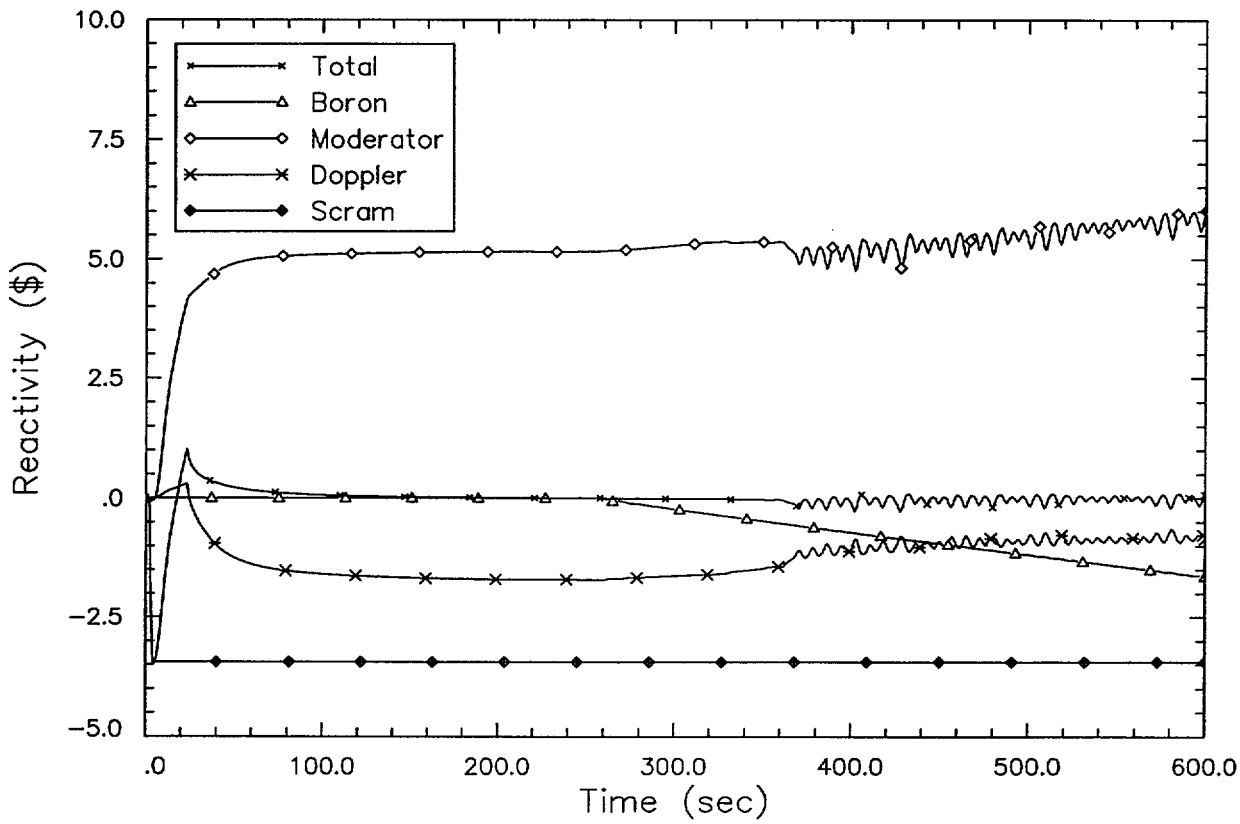

Figure 6.2.5-6 Reactivities for Main Steamline Break Limiting Case (HZP, Offsite Available, Stuck Rod)

6.2.6 Steam Pressure Regulator Malfunctions (FSAR Event 15.2.1)

There are no steam pressure regulators in the Harris Nuclear Plant whose failure or malfunction could cause a steam flow transient. Therefore, this event is not part of the plant licensing basis.

6.2.7 Loss of External Load (FSAR Event 15.2.2)

6.2.7.1 Identification of Causes and Accident Description

A Loss of External Load event can result from loss of external electrical load due to some electrical system disturbance or from a turbine trip. Offsite electrical power is available to operate the reactor coolant system pumps and other station auxiliaries. Following the loss of generator load, the turbine control valve closes, terminating the steam flow and causing the secondary system temperature and pressure to increase. Primary-to-secondary heat transfer decreases as the secondary system temperature increases.

If the reactor is not tripped when the turbine is tripped, the primary system temperature will continue to rise. The primary liquid will expand into the pressurizer causing the pressurizer pressure to rise. If this continues, the reactor will trip on high pressurizer pressure, reducing the primary heat source. As the heat load into the primary decreases, the primary system pressurization will begin to diminish. If the setpoint for opening the primary system code safety valves is exceeded during the initial system overpressurization, these valves will open to relieve pressure and to mitigate the pressure transient. Energy is removed during the early phase of the transient through the steam generator safety valves when the steam generator pressure exceeds the safety valve opening setpoint.

The pressurizer safety valves and steam generator safety valves are sized to protect the RCS and steam generator against overpressurization for all load losses without assuming the operation of the Steam Dump System, pressurizer spray, and pressurizer power operated relief valves. The steam generator safety valve capacity is sized to remove the steam flow at the engineered safety features rating from the steam generator without exceeding 110 percent of the steam system design pressure. The pressurizer safety valves capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load, along with operation of the steam generator safety valves. The pressurizer safety valves are then able to relieve sufficient steam to maintain the RCS pressure within 110 percent of the RCS design pressure.

No single active failure will prevent operation of any system required to function.

6.2.7.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The loss of external load event is initiated by a loss of external electric load, resulting in automatic closure of the turbine control valves. Fast closure of the turbine control valves occurs slightly more slowly than the closure of the turbine stop valves that is simulated in Event 15.2.3. The simulations of Event 15.2.3 take no credit for direct reactor trip on turbine trip in order to bound the loss of external load. Due to its slower evolution, the loss of external load event poses

less challenge to SAFDLs and the vessel pressurization limits. The event results are bounded by the analysis of Event 15.2.3.

Reactor protection is afforded by the OTΔT, high pressurizer pressure, high pressurizer water level, and steam generator low-low level reactor trips.

Modes 2 through 6: There is no significant heat load on the reactor in Modes 2 through 6, and hence no driving force for a load rejection event. The Mode 2 through 6 events are therefore bounded by the Mode 1 event.

6.2.7.3 Acceptance Criteria

A Loss of External Load event is classified as a Condition II event. The acceptance criteria for this event are the same as those listed for the Turbine Trip event in Section 6.2.8.3.

6.2.7.4 Results

The Loss of External Load (Event 15.2.2) is bounded in Mode 1 by Mode 1 of the Turbine Trip (Event 15.2.3), and need not be further analyzed. The event in Modes 2-6 event is bounded by Mode 1.

6.2.7.5 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.7.6 References

None.

6.2.8 Turbine Trip (FSAR Event 15.2.3)

6.2.8.2 Identification of Causes and Accident Description

This event is initiated by a turbine trip which results in rapid closure of the turbine stop valves. Normally, a reactor trip would occur on a turbine trip and the steam dump system would operate to mitigate the consequences of this event. However, without a reactor trip on turbine trip and without the steam dump system, the loss of steam flow results in an almost immediate rise in secondary system temperature and pressure with a resultant primary system transient as described in Section 6.2.7 for the Loss of External Load event. A slightly more severe transient occurs for the Turbine Trip event since the turbine stop valves close more rapidly than the turbine control valves in the Loss of External Load event.

No single active failure will prevent operation of any system required to function.
The primary system is protected against overpressurization by the pressurizer safety and relief valves. Pressure relief on the secondary side is afforded by the steam line safety/relief valves.

6.2.8.3 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The event is analyzed. The event simulations are structured to bound the effects of Events 15.2.2, 15.2.4, and 15.2.5. The event simulation assumes the most rapid event initiator (closure of the turbine stop valves), that no direct reactor trip on turbine trip occurs, that only the steam generator safety valves are available for steam relief, and that main feedwater is isolated on turbine trip. Steam dump to the condenser is assumed unavailable, to ensure an event simulation which conservatively bounds Events 15.2.4 and 15.2.5.

Reactor protection is afforded by the OTΔT, high pressurizer pressure, high pressurizer water level (above P-7 interlock), and steam generator low-low level reactor trips.

Modes 2 through 6: There is no significant heat load on the reactor in Modes 2 through 6, and hence no driving force for a load rejection event. The Mode 2 through 6 events are therefore bounded by the Mode 1 event.

Based on the above evaluations, three cases are analyzed for this event: one challenging the primary overpressurization criterion, one challenging the secondary overpressurization criterion, and one challenging the fuel design limits. In all three cases, the input parameters are biased (BOC kinetics) to maximize the increase in reactor power during the transient. However, in the first case the parameters and equipment operational states are selected to maximize the primary system overpressurization, in the second case the parameters and equipment operational states are selected to maximize the secondary system overpressurization, and in the third case the parameters and equipment states have been selected to reduce the primary system pressurization which provides a conservative estimate of the minimum DNBR during the transient.

This event is analyzed for a complete loss of steam load from full power without a direct reactor trip signal from any of the sensors on the turbine stop valves. This results in a delay of a reactor trip until conditions in the reactor coolant system result in a trip due to other signals (high pressurizer pressure, OTΔT, high pressurizer water level, and low-low steam generator water level).

The purpose of analyzing this event is to demonstrate that the primary and secondary pressure relief capability is sufficient to limit the pressures to less than 110% of their respective design values. This event is also analyzed to ensure that the reactor protection system is properly set to prevent penetration of the SAFDLs under the limiting assumptions of no credit for a direct reactor trip on turbine trip.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.8.4 Acceptance Criteria

A Turbine Trip event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are :

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

(3) The event should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained

6.2.8.5 Results

The results of the analysis demonstrate that the event acceptance criteria are met. For the overpressurization cases, both the maximum reactor primary system pressure and the maximum secondary system pressure are less than the design limits of 2750 psia and 1320 psia, respectively. For the MDNBR case, the predicted MDNBR is greater than the safety limit. The critical heat flux

correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event.

The sequence of events for the primary overpressurization case is given in Table 6.2.8-1. The responses to key system variables are given in Figure 6.2.8-1 to Figure 6.2.8-4. Evaluation of part power primary overpressurization cases indicated that the full power case with a 0.0 pcm/°F MTC was the limiting primary overpressurization case.

The sequence of events for the secondary overpressurization case is given in Table 6.2.8-2. The responses to key system variables are given in Figure 6.2.8-5 to Figure 6.2.8-8.

The sequence of events for the MDNBR case is given in Table 6.2.8-3. The responses to key system variables are given in Figure 6.2.8-9 to Figure 6.2.8-11. Evaluation of part power MDNBR cases indicated that the full power case with a 0.0 pcm/°F MTC was the limiting MDNBR case.

The allowable high flux trip setpoints as a function of the number of inoperable MSSVs were recalculated for SGR/Uprating conditions. Table 6.2.8-4 presents the results of this calculation.

6.2.8.6 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%.

6.2.8.7 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.8-1 Event Summary for Turbine Trip Primary Overpressurization Limiting Case

Event	Time (s)
Turbine trip	0.0
Reactor trip signal (high pressure)	5.03
Pressurizer safety valve setpoint reached	6.5
Scram initiation	7.04
Full flow through pressurizer safety valve	7.6
Peak pressurizer pressure	7.8
SG 1st Stage MSSVs open	8.4
SG 2nd Stage MSSVs open	9.3
SG 3rd Stage MSSVs open	10.8
SG 4th Stage MSSVs open	---
SG 5th Stage MSSVs open	---

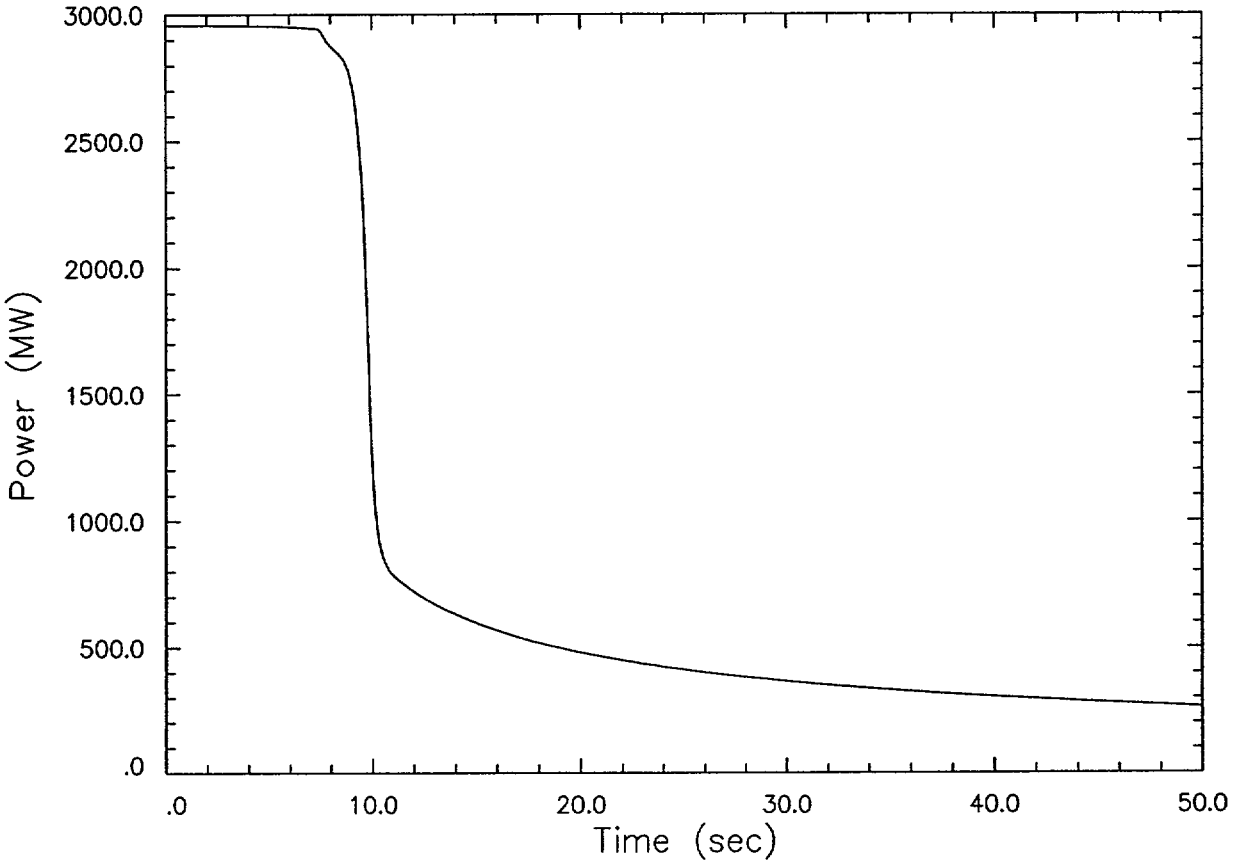

Figure 6.2.8-1 Reactor Power for Turbine Trip Primary Overpressurization Case

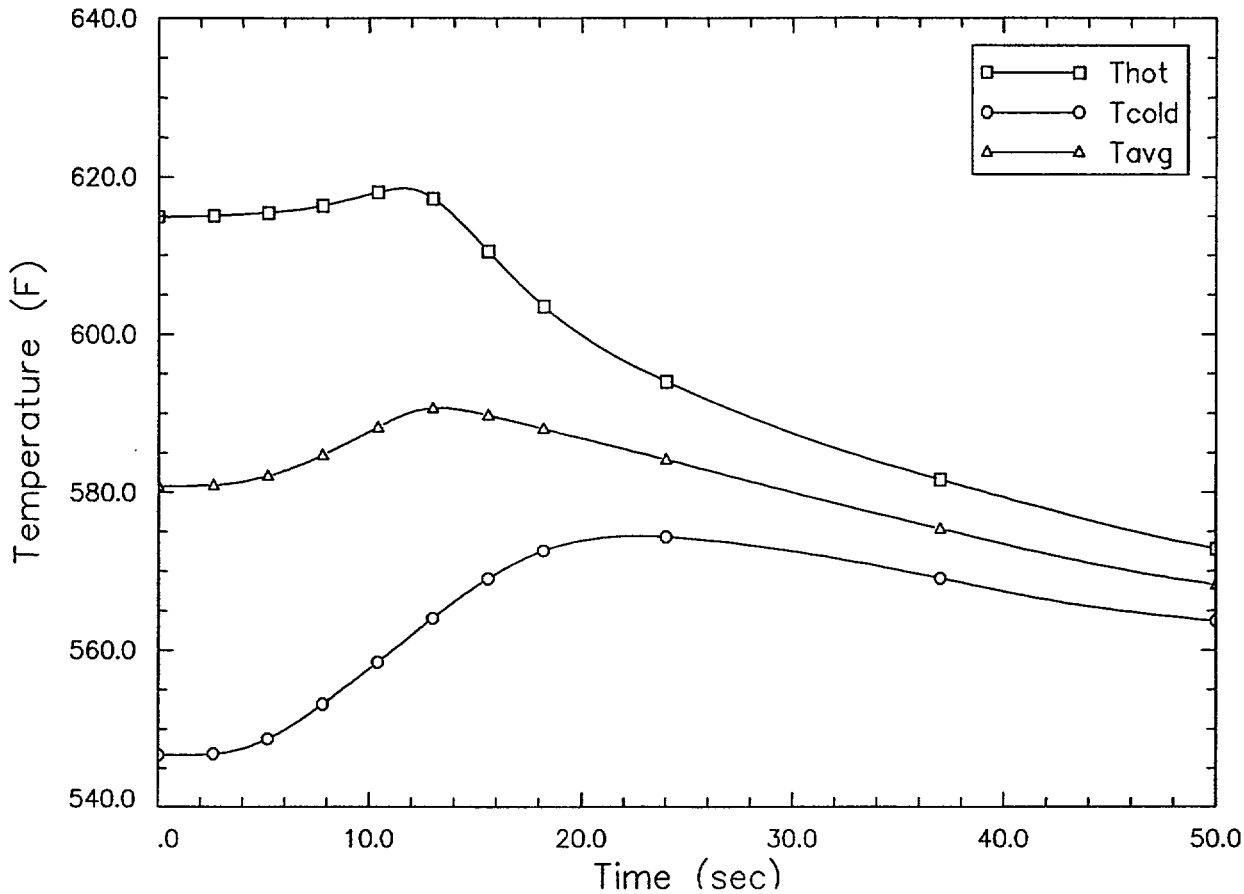

Figure 6.2.8-2 Primary System Temperatures for Turbine Trip Primary Overpressurization Case

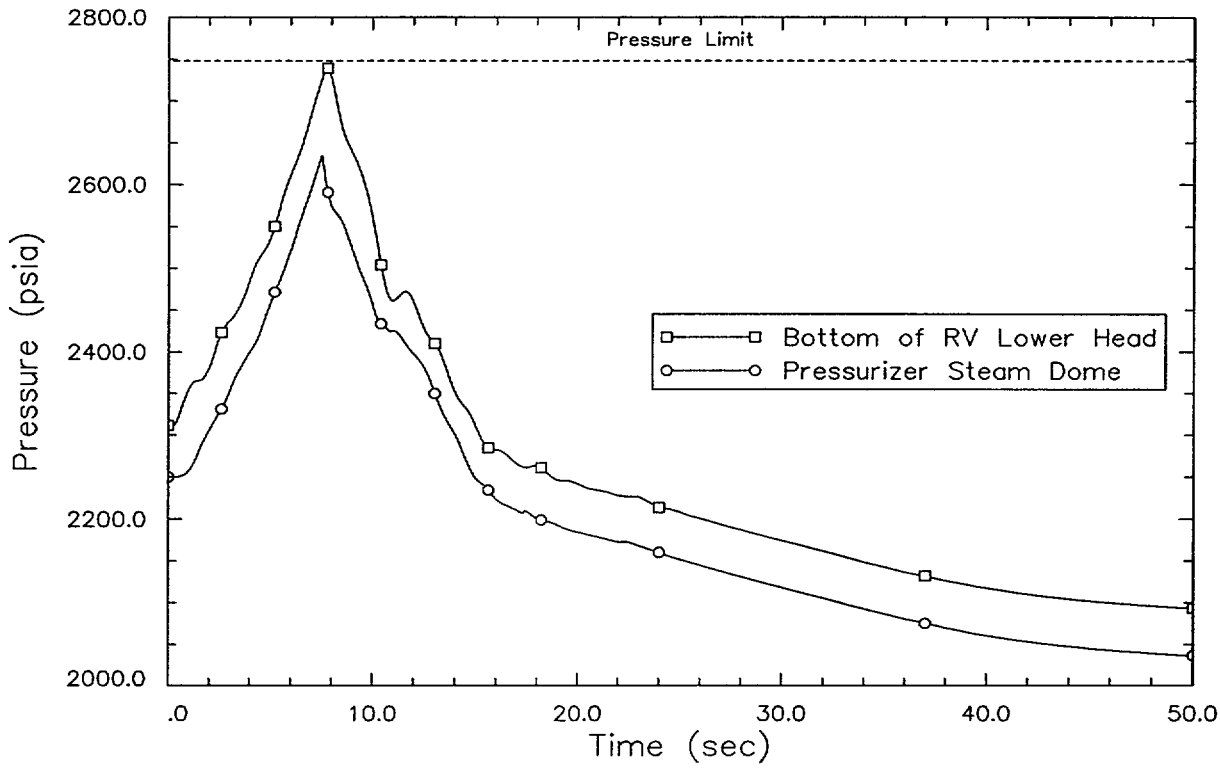

Figure 6.2.8-3 Pressurizer Pressure and Lower Head Pressure for Turbine Trip Primary Overpressurization Case

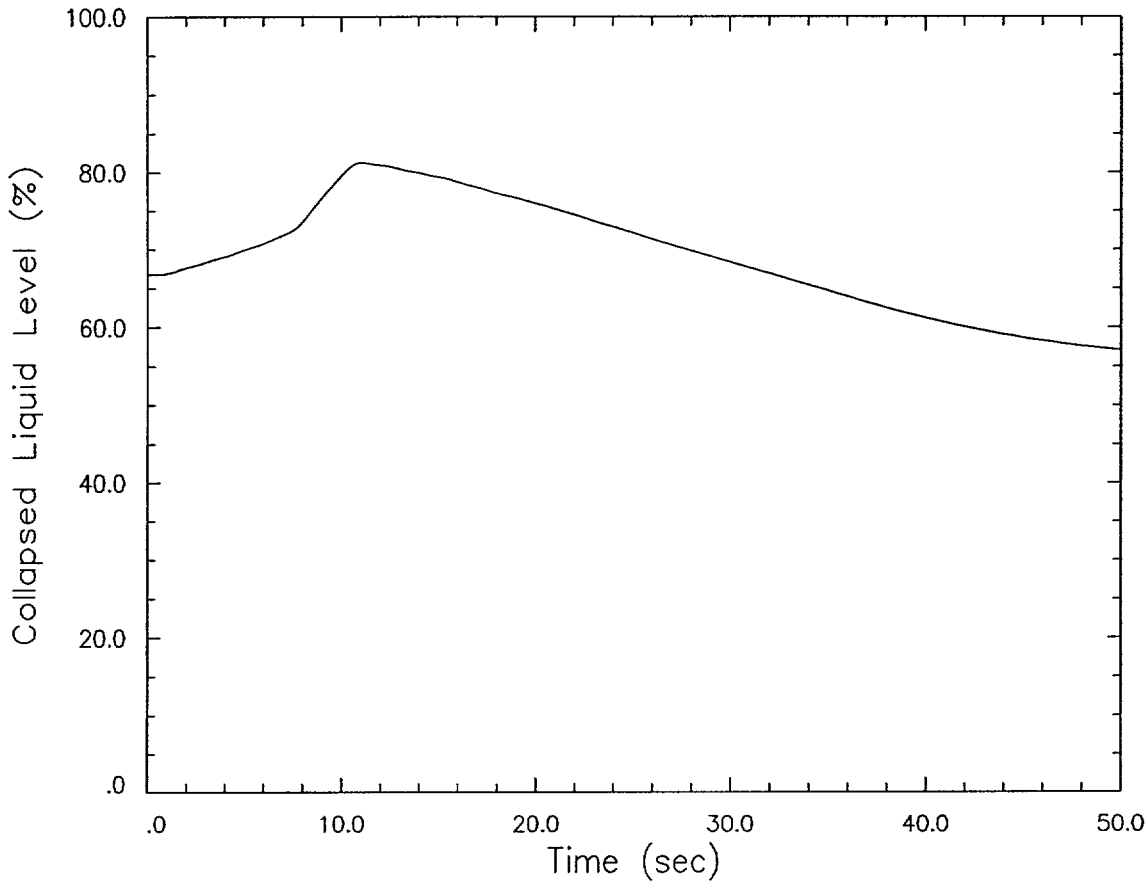

Figure 6.2.8-4 Pressurizer Level for Turbine Trip Primary Overpressurization Case

Table 6.2.8-2 Event Summary for Turbine Trip Secondary Overpressurization Limiting Case

Event	Time (s)
Turbine trip	0.0
Pressurizer spray on	1.0
Pressurizer compensated PORV open	1.20
Pressurizer uncompensated PORV open	4.3
SG 1st Stage MSSVs open	5.4
SG 2nd Stage MSSVs open	6.5
SG 3rd Stage MSSVs open	7.9
SG 4th Stage MSSVs open	10.1
OTΔT trip	11.16
Scram initiation	12.41
SG 5th Stage MSSVs open	13.2
Peak pressurizer level	16.2
Peak SG secondary pressure	18.9

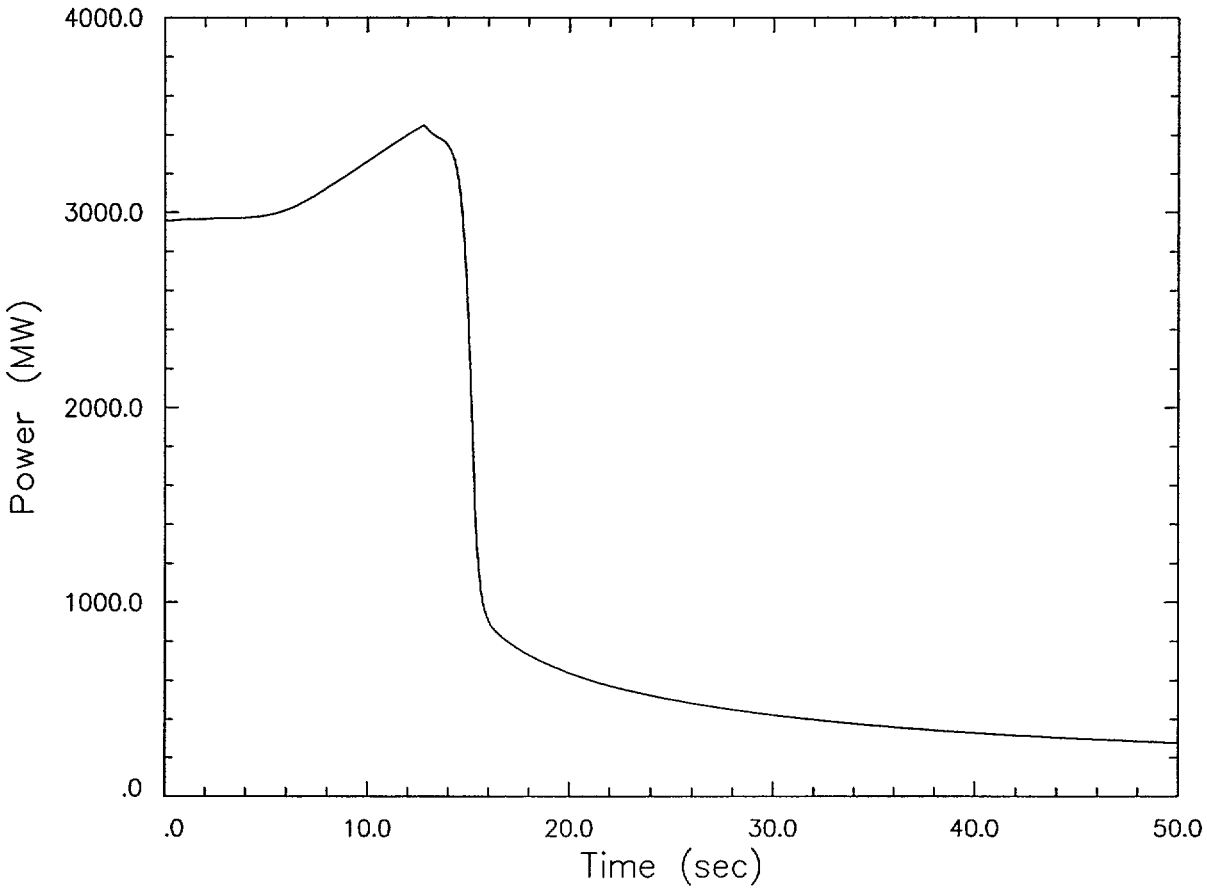

Figure 6.2.8-5 Reactor Power for Turbine Trip Secondary Overpressurization Case

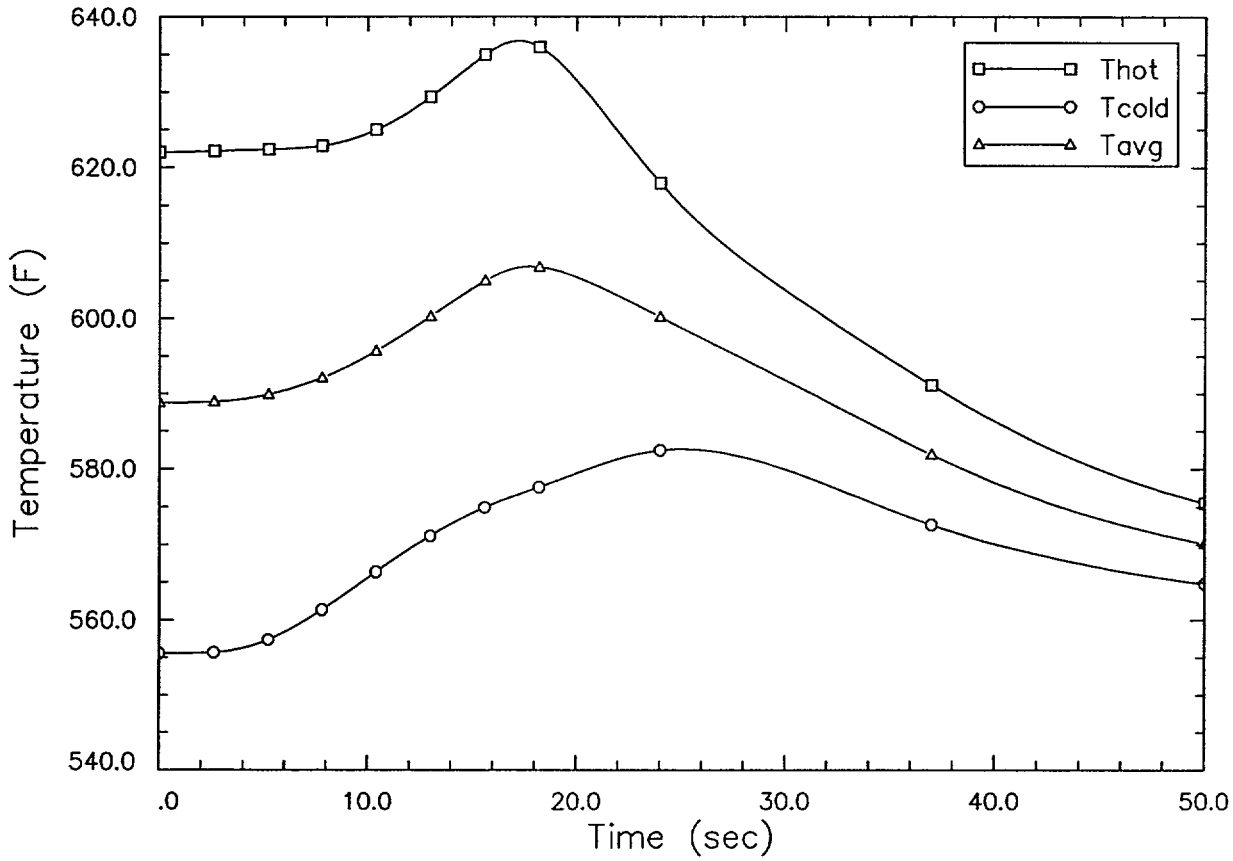

Figure 6.2.8-6 Primary System Temperatures for Turbine Trip Secondary Overpressurization Case

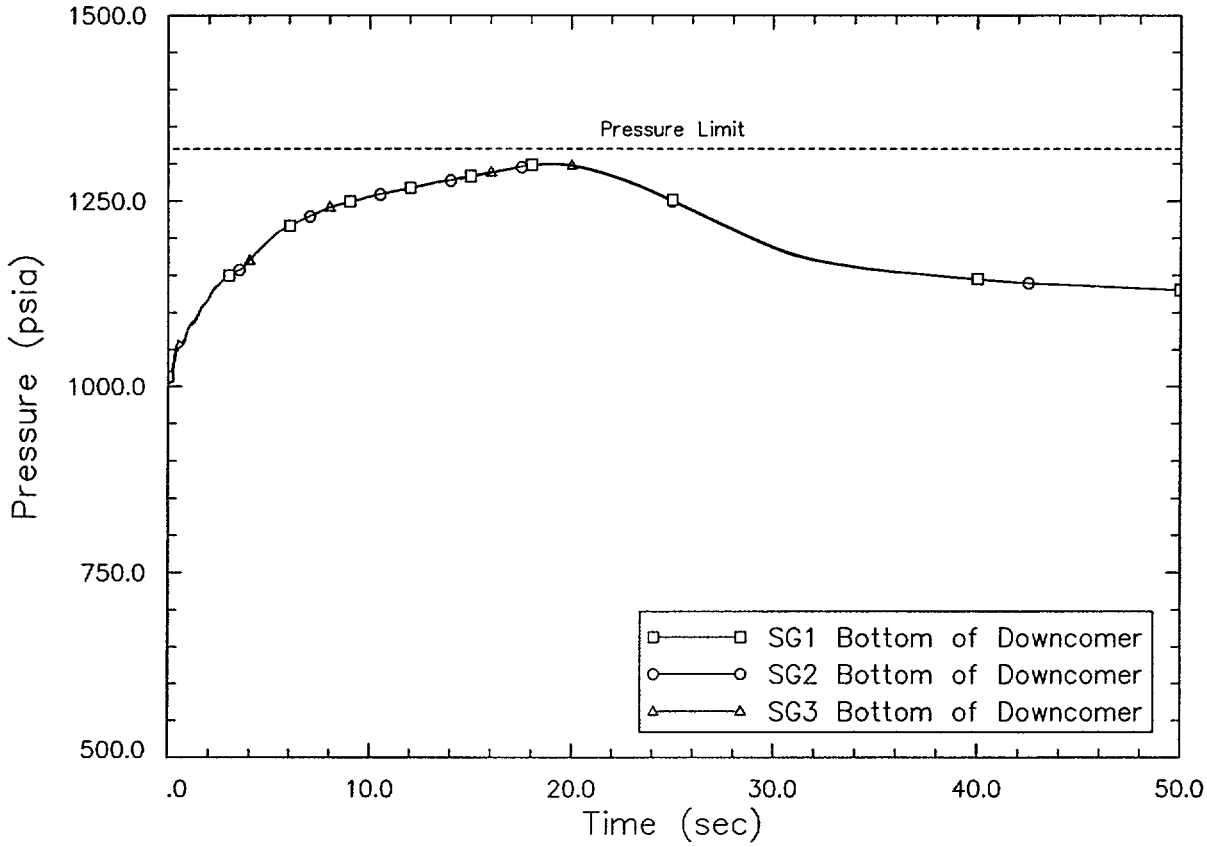

Figure 6.2.8-7 Steam Generator Secondary Pressure at the Bottom of the Downcomer for Turbine Trip Secondary Overpressurization Case

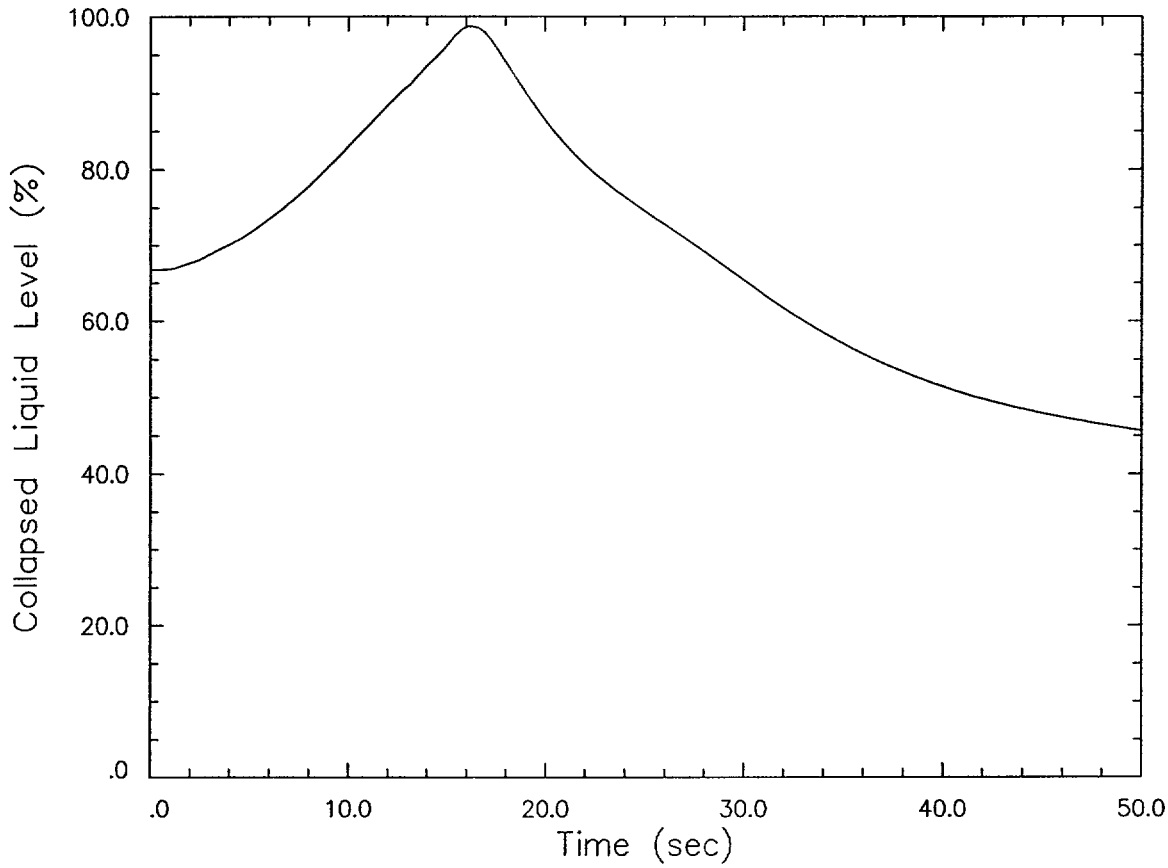

Figure 6.2.8-8 Pressurizer Level for Turbine Trip Secondary Overpressurization Case

Table 6.2.8-3 Event Summary for Turbine Trip MDNBR Limiting Case

Event	Time (s)
Turbine trip	0.0
Pressurizer spray on	1.0
Pressurizer compensated PORV open	1.24
Pressurizer uncompensated PORV open	4.8
SG 1st Stage MSSVs open	5.5
SG 2nd Stage MSSVs open	6.6
SG 3rd Stage MSSVs open	8.0
SG 4th Stage MSSVs open	10.4
OTΔT trip	11.55
Scram initiation	12.80
MDNBR	13.6
SG 5th Stage MSSVs open	13.9
Peak pressurizer level	16.1
Peak SG secondary pressure	18.6

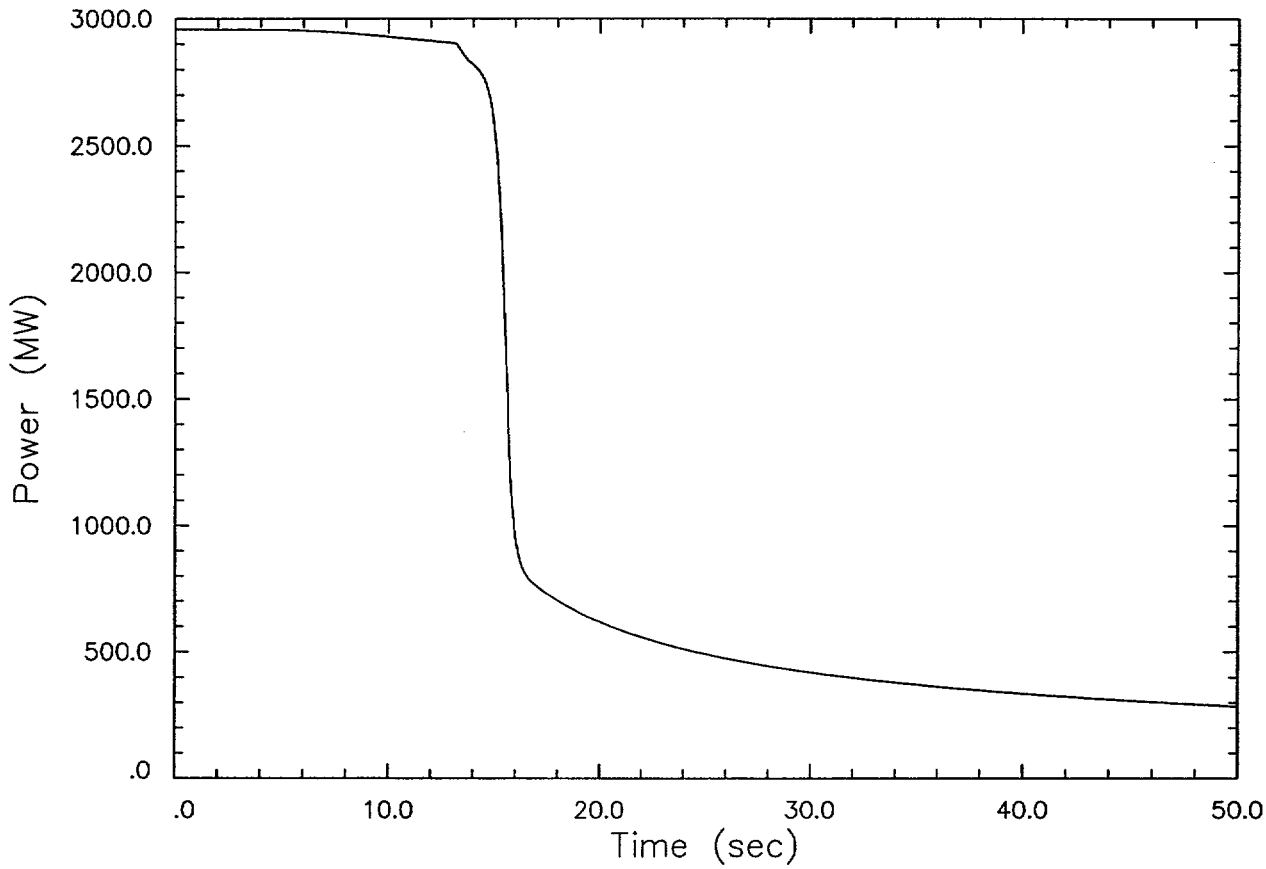

Figure 6.2.8-9 Reactor Power for Turbine Trip MDNBR Case

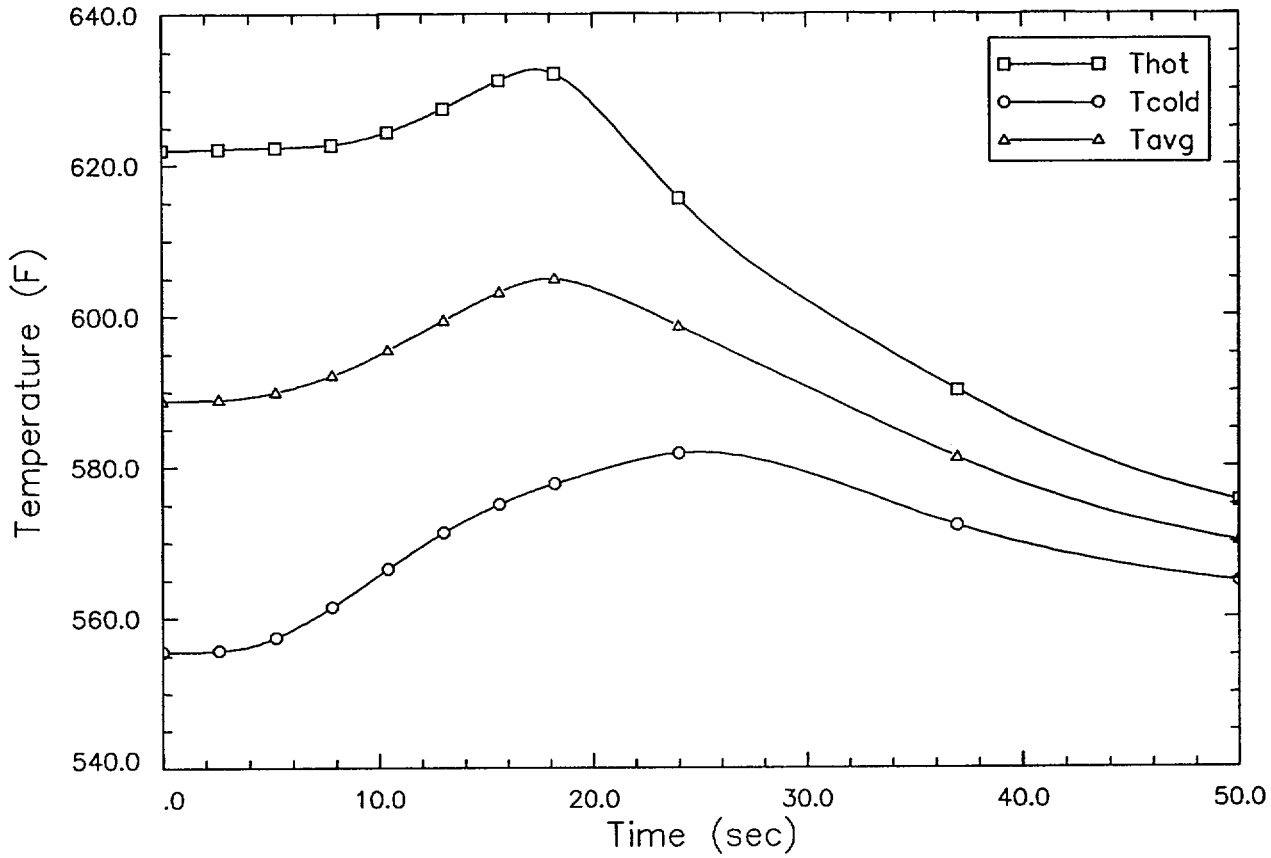

Figure 6.2.8-10 Primary System Temperatures for Turbine Trip MDNBR Case

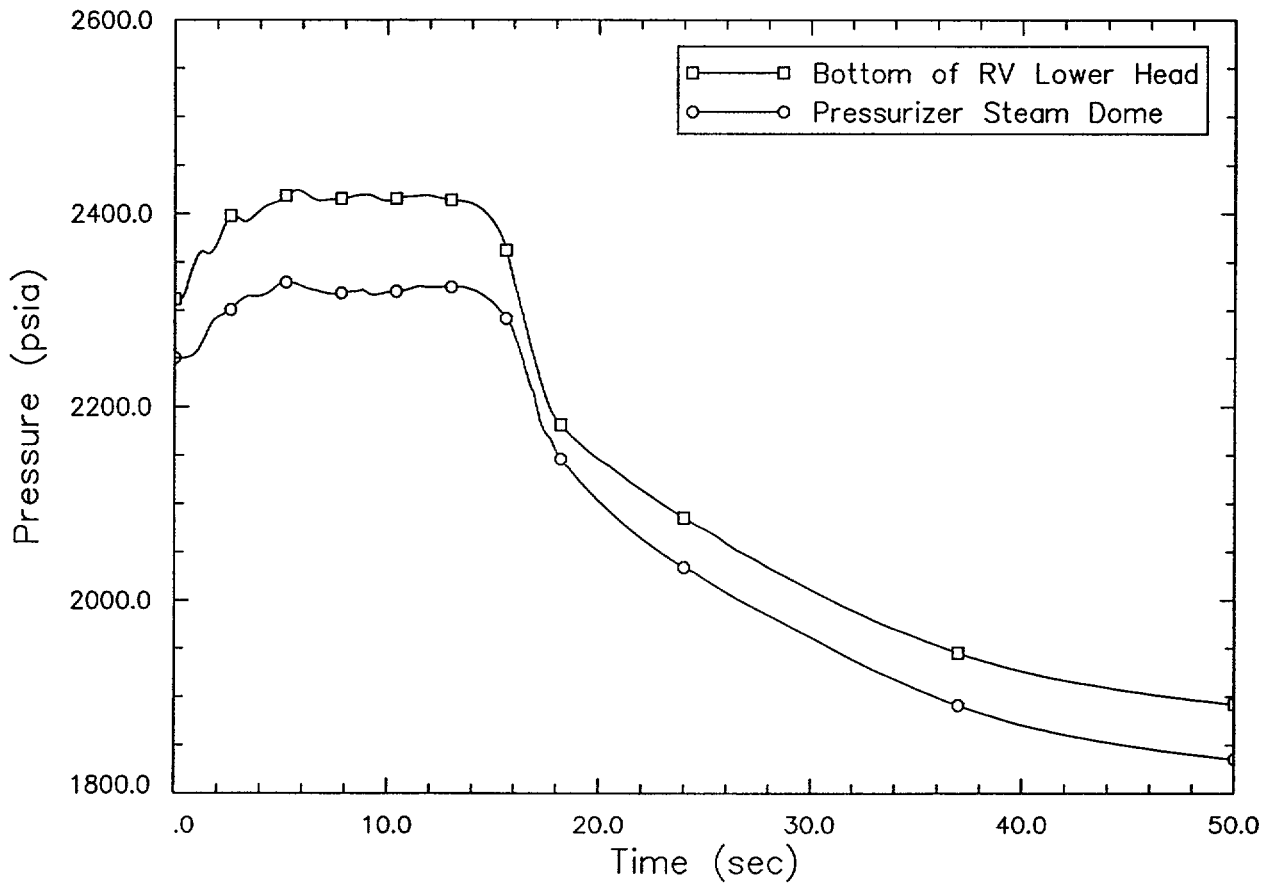

Figure 6.2.8-11 Pressurizer Pressure and Lower Head Pressure for Turbine Trip MDNBR Case

Table 6.2.8-4 Maximum Allowable High Flux Setpoint With Inoperable MSSVs

Maximum Number of Inoperable MSSVs per Steam Generator	Maximum Allowed High Flux Setpoint[a] (% Rated Power)
1	50
2	33
3	16

[a] The high flux setpoints were calculated using the following equation and account for a 9% uncertainty:

$$Hi\Phi = \frac{100}{Q} \times \frac{w_s h_{fg} N}{K}$$

where:

Q	=	nominal NSSS power rating (including RCP heat), MWt
K	=	conversion factor, 947.82 (Btu/sec)/MWt
w_s	=	minimum total steam flow rate capability of the operable MSSVs on any steam generator at the highest MSSV opening pressure including tolerance and accumulation, lbm/sec
h_{fg}	=	heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, Btu/lbm
N	=	number of loops in the plant

6.2.9 Closure of the Main Steam Isolation Valves (FSAR Event 15.2.4)

6.2.9.2 Identification of Causes and Accident Description

Inadvertent closure of the main steam isolation valves (MSIVs) would result in a complete loss of steam flow similar to the turbine trip event analyzed in Section 6.2.8. However, the main steam line isolation valves close more slowly than the turbine stop valves, resulting in a less severe transient.

6.2.9.3 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The inadvertent closure of the MSIVs would result in a complete loss of steam flow with consequent increase in reactor coolant system temperature and pressure. The MSIVs close more slowly than the turbine stop valves, resulting in a slightly slower load rejection than Event 15.2.3. Due to its slower evolution, the inadvertent closure of the MSIVs poses less challenge to SAFDLs and the vessel pressurization limits. The event results are bounded by the analysis of Event 15.2.3. Reactor protection is afforded by the OTΔT, high pressurizer pressure, high pressurizer water level, and steam generator low-low level reactor trips.

Modes 2 through 6: There is no significant heat load on the reactor in Modes 2 through 6, and hence no driving force for a load rejection event. The Mode 2 through 6 events are therefore bounded by the Mode 1 event.

6.2.9.4 Acceptance Criteria

The Closure of the MSIVs event is classified as a Condition II event. The acceptance criteria for this event are the same as those listed for the Turbine Trip event in Section 6.2.8.3.

6.2.9.5 Results

The Closure of the MSIVs (Event 15.2.4) is bounded in Mode 1 by Mode 1 of the Turbine Trip (Event 15.2.3), and need not be further analyzed. The event in Modes 2-6 event is bounded by Mode 1.

6.2.9.6 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.9.7 References

None.

6.2.10 Loss of Condenser Vacuum (FSAR Event 15.2.5)

6.2.10.1 Identification of Causes and Accident Description

Loss of condenser vacuum is one of the events that can cause a turbine trip. Turbine trip initiating events are described in Section 6.2.8. A loss of condenser vacuum would preclude the use of steam dump to the condenser; however, since steam dump is assumed not to be available in the turbine trip analysis, no additional adverse effects would result if the turbine trip were caused by loss of condenser vacuum.

6.2.10.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: Loss of condenser vacuum would result in turbine trip with consequent reactor trip. The simulation of Event 15.2.3 conservatively neglects the direct reactor trip and takes no credit for steam dump to the condenser. This event is therefore bounded by the Event 15.2.3 analysis. Reactor protection is afforded by the OTΔT, high pressurizer pressure, high pressurizer water level, and steam generator low-low level reactor trips.

Modes 2 through 6: There is no significant heat load on the reactor in Modes 2 through 6, and hence no driving force for a load rejection event. The Mode 2 through 6 events are therefore bounded by the Mode 1 event.

6.2.10.3 Acceptance Criteria

The Loss of Condenser Vacuum event is classified as a Condition II event. The acceptance criteria for this event are the same as those listed for the Turbine Trip event in Section 6.2.8.3.

6.2.10.4 Results

The Loss of Condenser Vacuum (Event 15.2.5) is bounded in Mode 1 by Mode 1 of the Turbine Trip (Event 15.2.3), and need not be further analyzed. The event in Modes 2-6 event is bounded by Mode 1.

6.2.10.5 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.10.6 References

None.

6.2.11 Loss of Nonemergency AC Power to the Station Auxiliaries (FSAR Event 15.2.6)

6.2.11.1 Identification of Causes and Accident Description

A Loss of Nonemergency AC Power to the Station Auxiliaries event may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip.

A complete loss of nonemergency AC power may result in the loss of all power to station auxiliaries including the reactor coolant pumps. Loss of main feedwater occurs on turbine trip. The combination of the decrease in primary coolant flow rate, the cessation of main feedwater flow and trip of the turbine generator compounds the event consequences. The decrease of main feedwater to the steam generators decreases the primary -to-secondary system heat transfer rate resulting in heatup of the primary coolant system. The increase in primary coolant temperature results in overpressurization of the RCS. The initial overpressurization is terminated by a scram and subsequent turbine trip initiated by a steam generator low-low level trip. The auxiliary feedwater pumps are also automatically started upon a steam generator low-low water level trip. This event is comprised of two distinct phases. The near-term phase is concerned with the system response that is dominated by the flow coastdown due to the loss of power to the main reactor coolant pumps. The second phase is concerned with the long term event consequences that are dominated by the loss of feedwater flow in conjunction with the loss of flow.

6.2.11.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: In the short term, the event challenges the vessel pressurization criteria. In the longer term, the principal concern is removal of decay heat to avoid liquid discharge from the pressurizer safety relief valves. The limiting event scenario is from full power, which maximizes the pressurization and long term heat removal consequences.

The DNB consequences of this event result from the reduction in primary coolant flow following coastdown of the reactor coolant pumps. The loss of power to the RCCAs, or the reactor coolant pump bus undervoltage and underfrequency trips ensure a direct reactor trip in the loss of non-emergency AC power event. A complete loss of forced reactor coolant flow is addressed in the analysis of Event 15.3.2. The analysis of Event 15.3.2 adequately represents the DNB degradation for the loss of non-emergency AC power.

A degradation of primary-to-secondary heat transfer results from the reduction of primary flow, the possible turbine trip and consequent loss of main feedwater. Primary temperature increases, causing expansion of the primary coolant and an increase in the pressurizer pressure. In the event of a turbine trip and main feedwater isolation, a direct reactor trip results from the turbine trip or from loss of power to the RCCAs, rendering the event less challenging to the vessel pressurization limit than the Event 15.2.3 analysis, in which the direct reactor trips are conservatively neglected.

The long term decay heat removal capacity of the plant is addressed both in this event and in Event 15.2.7. Dryout of the steam generators could lead to a more serious plant condition without other faults occurring independently.

Reactor protection is afforded by the pump bus underfrequency and undervoltage trips, the low flow trip, the high pressurizer pressure trip, and steam generator low-low level reactor trip. Loss of power to the RCCAs and reactor trip on turbine trip also provide protection for this event.

Modes 2 through 6: There is no significant thermal load on the plant in these Modes. Reactor vessel pressurization is therefore not a concern. Natural circulationprovides sufficient cooling, so no significant degradation of the margin to SAFDLs can occur. The Mode 2 through 6 events are therefore bounded by the Mode 1 event.

Based on the above evaluations, the transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The input parameters and biasing for the analysis of this event were consistent with the approved methodology. The single failure assumption was the loss of the turbine-driven AFW pump, with no credit given for one of the two motor-driven AFW pumps.

6.2.11.3 Acceptance Criteria

The Loss of Nonemergency AC Power to the Station Auxiliaries event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

(3) The event should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained.

6.2.11.4 Results

The results of the analysis demonstrate that the event acceptance criteria are met since pressurizer filling is avoided and liquid discharge through the pressurizer relief or safety valves does not occur. Additionally, it is demonstrated that the assumed minimum motor driven auxiliary feedwater pump capacity of 390 gpm is sufficient to prevent steam generator dryout and to accomplish long term decay heat removal.

The sequence of events is given in Table 6.2.11-1. The responses to key system variables are given in Figure 6.2.11-1 to Figure 6.2.11-5.

6.2.11.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.11.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

Table 6.2.11-1 Event Summary for Loss of AC Power

Event	Time (s)
Initiate transient (total loss of MFW)	0.0
Pressurizer PORV opens	12.0
AFW actuation signal on low-low SG level	18.18
Reactor trip on low-low SG level	21.70
Main turbine trip	21.73
RCP trip on loss of offsite power	21.75
MSSVs open	25.0
Maximum pressurizer level	26.5
Maximum post-trip RCS average temperature	28.5
Motor-driven AFW pump starts, blowdown isolated	79.68
Minimum SG liquid inventory	2100.0

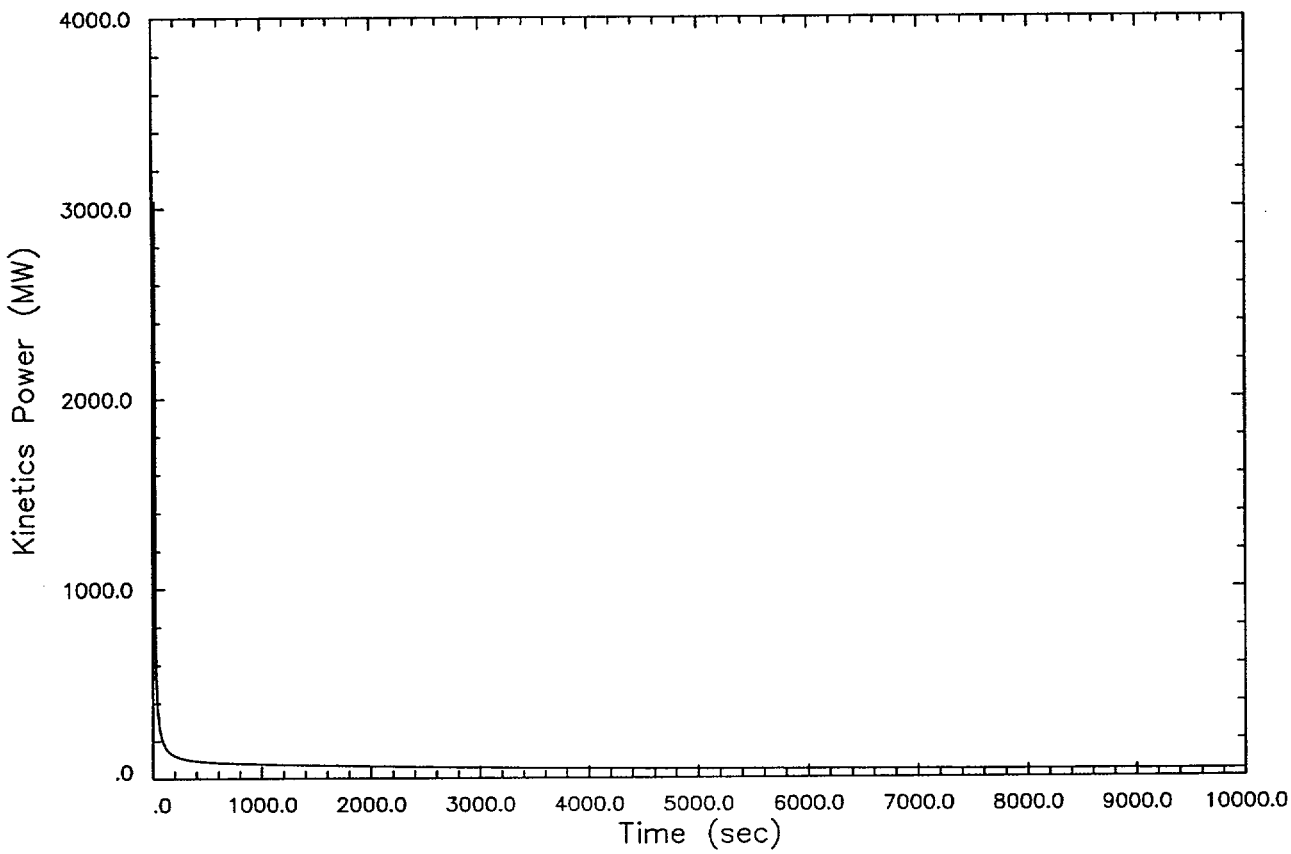

Figure 6.2.11-1 Reactor Power for Loss of Nonemergency AC Power to the Station Auxiliaries

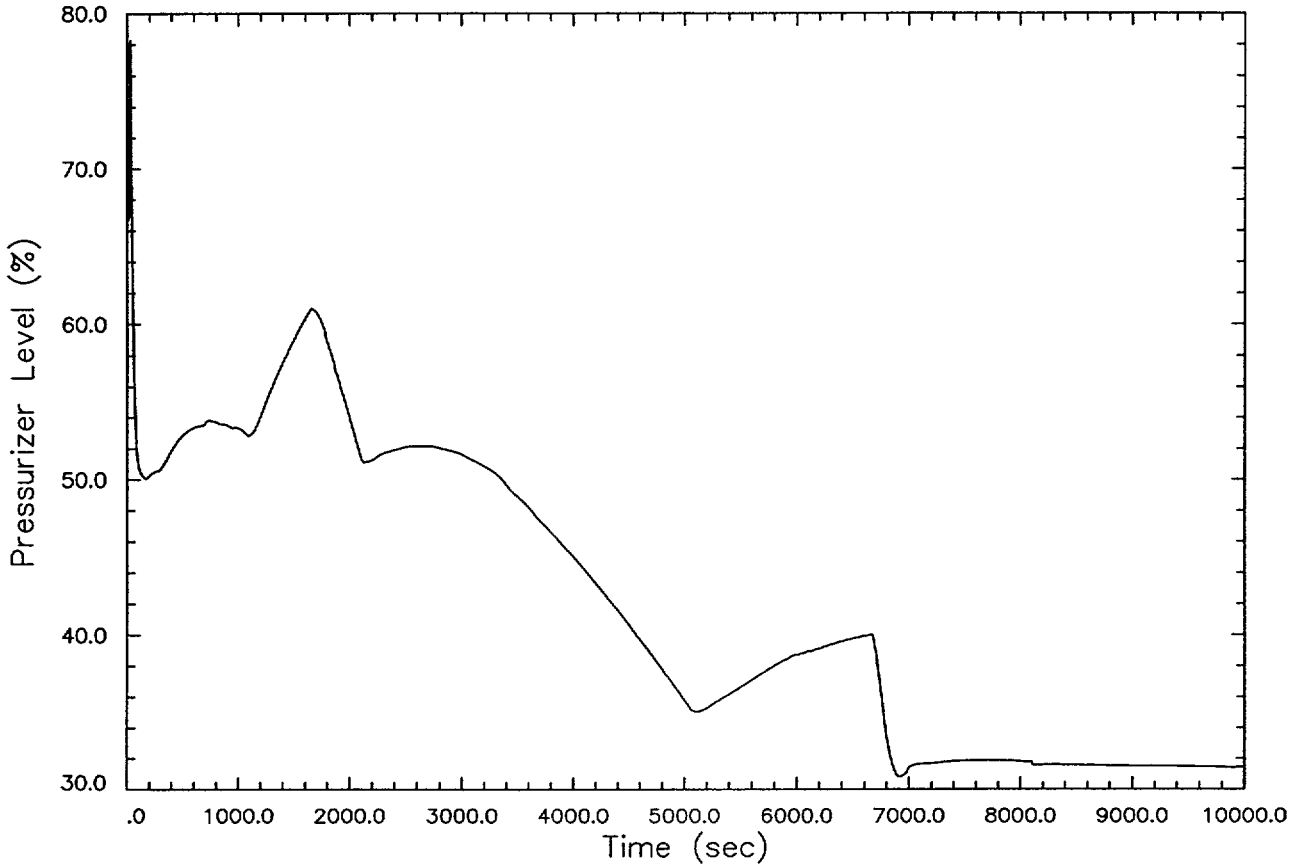

Figure 6.2.11-2 Pressurizer Level for Loss of Nonemergency AC Power to the Station Auxiliaries

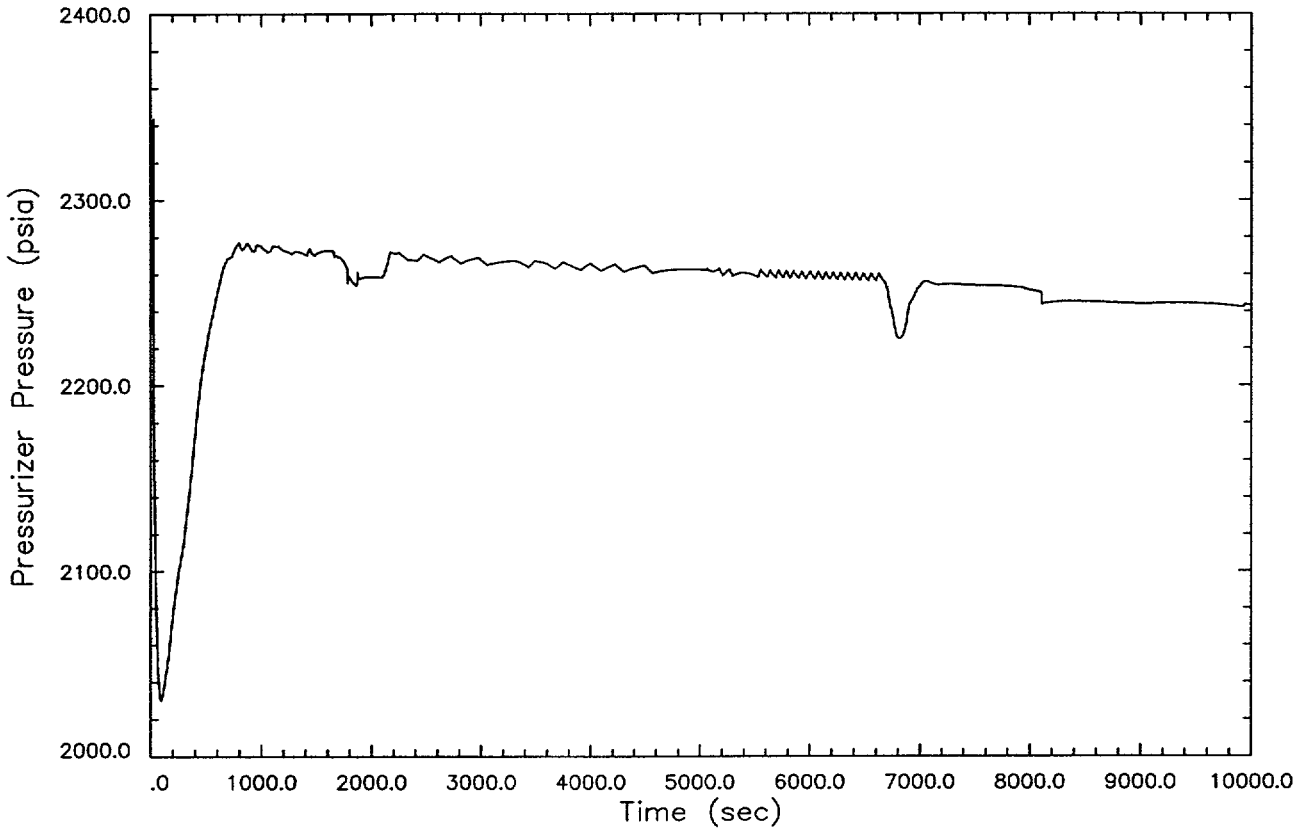

Figure 6.2.11-3 Pressurizer Pressure for Loss of Nonemergency AC Power to the Station Auxiliaries

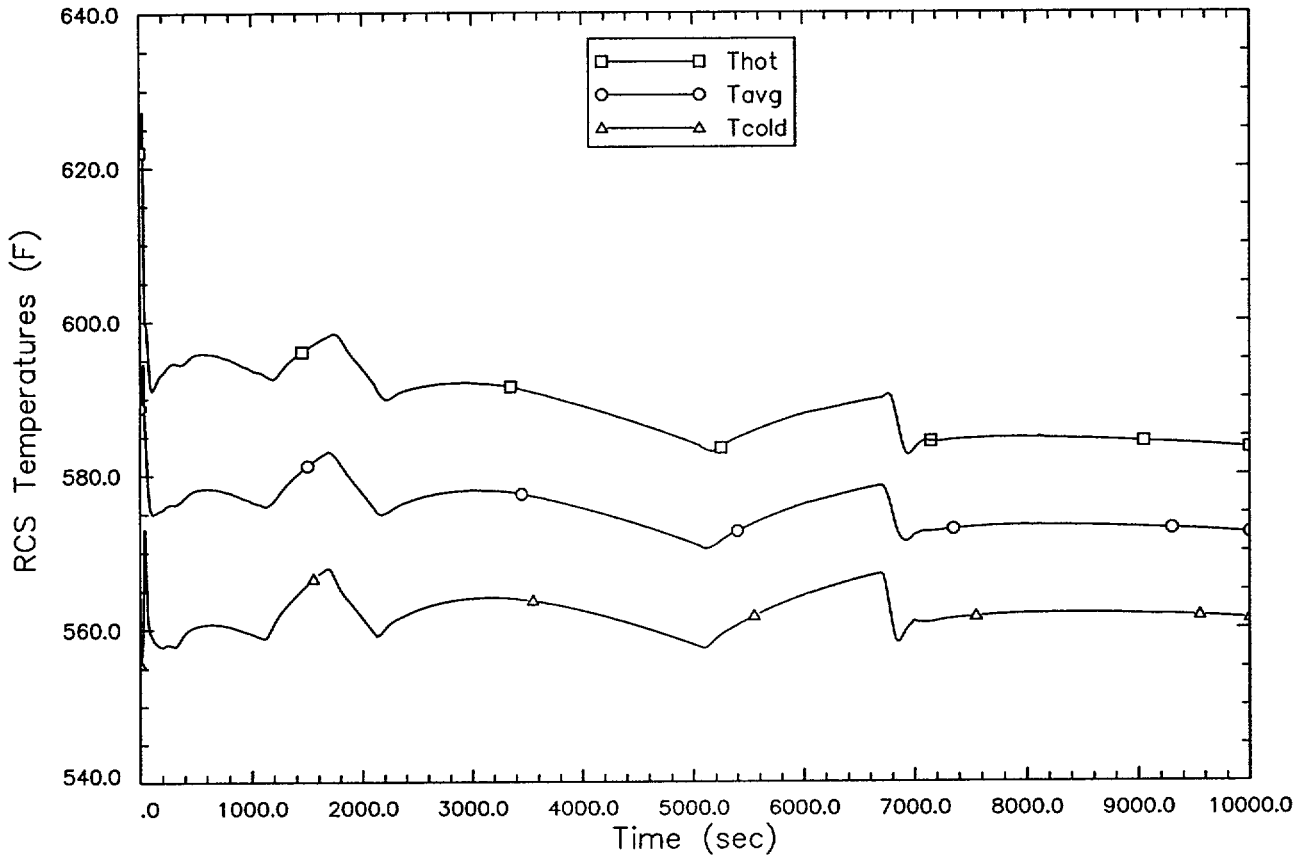

Figure 6.2.11-4 Primary System Temperatures for Loss of Nonemergency AC Power to the Station Auxiliaries

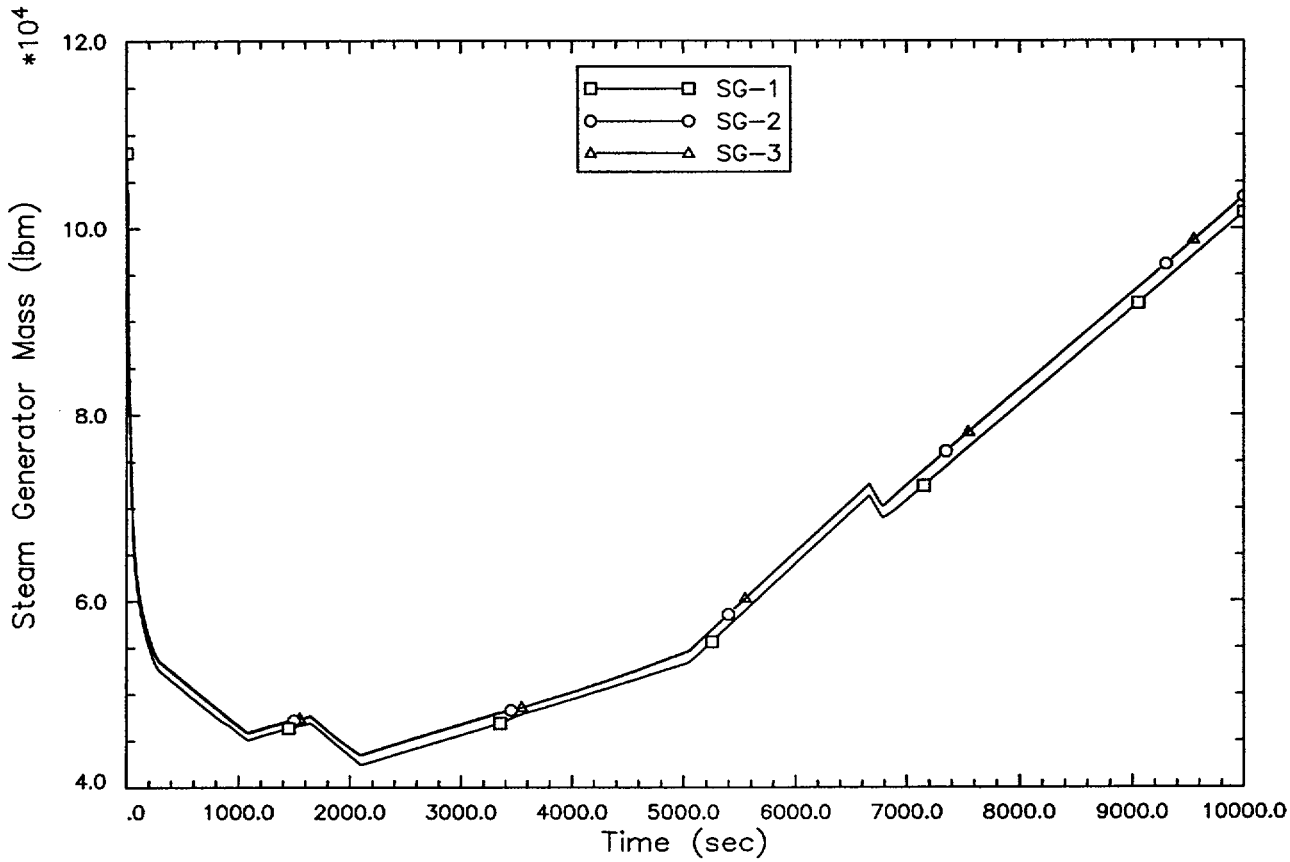

Figure 6.2.11-5 Steam Generator Secondary Mass Inventory for Loss of Nonemergency AC Power to the Station Auxiliaries

6.2.12 Loss of Normal Feedwater Flow (FSAR Event 15.2.7)

6.2.12.1 Identification of Causes and Accident Description

A Loss of Normal Feedwater Flow transient is initiated by a trip of the main feedwater pumps or a malfunction in the feedwater control valves, which results in a total loss of all main feedwater flow to the steam generators. The loss of main feedwater flow decreases the amount of subcooling in the secondary-side downcomer which diminishes the primary -to-secondary system heat transfer and leads to an increase in the primary system coolant temperature. The increase in primary coolant temperature and the commensurate fluid expansion into the pressurizer result in overpressurization of the RCS.

The opening of the secondary-side safety valves acts to remove decay heat load and to mitigate the primary system heatup. The long-term cooling of the primary system is governed by the heat removal capacity of the auxiliary feedwater flow. Two motor-driven auxiliary feedwater pumps are automatically started on the following signals: low-low level in any steam generator, trip of all main feedwater pumps, a safety injection signal, or loss of offsite power. One turbine-drive auxiliary feedwater pump is started on any of the following signals: low-low level in any two steam generators or loss of offsite power.

6.2.12.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: A Loss of Normal Feedwater Flow event is only credible for rated power and power operating conditions. The worst consequences occur when the feedwater is lost during rated power operation since more stored heat is contained in the fuel than in other modes of operation. This event will be analyzed for Mode 1 conditions with offsite power available. The loss of normal feedwater event assuming a coincident loss of offsite power is discussed in Section 6.2.11, as the Loss of Nonemergency AC Power event.

For the initial RCS heatup phase of the transient, the primary system pressurization criterion is challenged. Another concern in this event is pressurizer overfill, causing liquid discharge through the pressurizer relief or safety valves, which could result in a more serious plant condition. The DNB SAFDL is not challenged, since a reactor scram occurs before the steam generator heat transfer capability becomes significantly degraded. After the reactor trip system is activated, the core power is drastically reduced alleviating any challenge to DNB. The Turbine Trip event (Event 15.2.3) bounds the short term DNB consequences and the RCS pressurization consequences (as long as the pressurizer does not fill solid) of a loss of normal feedwater transient.

For the long term phase of the transient, the slow RCS heatup is analyzed for possible steam generator dryout. The parameters influencing the severity of the long term phase of the transient include: (1) decay heat generation, (2) secondary safety/relief valve settings, (3) reactor coolant pump operation, (4) auxiliary feedwater flow rate, and (5) steam generator secondary side mass at the time of reactor trip.

Reactor protection is provided by the steam generator low-low water level trip, the high pressurizer pressure trip, and the reactor trip on steam-feed flow mismatch coincident with low steam generator level.

Modes 2 through 6: Bounded by Mode 1, per discussion above.

Based on the above evaluations, the transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.12.3 Acceptance Criteria

The Loss of Normal Feedwater Flow event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur. In addition, fission product decay heat must be transferred from the reactor coolant system following a loss of normal feedwater flow (i.e., steam generator dryout is avoided).

(3) The event should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained.

6.2.12.4 Results

The results of the analysis demonstrate that the event acceptance criteria are met since pressurizer filling is avoided and liquid discharge through the pressurizer relief or safety valves does not occur. Additionally, it is demonstrated that the assumed minimum motor driven auxiliary feedwater pump capacity of 390 gpm is sufficient to prevent steam generator dryout and to accomplish long term decay heat removal.

The sequence of events is given in Table 6.2.12-1. The responses to key system variables are given in Figure 6.2.12-1 to Figure 6.2.12-5.

6.2.12.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.12.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

Table 6.2.12-1 Event Summary for Loss of Normal Feedwater

Event	Time (s)
Initiate transient (total loss of MFW)	0.0
Pressurizer PORV opens	12.0
AFW actuation signal on low-low SG level	18.18
Reactor trip on low-low SG level	21.70
Main turbine trip	21.73
MSSVs open	25.0
Maximum pressurizer level	26.0
Maximum post-trip RCS average temperature	26.5
Pressurizer PORV closes	27.5
Motor-driven AFW pump starts, blowdown isolated	79.68
Minimum SG liquid inventory	2480.0

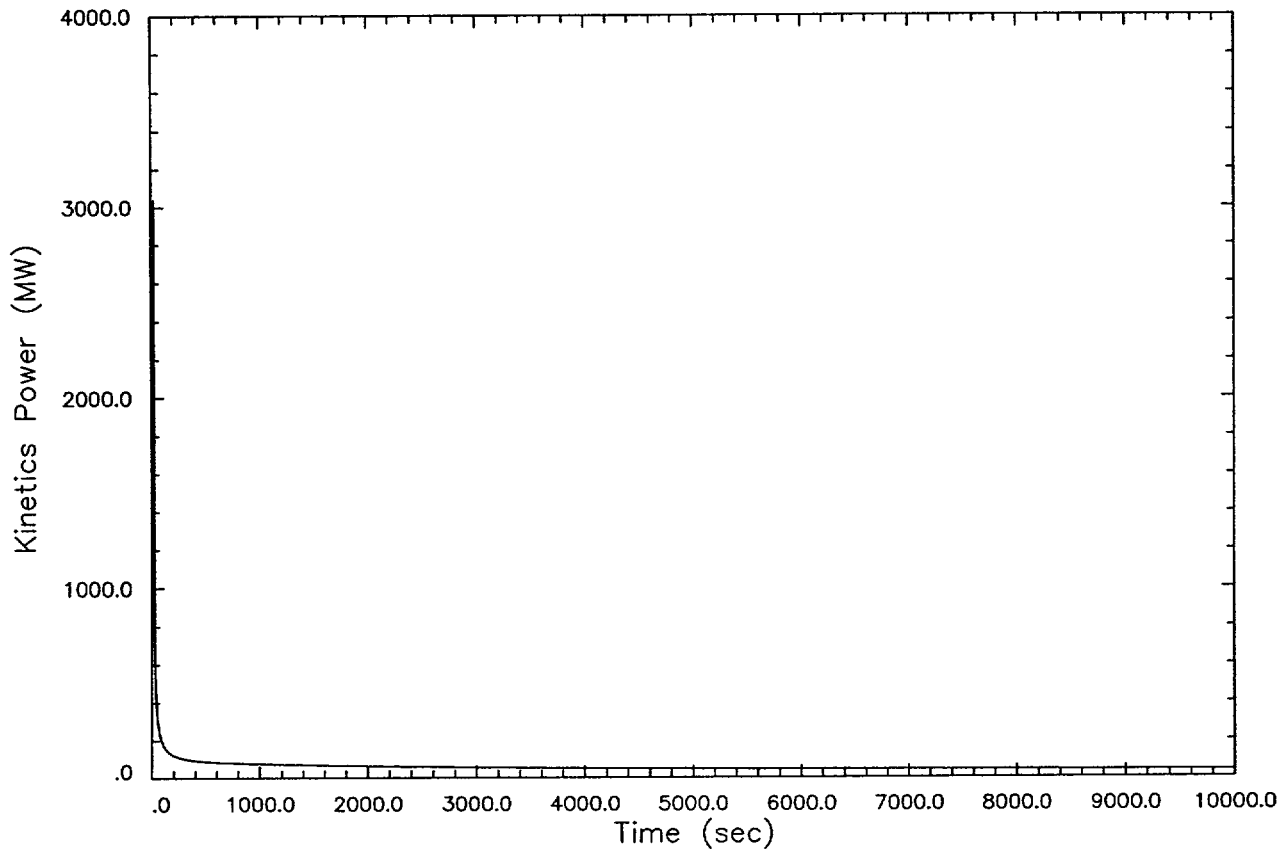

Figure 6.2.12-1 Reactor Power for Loss of Normal Feedwater

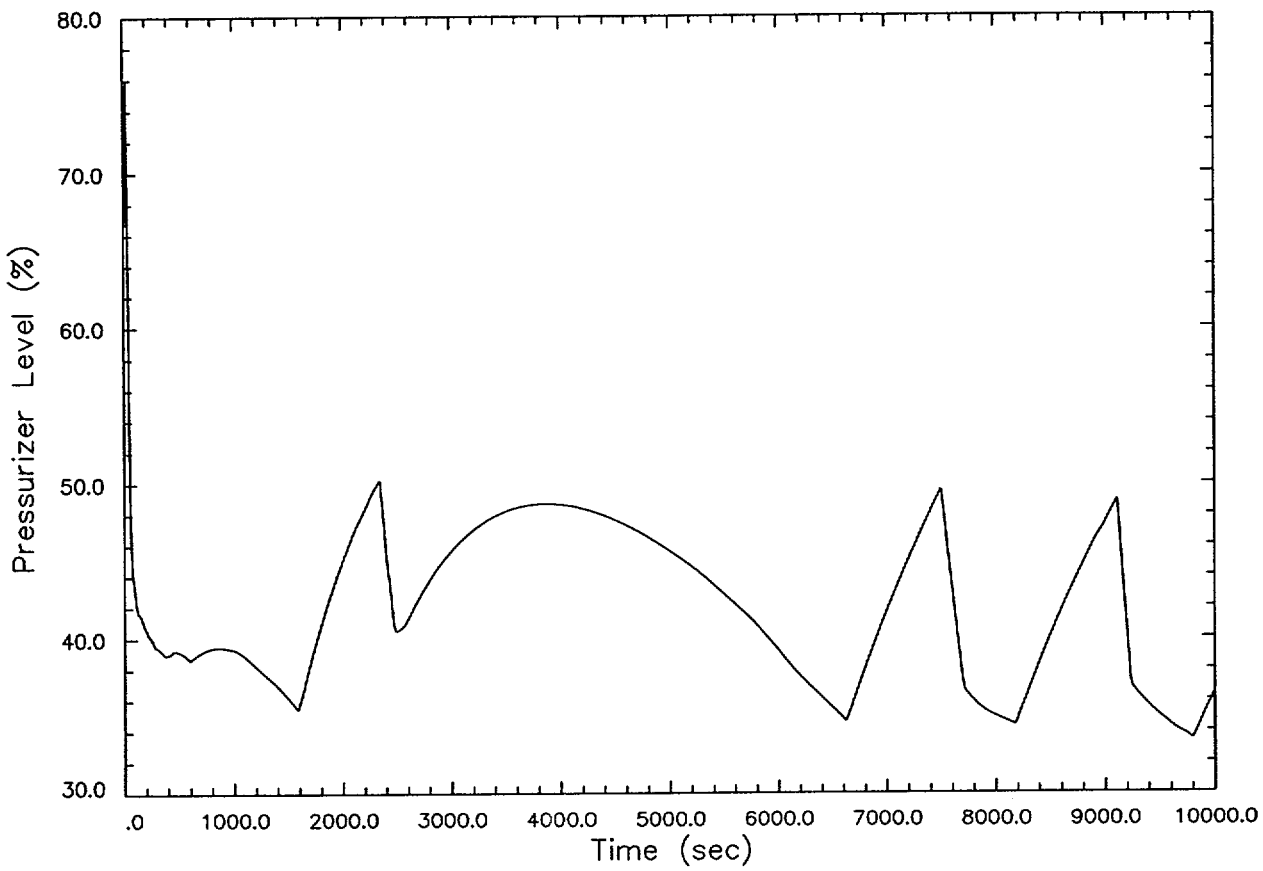

Figure 6.2.12-2 Pressurizer Level for Loss of Normal Feedwater

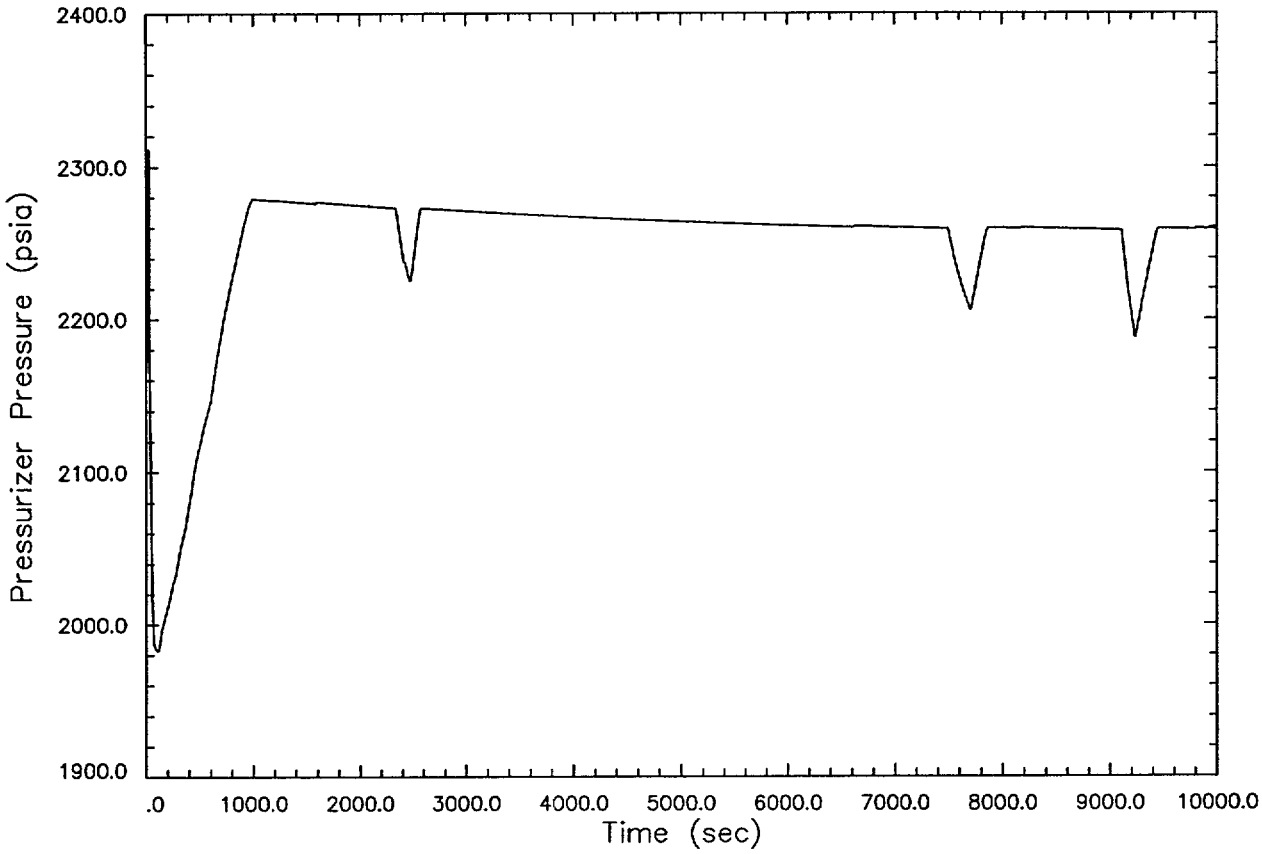

Figure 6.2.12-3 Pressurizer Pressure for Loss of Normal Feedwater

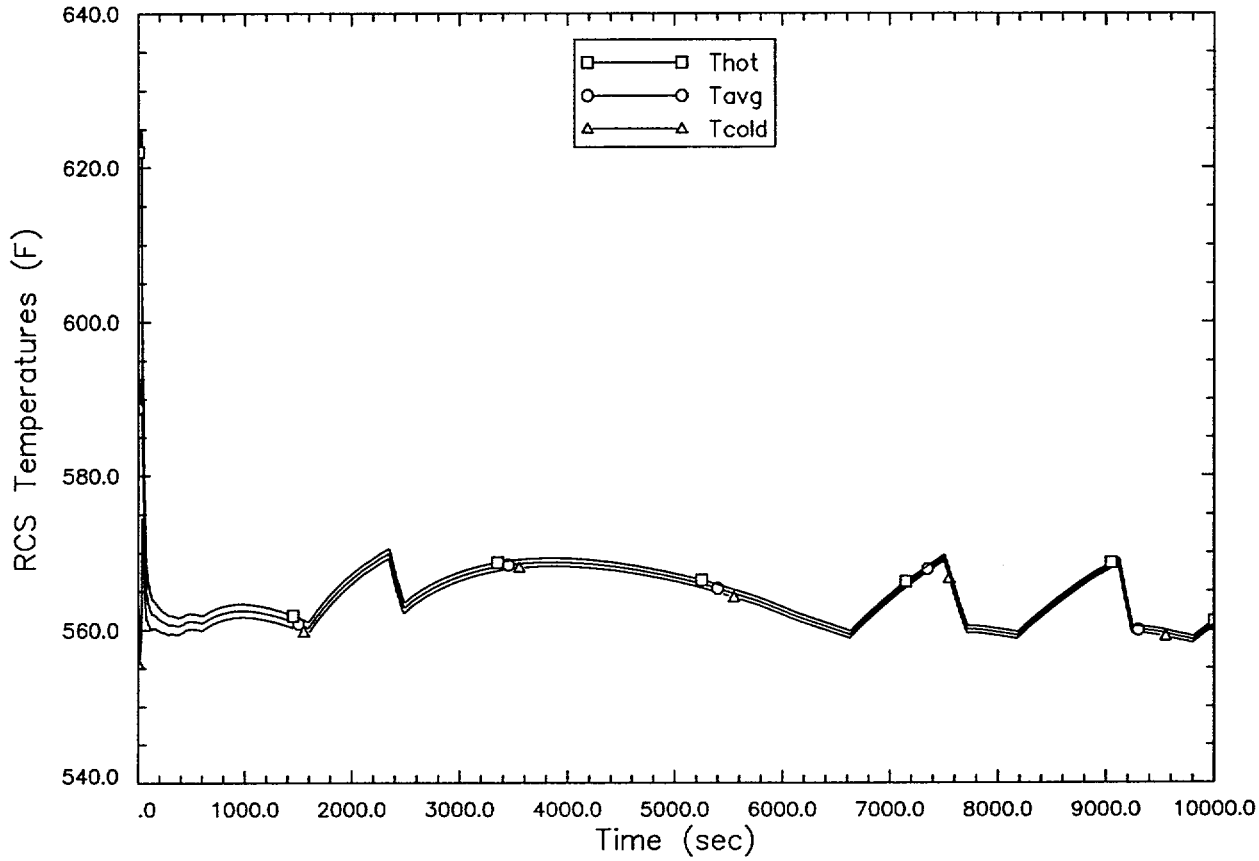

Figure 6.2.12-4 Primary System Temperatures for Loss of Normal Feedwater

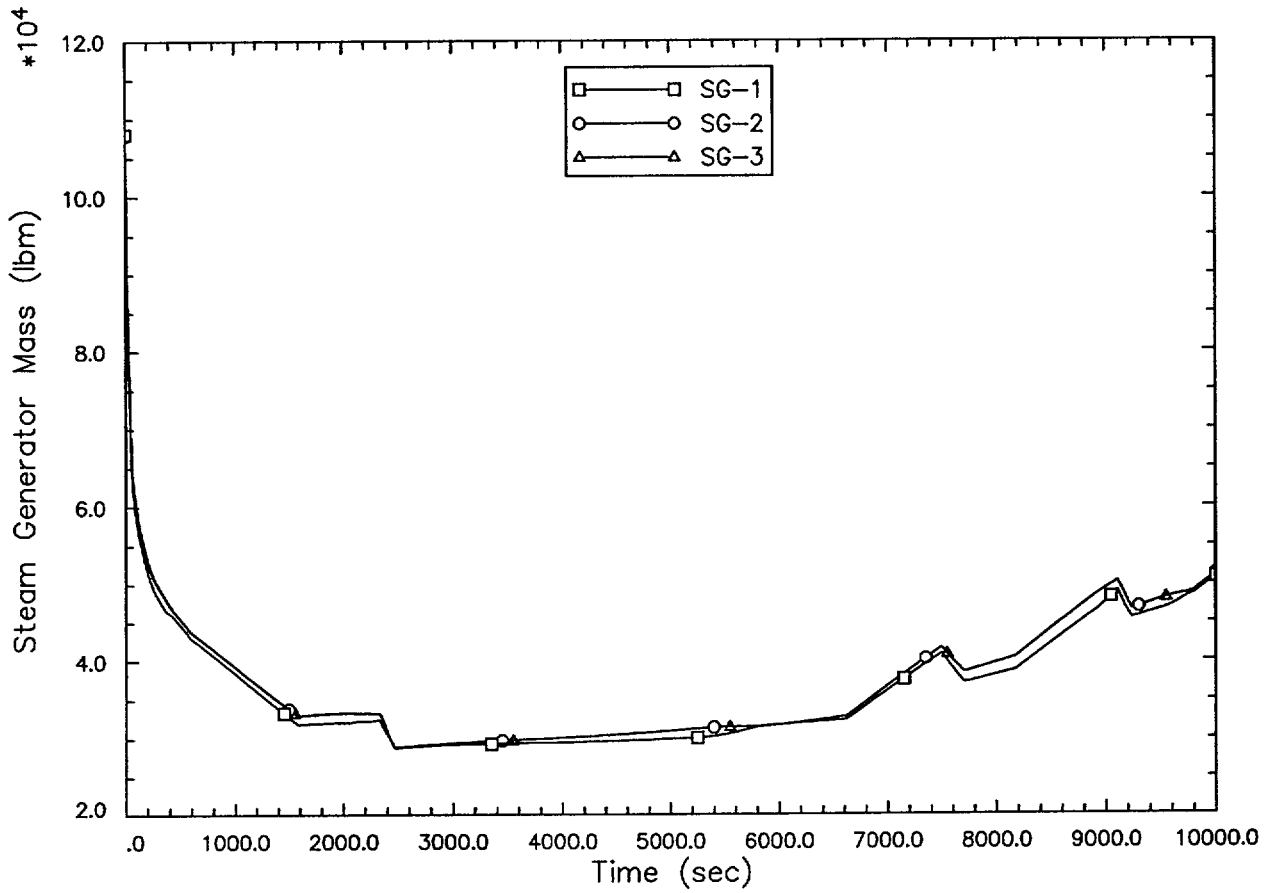

Figure 6.2.12-5 Steam Generator Secondary Mass Inventory for Loss of Normal Feedwater

6.2.13 Feedwater System Pipe Breaks Inside and Outside Containment (FSAR Event 15.2.8)

6.2.13.1 Identification of Causes and Accident Description

The Feedwater System Pipe Break event is initiated by a postulated double-ended rupture in the main feedwater piping. This is sufficient to prevent the addition of main feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in the feedline between the steam generator and the main feedline check valve, then fluid may be discharged from the steam generators out through the postulated break. A break upstream of the check valve would only result in a loss of feedwater flow to the affected steam generator. There would be little fluid discharge from the steam generator during the valve closing time interval and the transient would proceed similar to a loss of normal feedwater.

The main feedwater is injected into the upper regions of the steam generator via a feedwater ring. The auxiliary feedwater is injected into the downcomer at an elevation above the top of the U-tubes. This ensures that auxiliary feedwater can be injected into the steam generators at any later time during the transient. Depending on the size of the break and the plant operating conditions, the primary system may respond to the postulated break as a cooldown event or as a heatup event. The cooldown event occurs due to excess energy removal capability via flow out the break. The heatup of the reactor coolant system results from a decrease in the energy removal capability of the secondary system due to the combination of a reduction in the addition of subcooled feedwater to the steam generators and a loss of shell-side inventory in the steam generators by discharge through the break.

6.2.13.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The parameters controlling the cooldown phase of this event are the same as those controlling the Main Steam Line Break event (Event 15.1.5) described in Section 6.2.5. The cooldown consequences of this event are bounded by the Main Steam Line Break event, where blowdown of high energy steam minimizes the additional thermal load on the reactor.

The heatup phase of the event is analyzed with conservative assumptions intended to maximize the over pressurization effects. This overpressurization event is most limiting when initiated from full power conditions, as the fuel stored heat is maximized. This event has two potential times for overpressurization to occur; the first peak response time period prior to reactor scram, and the second peak response time period prior to steam generator refill and establishment of adequate decay heat removal. The severity of the second peak consequences is significantly affected by the minimum heat removal capacity of the auxiliary feedwater system and by the assumptions regarding loss of offsite power and reactor coolant pump flow coastdown. Two cases are analyzed, one with and one without loss of offsite power.

Reactor protection is provided by the steam generator low-low water level trip, the high pressurizer pressure trip, and the OTΔT trip.

Modes 2 through 6: The heatup phase of the event is most limiting in Mode 1, because there the stored energy and decay heat removal are maximized. The cooldown branch is bounded by Event 15.1.5, where extraction of high energy steam places a greater thermal load on the reactor.

Based on the above evaluations, various cases are run to determine the limiting scenarios with respect to offsite power availability. A limiting scenario is determined for both offsite power available and loss of offsite power conditions. Additional cases are run to determine the limiting time for loss of offsite power to occur.

In addition, a sensitivity study was run to verify that the possible case crediting operator manual action to trip off the reactor coolant pumps is bounded by the above cases. Plant operating procedures call for manual trip of the reactor coolant pumps on loss of subcooling margin. The reactor coolant pump trip criteria indicates that if both of the following occur, then stop all reac tor coolant pumps:

- Safety Injection flow greater than 200 gpm

- Reactor coolant system pressure less than 1360 psig

(This case is included as one of the LOOP timing sensitivity studies.)

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.13.3 Acceptance Criteria

The Feedwater System Pipe Breaks Inside and Outside Containment event is classified as a Condition IV event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110% of design pressures for low probability events and below 120% of design pressures for very low probability events such as double-ended guillotine breaks.

(2) The potential for core damage is evaluated on the basis that it is acceptable if the minimum DNBR remains above the 95/95 DNBR limit. If DNBR falls below the 95/95 DNBR limit, fuel failure must be assumed for all rods that do not meet this criteria unless it can be shown, based on an acceptable fuel damage model, which includes the potential adverse effects of hydraulic instabilities, that few er failures occur. Any fuel damage calculated to occur must be of sufficiently limited extent

that the core will remain in place and intact with no loss of core cooling capability.

(3) Any radioactivity release must be such that the calculated doses at the site boundary are a small fraction of the 10 CFR Part 100 guidelines. "Small fraction" means 10 percent or less of the 10 CFR Part 100 exposure guideline values, i.e., 2.5 rem for whole body and 30 rem for thyroid doses.

(4) The integrity of the reactor coolant pumps should be maintained such that loss of AC power and containment isolation will not result in seal damage.

(5) The auxiliary feedwater system must be safety grade and automatically initiated when required.

(6) Tripping of the reactor coolant pumps should be consistent with the resolution to TMI Action Plan Item II.K.3.5.

6.2.13.4 Results

The results of the analysis demonstrate that the event acceptance criteria are met since over pressurization of the primary and secondary systems is avoided. In addition, the analysis indicates that long term decay heat removal occurs with the assumed loss of turbine-driven auxiliary feedwater pump.

Feedwater Line Break with Offsite Power Available

The limiting case with offsite power available includes BOC kinetics, maximum HHSI, and failure of the turbine-driven auxiliary feedwater (AFW) pump. The sequence of events for the Feedwater Line Break case with offsite power is given in Table 6.2.13-1. The responses to key system variables are given in Figure 6.2.13-1 to Figure 6.2.13-10.

Operator actions are credited in this transient simulation with terminating HHSI and cycling AFW flow, both beginning at 30 minutes.

Feedwater Line Break with Loss of Offsite Power

Based on sensitivity calculation results, this transient conservatively assumes that the reactor coolant pumps trip off 15 minutes after the time of the subcooling margin trip. The limiting case with loss of offsite power includes EOC kinetics, maximum HHSI, and failure of the turbine-driven AFW pump.

The sequence of events for the Feedwater Line Break with Loss of Offsite Power case is given in Table 6.2.13-2. The responses to key system variables are given in Figure 6.2.13-11 to Figure 6.2.13-20.

Operator actions are credited to terminate HHSI and cycle AFW flow, both beginning at 30 minutes.

6.2.13.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.13.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

Table 6.2.13-1 Event Summary for Feedwater Line Break with Offsite Power Available

Event	Time (s)
Initiate transient (MFW line break)	0.0
Low-low SG level signal	4.8
Reactor trip on low-low SG level signal	8.3
Turbine trip on reactor trip	8.8
SIS on low pressurizer pressure	54
AFW flow begins to intact SGs	66
Pressurizer drained	67
HHSI flow initiated	83
MSIS on low steam pressure; intact SGs isolated from blowdown	148
Pressurizer began to refill	192
AFW isolation on high steam pressure differential plus delay	197
Pressurizer SRVs begin cycling	492
Maximum reactor vessel pressure	492
Pressurizer water solid	704
Operator control of HHSI and AFW assumed	1800
HHSI terminated by operator due to high pressurizer liquid level	1802
First intact SG MSSV opened	3688
Maximum SG pressure	3691

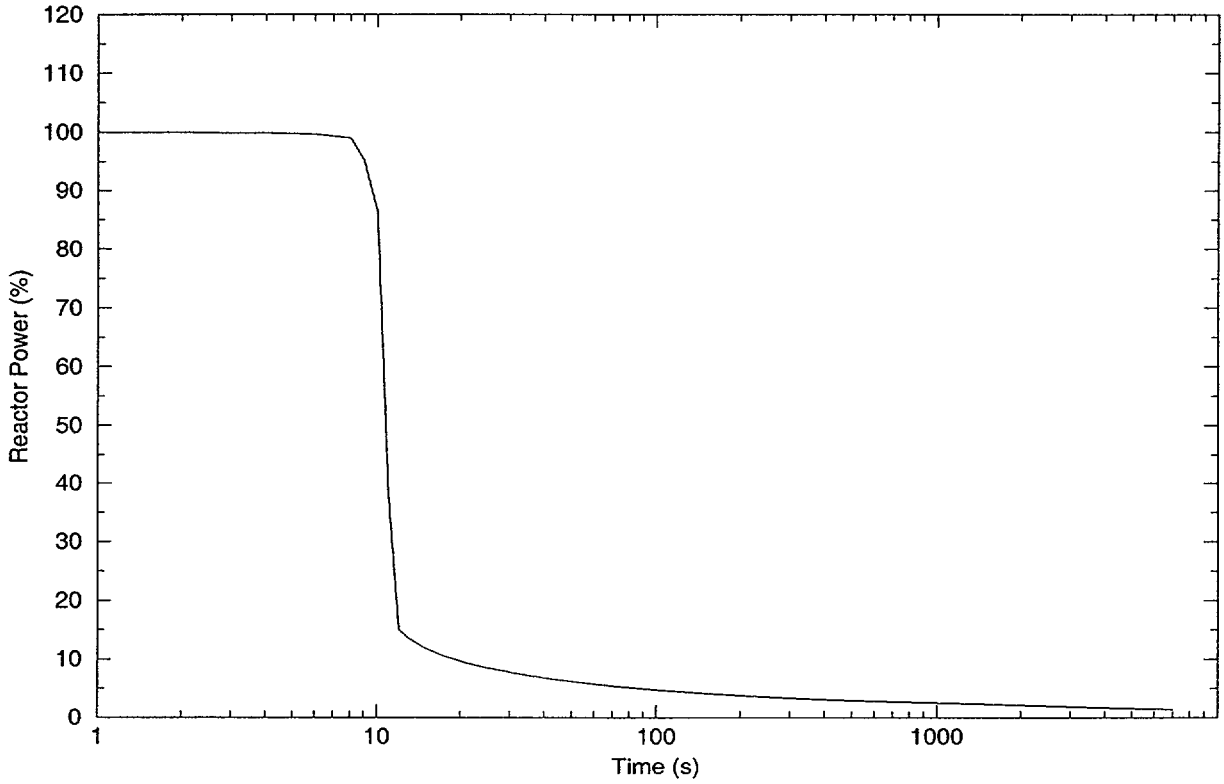

Figure 6.2.13-1 Reactor Power for Feedwater System Pipe Break with Offsite Power

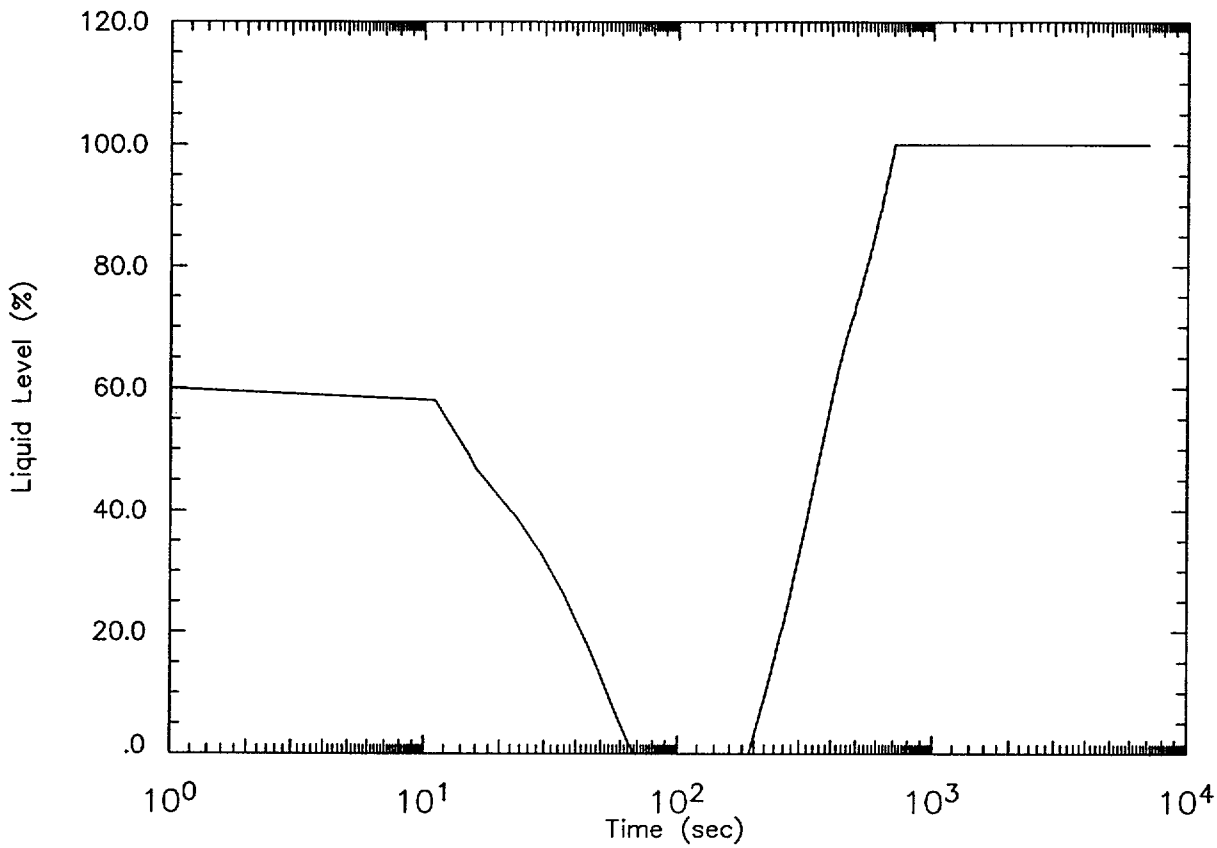

Figure 6.2.13-2 Pressurizer Level for Feedwater System Pipe Break with Offsite Power

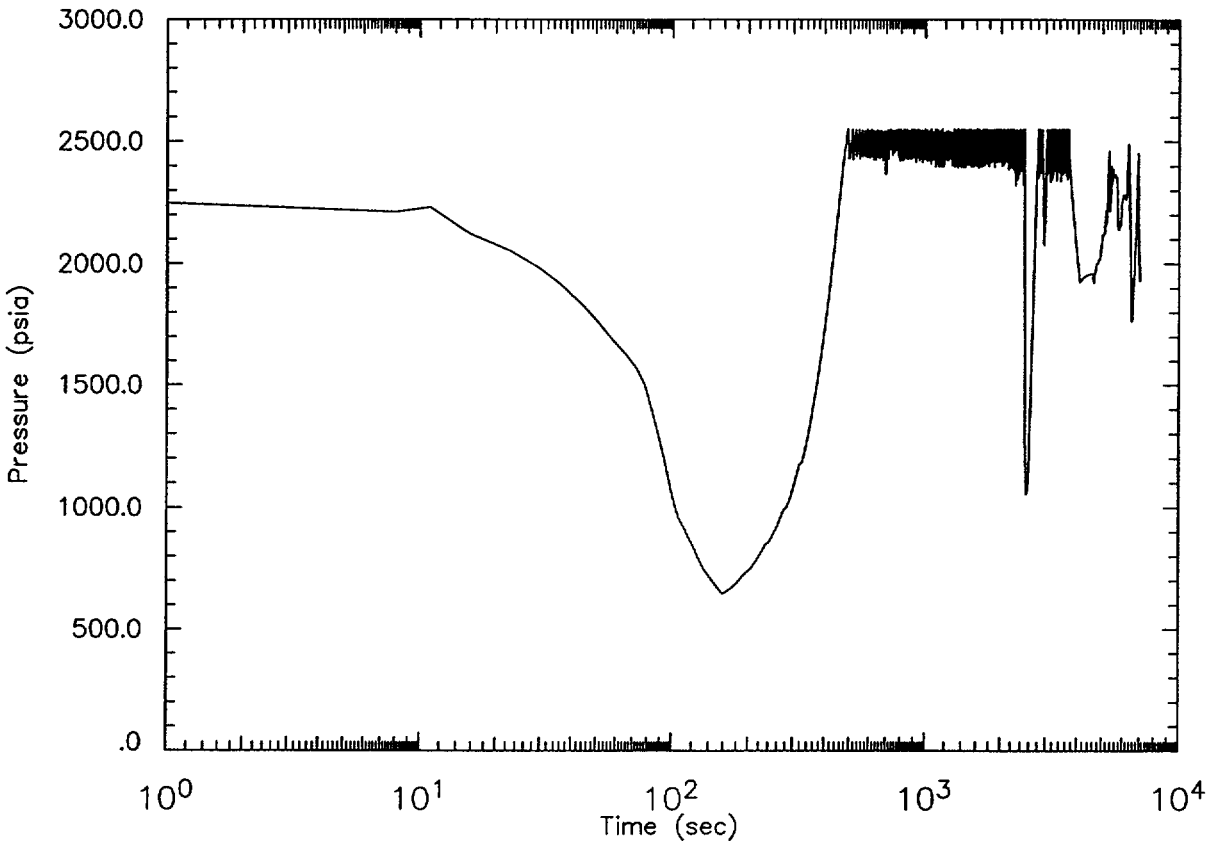

Figure 6.2.13-3 Pressurizer Pressure for Feedwater System Pipe Break with Offsite Power

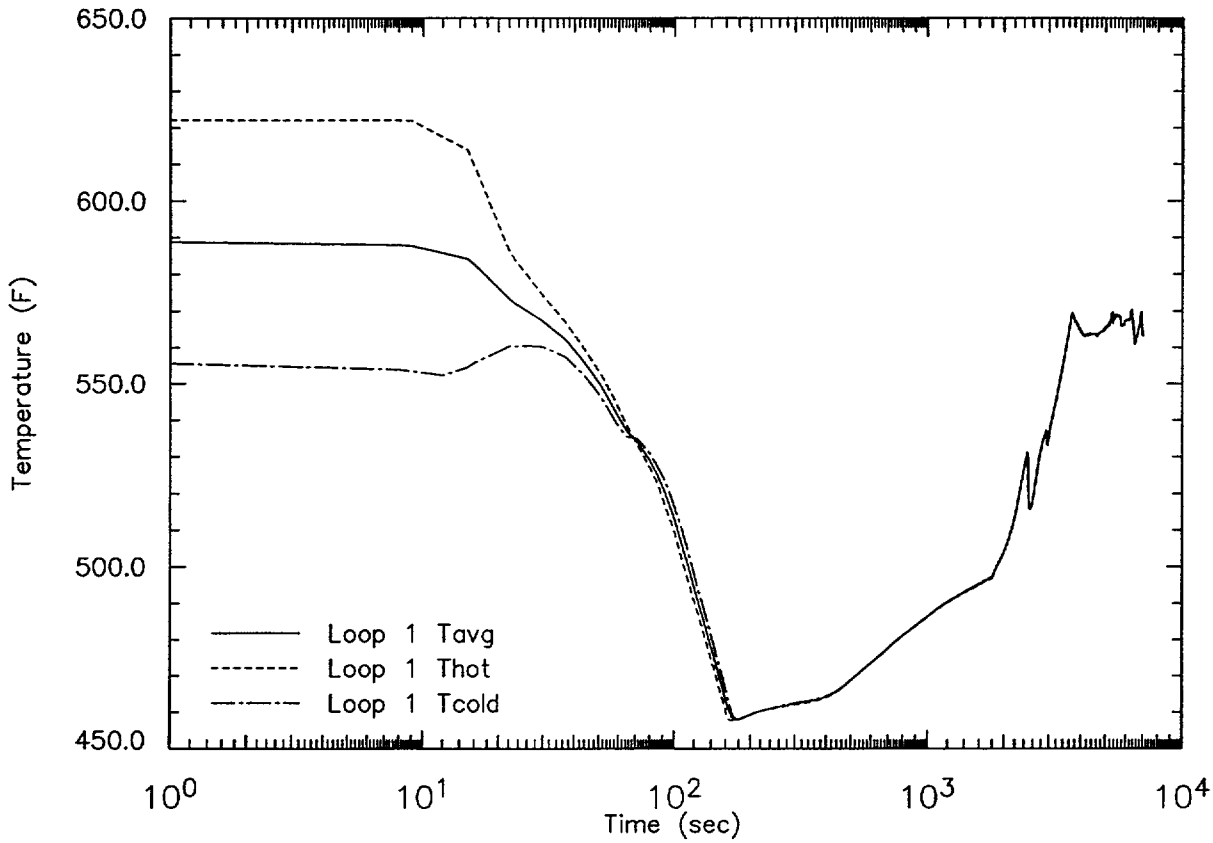

Figure 6.2.13-4 Loop 1 Primary System Temperatures for Feedwater System Pipe Break with Offsite Power

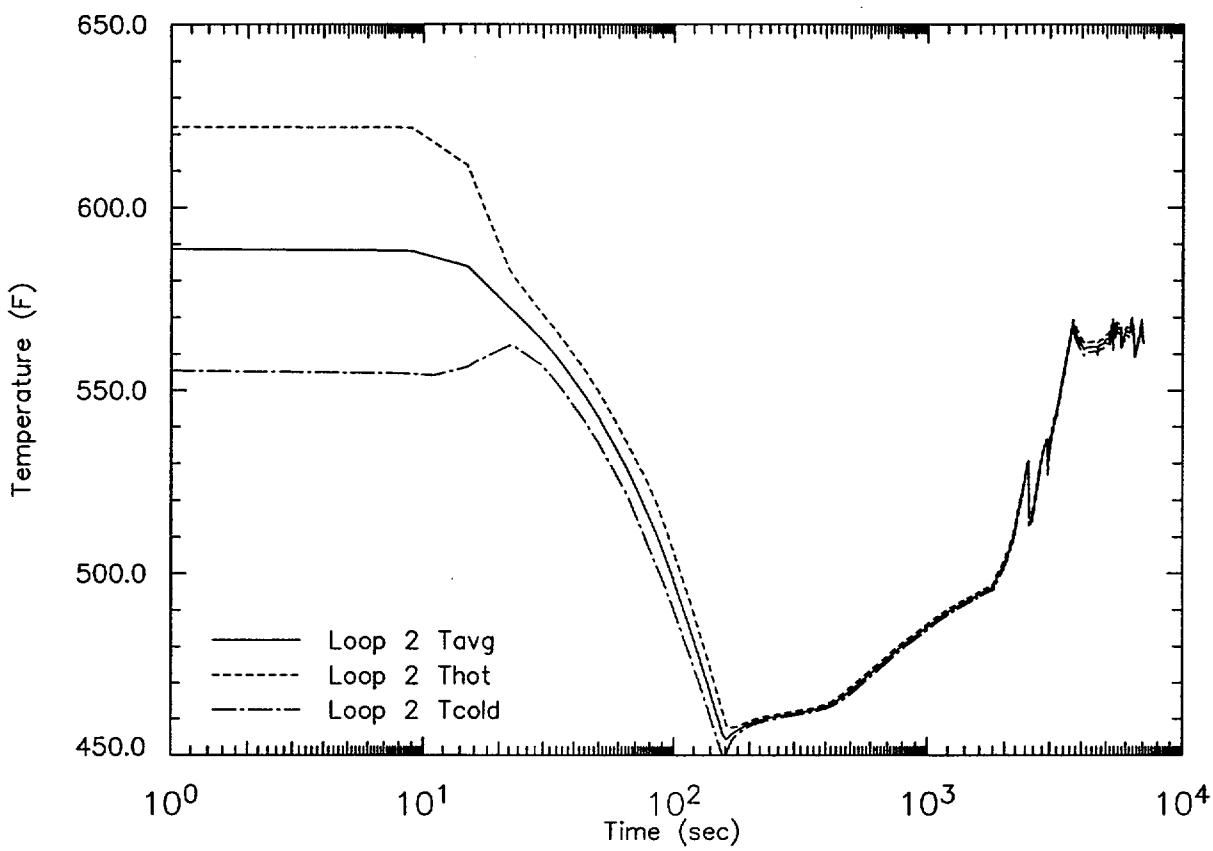

Figure 6.2.13-5 Loop 2 Primary System Temperatures for Feedwater System Pipe Break with Offsite Power

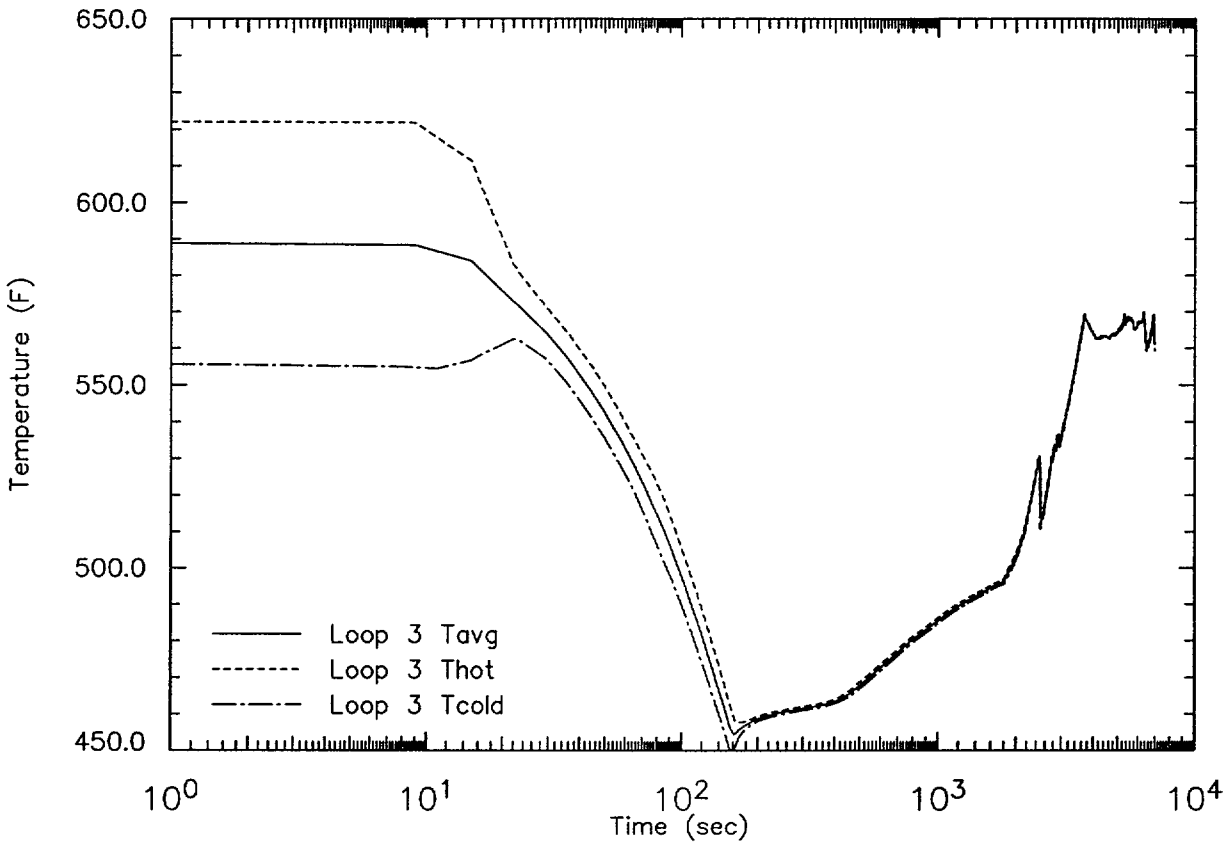

Figure 6.2.13-6 Loop 3 Primary System Temperatures for Feedwater System Pipe Break with Offsite Power

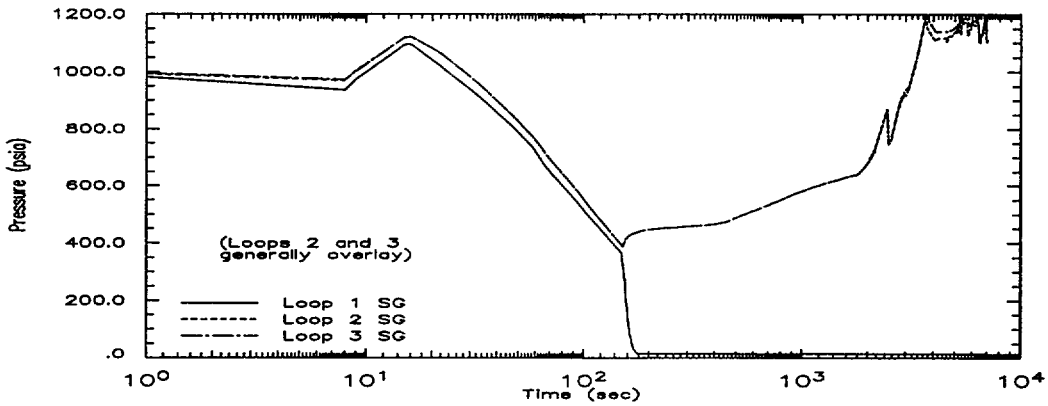

Figure 6.2.13-7 Steam Generator Pressure for Feedwater System Pipe Break with Offsite Power

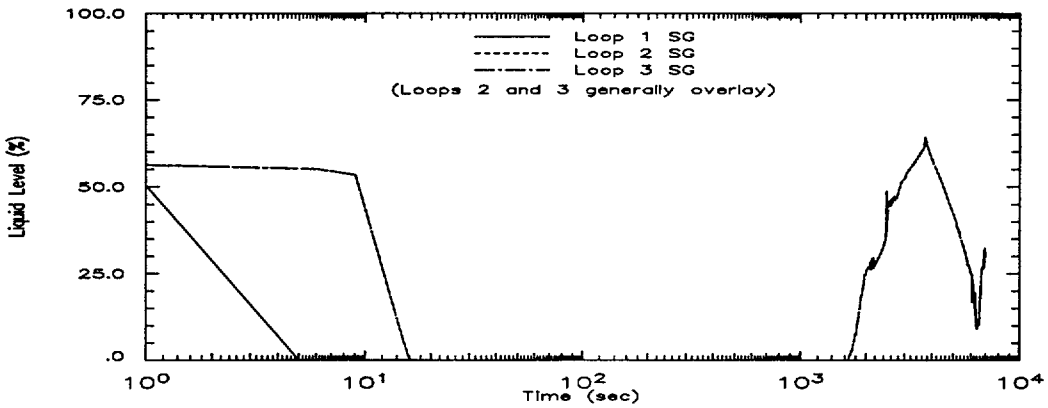

Figure 6.2.13-8 Steam Generator Downcomer Collapsed Level for Feedwater System Pipe Break with Offsite Power

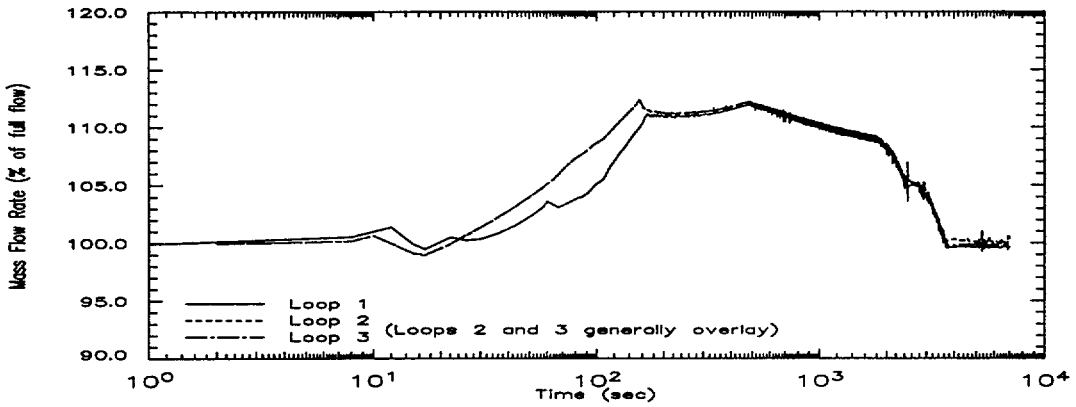

Figure 6.2.13.9 Reactor Coolant System Flow for Feedwater System Pipe Break with Offsite Power

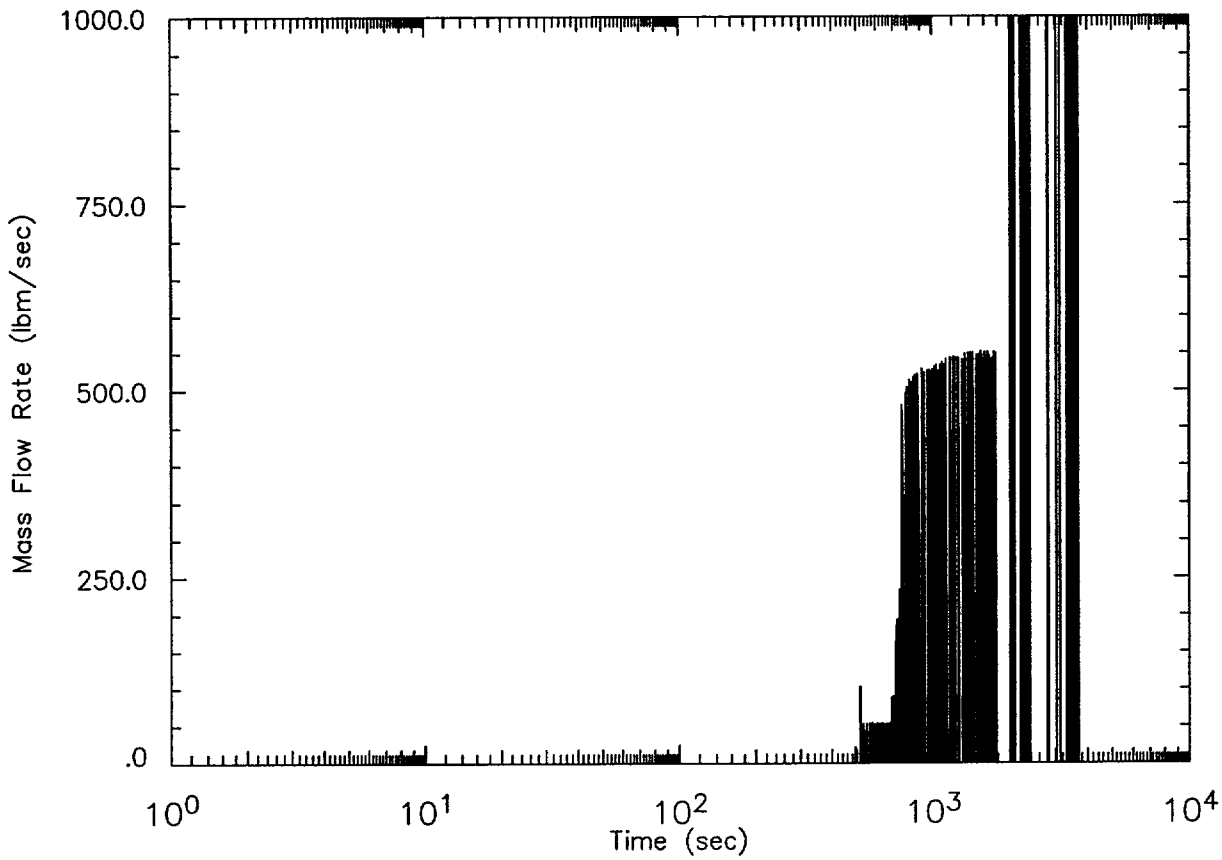

Figure 6.2.13-10 Pressurizer Relief Flow for Feedwater System Pipe Break with Offsite Power

Table 6.2.13-2 Event Summary for Feedwater Line Break with Loss of Offsite Power

Event	Time (s)
Initiate transient (MFW line break)	0.0
Low-low SG level signal	4.8
Reactor trip on low-low SG level signal	8.3
Turbine trip on reactor trip	8.8
SIS on low pressurizer pressure	57
AFW flow begins to intact SGs	66
Pressurizer drained	71
HHSI flow initiated	85
Pressurizer began to refill	139
MSIV closed; affected SG isolated	194
AFW isolation on high steam pressure differential plus delay	243
Pressurizer SRVs begin cycling	330
Maximum reactor vessel pressure	397
Pressurizer water solid	764
Loss of offsite power (RCPs trip)	992
Operator control of HHSI and AFW assumed	1800
HHSI terminated by operator due to high pressurizer liquid level	1800
First intact SG MSSV opened	3945
Maximum SG pressure	3948

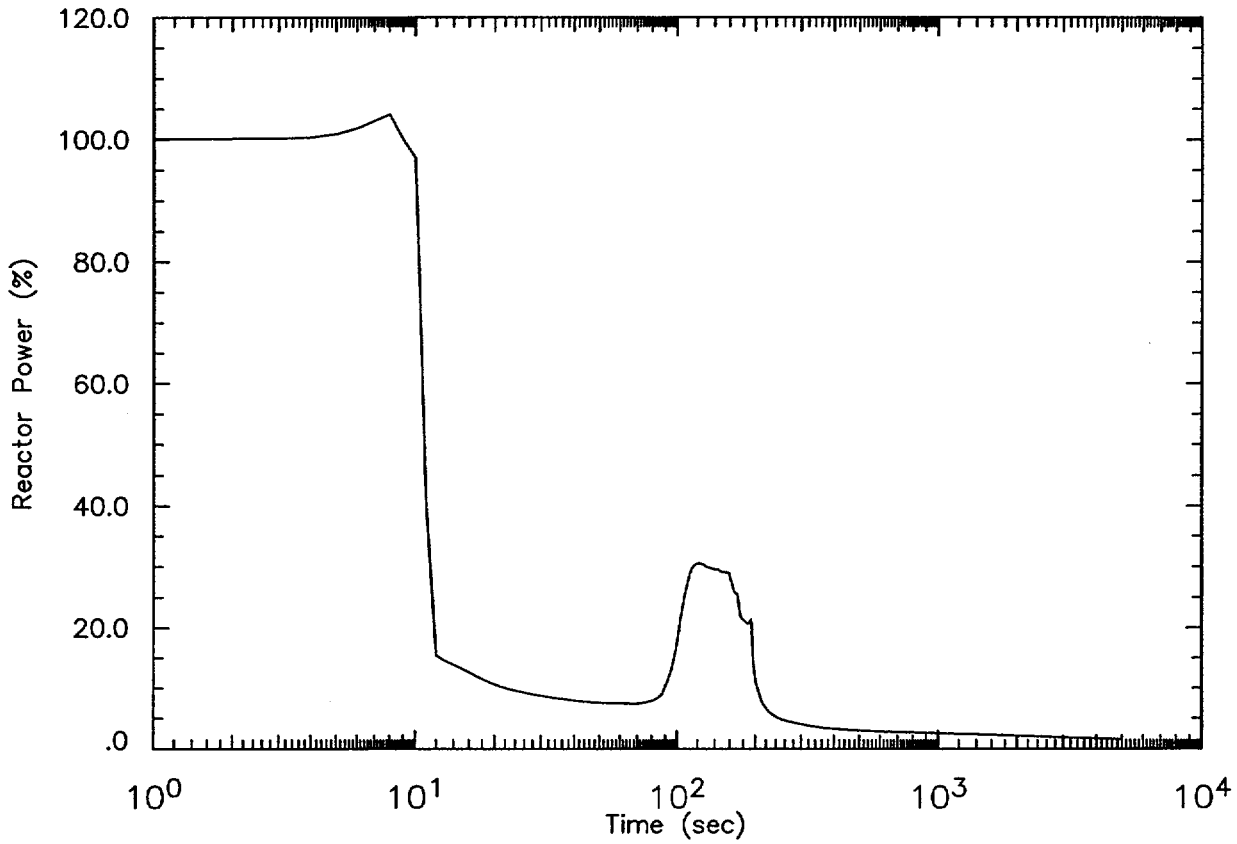

Figure 6.2.13-11 Reactor Power for Feedwater System Pipe Break with Loss of Offsite Power

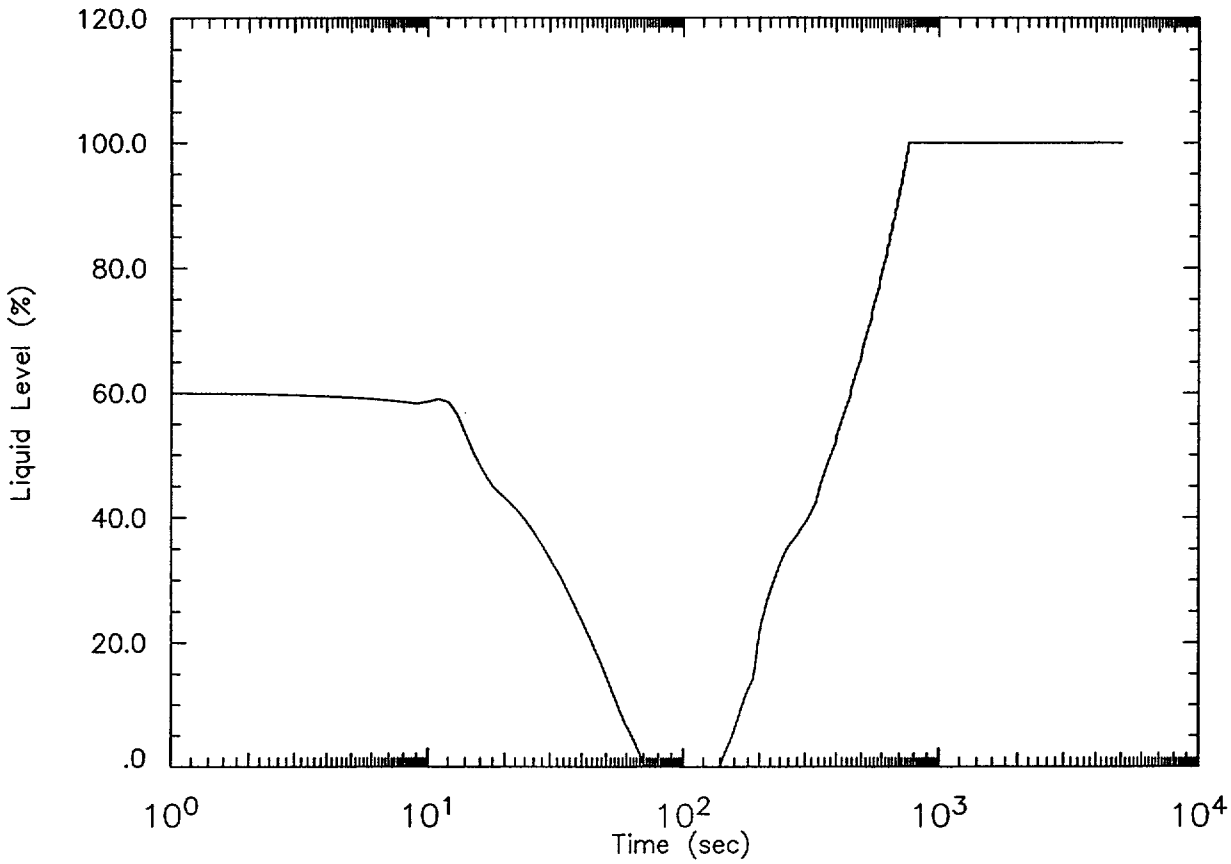

Figure 6.2.13-12 Pressurizer Level for Feedwater System Pipe Break with Loss of Offsite Power

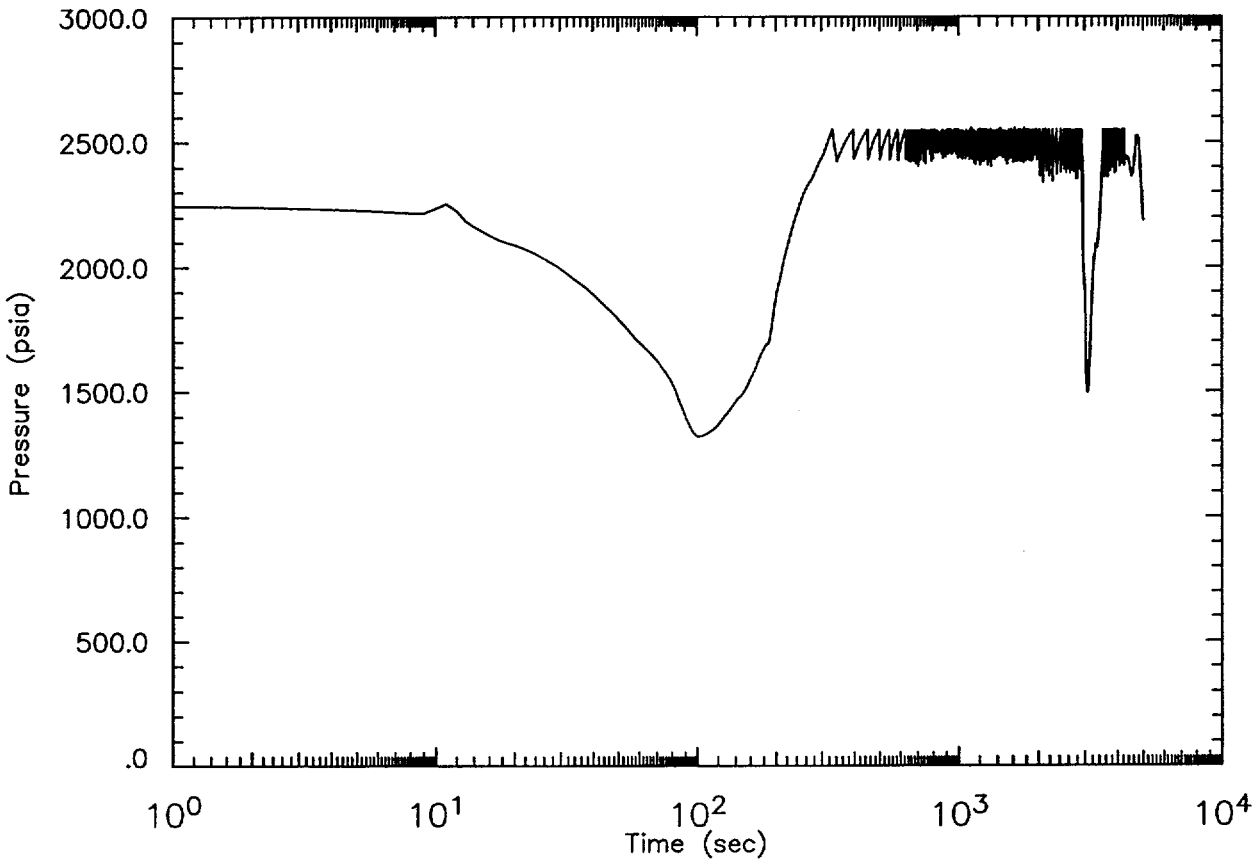

Figure 6.2.13-13 Pressurizer Pressure for Feedwater System Pipe Break with Loss of Offsite Power

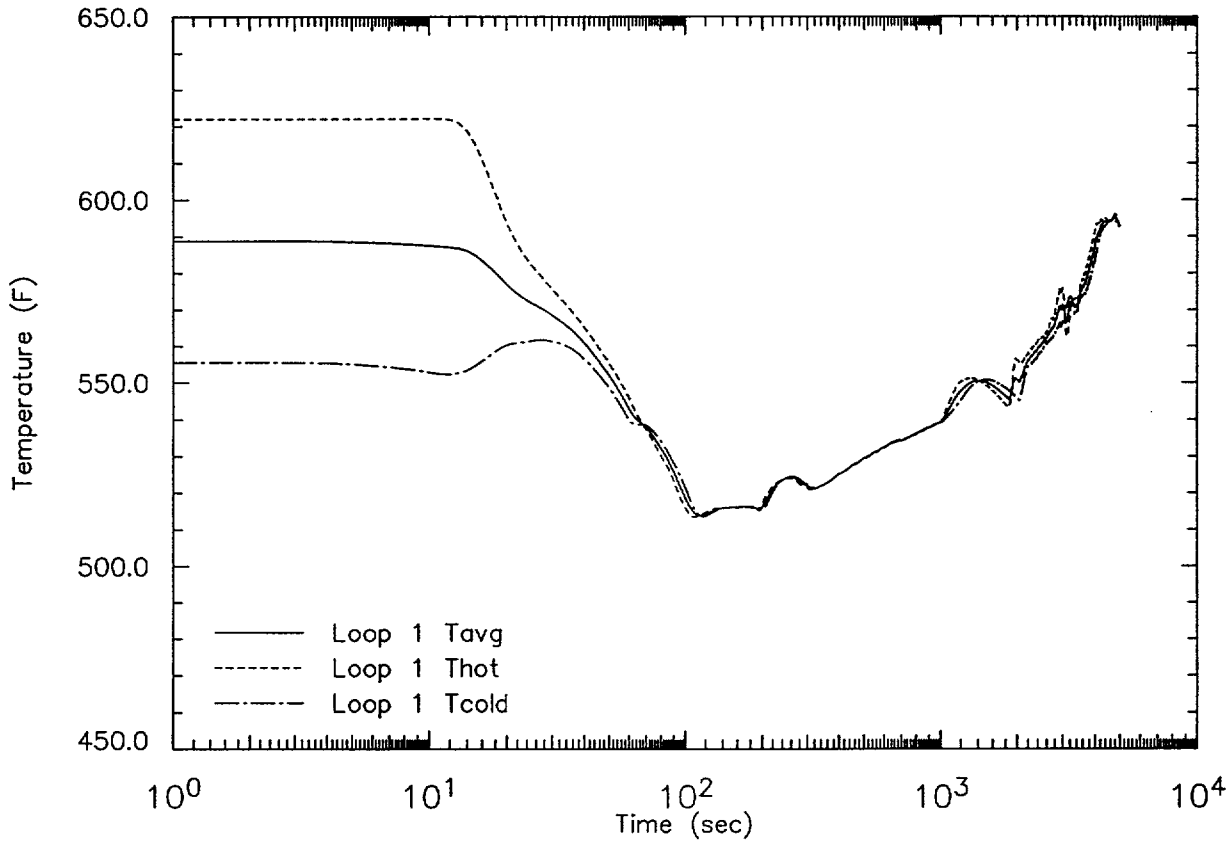

Figure 6.2.13-14 Loop 1 Primary System Temperatures for Feedwater System Pipe Break with Loss of Offsite Power

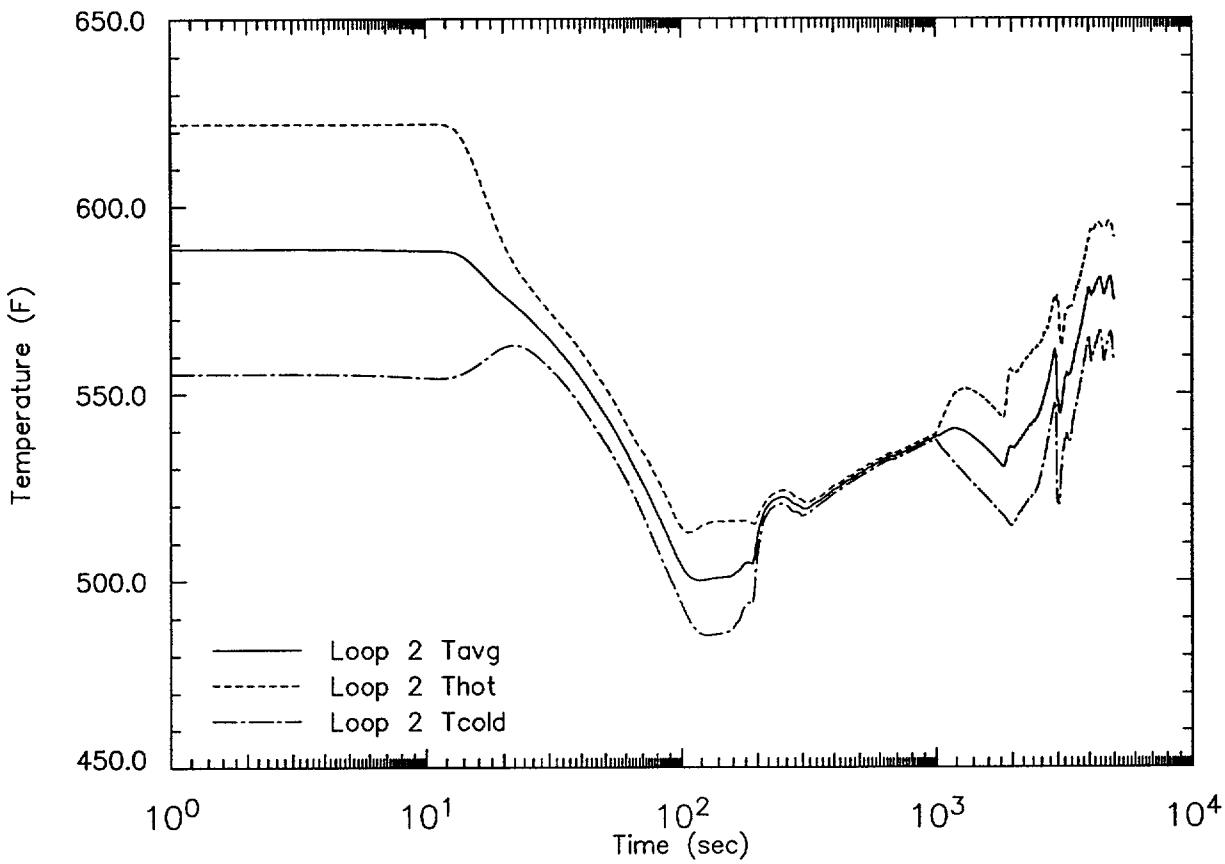

Figure 6.2.13-15 Loop 2 Primary System Temperatures for Feedwater System Pipe Break with Loss of Offsite Power

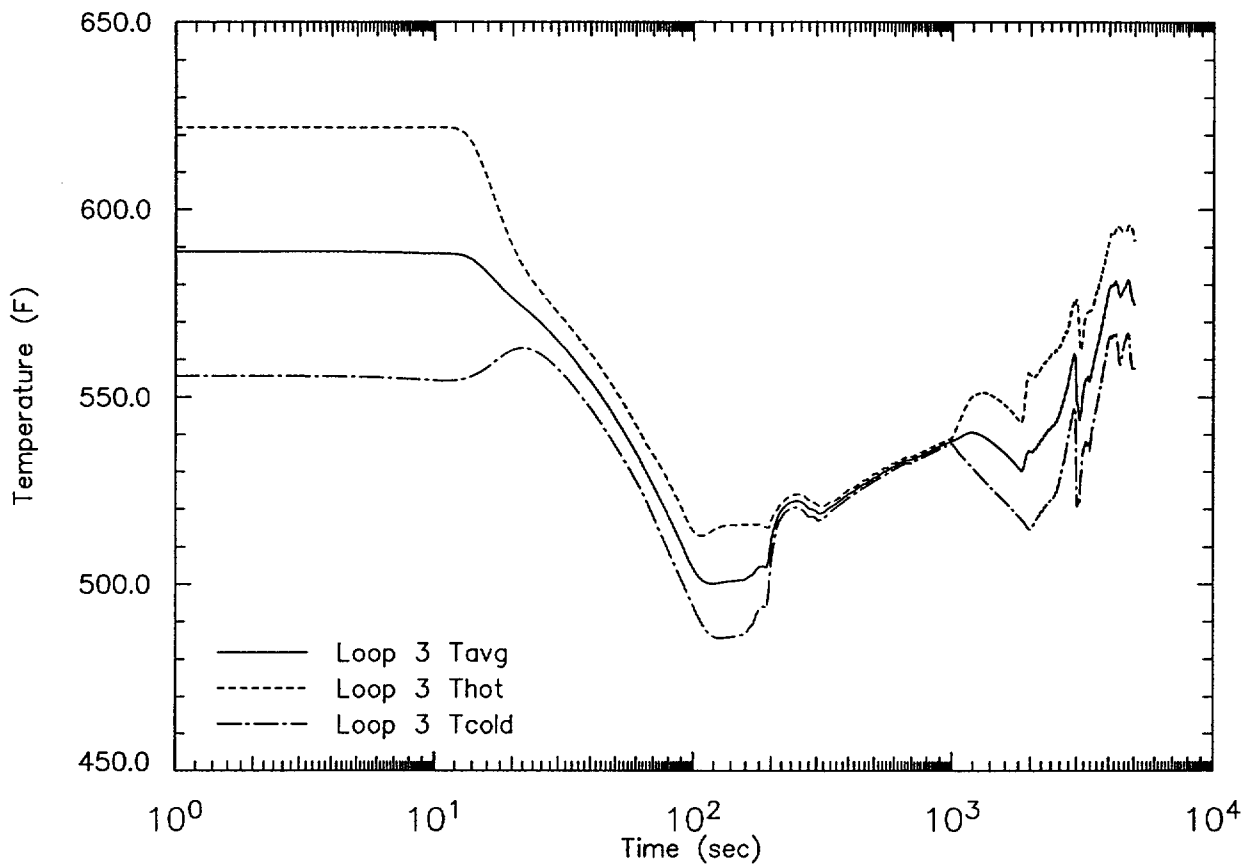

Figure 6.2.13-16 Loop 3 Primary System Temperatures for Feedwater System Pipe Break with Loss of Offsite Power

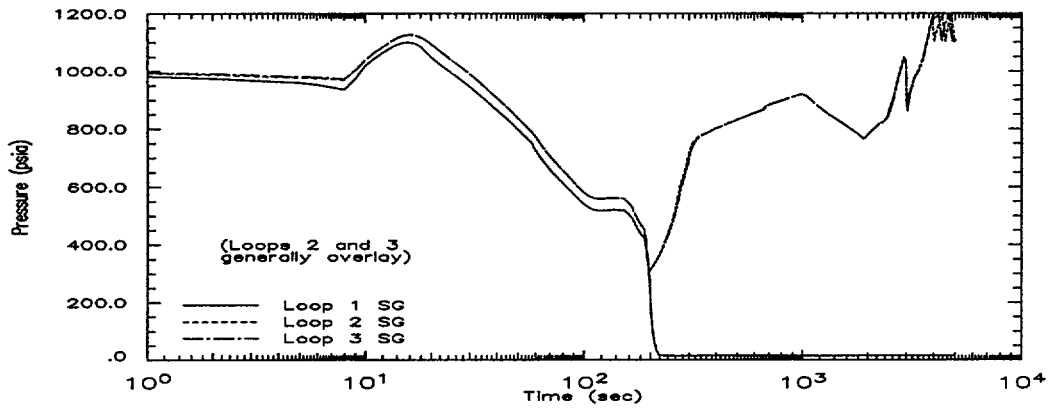

Figure 6.2.13-17 Steam Generator Pressure for Feedwater System Pipe Break with Loss of Offsite Power

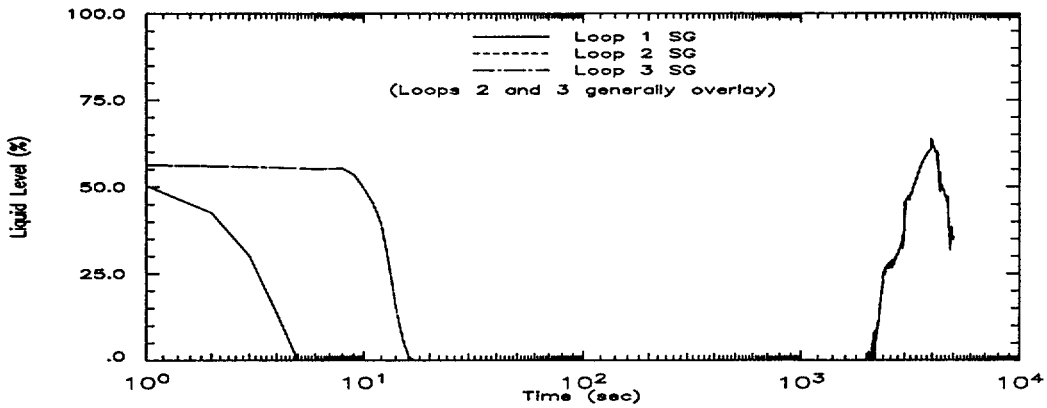

Figure 6.2.13-18 Steam Generator Downcomer Collapsed Level for Feedwater System Pipe Break with Loss of Offsite Power

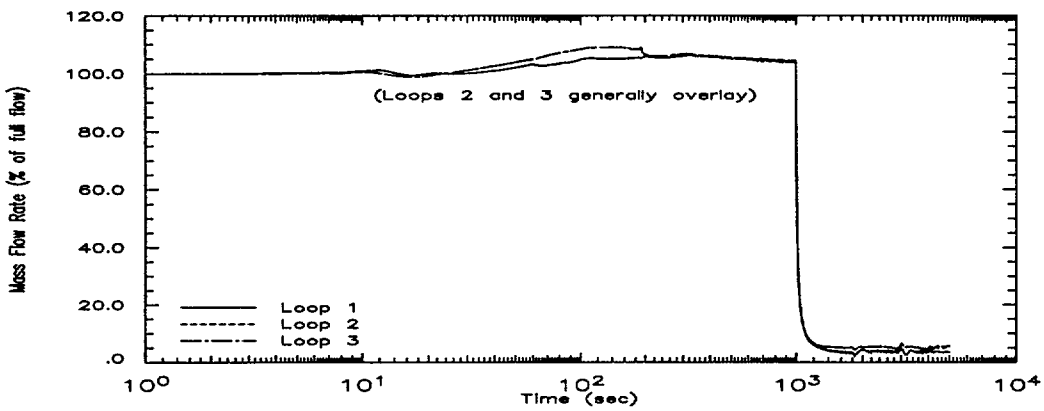

Figure 6.2.13-19 Reactor Coolant System Flow for Feedwater System Pipe Break with Loss of Offsite Power

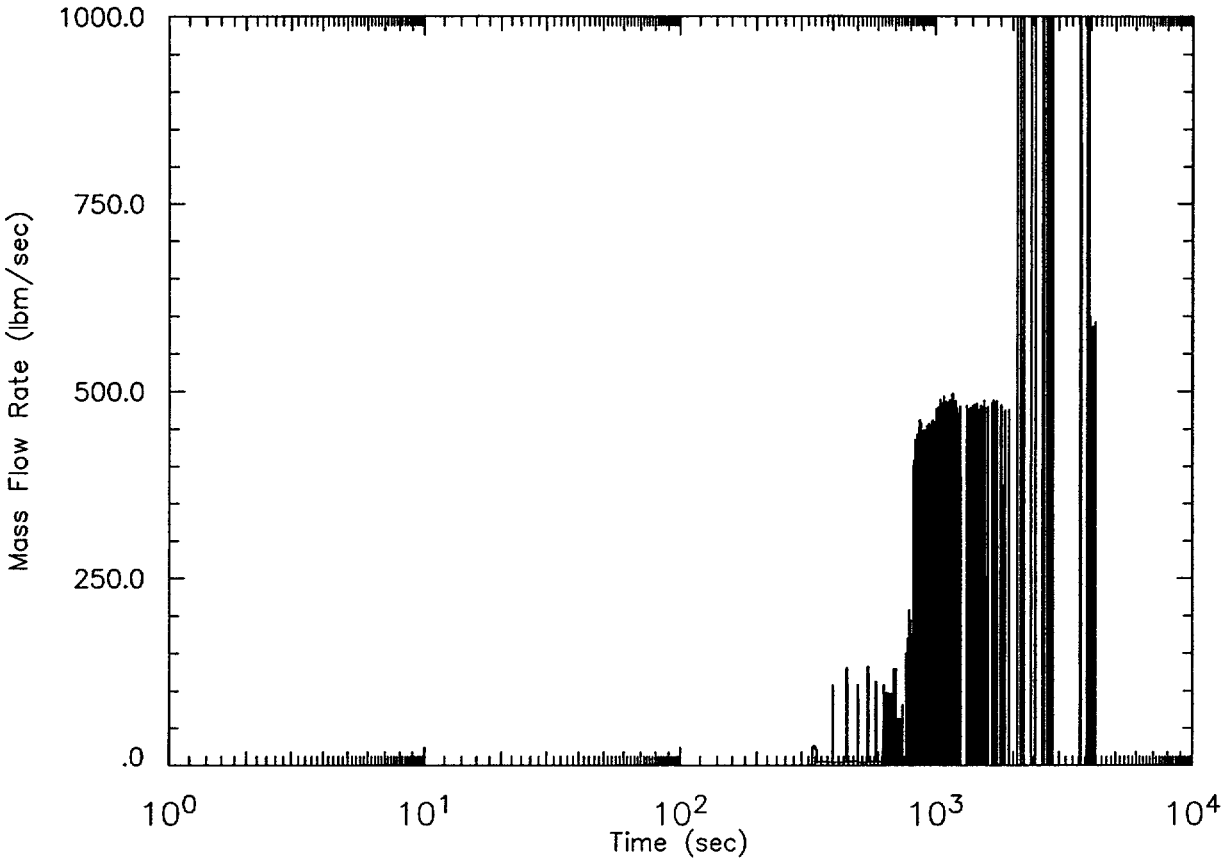

Figure 6.2.13-20 Pressurizer Relief Flow for Feedwater System Pipe Break with Loss of Offsite Power

6.2.14 Partial Loss of Forced Reactor Coolant Flow (FSAR Event 15.3.1)

6.2.14.1 Identification of Causes and Accident Description

This event is characterized by a partial loss of forced reactor coolant flow which is caused by the mechanical or electrical failure in a reactor coolant pump, or from a fault in a reactor coolant pump bus. Following the loss of electrical power, the reactor coolant pump begins to coast down. If the reactor is at power when the event occurs, the loss of forced coolant flow causes the reactor coolant temperatures to rise rapidly. This results in a rapid reduction in DNB margin, and could result in DNB if the reactor is not tripped promptly.

No single active failure will adversely affect the consequences of the event.

6.2.14.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1 (Above P-7): The amount of flow reduction and the rate of flow decrease is less than that in the Mode 1 of Event 15.3.2, because only one reactor coolant pump is affected in Event 15.3.1. The challenge to SAFDLs is therefore bounded for this event by Event 15.3.2, as long as Event 15.3.2 satisfies the SAFDLs since Event 15.3.2 is classified as a Condition III event.

Above P-8, reactor trip occurs on low flow in any reactor coolant loop. Below P-8 and above P-7, a reactor trip will occur on low flow in any two coolant loops. The initial power level and the power to flow ratio which may be achieved between P-7 and P-8 as a result of complete or partial loss of flow is significantly less limiting with respect to SAFDLs than at the rated power condition.

Reactor protection is provided by the low reactor coolant flow trip.

Mode 1 (Below P-7) and Mode 2: The reactor trips on low flow, pump bus undervoltage or underfrequency are not required. If DNB limits are approached, the OTΔT trip will act to ensure that sufficient margin to the DNB SAFDL is maintained due to the increase in loop ΔT that occurs as flow decreases. Fuel centerline melt limits are not challenged due to the low power level. Reactor coolant temperature increases occur slowly due to the low initial power level, so pressurization effects are not limiting. The event is bounded in these modes by the Mode 1 analysis.

Mode 3 through 6: Because the reactor is not critical, margin to SAFDLs is not a concern in these modes. Ample decay heat removal is assured by the residual heat removal system if it is in operation. If a residual heat removal (RHR) pump or RCP fails, the operator must eventually take action to actuate an alternate heat removal system. Because the heat loads are small, reactor coolant temperature will increase slowly, assuring adequate time for the operator to recognize the event and take appropriate action. The event is bounded in these modes by the Mode 2 event.

6.2.14.3 Acceptance Criteria

The Partial Loss of Forced Reactor Coolant Flow event is classified as a Condition II event. The acceptance criteria for this event are the same as those listed for the Complete Loss of Forced Reactor Coolant Flow event in Section 6.2.15.3.

6.2.14.4 Results

The Partial Loss of Forced Reactor Coolant Flow (Event 15.3.1) is bounded in Mode 1 (above P-7) by Event 15.3.2 (as long as Event 15.3.2 satisfies the SAFDLs since Event 15.3.2 is classified as a Condition III event) and need not be further analyzed. The event in Mode 1 (below P-7) and Mode 2 is bounded by Mode 1. The event in Modes 3-6 is bounded by Mode 2.

6.2.14.5 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.14.6 References

None.

6.2.15 Complete Loss of Forced Reactor Coolant Flow (FSAR Event 15.3.2)

6.2.15.1 Identification of Causes and Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of loss of forced reactor coolant flow is a rapid increase in the reactor coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not tripped promptly.

The reactor trip on reactor coolant pump undervoltage is provided to protect against conditions which can cause a loss of voltage to all reactor coolant pumps, i.e., station blackout.

The reactor trip on reactor coolant pump underfrequency is provided to trip the reactor for an underfrequency condition, resulting from frequency disturbances of the power grid. If the maximum grid frequency decay rate is less than approximately 5 Hz/sec, this trip function will protect the core from underfrequency events without requiring tripping of the RCP breakers.

No single active failure will adversely affect the consequences of the event.

6.2.15.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1 (Above P-7): The event is analyzed at rated power conditions, because the available margin to SAFDLs is minimized at the maximum power level.

Reactor protection is afforded by the pump bus undervoltage and underfrequency trips, and by the low coolant flow trip.

Mode 1 (Below P-7) and Mode 2: The reactor trips on low flow, pump bus undervoltage or underfrequency are not required. If DNB limits are approached, the OTΔT trip will act to ensure that sufficient margin to the DNB SAFDL is maintained due to the increase in loop ΔT that occurs as flow decreases. Fuel centerline melt limits are not challenged due to the low power level. Reactor coolant temperature increases occur slowly due to the low initial power level, so pressurization effects are not limiting. The event is bounded in these modes by the Mode 1 analysis.

Mode 3 through 6: Because the reactor is not critical, margin to SAFDLs is not a concern in these modes. Ample decay heat removal is assured by the residual heat removal system if it is in operation. If an RHR pump or RCP fails, the operator must eventually take action to actuate an alternate heat removal system. Because the heat loads are small, reactor coolant temperature will increase slowly, assuring adequate time for the operator to recognize the event and take appropriate action. The event is bounded in these modes by the Mode 2 event.

Based on the above evaluations, two cases were analyzed: one for a reactor trip actuated by the pump power supply undervoltage trip and the other for a reactor trip actuated by pump power supply underfrequency trip with a maximum grid frequency decay rate of 5 Hz/sec. In addition, a part-power (70% power) case was run to verify that the 100% power case was limiting.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.15.3 Acceptance Criteria

The Complete Loss of Forced Reactor Coolant Flow event is classified as a Condition III event, but is analyzed against Condition II acceptance criteria. Consistent with the current licensing basis, the Condition II acceptance criteria are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

(3) The event should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained.

6.2.15.4 Results

The results of the analysis indicate that the predicted MDNBR is greater than the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event. Thus, Condition II acceptance criteria are met for this event. Since Condition II acceptance criteria are met for this event, Event 15.3.1 is bounded.

The underfrequency event was more limiting than the undervoltage event. The underfrequency case run at 100% power with an MTC of 0.0 pcm/°F was more limiting than at 70% power with an MTC of +5.0 pcm/°F. This limiting loss of flow case tripped on pump power supply

underfrequency. The sequence of events for the underfrequency event is given in Table 6.2.15-1. The responses to key system variables are given in Figure 6.2.15-1 to Figure 6.2.15-7.

6.2.15.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.15.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.
2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.
3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.15-1 Event Summary for Loss of Forced Reactor Coolant Flow

Event	Time (s)
Initiate transient (three-pump coastdown)	0.0
Reactor scram on underfrequency trip (begin rod insertion)	1.2
Compensated PORV opens	2.0
Peak power-to-flow ratio	2.7
Uncompensated PORV opens	3.1
MDNBR	3.1
Peak core average temperature	3.6

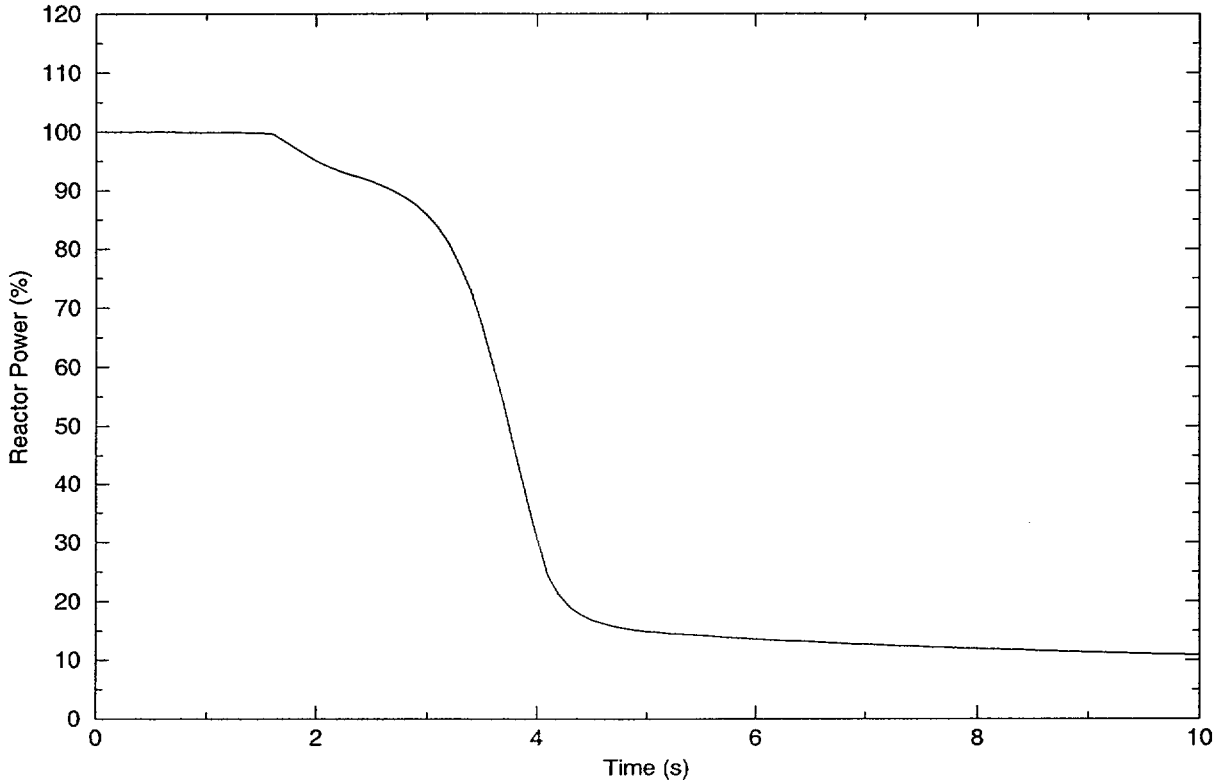

Figure 6.2.15-1 Reactor Power for Loss of Forced Reactor Coolant Flow – Underfrequency Case

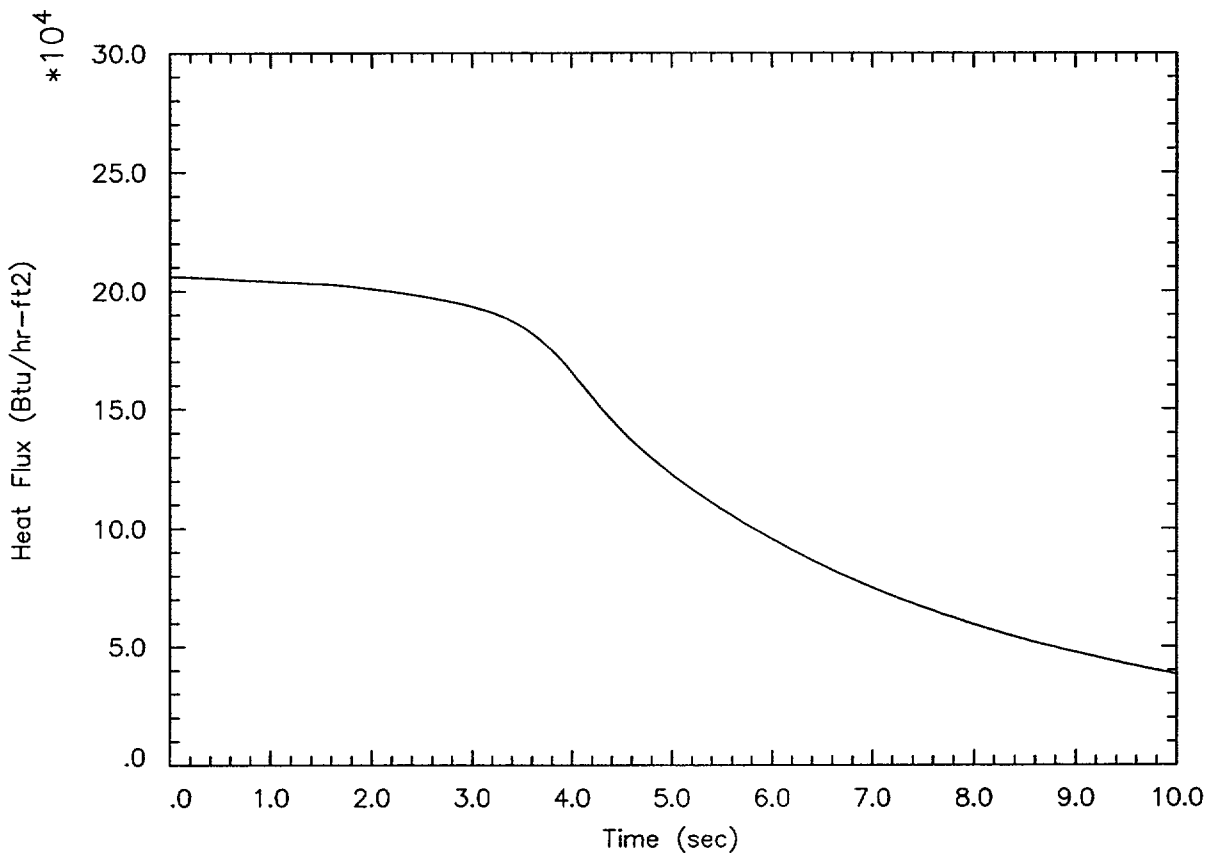

Figure 6.2.15-2 Core Average Heat Flux for Loss of Forced Reactor Coolant Flow – Underfrequency Case

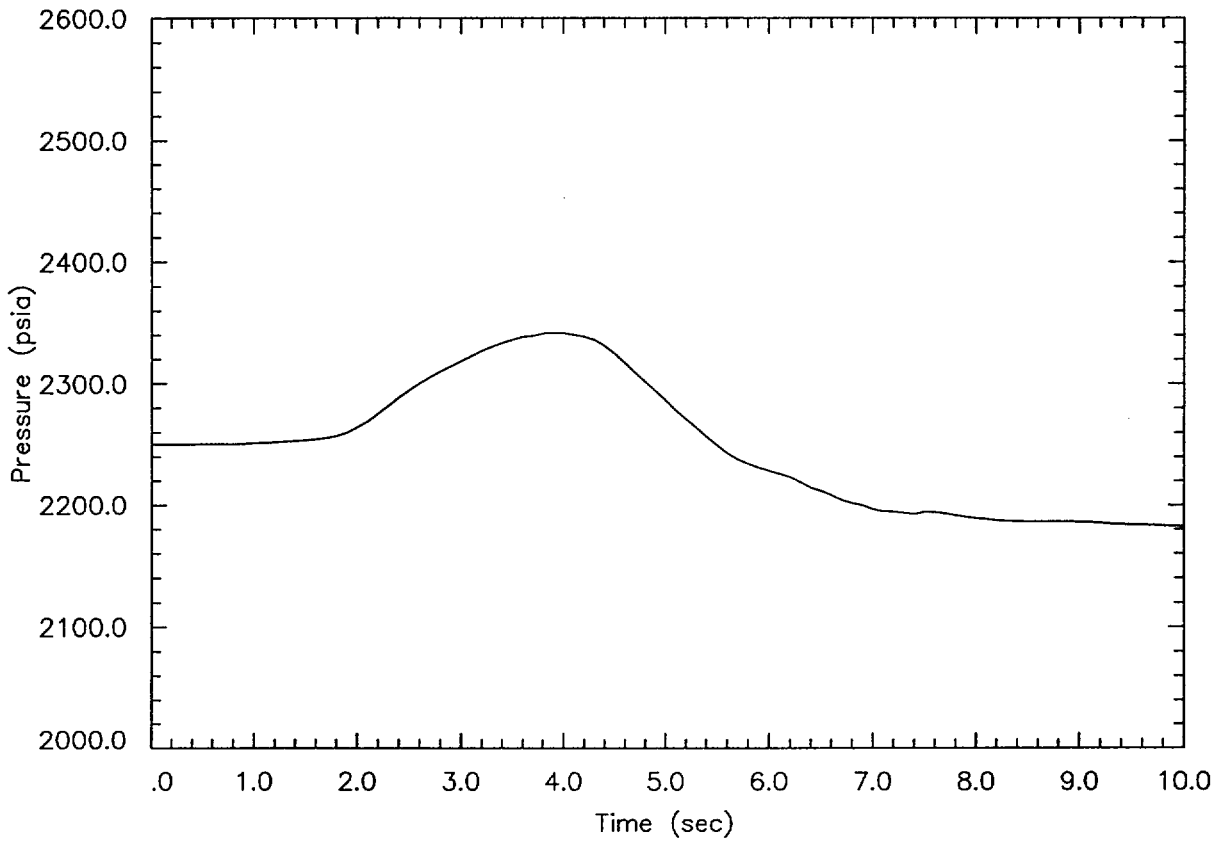

Figure 6.2.15-3 Pressurizer Pressure for Loss of Forced Reactor Coolant Flow – Underfrequency Case

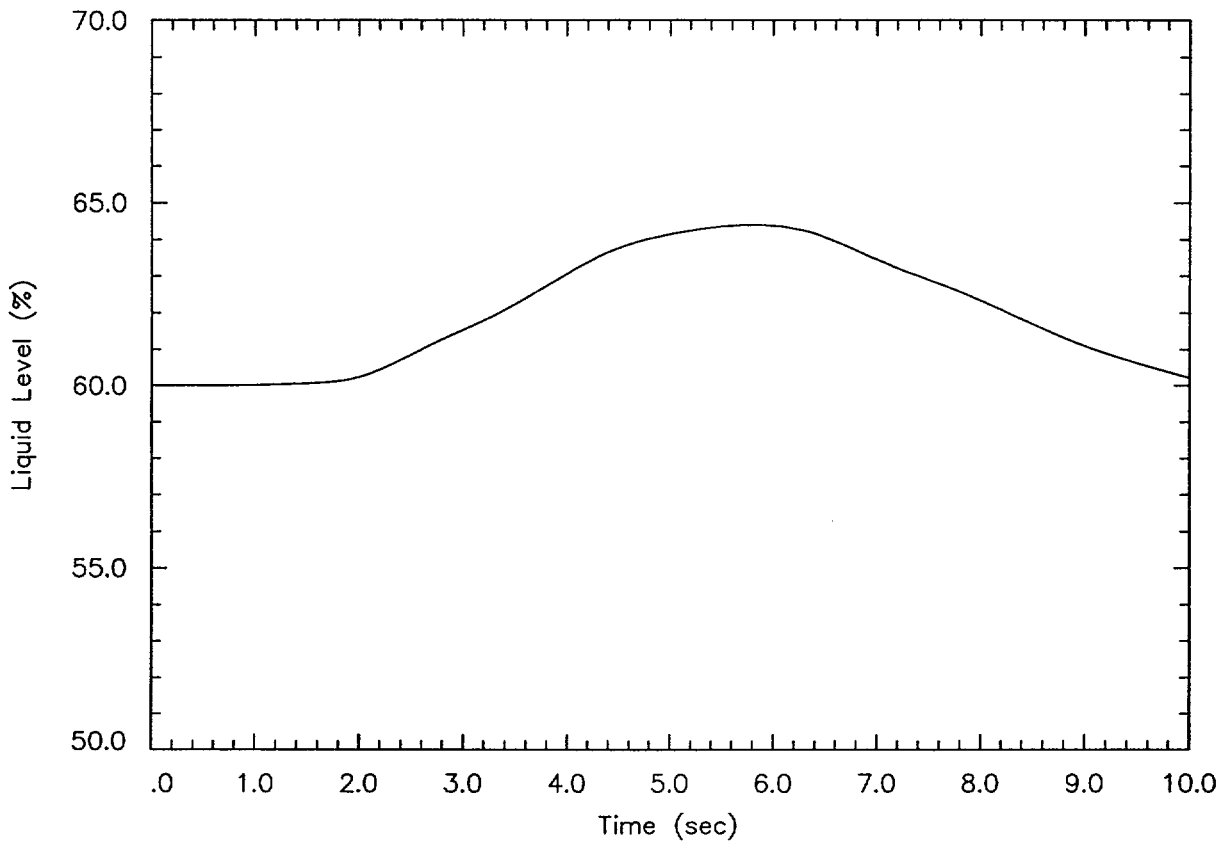

Figure 6.2.15-4 Pressurizer Level for Loss of Forced Reactor Coolant Flow – Underfrequency Case

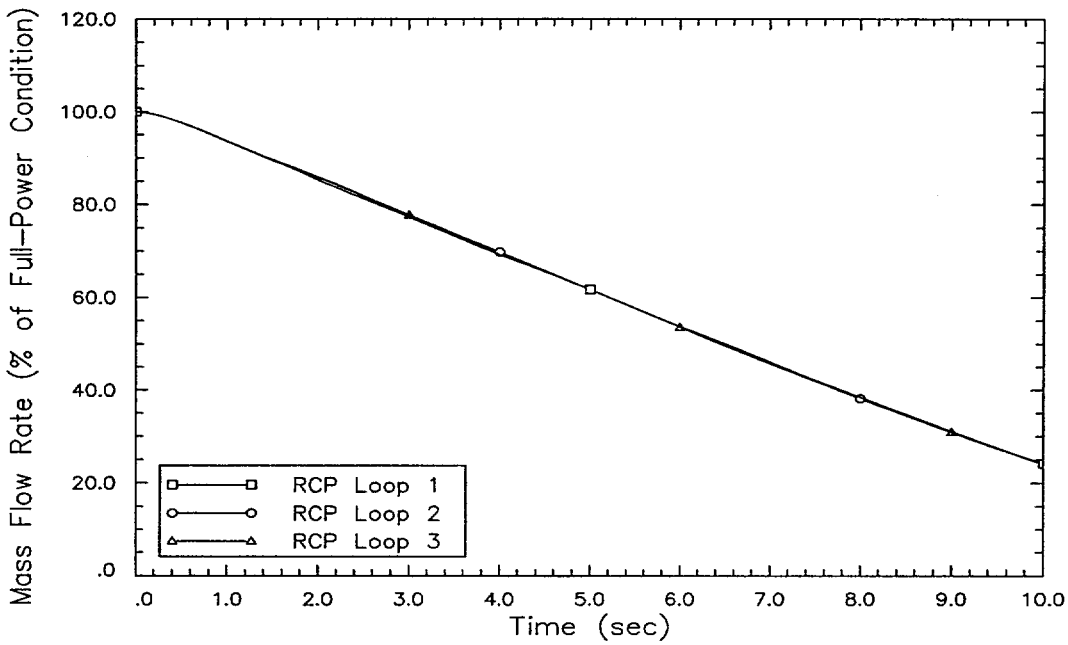

Figure 6.2.15-5 Reactor Coolant System Mass Flow Rate for Loss of Forced Reactor Coolant Flow – Underfrequency Case

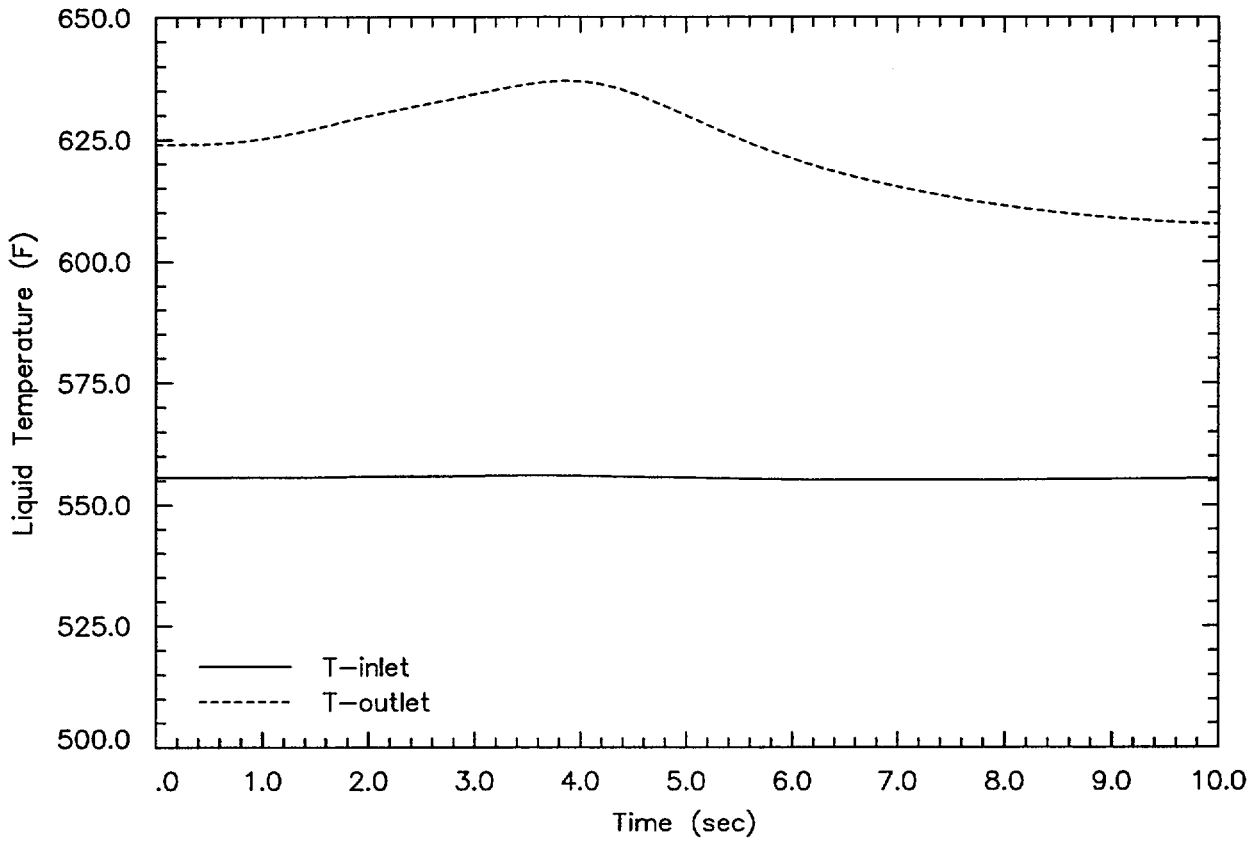

Figure 6.2.15-6 Core Inlet and Outlet Temperatures for Loss of Forced Reactor Coolant Flow – Underfrequency Case

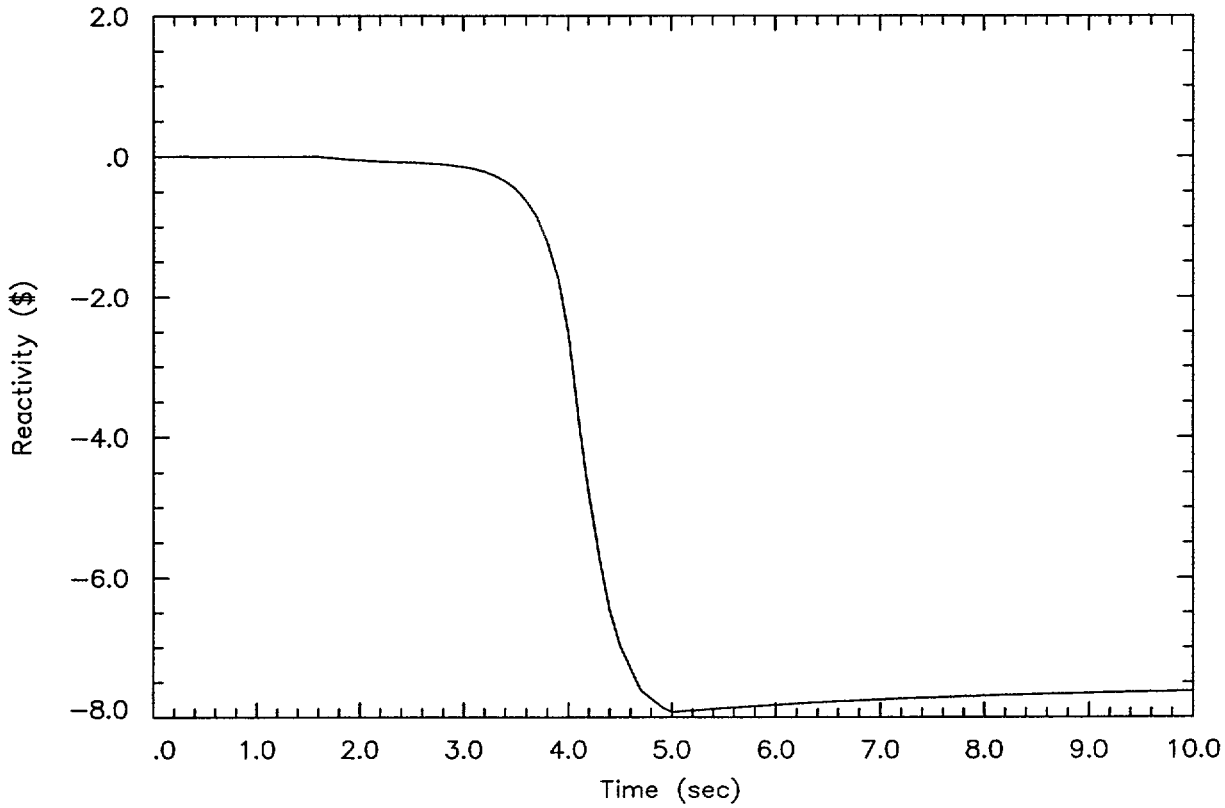

Figure 6.2.15-7 Total Core Reactivity for Loss of Forced Reactor Coolant Flow – Underfrequency Case

6.2.16 Reactor Coolant Pump Rotor Seizure/Locked Rotor (FSAR Event 15.3.3)

6.2.16.1 Identification of Causes and Accident Description

The Locked Rotor event is caused by an instantaneous seizure of a primary coolant pump rotor. Flow through the affected loop is rapidly reduced, causing a reactor trip due to a low primary loop flow trip. Following the reactor trip, the heat stored in the fuel rods continues to be transferred to the primary coolant. Because of the reduced core flow, the coolant temperatures will begin to rise, causing expansion of the primary coolant and consequent pressurizer insurge flow and RCS pressurization. As the pressure increases, pressurizer sprays, PORVs, and safety valves would act to mitigate the pressure transient.

The rapid reduction in core flow and the increase in coolant temperature may seriously challenge or penetrate the DNBR SAFDL. The event is evaluated to assess overpressure and DNBR limits.

No single active failure will adversely affect the consequences of the event.

6.2.16.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1 (Above P-7): The event is analyzed at rated power conditions because the available margin to SAFDLs is minimized at the maximum power level.

Above P-8, reactor trip occurs on low flow in any reactor coolant loop. Below P-8 and above P-7, a reactor trip will occur on low flow in any two coolant loops. The initial power level and the power to flow ratio which may be achieved between P-7 and P-8 as a result of a reactor coolant pump shaft seizure is significantly less limiting than at the rated power condition.

Reactor protection is afforded by the low coolant flow trip and the high pressurizer pressure trip.

Mode 1 (Below P-7) and Mode 2: The reactor trip on low flow is not required. Three primary coolant pumps must be operating in these modes. A pump shaft seizure leaves two pumps operating, with more than sufficient primary flow to ensure adequate margin to the DNB SAFDL. Fuel centerline melt limits are not challenged due to the low power level. Reactor coolant temperature increases occur slowly due to the low initial power level, so pressurization effects are not limiting. The event is bounded in these modes by the Mode 1 analysis.

Mode 3 through 6: Because the reactor is not critical, margin to SAFDLs is not a concern in these modes. Ample decay heat removal is assured by natural circulation and/or the residual heat removal system. The event is bounded in these modes by the Mode 2 event.

Based on the above evaluations, both an overpressurization case and a MDNBR case are analyzed for this event. The analysis is performed with BOC kinetics parameters.

Normal power for the reactor coolant pumps is supplied through individual buses connected to the turbine generator. When a generator trip occurs, the buses are automatically transferred to a transformer supplied from external power lines, and the reactor coolant pumps will continue to supply coolant flow to the core. Following any turbine trip where there are no electrical faults which require tripping the generator from the network, the generator remains connected to the network for approximately 30 seconds. The reactor coolant pumps remain connected to the generator ensuring full flow for approximately 30 seconds after the reactor trip before any supply power transfer is made. This analysis conservatively assumes the remaining two pumps are connected to the generator for 3 seconds following the low flow trip, consistent with the current licensing basis.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.16.3 Acceptance Criteria

The Reactor Coolant Pump Rotor Seizure/Locked Rotor event is classified as a Condition IV event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressure in the reactor coolant and main steam systems should be maintained below acceptable design limits (i.e., the pressure in the reactor coolant and main steam systems should be maintained below 120% of the design pressures).

(2) The potential for core damage is evaluated on the basis that it is acceptable if the minimum DNBR remains above the 95/95 DNBR limit. If DNBR falls below the 95/95 DNBR limit, fuel failure must be assumed for all rods that do not meet this criteria unless it can be shown, based on an acceptable fuel damage model, which includes the potential adverse effects of hydraulic instabilities, that fewer failures occur. Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capacity.

(3) Any reactivity release must be such that the calculated doses at the site boundary are a small fraction of the 10 CFR Part 100 guidelines.

(4) A rotor seizure or shaft break in a reactor coolant pump should not, by itself, generate a more serious condition or result in a loss of function of the reactor coolant system or containment barriers.

(5) This event should be analyzed assuming turbine trip and coincident loss of offsite power and coastdown of undamaged pumps.

6.2.16.4 Results

For the overpressurization case, both the maximum reactor primary system pressure and the maximum secondary system pressures are less than the design limits of 3000 psia and 1440 psia, respectively.

For the MDNBR case, the predicted MDNBR is less than the 95/95 safety limit. Approximately 5.1% of the fuel is predicted to fail based on DNB criterion. In addition, centerline melt is not predicted to occur in other assemblies that do not experience DNB.

This transient tripped on low primary coolant flow. Since there would be no power increase for this event at EOC, the peak pressure results from the BOC case bound the EOC case. The sequence of events for the bounding overpressurization case is given in Table 6.2.16-1. The responses to key system variables are given in Figure 6.2.16-1 to Figure 6.2.16-6.

The sequence of events for the MDNBR case is given in Table 6.2.16-2. This transient tripped on low primary coolant flow. The responses to key system variables are given in Figure 6.2.16-7 to Figure 6.2.16-13.

6.2.16.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that acceptance criteria for this event are met for SGR/Uprating conditions, with the exception of conclusions related to radiological consequences. The conclusions of the analysis of the radiological dose consequences are documented in the BOP Licensing Report. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.16.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.16-1 Event Summary for Locked Rotor Overpressurization Case

Event	Time (s)
Initiate transient (seizure of one RCP rotor)	0.0
Main turbine trip	0.0
MFW isolated	0.0
Low RCS flow signal	0.125
Reactor scram	1.15
Reverse flow in affected loop	1.75
Peak power	2.50
Remaining RCS pumps tripped	3.00
Pressurizer safety valves open	3.50
Maximum primary side pressure	4.75
Maximum pressurizer level	6.25
Maximum secondary side pressure	12.0

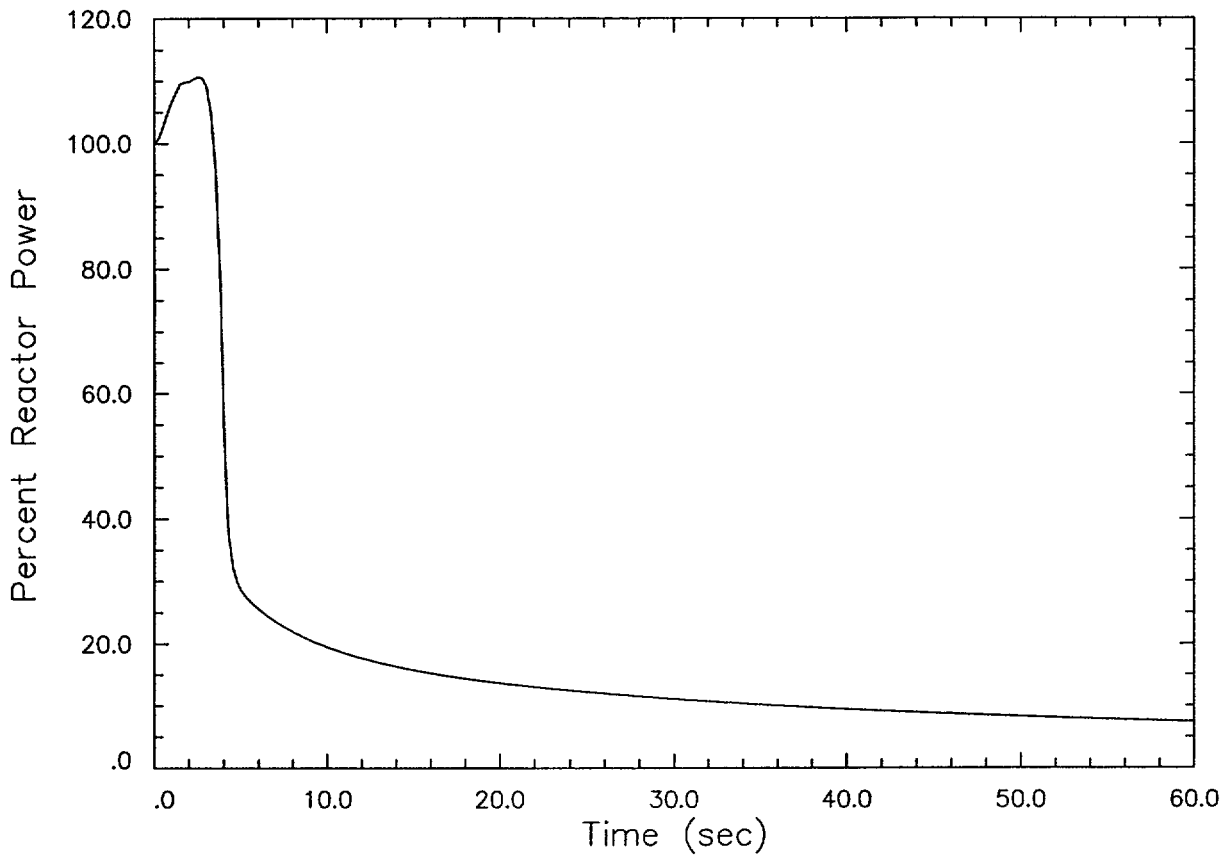

Figure 6.2.16-1 Reactor Power for Locked Rotor Overpressurization Case

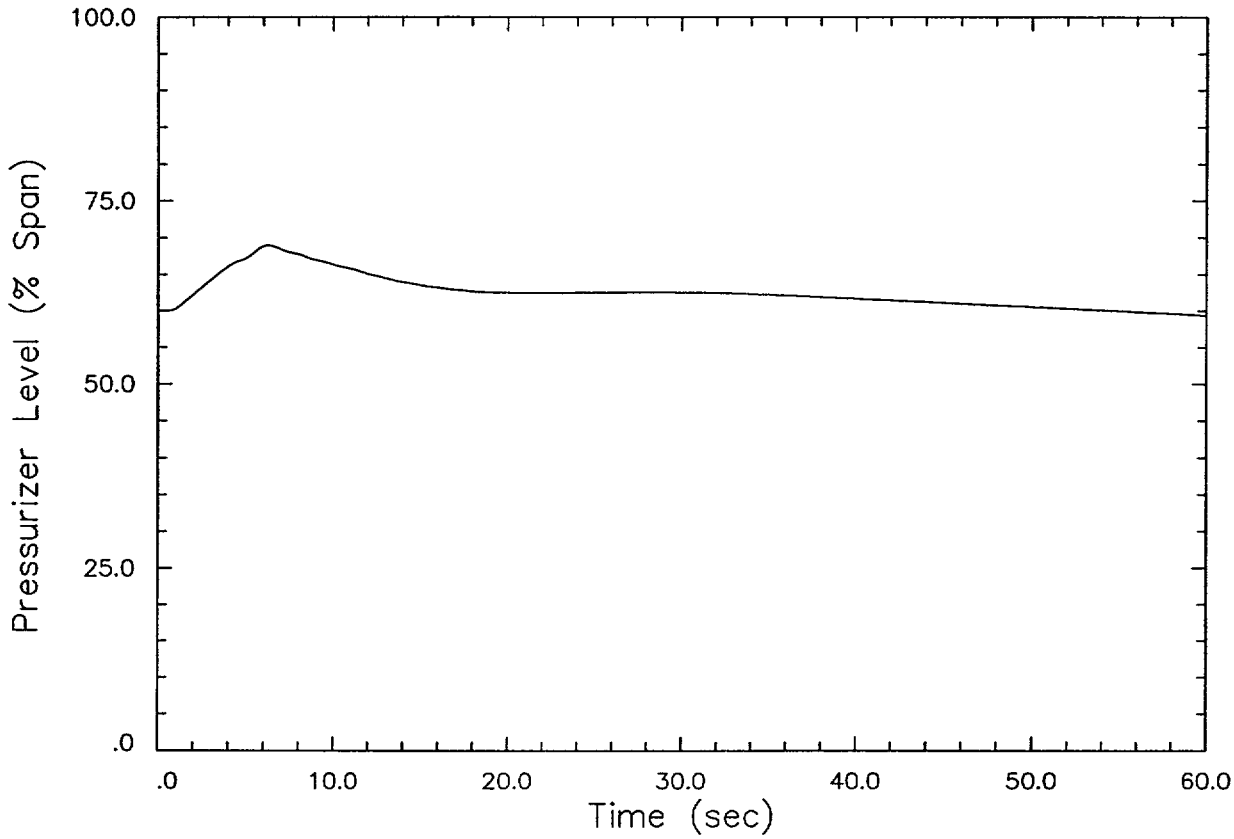

Figure 6.2.16-2 Pressurizer Level for Locked Rotor Overpressurization Case

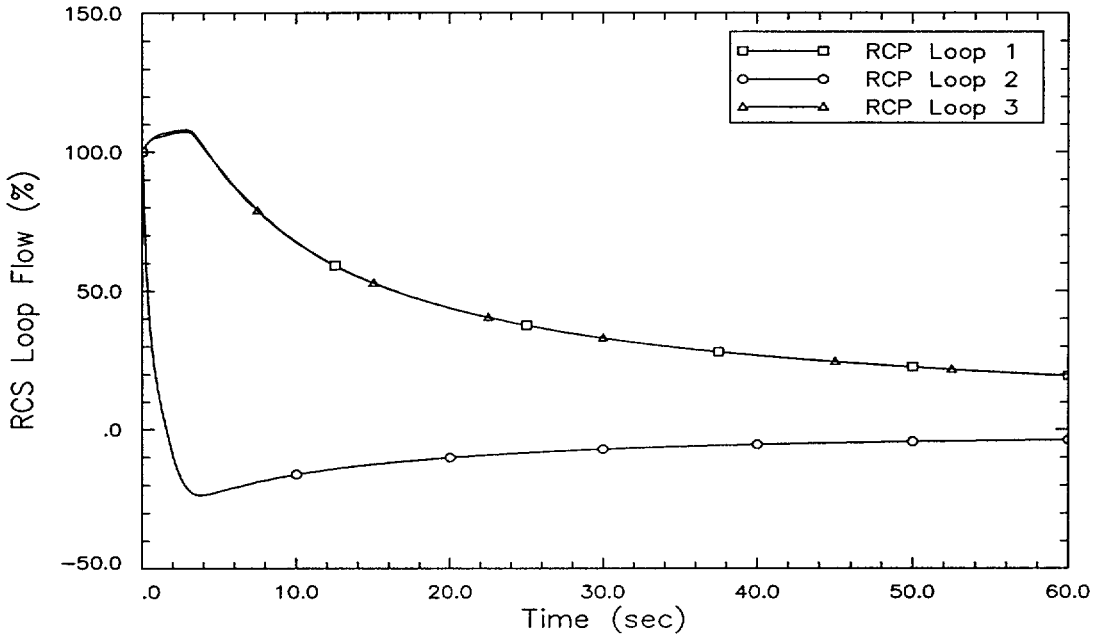

Figure 6.2.16-3 Reactor Coolant System Mass Flow Rate for Locked Rotor Overpressurization Case

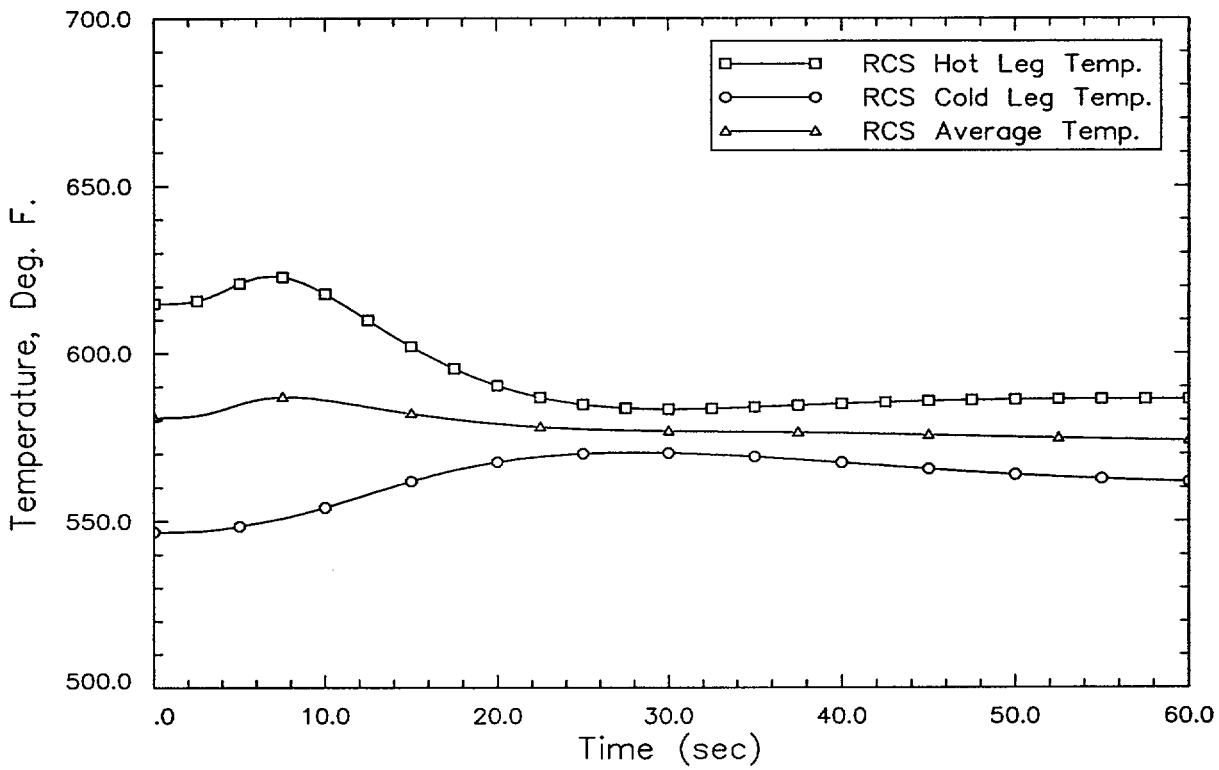

Figure 6.2.16-4 Primary System Temperatures for Locked Rotor Overpressurization Case

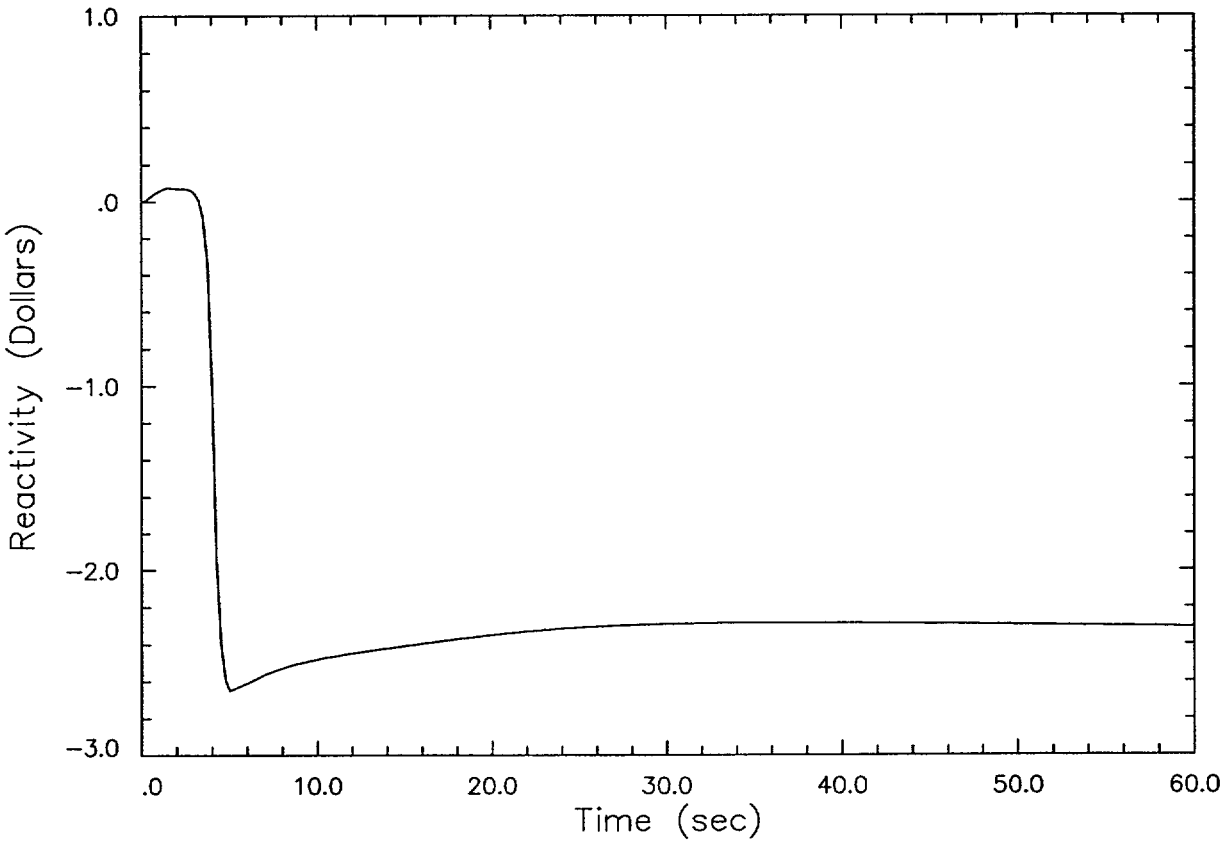

Figure 6.2.16-5 Total Core Reactivity for Locked Rotor Overpressurization Case

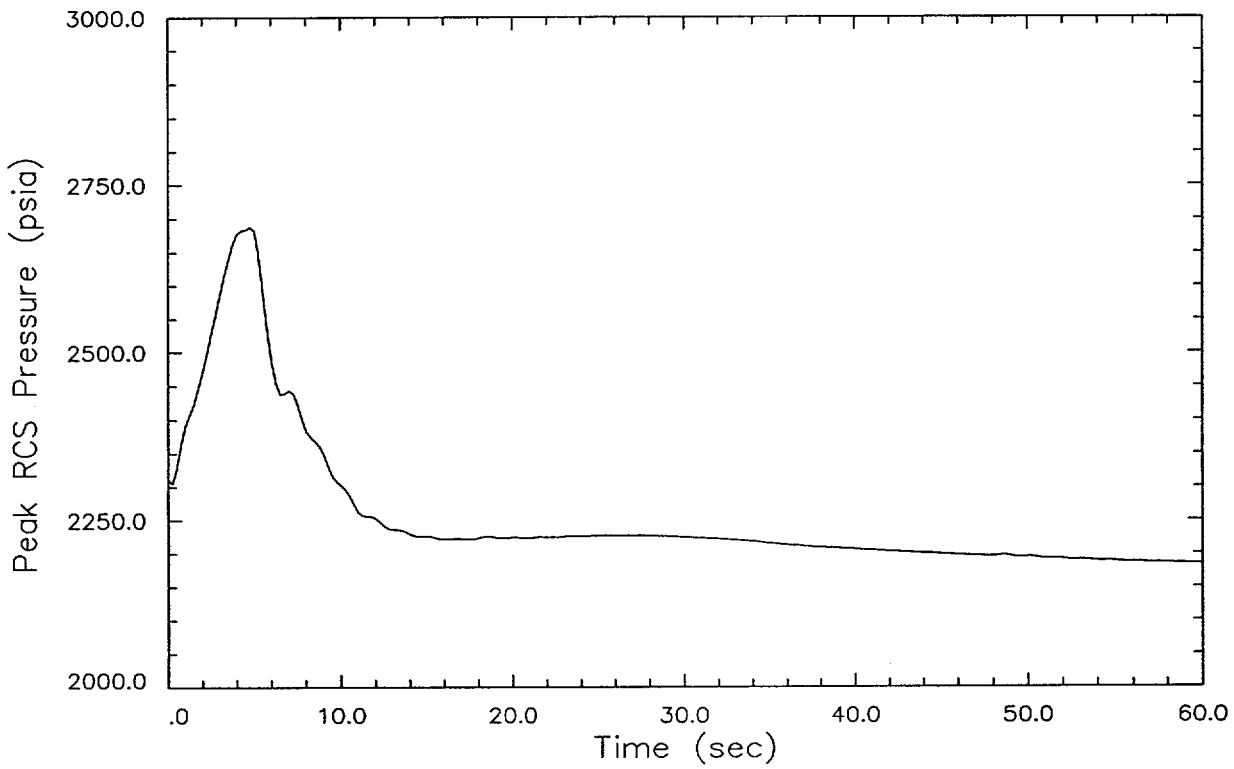

Figure 6.2.16-6 Maximum Primary System Pressure for Locked Rotor Overpressurization Case

Table 6.2.16-2 Event Summary for Locked Rotor MDNBR Case

Event	Time (s)
Initiate transient (seizure of one RCP rotor)	0.0
Main turbine trip	0.0
MFW isolated	0.0
Low RCS flow signal	0.125
Reactor scram	1.15
Reverse flow in affected loop	1.75
Peak power	2.50
Remaining RCS pumps tripped	3.00
Peak core-average LHGR	3.25
MDNBR	3.50
Pressurizer safety valves open	3.625
Maximum primary side pressure	3.75
Maximum pressurizer level	6.25
Maximum secondary side pressure	10.0

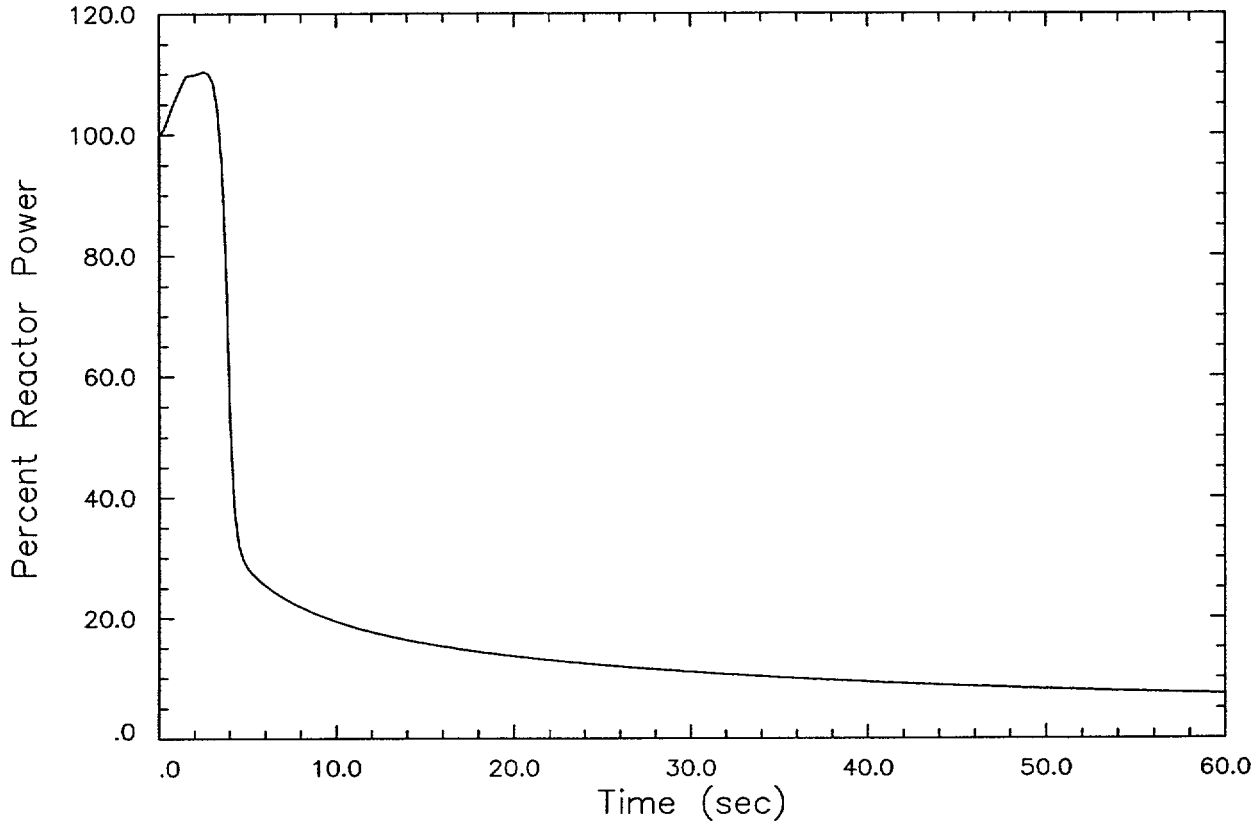

Figure 6.2.16-7 Reactor Power for Locked Rotor MDNBR Case

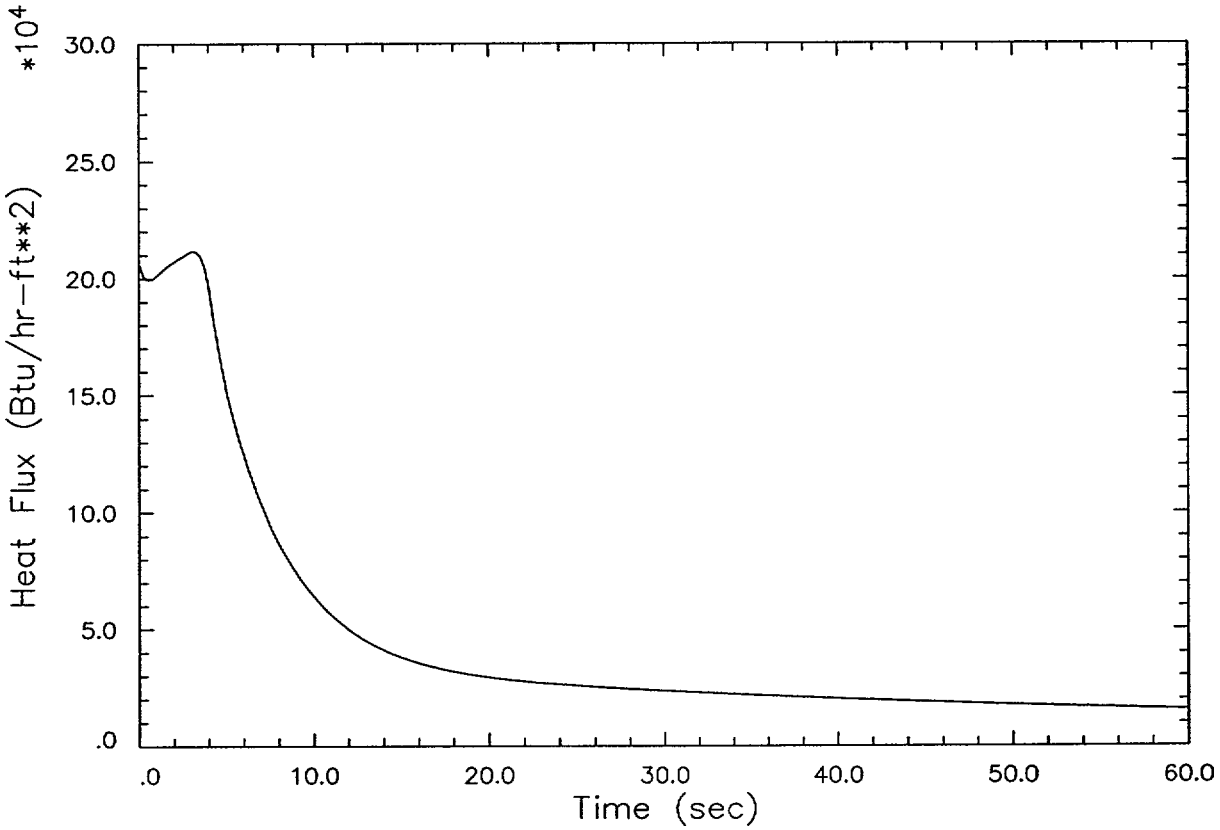

Figure 6.2.16-8 Core Average Heat Flux for Locked Rotor MDNBR Case

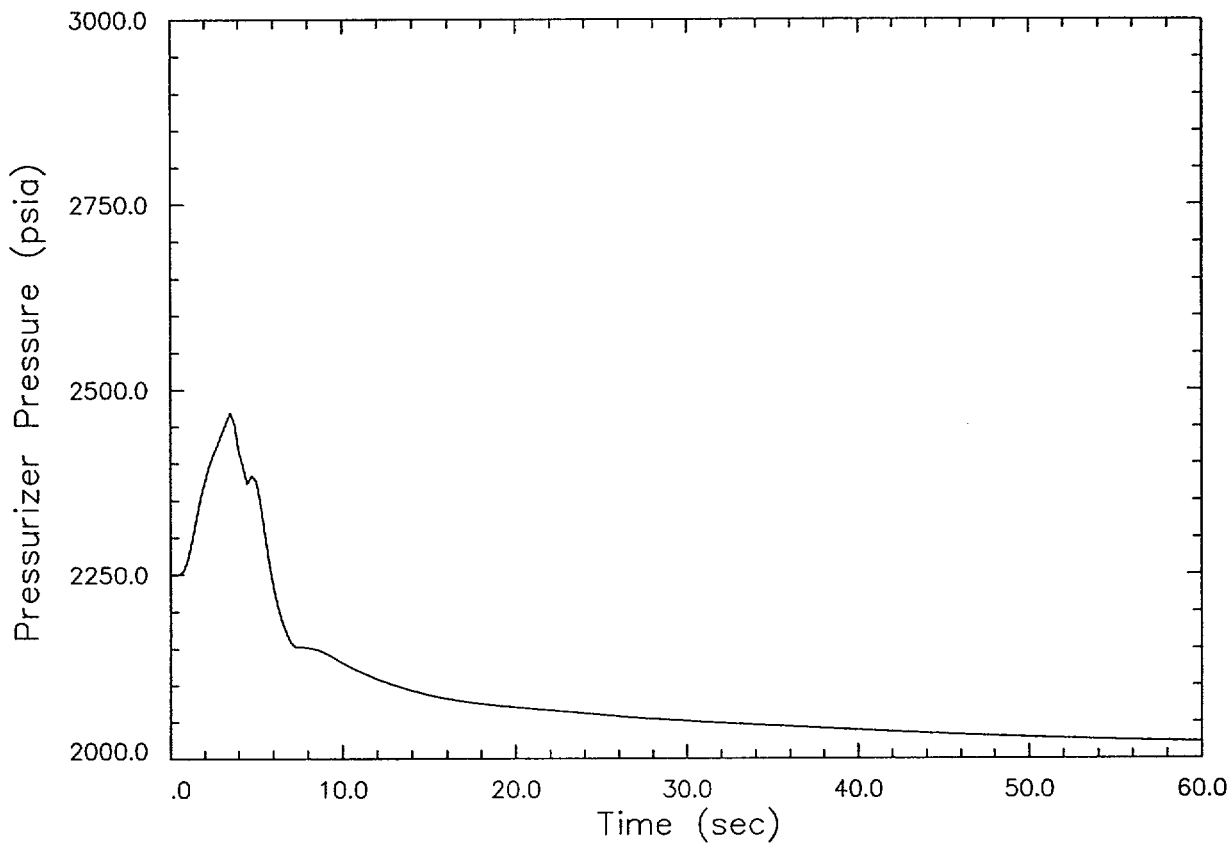

Figure 6.2.16-9 Pressurizer Pressure for Locked Rotor MDNBR Case

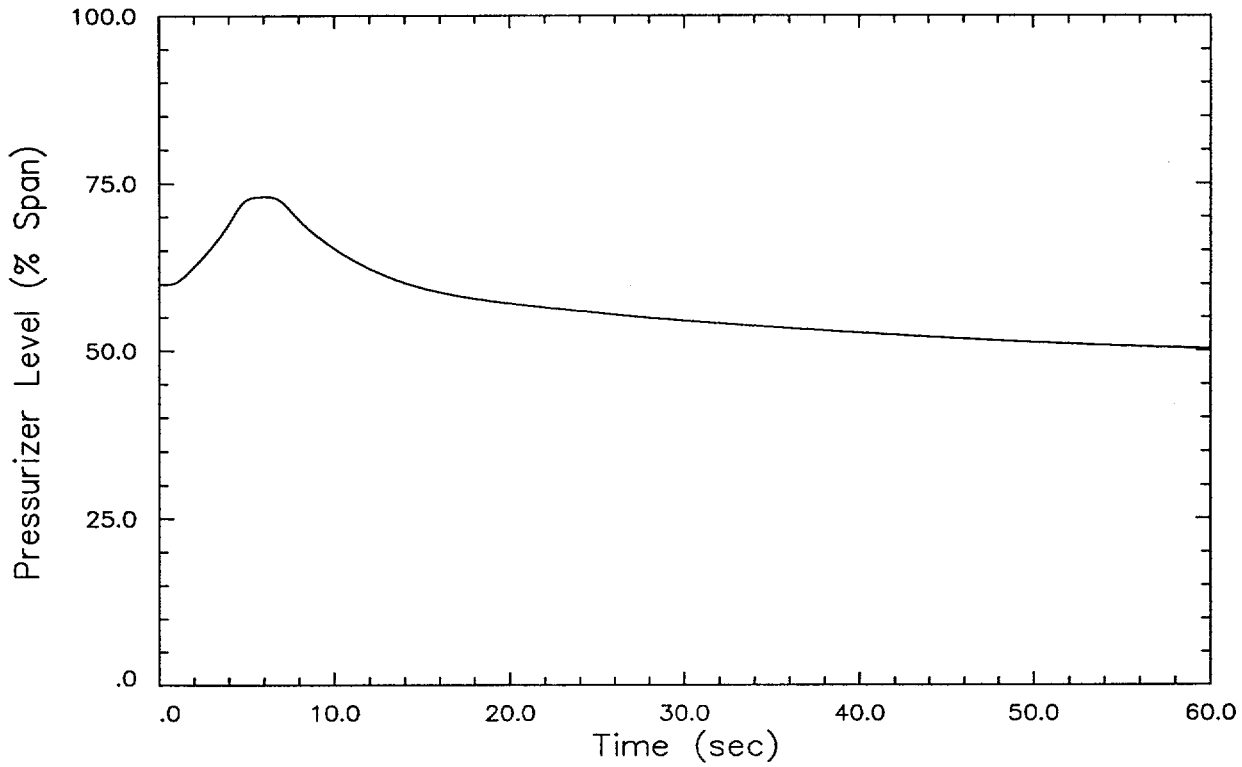

Figure 6.2.16-10 Pressurizer Level for Locked Rotor MDNBR Case

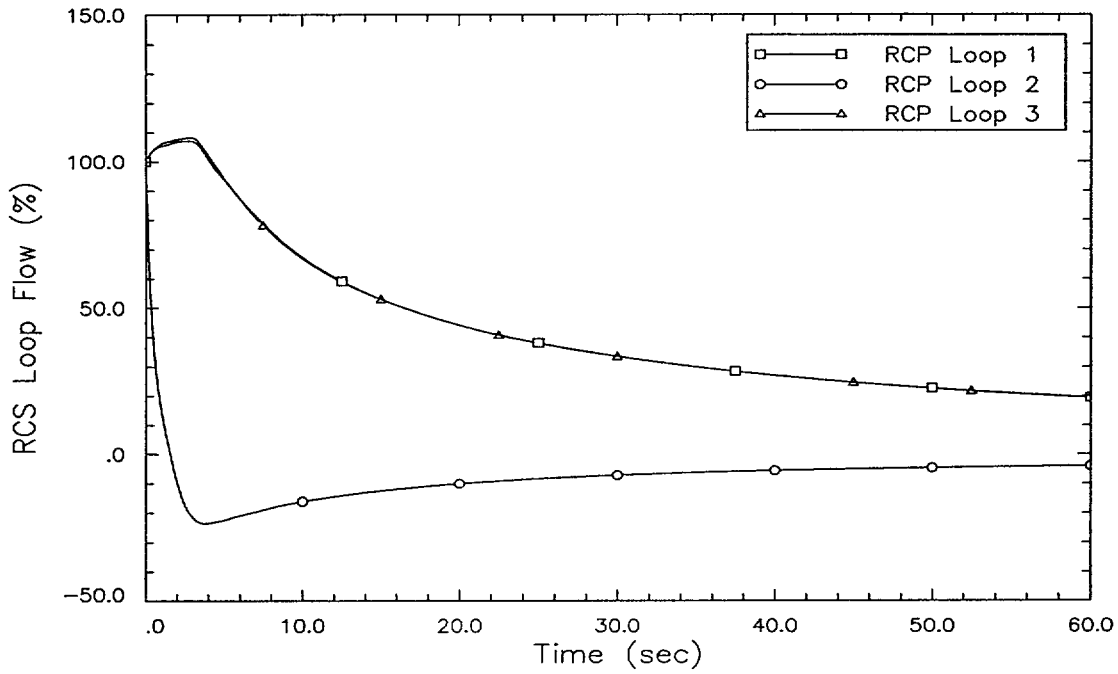

Figure 6.2.16-11 Reactor Coolant System Mass Flow Rate for Locked Rotor MDNBR Case

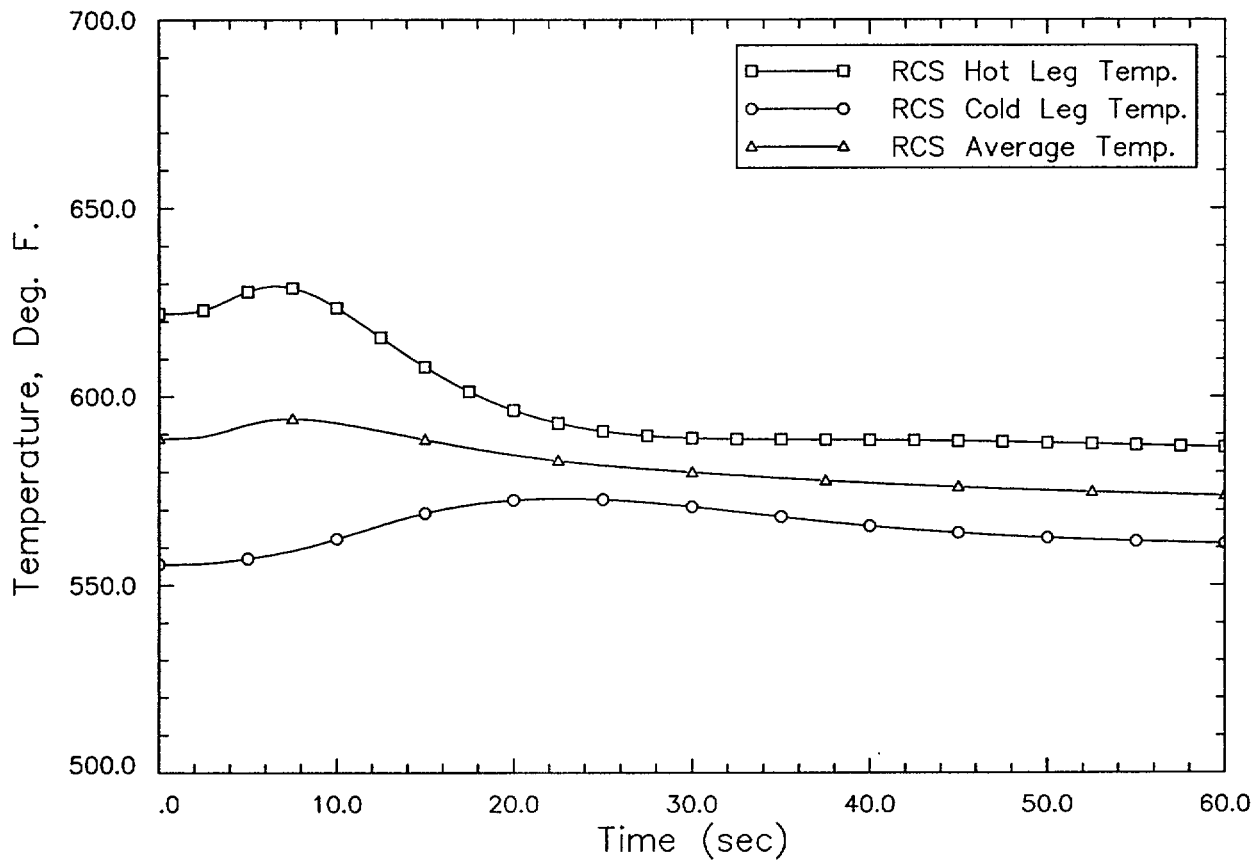

Figure 6.2.16-12 Primary System Temperatures for Locked Rotor MDNBR Case

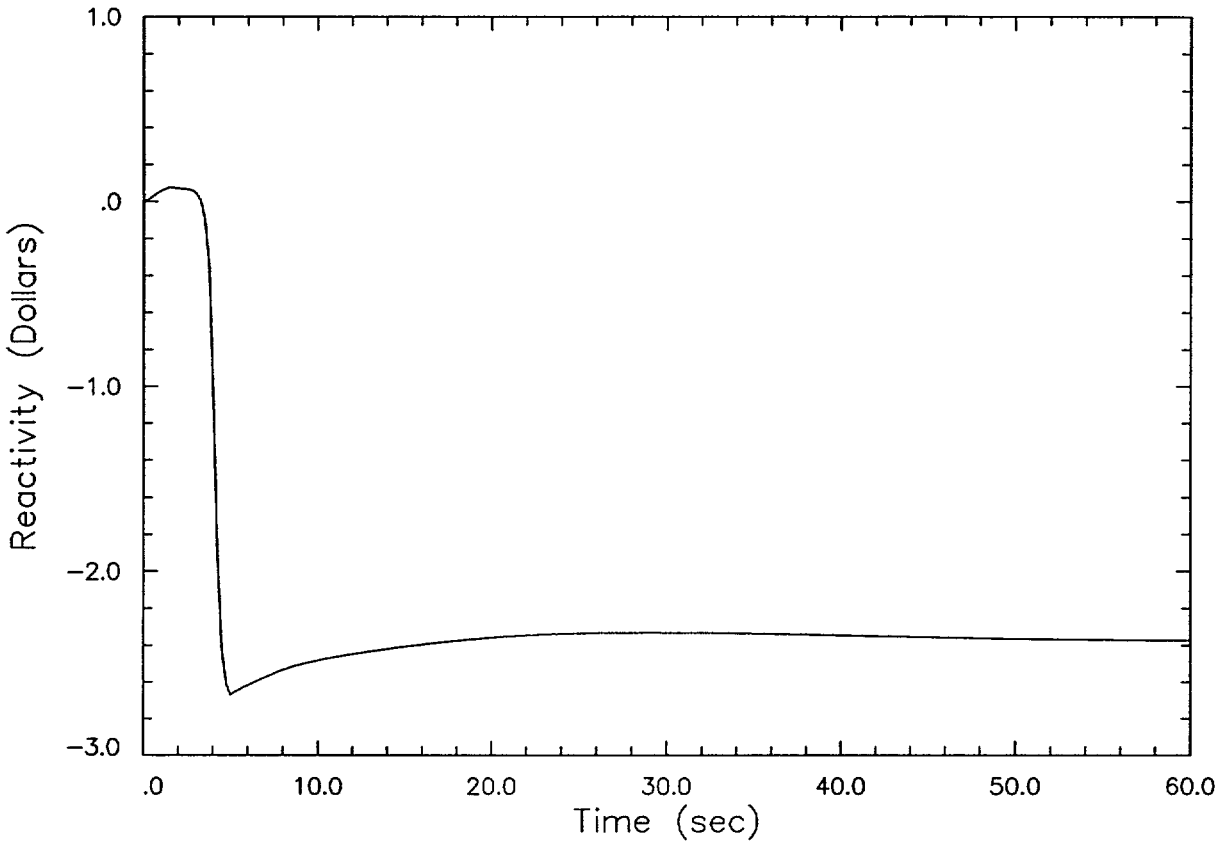

Figure 6.2.16-13 Total Core Reactivity for Locked Rotor MDNBR Case

6.2.17 Reactor Coolant Pump Shaft Break (FSAR Event 15.3.4)

6.2.17.1 Identification of Causes and Accident Description

This event is initiated by the instantaneous shearing of an RCP shaft, resulting in a free-wheeling impeller. The impact of a coolant pump shaft break is a loss of pumping power from the affected pump and a reduction in the RCS flow rate. The flow reduction due to the seizure of a pump rotor is more severe than that for a shaft break; however, the potential for flow reversal is greater for the shaft break event. The event is terminated by the low reactor coolant flow trip.

No single active failure will adversely affect the consequences of the event.

6.2.17.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1 (Above P-7): The event is analyzed at rated power conditions because the available margin to SAFDLs is minimized at the maximum power level.

Above P-8, reactor trip occurs on low flow in any reactor coolant loop. Below P-8 and above P-7, a reactor trip will occur on low flow in any two coolant loops. The initial power level and the power-to-flow ratio which may be achieved between P-7 and P-8 as a result of a reactor coolant pump shaft break is significantly less limiting than at the rated power condition.

Reactor protection is afforded by the low coolant flow trip and the high pressurizer pressure trip.

Mode 1 (Below P-7) and Mode 2: The reactor trip on low flow is not required. Three primary coolant pumps must be operating in these modes. A sheared pump shaft leaves two pumps operating, with more than sufficient primary flow to ensure adequate margin to the DNB SAFDL. Fuel centerline melt limits are not challenged due to the low power level. Reactor coolant temperature increases occur slowly due to the low initial power level, so pressurization effects are not limiting. The event is bounded in these modes by the Mode 1 analysis.

Mode 3 through 6: Because the reactor is not critical, margin to SAFDLs is not a concern in these modes. Ample decay heat removal is assured by natural circulation and/or the residual heat removal system. The event is bounded in these modes by the Mode 2 event.

Based on the above evaluations, both an overpressurization case and a MDNBR case are analyzed for this event. The analysis is performed with BOC kinetics parameters.

Normal power for the reactor coolant pumps is supplied through individual buses connected to the turbine generator. When a generator trip occurs, the buses are automatically transferred to a transformer supplied from external power lines, and the reactor coolant pumps will continue to supply coolant flow to the core. Following any turbine trip where there are no electrical faults which require tripping the generator from the network, the generator remains connected to the

network for approximately 30 seconds. The reactor coolant pumps remain connected to the generator ensuring full flow for approximately 30 seconds after the reactor trip before any supply power transfer is made. This analysis conservatively assumes the remaining two pumps are connected to the generator for 3 seconds following the low flow trip.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.17.3 Acceptance Criteria

The Reactor Coolant Pump Shaft Break event is classified as a Condition IV event. The acceptance criteria for this event are the same as those listed for the Pump Rotor Seizure/Locked Rotor event in Section 6.2.16.3.

6.2.17.4 Results

The calculations performed for this event showed that the MDNBR, fuel centerline melt, and overpressurization consequences are bounded by those of the Pump Rotor Seizure/Locked Rotor event. As noted in Section 6.2.16.5, the Condition IV acceptance criteria are met for the Pump Rotor Seizure/Locked Rotor event.

6.2.17.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.17.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

6.2.18 Uncontrolled Rod Cluster Control Assembly Withdrawal from a Subcritical or Low Power Startup Condition (FSAR Event 15.4.1)

6.2.18.1 Identification of Causes and Accident Description

This event is initiated by the uncontrolled withdrawal of a rod cluster control assembly (RCCA) bank from subcritical or low power. The event could be caused by a malfunction in the reactor control or rod control systems. The malfunction could result in a rapid and large positive reactivity insertion, which is terminated by a high neutron flux reactor trip.

The RCCA drive mechanisms are wired together into preselected bank configurations. These circuits prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power is supplied to the banks in such a way that no more than two banks can be withdrawn at the same time and in their proper withdrawal sequence.

The positive reactivity insertion rate is rapid enough that very high neutron powers are calculated, but of short enough duration that excessive energy deposition does not occur. Rod surface heat flux lags the neutron power but still approaches a significant fraction of full power. Because the event is very rapid, an increase in primary coolant temperature lags behind power. The reactivity insertion rate is initially countered by the fuel temperature reactivity (Doppler) coefficient followed by trip and rod insertion.

The power transient (as well as the RCCA withdrawal) is eventually terminated by the reactor protection system on one of the following signals: source range high neutron flux reactor trip, intermediate range high neutron flux reactor trip, power range high neutron flux reactor trip (low setting), power range high neutron flux reactor trip (high setting), or high nuclear flux rate reactor trip.

No single active failure will adversely affect the consequences of the event.

6.2.18.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The event is considered in Event 15.4.2.

Modes 2 and 3: The event is analyzed, with two operating primary coolant pumps providing coolant flow through the reactor core. The event considered is the simultaneous withdrawal of the combination of two sequential control banks having the maximum combined worth at maximum speed. The initial reactor coolant temperature is at the zero load program value. The event initiates from a zero power critical condition to ensure a bounding analysis. These assumptions maximize the challenge to SAFDLs.

Protection is provided by the power range neutron flux trip, high and low settings, the power range neutron flux trip on high positive rate, the intermediate range neutron flux trip, and the source range neutron flux trip.

Modes 4, 5, and 6: The reactor coolant temperature is below 350 °F. The challenge to SAFDLs is thus less than that resulting in Mode 3. The event in these modes is bounded by the Mode 3 event. Based on the above evaluations, the objective of this analysis is to bound plant operational modes below approximately 10% of rated power to where the operational state (shutdown margin) precludes return to power in an anticipated operational occurrence.

This event is driven by the magnitude and rate of reactivity insertion. The reactivity insertion rate is rapid enough that very high neutron powers are calculated, but of short enough duration that excessive energy deposition does not occur. Because the event is very rapid, an increase in primary coolant temperature lags behind power. The low coolant flow rate in the core accompanied by a rapid surge of power makes this event a challenge to the SAFDLs, which is controlled by the rate of energy dissipation from the fuel rod.

A low initial power yields the maximum margin to trip and, hence, maximum time for withdrawal to trip. This will yield the largest prompt multiplication which maximizes overshoot past trip. The initial power selected conservatively bounds the shutdown condition. Therefore, this event is analyzed at HZP conditions. Two reactor coolant pumps are assumed operational to minimize the coolant flow. The event is analyzed using BOC neutronics conditions.

The analysis bounds operating modes from where shutdown margin permits criticality due to rod withdrawal to the power range flux trip (low setting) reset setpoint, approximately 10% rated power.

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.18.3 Acceptance Criteria

The Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Startup Condition event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the

applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

6.2.18.4 Results

The predicted MDNBR is greater than the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold temperature is not penetrated during this event. Thus, the acceptance criteria for this event are met.

This transient tripped on power range neutron flux, low setting. The sequence of is given in Table 6.2.18-1. The responses to key system variables are given in Figure 6.2.18-1 to Figure 6.2.18-4.

6.2.18.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal no-load primary T_{avg} of 557°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal no-load primary T_{avg} of 557°F for steam generator tube plugging from 0% to 10%.

6.2.18.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.18-1 Event Summary for Uncontrolled Bank Withdrawal from a Subcritical or Low Power Condition

Event	Time (s)
Initiate transient (RCCA withdrawal began)	0.0
Power range high neutron flux (low setting) reactor trip signal	27.9
Scram initiated	28.4
Peak power	28.8
MDNBR occurred	30.7
Peak fuel centerline temperature	31.0
Peak RCS pressure	31.3

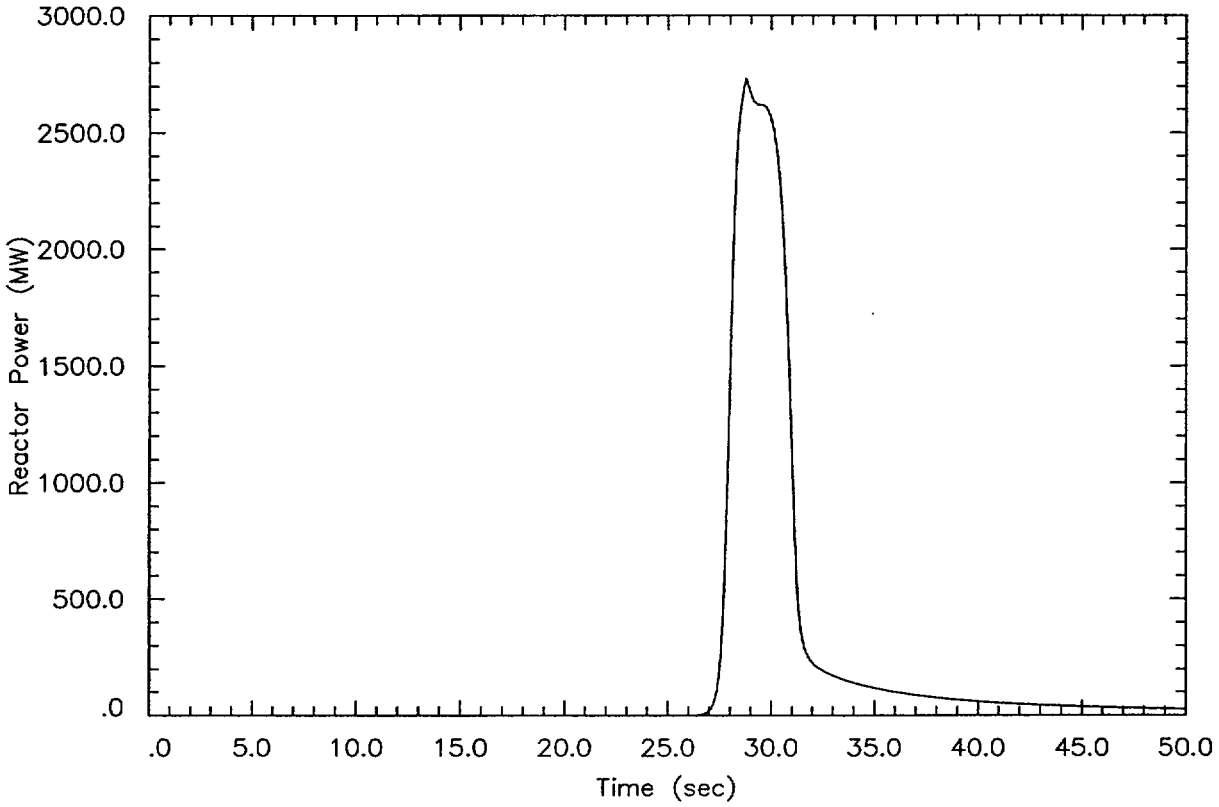

Figure 6.2.18-1 Reactor Power for Uncontrolled RCCA Bank Withdrawal at HZP

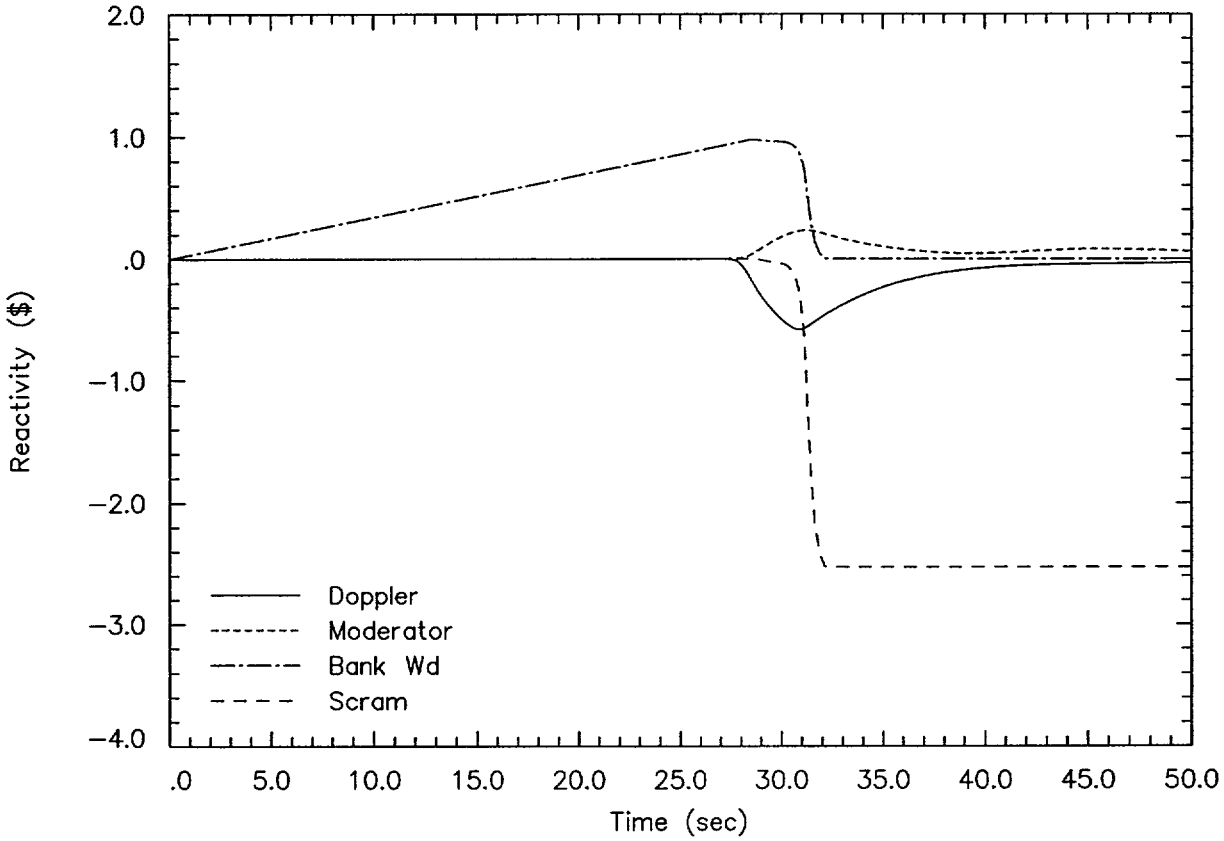

Figure 6.2.18-2 Reactivities for Uncontrolled RCCA Bank Withdrawal at HZP

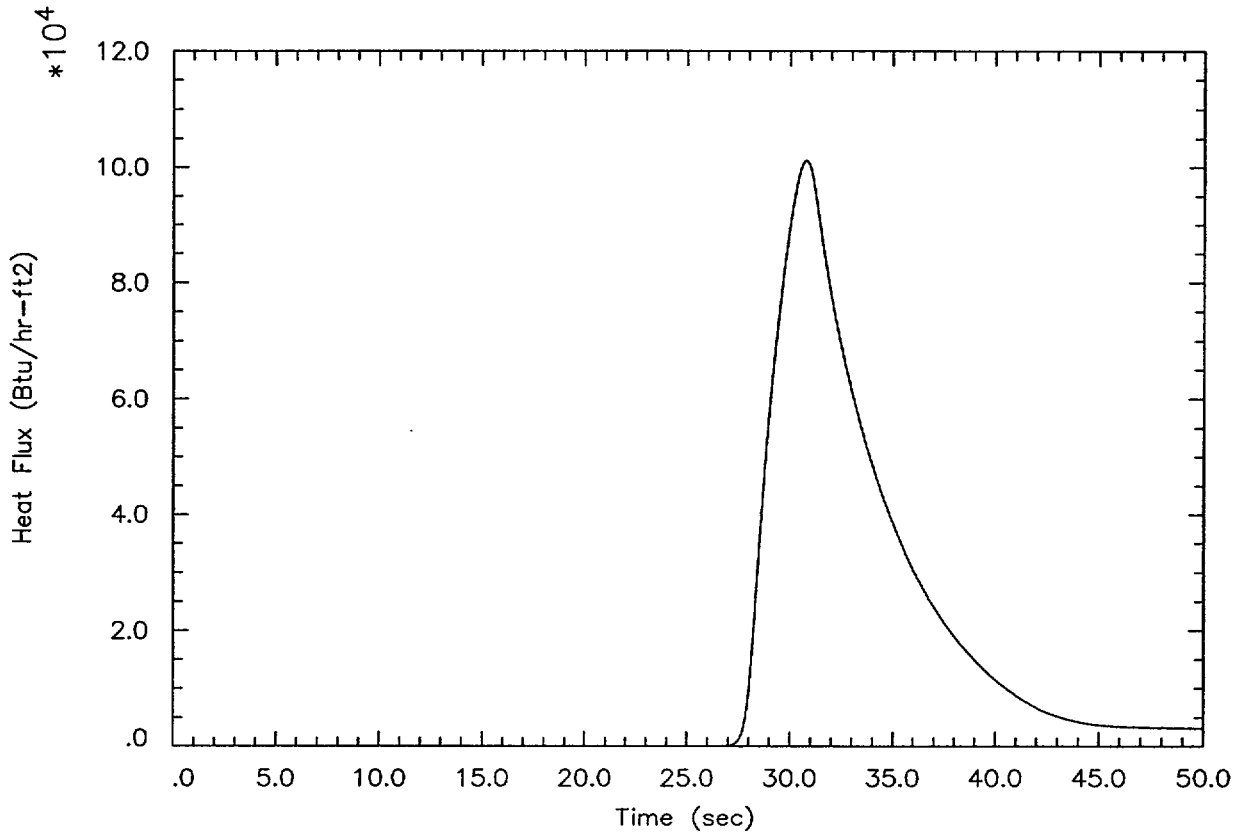

Figure 6.2.18-3 Core Average Heat Flux for Uncontrolled RCCA Bank Withdrawal at HZP

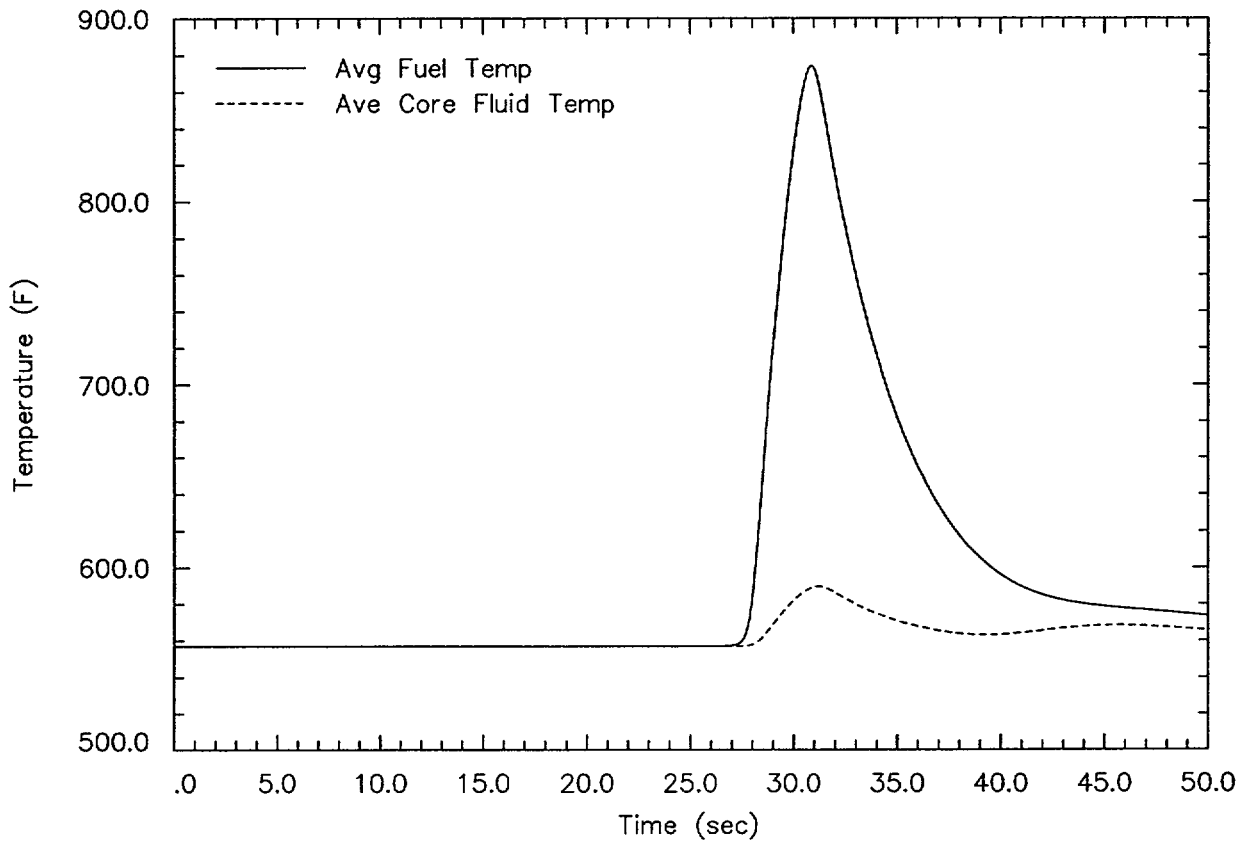

Figure 6.2.18-4 Average Fuel and Average Core Fluid Temperature for Uncontrolled RCCA Bank Withdrawal at HZP

6.2.19 Uncontrolled Rod Cluster Control Assembly Withdrawal at Power (FSAR Event 15.4.2)

6.2.19.1 Identification of Causes and Accident Description

This event is initiated by an uncontrolled withdrawal of a RCCA bank at power. The RCCA withdrawal adds positive reactivity to the core which leads to a power excursion. The increase in core power results in an increase in the core heat flux, creating a challenge to the DNB margin. The challenge to the DNB margin is further accentuated by the mismatch between the energy removal from the steam generators and the power produced in the core (assuming an essentially constant steaming rate). This mismatch in power causes the primary system temperatures to increase, reducing the DNB margin.

The challenge to the fuel design limits is terminated by the automatic action of the reactor protection system, which terminates the bank withdrawal and inserts negative reactivity to terminate the power/heat flux transient. The automatic action of the reactor protection system is initiated as the results of one of the following signals: power range high neutron flux (high setting), high flux rate (positive setting), OTΔT, OPΔT, high pressurizer pressure, or high pressurizer water level.

No single active failure will adversely affect the consequences of the event.

6.2.19.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1 (Above P-10): The event is analyzed to assess the challenge to SAFDLs. The event analysis considers both BOC and EOC operating points, and a bounding spectrum of reactivity insertion rates for each.

Reactor protection is afforded by the power range neutron flux trip (high and low setting), the high flux rate trip (positive setting), the OTΔT trip, the high pressurizer pressure and level trips, and the OPΔT trip.

Mode 1 (Below P-10): The power range neutron flux trip system interlock P-10 automatically enables the power range neutron flux trip, low setting, and the intermediate range neutr on flux trip for power levels below 10%. These trips preclude the reactor power from increasing beyond 35% of rated power, and thus effectively preclude any significant challenge to the SAFDLs. The event in Mode 1 (Below P-10) is bounded by that analyzed in Mode 1 (Above P-10).

Reactor protection is provided by the power range neutron flux trip, low setting, the intermediate range neutron flux trip, the high pressurizer pressure trip, and the OTΔT trip.

Modes 2 through 6: These events are considered in Event 15.4.1.
Based on the above evaluations, the power range to be considered in this analysis is from the power range high flux (low setting) trip reset point (approximately 10% of rated power), up to full power. This analysis considers a spectrum of reactivity insertion rates at initial power levels of 60% and 100%. Since the 60% power level cases were less limiting than the full power cases, no cases were analyzed at power levels below 60%. Since neutronic feedback as a function of cycle exposure and design also influences the results, these effects are also included in the analysis.

A broad range of reactivity insertion rates are possible. Therefore, a spectrum of reactivity insertion rates were evaluated in order to bound events ranging from a slow dilution of the primary system boron concentration to the maximum possible RCCA bank withdrawal rate at maximum bank worth. Specifically, the analysis encompasses reactivity insertion rates up to 100 pcm/sec.

Reactivity feedback effects are bounded by analyzing a series of BOC cases representing the minimum reactivity feedback (positive moderator coefficient and least negative Doppler coefficient) and a series of EOC cases representing maximum feedback (conservatively large negative moderator coefficient and most negative Doppler coefficient).

The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The final MDNBR results were obtained by a statistical analysis with the approved SPC statistical methodology (References 4 and 5). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.19.3 Acceptance Criteria

The Uncontrolled RCCA Withdrawal at Power event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressure in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

6.2.19.4 Results

Reactivity insertion transient calculations demonstrate that the DNB correlation limit will not be penetrated during any credible reactivity insertion transient at full power. Analysis results demonstrate that transients initiated at power levels below full power are less limiting. The critich heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not

expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event.

Figure 6.2.19-1 presents the MDNBR trend, based on a deterministic combination of uncertainties, for the range of reactivity addition rates analyzed for the full power BOC and EOC cases. The limiting uncontrolled RCCA bank withdrawal transient occurred at full power with EOC kinetics and a reactivity insertion rate of 27.6 pcm/sec.

The sequence of events for the limiting Uncontrolled RCCA Bank Withdrawal transient is given in Table 6.2.19-1. The responses to key system variables for the limiting transient are given in Figure 6.2.19-2 to Figure 6.2.19-9. Note that the reactor power shown in Figure 6.2.19-2 stabilizes at a power of about 35% of rated. The power stabilizes at this relatively high level because the reactor trip reactivity insertion is conservatively assumed to be the minimum allowed shutdown margin with the most reactive rod stuck out of the core, which is a much lower reactivity than the minimum HFP scram worth with the most reactive rod stuck out of the core.

6.2.19.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.19.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

4. EMF-92-081(P) Revision 1, Statistical Setpoint/Transient Methodology for Westinghouse Type Reactors, Siemens Power Corporation, December 1998.

5. Letter from S. A. Richards (USNRC) to J. F. Mallay (SPC), Acceptance for Referencing of Licensing Topical Report EMF-92-081, Revision 1, "Statistical Setpoint/Transient

Methodology for Westinghouse Type Reactors," (TAC No. MA4593), February 10, 2000.

Table 6.2.19-1 Event Summary for Uncontrolled Bank Withdrawal at Power Limiting Case (EOC, 27.6 pcm/sec insertion rate)

Event	Time (s)
Initiate transient (RCCA withdrawal began)	0.0
Compensated PORVs open	14.1
OTDT reactor trip setpoint reached	30.2
Scram initiated	31.5
MDNBR	31.5
Peak pressurizer pressure	31.6
Peak secondary pressure	38.9

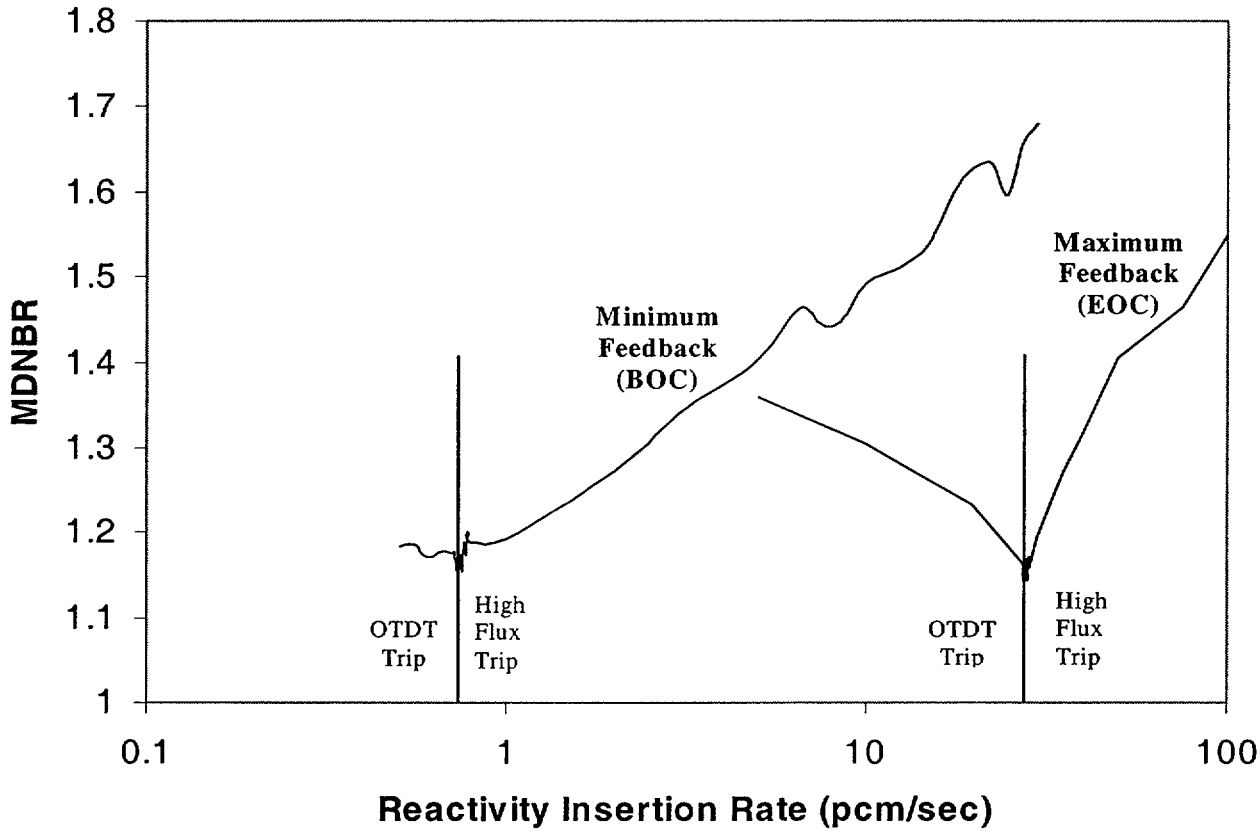

Figure 6.2.19-1 Deterministic MDNBR versus Reactivity Insertion Rate for Full Power Uncontrolled RCCA Bank Withdrawal

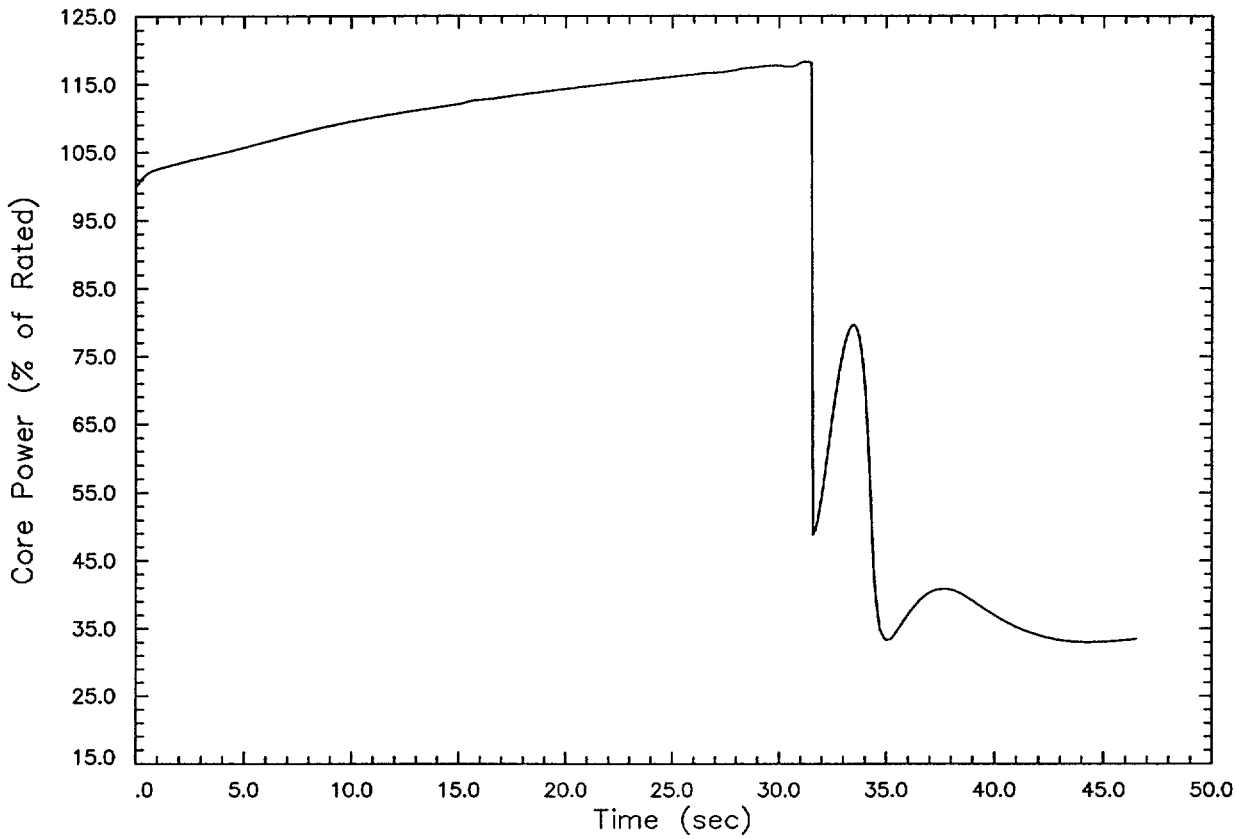

Figure 6.2.19-2 Reactor Power for Limiting Uncontrolled RCCA Bank Withdrawal Case

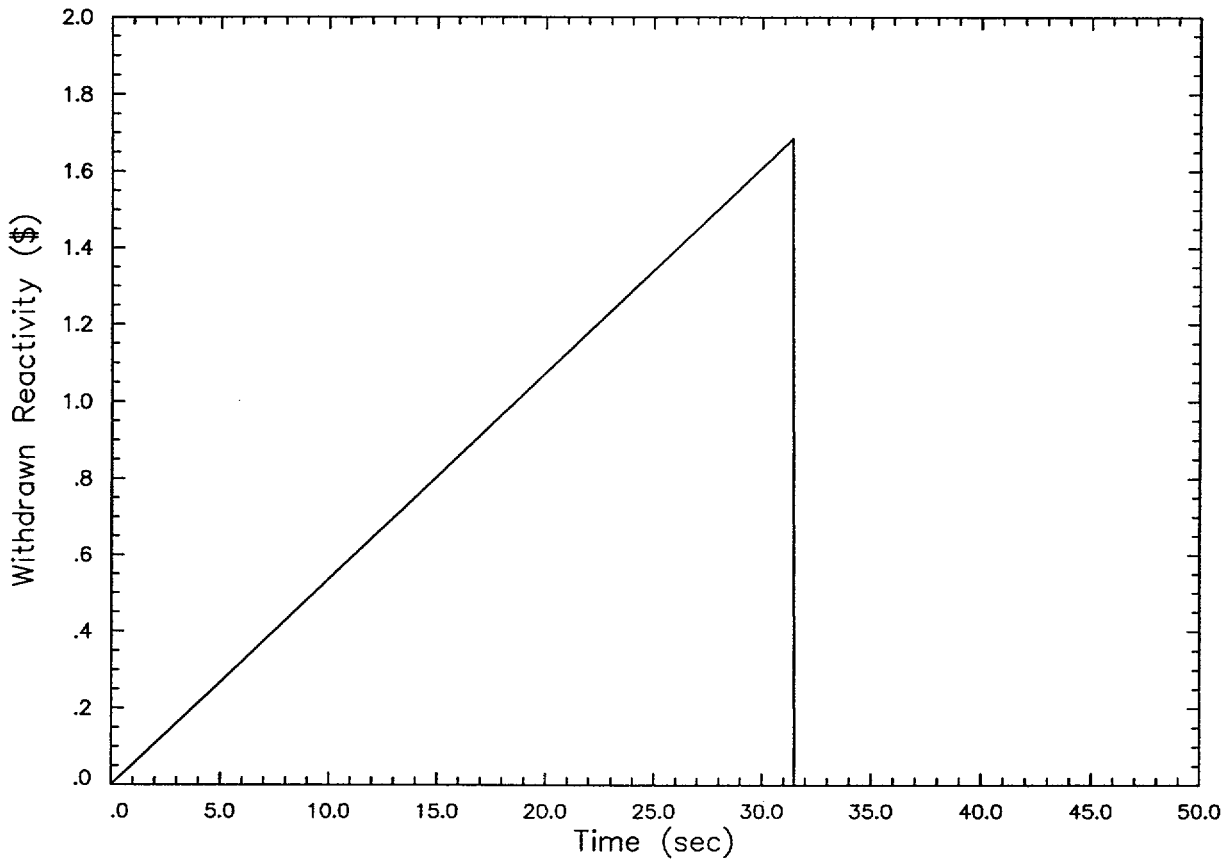

Figure 6.2.19-3 Bank Withdrawal Reactivity for Limiting Uncontrolled RCCA Bank Withdrawal Case

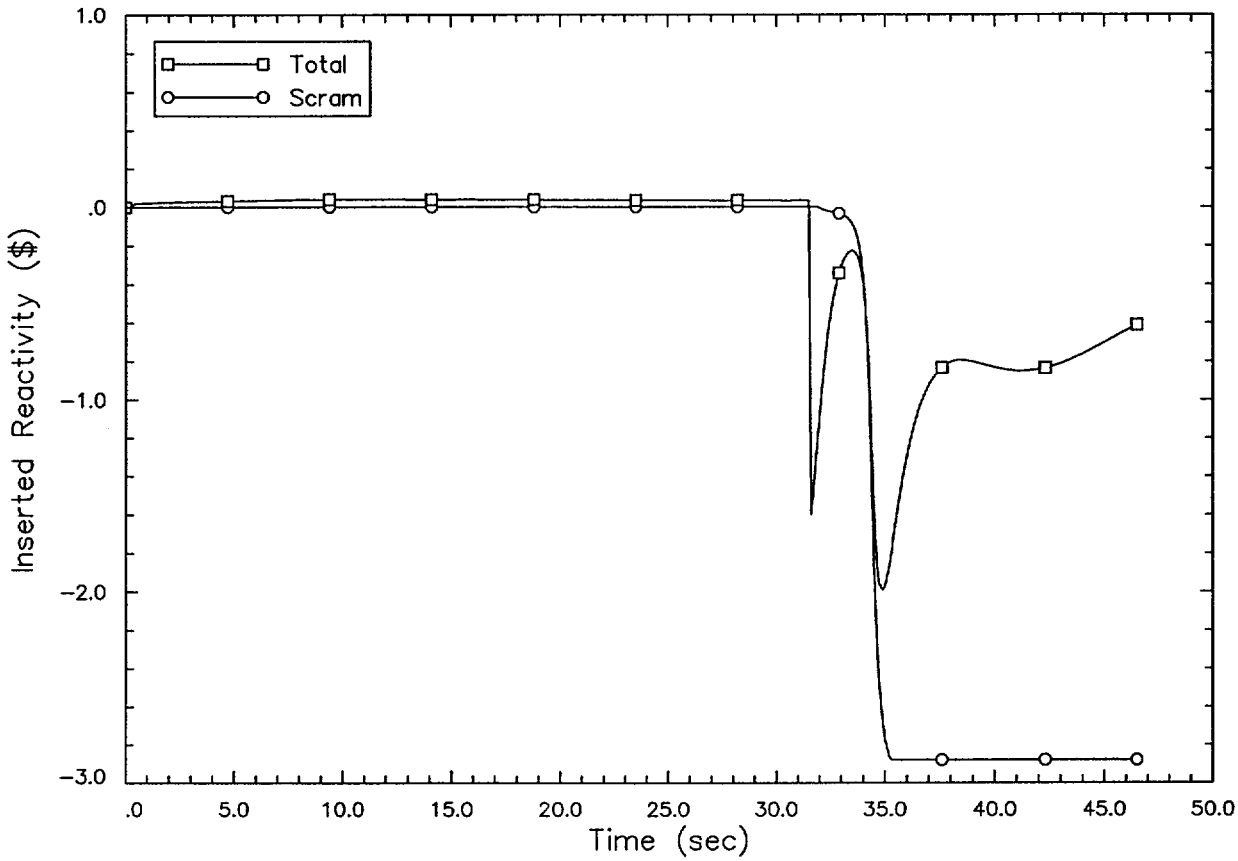

Figure 6.2.19-4 Reactivities for Limiting Uncontrolled RCCA Bank Withdrawal Case

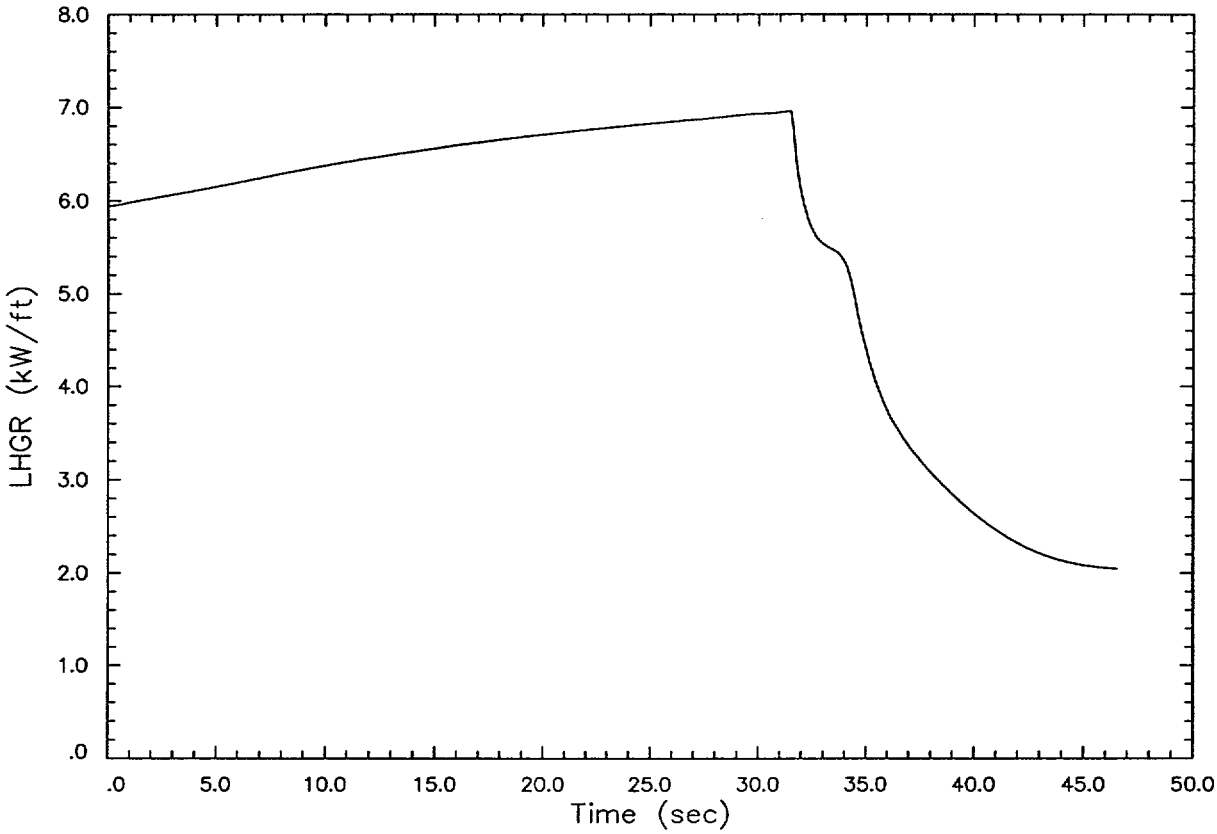

Figure 6.2.19-5 Average Core LHGR for Limiting Uncontrolled RCCA Bank Withdrawal Case

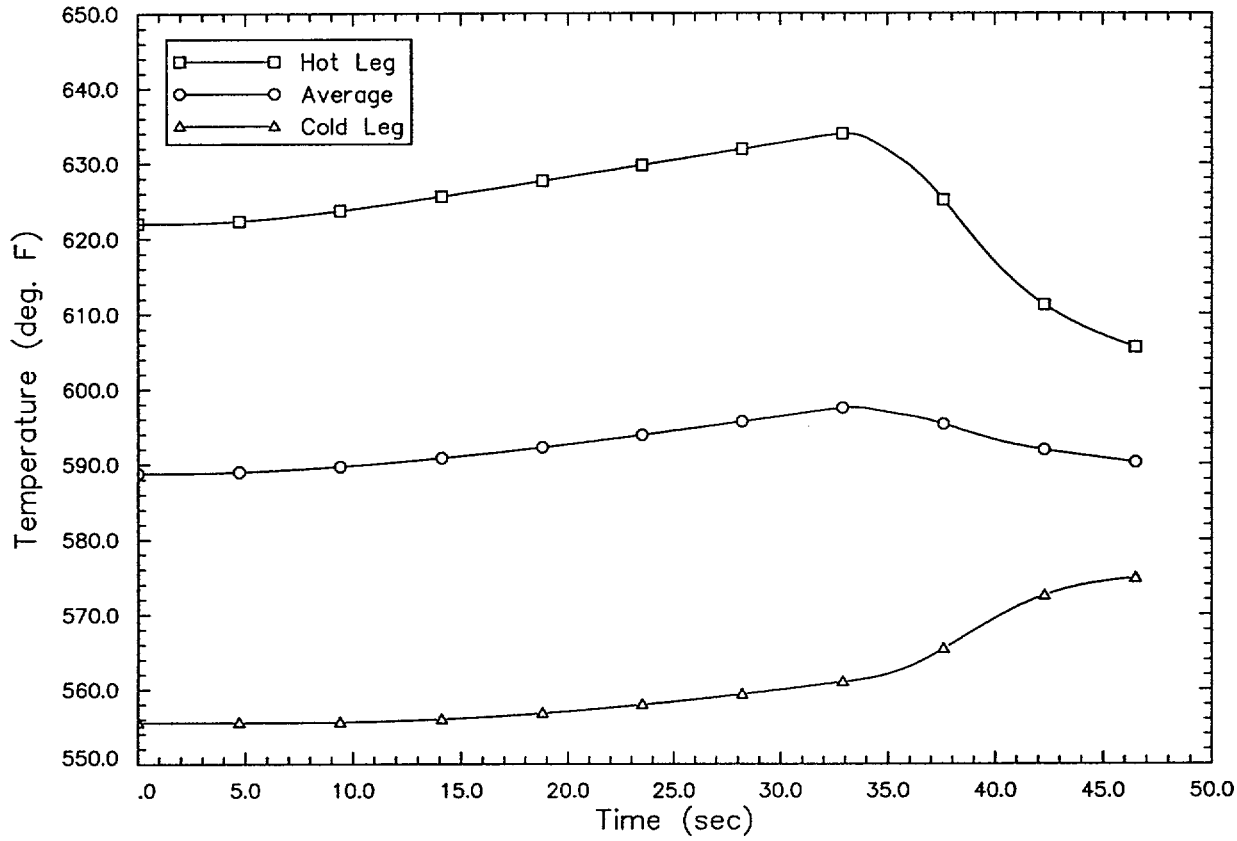

Figure 6.2.19-6 Primary System Temperatures for Limiting Uncontrolled RCCA Bank Withdrawal Case

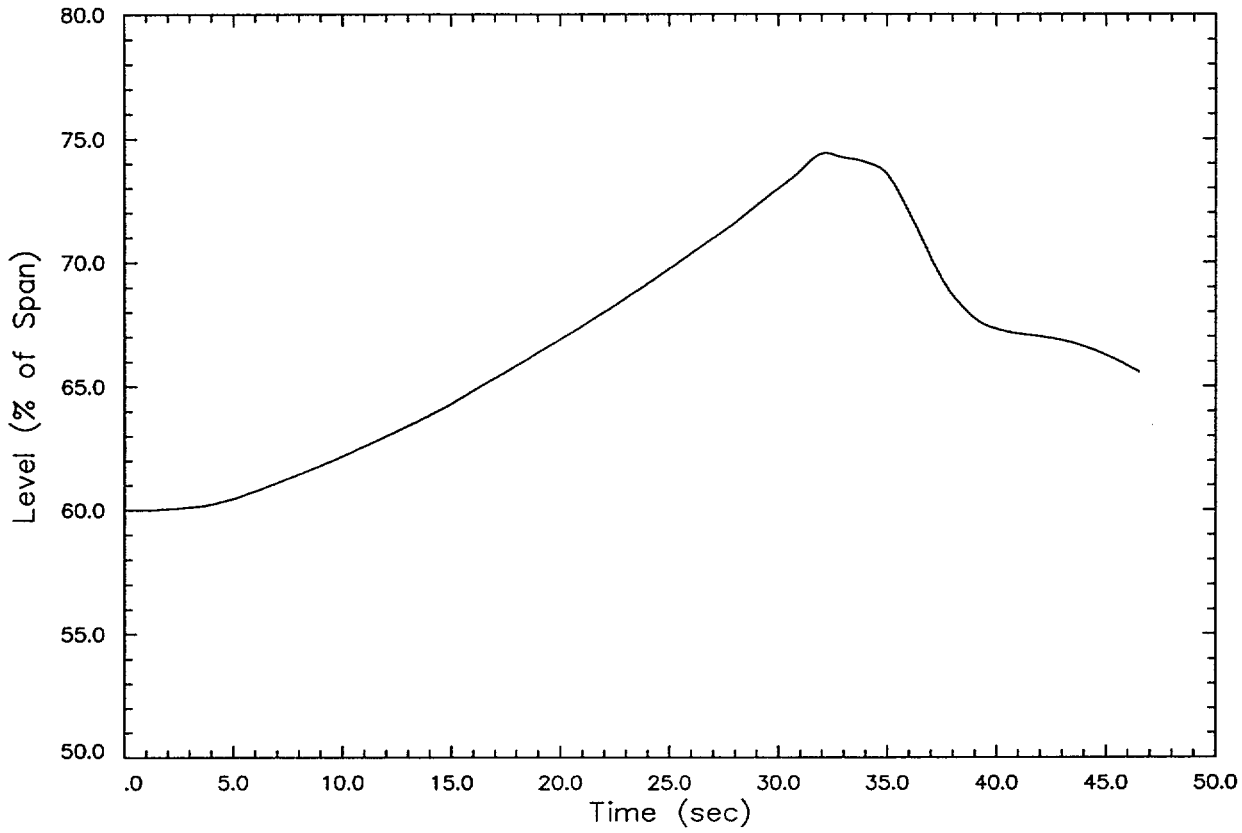

Figure 6.2.19-7 Pressurizer Level for Limiting Uncontrolled RCCA Bank Withdrawal Case

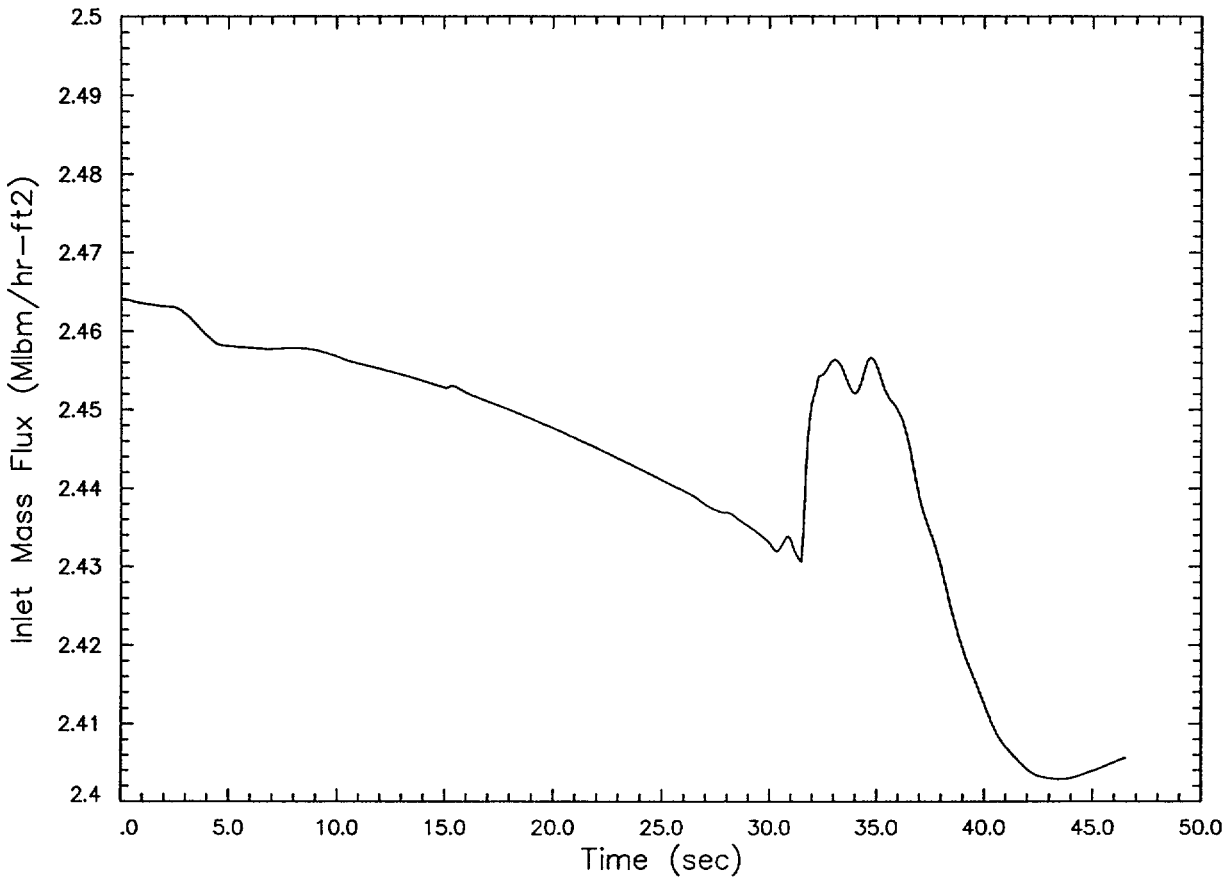

Figure 6.2.19-8 Core Inlet Mass Flux for Limiting Uncontrolled RCCA Bank Withdrawal Case

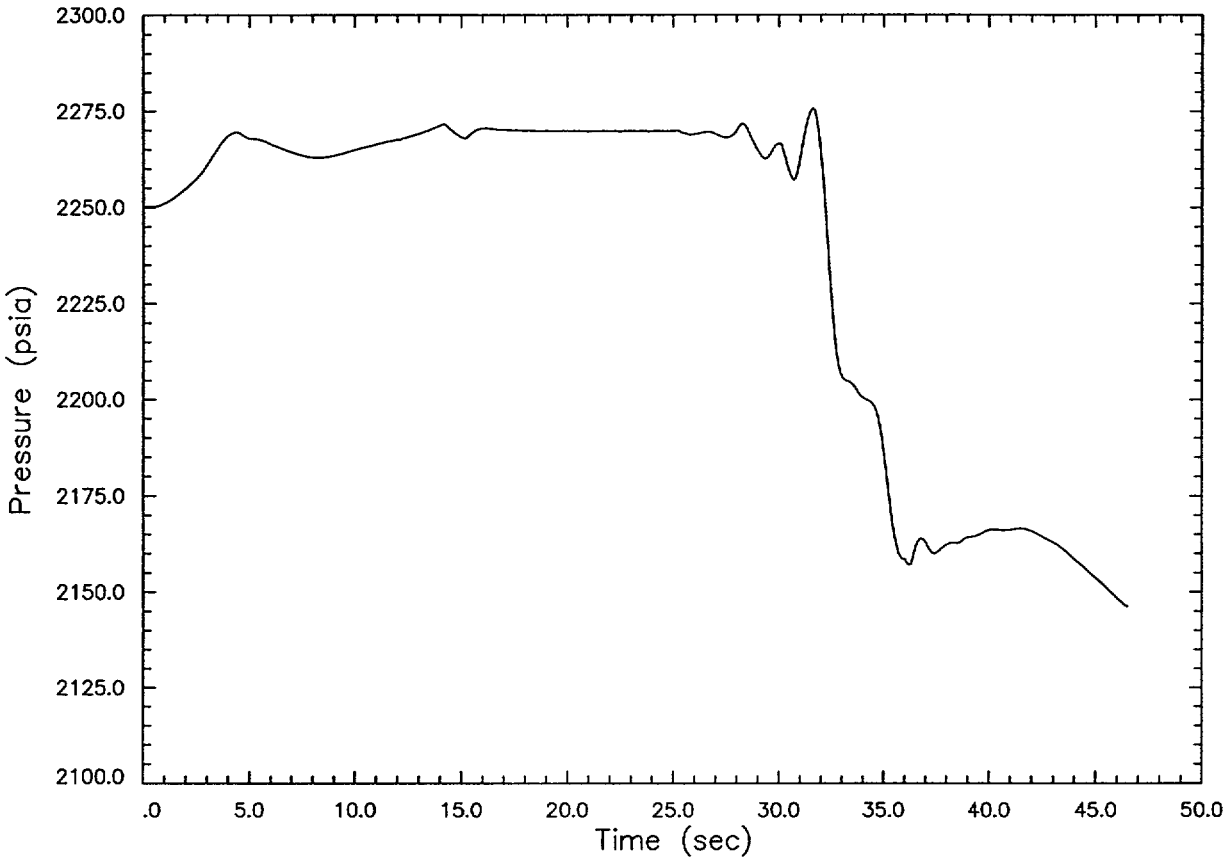

Figure 6.2.19-9 Pressurizer Pressure for Limiting Uncontrolled RCCA Bank Withdrawal Case

6.2.20 Control Rod Misoperation (FSAR Event 15.4.3)

The control rod misoperation events encompass transient and steady state configurations resulting from different event initiators. The specific events analyzed under this event category are:

(1) Dropped full length RCCA or RCCA bank

(2) Withdrawal of a single full length RCCA

(3) Statically misaligned RCCA or RCCA bank

Each RCCA has a position indicator which displays the position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod bottom signal, which actuates a local alarm and a Control Room annunciator. Group demand position is also indicated. The full length RCCAs are always modeled in preselected banks and the banks are always moved in the same preselected sequence with a specified overlap.

6.2.20.1 Identification of Causes and Accident Description

Dropped Full Length RCCA or RCCA Bank

The dropped RCCA and dropped RCCA bank events are initiated by a de-energized control rod drive mechanism or by a malfunction associated with a RCCA bank during power operation. The result is that a single RCCA or RCCA bank falls into the core. The dropped rod promptly inserts negative reactivity which reduces reactor power and disturbs the power distribution, resulting in increased local power peaking. Elevated clad heat flux in the hot assembly may result in an approach to the DNBR SAFDL. Two operational states are available at the Harris Plant: manual and automatic rod control (ARC).

In the manual rod control mode at EOC conditions, the decrease in moderator temperature and the strongly negative moderator temperature coefficient can return the reactor to a full power condition with an elevated radial power peaking factor subsequent to the dropped RCCA. An automatic and redundantly actuated reduction in turbine load demand (turbine runback) is provided as protection for this event. When turbine runback occurs, the turbine load reduction reduces secondary steam flow, causing an increase in secondary side temperature and pressure. Thus, the primary coolant temperature decrease is mitigated, reducing the reactivity insertion contingent on cooldown and reducing the ultimate power level at which the reactor stabilizes.

In the ARC mode, the ARC system receives signals from the excore detectors and the turbine to indicate a primary/secondary side power mismatch. In an attempt to eliminate the mismatch, the ARC system initiates the withdrawal of a partially inserted control bank. Power overshoot may occur, after which the control rod system will insert the control bank and return the plant to nominal power. The magnitude of the power overshoot is a function of the core reactivity coefficients, the dropped rod worths, the differential bank worths, and the rod shadowing factors.

An automatic and redundantly actuated turbine runback is provided as protection for this event. When turbine runback occurs, the ARC setpoint reference temperature is also set back to an average primary coolant temperature corresponding to the new turbine load demand. With turbine runback, the reduction in load initially results in a load mismatch if the dropped rod (bank) reactivity does not match that required for the setback power level. If the dropped rod worth is not equal to the reactivity to match the power runback, a power mismatch between primary and secondary occurs and is detected by either coolant temperature or neutron power deviation from the respective setpoint. The controller output signal is sent to the control rod driver controller, which acts to minimize the mismatch.

The ARC system utilizes the signal from one excore flux detector position. The ARC acts to mitigate the power increase except when the dropped rod is close to the control excore flux detector. When the dropped rod is close to the control detector, the detector is "shadowed" and the reduction in detected flux is greater than the core average. The detector may, therefore, indicate a lower than actual power, with an output signal sent to the rod controller resulting in overcompensation. The overcompensation may result in an increase in core power from the prompt reduction due to rod drop.

Withdrawal of Single Full-Length RCCA

The rod withdrawal event is initiated by an electrical or mechanical failure in the rod control system that causes the inadvertent withdrawal of a single RCCA. This causes an increase in positive reactivity that results in a power transient. The movement of a single control rod assembly out of sequence from the other rods in the bank also results in a local power distribution increase. The combination of these two factors results in a challenge to the DNB margin. The DNB margin is further reduced by the mismatch between the constant energy removal rate of the steam generators and the increased energy generation rate in the core which increases the primary system temperature.

The system response is essentially the same as that occurring in the Uncontrolled Bank Withdrawal event at power (Event 15.4.2). The single RCCA withdrawal is distinguished from the withdrawal of an RCCA bank by the severe radial power redistribution. High radial peaking is localized in the region of the single withdrawn RCCA and may, in severe cases, surpass the design limits.

Automatic protection for this event is provided by the OTΔT trip. However, because of the localized power peaking the possibility of a violation of the core safety limits may occur. This is acceptable, since this event is classified as a Condition III event, provided only a small fraction of the fuel is predicted to exceed the safety limits.

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single RCCA from the inserted RCCA bank during full power operation. The operator could deliberately withdraw a single control rod assembly. The event can occur only as a result of multiple wiring failures or multiple significant operator actions in disregard of available event indications. The probability of such a combination of conditions is low and the limiting consequences may include slight fuel damage.

No single failure will prevent operation of any system required to function.

Statically Misaligned RCCA or RCCA Bank

The static misalignment event occurs when a malfunction of the Control Rod Drive (CRD) mechanism causes a control rod to be out of alignment with its bank. Misalignment occurs when the rod is either higher or lower than any of the other control rods in the same bank. During this event, the reactor is at steady-state rated full power conditions, and no excursion of core temperature, pressure, flow, or power occurs. The resulting local power distribution disturbance causes an increased radial peaking factor. This increased power peaking results in a reduction in the margin to DNB.

Misaligned assemblies are detected by asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples, a rod deviation alarm, or rod position indicators. Following the identification of a statically misaligned control rod assembly by the operator, the operator is required to take action as required by the plant technical specification and operating instructions.

No single failure will prevent operation of any system required to function.

6.2.20.2 Description of Analysis

Dropped Full Length RCCA or RCCA Bank

The event is evaluated on a mode-by-mode basis.

Mode 1: The event is analyzed to evaluate the challenge to SAFDLs.

Reactor protection is provided by the OTΔT trip, the OPΔT trip, the power range neutron flux trip (high setting), and the power range neutron flux trip on high negative rate.

Modes 2 through 6: The challenge to SAFDLs is significantly reduced in these modes due to reduced operating power or because the reactor is in a subcritical state. The Mode 1 event therefore bounds the event in Modes 2 through 6.

Based on the above evaluations, a comprehensive analysis of the possible dropped RCCA configurations was performed considering both BOC and EOC kinetics parameters. Case specific quadrant NI detector signals were modeled to simulate the detector response due to asymmetric radial power redistribution. The limiting single failure was a failure of a NI detector which results in fewer RCCA dropped cases initiating either a high negative flux rate or high neutron flux RPS trip. The analysis covered possible combinations and spectra of rod worth, bank differential worth, rod shadowing factor, and MTC.

The characteristic system response for this event is strongly dependent on the neutron kinetics feedback, the worth of the dropped RCCA or RCCA bank, and on the availability of the ARC system. Cases involving dropped RCCA banks do not result in appreciable degradation of

MDNBR due to the action of the high negative flux rate trip, which is used in this analysis, combined with the large initial power reduction. Therefore, only the dropped RCCA is evaluated.

The XTGPWR code (Reference 1) is used to calculate neutronics parameters such as rod worth and power peaking augmentation factors. The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 2). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 3 and 4). The final MDNBR results were obtained by a statistical analysis with the approved SPC statistical methodology (References 5 and 6). A radial power peaking factor on $F_{\Delta H}$ is included in the MDNBR calculation to account for radial power redistribution effects typical of the event.

Withdrawal of Single Full-Length RCCA

The event is evaluated on a mode-by-mode basis.

Mode 1: This subevent will be analyzed for the challenge to SAFDLs.

Reactor protection is provided by the OTΔT trip, the OPΔT trip, the power range neutron flux trip (high setting), and the power range neutron flux trip on high negative rate.

Modes 2 through 6: The challenge to SAFDLs is significantly reduced in these modes due to reduced operating power or because the reactor is in a subcritical state. The Mode 1 event therefore bounds the events in Modes 2 through 6.

The overall system response for a single RCCA withdrawal is identical to that of the analysis of the uncontrolled RCCA bank withdrawal event (Event 15.4.2). The difference is in the local peaking in the region of the single withdrawn RCCA that is not present if the entire bank is withdrawn. Therefore, the MDNBR calculation for the most limiting full power case from the RCCA bank withdrawal analysis will be reevaluated with a conservative radial peaking augmentation factor.

The event considers the radial redistribution of power in the core, and can result in radial peaking factors in excess of Technical Specification limits. The analysis is performed by coupling a conservative power peak to transient response and DNB calculations. The power peak associated with each event is characterized through an augmentation factor which relates the maximum power peak to the steady- state power peak. The steady-state power distributions and augmentation factors are calculated with the XTGPWR reactor simulator (Reference 1).

In the analysis of the single RCCA withdrawal event, the core boundary conditions of average heat flux, temperature, pressure and flow are selected from the limiting Uncontrolled RCCA Bank Withdrawal event (Event 15.4.2). These core boundary conditions are then combined in an XCOBRA-IIIC calculation (References 3 and 4) with a radial augmentation peaking factor calculated to bound the possible single rod withdrawal radial power redistribution.

Statically Misaligned RCCA or RCCA Bank

The event is evaluated on a mode-by-mode basis.

Mode 1: This subevent will be analyzed to verify the full power rod insertion limits for the SGR/Power Uprating.

Event indication is provided by detection of asymmetric core power distributions, rod deviation alarm, and rod position indicators.

Modes 2 through 6: The challenge to SAFDLs is significantly reduced in these modes due to reduced operating power or because the reactor is in a subcritical state. The Mode 1 events therefore bound the events in Modes 2 through 6.

The analysis of the statically misaligned RCCA or RCCA bank is performed using the XCOBRA-IIIC computer code (References 3 and 4). A conservative radial peaking augmentation factor is used.

6.2.20.3 Acceptance Criteria

Dropped Full Length RCCA or RCCA Bank

The Dropped Full Length RCCA or RCCA Bank event is classified as a Condition II event. Consistent with the current licensing basis, the Condition II acceptance criteria are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

Withdrawal of Single Full-Length RCCA

The Withdrawal of a Single Full-Length RCCA event is classified as a Condition III event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) A small fraction of fuel failures may occur, but these fuel failures should not hinder core coolability.

(3) Radiological consequences should be a small fraction of the 10 CFR 100 guidelines (generally <10%).

(4) The event should not generate a limiting fault or result in the consequential loss of the reactor coolant or containment barriers.

Statically Misaligned RCCA or RCCA Bank

The Statically Misaligned RCCA or RCCA Bank event is classified as a Condition II event. The acceptance criteria for this event are:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110% of design values (Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code).

(2) Fuel clad integrity shall be maintained by ensuring that the minimum DNBR will remain above the 95/95 DNBR limit for PWRs.

(3) An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained.

6.2.20.4 Results

Dropped Full Length RCCA or RCCA Bank

The predicted MDNBR is greater than the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event. Thus, the acceptance criteria for this event are met.

The sequence of events and results for the limiting case are given in Table 6.2.20-1. The responses to key system variables for the limiting case are given in Figure 6.2.20-1 to 6.2.20-9.

Withdrawal of Single Full-Length RCCA

The results of the analysis of the Single Control Rod Withdrawal event demonstrate that Condition III acceptance criteria are met, with the exception of the radiological consequences. The results of this analysis were provided for use in the analysis of the radiological dose consequences, which is documented in the BOP Licensing Report. The MDNBR for this event is less than the safety limit. A total of one assembly was predicted to fail, for a core failure percent of 0.64 %. The fuel centerline melt threshold is not penetrated during this event.

Statically Misaligned RCCA or Bank

The predicted MDNBR is greater than the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event. Thus, the acceptance criteria for this event are met.

6.2.20.5 Conclusions

Dropped Full Length RCCA or RCCA Bank

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

Withdrawal of Single Full-Length RCCA

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions, with the exception of conclusions related to radiological consequences. The conclusions of the analysis of the radiological dose consequences are documented in the BOP Licensing Report. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

Statically Misaligned RCCA or RCCA Bank

The current licensing basis identifies this event as being bounded by the Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (Event 15.4.7). However, for the SGR/Uprating conditions this event was explicitly analyzed and the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.20.6 References

1. XN-CC-28(A) Revision 3, XTG: A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing, Exxon Nuclear Company, September 1975.

2. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

3. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

4. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

5. EMF-92-081(P) Revision 1, Statistical Setpoint/Transient Methodology for Westinghouse Type Reactors, Siemens Power Corporation, December 1998.

6. Letter from S. A. Richards (USNRC) to J. F. Mallay (SPC), Acceptance for Referencing of Licensing Topical Report EMF-92-081, Revision 1, "Statistical Setpoint/Transient Methodology for Westinghouse Type Reactors," (TAC No. MA4593), February 10, 2000.

Table 6.2.20-1 Event Summary for Dropped RCCA

Event	Time (s)
Initiate rod drop transient	0.0
Maximum pressurizer pressure	27.80
Maximum core average power level	31.20
Maximum core average LHGR	36.20
MDNBR	36.20
Maximum pressurizer level	96.20

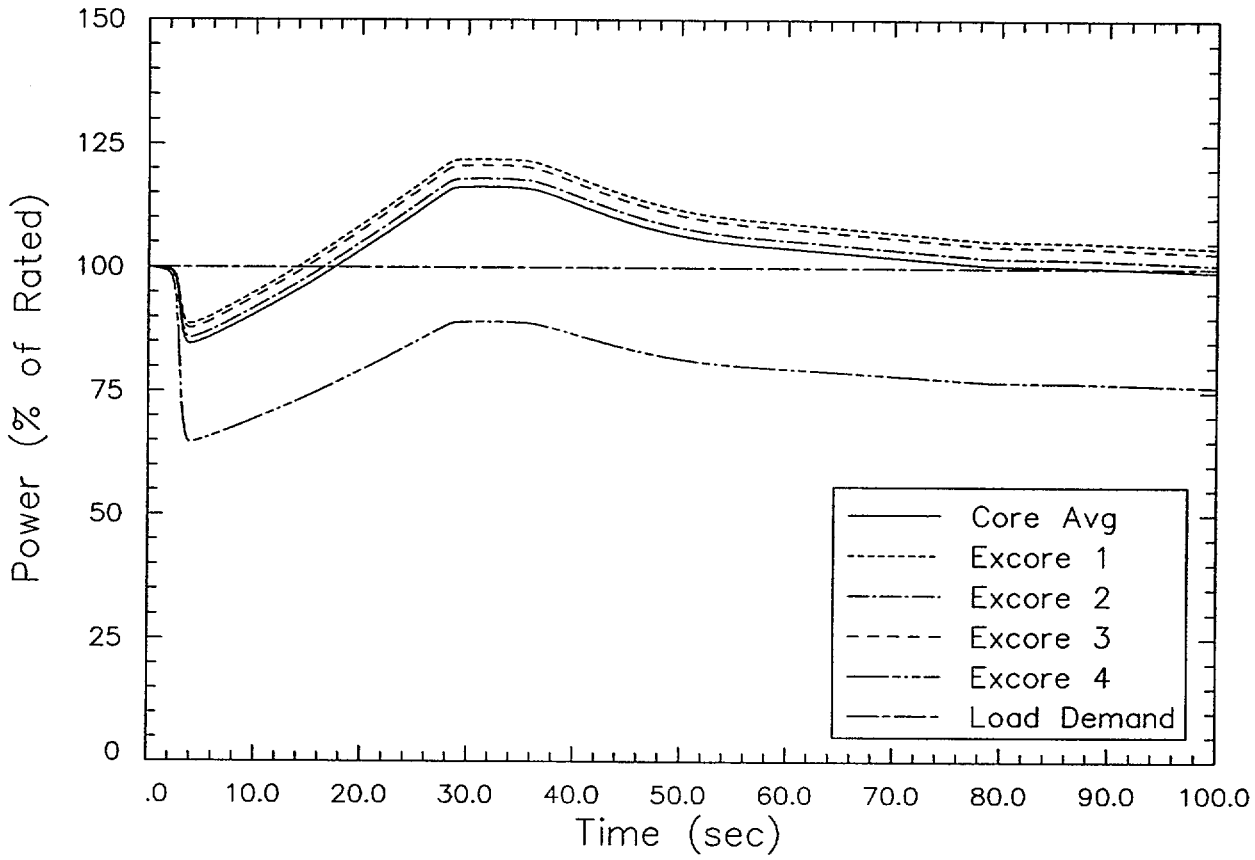

Figure 6.2.20-1 Reactor Power for Limiting Dropped Rod Case

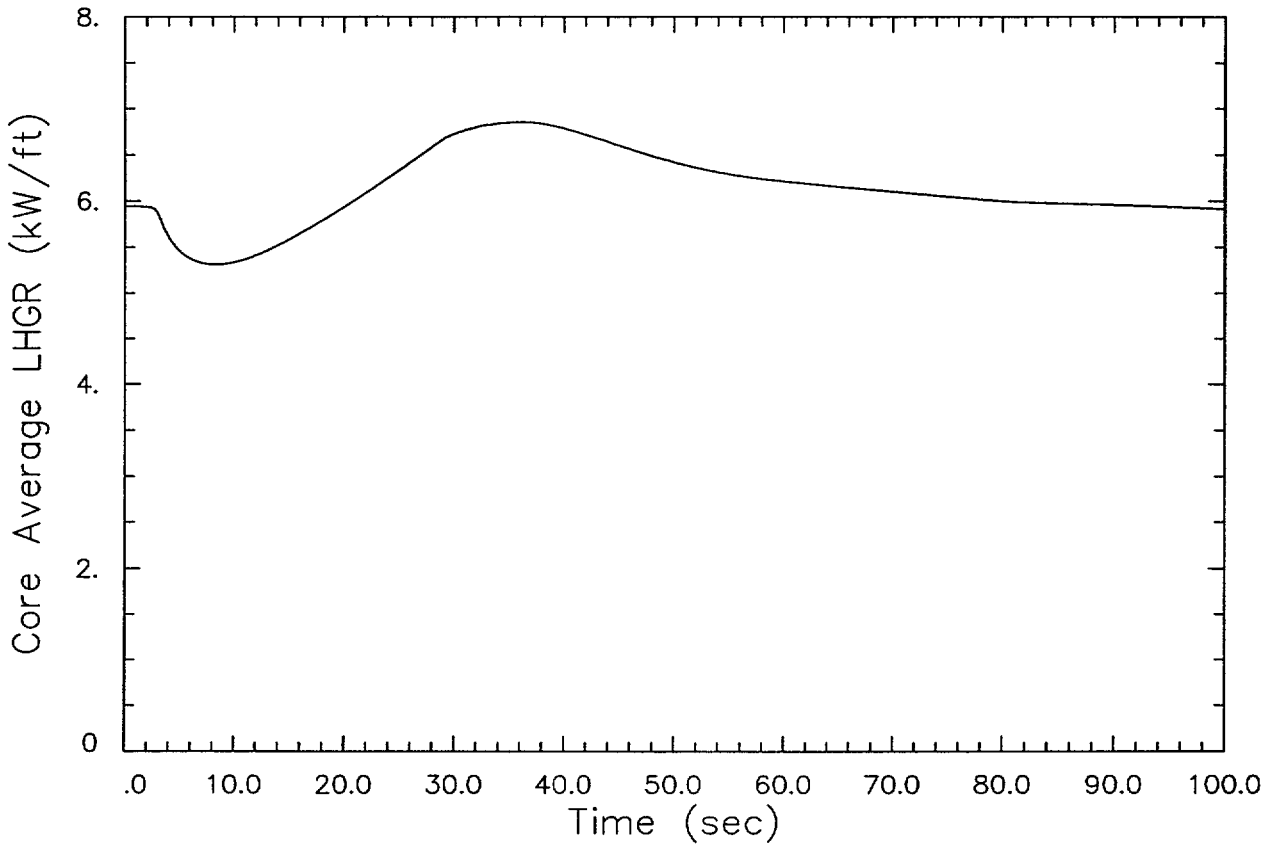

Figure 6.2.20-2 Core Average LHGR for Limiting Dropped Rod Case

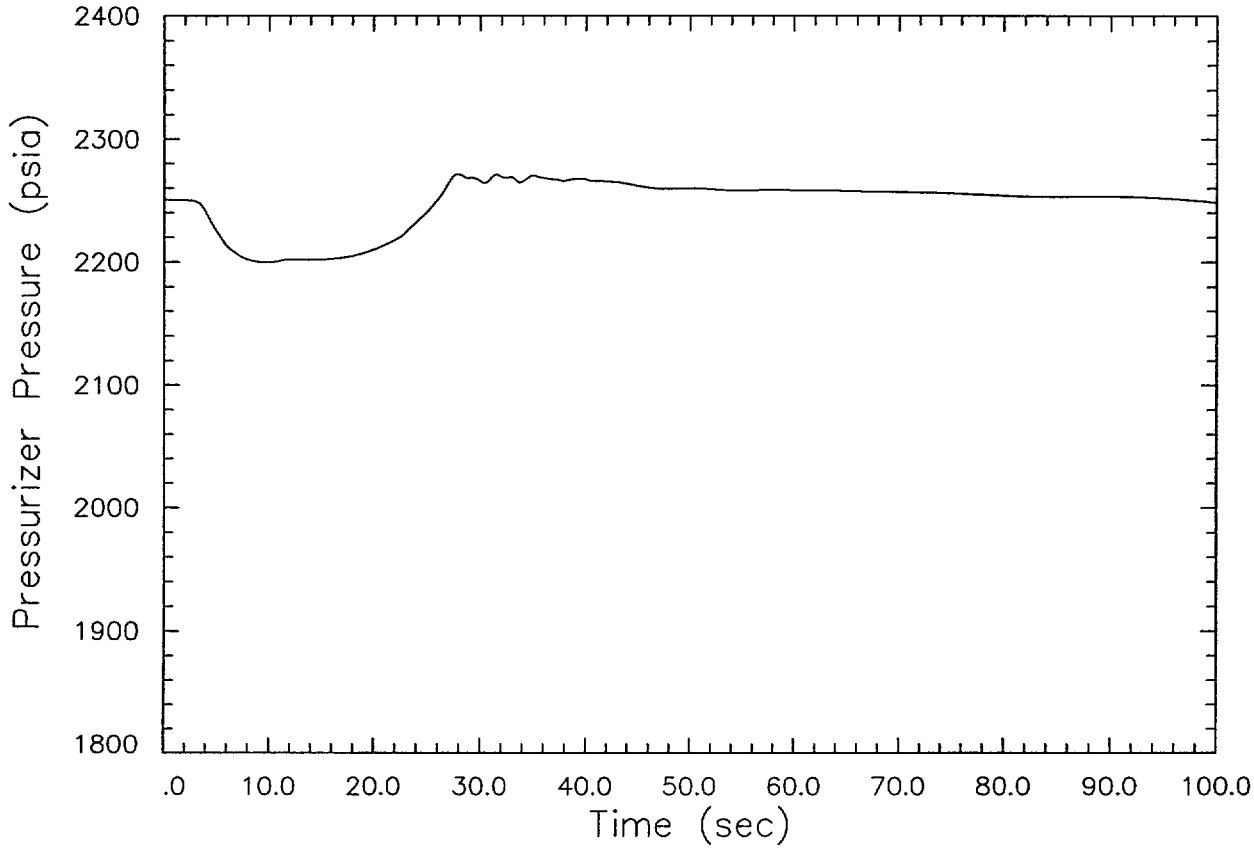

Figure 6.2.20-3 Pressurizer Pressure for Limiting Dropped Rod Case

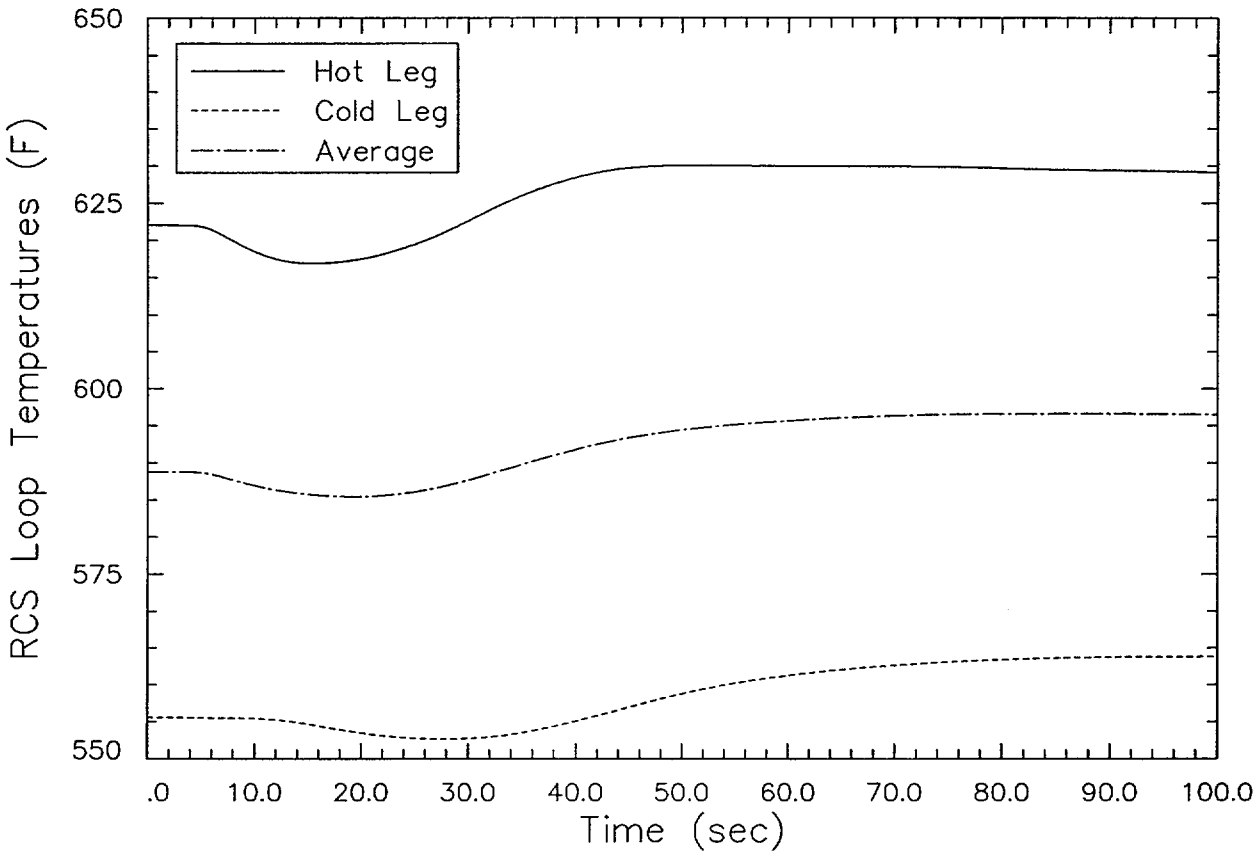

Figure 6.2.20-4 Primary System Temperature for Limiting Dropped Rod Case

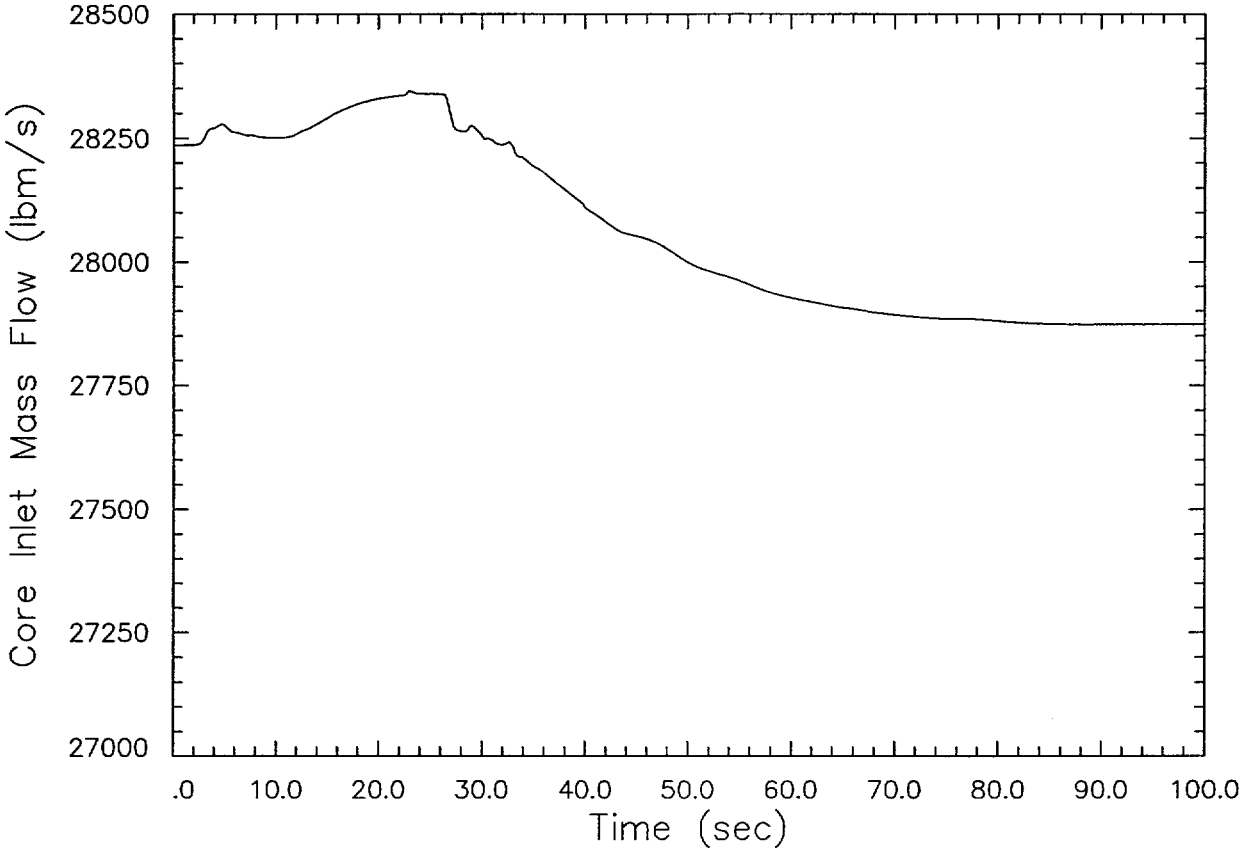

Figure 6.2.20-5 Core Inlet Flow for Limiting Dropped Rod Case

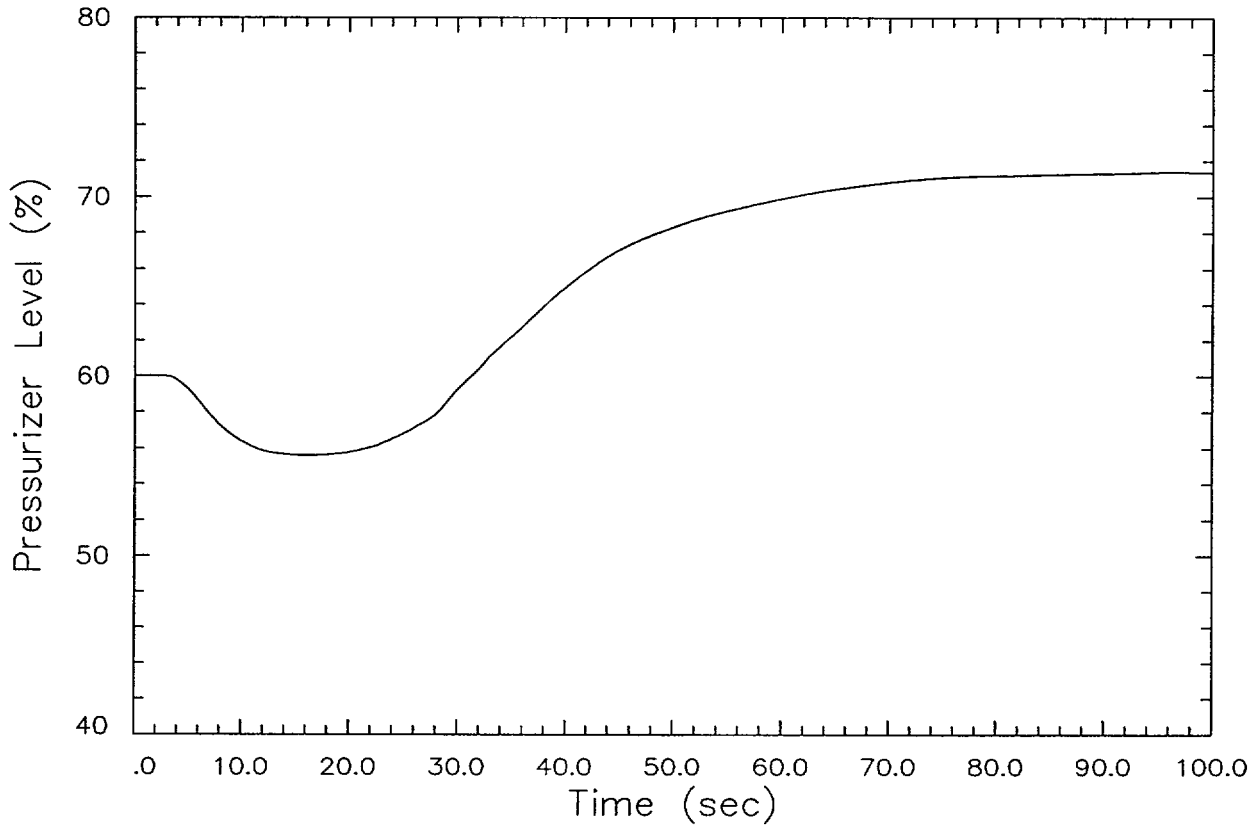

Figure 6.2.20-6 Pressurizer Level for Limiting Dropped Rod Case

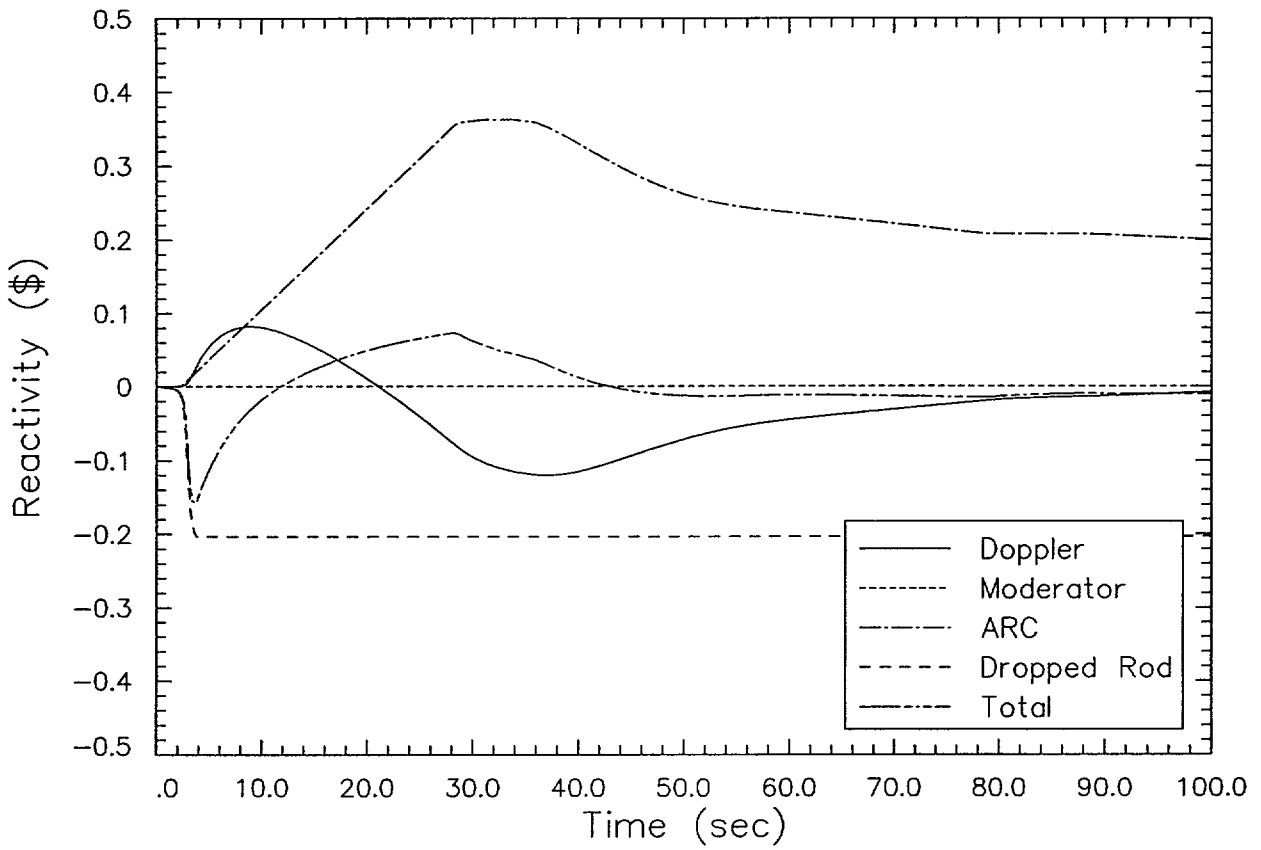

Figure 6.2.20-7 Reactivities for Limiting Dropped Rod Case

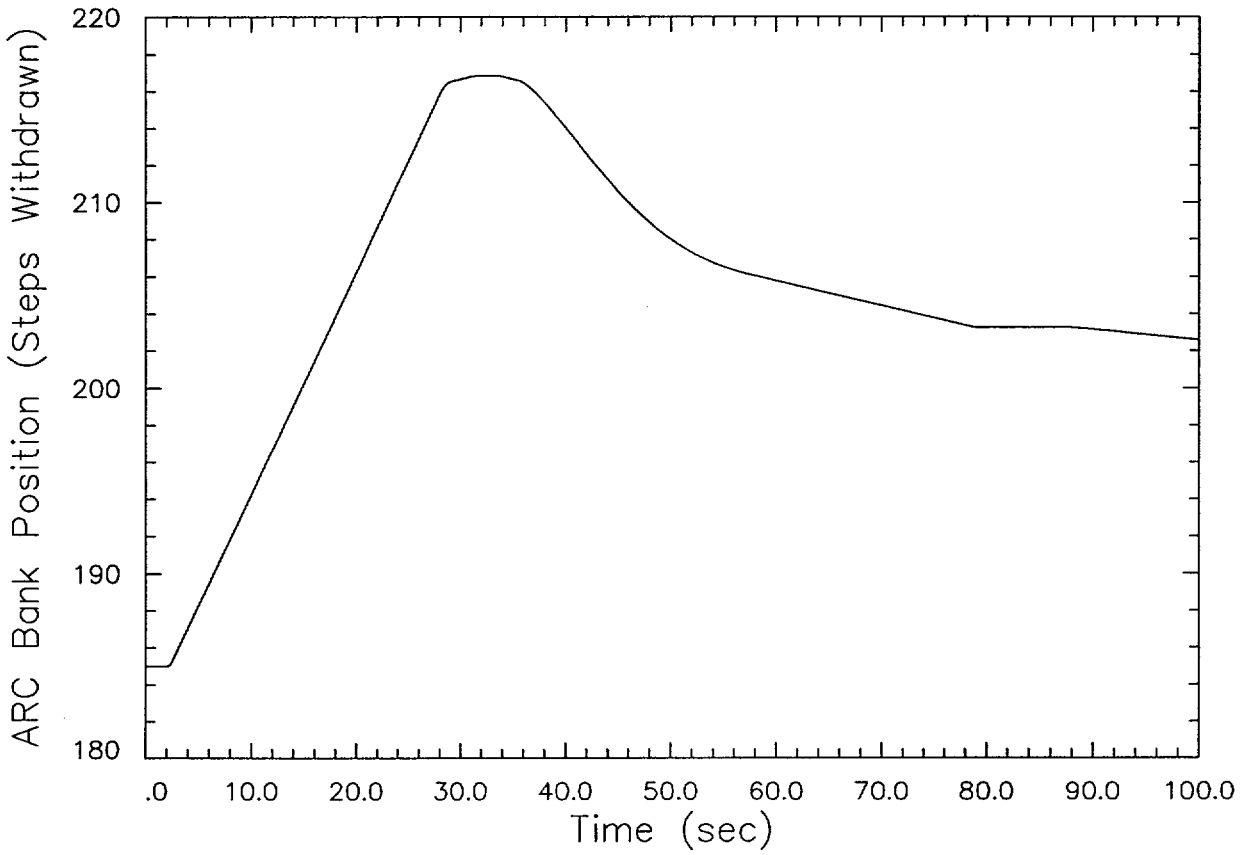

Figure 6.2.20-8 Rod Position for Limiting Dropped Rod Case

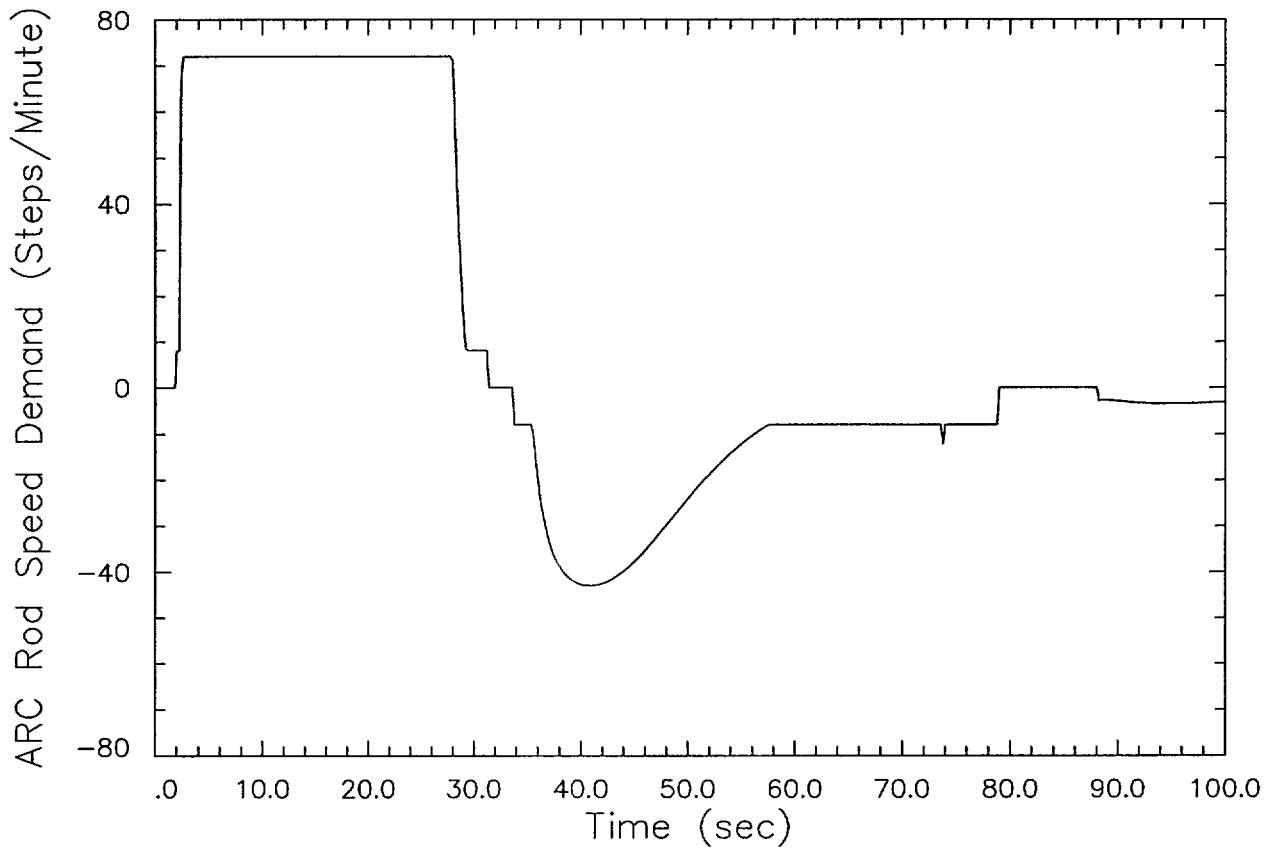

Figure 6.2.20-9 Rod Speed for Limiting Dropped Rod Case

6.2.21 Startup of an Inactive RCP at an Incorrect Temperature (FSAR Event 15.4.4)

6.2.21.1 Identification of Causes and Accident Description

This event is initiated by the startup of an inactive reactor coolant pump. The startup of an inactive reactor coolant pump from an at power configuration assumes N-1 loop operation. If this were the case, there would be reverse flow through the inactive loop due to the pressure difference from the loops with pumps in operation. Assuming that the secondary side of the steam generator in the inactive loop is not isolated, there would be a temperature drop through the steam generator and, with the reverse flow, the hot leg temperature of the inactive loop would be lower than the reactor core inlet temperature. The concern then is that the inadvertent actuation of an inactive pump would result in a decrease in the reactor core inlet temperature, which in the presence of a negative moderator coefficient, would cause an increase in core reactivity with a resultant increase in core power level.

No single active failure will adversely affect the consequences of the event.

6.2.21.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Modes 1 and 2: The event is incredible in these modes because the Plant Technical Specifications require that three reactor coolant pumps operate in Modes 1 and 2.

Modes 3 through 6: In these modes, the reactor is subcritical and there is no significant load on the plant. The potential for a significant reactivity excursion is nil. Even low levels of backflow through the inactive loop will preclude a static condition in which significant cooling of the inactive loop water inventory might occur, and the primary system will remain essentially isothermal. The consequences of the event in these modes are bounded by those of Event 15.4.1.

6.2.21.3 Acceptance Criteria

The Startup of an Inactive RCP at an Incorrect Temperature event is classified as a Condition II event. The acceptance criteria for this event are the same as those listed for the Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Startup Condition event in Section 6.2.18.3.

6.2.21.4 Results

The Startup of an Inactive Reactor Coolant Pump at an incorrect Temperature for Modes 1 and 2 is not credible due to Technical Specification requirements. The consequences of the event in Modes 3-6 are bounded by those of Event 15.4.1.

6.2.21.5 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.21.6 References

None.

6.2.22 Malfunction or Failure of the Flow Controller in a BWR Loop that Results in an Increased Reactor Coolant Flow Rate (FSAR Event 15.4.5)

There are no flow controllers on the RCS at the Harris Nuclear Plant. Therefore, this event is not credible.

6.2.23 CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant (FSAR Event 15.4.6)

6.2.23.1 Identification of Causes and Accident Description

A boron dilution event can occur when primary grade water is added to the reactor coolant system via the Chemical Volume and Control System (CVCS), resulting in decreasing boron concentration in the reactor coolant system. The dilution of primary system boron adds positive reactivity to the core. This event can lead to an erosion of shutdown margin for subcritical initial conditions, or a slow power excursion for at-power conditions. A boron dilution event can result from any of the following:

a) Resin sluice connection to the CVCS and Boron Thermal Regeneration System (BTRS) demineralizers.

b) Reactor makeup water connection to the BTRS.

c) Pumping water of unknown boron concentration from the recycle holdup tanks to the charging pump suction.

d) Reactor makeup water connection to the boric acid batching tank(s).

e) Operation of the BTRS in the dilution mode.

f) Malfunction of the CVCS reactor makeup control system.

All of the above items except e) and f) require the opening of normally closed local manual valves, some of which are normally locked closed.

The worst single active failure is malfunction of the reactor makeup water system flow indication so that actual flow is higher than indicated. The flow rates assumed in this analysis satisfy the single failure criteria.

6.2.23.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The reactivity insertion rate resulting from this event while in manual rod control is bounded by the range of reactivity insertion rates considered in the analysis of Event 15.4.2. The event is therefore bounded by the analysis of Event 15.4.2 with respect to SAFDLs.

Reactor protection is provided by the power range neutron flux trip, high and low setting, the OTΔT trip, the OPΔT trip, the source range flux trip, and the intermediate range flux trip.

The event will be analyzed to assess the adequacy of allowed operator response time s while in automatic rod control.

Modes 2 through 5: The event will be analyzed for each mode to assess the adequacy of allowed operator response times.

Mode 6: Administrative controls are in place at the Harris plant which preclude a boron dilution from occurring during refueling operation. These controls require that all valves that connect to systems which may inject unborated water to be locked in the closed position. Therefore, a boron dilution analysis is not required for Mode 6.

Based on the above evaluations, boron dilution during Modes 5 through 1 are analyzed. The purpose of the analysis is to demonstrate that sufficient time exists for the operator to determine the cause of dilution, isolate the primary grade water sources, and initiate reboration, before shutdown margin is lost. The specific requirements for each operational mode are listed below:

6.2.23.3 Acceptance Criteria

The Boron Dilution event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) During cold shutdown (Mode 5):

If operator action is required to terminate the transient, a minimum time interval of 15 minutes must be available between the time when an alarm announces an unplanned moderator dilution and the time of loss of shutdown margin.

(2) During hot shutdown, hot standby, startup, and power operation (Modes 4, 3, 2, and 1):

If operator action is required to terminate the transient, a minimum time interval of 15 minutes must be available from the time of initiation of the dilution and the time of loss of shutdown margin.

6.2.23.4 Results

The results of the boron dilution analysis show that there is adequate time for the operator to manually terminate the source of dilution flow during all modes of operation. Boron dilution during power operation is bounded by the analysis presented in Section 15.4.2.

6.2.23.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The results bound operation with the Model Delta 75 replacement steam generators at the uprated core power level of 2900 MWt as well as

operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.23.6 References

None.

6.2.24 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (FSAR Event 15.4.7)

6.2.24.1 Identification of Causes and Accident Description

Potential fuel and core loading errors include fabricating a fuel assembly with one or more pellets of improper enrichment or burnable poison characteristics and loading one or more fuel assemblies into improper core locations. These loading errors can result in severe changes in the core power distribution which may be undetectable by the incore instrumentation.

There is no single failure for this event, since no transient analysis is involved and no protective action required.

Fuel assembly loading errors are prevented by administrative procedures and controls implemented during fabrication. To reduce the probability of misloading assemblies within the core, each fuel assembly is marked with an identification number and loaded in accordance with a core loading diagram. During core loading, the identification number will be checked before each assembly is moved into the core. Core loading errors are unlikely as a result of these administrative procedures. The misloaded assembly event is analyzed for the unlikely situation in which assemblies are interchanged within the core. The misloading analyses include:

(1) Interchange of an exposed assembly with another exposed assembly

(2) Interchange of an exposed assembly with a fresh assembly

(3) Interchange of fresh assemblies with different enrichment and/or burnable absorber characteristics

Cycle operation with an improperly loaded core could result in core power distributions which are significantly more peaked than predicted. Misloadings which cannot be detected with plant instrumentation are evaluated to assess the challenge to SAFDLs.

6.2.24.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The event is analyzed to assess the challenge to SAFDLs.

Modes 2 through 6: In these modes, the reactor power is either very low or the reactor is in a subcritical state. The challenge to SAFDLs is therefore less than that in Mode 1. The event is bounded in theses modes by the Mode 1 event.

The analysis of the Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position is performed using the XCOBRA-IIIC computer code (References 1 and 2) and the XTGPWR computer code (Reference 3). Full power operation with the most severe peaking at any location resulting from undetected misloadings will be analyzed.

6.2.24.3 Acceptance Criteria

The Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position event is classified as a Condition III event. The acceptance criteria for this event are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) A small fraction of fuel failures may occur, but these fuel failures should not hinder core coolability.

(3) Radiological consequences should be a small fraction of the 10 CFR 100 guidelines (generally < 10%).

(4) The event should not generate a limiting fault or result in the consequential loss of the reactor coolant or containment barriers.

6.2.24.4 Results

The results of the analysis of the Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position event demonstrate that Condition III acceptance criteria are met, with the exception of the radiological consequences. The results of this analysis were provided for use in the analysis of the radiological dose consequences, which is documented in the BOP Licensing Report.

Less than 4% of the fuel is predicted to fail based on DNB criterion. Less than 2% of the fuel is predicted to fail based on fuel centerline melt criterion.

6.2.24.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions, with the exception of conclusions related to radiological consequences. The conclusions of the analysis of the radiological dose consequences are documented in the BOP Licensing Report. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.24.6 References

1. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

2. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

3. XN-CC-28(A) Revision 3, XTG: A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing, Exxon Nuclear Company, September 1975.

6.2.25. Spectrum of Control Rod Ejection Accidents (FSAR Event 15.4.8)

The analysis supporting the evaluation of the spectrum of control rod ejection accidents is provided in Section 6.1.5.

6.2.26 Inadvertent Operation of the Emergency Core Cooling System During Power Operation (FSAR Event 15.5.1)

6.2.26.1 Identification of Causes and Accident Description

FSAR Section 15.5.1 indicates that Inadvertent Operation of the Emergency Core Cooling System (IOECCS) could result from operator error or a false electrical actuation signal. Following the actuation signal, the suction of the charging pumps is re-aligned to the Refueling Water Storage Tank (RWST) from the Volume Control Tank (VCT). The valves isolating the Boron Injection Tank (BIT) from the charging pumps and the valves isolating the BIT from the injection header automatically open. The charging pumps then force concentrated boric acid from the RWST into the Reactor Coolant System (RCS). If a reactor trip does not occur coincident with safety injection actuation, the turbine throttle valves will open to offset the addition of negative reactivity from the Safety Injection System (SIS). The transient is eventually terminated by the reactor protection system due to low pressurizer pressure or manual trip. The time to trip is affected by the initial operating conditions including core burnup history that affects boron concentration, rate of change of boron concentration, and doppler and moderator coefficients.

The operator will determine if Safety Injection should be terminated. For spurious occurrence, the operator would stop the safety injection after ensuring satisfactory plant conditions per operating procedures and maintain the plant in hot standby conditions.

6.2.26.2 Description of Analysis

Although Steam Generator Replacement will increase T_{avg} relative to current operations, the analysis of record was performed prior to T_{avg} reduction (ie. at the targeted Post-SGR T_{avg}). Also, the other parameters identified in Westinghouse documentation of the analysis of record (eg. Reactor power, RCS Pressure, Calibration allowances, initial pressurizer conditions) were reviewed and determined to not be affected by SGR. Consequently, a re-analysis specific to Steam Generator Replacement was not performed.

6.2.26.3 Acceptance Criteria

FSAR Section 15.5.1.4 states that the IOECCS event has three acceptance criteria as follows:

1. The pressure in the reactor coolant and main steam systems should be maintained below 110% of design values.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 limit for PWRs.

3. An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

6.2.26.4 Results

FSAR Section 15.5.1.4 indicates that the acceptance criteria are not challenged by the IOECCS event. The reasons given are as follows:

Acceptance Criteria 1 and 3

The relief capacity of the pressurizer Safety Relief Valves (SRVs) far exceeds the required relief capacity resulting from the IOECCS event. If the pressurizer overfills, the SRVs are qualified to relieve water at conditions present in the pressurizer at the time of relief. Additionally, the pressurizer Power Operated Relief Valves (PORVs), although not completely safety-related, are anticipated to mitigate the event thereby minimizing the use of the SRVs. The pressurizer PORVs are qualified for water relief over a wide range of conditions.

Acceptance Criteria 2

DNBR actually increases as a result of the event.

6.2.26.5 Conclusions

The conditions used in the analysis of record, identified in various revisions of the FSAR, were reviewed for changes that might be required for Steam Generator Replacement conditions. No changes to these conditions were identified. Since the Steam Generator Replacement activity does not change the significant conditions affecting the IOECCS event, the analysis of record continues to meet the acceptance criteria.

6.2.27 CVCS Malfunction that Increases Reactor Coolant Inventory (FSAR Event 15.5.2)

6.2.27.1 Identification of Causes and Accident Description

This event is initiated by an operator error or an erroneous electrical signal, resulting in the inadvertent operation of the charging system pumps. If the letdown system is not operating, this leads to an increase in the primary system coolant inventory and, potentially, an overpressurization of the primary system and/or a dilution of the primary system boron concentration (if unborated water is added).

6.2.27.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Modes 1, 2, and 3: The potential for water relief through the pressurizer safety relief valves is addressed in Event 15.5.1. The challenge to SAFDLs is addressed in Event 15.4.6. Pressure relief and safety valve operability requirements are the same for Modes 2 and 3 as for Mode 1. The event is thus bounded by the Mode 1 Events 15.5.1 and 15.4.6.

Modes 4, 5, and 6 (with vessel head in place): At least one PORV (or RCS vent) is available below 325 °F and provides adequate relief capacity at setpoint pressure equal to or less than 465 psia. If the PORV is relied upon to provide the necessary vessel overpressurization protection, the PORV block valve is required to be open, ensuring the availability of PORV relief. Vessel pressure will not approach the pressurizer safety relief valve setpoint with the low temperature overpressure protection available. The event does not challenge the acceptance criterion in these modes.

Mode 6 (vessel head not in place): The reactor vessel is not sealed, so that vessel pressure cannot reach the safety valve setpoint. The Mode 6 event is thus bounded by the Mode 1 event.

6.2.27.3 Acceptance Criteria

The CVCS Malfunction that Increases Reactor Coolant Inventory event is classified as a Condition II event. Consistent with the current basis, the acceptance criteria for this event are:

(1) The pressure in the reactor coolant and main steam systems should be maintained below 110% of design values.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for PWRs.

(3) An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently.

Also, the acceptance criteria includes those listed for the CVCS Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant event in Section 6.2.23.3.

6.2.27.4 Results

The CVCS Malfunction that Increases Reactor Coolant Inventory (Event 15.5.2) is bounded in Modes 1 through 3 by Events 15.5.1 and 15.4.6, and need not be further analyzed. The event in Modes 4 through 6 (with the vessel head in place) does not challenge the acceptance criteria. The event in Mode 6 (with the vessel head not in place) is bounded by Mode 1.

6.2.27.5 Conclusions

The results for SGR/Uprating conditions are consistent with the current licensing basis. This conclusion also applies to the conditions corresponding to the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt.

6.2.27.6 References

None.

6.2.28 Inadvertent Opening of a Pressurizer Pressure Safety or Power Operated Relief Valve (FSAR Event 15.6.1)

6.2.28.1 Identification of Causes and Accident Description

This event is initiated by the inadvertent opening of a pressurizer PORV or safety valve, which results in the blowdown of primary coolant as steam through the faulted valve. The primary system pressure decreases rapidly until the pressurizer liquid is depleted, and then to a pressure determined by the hot leg saturation temperature. This event provides a challenge to the DNB SAFDL resulting from the depressurization that occurs prior to reactor scram.

No single active failure will adversely affect the consequences of the event.

6.2.28.2 Description of Analysis

The event is evaluated on a mode-by-mode basis.

Mode 1: The event is analyzed from rated power conditions to assess the challenge to the DNB SAFDL resulting from system depressurization. Because no significant power increase will occur, there is no threat to the fuel centerline melt limit. Vessel pressurization is not a concern because this is a depressurization event.

Reactor protection is afforded by the low pressurizer pressure trip, high pressurizer water level trip, and the OTΔT trip.

Modes 2 through 6: The event poses no significant challenge to SAFDLs in these modes, due to very low or zero operating power level. The consequences are bounded by those of the Mode 1 event.

Based on the above evaluations, this event is a depressurization of the primary coolant system. No pressurization criteria need therefore be addressed. The analysis utilized a steam flow rate from the pressurizer equivalent to the maximum flow capacity for one pressurizer safety valve.
The transient response of the reactor system is calculated using the ANF-RELAP computer program (Reference 1). The core thermal hydraulic boundary conditions from the ANF-RELAP calculation are used as input to the XCOBRA-IIIC code to predict the MDNBR for the event (References 2 and 3). The input parameters and biasing for the analysis of this event were consistent with the approved methodology.

6.2.28.3 Acceptance Criteria

The Inadvertent Opening of a Pressurizer Pressure Safety or Power Operated Relief Valve event is classified as a Condition II event. Consistent with the current licensing basis, the acceptance criteria for this event are:

(1) The pressures in the reactor coolant and main steam systems should be less than 110% of design values.

(2) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded. This is demonstrated by assuring that the minimum calculated departure from nucleate boiling ratio (DNBR) is not less than the applicable limits of the DNBR correlation being used and that fuel centerline melt does not occur.

(3) The event should not generate a more serious plant condition without other faults occurring independently.

(4) For transients of moderate frequency in combination with a single failure, no loss of function of any fission product barrier, other than fuel element cladding, shall occur. Core geometry is maintained in such a way that there is no loss of core cooling capability and control rod insertability is maintained.

6.2.28.4 Results

The results of the analysis demonstrate that the event acceptance criteria are met. The predicted MDNBR is greater than the safety limit. The critical heat flux correlation limit ensures that, with 95% probability and 95% confidence, DNB is not expected to occur; therefore, no fuel is expected to fail. The fuel centerline melt threshold is not penetrated during this event.

The sequence of events is given in Table 6.2.28-1. The responses to key system variables are given in Figure 6.2.28-1 to Figure 6.2.28-7.

6.2.28.5 Conclusions

Consistent with the current licensing basis, the results demonstrate that the acceptance criteria for this event are met for SGR/Uprating conditions. The analysis for this event supports operation with the Model Delta 75 replacement steam generators at core power of 2900 MWt with nominal primary T_{avg} at full power from 580.8°F to 588.8°F for steam generator tube plugging from 0% to 3%. The analysis also bounds operation with the Model Delta 75 replacement steam generators at the currently licensed core power of 2775 MWt with nominal primary T_{avg} at full power from 572°F to 588.8°F for steam generator tube plugging from 0% to 10%.

6.2.28.6 References

1. EMF-89-151(P)(A), ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, Advanced Nuclear Fuels Corporation, May 1992.

2. XN-NF-82-21(P)(A) Revision 1, Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, Exxon Nuclear Company, September 1983.

3. XN-75-21(P)(A) Revision 2, XCOBRA-IIIC: A Computer Code to Determine the Distribution of Coolant During Steady State and Transient Core Operation, Exxon Nuclear Company, January 1986.

Table 6.2.28-1 Event Summary for Inadvertent Opening of a Pressurizer Safety Valve or PORV

Event	Time (s)
Initiate transient (pressurizer SRV opens)	0.0
Low pressurizer pressure reactor trip signal	24.45
Turbine trip	24.50
Maximum core-average heat flux	24.70
MDNBR	24.70
Peak power	24.80
Scram initiated	24.82
MSSVs open	30.00
Peak SG pressure	32.00

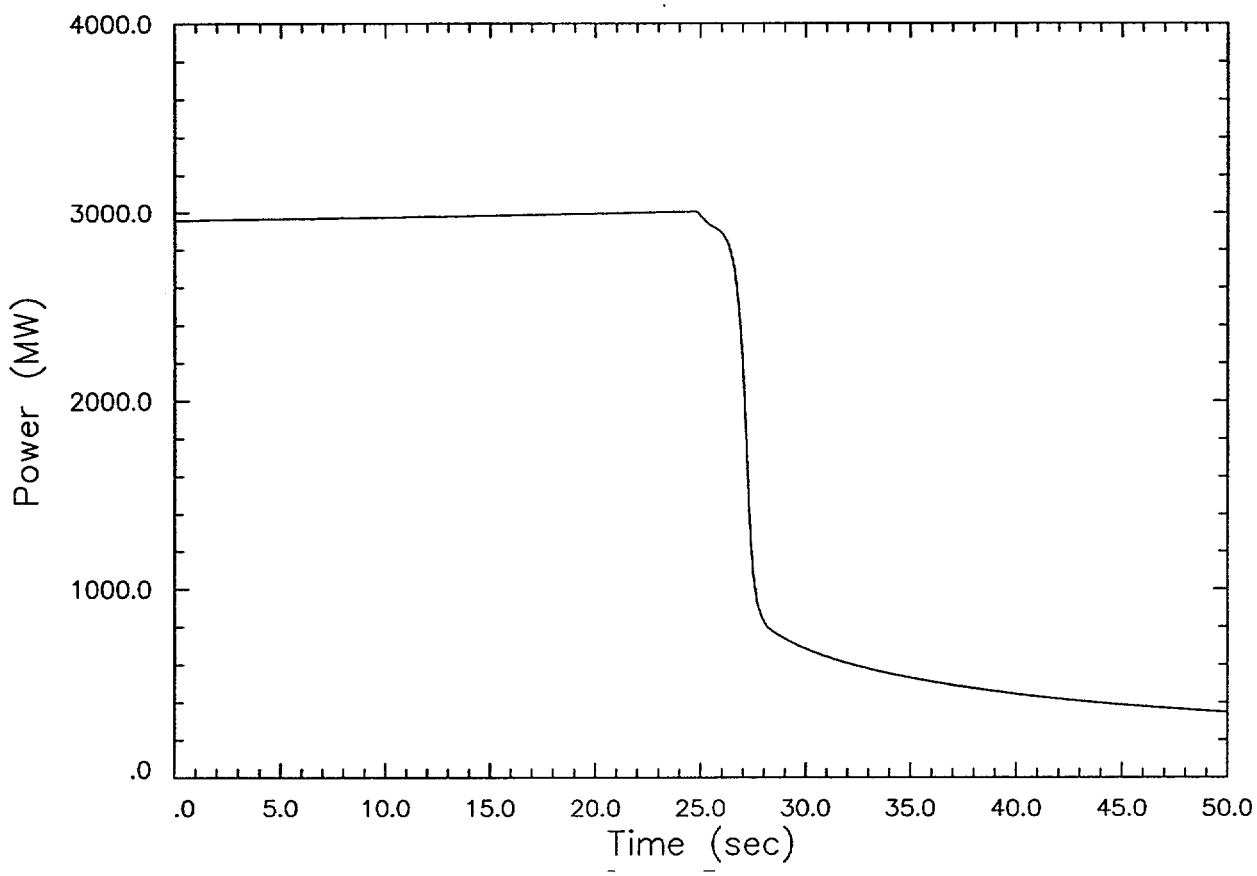

Figure 6.2.28-1 Reactor Power for Inadvertent Opening of a Pressurizer Safety or Power Operated Relief Valve

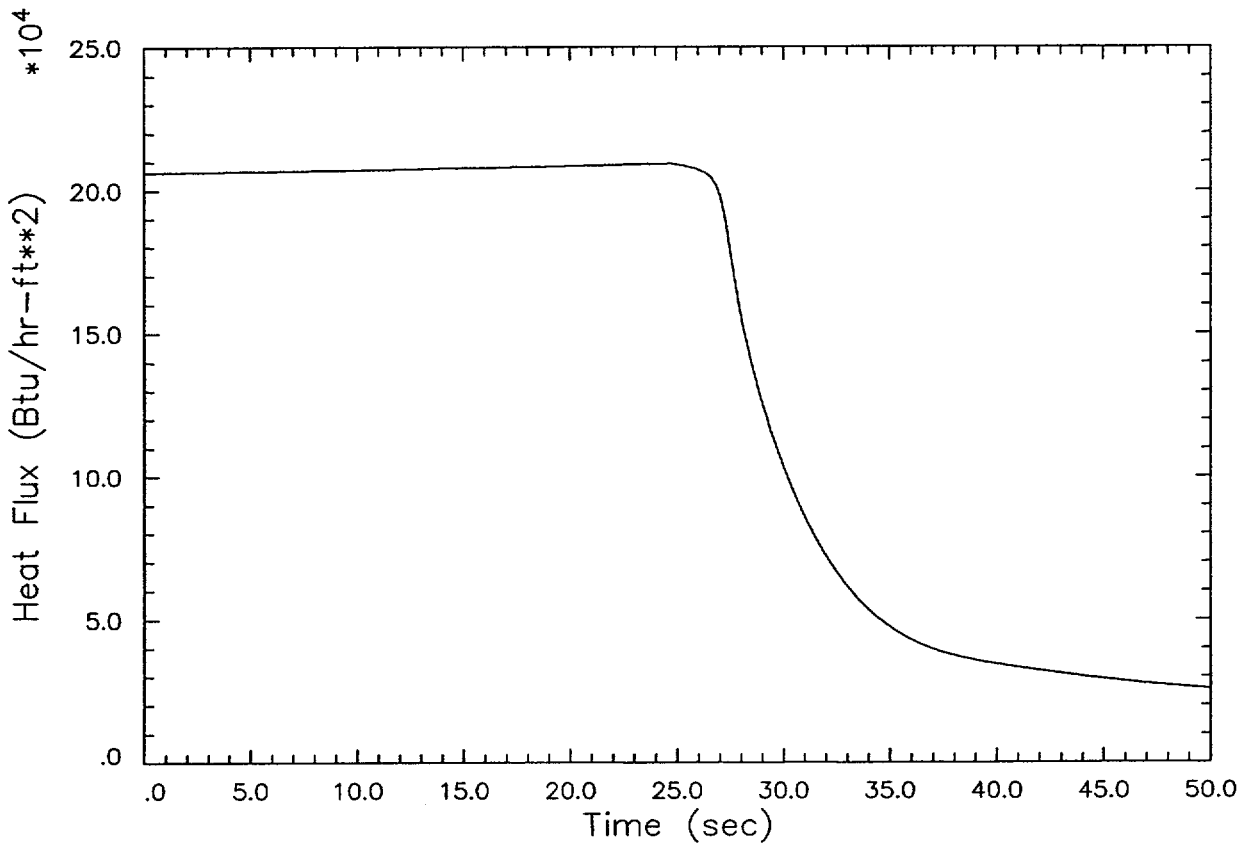

Figure 6.2.28-2 Core Average Heat Flux for Inadvertent Opening of a Pressurizer Safety or Power Operated Relief Valve

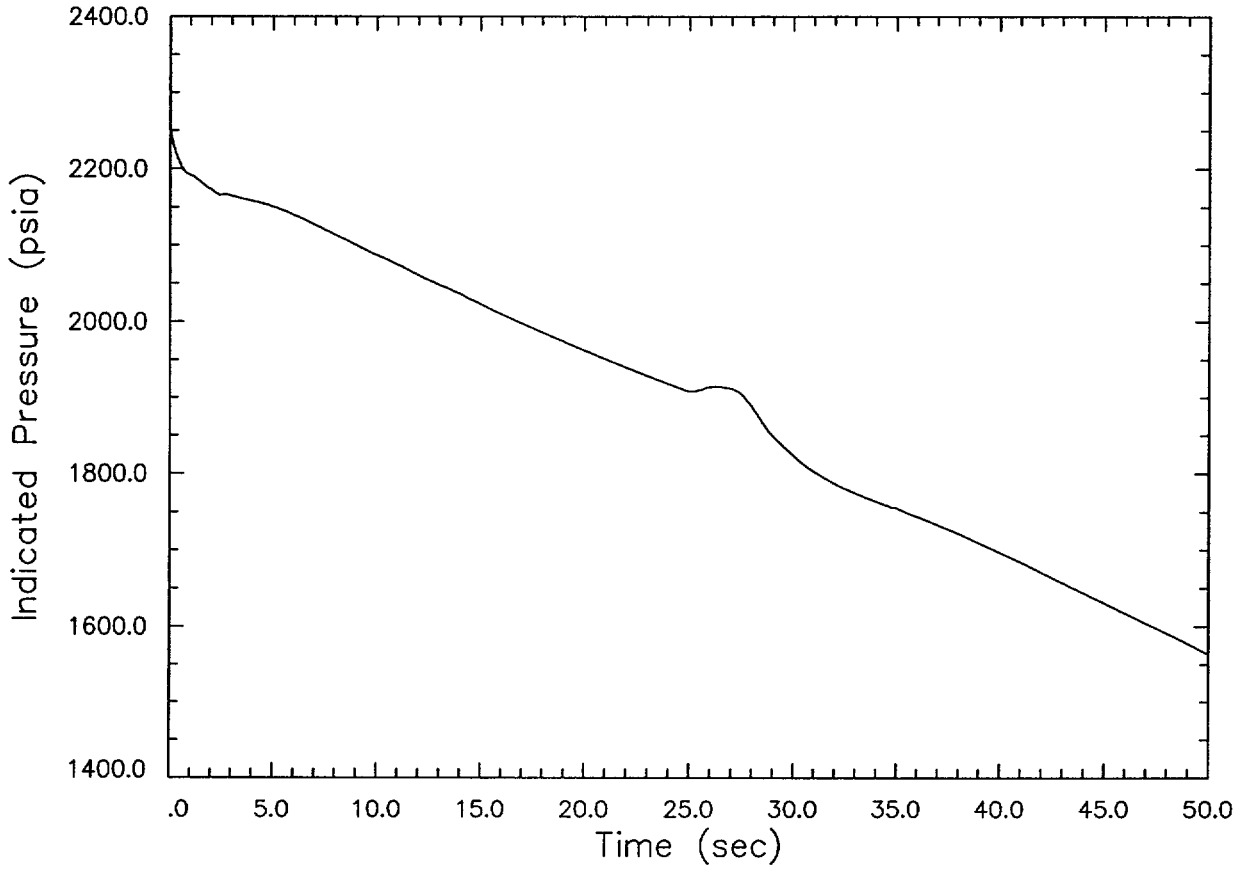

Figure 6.2.28-3 Pressurizer Pressure for Inadvertent Opening of a Pressurizer Safety or Power Operated Relief Valve

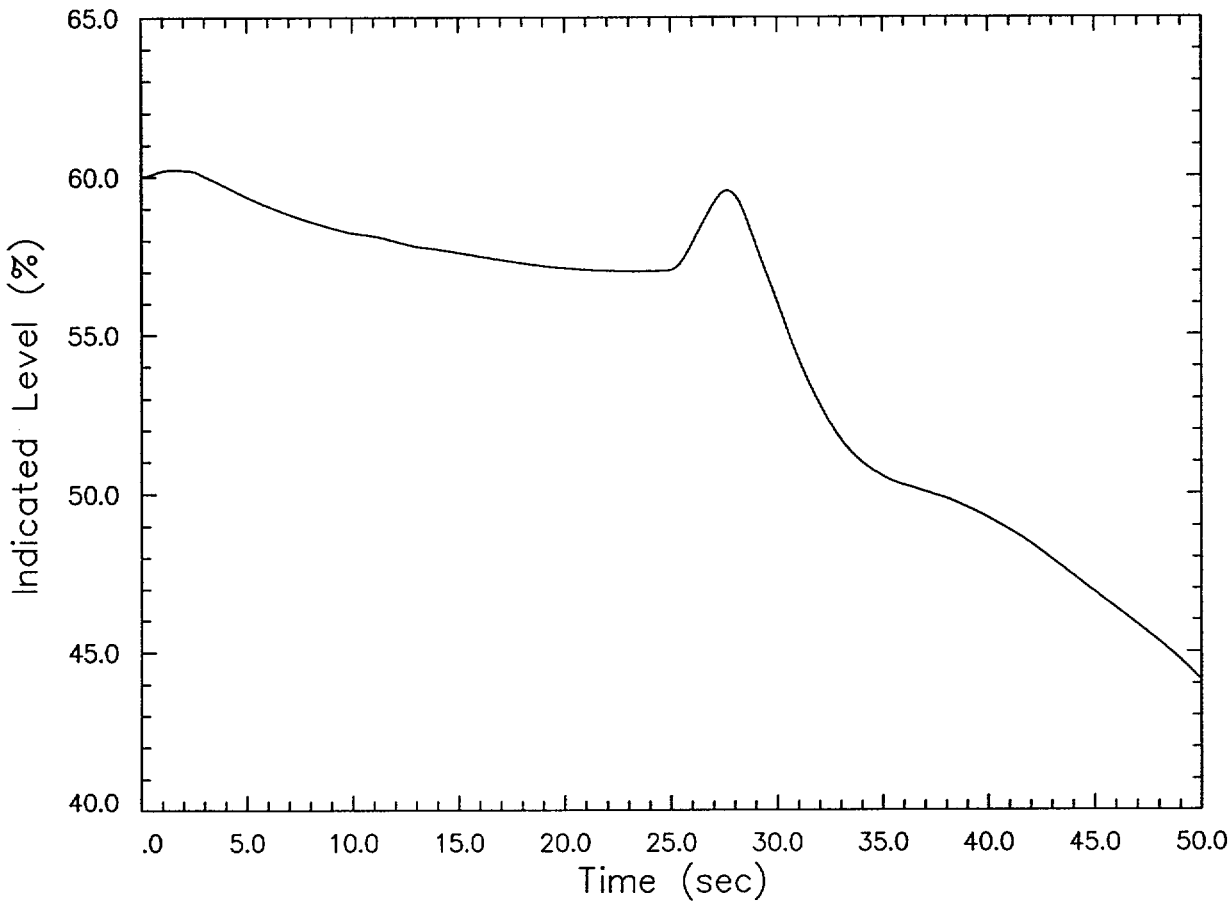

Figure 6.2.28-4 Pressurizer Level for Inadvertent Opening of a Pressurizer Safety or Power Operated Relief Valve

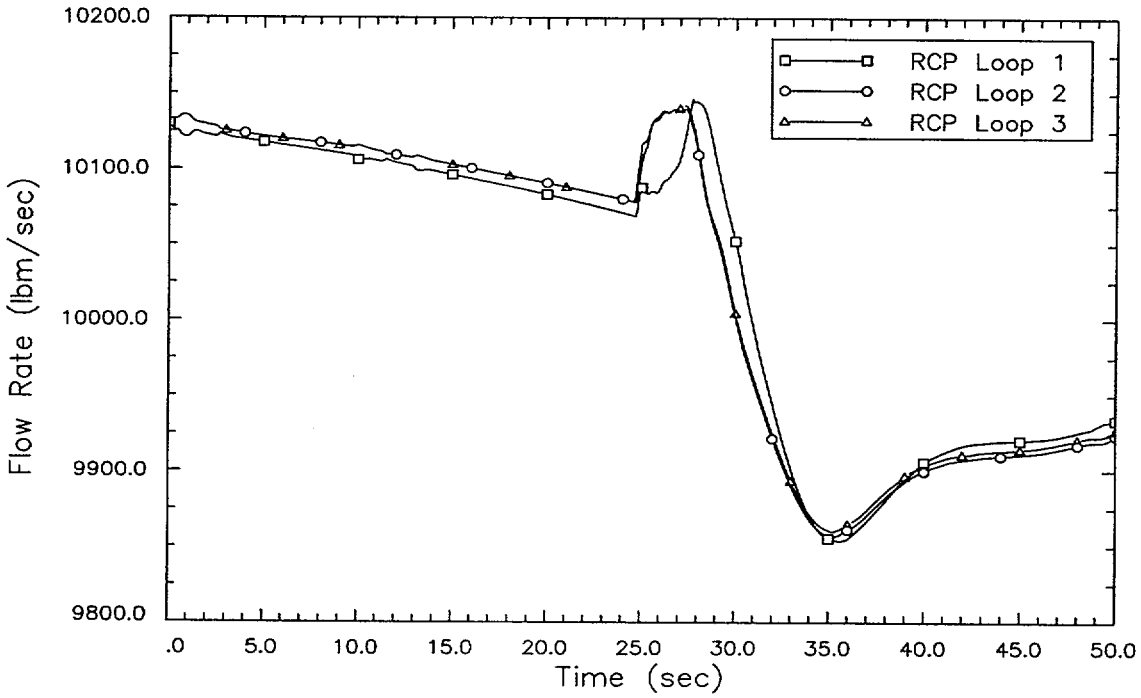

Figure 6.2.28-5 Reactor Coolant System Mass Flow Rate for Inadvertent Opening of a Pressurizer Safety or Power Operated Relief Valve

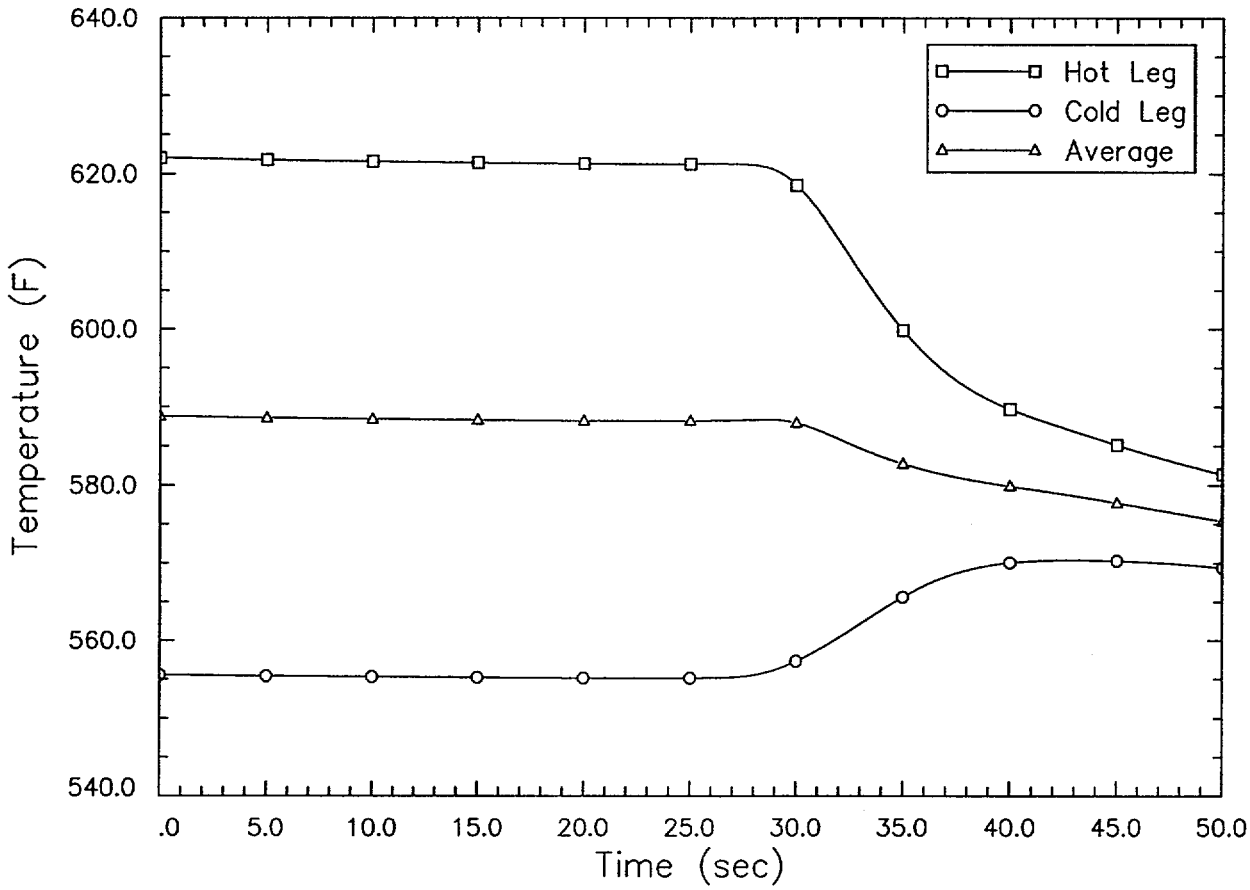

Figure 6.2.28-6 Primary System Temperatures for Inadvertent Opening of a Pressurizer Safety or Power Operated Relief Valve

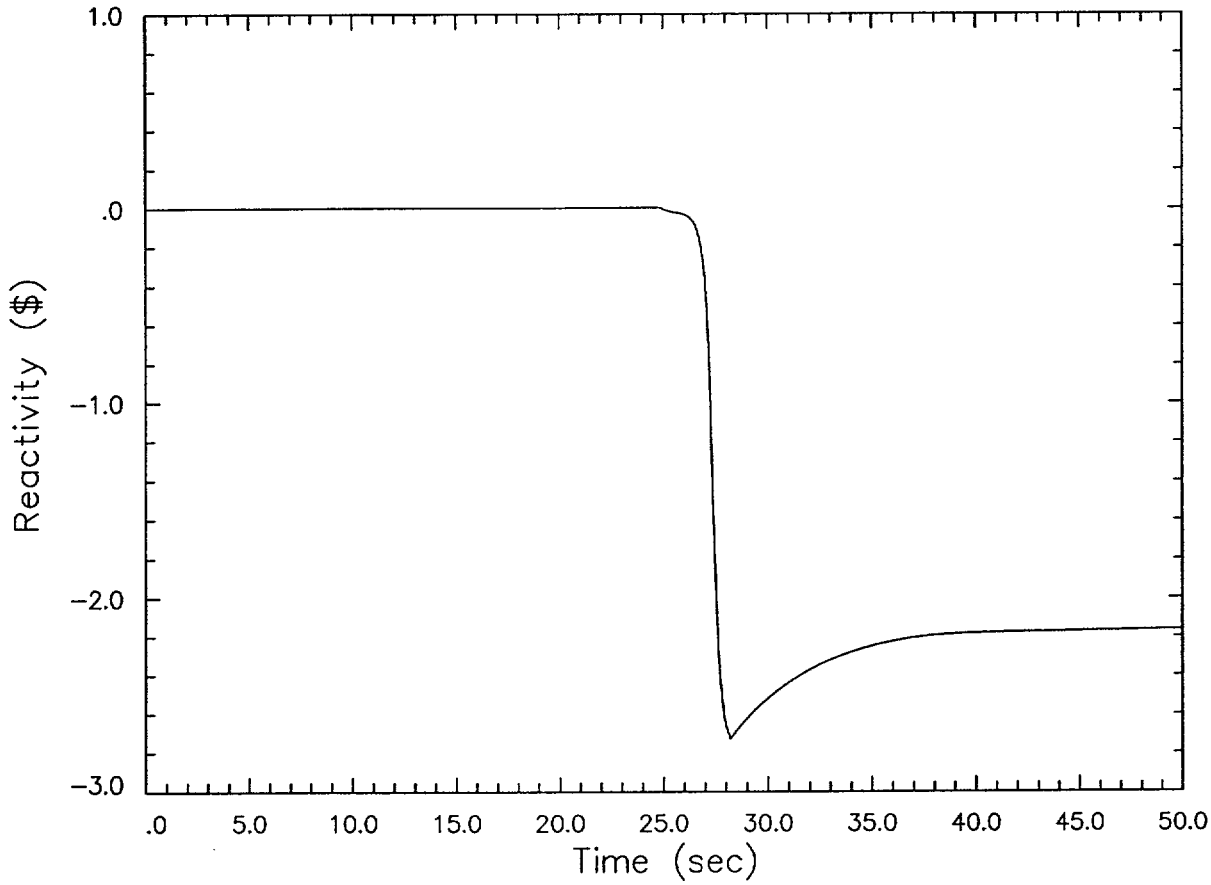

Figure 6.2.28-7 Total Core Reactivity for Inadvertent Opening of a Pressurizer Safety or Power Operated Relief Valve

6.2.29 Radiological Consequences of a Break in Instrument Line or Other Line From Reactor Coolant Pressure Boundary that Penetrates Containment (FSAR Event 15.6.2)

Radiological consequences for this event are presented in BOP LR Section 2.22, Table 2.22-8.

6.2.30 Radiological Consequences of Steam Generator Tube Rupture (FSAR Event 15.6.3)

This event is described and evaluated in NSSS LR Section 6.3. Radiological consequences for this event are presented in NSSS LR Section 6.3.3, Tables 6.3.3-10 through 6.3.3-14.

6.2.31 Radiological Consequences of a Main Steam Line Failure Outside Containment-BWR (FSAR Event 15.6.4)

This event pertains to BWRs and is therefore not applicable to the Harris Nuclear Plant.

6.2.32 Loss of Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary (FSAR Event 15.6.5)

The analysis supporting the evaluation of the LBLOCA event is provided in Section 6.1.1. The analysis supporting the evaluation of the SBLOCA event is provided in Section 6.1.2.

6.2.33 Radioactive Waste Gas System Leak or Failure (FSAR Event 15.7.1)

Radiological consequences for this event are presented in BOP LR Sections 2.22, Table 2.22-11.

6.2.34 Liquid Waste System Leak or Failure (FSAR Event 15.7.2)

Radiological consequences for this event are presented in BOP LR Sections 2.22, Table 2.22-12.

6.2.35 Postulated Releases Due to Liquid Tank Failure (FSAR Event 15.7.3)

Radiological consequences for this event are presented in BOP LR Sections 2.22, Table 2.22-13.

6.2.36 Fuel Handling Accidents (FSAR Event 15.7.4)

Radiological consequences for this event are presented in BOP LR Sections 2.22, Table 2.22-14.

6.2.37 Spent Fuel Cask Drop Accidents (FSAR Event 15.7.5)

Radiological consequences for this event are presented in BOP LR Sections 2.22, Table 2.22-15.

6.2.38 Anticipated Transients Without Scram (FSAR Event 15.8)

This event is described and evaluated in NSSS LR Section 6.8.